Sequential Injection of Carbonated Water: A Possible Process for Coupling CO_2 Enhanced Oil Recovery and Storage

Abdulrazag Y. Zekri, Li Yang, Gamal Alusta, Mamdouh Ghannam

Abstract**: *Low salinity and carbonated water flooding have been investigated as possible techniques of improved/enhanced oil recovery. Carbonated water injection consists of dissolving carbon dioxide CO2 in water prior to injection and could be considered as a way to store greenhouse gas safely. Low salinity water flooding is a process of diluting high salinity injection water to a very low level of salinity. In this project, the effect of combining the two techniques in a sequential flooding was studied. The primary aim of this study is to optimize the oil recovery and evaluate CO2 storage during this process, employing low permeability carbonate cores and different sequential carbonated and non-carbonated brines flooding. Formation brine, seawater, low salinity carbonated and non-carbonated were used in this work. Core samples grouped as composite cores with similar over all reservoir permeability. Different sequences of brines were employed to determine the optimum system. The experiment's result showed that carbonated water performs better than the noncarbonated brines. A new technique for estimate CO2 retention based on the displacement efficiency of the carbonated water flooding system is presented. The interfacial tension, contact angle measurements results indicated that wettability is the dominant mechanism of the studied systems. A sequential composite core flooding consists of carbonated low salinity followed by low salinity and seawater injection (CLSW- LSW-SW) is the optimum flooding system among the studied systems. Technically, CLSW flooding displayed an excellent incremental displacement efficiency ∆DE of 21.4% and CSW exhibited the best CO2 retention per incremental ∆Np.***

Keywords: CO2 storage, Sequential Flooding, Carbonated Water, CO2-EOR, Low Salinity, Low Permeability.

I. INTRODUCTION

Carbon dioxide (CO_2) injection to improve oil recovery exhibited two drawbacks mainly low sweep efficiency and gravity segregation (Sohrabi et al., 2008). To reduce the damaged stated previously, the oil industry started looking at two different techniques of CO_2 injection mainly water-alternate- gas injections WAG (Zekri et al., 2015) and carbonated water flooding (CWF). CWF is the process of injecting water saturated with CO_2 to improve the sweep efficiency and reduce the segregation phenomena. Dong et al. (2011) indicated that there are two major technical differences between CWF and conventional CO_2 injection and/or (WAG) injection. First one, no separate CO_2-rich phase in the reservoir and the mount of CO_2 injection is a function of CO_2 solubility in the injection water. The second difference is the displacement efficiency (DE) depends on the mount of CO_2 that transfers from CW to the oil phase. Therefore, no-transition zone developed during CWF. Another mechanism responsible for the improvement of displacement efficiency of CWF is the reduction of oil viscosity due to transfer of CO_2 from CW phase to the oil phase. Lower oil viscosity improves the mobility ratio and that contribute to the increase of DE. Oil welling will also prevail because of the transfer of CO_2 to the oil phase. Assuming the residual oil saturation is the same for carbonated and non-carbonated oil, i.e. oil remains after flooding in the reservoir; then less stock tank oil will remain in the reservoir for carbonated oil. Additional benefit associated with CWF are the improvement in the injectivity as result of the formation of week acid during CWF due to CO_2 solubility in water. Injectivity (I_w) defined as follows:

$I_w = Q_w/\Delta p$……………………………………………….. (1)

Where Q_w = water injection rate bbl/d, ∆p = pressure difference between injection well and production well in psia. Higher injectivity translated to higher oil productivity. Carbonated water flooding (CWF) was investigated at the laboratory stage by the oil industry. Sohrabi et al. (2008) reported higher sweep efficiency during CWF as compared to supercritical CO2 injection. Steffens[5] conducted CWF experiments employing sandstone and n-hexadecane. He concluded that oil swelling is the mechanism behind the improvement of oil recovery. Dong et al. (2011) reported an improvement of recovery by CWF as compared to water flooding. They also indicated that CWF are easy to implement in the field, i.e. no major modification of water flooding facilities required and suitable for offshore fields. Alizadeh et al. (2011) conducted CWF using Berea sandstone. They concluded that rock dissolution is the main mechanism of CWF process.

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Mohammadkhani et al. (2019) reported that the injection of bicarbonate solutions leads to increase in pressure drop across the homogeneous core plug during injection and concluded that permeability reduction may be caused by fine production. Fines migration was the cause for the microscopic flow diversion to the oil-saturated regions and additional recovery from the heterogeneous rocks.

