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The Performance of Engineered Water Flooding to Enhance High Viscous Oil Recovery

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Abstract: Low salinity/engineered water injection is an effective enhanced oil recovery method, confirmed by many laboratory investigations. The success of this approach depends on different criteria such as oil, formation brine, injected fluid, and rock properties. The performance of this method in heavy oil formations has not been addressed yet. In this paper, data on heavy oil displacement by low salinity water were collected from the literature and the experiments conducted by our team. In our experiments, core flooding was conducted on an extra heavy oil sample to measure the incremental oil recovery due to the injected brine dilution and ions composition. Our experimental results showed that wettability alteration occurred during the core flooding as the main proposed mechanism of low salinity water. Still, this mechanism is not strong enough to overcome capillary forces in heavy oil reservoirs. Hence, weak microscopic sweep efficiency and high mobility ratio resulted in a small change in residual oil saturation. This point was also observed in other oil displacement tests reported in the literature. By analyzing our experiments and available data, it is concluded that the application of standalone low salinity/engineered water flooding is not effective for heavy oil formations where the oil viscosity is higher than 150 cp and high oil recovery is not expected. Hence, combining this EOR method with thermal approaches is recommended to reduce the oil viscosity and control the mobility ratio and viscous to capillary forces.

Keywords: low salinity water; engineered water; viscosity; heavy oil; screening

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Citation: Ganiyeva, A.; Karabayanova, L.; Pourafshary, P.; Hashmet, M.R. The Performance of Engineered Water Flooding to Enhance High Viscous Oil Recovery. *Appl. Sci.* **2022**, *12*, 3893. https://doi.org/10.3390/app12083893

Academic Editor: Eugenio Quaranta

Received: 7 March 2022
Accepted: 9 April 2022
Published: 12 April 2022

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1. Introduction

Nowadays, most active large reservoirs are at the tertiary development stage. Different enhanced oil recovery (EOR) approaches are designed to improve oil production at this stage. The main aim of EOR techniques is to reduce the residual oil saturation after primary recovery or secondary recovery methods such as waterflooding. It is estimated that about 45% of OOIP is the objective of enhanced oil recovery techniques [1]. Besides well-known, classical EOR methods such as chemical EOR, gas flooding, and thermal methods, some new ones are gaining attention lately. One of them is Low Salinity Water Injection (LSWI), which is one of the promising techniques of tertiary recovery and is simple from the point of technical implementation. In general, it is the same as a waterflooding process, but with the optimized water, in the case of salinity and ionic composition. The low salinity water (LSW) is prepared by seawater dilutions and adjusting ions compositions in the injected brine, also called engineered water (EW).

LSW injection (LSWI) impacts the primary crude oil-brine-rock (CBR) system mainly by disturbing the system equilibrium by altering the ion composition of water [2]. Changing the interactions in the CBR system modifies the wettability, enhances the microscopic sweep efficiency and affects the capillary pressure and other CBR parameters such as rock surface properties. The performance of LSW and EW flooding in carbonate and sandstone

formations was studied by different experimental and modeling approaches. They prove the effectiveness of this technique in reducing the residual oil in various cases [3,4]. This method is less investigated in carbonate rocks than in sandstones [5]. It was believed that the presence of clays is required for a successful LSW injection, but the recently promising implementations of LSW in carbonates are reported in papers [6,7].

Different mechanisms are active during the oil recovery by LSWI in carbonates and sandstones [8–10]. For carbonates, there are different proposed mechanisms that affect the rock-fluid and fluid-fluid interactions. The rock-fluid interactions are recognized as the reason for wettability alteration. Mechanisms such as multi-ion exchange, mineral dissolution, change in surface charge, and the adhesion energy of CBR are the main mechanisms observed in the literature [2,11,12]. The Multi-Ion exchange mechanism is due to the presence of Ca^{2+}, Mg^{2+} and SO_4^{2-} ions and their interactions with oil and rock surface. The negatively charged SO_4^{2-} approaches the positively charged carbonate rock surface and wetting water phase; while, $Ca^{2+}Mg^{2+}$ reacts with negatively charged crude oil components and separates them from the rock surface, resulting in the wettability alteration [13]. For sandstone reservoirs, the polar compounds of oil (including asphaltene and resin content) with multivalent cations form a bond on a clay surface [2]. This statement cannot be confirmed for the carbonate case because of the lack of clay content. Another mechanism, mineral dissolution, occurs due to the difference in the ions composition in the injected water and the rock, which results in the movement of cations from the rock surface to the water, which leads to oil detachment and wettability alteration. This process is recognized as one of the independent wettability alteration mechanisms [14]. All listed mechanisms lead to the wettability alteration to a more water-wet state, resulting in the oil's detachment from rock surfaces.

The success of this method depends on factors such as the injected water properties, the rock type, oil characteristics, and injection scenarios. All these parameters directly or indirectly affect the wettability change process. This topic is well covered by Austad et al. [15]. Carbonates wetting state depends on the chemical properties (carboxylic material) of crude oil, reservoir conditions, and the reservoir rock composition. Hence, the wetting can be altered by affecting the CBR interactions, such as the salinity and the concentration of reactive ions in the injected water, also called potential determining ions (PDIs).

