Numerical simulation of mineral precipitation in hydrocarbon reservoirs and wellbores

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A R T I C L E   I N F O

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Oil recovery

A B S T R A C T

Mineral precipitation or scale formation in reservoirs, injection, and production wells is recognized as an obstacle for hydrocarbon recovery. Significant production drops and injection losses can occur as a result of mineral precipitations during water flooding. Several attempts have been made to better understand the underlying mechanisms of mineral precipitation through experimental and numerical simulation studies. In this study, we have investigated the impact of mineral precipitation on oil recovery and injection performance of a synthetic reservoir through numerical simulations. Additionally, we studied the scaling (scale formation) tendency and precipitation amount of various minerals in wellbore based on water compositions from the Gulf of Mexico. We also studied the impact of mineral precipitation on water flooding efficiency by analyzing saturation profiles of the injected water. Our results indicate that the reservoir experiences severe damage with respect to ultimate recovery, and injectivity loss due to the scale formation. Water saturation profiles reveal that mineral precipitation in reservoirs not only leads to non-ideal displacement of the in-situ hydrocarbon, but also causes earlier water breakthrough. The results of mineral precipitation in wellbore show that while some minerals (e.g., calcite) precipitate in large amounts, other minerals (e.g., gypsum) remain in equilibrium with the flowing brine in wellbore under the same pressure and temperature conditions.

1. Introduction

Mineral precipitation or scale formation occurs when a brine becomes supersaturated with respect to one or multiple minerals [1]. It is a common issue in oil and gas recovery, and usually occurs during water flooding. It happens most often when the used water is a saline water that is compositionally different from the native brine within the formation [2,3]. However, it can happen in any offshore and onshore reservoirs where a flowing saline brine is in contact with material surfaces. For example, seawater is usually rich in anions (e.g., \( \text{SO}_4^{2−} \)) and carbonates, while formation waters are usually rich in cations (e.g., \( \text{Ba}^{2+} \), barium and \( \text{Ca}^{2+} \), calcium) [4]. Mixing these waters may lead to mineral precipitation such as barium sulfate (\( \text{BaSO}_4 \)) and calcium carbonate (\( \text{CaCO}_3 \)). Other types of scale minerals that have been observed in oil fields include calcium sulfate (\( \text{CaSO}_4 \)), strontium sulfate (\( \text{SrSO}_4 \)), zinc/lead, and iron sulfide scales [5]. Different parameters are known to affect mineral nucleation and precipitation, including temperature, pressure, injection rate, solubility, the physical and chemical properties of the medium, and concentration of ions [1].

Mineral nucleation and growth are highly affected by the scale (size) of medium in which they are studied. The scale varies from pore-scale to field-scale. At the pore-scale level, there are three main processes that inhibit mineral nucleation and growth, as per our prior work [1]: (i) nucleation is a stochastic process in which the random collisions of the ions lead to the formation of clusters of precipitates. In the smaller pores, the probability of these collisions is small due to the smaller number of ions present, (ii) the crystal growth is limited by the small size of the pore and there is a possibility that a supersaturated solution in larger pores could be undersaturated in smaller pores, and (iii) the pore surfaces play an important role in precipitation. For example, a favorable surface chemistry can promote the nucleation process [6]. In the case of scale formation in porous media, the corresponding formation damage is evaluated in terms of permeability reduction. Accurate models have been developed for predicting permeability reduction due to scale formation with a mean absolute error as small as 11.16% compared with the experimental observations [7].
The detailed descriptions of formation damage models have been reported in previous literature [8].

The impact of mineral precipitation on oil recovery can also be captured from a macroscopic standpoint. Mineral precipitation can significantly affect the success of a water flooding project. Field cases have shown that ignoring the scaling issue can lead to significant losses of injectivity and productivity and therefore, care should be taken before designing water flooding projects. An example is the Siri offshore oil field with four platforms located in the Persian Gulf [9]. The oil field was discovered in 1970, and the drilling process began in 1975. A total of 33 wells were drilled, from which 24 were chosen as producers, 7 selected as injectors, and 2 designated as producer/injector wells. Production began in 1978. The total amount of cumulative oil production after the primary production stage was 13 MMSTB, which was about 2.3% of the oil in place. The water flooding process started in 1984 with an initial injection rate of 9100 bbl/day. However, after six years of injection and production, the water injection rate decreased to only 2200 bbl/day (7000 bbl/day reduction) as a result of scale formation, and consequently, the water flooding project was terminated.

Another example is in a well in the North Sea at Miller Field. Oil production decreased from 30,000 bbl/day to zero within 24 h [10]. Extensive studies of scaling issue in the Iranian oil fields and production equipment resulting from incompatible water flooding projects have also shown that mineral precipitation can significantly affect injection-production performance. Experimental works on the samples of these fields have shown that permeability decreases up to 90% of the initial permeability depending on temperature, flow rate, injection period, initial permeability, and the solution's composition [9,11].