CO_2 as a gas has a major contribution to the environmental problem known as greenhouse effect. CWF is one way can be utilized in CO_2 sequestration, and the technique will contribute to the reduction of greenhouse gases. It is required to reduce the global CO2 emission by 30-50% in 30 years to alleviate the climate change and its side effect (Metz, 2007). Based on that, removing CO_2 from the environment and storing it in a safe place through different techniques has huge importance and became the hottest issue for the whole world. McGlade (2019) reported that 70% of the roughly 30 Mt CO_2 captured today is collected from oil and gas activities. He posted the following very interesting question: Can CO_2-EOR really provide carbon-negative oil?. He reported that currently between 300 and 600 kg CO_2 is injected in EOR processes per barrel of oil produced in the United States. He indicated that a barrel of oil releases around 400 kg CO_2 when combusted, and around 100 kg CO_2 on average during the production, processing and transport of the oil, this means that for the full life cycle of CO_2 emissions intensity of oil to be neutral or even "carbon-negative". The only point he makes is that none of the injected CO_2 is produced from naturally occurring underground CO_2 deposits. This full life cycle of CO2 emissions should be followed worldwide. In UAE no naturally occurring underground CO_2 deposit discovered so far, therefore the industry is planning to inject the captured CO_2 from the environment. CWF has an advantage over conventional CO_2 flooding with respect to segregation, where CO_2 tends to move close to the top of the reservoir, and that increases the possibility of gas leakage through microspores of the cap rock (Herzog 2000). On the other hand, in CWF carbonated water moves to the bottom of the reservoir due to higher density and that mask the chance of buoyancy driven leakage, which is usually associated with CO_2 injection (Burton and Bryant 2009).

Carbon dioxide solubility in water is an important parameter for coupling of CO_2 sequestration and EOR. The combination of the two techniques in one process will contribute to a huge reduction of both energy shortage and climate change concerns. Different correlations have been used for evaluation of CO_2 solubility in water Chang et al. (1998), Welker and Dunlop (1963), Chung et al. (1998). Enick and Klara (1990) developed a correlation of the CO_2 solubility in brine at ambient condition and they indicated that the correlation is applicable at reservoir conditions as well. Bisweswar et al. (2019) concluded that the salt type has no effect on the solubility and CO_2 solubility in brine dependent only on the total dissolved solids (TDS). Chang et al. (1998) reported good agreement between the measured and calculated values of CO_2 solubility in brine using the following Kechut et al. (2011) equation:

$$\log\frac{R_{sb}}{R_{sw}} = -0.028 \times S \times T^{-0.12} \quad \ldots\ldots\ldots\ldots\ldots (2)$$

Where *R*sb: solubility of CO2 in brine of salinity *S* (*scf/STB*), *R*sw: solubility of CO2 of water (*scf/STB*), *S*: salinity of brine in *weight %* of solid and *T*: temperature (°*F*).

In this project, carbonated low salinity/smart water flooding in a sequential format was investigated employing carbonated and non-carbonated formation brine, seawater, and low salinity water. The goal is to assess the degree of improvement of displacement efficiency DE and CO_2 sequestering. The cost of CO_2 purchase or capture, purification, transportation, and compression could easily be covered by extra oil recovery and or carbon credit. The oil recovery by CWF can be estimated from the following equation:

$$Np = E_D \times E_v \times E_C \times N_i \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (3)$$

Where N_p oil recovery stb, E_D displacement efficiency (amount of oil displaced/oil in place), E_V volumetric sweep efficiency (pore volume swept by injection water/total pore volume), E_C capture sweep efficiency (amount of oil reaching production well/oil contacted and displaced), Ni oil in the reservoir at the start of the water flooding. Normally E_c assumed to be equal to 1.0 to simplify the problem. The previous equation normally used to estimate the oil recovery due to water flooding. The same equation can be used to estimate the oil recovery due to carbonated water flooding after modifying both E_D and E_V taking in consideration the alteration of residual oil saturation and mobility ratio due to carbonated water flooding. The difference in oil recovery between carbonated and non-carbonated water flooding represents the incremental oil recovery due to carbonated water flooding assuming secondary flooding process. To estimate the amount of CO2 stored in the reservoir, we propose to employ the following:

$$V_{CO2} = E_v \times (1- S_{orcw})\, V_p\,(stb) \times Rsb\,(scf/stb) \quad \ldots\ldots\ldots\ldots (4)$$

$$V_{CO2} = E_A \times E_I \times (1 - S_{ORW})\, V_p \times R_{sw} \times e^{-0.028 \times S \times T^{-012}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (5)$$

Where E_A is area sweep efficiency function of mobility ratio and water cut, E_I is the vertical sweep efficiency, Vp reservoir pore volume. Vertical sweep efficiency (E_I) strongly depends on parameters such as mobility ratio and total volume of fluid injected. Normally the project is terminated at 85 to 95 water cut depending on the economics at the time of project implementation. The mobility ratio can be determined using the following equation:

$$MR = \frac{M_{displacing}}{M_{displaced}} = \frac{K_{rw}}{\mu_w} \times \frac{\mu_o}{K_{ro}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (6)$$