Most of the review papers highlighted the critical criteria for successful LSWI implementation. In the paper of Tetteh et al. [6], the authors went through several key parameters that affect the performance of LSWI in carbonates. The effect of temperature, injected water salinity and composition, the composition of oil sample (acid and base numbers), rock structure specifications, and aging duration were analyzed. The authors also proposed different mechanisms based on the media length scale. Another screening criteria was also discussed by Chavan et al. [16]. The salinity of injected brines, oil compositions, the wettability state of rock, and the connate water properties were considered for screening and predicting a favorable condition for LSWI performance in carbonates. They suggested that high clay content, optimum brine salinity, basic environment, presence of polar components in the oil, oil-wet state of the rock, and brackish connate water are required to achieve a successful LSWI.

With the help of machine learning methods, other screening criteria were developed by analyzing available data of different successful and unsuccessful experimental studies reported in the literature. Wang et al. reported such an approach to screening required criteria for LSWI in sandstone reservoirs [17]. The authors mentioned that a combination of criteria is needed to achieve the wettability alteration, and the effect of a single parameter is not enough to evaluate the method's performance. A similar data-driven analysis was reported by Salimova et al. for carbonate formations [18]. Data from different sources were analyzed to investigate the effect of rock and fluid properties on the active mechanisms of LSWI in carbonates and the success of the approach. They found that parameters such as pH, water salinity, and ion composition are strong parameters to forecast the possible outcome of the LSWI implementation.

The effect of oil properties as a screening parameter on the performance of LSWI was also discussed in other sources such as Tetteh et al. [6] and Hao et al. [7]. It is widely reported that the initial state of wettability is strongly affected by the crude oil properties. Presence of polar components in oil results in a more oil-wet state due to their adsorption to the rock surface. Parameters such as the acid and the base number impact carbonates wettability and, consequently, recovery due to the wettability alteration by LSWI. The higher the acid number, the more oil-wet rock is, which affects the oil extraction by LSWI [19]. Base number variation was also studied by Puntervold et al. (2008) [20]. Hence, acid and base numbers are other oil properties that should be considered for a successful selection and design of LSWI [21]. The effect of other properties, such as the fraction of heavy polar components in oil, was also investigated by Tang et al. [22,23].

Even though considering the oil parameters are significant in the LSWI screening and implementation, the effect of physical oil parameters such as oil viscosity and API on the success of LSWI has not been investigated yet. [16]. For example, in 160 core flooding tests analyzed by Salimova et al. [18], the viscosity of only 3% of oil samples was higher than 15 cp, which shows the tendency to apply LSWI for light oils. Hence, there is still a question on the performance of LSWI in heavier oil, where other parameters such as acid number are favorable.

The application of LSWI in the combination of thermal EOR methods for heavy oil was reported in a few papers in the literature. Abbas et al. [23] conducted oil displacement experiments with different oil samples with 1700, 1000, and 700 cp viscosity. Hot water was used in their tests, which combined thermal EOR and LSWI. Their results showed a low recovery for oil samples with 1700 cp viscosity. Al-Saedi et al. [24,25] conducted a similar approach with LSWI and thermal steam injection to a core saturated with a 600 cp oil sample. The core flooding was conducted on a cycled injection scheme. Despite the steam effect here, the injection of LSWI resulted in higher recovery than the standalone steam flooding, which shows the possible activity of LSWI mechanisms for heavy oil. Sekerbayeva et al. [26] and Shakeel et al. [27] also used LSWI for 170–190 cp oil combined with chemical EOR methods. Due to the high temperature and presence of chemicals, still, the effect of LSWI is not clear. Similar recovery tests for heavy oil were reported in the papers [28–34].

Hence, still, the applicability of LSWI as a standalone EOR approach for heavy oil is not clear. Oil viscosity should be another criterion for screening LSWI as an EOR approach. In this study, we will answer these questions by conducting laboratory experiments and collecting data reported in the literature.

2. Materials and Methods

The effect of LSWI on the heavy oil displacement and recovery in carbonates is analyzed by data measured in our experiments and data collected from the literature. This section defines the data collection procedure and experiments methodology in detail.

2.1. Experiments Methodology

2.1.1. Materials

To study the effect of EW on heavy oil recovery, an oil sample from a heavy oil field in West Kazakhstan was collected with a reservoir depth is 362–376 m and an average reservoir temperature of 26–36 °C [35]. The oil flashpoint is 108 °C, and the pour point is −17 °C. Table 1 shows the oil properties. The oil is highly resinous (25.8%) and contains 1.4% of paraffin, 4.1% of asphaltenes, and a significant amount of sulfur (2.51%) [36]. The acid number of crude oil is equal to 4.77 mg/KOH.

Table 1. Oil properties.

Temperature (°C)	Dynamic Viscosity (mPa·s)	Density (g/cm^3)
20	967.36	0.938
30	442.49	0.932
40	225.97	0.925
50	125.58	0.919
60	75.28	0.912
70	47.88	0.905

Core plugs with a diameter of 37 mm and 69–75 mm in length were cut from an outcrop carbonate sample. Porosity, absolute, and effective permeability of core samples were measured by core flooding, as shown in Table 2. Injection of formation water was performed to reveal the absolute permeability, and then oil injection was conducted to calculate the effective permeability. To restore initial wettability, fully oil-saturated core samples were aged for a month at 80 °C in the oven.

Table 2. Core plugs properties.

Core Plug	Porosity, %	Absolute Permeability (md)	Effective Permeability (md)
№1	17.53	35.66	18.59
№2	17.75	34.18	25.01
№3	17.88	31.23	17.31
№4	17.75	23.56	15.58

The semicircle pellets were cut with 0.5–1.5 cm width from the same carbonate outcrop. They were also dried in the oven for 3 days and saturated with oil in a vacuum saturation pump for a week to achieve the initial oil-wet state.

