

Effects of Formation Mineral Compositions on the Performance of High- & Low-Salinity Brine Injection in Carbonate Reservoirs

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Abstract

Low-salinity flooding has been extensively investigated. However, the effects of several variables, such as mineralogical composition, have been neglected. In this regard, the main objective here was to optimize low-salinity water flooding of reservoirs with a wide range of rock mineralogy. Five different brines were determined in reservoirs with different mineral compositions. The mineral composition consisted of limestone and dolomite and the mineralogy varied between 0 and 100% limestone content. The results indicated that the optimum mineralogical system consists of 50% limestone and 50% dolomite flooded with 100% diluted formation brine. Additionally, reservoir mineral composition plays a significant role in the performance of low-salinity water flooding. The findings here will improve our understanding of rock composition effects on the performance of low-salinity water flooding and provide the industry with data that can scientifically improve process optimization.

Keywords

Water Flooding, Low Salinity, Carbonate Reservoirs, Rock Mineralogy, Limestone

1. Introduction

The use of low-salinity brine injection has gained attention as an enhanced oil recovery method in carbonate reservoirs. This technique involves injecting brine with reduced salinity into the reservoir, which alters the surface properties of the rock formation and enhances oil recovery. Identifying the optimal brine concentration for a given reservoir is key to the success of low-salinity water flooding. A number of studies have examined how low-salinity brine affects oil recovery [1]

and have shown that altering the injection water salinity can lead to alterations in the rock surface wettability. In turn, this affects oil displacement efficiency. Furthermore, the optimum brine concentration varies according to reservoir characteristics, such as rock type, clay mineralogy, and initial water saturation [2]. Field trials have also been conducted to assess the impact of low-salinity water flooding on actual oil recovery [3], and the results have provided valuable insight into optimizing brine concentrations in real-world reservoirs. The effects of formation mineral composition on low-salinity water flooding have been investigated. The results have shown that the mineral composition of carbonate reservoirs can notably impact the effectiveness of low-salinity brine injection. For example, the presence of certain minerals, such as clay minerals or iron oxides [1] [3], can lead to a reduction in the effectiveness of low-salinity brine injection by causing blockages and hindering fluid flow.

Mineral compositions can also affect rock surface wettability, which plays a crucial role in determining oil-water interactions and subsequent oil recovery [2]. Furthermore, the mineral composition of the reservoir formations influences the chemical reactions that occur during low-salinity brine injection [3] [4]. These reactions can lead to the dissolution and precipitation of minerals, which can alter the pore structure and permeability of the reservoir rock [5]. In sandy dolomite strata, water-rock interactions can cause degradation and alter the distribution of pores and stress within the rocks [6]. Another factor is the potential for hysteresis effects in low-permeability reservoirs, such as shale, tight sandstone, and tight carbonates. The hysteresis effect refers to the phenomenon where changes in fluid saturation and flow rates do not occur instantaneously in response to pressure changes or other driving forces. Accounting for the hysteresis effect in low-permeability reservoirs is crucial for optimizing production strategies in these reservoir types [7]. Shehata and Nasr-El-Din [8] evaluated the effects of mineral type on the performance of low-salinity water flooding of sandstone oil reservoirs. They concluded that the presence of dolomite and calcite would more likely decrease the oil recovery effect of the low-salinity brine. Although several studies have examined the effects of formation mineral compositions on the performance of low-salinity flooding, the impact of rock types (limestone and dolomite %) has not been adequately assessed. Su *et al.* [9] studied the effect of the mineral composition of carbonate rocks on the relative permeability of low-salinity water flooding and concluded that the oil relative permeability is improved by the higher calcium content (Ca⁺⁺) of carbonates compared to dolomites (Mg⁺⁺).

In summary, the mineral composition of carbonate reservoirs plays a notable role in the performance of low-salinity brine injection. It influences fluid flow, wettability, chemical reactions, and the hysteresis effect, all of which impact the effectiveness of low-salinity brine injection for oil recovery in carbonate reservoirs. Therefore, this project aimed to investigate the effect of mineral composition of carbonate oil reservoirs (limestone and dolomite) on the performance of water flooding of different salinity systems. The brine concentrations of flooding

water varies from $\approx 240,000$ to 500 ppm. Relative permeability data generated by Su *et al.* [9] was used in our model to predict the performance of different flooding systems.

To the best of our knowledge, carbonate reservoir performance has never been studied, considering the combined variation in salinity and mineral composition. For low-salinity water flooding, the primary objective is to determine the optimum lithology in the reservoir to maximize oil recovery during low-salinity water flooding by taking into account the different mineral compositions in the reservoir. It will be possible for the designer of low-salinity project engineering to recommend the reservoir target area based on that information and the reservoir lithological description. As a result of this research, we will gain a better understanding of how water salinity and rock composition affect the performance of high and low-salinity water flooding of carbonate reservoirs.

2. Methods

The reservoir model used here was a 40-acre five-spot pattern consisting of five layers with different permeabilities (Figure 1). The rock mineralogy of the carbonate reservoir (calcite/dolomite) was distributed in the following proportions: 0:100%, 25:75%, 50:50%, 75:25%, and 100:0% as employed by Su *et al.* [6]. The Craig, Geffen, and Morse model were employed in predicting the performance of high- and low-salinity water flooding.

