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NOVEL COUPLING SMART WATER-CO_2 FLOODING FOR SANDSTONE RESERVOIRS; SMART SEAWATER-ALTERNATING-CO_2 FLOODING (SMSW-AGF)

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ABSTRACT

CO_2 flooding is an environmentally friendly and cost-effective EOR technique that can be used to unlock residual oil from oil reservoirs. Smart water is any water that is engineered by manipulating the ionic composition, regardless of the resulting salinity of the water. One CO_2 flooding mechanism is wettability alteration, which meets with the main smart water flooding function. Injecting CO_2 alone raise an early breakthrough and gravity override problems, which have already been solved using water alternating gas (WAG) using regular water. WAG is an emerging enhanced oil recovery process designed to enhance sweep efficiency during gas flooding. In this study, we propose a new method to improve oil recovery via synergistically smart seawater with CO_2. This new method takes advantage of the relative strengths of both processes. We hypothesized that SW depleted in NaCl provided more oil recovery. We also added that depleting NaCl in seawater is not the end of the story; diluting divalent cations/anions in the seawater depleted in NaCl provides higher oil recovery. Injecting smart seawater depleted in NaCl with diluted Ca^{2+} and CO_2 resulted in a high oil recovery percentage among the other scenarios. Thus, the above water design was applied as a WAG in three cycles, which resulted in a much higher oil recovery of 24.5% of the OOIP. This improved heavy oil recovery is a surprising and promising percentage. The spontaneous imbibition agreed with the oil recovery results. This study sheds light on how manipulating ions in the water used in WAG can significantly enhance oil recovery.

INTRODUCTION

The injected water composition has a thorough effect on the efficiency of water flooding. We reported that the concentration of Ca^{2+} and Mg^{2+} affects the wettability alteration of sandstone reservoirs (Al-Saedi et al., 2019a, 2019d). In this study, we investigate NaCl removal from the seawater and combine the resulted optimum smart water with immiscible CO_2 flooding to propose a new water alternating gas (WAG) process instead of using regular water that used in WAG to provide more oil recovery from heavy oil reservoirs. We also studied replacing regular water used in WAG with LS water to attain more oil recovery by altering the sandstone wettability and enhancing gas sweep efficiency (Al-Saedi et al., 2019d).

Recently, the interest in WAG has increased noticeably to enhance the gas sweep efficiency. The produced gas has been employed in pressure maintenance and enhanced oil recovery by contacting the unswept zones, improving gas mobility, and improving microscopic sweep efficiency. The environmental issues, taxes on CO_2, and the regulations of gas flaring are other advantages of reinjecting the gas (Christensen and Skauge, 1998).

The main functions of injecting CO_2 are (1) oil swelling (2) viscosity reduction (3) wettability modifications. The third function is met with smart water in wettability alteration towards being more water-wet. Wettability is playing a significant role in the performance of enhanced oil recovery (EOR) methods. Rock wettability can be determined by the thickness of the water film between the rock surface and the crude oil (Hirasaki, 1991). Wettability can be determined by various methods such as Amott-Harvey, contact angle, the United States Bureau of Mines (USBM), chromatographic separation method for carbonate, and chromatographic separation method for sandstone (Amott, 1959; Donaldson et al., 1969; McCaffery, 1972; Anderson, 1986; Strand et al., 2006; Al-Saedi et al., 2018). Numerous studies have shown that using smart water can alter the rock wettability and increase oil recovery in both carbonate and sandstone reservoirs (RezaeiDoust et al., 2009; Strand et al., 2009; Fathi et al., 2010, 2011; RezaeiDoust et al., 2011; Austad, 2013; Ghosh et al., 2016; Strand and Puntervold, 2018; Al-Saedi and Flori et al., 2018g). Other than the multifunctional features that CO_2 provides, rock wettability alteration is one of the main advantages (Stalkup, 1987; Grigg, 1998, 1999; Ghedan,

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2009; Salem and Moawad, 2013).

The resulted residual oil saturation after the WAG process is lower than residual oil saturation in water flooding and gas flooding (Wylie and Mohanty, 1999). The remaining oil saturation after WAG by LS water is lower than that in WAG by FW (Al-Saedi et al., 2019h). We believe that smartening the water will provide a lower residual oil saturation. To our knowledge, no experimental studies have been performed to consider brine composition manipulation combined with CO_2 flooding. Series of core-flooding experiments and spontaneous imbibition tests have been carried out to investigate the proposed study. Heavy crude oil and reservoir sandstone core plugs were utilized to apply the mentioned theory. It is worth mentioning that all CO_2 flooding in this study was carried out in the immiscible state.

EXPERIMENTAL METHODOLOGY

In order to evaluate our new proposed method, several successively core-flood experiments of smart water and CO_2 were conducted. The core-flood experiments include injection of the seawater, smart seawater sequentially, and ultimately CO_2 in reservoir sandstone cores taken from Bartlesville Sandstone Reservoir (Eastern Kansas). The core-flood experiments provided promising results that could change the traditional EOR methods.