There is a large body of research on reactive transport and mineral precipitation (scale formation) [3,12–26]. In 1973, Pitzer et al. [27] proposed a model for activity coefficients based on ion interactions, which has been used as the base model for many other thermodynamic studies. Yuan et al. [28] used Pitzer's model to determine scale formation of strontium, barium, and calcium sulfates, accounting for the effects of pressure and temperature. Nasr-El-Din et al. [29] and Ahmed, S.J., 2004. [30] investigated the effect of scale formation on permeability impairment. Naseri et al. [31] studied the impact of composite BaSO$_4$-CaSO$_4$ scale deposition on permeability impairment, and concluded that the effect of temperature on scale formation in the composite BaSO$_4$-CaSO$_4$ case contrasts with its effect in a single BaSO$_4$ Duggirala et al. [32] studied CaCO$_3$ scale formation and control in continued digesters, and suggested that chemical control of particle growth, morphology, and agglomeration can dramatically prevent CaCO$_3$ scale formation. Xing et al. [33] studied CaCO$_3$ scale formation by conducting CaCO$_3$ fouling experiments, in addition to investigating the effect of ion concentration, and proposed that the fouling process is limited by mass diffusion. MacAdam et al. [34] reported that the factors in CaCO$_3$ scale formation are temperature, pH level, super-saturation level, and flow velocity.

BaSO$_4$ is known as one of the main minerals (scale types) that can precipitate in both porous media and wellbore. Once it precipitates and forms scales, its removal is very difficult due to its low solubility in most fluids and the low reactivity of most acids with BaSO$_4$ scale [35,36]. Therefore, care should be taken in scale formation prohibition prior to its crystallization and mineral precipitation by using squeeze inhibitors. Experimental tests on barite (BaSO$_4$) scale in both beamers and sand packs have shown that the permeability reduction is mainly influenced by the crystal growth of barite instead of flow blockage and particle transport. In addition, it has been observed that the first contact point of chemically incompatible brines consists of the highest amount of precipitation [37]. Core flooding tests by evaluating the amount of barite precipitation, using sulfate and barium profiles on the West Africa offshore reservoir samples at atmospheric pressure, ambient temperature, and constant injection rate, revealed that for seawater containing less sulfate, the scaling tendency tends to be reduced. These observations were verified by the results of SEM analysis [36]. We mainly focused on barite precipitation as opposed to other minerals in this study, since it can cause significant issues for hydrocarbon recovery as discussed later in this article.

Predictive models have been developed to estimate the possibility and amount of mineral precipitation (scale formation). For example, OSPMod was developed to predict scaling tendency based on kinetic and thermodynamic data. By determining the critical saturation indices, this model first predicts the possibility of scale formation, and then the amount of scale formation in terms of scale profiles as a function of time and location [38]. This model, however, is limited to the well and surface locations. In other words, this model is not able to model scaling in reservoirs. AGIPS is a finite difference numerical model that was developed through coupling a chemical equilibrium code with a fluid flow simulator. This model is able to capture the impact of temperature and incompatible injection on the scale formation issue in reservoirs and wells. It has been shown to be able to reproduce experimental measurements on different water compositions taken from the North African oil fields [39]. FROCKI is another predictive model through which the impact of rock-fluid interactions on permeability reduction during production and injection in oil fields has been investigated. In this model, the rock fluid interactions are related to changes in temperature, ionic strength, pH, and the hydromechanical processes within reservoir [40]. However, a comprehensive study on the effect on oil recovery as a result of scale disposition in formation has not yet been conducted [39,41–45].

The goal of this study is to fill that important gap by offering a better understanding of how mineral precipitation reactions affect reservoir injection performance, as well as oil recovery. We perform geochemical, flow, and transport simulations using CMG-GEM [46] to study mineral precipitation in a reservoir. We consider barite the main precipitating mineral to determine the impact of mineral precipitation on injection performance. A one-dimensional (1D) reservoir model is developed in which injection and production are performed at the same time, and the results are compared to a base case where there is no mineral precipitation considered and water flooding is simulated with an idealized distilled water. Then, we investigate the impact of mineral precipitation on the profile of water saturation during water flooding. Finally, we consider multiple mineral precipitations in wellbore, and the impact of injected seawater fraction on the saturation index of minerals and amount of precipitation in the Gulf of Mexico is studied. The models used in this study are uniquely able to model scale formation in reservoirs and wellbore, while capturing the interplay of important variables such as pressure and temperature.

As such, this work is a novel investigation of mineral precipitation and its impact on flow properties at the field scale. In particular, this comprehensive study provides an unprecedented quantitative evaluation of the negative impact of mineral precipitation on the reduction of the oil recovery factor and the inevitable increase in the bottom hole pressure of an injection well with a scaling issue in the reservoir. Further, this work quantifies the impact of mineral surface area on oil production and potential precipitation of various minerals in the wellbore of a Gulf Coast field, which is notably absent from previous literature.