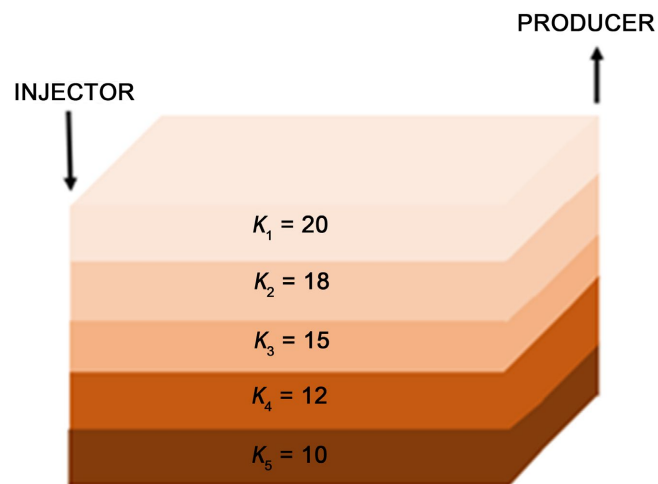


Figure 1. Reservoir model, with different permeability (k) values.

High-salinity water (240,000 ppm) is called formation water (FW) which was used as the base water. Four brine samples with different salinities were used here: FW-50 (≈ 5000 ppm), FW-100 (≈ 2500 ppm), FW-200 (≈ 1000 ppm), and FW-500 (≈ 500 ppm) in addition to the FW. A detailed description of the water compositions and the relative permeability data for the conducted runs can be found in Su *et al.* [9]. A total of 25 runs were conducted to determine the optimal system for the five-rock mineral compositions and to optimize brine salinity based on the

chemical composition of carbonate rocks. The project plan of the study is shown in **Figure 2**. The study plan shows the range and variations in mineral composition employed in this study as follows: LS 100%- DL 0%, LS 75%- DL 25%, LS 50%- DL 50%, LS 25%- DL 75%, LS 0%, DL 100%. These variations were randomly selected to cover the most likely combinations in real-world reservoir scenarios.

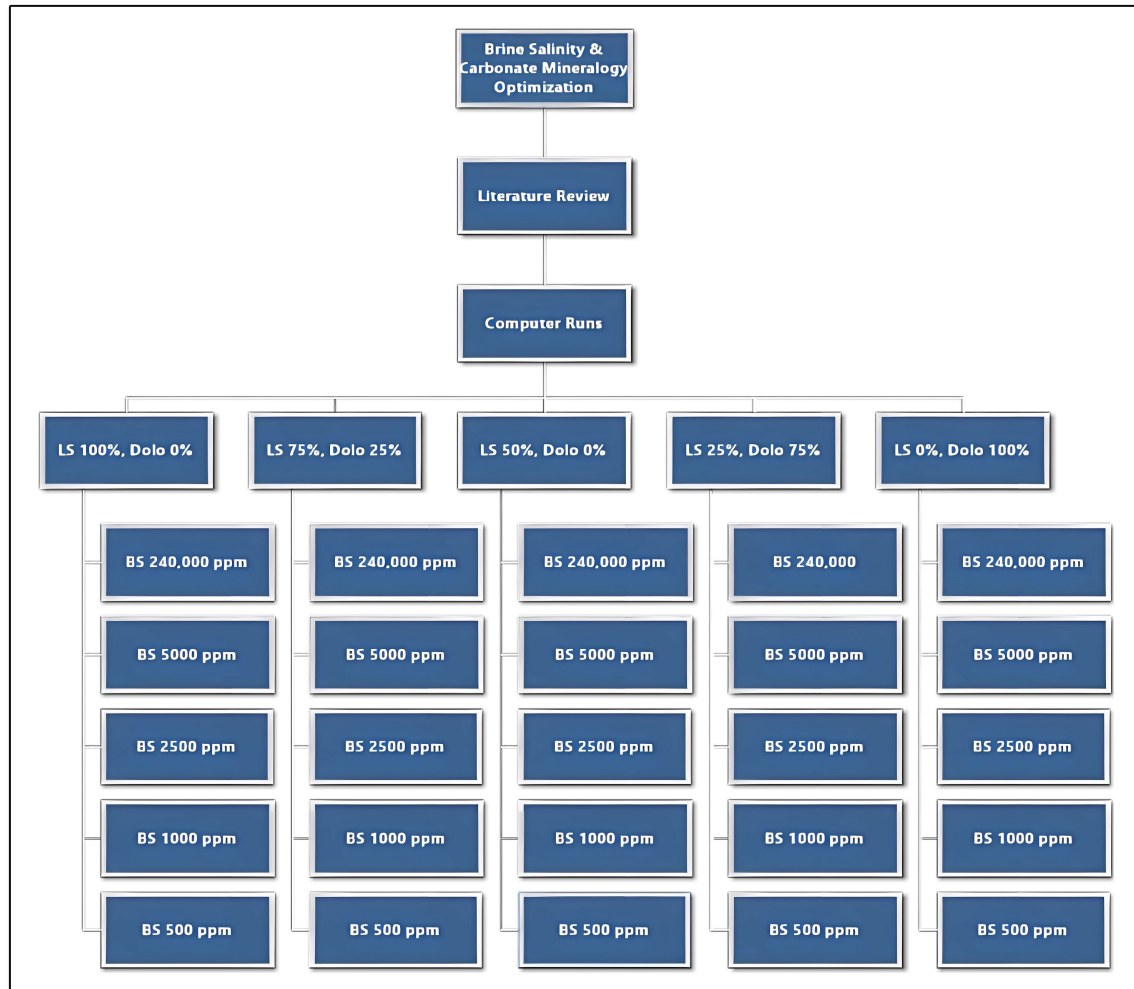


Figure 2. Study plan.