The cores were delivered fully saturated with reservoir fluids and well coated with plastic wrap. Because the cores were bearing heavy oil, the following procedure was carried out:

1. The cores were cleaned by injecting kerosene until a clear effluent was observed.

2. Toluene was then pumped to displace the kerosene and to achieve extra cleaning.

3. Water with 3000 ppm NaCl replaced toluene and for dissolving formation water (FW) fluids.

4. The cores were then transferred to Soxhlet extractor for further cleaning.

5. The cores spent one day drying in the oven at 80°C.

The cores were then transferred to a vacuum container for evacuation purposes. A one-day vacuum was performed on all the cores; after that, synthetic FW with salinity of 104,000 ppm was presented to the cores under vacuum. FW basically consists of NaCl, $CaCl_2$, $MgCl_2$, Na_2SO_4, and KCl. Seawater contains the same salts except for KCl. The brine description is shown in Table 1. The XRD test on the reservoir core fragments indicated that the abundant minerals are quartz followed by clays. Crude oil was delivered from the same reservoir with viscosity around 600 cP and 0.83 gm/cc density. The crude oil was diluted with heptane in a 10/90 heptane/oil ratio. The resulting oil properties after dilution are shown in Table 2.

Porosity was measured by the weight difference between dry and wet weight. To saturate FW in the cores, a high injection pressure of 1000 psi was applied with an injection rate of 0.25 ml/min. FW was injected into the core to measure permeability using different flow rates. The criteria for changing the flow rate was obtaining a constant pressure. The FW was then displaced by three pore volumes (PVs) crude oil in both directions to establish S_{wi}, taking the same permeability measurement criteria in addition to no water observation in the effluent. To saturate crude oil in the cores, the same FW saturation procedure was performed. The cores were then aged in the crude oil for three weeks at 90°C to bring back the initial wettability.

After pre-aging duration has completed, the cores were then flooded with 2 PVs SW followed by 3 PVs smart seawaters (SMSW) (SMSW are described in Table 1), and then 5 PVs of CO_2 at 50°C. SW and SMSW were DDD
injected into the cores until no more oil was produced and the stabilized pressure was observed. The reservoir cores were flooded using the following scenarios:

1. RC16a was flooded with CO_2 only.

2. RC17a was flooded with SW followed by CO_2.

3. RC17b was flooded with SW followed by SW–0NaCl and CO_2.

4. RC17c was flooded with SW followed by SMSW1 and CO_2.

5. RC17d was flooded with SW followed by SMSW2 and CO_2.

6. RC17e was flooded with SW followed by SMSW3 and CO_2.

7. RC17e was flooded with SW followed by SMSW3 and CO_2 but in shorter cycles using our proposed design for low-salinity-alternating-steam-flooding (LSASF) (Al-Saedi and Flori et al., 2018d), which was 0.5 PV CO_2 + 0.5 SMSW3 + 0.5 PV CO_2 + 0.5 PV SMSW3 + 0.5 PV CO_2 + 0.5 PV SMSW3.

Table 1— Composition of the injected brine (mg/l).

Compound	FW	SW	SW–0NaCl	SMSW1 0NaCl—d5Ca	SMSW2 0NaCl—d5Mg	SMSW3 0NaCl—d5SO4
$NaCl$	81,000	25,000	0	0	0	0
$CaCl_2$	17,000	2000	2000	400	2000	2000
$MgCl_2$	5000	10,500	10,500	10,500	2100	10500
Na_2SO_4		4900	4900	4900	4900	980
KCl	1000	-	-	-	-	-
TDS	104,000	43,400	18,400	15,800	9,000	13,480

Table 2— Crude oil properties.