The LSW used in this experiment was based on dilution and ion adjustment of Caspian seawater (CSW). The composition of the formation water and CSW are shown in Table 3. Low salinity water (LSW) and engineered water (EW) options (EW1, EW2, EW3) were designed to achieve the highest wettability alteration. LSW was prepared by diluting the CSW 5, 10, and 20 times when the EW design was based on the optimal ions concentration adjustment. The best design was selected by investigation of wettability by contact angle measurement. The compositions of all EW/LSW samples used in our experiments are also shown in Table 3.

Table 3. Composition of formation water, seawater, LSW, and EW samples.

Ions	Formation Water, ppm	Caspian Seawater (CSW), ppm	5× Diluted CSW (LSW), ppm	5× Diluted CSW with 2Ca * 2SO_4 Ions (EW1), ppm	5× Diluted CSW with 2Mg * 2SO_4 Ions (EW2), ppm	5× Diluted CSW with 2Ca * 2Mg * 2SO_4 Ions (EW3)., ppm
Sodium (Na^+)	54,500	3300	660	660	660	660
Potassium (K^+)	0	155	31	31	31	31
Calcium (Ca^{2+})	9450	360	72	144	72	144
Magnesium (Mg^{2+})	1450	740	148	148	296	296
Chloride (Cl^-)	105,000	5400	1080	1080	1080	1080
Sulfate (SO_4^{2-})	0	3050	610	1220	1220	1220
Total concentration	170,400	13,005	2601	3283	3359	3431

2.1.2. Contact Angle Measurements and Chromatography Analysis

The contact angle measurements were conducted by an OCA 15EC video-based optical device using the bubble caption method. All oil-saturated pellets were aged in different diluted CSW samples and diluted brine with adjusted PDIs composition in a closed vessel. Contact angle measurements were done before and after the brine aging process, which lasted for 168 h. Different variations of PDIs (calcium, magnesium, and sulfates) were used to achieve the strongest effect on the CBR equilibrium. The best samples that showed the highest wettability alteration were 5× Diluted CSW (LSW) and 5× Diluted CSW with the different spiked compositions of cations and sulfate ions.

During the pellet aging process, the brine samples were collected to conduct the chromatography analysis separately in tubes. Dionex ICS 6000 chromatography device was used to study the ions composition alteration and active mechanisms during the interaction of LSW with heavy oil and carbonates. The brine samples were collected at 24, 72, 120, and 168 h after the start of the aging to track ion activity.

2.1.3. Core Flooding Procedure

The core flooding experiments were conducted on saturated cores to study the effect of dilution and PDIs on the heavy oil recovery. 4 injection scenarios were implemented to track investigate these effects as

Seawater (CSW) → 5× Diluted CSW (LSW);
Seawater (CSW) → 5× Diluted CSW with 2Ca∗ $2SO_4$ ions (EW1);
Seawater (CSW) → 5× Diluted CSW with 2Mg∗ $2SO_4$ ions (EW2);
Seawater (CSW) → 5× Diluted CSW with 2Ca∗ 2Mg∗$2SO_4$ ions (EW3).

Seawater was injected for secondary recovery in all tests until there was no further oil production. After this, LSW/EW was injected as the tertiary stage. The injection continued until the production stopped. These measured recovery points will be the basis for mechanism discussion and useful for viscosity analysis.

2.2. Data Collection

Some sources report LSWI to sandstones/carbonates saturated with oil with a viscosity higher than 150 cp. These data are collected and shown in Table 4. The recovery factor indicated in the table is the incremental recovery for low salinity water/engineered water injection. The main criteria for data selection were the temperature of the test (to be less than 60 °C) and the oil viscosity (to be more than 150 cp at room temperature). All these data are measured by core flooding tests. Injection at the secondary stage resulted in high recovery due to the high initial oil saturation. In most reported core flooding at the tertiary stage, the recovery is low and less than 10%.

Table 4. Data reported in the literature for the LSWI to heavy oil formations.

Source	Rock type	Viscosity, cp	Acid Number	Injection Mode	Recovery Factor by LSWI, %
Zhao et al. [29]	sandstone	202 @21 °C	Not reported	Tertiary	8.70%
					3%
					5.60%
				Secondary	49.40%
Hernandez et al. [32]	sandstone	2000 @54 °C	2.36	Secondary	24%
					28%
Ding. Et al [33]	sandstone	61,637 @22.5 °C	Not reported	Secondary	14.7%
					26%
Al-Saedi et.al [31]	sandstone	600	1.1	Tertiary	4.45%
					5.80%
					7.80%

Table 4. Data reported in the literature for the LSWI to heavy oil formations.

Source	Rock type	Viscosity, cp	Acid Number	Injection Mode	Recovery Factor by LSWI, %
Nasralla et.al [35]	carbonate	179.2 @20 °C	Not reported	Secondary	79%
					64%
				Tertiary	2%
					3%
					14%
					8%
					3%
					9%
					7%
					3%
					2%
					5%
Bhicajee et al. [37]	sandstone	3622	Not reported	Secondary	24%
					23.50%