3. Results and Discussion

In carbonate oil reservoirs, limestone and dolomite are usually present in varying percentages, with limestone containing a higher percentage than dolomite. Certain parts of the reservoir could contain 100% limestone or dolomite and other areas could have a percentage variation of these minerals. It is, therefore, important to consider the mineralogical distribution of limestone and dolomite when performing reservoir simulations of low-salinity water flooding. According to Su *et al.* [10], carbonates with different mineral compositions respond differently to low-salinity flooding in terms of wettability alteration. Almost all published articles have used only limestone or dolomite carbonate reservoirs in their

analyses of carbonate reservoir performance. Therefore, it is necessary to investigate the performance of limestone FW in carbonate reservoirs containing both limestone and dolomite. In this section, we will present and discuss the results of a set of runs to estimate the water-flooding performance of carbonate reservoirs with different salinity brines (FW and its dilutions) and different composition carbonate rocks, where calcite/dolomite content varies between 100% and 0% dolomite in each studied case.

3.1. Mineral Composition Limestone 100% - Dolomite 0%

Since porosity and permeability of carbonate rocks affect wettability and low-salinity water flooding efficiency [11], the porosity and permeability of each layer were kept constant for all studied cases. The permeability of each layer is displayed in **Figure 1** and a 20% porosity was assigned to all layers.

Several studies have investigated how initial water saturation impacts low-salinity water flooding [12]. The adsorption of divalent cations, such as calcium and magnesium, on the rock surface can alter wettability towards a more water-wet state, leading to improved oil recovery [13]. When water saturation is too high, low-salinity water may have a lower chance of coming into contact with the oil, preventing wettability modification and other beneficial interactions from occurring. Based on this, an initial water saturation of 20% was employed for all runs.

The injection rate of low-salinity water can also play a crucial role in technique effectiveness [14]. A slower injection rate allows more time for low-salinity water to interact with the rock and crude oil, potentially leading to more pronounced wettability alteration and other favorable effects [12] [13] [15] [16]. Conversely, higher injection rates may be necessary to overcome permeability reduction caused by fine migration or mineral dissolution [16]. For example, Seccombe *et al.* [17] observed a constant water relative permeability at residual oil saturation for both low- and high-salinity water injections, suggesting that the injection rate did not markedly impact the process [18]. Therefore, a constant pressure difference of 3000 psia was used between the injection and production wells here.

In this section, the performance of five different brines—240,000 ppm (FW), 5000 ppm (FW50), 2500 ppm (FW100), 1200 ppm (FW200), and 500 ppm (FW500)—when flooded into the selected carbonate oil reservoir, which consists of 100% limestone mineralogy, were investigated in detail. The recovery factors of the brines used in the 100% limestone environment are shown in **Figure 3**. The results revealed that formation brine diluted 100 times (2400 ppm, 0.24 wt%) had the best performance. The optimal brine concentration obtained in this case is confirmed by Chandrashegaran's [19] conclusion that 0.2 wt% is the optimal concentration for most rock types and scenarios. The recovery factor of FW 100 in this reservoir is $\approx 73\%$ of oil in place (OIP). The reduction of injection water salinity from ≈ 240000 to 2400 ppm resulted in $\approx 50\%$ improvement in overall oil recovery.

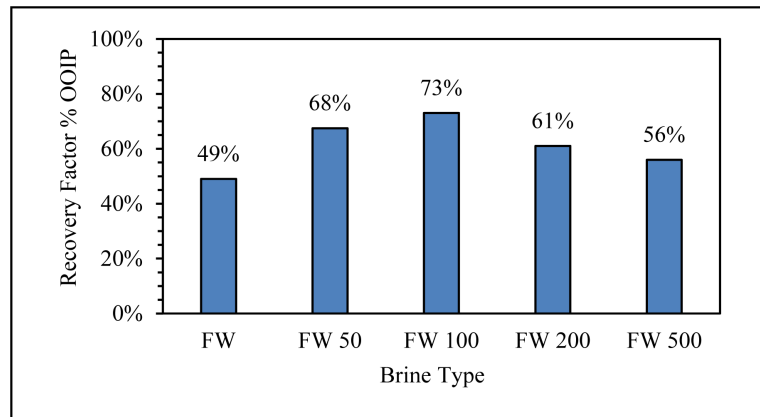


Figure 3. Recovery factor for different brines: 100% limestone (OIP = oil in place).

Previous results showed a notable improvement in the recovery factor, confirming that low-salinity water works well in this environment. By diluting the formation brine by 50 times (4800 ppm), the recovery factor of the 100% limestone carbonate reservoir improved by 39% (**Figure 3**). The time and amount of oil recovery at water breakthrough (WBT) is a critical parameter that should be considered when evaluating the performance of water flooding.

Water breakthrough time refers to the time taken for the first droplet of water to reach the wellbore. This marks the end of clean oil production from the well. **Figure 4** shows the time, oil production rate, and oil recovery at water breakthrough for high- and low-salinity brines in a 100% limestone environment. A 5000 ppm (0.5wt%) brine performed slightly better at water breakthrough than a 2400 ppm (0.24wt%) brine. Favorable conditions include a late breakthrough time and higher oil recovery. Since the breakthrough performance estimate differs from the end of the project, technically, it is not clear which brine concentration is the optimum concentration. An effective way to determine this is to assess the economic viability of the project.