2. Geochemical and reactive transport processes

Scale formation tendency is evaluated by using the saturation index (SI), which is defined as follows [1,47]:

$$SI = \log\left(\frac{\text{ion activity product (IAP)}}{K_{sp}}\right)$$  (1)

For example, barite dissolves and forms based on the following reaction:

$$\text{BaSO}_4 \rightleftharpoons \text{Ba}^{2+} + \text{SO}_4^{2-}$$  (2)
Thus, its saturation index would be:

\[
S_{\text{barite}} = \log \left[ \frac{(a_{\text{Ba}^{2+}})(a_{\text{SO}_4^{2-}})}{K_{\text{sp,barite}}} \right] = \log \left[ \frac{[\text{Ba}^{2+}][\text{SO}_4^{2-}]}{K_{\text{sp,barite}}} \right]
\]

(3)

In Eq. (3), \(a_{\text{Ba}^{2+}}\) and \(a_{\text{SO}_4^{2-}}\) represent the ionic activity of barium and sulfate, respectively, and \([\text{Ba}^{2+}]\) and \([\text{SO}_4^{2-}]\) denote the concentration of these ions. \(K_{\text{sp,barite}}\) is the solubility product of barite as a function of temperature and pressure, which can be found in past studies \([48,49]\), all in SI units. \(\gamma_{\text{Ba}^{2+}}\) and \(\gamma_{\text{SO}_4^{2-}}\) are the activity coefficients of barium and sulfate, respectively, which are functions of ionic strength, temperature, and pressure, and can be determined by Pitzer’s equations \([27]\).

Bethke \([46,50]\) proposed the following expression for mineral precipitation or dissolution rate:

\[
r_\beta = A_\beta k_\beta \left( 1 - \frac{Q_\beta}{K_{\text{sp}}} \right)^{\beta - 1}, \ldots, K_{\text{sp}}
\]

(4)

In Eq. (4), \(k_\beta\) is the rate constant, \(A_\beta\) is the reactive surface area of mineral \(\beta\), and \(r_\beta\) is the reaction rate, all in SI units. The term \(Q_\beta/K_{\text{sp}}\) in Eq. (4) is the saturation index of the reaction (after taking the log). If the saturation index is positive, mineral precipitation occurs. Mineral dissolution occurs at negative saturation index values, and when the saturation index is equal to zero, the reaction is in equilibrium.

\(Q_\beta\) is the activity product for mineral \(\beta\) and can be determined by the following equation,

\[
Q_\beta = \prod_{k=1}^{n_{\beta}} a_k^{m_k}
\]

(5)

where \(a_k\) is the activity of component \(k\) and \(m_k\) is the stoichiometry coefficient, as demonstrated for barite.

Kan et al. \([47]\) proposed different scenarios for barite mineral precipitation in wellbore using SI: (i) If SI > 1.5 (at 120 °C) in the perforation zone at the bottom of the well, precipitation occurs on the tubing walls and a large amount of crystals is formed. This results in smaller values for SI. (ii) If SI is between 0.3 and 1.5 in the perforation zone, mineral precipitation occurs on the tubing walls at the bottom of the well, but the mass barite scale per unit brine is negligible (iii) if SI < 0.3 in the perforation zone, mineral precipitation does not occur at the bottom of the well and may occur near the surface due to changes in pressure and temperature.

The activity coefficients in Eq. (3) can be calculated based on the B-dot model using \([46,50]:\)

\[
\log y_i = -\frac{A_\beta z_i^2 q_i^2}{1 + a_i c^0} + \beta i
\]

(6)

where \(a_i\) is the ion size parameter. The \(A_\alpha\), \(B_\gamma\), and \(B_\beta\) are temperature-dependent parameters, and \(\beta\) is the ionic strength calculated by the following equation,

\[
\beta = \frac{1}{2} \sum_{k=1}^{n_{\beta}} m_k z_k^2
\]

(7)

where \(z_k\) is the ionic charge of the \(k_{\text{th}}\) ion, and \(m_k\) is the molarity of the \(k_{\text{th}}\) ion.

Importantly, we used the following expressions to calculate the updated porosity changes due to mineral dissolution-precipitation \([46]:\)

\[
\phi = \phi_0 [1 + c_q(R - P*)]
\]

(8)

and,

\[
\phi = \phi_0 - \frac{\sum_{\beta} (N_\beta - N_\beta^0)}{P_\beta}
\]

(9)

In Eq. (8), \(\phi_0\) is the current porosity, \(\phi^*\) is the reference porosity when dissolution or precipitation is included, \(c_q\) is the rock compressibility, \(\beta\) is the current pressure, and \(P^*\) is the reference pressure. In Eq. (9), \(\phi_0\) is the reference porosity without mineral dissolution or precipitation, and \(P^*\) is the molar density of mineral \(\beta\). The resulting changes in permeability due to changes in porosity are calculated using the Kozeny-Carman equation \([46]:\)

\[
\frac{K_\beta}{K_0} = \phi_0^2 (1 - \phi_0)^2 \frac{1}{\phi^2 (1 - \phi^2)^2}
\]

(10)