Viscosity, cP	Density, gm/cc	TAN, mg KOH/g	TBN, mg KOH/g
150	0.821	1.01	1.7

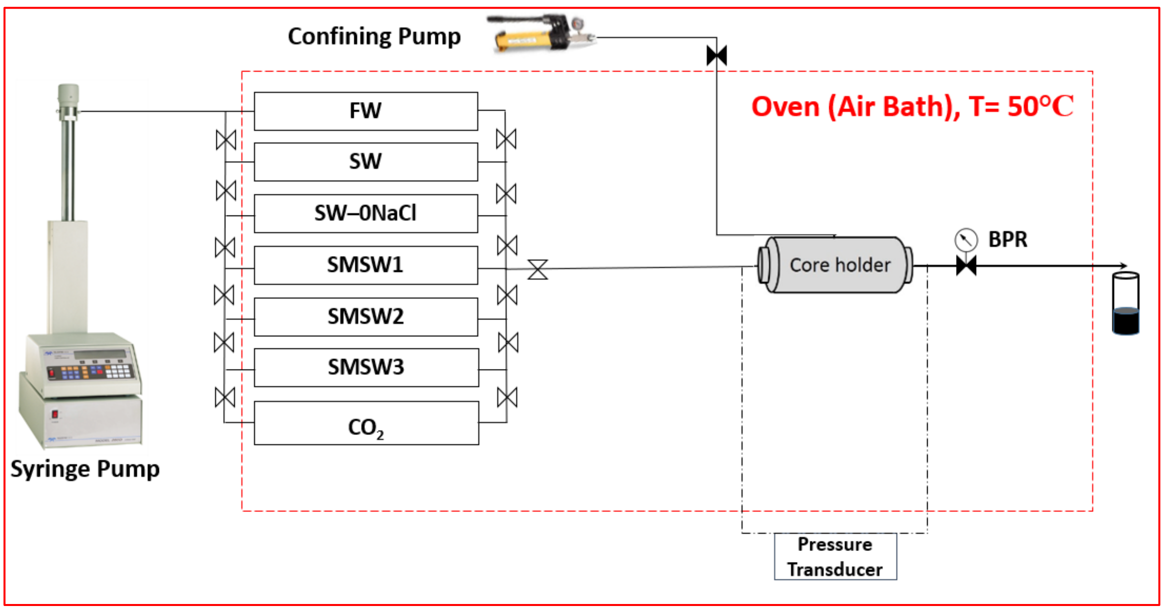

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Figure 1— Schematic of the core-flooding system.

The pressure across the core during core-flooding experiments was recorded using a pressure transducer on both sides of the core holder. A confining pressure 600 psi higher than injection pressure was applied to imitate the overburden pressure on the sandstone reservoir core plugs. The whole experimental equipment was installed inside the dispatch oven, which was set on 50°C (Figure 1). The minimum miscible pressure (MMP) was above 2000 psi. The backpressure regulator was established at 1200 psi, which provides immiscible CO_2 conditions.

CONTACT ANGLE MEASUREMENTS

The same brines that were used in the core-flooding experiments were also used for this test. The core substrates were cut and sanded on two sides using fine sandpaper. The substrates were treated with air to remove minerals' fins and were then rinsed with deionized water and treated again with air. The wet substrates were mounted in the oven to dry. The substrates were then attached to the glass platelet by glue. The specified brine was poured into the test chamber, and the entire glass platelet and the substrate were immersed inside the chamber until the substrate was immersed completely in the brine. The oil droplet was initiated via needle underneath the substrate until the droplet attached to the substrate surface. The light source and digital camera in the Ramé-hart advanced goniometer 500-F1 were used to measure contact angle using the pendant drop method.

SPONTANEOUS IMBIBITION TEST

For further wettability investigation of our proposed procedure, an imbibition test was conducted using the Amott cell. The cores that were used in the core-flooding experiments were cleaned as described previously and used in a spontaneous imbibition test. This was performed to limit the measurements' uncertainty due to mineralogy. Five brines were used, SW, SW–0NaCl, SMSW1, SMSW2, and SMSW3. RC17a, RC17b, RC17c, RC17d, and RC17e were immersed in an Amott cells filled with SW, SW–0NaCl, SMSW1, SMSW2, and SMSW3, respectively. The cores were immersed in the imbibing fluid for 20 days.

RESULTS AND DISCUSSION

CO_2 FLOODING

The results of this experiment are plotted vs. injected PVs in Figure 2. In this experiment, only CO_2 was injected to compare our findings with injecting gas only. RC16a was allotted for this experiment. The total injected pore volumes were 5 PVs. No oil recovery was observed at the beginning of CO_2 flooding. The oil produced out the core after injecting 0.25 PV CO_2. The pressure drop started at zero and kept increasing until reaching 7.4 psi after injecting 0.7 PV CO_2; thereafter, the pressure declined. The inclination of the pressure to decline began when the CO_2 breakthrough occurred, which is marked by the red point on the oil recovery curve. The oil recovery increased linearly until the gas breakthrough. The oil recovery at the gas breakthrough point was 38%. The gas breakthrough causes oil recovery to reduce before injecting one complete PV (as usually happens when injecting water). However, the oil recovery increased slowly from the 0.7 PV point until injecting a total of 2.1 PV CO_2. At this point, the oil stopped flowing out of the system until all 5 PVs CO_2 was injected. The total oil recovery was 45.8% of the OOIP. The pressure dropped from 7.4 psi at the breakthrough until reaching 0.1 psi. As can be seen from this experiment, an early breakthrough occurred because of the low CO_2 density.

SEAWATER AND CO_2 FLOODING

This experiment was conducted on RC17a. Contrary to the previous experiment, the core was flooded initially with SW in the secondary recovery mode, and then followed with CO_2 in the tertiary recovery mode. As discussed earlier in the methodology section, 2 PVs of SW was injected initially, followed with 5 PVs CO_2. This experiment was conducted in order to illustrate what would happened if we inject water before CO_2 in contrast to the previous experiment. The oil recovery due to injecting 2 PVs SW was 43.64% of the original oil in place (OOIP). This recovery percentage was lower than injecting CO_2 alone. Despite poor sweep efficiency, CO_2 has multiple functions in improving oil recoveries, such as oil swelling and viscosity reduction. However, upon switching to CO_2 flooding, the oil recovery improved to 47.64% the of OOIP, meaning that injecting 5 PVs of CO_2 after SW provided 4% of the OOIP. The experimental results of this experiment are shown in Figure 3. The injected PVs in this experiment is larger in DDD 2 PVs, but the oil recovery stopped to increase after injecting less than 2 PVs of CO_2. Thus, the PVs differences cannot be considered as an influencing factor. As a result, the total oil recovery from this experiment is higher than the previous one that injected CO_2 only. It is obvious that injecting seawater before CO_2 was able to improve the CO_2 sweep efficiency, and in turn, the oil recovery was improved too.