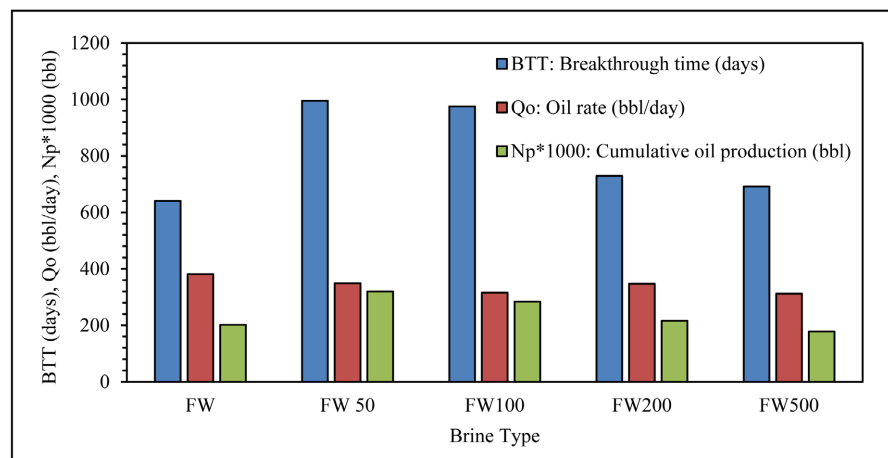


Figure 4. Time, oil production rate, and oil recovery at WBT of different brines: 100% limestone.

3.2. Mineral Composition Dolomite 100%

In this section, the performance of five different brines 240,00 ppm (FW), 5000 ppm (FW50), 2500 ppm (FW100), 1200 ppm (FW200), and 500 ppm (FW500)—when flooded into the selected carbonate oil reservoir, which consists of 100% dolomite mineralogy, was investigated in detail. An assessment of the performance of high- and low-salinity water flooding of a 100% dolomite reservoir was performed using the same model and conditions used in section 3.1. The recovery factors of the brines used in the 100% dolomite environment are shown in **Figure 5**.

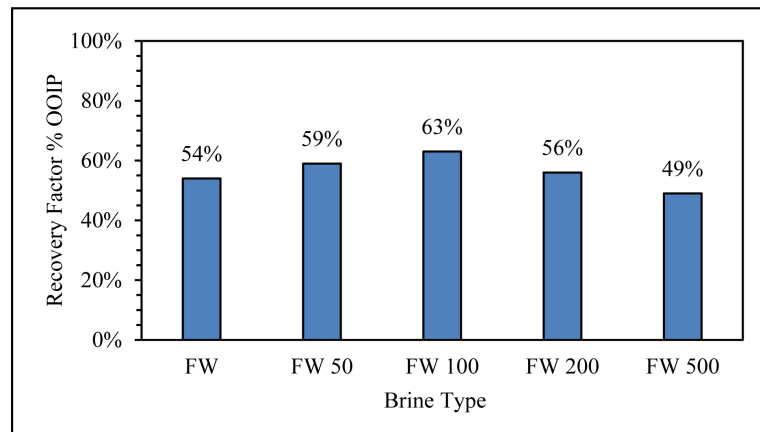


Figure 5. Recovery factor for different diluted brines: dolomite 100%.

The results revealed that formation brine diluted 100 times (2400 ppm, 0.24 wt%) had the best performance. In this reservoir environment (100% dolomite), the recovery factor for FW100 is $\approx 63\%$ of oil in place, which is 14% less than the optimum value for 100% limestone. The optimum brine concentration is not affected by carbonate mineralogy of pure limestone and dolomite reservoirs. Carbonate rock wettability modification is due to the synergistic interaction between Ca^{2+} , Mg^{2+} , and SO_4^{2-} and the rock surface [20]. Pure dolomite displays a lower recovery factor than silicate limestone due to a lower affinity for sulfate toward the dolomite surface [20]. As a result, the rock wettability is less affected [20]. **Figure 6** shows the time, oil production rate, and oil recovery at water breakthrough for high- and low-salinity brines in a 100% limestone environment. Dolomite and limestone oil reservoirs have the same optimal brine salinity (FW50, 0.5 wt%) at water breakthrough; however, limestone is more effective. Zekri *et al.* [21] reported that low-salinity flooding performs better in limestone than dolomite reservoirs.

3.3. Mineral Composition Limestone 75%–Dolomite 25%

To evaluate the effect of mixed mineralogical environments (limestone and dolomite), three different mixed groups were subjected to low/high-salinity water flooding runs. Calcite and dolomite were used in the following ratios: 75% calcite: 25% dolomite, 50% calcite: 50% dolomite, and 25% calcite: 75% dolomite. All the

factors mentioned in section 3.1 that might affect low-salinity flooding were held constant for all groups studied. In this section, we investigated the effect of slightly reducing the limestone content (limestone 75% and dolomite 25%) of the reservoir on the performance of low/high-salinity water flooding. The recovery factors of the brines used in this mixed rock mineralogy environment are shown in **Figure 7**. The highest performance was obtained with formation brine diluted 100 times (2400 ppm, 0.24 wt%), indicating that either a single or slightly mixed mineralogy had no effect on optimum brine concentration. However, the mixed mineralogy environment investigated in this section was found to produce a lower performance than that of single environments.

