Mathematical Characterization of Inorganic Salt Precipitation From the Reaction of CO$_2$ With Formation Brine and Its Application

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In the process of CO$_2$ enhanced oil recovery (CO$_2$-EOR), CO$_2$ interacts with formation brine containing high concentrations of scale-forming ions to produce inorganic salt precipitation, which blocks the rock pore throats, changes the characteristics of the reservoir, and thereby reduces the oil recovery rate. In this study, a series of experiments on the static reaction of CO$_2$–formation brine was conducted. The amounts of precipitation formed from the interaction of CO$_2$–formation brine under various conditions were tested. Using the PHREEQC software, the mathematical characterization formulas between the precipitation amount and various environmental factors (e.g., temperature, pressure difference, scale-forming ion concentration, and pH) were established. On this basis, a numerical simulation model of CO$_2$ flooding in a typical area of oil field C was established. The distribution of inorganic salt precipitation during continuous gas flooding was predicted, and the effect of inorganic salt precipitation on oil field recovery was analyzed.

Keywords: CO$_2$–formation brine, inorganic salt precipitation, mathematical characterization formula, numerical simulation, CO$_2$-EOR

INTRODUCTION

As indicated by relevant studies on CO$_2$ flooding for enhanced oil recovery (EOR), the injected CO$_2$ is involved in strong chemical reactions with the formation brine, and the generated precipitates block the rock pore throats and reduce the porosity and the permeability of the reservoir. This leads to significant changes in the physical properties of the formation rocks (Fischer et al., 2010; Zhao et al., 2010; Liu et al., 2012; Yu et al., 2012; Alam et al., 2014; Lu et al., 2016) and thereby lowers the oil recovery rate.

The laboratory experiment is the most commonly used method to investigate the CO$_2$–brine interaction. The research results by Wigand et al. (2008), Ketzer et al. (2009), Fischer et al. (2010), and Wandrey et al. (2011) are the most representative. Studies have shown that the reaction between CO$_2$ and formation brine is reversible, the equilibrium of which is affected by temperature, pressure, and the mineralization degree of the formation brine. Inorganic carbonate precipitates are formed in the case of over-equilibrium.

Upon dissolving in the formation brine, most CO$_2$ still exist in the form of free molecules, while only a small fraction of CO$_2$ combines with the formation brine to form carbonic acid (H$_2$CO$_3$).
Due to the dissociation of $\text{H}_2\text{CO}_3$, bicarbonate ($\text{HCO}_3^-$) and carbonate ($\text{CO}_3^{2-}$) ions are further generated, which then interact with scale-forming ions in the formation brine to produce inorganic carbonate precipitation (e.g., $\text{CaCO}_3$ and $\text{MgCO}_3$).

Sbai (2011) described the kinetic mechanism of solid particle suspension in porous media and suggested that these particles may cause clogging of the pores. Shiraki and Dunn (2000), Assayag et al. (2009), Bacci et al. (2010), and Luquot et al. (2012) conducted a series of $\text{CO}_2$ core displacement experiments under reservoir conditions. The experiments indicated that when $\text{CO}_2$ is injected into geological reservoirs, it reacts with the formation brine to form carbonates, and the precipitation of carbonates significantly affects the porosity and the permeability of the formation rocks.

Employing numerical simulation technology, Zeidouni (2009) simulated the carbonate precipitation phenomenon during the $\text{CO}_2$ flooding process and evaluated the impact of salt precipitation on oil field development. Yang et al. (2010) and Delshad et al. (2010) also conducted corresponding studies to simulate $\text{CO}_2$ distribution during the $\text{CO}_2$-EOR process.

At present, most studies are qualitative research studies that have not quantified the influencing factors of the precipitation amount. Based on previous research results, in this paper, the influences of various environmental factors (e.g., pressure difference, temperature, and scale-forming ion concentration) on precipitation formation from the reaction of $\text{CO}_2$ and brine were investigated quantitatively. Meanwhile, using the PHREEQC software, the effect of pH values was also simulated, and the corresponding exponential mathematical characterization formula was established via mathematical regression. On this basis, the Eclipse E300 module was used with the mathematical characterization formula to correct mathematical model parameters, optimize reservoir engineering parameters, simulate the distribution pattern of inorganic salt precipitation generated during the $\text{CO}_2$-EOR process in a block of oil field C, and determine the effect of precipitation on the oil field’s ultimate recovery rate.