3. Modeling approach

To study the impact of mineral precipitation on reservoir performance (e.g., production rate and injection pressure), we consider a 1D model for a reservoir with homogeneous permeability and porosity. The injection is performed from one side and production from the other side of the reservoir. The model represents an oil-bearing reservoir undergoing water flooding for pressure maintenance. To perform the simulations, the CMG-GEM reservoir simulator was employed to investigate the impact of precipitation on flow during the reactive transport of fluids within reservoir and injection wells. The model parameters are summarized in Table 1 below. The reservoir fluid components and compositions are shown in Table 2. The relative permeability curves of water and oil are obtained by using the Stone model \([51]\) as follows:

\[
k_{\text{up}} = k_{\text{up,low}} S_w \frac{\log \omega_0}{\log (1 - S_w)} \frac{\log (1 - S_w)}{\log (1 - S_w^0)}
\]

(11)

The relative permeability curves are shown below in Fig. 1.

In this section, barium sulfate was considered to be the precipitating mineral in the reservoir as a result of incompatible water injection. The concentration of barium in the formation water and the composition of sulfate in the seawater were derived from previous literature \([50]\). The mineral precipitation reaction properties are from past studies, and are shown in Table 3 \([52,53]\). No reaction occurs between the hydrocarbon components.

There are two wells in our 1D model, one for injection on the left side and one for production on the right side. We continue injection and production for 9 years. In order to better understand the impact mineral precipitation on the injection performance and oil recovery, different Table 1

<table>
<thead>
<tr>
<th>Reservoir properties</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>grid</td>
<td>100 × 1 × 1</td>
</tr>
<tr>
<td>grid size</td>
<td>Δx = 6 ft (1.83 m)</td>
</tr>
<tr>
<td>permeability</td>
<td>Δy = 600 ft (183 m)</td>
</tr>
<tr>
<td>porosity</td>
<td>Δz = 150 ft (46 m)</td>
</tr>
<tr>
<td>depth to reservoir top</td>
<td>300 md</td>
</tr>
<tr>
<td>reservoir temperature</td>
<td>9500 ft (2900m)</td>
</tr>
<tr>
<td>reservoir pressure</td>
<td>161°F (72 °C)</td>
</tr>
<tr>
<td>rock compressibility</td>
<td>4800 ps (330 bar) at 9600 ft</td>
</tr>
</tbody>
</table>

Table 2

| Hydrocarbon components and compositions [1]. |
|----------------------|-------|
| Component | Composition | Molecular weight (g/mol) | Critical pressure (psi) | Critical temperature (°F) |
| CO₂ | 0.0023 | 44.01 | 381.71 | 87.89 |
| N₂ | 0.0063 | 28.01 | 492.31 | 232.51 |
| CH₄ | 0.3624 | 16.04 | 667.78 | 116.59 |
| C₂H₆ | 0.0279 | 30.07 | 708.34 | 90.104 |
| C₃H₈ | 0.0225 | 44.09 | 615.76 | 205.97 |
| C₄H₁₀ | 0.0204 | 58.12 | 532.58 | 297.35 |
| C₅H₁₂ | 0.0139 | 72.15 | 479.81 | 380.20 |
| C₆H₁₄ | 0.0166 | 86.00 | 477.16 | 453.83 |
| C₇⁺ | 0.5277 | 300.00 | 208.59 | 1096.85 |
scenarios are examined in the Results and Discussion component of this study.

To study mineral precipitation within wellbore, ScaleSoftPitzer™ software from Brine Chemistry Consortium-Rice University [47,54] was used. This software was developed to calculate pH, predict scaling tendency and inhibitor needs for oil and gas wells. The calculations are made based on Pitzer theory of electrolytes. A wider range of pressures, temperatures, total dissolved solids, and cosolvents are permitted with the use of this software than those of previously used empirical methods. ScaleSoftPitzer™ also calculates the SI, and different predictions of what minerals would precipitate in the wellbore are made based on the SI values. Various inhibitors including NTM [nitrilotri(methylene phosphonic) acid] and BHMP [bis-hexamethylenetramine penta (methylene phosphonic) acid] can be employed in ScaleSoftPitzer™. In this software, CO₂ partial pressure (PₐCO₂) is used instead of pH for calculating saturation index, since PₐCO₂ is more widely known and easily measured than the brine pH. More details about the software are provided by its developers [47,54]. The composition analysis of formation water and seawater are from the Gulf of Mexico (GOM) [55] as shown in Table 4. The concentration of sulfate (SO₄²⁻) is significantly larger in the injected water than in the formation water. On the other hand, the concentration of Ba²⁺ (barium) is nearly two orders of magnitude larger in the formation water than that of the injected water. Also, the alkalinity of the formation water is larger than that of the injected water, implying that it possesses a higher capacity to neutralize acids.

4. Results and discussion

In this section, we present the impacts of mineral precipitation on the change in bottom hole pressure and oil recovery during injection and production. In addition, we present the impact of barite’s reactive surface area on the injection performance. Next, we investigate the impact of mineral precipitation on water saturation during water flooding. Finally, multiple minerals capable of precipitating are considered in wellbore and the impact of injected seawater fraction on the saturation index of these minerals and amount of precipitation is presented.