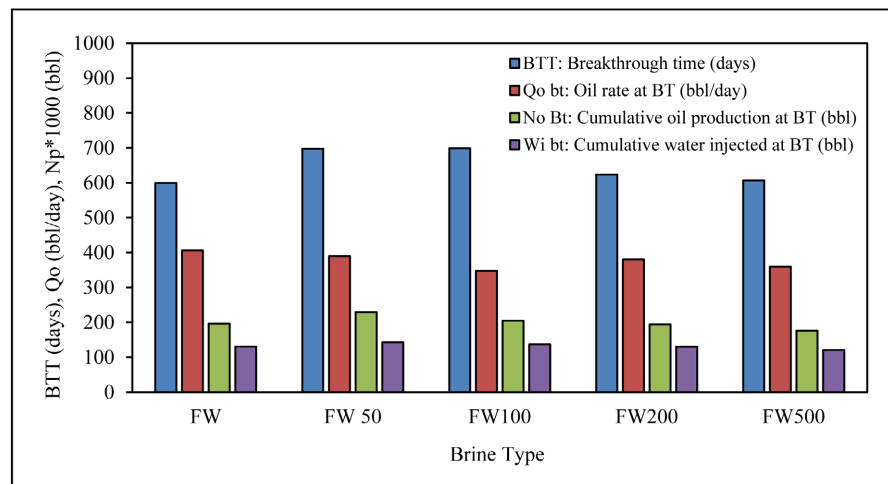


Figure 6. Time, oil production rate, oil recovery at WBT of different brines: Dolomite 100%.

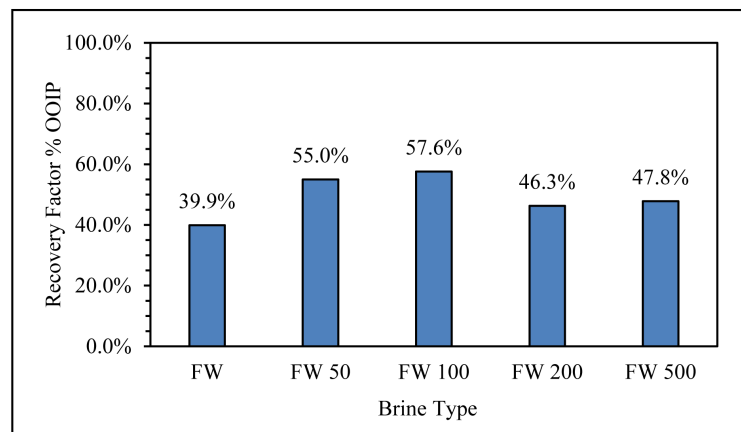


Figure 7. Recovery factor for different diluted brines: Limestone 75% - dolomite 25%.

Low-salinity flooding performed best in the tested mineralogy systems in the following order: limestone 100% > dolomite 100% > (limestone 75%, dolomite 25%). The lower performance exhibited when mixing 75% calcite with 25% dolomite could be attributed to limestone having a more favorable wettability alteration nature than dolomite [22]. **Figure 8** displays time, oil production rate, and

oil recovery at WBT of different brines for the limestone 75% and dolomite 25% system. The optimum brine concentration at WBT is 5000 ppm which was obtained for the limestone and dolomite reservoirs. A similar water breakthrough time was observed for both 2400 and 5000 ppm brines with high-salinity water (240,000 ppm), which showed a water breakthrough in a relatively short time.

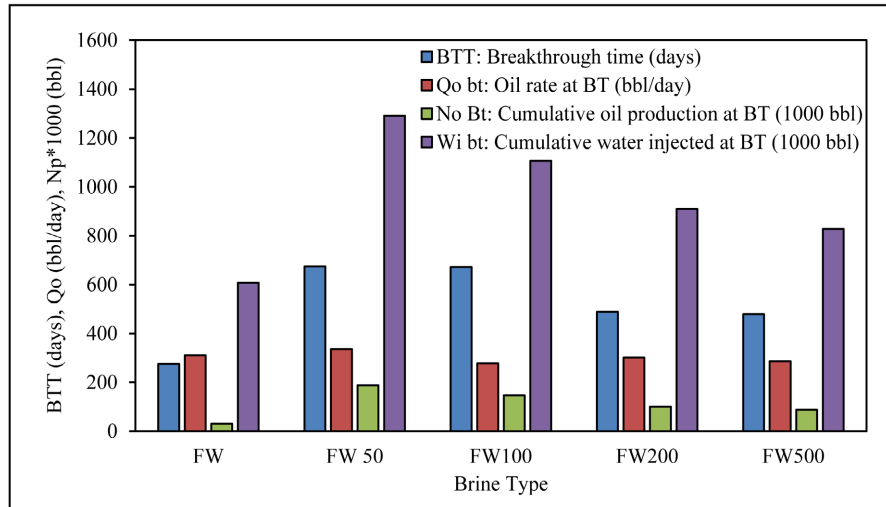


Figure 8. Time, oil production rate, oil recovery at WBT of different brines: Limestone 75% - dolomite 25%.