3. Results and Discussion

3.1. Contact Angle Measurement and Chromatography Analysis

All core samples were initially strongly oil-wet. Due to the aging by different LSW/EW designs, wettability was altered to a more water-wet state, which can be observed by the change in the contact angle. Figure 1 shows the difference between initial and changed contact angles for different brines. The changes in the contact angle for diluted Caspian seawater vary from 7.7° to 13.77°. The change is explained by the surface charge alteration. The sulfate ions are adsorbed on the carbonate surface and replace the negatively charged carboxyl groups. The carboxyl groups leave the surface with positively charged cations, which previously were in the composition of injected brine. This action changes the wettability to a more water-wet state. Figure 1 represents the differences in contact angles by different dilutions of Caspian seawater (LSW) and ion-tuned water (EW). Five times diluted seawater (5× Diluted CSW (LSW)) showed the best wettability alteration by dilution, and it is chosen as the optimum dilution for engineered water preparation. By spiking Ca^{2+} cation and SO_4^{2-} anion, a bit higher alteration to the weaker oil-wet state was also observed among engineered water options. The results showed that the activity of cations affects the oil detachment from the rock. These interpretations were based on Zhang et al. [13,38]. In these papers, the role of PDI (potential determining ions) activity in wettability alteration was discussed.

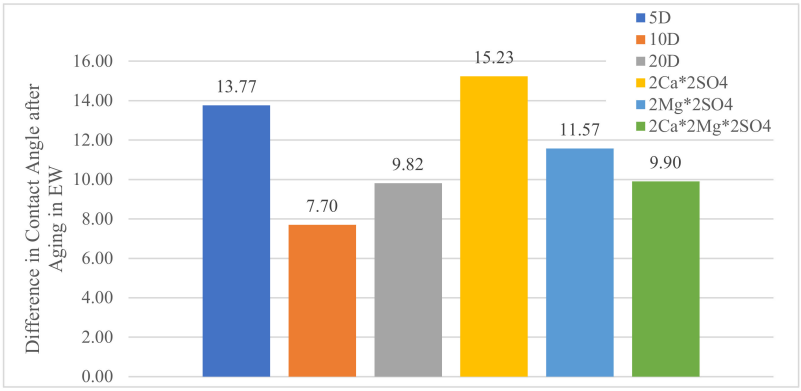


Figure 1. Contact angle difference by aging with Low Salinity Water/Engineered Water samples.

The chromatography analysis results are shown in Figure 2. On the graphs, the *x*-axis shows the time after the start of the experiment, and the *y*-axis is for the concentration ratio (C/C_0). C is the concentration at a given time t, and C_0 is the initial ion concentration. The figure on the left shows the ions concentration change in 5 times Diluted CSW (LSW) brine during the aging of the oil-saturated pellet. The right figure shows the dynamic ions concentration during the aging of the clean pellet with the same LSW sample. The increase of calcite and sulfate concentrations during the aging of the clean core shows that the rock dissolution mechanism is active. However, the magnesium concentration is stable, which means magnesium is not significantly active during the dissolution. The presence of oil also activated the multi-ion exchange mechanism, confirmed by the adsorption of cations on the rock at later times, as shown in the left figure. Hence, contact angle and chromatography results showed that the well-known mechanisms such as rock dissolution and multi-ions exchange were active, leading to wettability alteration.

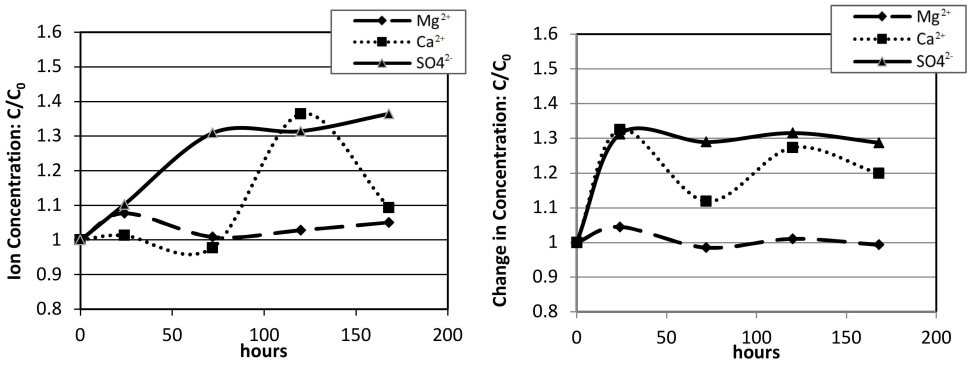


Figure 2. Change of Potential Determining Ions concentration during aging of an oil-saturated rock (**left**) and a clean rock (**right**) with Low Salinity Water (5× Diluted CSW).

3.2. Oil Displacement

Four core flooding experiments were conducted with different LSW/EW brines. For all experiments, the secondary mode showed a significant recovery factor by seawater injection, but still, a noticeable amount of residual oil remained in the porous media. As an EOR stage, the low salinity water and three options of engineered water were injected. In scenario 1 (injection of 5× Diluted CSW), the experiment was held on the core №1. The recovery factor, pressure difference, and injection rates are presented in Figure 3. Recovery for seawater was identified as 67.51%, and the final recovery has not changed %, which means there is no incremental oil recovery by LSW.

The core flooding experiment for scenario 2 was held on core №2. The tertiary stage was implemented by injecting the EW1, ion-tuned water with doubled calcium and sulfate ions concentration (5× Diluted CSW with $2Ca * 2SO_4$ ions). All results for the second flooding are presented in Figure 4. Recovery for seawater was identified as 72.7%, and no additional recovery was observed by the designed EW with doubled calcium ions.

The core flooding experiment for scenario 3 was held on core №3. For this case, the magnesium/sulfate ions concentration was doubled in the engineered water (5× Diluted CSW with $2Mg * 2SO_4$ ions, EW2) injected after seawater. Results for the third flooding are presented in Figure 5. Recovery for seawater was identified as 74.95%, and with ion-designed water, it reached 76.93%. The additional recovery was 1.98%.