4.1. Injection performance

4.1.1. Bottom hole pressure

First, we investigate how mineral precipitation affects bottom hole pressure (BHP). In the first scenario, the injection well was assigned a BHP that ensures a constant water injection of 340 bbl/day. The production well was constrained to a BHP of 2500 psi and a maximum liquid rate of 300 bbl/day. Water flooding was continued for 9 years in the simulations without adding any geochemical reactions in our model. Therefore, as expected there is no mineral precipitation. Then we add the reaction describing barite precipitation. The results are illustrated in Fig. 2.

As shown in this figure, mineral precipitation increases the pressure response in the formation. This is due to changes in petrophysical properties (e.g., porosity and permeability). Porosity decreases from 0.2 to nearly 0.07, which also changes the permeability (Eq. (10)). As the porosity decreases (approximately 65% decrease here) the available pore volume for fluid flow decreases [1]; as a result, the pressure increases to maintain the same injection rate. In fact, when the dissolution or precipitation process is not considered, the required BHP increases from 4800 psi (initial pressure) to 5542 psi to maintain the constant injection rate. Our results are aligned with the observations in Siri offshore oil field in the Persian Gulf [9], where the water flooding project was stopped after 6 years as the water injection rate decreased.

![Fig. 2. The impact of scaling on well performance: Scaling leads in an increase in the bottom hole pressure required for a constant production rate.](image_url)

**Table 3**

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barium modality in formation aqueous phase</td>
<td>0.0043 m</td>
</tr>
<tr>
<td>Sulfate modality in seawater</td>
<td>0.028 m</td>
</tr>
<tr>
<td>Activation energy of barite reaction</td>
<td>22 kJ/mol</td>
</tr>
<tr>
<td>Barite reactive surface area</td>
<td>900 m²/m³</td>
</tr>
<tr>
<td>log of barite reaction constant at 25 °C</td>
<td>~8 mol/m³</td>
</tr>
<tr>
<td>Log of barite chemical equilibrium constant</td>
<td>~9.97</td>
</tr>
</tbody>
</table>

**Table 4**

<table>
<thead>
<tr>
<th>Ion</th>
<th>Formation water</th>
<th>Injected water</th>
</tr>
</thead>
<tbody>
<tr>
<td>Na⁺</td>
<td>13,537</td>
<td>10,556</td>
</tr>
<tr>
<td>K⁺</td>
<td>78.9</td>
<td>380</td>
</tr>
<tr>
<td>Mg²⁺</td>
<td>90</td>
<td>127</td>
</tr>
<tr>
<td>Ca²⁺</td>
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<td>400</td>
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<tr>
<td>Sr²⁺</td>
<td>38</td>
<td>13</td>
</tr>
<tr>
<td>Ba²⁺</td>
<td>22</td>
<td>0.02</td>
</tr>
<tr>
<td>Fe³⁺</td>
<td>0.9</td>
<td>0.00</td>
</tr>
<tr>
<td>Zn⁺</td>
<td>2</td>
<td>0.01</td>
</tr>
<tr>
<td>Cl⁻</td>
<td>20,522</td>
<td>18,980</td>
</tr>
<tr>
<td>SO₄²⁻</td>
<td>23</td>
<td>26.49</td>
</tr>
<tr>
<td>F⁻</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Alkalinity</td>
<td>84,546</td>
<td>140</td>
</tr>
<tr>
<td>Carboxylic acids</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Total dissolved solids (TDS)</td>
<td>35,439</td>
<td>34,391</td>
</tr>
</tbody>
</table>
from 9100 to 2200 bbl/day, due to scale formation issues. Here, we ensured a constant injection rate to determine the BHP. Our results suggest that careful consideration is required during water flooding due to scale formation issues, and mineral precipitation could significantly affect the pressure response. Therefore, geochemical data, petrological data, and geochemical modeling combined with reactive transport modeling can enhance our understanding of pressure responses in the target formation during water flooding operations.

4.1.2. Reactive surface area

Dissolution and precipitation rates are affected by the reactive surface area of minerals. One simple kinetic reaction law for determining the dissolution or precipitation rate is as follows [56]:

\[ r = Ak(1 - \Omega) \]  

where \( r \) [mol/s] is the dissolution or precipitation rate, \( A \) [m²] is the mineral reactive surface area, \( k \) is the rate constant [mol/m²s], and \( \Omega \) is a function of SI (\( \Omega = 10^\Delta \)).

Measurement of the reactive surface area of minerals has been a challenging task in mineral precipitation and dissolution studies [56,57]. In numerical simulations, this parameter is usually normalized and reported in m²/m³ of bulk volume of rock. When the reaction is far from equilibrium (dissolution and precipitation conditions), the rate is essentially dependent on the reactive surface area and the pH. In fact, the variation in reactive surface area affect the reactive transport properties within a rock [56]. The reactive surface area also changes as the reaction proceeds [58].