3.4. Mineral Composition Limestone 50% - Dolomite 50%

Five runs at high- and low-salinity were performed to examine the effects of the mineralogical environment consisting of limestone 50% and dolomite 50%. The following five brine concentrations were employed: FW (240,000 ppm), FW50 (\approx 5000 ppm), FW100 (2400 ppm), FW200 (\approx 1000 ppm), and FW500 (500 ppm). The FW100 (2400 ppm) brine concentration is optimal for this system, as shown in **Figure 9**, which is the same as that of limestone, dolomite, and limestone 75%-dolomite 25%. Of the studied systems, the limestone 50%-dolomite 50% exhibited the highest optimum performance. Some theories have been proposed to explain the success of low-salinity water flooding in carbonate reservoirs [11] [23] [24]. A summary of some proposed low-salinity recovery mechanisms is presented in **Figure 10** [25]. A key mechanism is the exchange of Ca^{2+} and Mg^{2+} between the aqueous and carbonate phases. This ion exchange can lead to wettability changes in the rock, which in turn can improve the flow of oil through the pore spaces [21]. In low-salinity water flooding, carbonate minerals; Such as calcite and magnesium, can dissolve, altering the brine composition [25]. This may affect the concentration of divalent ions on the rock surface, thereby improving recovery from low-salinity water flooding.

Two observations were made during the injection of low-salinity brine, that there was an increase in recovery when divalent cations, especially Ca^{2+} , were present in the formation brine [21] and that effluents from low-salinity tests showed

a strong reduction in Mg^{2+} concentration, suggesting that oil recovery was increased since the divalent ions were in balance. The high-performance result presented for the limestone 50% - dolomite 50% could be due to possible dissolution and multi-component exchange of ionic processes during low-salinity flooding. The limestone 50% - dolomite 50% environment will yield a balanced amount of calcium and magnesium in the brine, which will result in a maximizing of Multi-component ion exchange as explained. **Figure 11** shows the time, oil production rate, and oil recovery at WBT of different brines for the limestone 50% - dolomite 50% system. In terms of oil recovery and breakthrough time, FW100 displayed the best performance—higher recovery and higher WBT. The results also indicated that an equal amount of water was injected to reach the breakthrough for all brines tested.

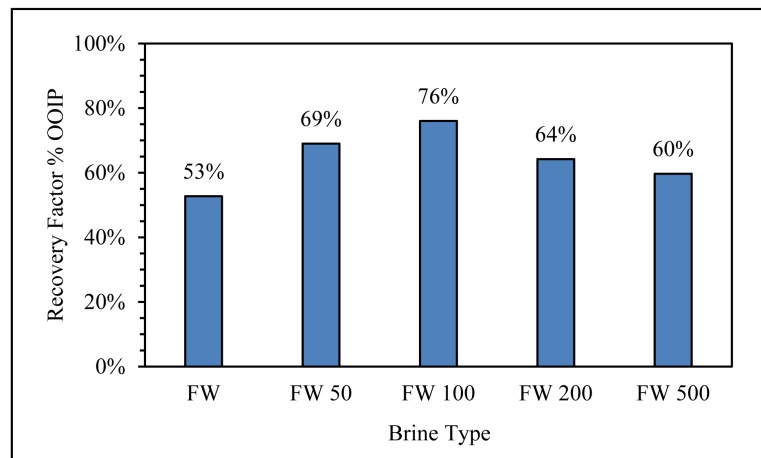


Figure 9. Recovery factor for different diluted brines: Limestone 50% - dolomite 50%.

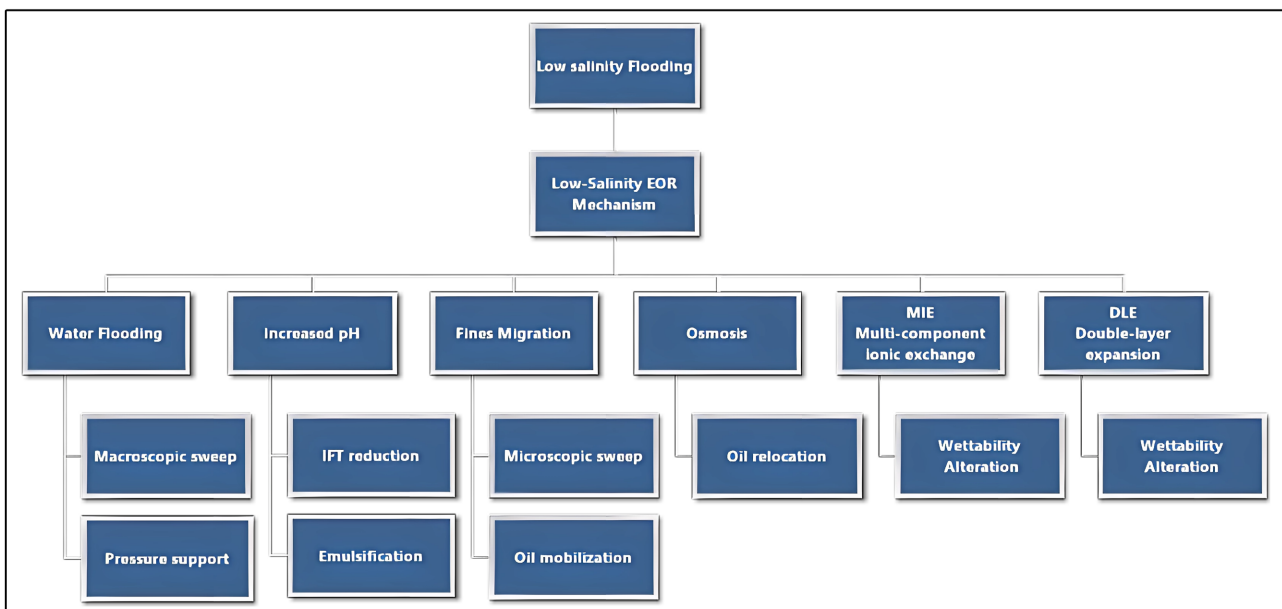


Figure 10. Summary of proposed low-salinity recovery mechanisms [25].