### Determination of Precipitation Amount After the Interaction of $\text{CO}_2$ and Formation Brine

#### Experimental Method and Procedure

In this experiment, formation water, taken from three wells in a block of oil field C (the water properties are shown in Table 1), was used as the medium. Afterward, $\text{CO}_2$ was injected into a high-temperature and high-pressure reaction device (Figure 1) filled with 100 ml formation water until saturation was reached. Using the ISCO pump to raise the pressure of the device to the target pressure (8–16 MPa), it was put into the thermostat, and the pressure and the temperature (20–80°C) were kept stable and left to stand for 6 days. Subsequently, the pressure was released to atmospheric pressure and the system was left still for 1 day, followed by the determination of ion concentrations, precipitation composition, and precipitation amount.

#### Experimental Results

According to the principle of orthogonal experiment design, three brine samples with varied properties were employed for static experiments under different temperature (20, 30, 50, and 80°C) and pressure difference (8, 10, 12, and 16 MPa) conditions.

The concentrations of $\text{Ca}^{2+}$ in the initial formation brine and the liquid samples taken out of the system each time were determined by inductively coupled plasma emission spectrometry. By subtracting the $\text{Ca}^{2+}$ concentration in the initial formation brine from the $\text{Ca}^{2+}$ concentration of each liquid sample, the variation of the $\text{Ca}^{2+}$ concentration under different temperature and pressure conditions was obtained, which was then used to calculate the mass of $\text{CaCO}_3$ precipitation based on the molecular weight of the precipitate.

Since the experimental pressure was too high to measure the pH value of the solution, the PHREEQC software was applied to fit the experimental and the simulation results of the precipitation amount under different pH conditions to obtain a complete set of

| Sample | Ca (mg/L) | Mg (mg/L) | Ba (mg/L) | Sr (mg/L) |
|--------|-----------|-----------|-----------|-----------|
| 1      | 2,012     | 198       | 0.006     | 19.4      |
| 2      | 5,145     | 209       | 0.057     | 25.4      |
| 3      | 10,590    | 222       | 0.028     | 18.8      |
data. The experimental and the simulation results are shown in Table 2.

In order to confirm the presence of inorganic carbonate, the precipitates produced in the experiment were processed and tested for elemental composition (Figure 2). The main elements in the precipitates were C, O, and Ca and a small amount of Mg. The main inorganic salt precipitate produced by the reaction was CaCO$_3$, with the rest being CaCl$_2$ and MgCl$_2$. The ratio of the three precipitates (CaCO$_3$:CaCl$_2$:MgCl$_2$) was 10:0.25:1. The specific concentrations are shown in Table 3.

### PRECIPITATION FACTOR ANALYSIS AND MATHEMATICAL CHARACTERIZATION METHOD OF CO$_2$–FORMATION BRINE INTERACTION

**Analysis of Mechanism and Influencing Factors of Precipitation Formation From CO$_2$–Formation Brine Interaction**

**Reaction Mechanism**

The precipitation formation from CO$_2$–formation brine interaction can be described by the following chemical reactions:

1. $\text{Ca}^{2+} + 2\text{HCO}_3^- \leftrightarrow \text{CaCO}_3 + \text{H}^+ + \text{CO}_2$ (1)
2. $\text{Ca}^{2+} + 2\text{HCO}_3^- \leftrightarrow \text{CaCO}_3 + \text{H}_2\text{CO}_3$ (2)
3. $\text{Ca}^{2+} + \text{CO}_3^{2-} + \text{H}_2\text{O} \leftrightarrow \text{CaCO}_3 + \text{H}_2\text{O}$ (3)

The precipitation and the dissolution of inorganic salts is a chemical equilibrium process. According to the chemical equations, the reversible reactions are affected by the concentrations of $\text{HCO}_3^-$, $\text{CO}_3^{2-}$, $\text{Ca}^{2+}$, and $\text{H}^+$ in the solution. Therefore, the conversion form of the CO$_2$–brine system must be clarified first.