Reactive surface area of minerals depends on the grain size. Different methods are used to measure the reactive surface area of minerals such as atomic force microscopy, vertical scanning interferometry, and laser confocal microscopy. However, these experimental approaches provide limited information for reactive transport modeling, as the surface area is highly affected by the scale at which the process is observed [57]. For example, in a geological carbon sequestration study, Shu et al. [57] showed that reactive surface area has a significant impact on mineral trapping of CO₂ in saline aquifers. They studied seven cases that featured different sizes for grain diameters of calcite and anorthite, resulting in different reactive surface areas for these minerals. They concluded that because of a reduction in the surface areas of calcite and anorthite, the amounts of dissolved anorthite and precipitated calcite and kaolinite decrease significantly. They also concluded that during 500 years, mineral trapping of CO₂ decreases from 11.8% to 0.65% because of the reduction in the reactive surface areas of calcite and anorthite from 838 to 83.8 m²/m³.

Here, in order to investigate the effect of amount of precipitation on well performance, we performed a sensitivity analysis to barite reactive surface area. The results are shown in Fig. 3. It is clear that any increase in the reactive surface area leads to more precipitation of barite, which in turn, increases the BHP in the injection well. In addition, by increasing the amount of precipitation, the injection curves deviate from the smooth trend, as the precipitates cause disturbance in the ease of flow.

4.2. Oil recovery

It is worth noting that recovery factor comprises the recoverable amount of hydrocarbon initially in place, normally expressed as the ratio of recovered oil to the amount of in-situ oil. We studied the potential impact of mineral precipitation or scaling on oil recovery. In this case, the production well was allowed to produce oil, based on the rate and pressure increase in the injection well with a minimum BHP of 3200 psi. The injection well was constrained to a maximum BHP of 3355 psi and a maximum water rate of 300 bbl/day. We considered two scenarios: one without mineral precipitation reactions, and one with reactions. The results for the first case are illustrated in Fig. 4: water flooding continued with a constant injection bottom hole pressure of 3200 psi (the minimum pressure required for the injection well) and a constant water rate of 300 bbl/day. The recovery factor (RF) increased to ~0.63.

In the second scenario, with chemical reactions (see Fig. 5), the injection pressure started to increase continuously until it reached the maximum BHP. The water rate remained constant during this time and

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Fig. 3. Impact of precipitation amount on well performance: Reactive surface area has a direct relationship with the amount of precipitation and a larger surface area leads to a higher bottom hole pressure required for injection.

Fig. 4. Recovery factor (RF) without considering the impact of mineral precipitation: RF reaches 0.63, which can be achieved when the effect of scaling issues on the reservoir formation is not included.

Fig. 5. Recovery factor (RF) with reactions included: Mineral precipitation is included. RF decreases due to precipitation of minerals. The BHP increases to overcome the reduction in the available void volume for flow due to precipitations until it reaches the maximum BHP enforced on the injection well. Once the maximum BHP is reached, the injection water rate starts to decrease leading in a smaller RF.
behavior factors that limit recovery as water breakthrough. As a result, the recovery factor tended to increase with a smaller slope. The final RF is approximately 0.35 which is nearly two times smaller than RF without including the impact of chemical reactions.

The maximum bottom hole pressure for the injection well was increased from 3355 psi to 3555 psi to see how much the increase would mitigate the negative effect of mineral precipitation on recovery factor. The results are shown in Fig. 6. The RF increases as BHP increases to 3555 psi for supporting oil production. This led to an increase in the recovery factor as a higher injection pressure causes greater production, as supported by the results. In addition, the injection water drop is delayed until the later stages of flooding, which leads to a higher recovery factor.

4.3. Saturation profile

Water flooding performance is usually evaluated by means of saturation profiles (saturation versus distance). In an ideal water flooding operation or piston-like displacement, the mobility ratio (relative permeability divided by viscosity) is less than one. However, in most cases, factors such as reservoir heterogeneity and capillarity change the configuration of displacement front. When the mobility ratio is greater than one, the displacing fluid bypasses the displaced fluid and the displacement deviates from piston-like behavior. When the displacement is not piston-like, the saturation profile is usually predicted by the Buckley-Leverett theory [59–61].

Here, we investigate the impact of mineral precipitation reactions on the saturation profile of the injected water by using a 1D model with 100 grid cells. Each grid block was 6 ft (1.8 m) in length and 150 ft (46 m) in height. The width of the reservoir was considered 600 ft (180 m). Other properties of the reservoir and the fluids are the same as before. We performed two simulations: water flooding with and without reactions. The saturation profiles at different injected pore volumes are plotted in Fig. 7. It is clear that our water flooding simulations closely follow piston-like behavior when ignoring the effects of mineral precipitation. However, when considering barite’s precipitation, the saturation profile deviates from the piston-like behavior. Also, mineral precipitation results in earlier water breakthrough. The reason is, in fact, related to the relative permeabilities of the water and oil phases in the fractional flow equations, and the formation porosity that decreases because of scale deposition. Also, as Fig. 7 demonstrates, the performance of water flooding is less efficient at later stages due to barite precipitation. Scale formation leads to earlier water breakthroughs for up to 60 ft (~18 m). This can affect the efficiency of the water flooding project.