Where k_{rw} relative permeability to water at the average water saturation at the selected water cut of the flood and k_{ro} relative permeability to oil at initial water saturation usually determined in the lab. The symbol μ_w and μ_o are the water and oil viscosities, respectively. Keeping in mind that carbonated water flooding reduces k_{rw} through alteration of wettability, increases water viscosity and reduces oil viscosity through swelling, Shu et al. (2016), Seyyedi et al. (2017). The overall effect of the previously mentioned mechanism is the reduction of the system mobility and that will result in an improvement of the volumetric sweep efficiency. Dykstra-Parsons simplified method normally used to predict the vertical sweep efficiency employing the system mobility ratio and permeability variation. At the end of the flood, i.e. the economic limit of the water cut, the volumetric sweep efficiency (volume swept by water over the reservoir pore volume) should be estimated.

The volume swept by injection water will be filled with the carbonated expect the volume that contains the residual oil that cannot be displaced by the injection water. The initial formation water (Swi) is completely displaced from the swept volume by the carbonated water due to complete miscibility between the injected carbonated water and connate water.

The displaced water will move forming a water bank ahead of carbonated water bank as shown in Figure 1. The volumetric sweep efficiency can be roughly estimated, with the assumption of a negligible change in oil formation volume factor Bo and zero voidage rate i.e. constant pressure throughout the reservoir, from the following equation (Ahmed, 2018);

$$E_V = \left[\frac{B_o}{(PV)(1 - S_{wi} - S_{or})}\right] \times N_p \qquad \text{.....(7)}$$

Where B_o oil formation factor, S_{wi} initial water saturation, S_{or} residual oil saturation, PV pore volume, and N_p cumulative oil produced during the water injection. Therefore, the amount of CO_2 trapped in the reservoir at the end of carbonated water flooding can be estimated from the following equation:

$$V_{CO2} = \left\{\left[\frac{B_o}{(PV)(1 - S_{wi} - S_{or})}\right] \times N_p \times (1 - S_{ORW})\, V_p \times R_{sw} \times e^{-0.028 \times S \times T^{-012}}\right\} - (R_{sCO2} \times N_p) \qquad \text{.....(8)}$$

Where R_{sCO2} the amount of CO2 diffused in oil, which is function of CO2 solubility in water, reservoir pressure and temperature, oil composition.

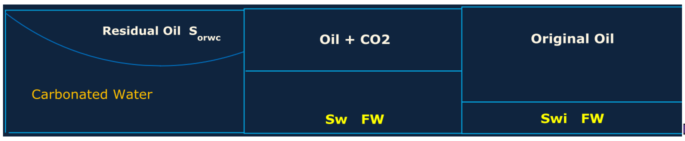


Fig. 1. The schematic of fluid zones in CWF process.

II. MARTIAL AND METHOD

A. Fluids

Light crude oil with API of 38.5 was used in this project. The oil was filtered through a 5mm filter paper prior to any lab application. No asphalting precipitation was observed during the storage. The crude oil had an acid number of 0.07 mg KOH/g, measured using a standard titration procedure of ASTM D664. The oil viscosity was measured using rolling ball viscometer at 20 °C. The measured viscosity was 3.96 cP and the crude density equal to 0.8322 g/cc. Six brines employed in this study as follows: formation brine (FB), seawater (SW), low salinity water (seawater diluted 10 times, LSW), carbonated formation brine (CFB), carbonated seawater (CSW), and carbonated low salinity water (CLSW). The composition of non-carbonated brines presented in Table 1.

B. Core samples

Seventeen identical pieces of approximately 1.5 inch in diameter gray colored limestone cores were used in this study. All core plugs showed to be completely limestone ($CaCO_3$) as they strongly reacted with HCl acid. Hand lens examinations showed a low porosity and light colored roughly spherical grains partly cemented by parry calcite. Results of basic measurements performed on cleaned plug samples are provided in Table 2. The table comprises dimensions, grain volume, grain density, porosity, pore volume, liquid permeability (Kw). All core plugs were flooded with oil to irreducible water saturation, S_{wr} and aged for a period of 40 days at 80 °C before core flooding. Four sets of composite cores were prepared employing a different type or ordering, each stack consists of four plugs except for Group 4 as shown in Figure 2. The permeability of different stacks varied from 0.43 to 0.70, which represents a low permeability reservoir. Table 3 presents flooding sequences for different composite cores. Composite core Group no. 1 (CCG1) was flooded with different waters as follows: formation brine (FW) followed by seawater (SW), then the system switched to low salinity water (LSW), at the end carbonated low salinity water (CLSW) was injected. The following sequential flooding was conducted employing CCG2; carbonated seawater (CSW), SW, LSW. The third run was performed employing CCG3 and the following sequential water-flooding scheme: carbonated formation water (CFW), FW, SW, LSW. The last run was focused on the LSW starting the sequential flooding with CLSW followed by LSW and SW as indicated in Table 3.