Gaseous CO$_2$ dissolves in brine and forms H$_2$CO$_3$:

$$\text{CO}_2 (g) + \text{H}_2\text{O} \leftrightarrow \text{H}_2\text{CO}_3 (aq)$$ (4)

H$_2$CO$_3$ then further ionizes:

$$\text{H}_2\text{CO}_3 \leftrightarrow \text{H}^+ + \text{HCO}_3^-$$ (5)

$$\text{HCO}_3^- \leftrightarrow \text{H}^+ + \text{CO}_3^{2-}$$ (6)

Based on Eqs (4–6), the following equations can be obtained:

$$K_{\text{CO}_2} = \frac{[\text{H}_2\text{CO}_3]}{P_{\text{CO}_2}}$$ (7)

$$K_1 = \frac{[\text{H}^+] + [\text{HCO}_3^-]}{[\text{H}_2\text{CO}_3]}$$ (8)

$$K_2 = \frac{[\text{H}^+] + [\text{CO}_3^{2-}]}{[\text{HCO}_3^-]}$$ (9)

### Table 2

| Sample | Temperature (°C) | Pressure difference (MPa) | pH value | Precipitation capacity (mg/L) |
|--------|------------------|----------------------------|----------|------------------------------|
| 1      | 20               | 8                          | 5.5      | 90                           |
| 2      | 20               | 8                          | 6.2      | 170                          |
| 3      | 20               | 8                          | 7        | 210                          |

(Continued)
TABLE 2 | Continued

| Sample | Temperature (°C) | Pressure difference (MPa) | pH value | Precipitation capacity (mg/L) |
|--------|-----------------|--------------------------|----------|-------------------------------|
| 20     | 16              | 490                      |          |                               |
| 20     | 18              | 650                      |          |                               |
| 30     | 16              | 280                      |          |                               |
| 50     | 16              | 190                      |          |                               |
| 80     | 16              | 40                       |          |                               |
| 3      | 20              | 8                        | 410      |                               |
| 20     | 10              | 720                      |          |                               |
| 20     | 12              | 790                      |          |                               |
| 30     | 16              | 920                      |          |                               |
| 50     | 16              | 750                      |          |                               |
| 80     | 16              | 370                      |          |                               |

$K_{CO_2}$ is the equilibrium constant for the dissolution of CO$_2$, while $K_1$ and $K_2$ are the equilibrium constants for H$_2$CO$_3$ dissociation and HCO$_3^-$ dissociation, respectively. The values in the square brackets represent the activity of each ion.

Under ambient temperature conditions, only H$_2$CO$_3$ exists in acidic (pH $< 4.5$) brine, while CO$_3^{2-}$ mainly exists in an alkaline (8.34 $<$ pH $< 12$) environment. As for neutral, weakly acidic, and weakly alkaline brine, the main species is HCO$_3^-$, without the presence of CO$_3^{2-}$. Moreover, this phenomenon is very weakly affected by temperature or fluid pressure (Zai-Hua and Dreybrodt, 2005).

The pH value of the formation brine used in this study is 6.2 at normal temperature and pressure. Thus, the ionization of Eq. 6 would not proceed. Therefore, it can be determined that the precipitation mechanism of the CO$_2$–formation brine interaction is as described by reactions (1) and (2).

It is generally considered that as long as the ion product of CaCO$_3$ is greater than its solubility product, CaCO$_3$ will precipitate. However, in actuality, CaCO$_3$ will only precipitate and deposit when the supersaturated state is exceeded. This is because CaCO$_3$ is a slightly soluble inorganic salt, and in its saturated solution, the supersaturation is often significantly greater than the solubility, causing the crystal nuclei to cease growing after nucleation. Therefore, only extremely high ion concentrations in the solution enable the growth and the precipitation of crystal nuclei.

Analysis of Influencing Factors

Influence of temperature

Figure 3 shows that temperature has a significant impact on the production of precipitation; the higher the temperature, the less precipitation there is. Moreover, the amount of precipitation is more sensitive to temperature when the scale ion content is high.

The phenomenon is evidently closely related to the solubility of the CO$_2$–formation brine system (i.e., temperature has a significant influence on H$_2$CO$_3$ formation from the dissolution of CO$_2$ in brine).

With a constant $P_{CO_2}$, $K_{CO_2}$ is inversely proportional to temperature. This is because temperature is inversely proportional to CO$_2$ solubility in brine, and the activity of H$_2$CO$_3$ decreases when temperature increases, leading to a lower HCO$_3^-$ concentration from its dissociation. Even if the chemical reaction rate increases upon temperature elevation (Shukla et al., 2010), the total amount of CaCO$_3$ precipitates will still decrease.