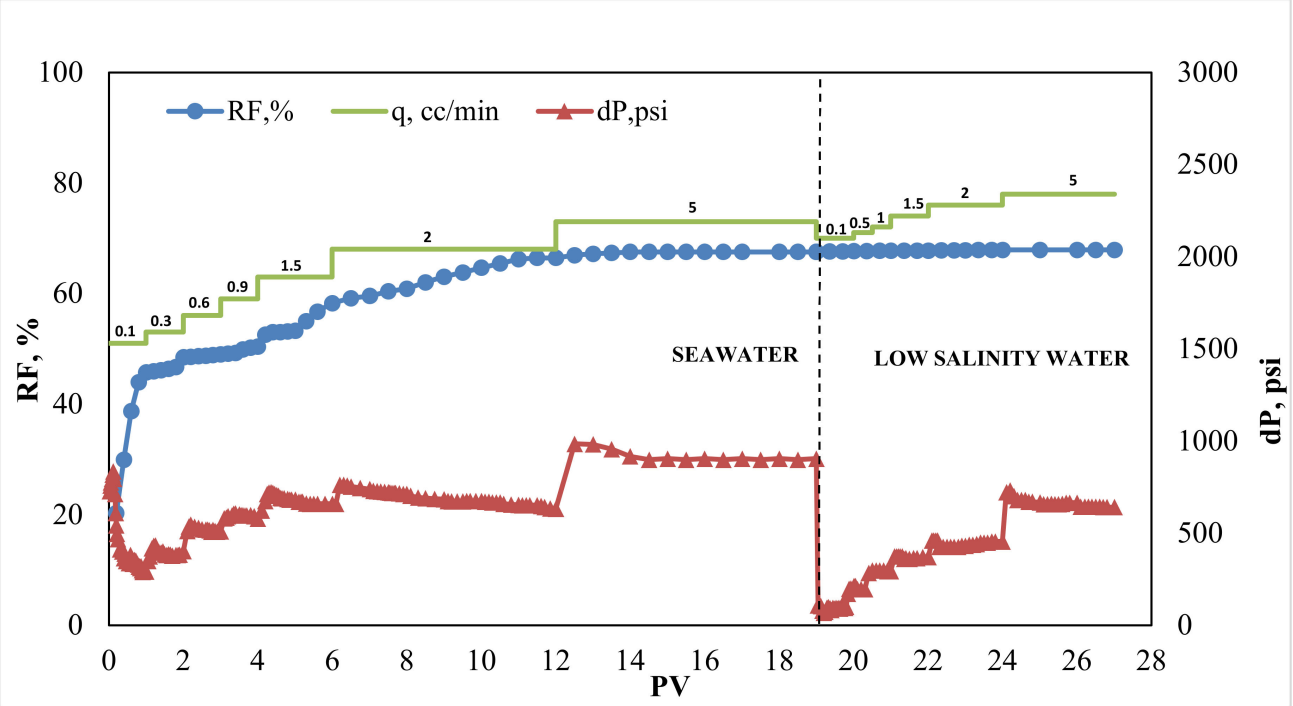


Figure 3. Low salinity water injection (5× Diluted CSW) core flooding results.