4.3.1. Reactive surface area & saturation profile

Reactive surface area plays an important role in determining the amount of precipitation or dissolution as discussed in Section 4.1.2. Also, we demonstrate that the mineral surface area strongly affects the pressure response in the formation. The motivation here is to understand if reactive surface area affects the saturation profiles presented in the previous section.

Our sensitivity analysis was performed at different injected pore volume to capture the impact of reactive surface area on water flooding performance. We considered 2 reactive surface areas of 90 and 900 m²/m³. Note that a larger surface area leads to more barite precipitation due to a higher reaction rate. The results are illustrated in Fig. 8, showing more non-ideal behavior and a slightly earlier breakthrough for the surface area of 900 m²/m³. These results show that a greater degree of precipitation causes displacement problems during water flooding. The injected pore volume is independent of reactive surface area. In other words, one of the rates in Fig. 8 was sufficient for conducting the sensitivity analysis; however, we have added three different pore volumes to investigate the impact of mineral precipitation and reactive surface at different stages of flooding.

![Saturation profile](image)

Fig. 7. Impact of mineral precipitation on the saturation profile during water flooding: The mineral deposition makes the saturation profiles deviate from ideal behavior and leads to an earlier water breakthrough.
5. Mineral precipitation in wellbore

In this section, we used ScaleSoftPitzer™ to study mineral precipitation in the wellbore. In this section, 1) scale formation is studied in the wellbore and not in the reservoir like in previous sections of this study; and 2) the brine compositions were derived from a real field (Gulf of Mexico) in contrast to the previous sections in which the brine compositions were adapted from existing literature. We mixed the formation water and seawater, with properties reported in Table 4, in the wellbore to measure the scaling tendency based on the existing ions in the brines, and amount of precipitation for each mineral including calcite (CaCO₃), barite (BaSO₄), halite (NaCl), gypsum (CaSO₄·2H₂O), hemihydrate (CaSO₄·0.5H₂O), anhydrite (CaSO₄), and celestite (SrSO₄). The oil and gas flow rates in the wellbore were assumed 1000 bbl/d and 8500 Mcf/d, respectively. The water flow was assumed to be 100 bbl/d with an increasing seawater fraction. Mixing the formation water and seawater results in the precipitation of the aforementioned minerals (calcite, barite, halite, gypsum, hemihydrate, anhydrite, and celestite). We have chosen these minerals because they are abundant underground and have the largest impact on the flow and transport of subsurface fluids, compared to other trace minerals.

We calculated SI to study the dissolution and precipitation behavior of minerals. We studied the mineral precipitation (i) at bottom-hole (B-H hereafter) with a pressure and temperature of 7000 psia and 340°F, respectively, and (ii) at the wellhead (W-H hereafter) with a pressure and temperature of 14.7 psia and 77°F, respectively, to investigate the effect of these two parameters on the precipitation of minerals.

Figs. 9 and 10 show the saturation index (SI) profile and concentration of precipitated barite in the wellbore for both B-H and W-H conditions. In the SI profile, supersaturation occurs under both conditions. Barite’s supersaturation initially increases by increasing seawater fraction (0.47), and then it starts to decrease when more than 50% of the mixture is diluted with the seawater. Fig. 10 shows how barite concentration changes when we increase the fraction of seawater. Likewise, the concentration of barite first increases and then decreases. The highest concentration of barite is observed when the seawater fraction equals ~0.2. Clearly, a higher SI does not translate into a higher amount of precipitation because the saturation index is mainly controlled by the concentration (or activity) of available ions in the solution, and only demonstrates how far the system is from attaining saturation equilibrium.

Figs. 11 and 12 show the SI and concentration of calcite under both W-H and B-H conditions. Calcite seems to have an opposite behavior compared to barite. By increasing the seawater fraction, calcite precipitation decreases initially and tends to increase when the fraction of seawater is around 90%. Similarly, it can be observed that the amount of calcite precipitation is higher under the wellhead condition, in which pressure and temperature are lower than the bottom-hole.
conditions. Calcite’s SI is one order of magnitude smaller than that of barite; however, its precipitated concentration of calcite is one order of magnitude larger than barite. The could be mainly due to a higher rate of calcite precipitation.

Here, we present the results of the minerals that are supersaturated at bottom-hole conditions (high pressure and temperature), which contrasts with the aforementioned minerals in previous figures. Figs. 13 and 14 show the supersaturation curves of halite and gypsum. Halite demonstrates a decreasing SI trend by increasing seawater fraction, while gypsum demonstrates an increasing trend. In addition, both minerals have higher SI values at the bottom-hole condition. We did not observe any precipitation within the wellbore for halite and gypsum, since their SI values were close to zero.