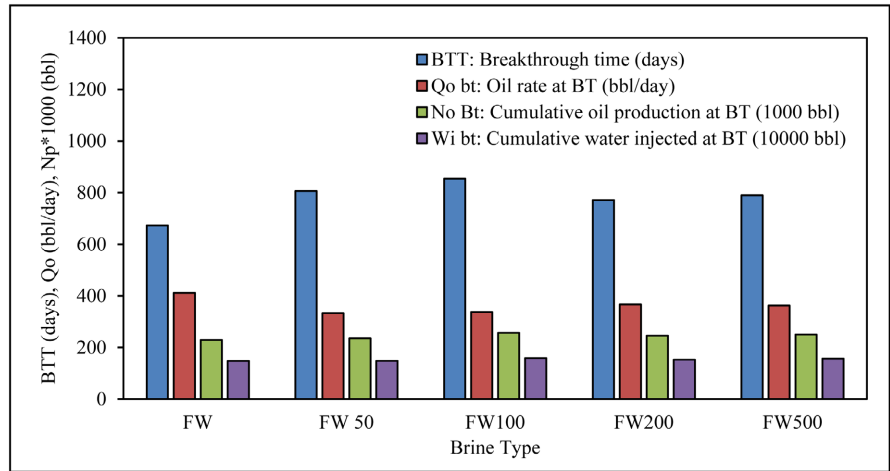


Figure 11. Time, oil production rate, and oil recovery at WBT of different brines: Limestone 50% - dolomite 50%.

3.5. Mineral Composition Limestone 25% - Dolomite 75%

Five runs were conducted to investigate the effects of a dolomite-dominated system (75%) during high- and low-salinity water flooding. **Figure 12** presents the recovery factor as a function of brine salinity. According to the study results, reducing the brine salinity by 100% improved the water-flooding recovery efficiency by 15%, with a similar trend for different mixing ratios of limestone and dolomite. The recovery factor increased with decreasing brine salinity up to an optimum salinity of FW100 (0.24 wt%) after which a reduction in the recovery factor was observed.

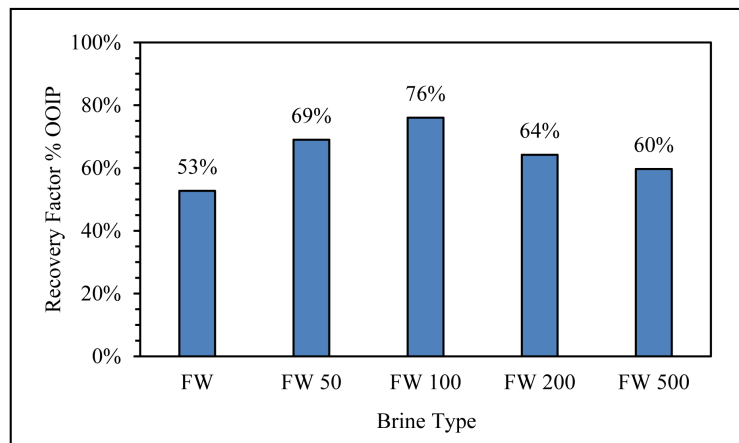


Figure 12. Recovery factor for different diluted brines: Limestone 25% - dolomite 75%.

The performance of a dolomite-dominated system at water breakthrough is presented in **Figure 13**. The time, oil production rate, and oil recovery for water injected at WBT of different brines for limestone 25% - dolomite 75% are presented in **Figure 13**. In terms of oil recovery, FW50 displayed the best performance—higher oil recovery. There was also no marked difference in the amount

of water injected to reach the breakthrough for all brines tested. FW50 and FW100 breakthrough times were identical and higher than other brines tested.

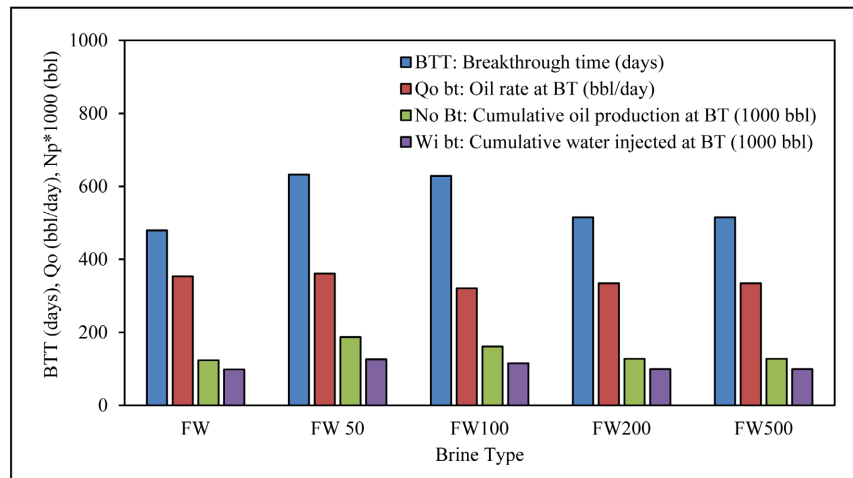


Figure 13. Time, oil production rate, and oil recovery at WBT of different brines: Limestone 25% - dolomite 75%.