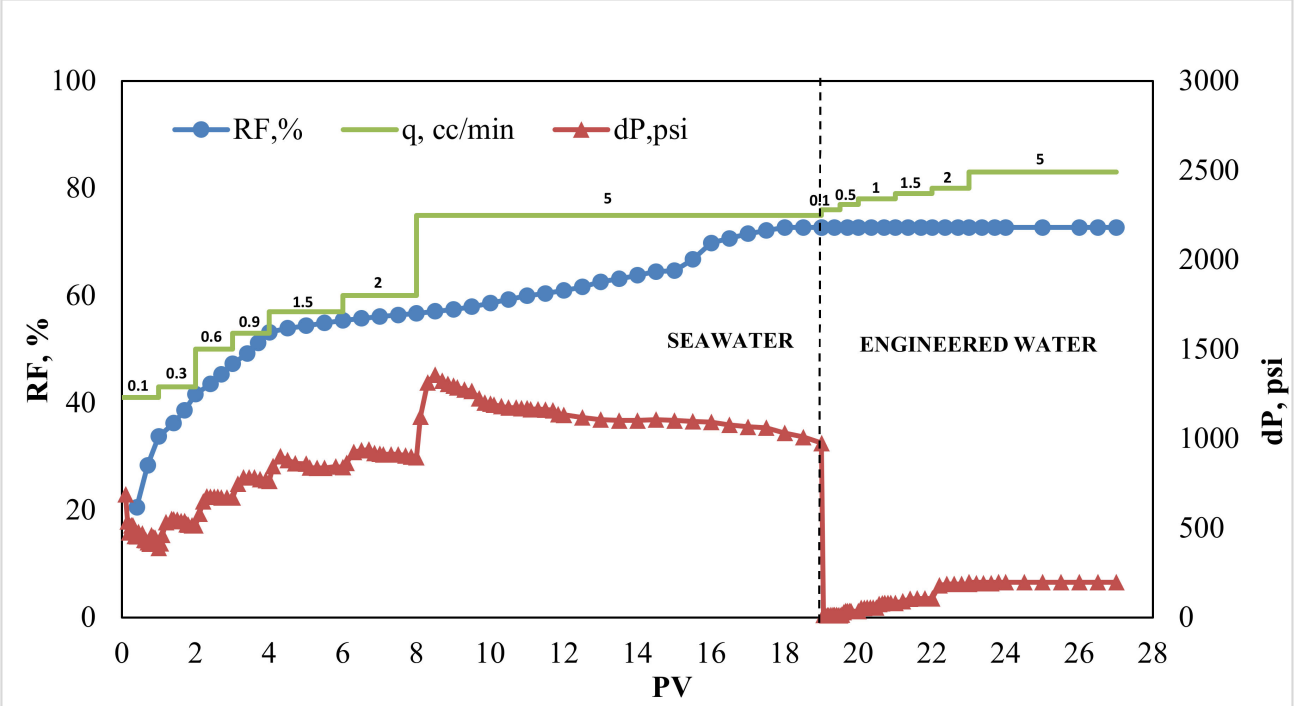


Figure 4. Engineered water (EW1) injection core flooding results (5× Diluted CSW with $2Ca * 2SO_4$ ions).

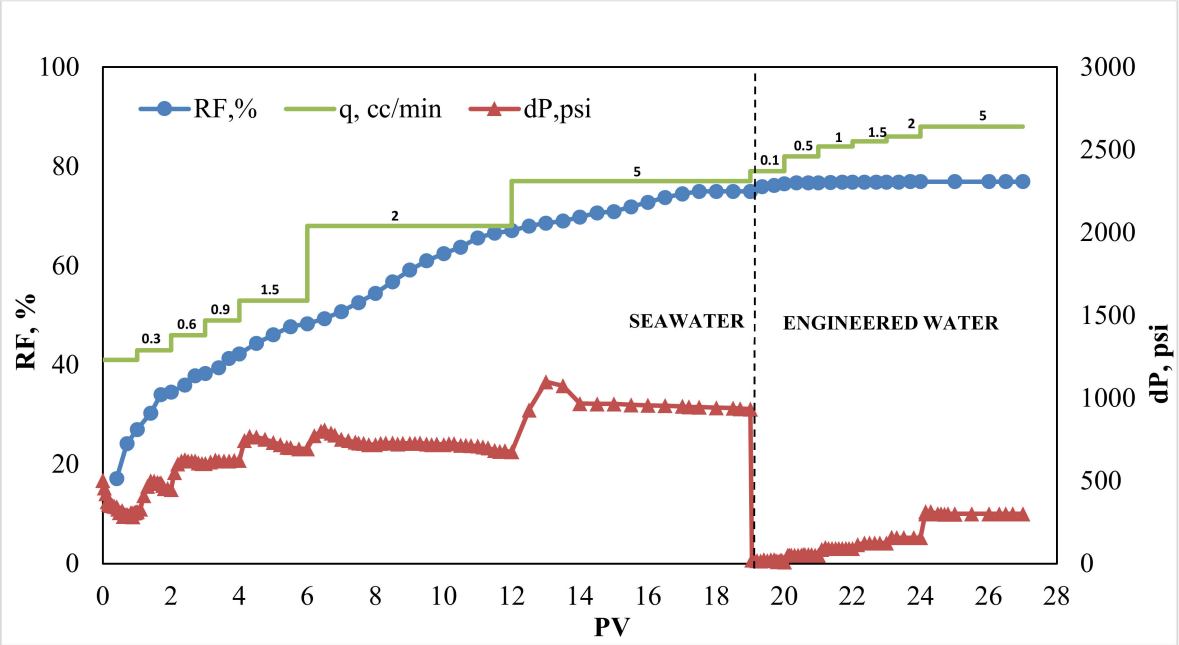


Figure 5. Engineered water (EW2) injection core flooding results (5× Diluted CSW with $2Mg * 2SO_4$ ions).

The core flooding experiment based on scenario 4 was conducted on core №4. The tertiary stage brine was designed with doubled cations (calcium and magnesium) and sulfate ion (5× Diluted CSW with $2Ca * 2Mg * 2SO_4$ ions (EW3). Results of flooding are presented in Figure 6. Recovery for seawater was identified as 66.79%, and with engineered water, it reached 70.15%. The additional recovery was 3.36%.