SW, SW–0NACL, AND CO_2 FLOODING

In this experiment, the effect of NaCl depletion in SW was investigated. The core-flooding procedure was in injecting 2 PVs SW in the secondary recovery mode followed by 3 PVs SW–0NaCl and then 5 PVs CO_2. The oil recovery by injecting 2 PVs SW was 43.4% of the OOIP, which was similar to that in the previous experiment (43.4% vs. 43.64%). This indicated that the reservoir cores and the experimental conditions were similar. The next injected 3 PVs of SW–0NaCl provided 2.85% of the OOIP, meaning that removing NaCl from seawater can be more beneficial than injecting SW as it is. This result of SW–0NaCl can be applied in water flooding or WAG or any EOR method. However, the injected fluid was then switched to CO_2, and the oil recovery due to injecting 5 PVs of CO_2 was 6.45% of the OOIP. The improved oil recovery in this experiment was higher than the previous one and the CO_2 only one. This higher recovery occurs from injecting the SW depleted in NaCl. Removing NaCl from SW can alter sandstone wettability towards water-wet status (see imbibition and contact angle tests). The active cations that affect EOR performance in sandstone were discussed in our previous studies (Al-Saedi et al., 2019a, 2019d). We found that Ca^{2+} and Mg^{2+} are the most effective cations, Ca^{2+} the most effective. In this experiment, the non-effective ions (i.e., NaCl) are investigated, and it seems to influence oil recovery. However, this will be explained in imbibition and contact angle results. The total injected PVs was not effective since dead injected volume was the most abundant as discussed in the previous experiment. The results are plotted in Figure 4.

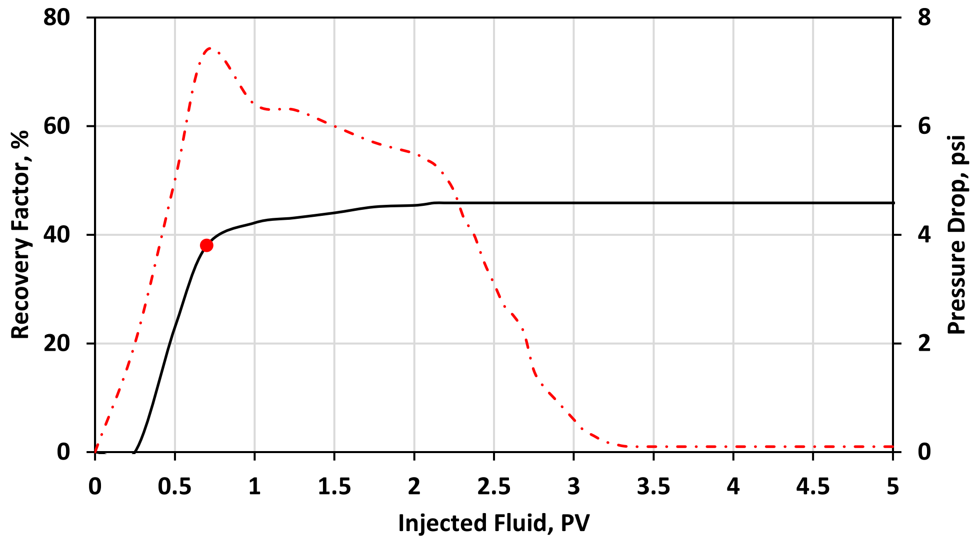

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Figure 2: - Oil recovery factor and pressure drop across RC16a after injecting 5 PVs of CO_2 only (Al-Saedi et al, 2019g).

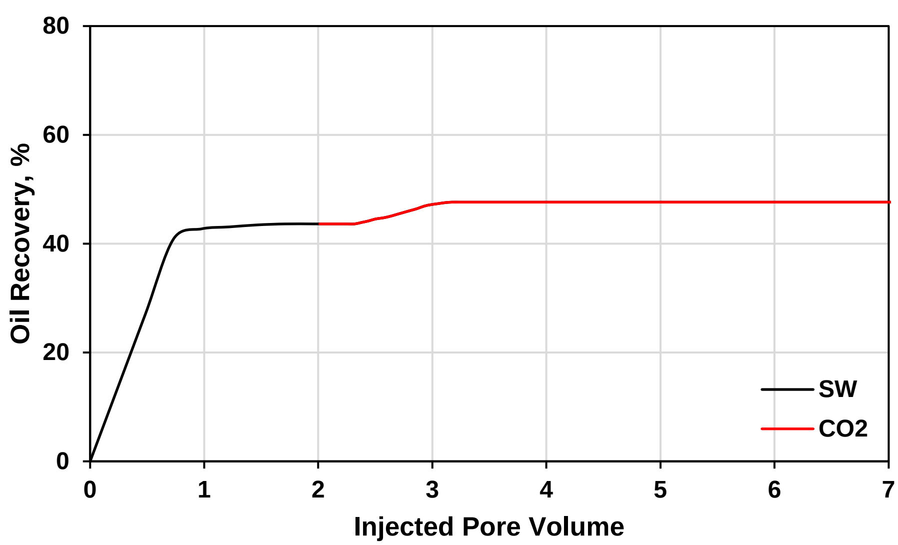

Figure 3: - Oil recovery factor for RC17a after injecting 2 PVs of SW as a secondary recovery mode and 5 PVs of CO_2 as a tertiary recovery mode.