TABLE 3 | Elemental composition of the precipitates generated from CO$_2$–formation brine interaction.

| Element | Concentration (m) | Unit |
|---------|------------------|------|
| C       | 10.08            | wt.% |
| O       | 44.87            | wt.% |
| Mg      | 1.91             | wt.% |
| Cl      | 7.56             | wt.% |
| Ca      | 34.57            | wt.% |
| Total   | 100.00           | wt.% |

FIGURE 2 | SEM images and energy spectrum of the precipitates.
**Influence of pressure difference**

A pressure increase does not lead to precipitation; conversely, precipitates appear upon lowering the pressure. This is because a higher pressure means a higher \( P_{CO_2} \), under a constant temperature. The activity of \( H_2CO_3 \) in the \( CO_2 \)--formation brine system improves with a higher \( P_{CO_2} \), which indirectly results in a higher activity of \( H^+ \) and thus increased acidity of the solution. Moreover, the solubility product of \( CaCO_3 \) is proportional to \( P_{CO_2} \). Thereby, even if the amount of \( CaCO_3 \) produced increases, it will only reach a saturated stable state without precipitation.

When the pressure starts to decrease, \( P_{CO_2} \) decreases, implying a lower solubility product of \( CaCO_3 \). Thus, \( CaCO_3 \) crystals grow and precipitate out of the solution.

**Influence of scale-forming ion concentration**

From Figure 5, we can see that the greater the scale ion content, the more sediment will be formed.

This is caused by the oversaturation of \( CaCO_3 \). The \( CaCO_3 \) saturation formula is:

\[
S_C = \frac{[Ca^{2+}][CO_3^{2-}]}{K_c}
\]  

(9)

where \( S_C \) is the saturation degree of \( CaCO_3 \), \( K_c \) is the activity product of \( CaCO_3 \), and the values inside the square brackets represent the activity of each ion.

The increased concentration of scale-forming ions implies a higher concentration of free \( Ca^{2+} \) ions, and the solution is highly supersaturated in terms of \( Ca^{2+} \), which results in higher nucleation and growth rate of \( CaCO_3 \) (Al Nasser and Al Salhi, 2014). According to formula (10), \( S_C \) increases, promoting the generation and the precipitation of \( CaCO_3 \). The activity of \( H^+ \) decreases rapidly with the increase of \( Ca^{2+} \) concentration, which is also very beneficial to the formation of \( CaCO_3 \).

It needs to be noted that in "Practical Aspects of CO2 Flooding," Perry and Charles (2002) pointed out that the salinity of the brine also affects the solubility of \( CO_2 \); specifically, the higher the salinity, the lower the solubility. However, in the current experiment, \( CO_2 \) dissolves in brine to form \( H_2CO_3 \), which then dissociates to generate \( HCO_3^- \). The \( HCO_3^- \) ions then react with the large amount of \( Ca^{2+} \) in the solution to form \( CaCO_3 \), which in turn causes more \( CO_2 \) to dissolve in brine and promotes the formation of more \( CaCO_3 \). The \( CaCO_3 \) generated will then precipitate after supersaturation is reached.

**Influence of pH**

Glenn and Reginald (2003) believes that the dissolution of \( CO_2 \) in formation brine from the formation fluids lowers the pH value of the formation brine and that \( CaCO_3 \), a weak acid salt, is greatly affected by the pH value, which is the main controlling factor of generation from \( H_2CO_3 \) dissociation. A higher pH value leads to increased \( HCO_3^- \) concentration and enhanced \( HCO_3^- \) activity and thereby an increase in the amount of \( CaCO_3 \).