Figs. 15 and 16 indicate the SI and precipitation curves for hemihydrate. As Fig. 15 shows, supersaturation continuously increases as seawater fraction increases. Furthermore, the SI is greater under the B-H condition. Fig. 16 indicates that no hemihydrate precipitation occurs under the wellhead condition, as SI is less than one. Also, no precipitation occurs under the B-H condition before the seawater fraction is ~70% at which point SI reaches one. This means enough sulfate ions exist in the seawater that supports hemihydrate precipitation.

Anhydrite curves in Figs. 17 and 18 demonstrate a similar behavior to hemihydrate. However, anhydrite starts to precipitate at a lower seawater fraction. It is worth noting that anhydrite precipitation can increase up to 1000 mg/l under bottom-hole conditions, while no precipitation occurs under wellhead conditions.

Celestite (SrSO₄) precipitates in the wellbore, according to the curves shown in Figs. 19 and 20. Celestite shows a similar behavior to barite, as its SI first increases and then decreases by increasing the seawater fraction. However, it can be noted that opposite to barite, celestite precipitation mainly occurs under the bottom-hole condition.
Likewise, the amount of celestite precipitation resembles that of barite as similar amounts of barium and strontium exist in the formation water, as reported in Table 4.

Careful inspection of the above results helps us with the identification of the main potential minerals that could precipitate at low and high pressures and temperatures, depending on the chemical composition of the mixing brines. Scale inhibitors, therefore, should only focus on minerals that precipitate in greater amounts and under all conditions, such as calcite, compared to more soluble minerals, such as gypsum, which remain at relative equilibrium with the brine under all conditions.

Our results show that while some minerals are more stable at lower temperature and pressure conditions, others can precipitate more easily in harsher environments. For instance, our results (Figs. 14 and 15) indicate that gypsum is more stable at wellhead conditions and transforms into a more stable structural form called hemihydrate at bottom-hole conditions. This observation matches the physical behaviors of gypsum and hemihydrate since by increasing the temperature, gypsum (CaSO$_4$.2H$_2$O) loses its water and transforms into hemihydrate (CaSO$_4$.0.5H$_2$O) [62]. Our study proposes that it is important to study scale formation in the wellbore, and specific scale inhibitors are needed at different conditions to combat the scaling issue within the wellbore. We presented our results at two temperature and pressure conditions (wellhead and bottom-hole conditions) to cover a wide range of pressures, temperatures, and the respective impacts on the precipitation of various minerals.

In addition, our results show that the stability of minerals can be controlled by the amount of seawater being injected into the reservoir.
For instance, there is a discernible difference in the stability of celestite when the seawater fraction in the mixed brine is 20% compared to when 80% of the mix is composed of seawater, based on our brines’ chemistry. Therefore, when designing scale inhibitors, one should consider both the stability (likelihood of precipitation) at different temperature and pressure conditions and the mixing ratio of injecting seawater (with known composition and concentration) to determine the optimized inhibitor and right time to perform the inhibition operation. Distilling the injected water is common in the petroleum industry; as such, scale formation is an inevitable part of any waterflooding project that uses seawater.

Our study provides a better understanding of mineral precipitation (scale formation) both in the reservoir and within the wellbore. We focused on barite precipitation in the reservoir since it is one of the least soluble minerals once it is formed (log Ksp = 9.97). A few studies have studied the precipitation of minerals in the hydrocarbon reservoir, but no study before has quantified the impact of mineral precipitation on oil recovery and the bottom hole pressures and production of injection wells. We extended our modeling work to the wellbore conditions and proposed which minerals would precipitate under certain conditions. This helps to determine which scale inhibitors should be used and at which stage of water flooding operation.

6. Conclusions

In this study, we developed a model to study mineral precipitation in reservoir. Barite is assumed the main precipitating mineral, to determine the impact of mineral precipitation on injection performance. A 1D two-phase flow model was developed in which injection and production are performed simultaneously, and the results were compared to a base case in which no mineral precipitation was considered and waterflooding was assumed to have been performed with an idealized distilled water. The impact of mineral precipitation on the profile of water saturation during water flooding was investigated. Multiple mineral precipitations were considered in wellbore and the impact of injected seawater fraction on the saturation index of minerals and amount of precipitation is studied at low- and high-pressure and temperature conditions. The following conclusions can be drawn from the present study:

1) Mineral precipitation within the reservoir reduces oil recovery as it plugs the pores and throats of the porous media within the reservoir. In addition, a higher bottom-hole injection pressure is needed to overcome the negative impact of precipitation on the permeability of a reservoir.

2) Mineral deposition within the reservoir causes water-flooding performance to deviate from ideal displacement. Non-ideal displacement due to mineral precipitation in reservoir leads to greater amounts of hydrocarbons to be trapped within the reservoir, an earlier water breakthrough is observed during the water flooding operation.

3) The results of mixing a sample formation water and seawater from the Gulf of Mexico indicate that several types of scaling can precipitate in wellbore during production from a well. While some minerals such as calcite can precipitate in large amounts from the flowing brine in wellbore, some minerals such as gypsum remain relatively at equilibrium with the brine, both at low- and high-pressure and temperature conditions.

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