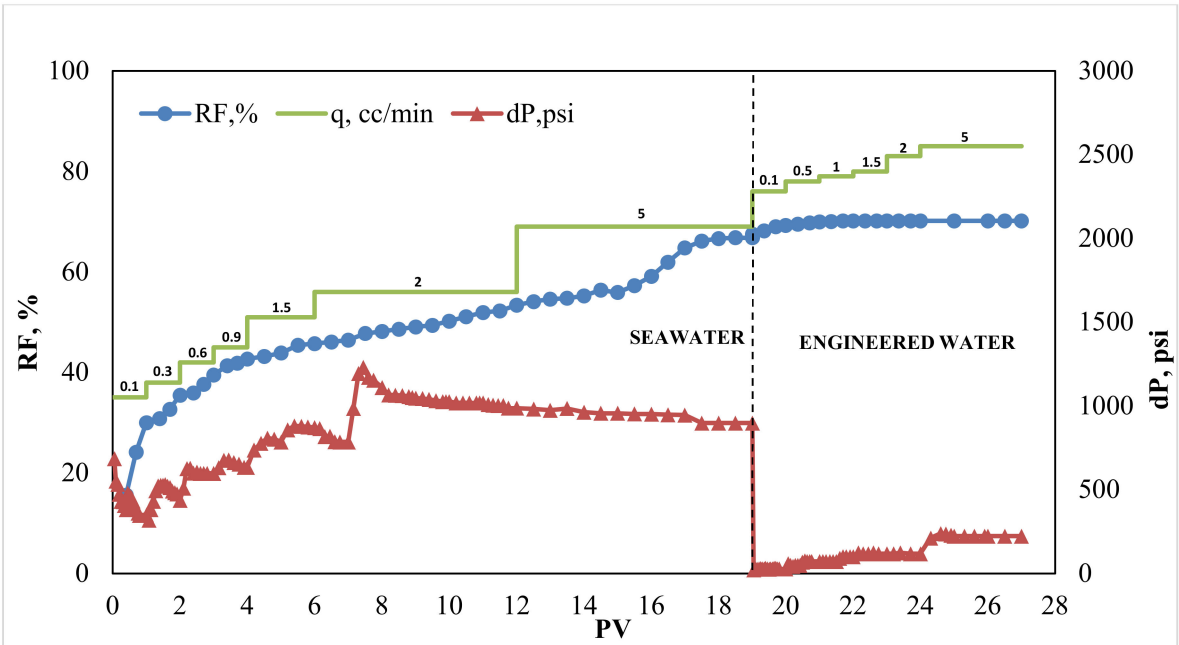


Figure 6. Engineered water (EW3) injection core flooding results (5× Diluted CSW with $2Ca * 2Mg * 2SO_4$ ions).

Figures 3–6 also show the flow rate (q) and pressure drop (dP) along with the recovery (RF) during the flooding. Each flow rate was maintained until we produced clean water.

The change in pressure drop occurred due to the increase in the flow rate and alteration in relative permeability by the decrease in the oil saturation in the porous media. A significant pressure drop variation was observed by switching the recovery stages from seawater to low salinity/engineered water. The numerical results for recovery, additional recovery, and remaining oil RF for all 4 cases are presented in Table 5.

Table 5. Core flooding results summary.

Test	Core №	RF by Seawater (% OOIP)	RF by LSW/EW (% OOIP)
LSW (5× Diluted CSW)	1	67.51	0
EW1(5 × Diluted CSW with 2Ca∗ $2SO_4$ ions)	3	72.7	0
EW2 (5 × Diluted CSW with 2Mg∗ $2SO_4$ ions)	2	74.95	1.98
EW3 (5 × Diluted CSW with 2Ca∗ 2Mg∗ $2SO_4$ ions)	4	66.79	3.36

3.3. Effect of Oil Viscosity on LSW/EW Performance

Data measured by our experiments (4 points for 967 cp viscosity), shown in Table 6, are added to the data list in Table 1. Totally 29 measured/collected data points were used for the study. The primary objective is to investigate the effect of oil viscosity on recovery factors by LSWI at secondary and tertiary injection stages.

Table 6. Core flooding results.

Data #	Papers	Rock type	Viscosity, cp	Acid Number	Injection Mode	Recovery Factor by LSWI,%
1	This study	carbonate	967	4.47	Tertiary	0
2						0%
3						1.98%
4						3.36%

The dependence of the recovery factor on the oil's viscosity for all measured/collected data was plotted, as shown in Figure 7. The figure contains the viscosity/recovery tertiary recovery data from papers listed in Table 4 [28,30,34] and the results of our core flooding tests. Small triangle points show actual recovery data for the tertiary development stage. These data can be categorized into three groups, one group for the recovery factor of oil samples with the viscosity in the range of 200 cp, the second the group with viscosity in the range of 600 cp, and the last one in the range of 1000 cp. The average arithmetic value of the recovery factor for each category is shown in Figure 7 by the grey rectangle point. These points clearly show the recovery trend with increasing viscosity. On average, tertiary recovery in porous media containing heavy oil with a viscosity higher than 150 cp cannot produce more than 6%, which is much lower than the typical recovery by LSW/EW. This number becomes much lower at viscosity values of more than 800 cp.

In Figure 8, the same data from Table 4 are reported but for the secondary recovery development (9 points) [28,31,32,34,37]. Similar to the previous graph, actual and average data are shown for different oil type categories. Oil samples are in the range of less than 1000 cp, 1000–10,000 cp, and more than 10,000 cp. For the highest viscosity range, the recovery factor is around 20%, which is low for the secondary recovery stage.

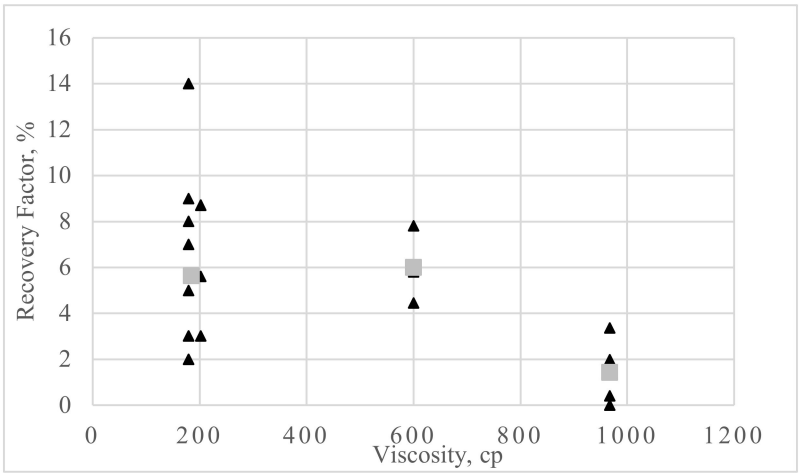


Figure 7. Incremental recovery factor and viscosity dependence for tertiary recovery.