**Mathematical Characterization Method of Precipitation Amount From CO2–Formation Brine Interaction**

According to Figures 4–6, the inorganic salt precipitation amount has an exponential relationship with temperature, pressure difference, and scale-forming ion concentration. The following mathematical formulas can be used:

\[
y = ae^{bx} \quad (11)
\]

Take the logarithm of both sides of (Eq. 11):

\[
lgy = lga + bx \quad (12)
\]

Assign \( Y \) as \( lgy \):

\[
Y = lga + bx \quad (13)
\]

Equation 13 is a linear equation where \( Y \) changes linearly with \( X \), and the data in Table 3 were substituted into Eq. 13 for linear regression. Each \( X \) value has a corresponding actual value \( Y_1 \) and predicted value \( Y_2 \). In order to minimize the square of the difference between the two values, set:

\[
Q(a, b) = \sum_{i=1}^{n} (Y_i - (aX_i + b))^2 \quad (14)
\]
Expand the brackets and take the average value:

\[ Q(a, b) = n\bar{Y}^2 - 2an\bar{X}\bar{Y} - 2bn\bar{Y} + a^2n\bar{X}^2 + 2abn\bar{X} + nb^2 \]  

(15)

By solving the partial derivatives of \( Q \) toward \( a \) and \( b \), respectively, and assigning 0 to the partial derivatives, the solution formulas of \( a \) and \( b \) were obtained:

\[ a = \frac{\bar{X}\bar{Y} - \bar{X}
\bar{Y}^2}{\bar{X}^2 - \bar{X}^2} \]  

(16)

\[ b = \frac{\bar{Y}}{\bar{X} - a\bar{X}} \]

As suggested by Table 4, the standard error is very small, indicating a high parameter accuracy. The corresponding \( P \)-value is less than 0.05–0.0001, and the confidence of the model is as high as 95–99.99%.

Therefore, the quantitative characterization equation of inorganic salt precipitation can be obtained:

\[ y = 2.30771e^{0.0000097M - 0.03435T + 0.0620371P + 0.667493pH} \]  

(10)
TABLE 5 | Model parameters.

| Parameter                          | Value                  |
|------------------------------------|------------------------|
| Crude oil viscosity (mPa's)        | 1.81                   |
| Reservoir temperature (°C)         | 80                     |
| Permeability (x 10^{-3} µm²)       | 0.2                    |
| Rock density (kg/m³)               | 2,500                  |
| Porosity (%)                       | 10                     |
| Dissolved gas-oil ratio (m³/m³)    | 43                     |
| Initial brine saturation           | 53%                    |
| Initial oil saturation             | 0.6                    |
| Reactant H₂O coefficient           | 1,280                  |
| Chemical reaction rate constant    | 5 x 10^{-6}            |

where $y$ is the precipitation amount (mg), $T$ is the temperature (°C), $P$ is the pressure difference (MPa), $M$ is the concentration of scale-forming ions (mg/L), and pH is the pH value of the solution.

ANALYSIS OF INFLUENCE OF PRECIPITATION FROM CO₂-FORMATION BRINE INTERACTION ON OIL FIELD DEVELOPMENT

Establishment of Reservoir Numerical Model Considering Inorganic Salt Precipitation

The reservoir in a block of oilfield C has an average porosity of 10.01% and a permeability of 0.3 mD. It is classified as an ultra-low permeability reservoir with an extremely low asphaltene concentration. The formation brine contains a high concentration of calcium ions (12,150 mg/L). The burial depth of
The reservoir is 2,700–2,900 m, with the formation temperature and pressure being 80°C and 21 MPa, respectively. Meanwhile, the comprehensive brine cut is 53%. The research block is a rhombic anti-nine-point well pattern with a water drive recovery factor of 35.4%, and there is a high permeability zone connecting the injection and the production well inside the well pattern. First, a suspended precipitation module was established, which simulated the precipitation formation with the production
well. Thereby, the precipitation amount generated by the CO$_2$–brine interaction could be directly output through the software. Then, the precipitation amount was fitted using Eq. 17 to obtain the key parameter: the reactant H$_2$O coefficient and the chemical reaction rate constant. On this basis, an adsorbed precipitation module was established for simulating the precipitation effect.

The CaCO$_3$ precipitation reaction is determined by the chemical reaction equation and the reaction rate. The chemical reaction equation is realized by adjusting the chemical reaction coefficient of the reactant and the product, and the specific process is as follows.