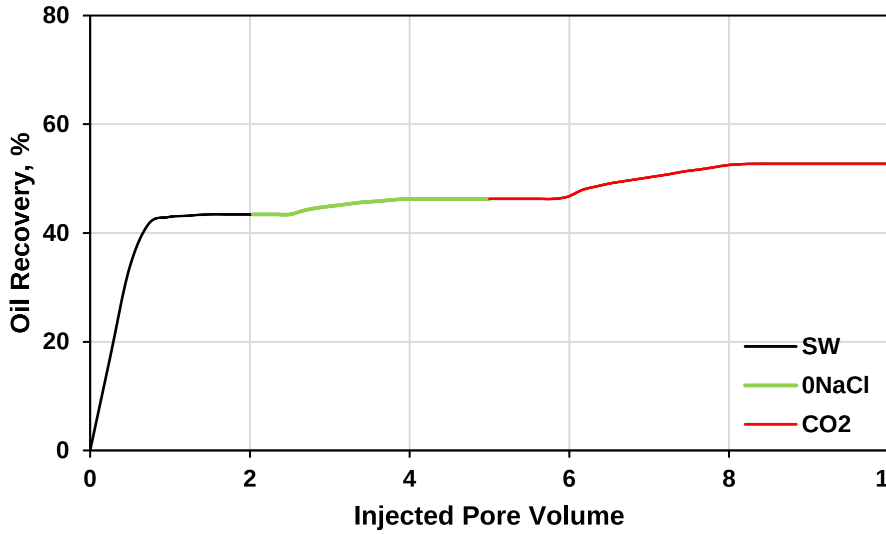

Figure 4: - Oil recovery factor for RC17b after injecting 2 PVs of SW as a secondary recovery mode and 3 and 5 PVs of SW–0NaCl and CO_2 as a tertiary recovery mode, respectively.

SMART WATER BRINES AND CO_2

The objective of the following experiments was to verify if modified seawater could enhance oil recovery, so that they can be merged with CO_2.

SW, SMSW1 AND CO_2

A similar secondary recovery mode was conducted by injecting SW as that in the previous experiments. The experimental procedure was injecting 2 PVs SW, 3 PVs SMSW1, and 5 PVs CO_2. SMSW1 is SW–0NaCl with diluting Ca^{2+} five times. The oil recovery due to SW flooding was also similar to that in the previous experiments, which means the conditions are the same for all the experiments. Injecting SW resulted in 44.2% of the OOIP. An additional 6.1% of the OOIP was observed after injecting SMSW1. Diluting Ca^{2+} in the SW–0NaCl added additional positive effect on the SW EOR flooding. It is clear that manipulating the seawater composition affects the oil recovery. The improved oil recovery in this experiment was higher than the previous one (6.1% vs. 2.85%).

The additional oil recovery from sandstone reservoirs is mostly due to wettability alteration towards being more water-wet. Diluting Ca^{2+} five times triggers the wettability of the sandstone core plug to be altered towards water-wet. This water-wet condition is also favorable conditions must be present before CO_2 flooding to obtain a higher oil recovery. For that, the oil recovery after injecting 5 PVs of CO_2 provided an additional oil recovery of 13.15% of the OOIP, which was undoubtedly the highest among the previous experiments. This higher recovery can be explained by the decreased solubility of the CO_2 in brine as the divalent cations decreased. This low solubility in brine
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redirects CO_2 to be more soluble in the crude oil, which helps to swell the oil and reduce its viscosity. We conducted CO_2 solubility in different brines, and as a result lower solubility of CO_2 was observed in the brine containing a lower Ca^{2+} concentration (Al-Saedi and Flori, 2019 Submitted). It is worth mentioning that although the salinity of SMSW1 is higher than SMSW2 and SMSW3, it produced higher oil.

SW, SMSW2 AND CO_2

Completing the investigation of depleting NaCl in SW with manipulating other ions, this experiment was performed the same way as the previous one, but instead of diluting Ca^{2+}, this time Mg^{2+} was diluted five times. The initial 2 PVs of injected SW resulted in 42.55% of the OOIP, which was also similar to the previous experiments. After that, the SMSW2 was injected. The injected 3 PVs of SMSW2 resulted in a 4% improved oil recovery. This improved recovery percentage is lower than the previous experiment when Ca^{2+} was diluted five times because Ca^{2+} can get closer to the oil and mineral surfaces than Mg^{2+} and have a more significant effect. The explanation for the more substantial Ca^{2+} effect can be found precisely in our study Al-Saedi et al. (2019a). A lower Mg^{2+} effect is undoubtedly influencing the CO_2 flooding as explained in the previous experiment. As was expected, the improved oil recovery by CO_2 was lower than the previous experiment, which was 8.1% of the OOIP. The ultimate enhanced oil recovery of this experiment was 12.1% of the OOIP. Compared to the previous experiment, the improved oil recovery was 12.1% vs. 19.25%. The experimental results are shown in Figure 6.