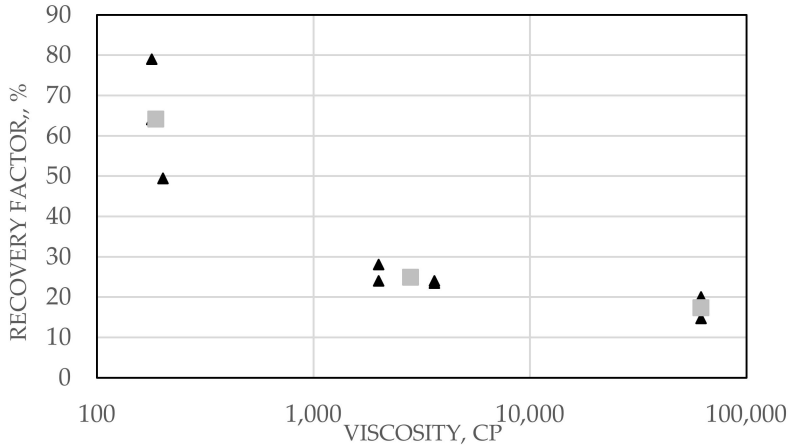


Figure 8. Incremental recovery factor and viscosity dependence for secondary recovery.

Figure 9 shows the normal distribution graph for the oil recovery during the EOR approach. This one-sided normal distribution curve shows that the observed data of the recovery factor has a limit with a certain value of viscosity. It can be observed that for 90% of collected data, the recovery is less than 10%, and for half of the data, the recovery is less than 4%, which is a poor indicator of a successful EOR method.

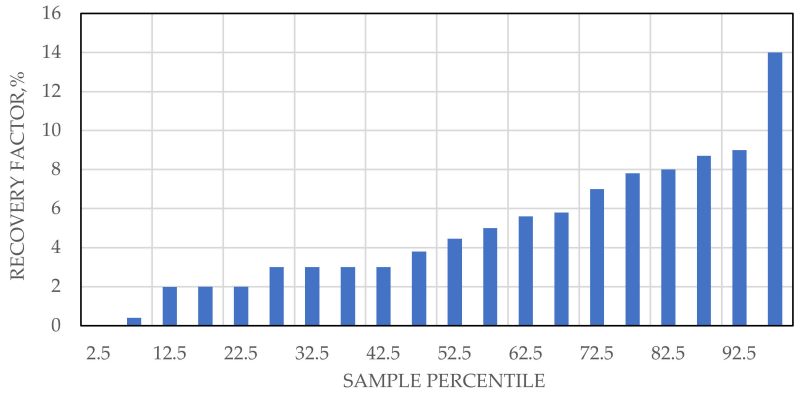


Figure 9. Normal distribution graph for tertiary recovery.

Our results show the poor performance of LSW/EW flooding when the oil viscosity is high. At high oil viscosity, the mobility ratio of the injected fluid and the oil is high, resulting in the propagation of channels, fingering, unfavorable flow, and low macroscopic sweep efficiency. The analysis showed that the wettability alteration mechanism is active during the LSW/EW flooding, and the presence of PDIs can even enhance it. However, due to the oil's high viscosity, the viscous force is still weak to overcome the capillary force and decrease the residual oil. Hence, the microscopic sweep efficiency is also low, leading to low oil recovery. Application of standalone LSW/EW is not recommended for reservoirs with an oil viscosity higher than 150 cp. It is better to apply hybrid EOR approaches such as thermal/LSW flooding. By applying thermal methods, oil viscosity decreases which improves the oil recovery in combination with the oil detachment by the LSW/EW interactions.

4. Conclusions

One novelty among the enhanced oil recovery methods is water injection with optimum salinity. As proven by many laboratory studies, the brine concentration affects the CBR system and leads to extra recovery. However, the technique is very case-dependent. The viscosity of the oil sample is a critical parameter that should be considered as another independent criterion for LSWI/EWI screening tables. The role of crude oil viscosity has been investigated in this work. The following conclusions were observed in this study:

- Contact angle measurements and chromatography analysis showed wettability changes in the CBR system via the mineral dissolution and activity of potential determining ions.
- The incremental recovery factor, on average, is less than 5% for high viscous oil at the tertiary stage. The average recovery for secondary recovery is 36%. The resultant analytical graph shows that the more viscous the oil (higher than 150 cp), the less the recovery factor. The successful implementation of LSWI is limited by viscosity dependence. Since the viscosity is a temperature-dependent parameter, LSWI is ineffective if the reservoir temperature is not high.
- If LSWI and engineered water injection are planned to conduct in heavy oil reservoirs, then using hybrid LSWI will boost the chances of extracting more oil. Hybrid LSWI includes a combination of LSW with a hot fluid injection. This technique will affect wettability alteration, enhance mobility ratio, and reduce the oil viscosity simultaneously. The study is based on core flooding experiments, and for field application, more investigations are required.

Author Contributions: Conceptualization, A.G. and L.K.; methodology, A.G. and L.K.; validation, A.G. and L.K. writing—review and editing, A.G. supervision, P.P. and M.R.H. All authors have read and agreed to the published version of the manuscript.

Funding: This research was funded by Nazarbayev University (grant number 11022021FD2910).

Acknowledgments: The authors would like to thank Nazarbayev University for supporting this research through the NU Faculty Development Competitive Research Grants Program (Grant number: 11022021FD2910).

Conflicts of Interest: The authors declare no conflict of interest.

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