Chemical reaction equation:

$$\sum (S_{Ri} \cdot C_i) \rightarrow \sum (S_{Pi} \cdot C_i)$$  \hspace{1cm} (11)

$S_{Ri}$: reaction coefficient of reactant $C_i$

$S_{Pi}$: reaction coefficient of product $C_i$

Reaction rate:

$$R_r = V_b \cdot A_r \cdot \exp \left( -\frac{E_r}{RT} \right) \cdot \prod_{c_i} n_i$$  \hspace{1cm} (12)

$V_b$: rock pore volume

$A_r$: reaction rate constant

$E_r$: reaction energy

$R$: gas constant

$T$: temperature

$n_i$: component index

Suppose the initial solid saturation is 0 and the final output solid saturation is the resulting precipitation saturation, the effect of solid deposition on fluidity is obtained. Changes in fluidity can also reflect changes in permeability.

$$M_p^f = x_p^c \Delta k_i \Delta k_{rp} \cdot S_p \cdot \frac{b_{rp}}{\mu_p}$$  \hspace{1cm} (13)

$x_p^c$: molar fraction of components

$k_i$: fluidity multiplier in the presence of solids

$k_{rp}$: relative permeability of phase $p$

$S_p$: saturation of phase $p$

$b_{rp}$: molar density of phase $p$

$\mu_p$: viscosity of phase $p$

$k_r$: reduced mobility caused by solid adsorption blocking pore throat

The model parameters are shown in Table 5.

**Evaluation of the Influence of Inorganic Salt Precipitation on Development**

By simulating the production situation after 10 and 40 years, the inorganic salt precipitation distribution and its influence on the reservoir were obtained, as shown in Figure 6.

**Figure 6** displays the precipitation distribution in the reservoir after production. Upon CO$_2$ injection, precipitation first occurs near the high-permeability zone. After 10 years of production, precipitates are gradually formed in the area, with relatively high permeability. In the 40th year, the precipitates are widely distributed in a large area in the research block and reach a maximum value at the production well and its surrounding area. This precipitation trend is because CO$_2$ is first injected along the high-permeability zone where the fluid pressure is relatively high and the CO$_2$ solubility is large in brine. Then, the soluble bicarbonate [Ca(HCO$_3$)$_2$] is formed rapidly from the reaction of CO$_2$ and scale-forming ions in the formation brine. In the presence of a pressure difference in the formation, the reaction equilibrium shifts toward the direction of precipitation, thereby generating calcium carbonate precipitates. The pressure difference at the production well and its surrounding area is the largest, which explains the highest precipitation amount.

**Figure 7** shows the distribution of fluidity change in the reservoir at the 40th year of CO$_2$-EOR. The fluidity of the study block decreases generally. This is because, during gas flooding, the pressure in the formation decreases gradually, resulting in the gradual generation of precipitation, which blocks the pore throats and reduces the fluidity.

**Figure 8** illustrates the recovery rate change during the CO$_2$-EOR process with and without considering precipitation. As suggested by the figure, precipitation already has a great impact from the early stage of oil field development, which is mainly due to the rapid reaction of CO$_2$–brine. As the development continues, more and more precipitates are generated, blocking the pore throats and reducing the recovery rate. The recovery rate excluding the influence of precipitation was 46%, and it dropped by 7 to 39% when the influence of precipitation was considered.

**CONCLUSION**

(1) In this paper, based on the static CO$_2$–brine immersion experiment, the reaction laws of the CO$_2$–formation brine system under various pressure difference, temperature, and scale-forming ion concentration conditions were studied. A greater pressure difference led to a larger amount of precipitation, while a higher temperature favored a smaller precipitation amount. Meanwhile, under constant pressure and temperature, greater concentrations of scale-forming ions in the formation brine led to the formation of larger amounts of precipitation.

(2) Quantitative research was conducted on the precipitation amount, and the corresponding exponential mathematical characterization formula was obtained.

(3) According to the numerical model, upon CO$_2$ injection, precipitation first occurs near the injection well. As CO$_2$ continues to migrate to the production well, the corresponding area has the highest precipitation amount.

(4) By employing the modified numerical model, the oil recovery in a block of oil field C was predicted. The recovery rate considering precipitation was 39%, while that excluding the influence of precipitation was 46%, with the difference being 7%. The poor development of the oil field considering precipitation is due to the universal deposition of the precipitates generated from the CO$_2$–formation brine interaction in the reservoir.
DATA AVAILABILITY STATEMENT

The raw data supporting the conclusions of this article will be made available by the authors, without undue reservation.

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Conflicts of Interest: The authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

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