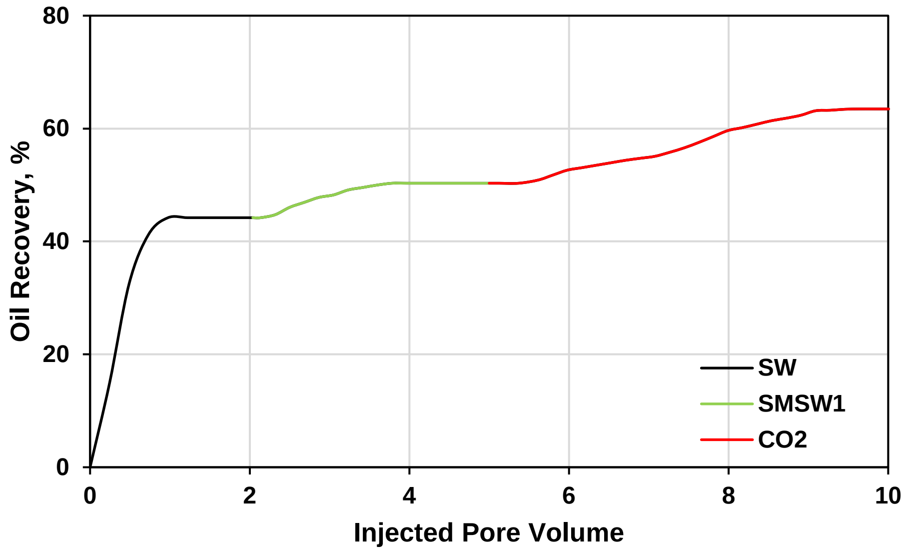

Figure 5: - Oil recovery factor for RC17c after injecting 2 PVs of SW as a secondary recovery mode and 3 and 5 PVs of SMSW1 (SW–0NaCl—d_{5Ca}) and CO_2 as a tertiary recovery mode, respectively.

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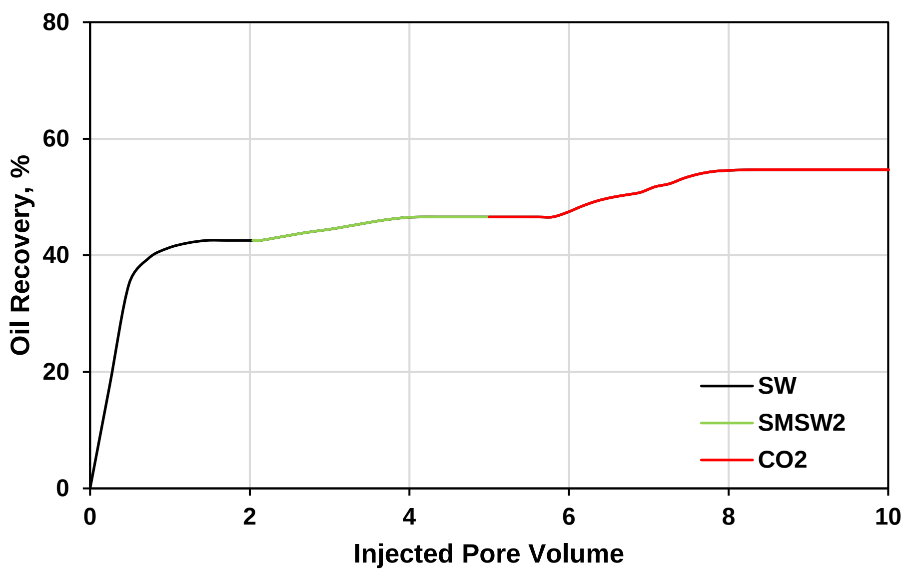

Figure 6: - Oil recovery factor for RC17d after injecting 2 PVs of SW as a secondary recovery mode and 3 and 5 PVs of SMSW2 (SW–0NaCl—d_{5Mg}) and CO_2 as a tertiary recovery mode, respectively.

SW, SMSW3 AND CO_2

RC17e was allotted for this experiment. This experiment is the final investigation of manipulating ions in the SW depleted in NaCl. Similar to all experiments carried on, 2 PVs of injected SW produced 42.6% of the OOIP. Upon switching to SMSW3, the improved oil recovery was 3.8%, which was similar to that in SMSW2 and way below SMSW1. The SMSW3 alters the wettability towards more water-wet, but SMSW1 does not. The improved oil recovery due to CO_2 flooding provided 9.43% more of the OOIP. Results of this study are illustrated in Figure 7.

Up to this point, the highest oil recovery was observed when flooding the RC17c with SMSW1. SMSW1 was clearly able to increase water wetness more than the other smart water brines. So, the design published in our study Al-Saedi et al. (2018d) was applied using SMSW1 to obtain a higher oil recovery from sandstone reservoirs bearing heavy oil.