3.6. Overall Comparison

The results indicated that limestone and dolomite percentages in the mixture had no effect on the optimum brine salinity and all mixtures had an optimum salinity of FW100 (2400 ppm). However, mixing limestone and dolomite had an effect on the amount of oil recovery at the end of the project and relations between the lithology and recovery were non-linear. In general, increasing limestone in the mixtures tends to increase the oil recovery and the optimum mixture for the studied systems is the balanced system of limestone 50%-dolomite 50% (Figure 14). Similar results were observed at water breakthrough. Generally, increasing limestone content results in better oil recovery; however, the optimum salinity for all mixtures is FW50 (≈ 5000 ppm) except for the limestone 50% - dolomite 50% mixture, where the optimum salinity is equal to FW100.

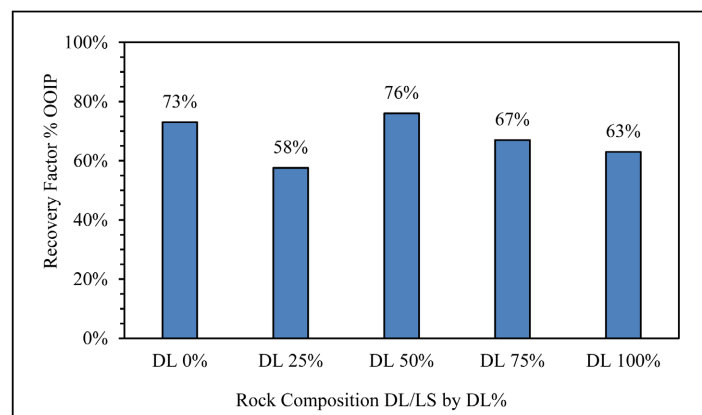


Figure 14. Recovery for different mixture of dolomite (DL) and limestone (LS) systems with factor and optimum brine FW100 diluted.

The findings here are consistent with previous trends in salinity at a given temperature, where limestone has a higher wettability alteration nature than dolomite. Furthermore, it has been reported that the mineralogical composition of reservoir rock can affect the effectiveness of high- and low-salinity water flooding [15] [26]. The dolomite to calcite (limestone) ratio is one key factor [15]. The behavior of dolomite-rich reservoirs during low-salinity flooding is different from that of calcite-rich reservoirs, as reported by Azim *et al.* [15] and confirmed here. Organic matter and sulfide minerals in dolomite rock, particularly pyrite, can play a key role in the interaction between water and rock [6]. During the oxidation of pyrite in the presence of ferric ions, the rock environment may become acidic, potentially impairing the wettability alteration process [27]. Further, the surface chemistry of dolomite is different from that of calcite, which can affect polar compound adsorption and desorption on the rock surface.

In dolomite-rich reservoirs, polar surfaces with excess charges may readily form bonds with ions or molecules in the surrounding medium. This causes surface oxidation reactions that negatively affect oil recovery as reported here and confirmed by Liao *et al.* [6]. In contrast, polar crude oil components tend to interact more strongly with positively charged carbonate surfaces in calcite-rich reservoirs than in dolomite reservoirs. This can result in a more favorable wettability alteration towards a more water-wet state during low-salinity water flooding, which is in line with our presented results [13] [15]. It has been shown in our work that low-salinity water flooding can have considerable differences between reservoirs rich in dolomite and those rich in calcite. A variety of factors can affect oil recovery, including dissolution of carbonate minerals, changes in surface chemistry, and wettability alteration. Dolomite and calcite are considered to be important factors in low-salinity water flooding, but their mechanisms are complex and not sufficiently understood. Further research is required to elucidate the underlying processes and optimize the application of this enhanced oil recovery technique to a variety of reservoir rock compositions [13] [15] [23] [28]. The overall comparison is summarized in **Table 1**.

Table 1. Comparison of the performance of brines for different mixtures of dolomite (DL) and limestone (LS) at WBT.

Mineral composition	LS 100%, 0% DL	LS 75%, 25% DL	LS 50%, 50% DL	LS 25%, 75% DL	LS 0.0%, 100 DL
Optimum brine	FW 50	FW 50	FW 100	FW 50	FW 50
Highest BT time, years	2.73	1.85	2.34	1.73	1.91
Highest Np*100000 bbl	3.20	1.88	2.57	1.87	2.29

4. Conclusions

The results of the performance of low- and high-water salinity flooding of carbonate reservoirs with a wide range of rock mineralogy revealed that the water salinity and mineral composition of carbonate rock are found to have a considerable effect on

ultimate oil recovery. The optimum salinity for different mineralogical compositions employed here was constant (2400 ppm). In general, increasing limestone in the mixtures tends to increase the oil recovery and the optimum mixture for the studied systems is the balanced lithology system of limestone 50% - dolomite 50%. Considering these findings, the following conclusions can also be drawn:

- Reservoirs rich in dolomite and those rich in calcite have different responses to low-salinity water flooding.
- The amount of oil recovered in a limestone/dolomite system tends to increase as the limestone content increases.
- It is believed that dolomite and calcite play an important role in low-salinity water flooding, but their mechanisms are complex and unresolved.
- In the design of low-salinity water flooding projects, mineral variations within the reservoir should be considered.

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Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

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