SW AND WAG OF SMSW1 AND CO_2

As stated previously, this experiment exploited the design used in our published article to enhance the steam sweep efficiency. Three cycles of SMSW1 and CO_2 0.5 PV each in each cycle was conducted on RC17f. The secondary recovery mode by injecting 2 PVs of SW produced 43.4% of the OOIP, which was also similar to all core-flooding experiments conducted in this study. The pressure drop across this core was recorded to monitor the pressure behavior during the WAG process. The pressure drop across RC17f during SW flooding increased slowly until stabilizing at more than 4 psi. The first cycle of SMSW1-CO_2 increased oil recovery noticeably. The observed improved oil recovery was 11.3% of the OOIP. Only 1 PV of SMSW1-CO_2 produced oil more than SW–0NaCl and CO_2 with many PVs. The second cycles resulted in another 8.15% OOIP. The first and second cycles both improved the oil recovery up to 19.45%, which represents the highest oil recovery of all the experiments conducted in this study with injecting only 2 PVs of SMSW1 and CO_2. The improved oil recovery during the third cycles reached 5.5% of the OOIP. The total improved oil recovery from the WAG process was 24.5% of the OOIP. Only 3 PVs of SMSW-CO_2 provided 24.5% of the OOIP. The optimum ion composition with the right selection of flooding design could extract vast quantities of heavy crude oil with less injected pore volumes and lower cost. Injecting the first 0.5 PV of SMWS1 did not significantly affect the pressure drop profile, but during CO_2 flooding, the pressure drop decreased dramatically due to its low density. The pressure profile maintained the same behavior of increasing and decreasing while injecting SMSW1 and CO_2 until the flooding was terminated at 5 PVs. The results of oil recovery and pressure drop versus injected pore volume are plotted in Figure 8.

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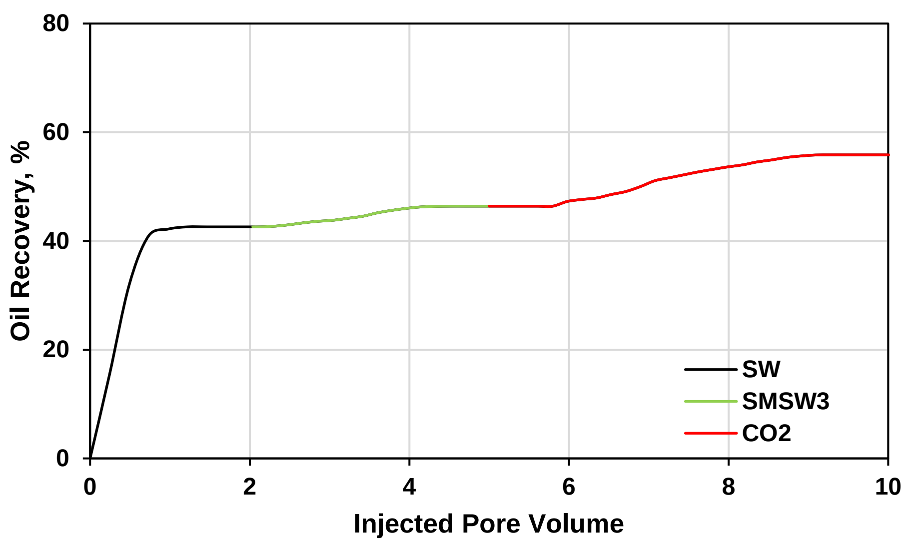

Figure 7: - Oil recovery factor for RC17e after injecting 2 PVs of SW as a secondary recovery mode and 3 and 5 PVs of SMSW3 (SW–0NaCl—d_{5SO_4}) and CO_2 as a tertiary recovery mode, respectively.

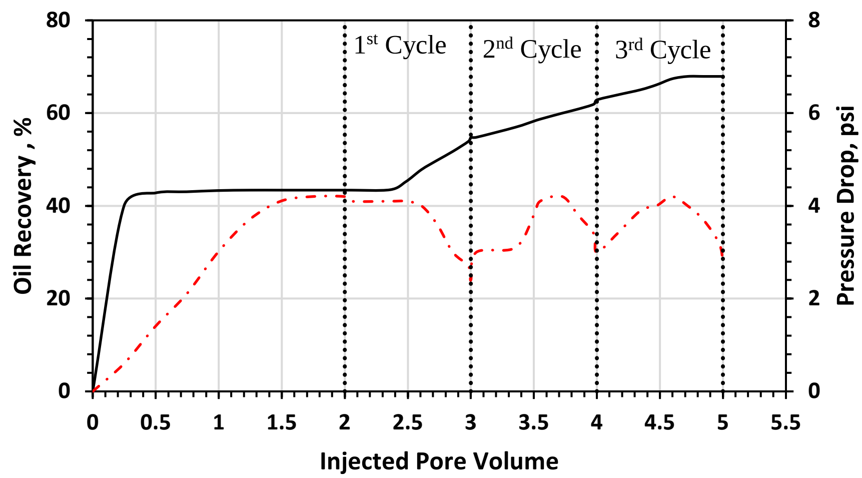

Figure 8: - Oil recovery factor for RC17f after injecting 2 PVs of SW as a secondary recovery mode and three cycles of SMSW3 (SW–0NaCl—d_{5Ca}) and CO_2 (3 PVs total, each cycle 0.5 PV of each) as a tertiary recovery mode, respectively.

WETTABILITY INVESTIGATION

The same brines that were used in the core-flooding experiments were used in this test. The procedure was illustrated in the methodology section. The results of this test are shown in Figure 9. As can be noticed from Figure 9, the lowest contact angle was observed with SMSW1, confirming the vital role of depleting NaCl in SW in addition to diluting Ca^{2+}. The importance of depleting NaCl in SW can be seen from the contact angle difference of SW and SW–0NaCl. The other smart water brines showed a low contact angle but higher than SMSW1.

On the other hand, spontaneous imbibition test results agreed with the contact angle and core-flooding experiments results. The brines imbibed into the cores and the oil released from the core in an average 15 days. The imbibition observation was terminated after 20 days, when there was no more oil floating in the Amott cell. As expected, the highest oil recovery was observed in the core imbibed in SMSW1. This observation confirms the role of SMSW1 in altering wettability of the sandstone core plug into water-wet condition. The same was observed for both SMSW2 and SMSW3 but at lower oil recovery percentage. As expected, the oil recovered from the core imbibed in the SW–0NaCl was higher than that in the SW. Depleting NaCl in SW triggers wettability alteration of the sandstone core plug towards more water-wet. The imbibition test results are shown in Figure 10. Even though the salinity of SMSW1 is higher than SMSW2 and SMSW3, the extracted oil from the core imbibed in SMSW1 is greater.

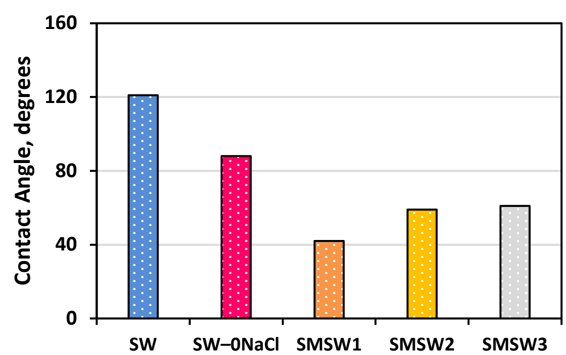

Figure 9: - Contact angle results of the brines used in this study.

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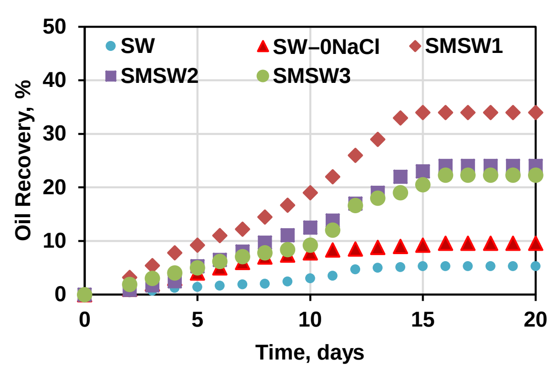

Figure 10: - Oil recovery results from imbibition test.

CONCLUSION

This study was presented with the purpose of extracting more heavy oil from sandstone reservoirs bearing heavy oil. Usually, heavy oil reservoirs are treated with thermal EOR methods, which are considered expensive and have technical difficulties such as heat loss in the reservoir and a thick pay zone must be present. However, we proposed different chemical compositions of SW be injected with CO_2 instead of regular water, which presents only sweep efficiency enhancement. SW could be more beneficial than regular water if its composition is engineered perfectly. Depleting NaCl in SW was one of our solutions and provided 10% more OOIP than SW with CO_2. We also offered to manipulate the depleted SW in NaCl in order to extract as much heavy oil as the new design can. The results of this study indicated that if SW is depleted in NaCl and then the concentration of Ca^{2+} is diluted five times, the improved oil recovery could reach 19.25% of the OOIP. The results also showed if the same water mentioned above is alternated with CO_2 in smaller slug size, the improved oil recovery can reach 24.5% of the OOIP. The other ion manipulation resulted in a higher oil recovery of 12.1 and 13.23%. It is worth mentioning that the total injected pore volumes of SMSW1 alternating CO_2 were lower than the entire experiments in this study. Thus, this design provided a higher heavy oil recovery and lower operational cost at the same time. Also, SMSW1 salinity is higher than in SMSW2, and SMSW3 indicated that salinity reduction does not always provide higher recovery. We believe that further investigation of diluting/depleting Ca^{2+} and/or the other divalent cations/anions in SW could give much higher oil recovery than what we observed in this study.

ACRONYMS

SMSW-AGF: Smart seawater alternating gas flooding.
WAG: Water alternating gas.
LS: Low salinity.
EOR: Enhanced oil recovery.
FW: Formation water.
PV: Pore volume.
SW: Seawater.

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