Table 1. Composition of non-carbonated brines

Ion	FW mg/L	FW ppm	LSW mg/L	LSW ppm	SW mg/L	SW ppm
Sodium	44261	44312	1905	1908	19054	19076
Calcium	13840	13856	69	69	690	691
Magnesiur	1604	1606	213	213	2132	2134
Barium	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Potassium	<0.1	<0.1	67	67	672	673
Zinc	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Phosphate	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Chloride	96560	96670	3584	3588	35836	35877
Bicarbona	332	332	12	12	123	123
Sulphate	885	886	394	395	3944	3949
Strontium	<0.1	<0.1	0	0	<0.1	<0.1
Nitrate	0	<0.1	0	0	<0.1	<0.1
Carbonate	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
TDS (mg/L	157482		6245		62451	
Total (ppm)		157662		6252		62522

Table 2. Physical properties of AS core plugs

Sample ID	Dry wt (gm)	Sat.wt (gm)	Length (cm)	Diameter (cm)	Pore Vol. air (cc)	Pore Vol. water(cc)	Bulk vol. (cc)	Grain vol. air (cc)	Grain vol. water (cc)	Grain den. (gm/cc)	Porosity air (%)	Porosity water (%)	Permeability Liquid (md)
2	171.35	185.20	6.884	3.801	14.57	12.67	78.15	63.57	65.47	2.70	19	16.2	0.29
3	173.44	188.04	6.929	3.806	14.57	13.36	78.86	64.11	65.51	2.71	19	16.9	0.40
4	175.12	190.55	7.091	3.797	15.08	14.12	80.33	65.25	66.21	2.68	19	17.6	0.55
5	169.02	185.52	6.986	3.798	16.47	15.10	79.18	62.71	64.08	2.70	21	19.1	2.01
7	169.89	181.15	6.507	3.805	10.86	10.30	74.00	63.16	63.72	2.69	15	13.9	0.15
10	94.98	108.15	4.262	3.792	13.01	12.05	48.15	35.15	36.10	2.70	27	25.0	3.77
13	140.50	158.94	6.186	3.797	18.02	16.87	70.07	52.06	53.20	2.70	26	24.1	1.03
14	105.73	118.63	4.633	3.797	13.24	11.80	52.48	39.24	40.68	2.69	25	22.5	1.45
17	132.48	148.51	5.716	3.807	16.00	14.67	65.09	49.10	50.43	2.70	25	22.5	1.43
18	164.65	177.28	6.609	3.800	12.97	11.55	74.98	62.01	63.43	2.66	17	15.4	0.16
19	130.14	145.39	5.649	3.798	15.66	13.95	64.02	48.36	50.07	2.69	24	21.8	0.75
21	102.23	113.85	4.407	3.799	12.09	10.63	49.97	37.88	39.34	2.70	24	21.3	1.41
23	106.69	118.46	4.538	3.798	12.17	10.77	51.43	39.27	40.66	2.72	24	20.9	1.45
24	138.20	154.48	5.988	3.799	16.68	14.89	67.90	51.22	53.01	2.70	25	21.9	1.04
25	142.78	159.34	6.157	3.793	16.73	15.15	69.60	52.87	54.45	2.70	24	21.8	1.60
26	145.89	163.86	6.401	3.814	19.26	16.44	73.16	53.90	56.72	2.71	26	22.5	1.44
28	107.96	120.01	4.692	3.825	13.49	11.02	53.94	40.45	42.91	2.67	25	20.4	1.28

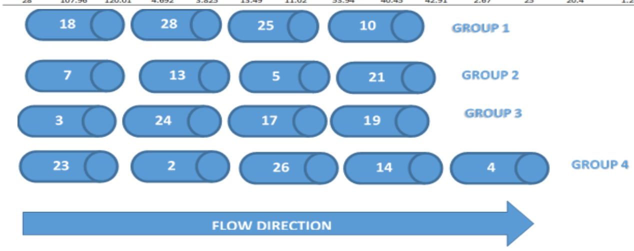


Figure 2. Composite cores stacks arrangements.

Table 3. Sequential flooding for different composite cores

Group 1		Group 2		Group 3		Group 4	
Sample No.	Flooding Sequence	Sample No.	Flooding Sequence	Sample No.	Flooding Sequence	Sample No.	Flooding Sequence
18		7		3		23	
28		13		24		2	
25	FW+SW+LSW+CLSW	5	CSW+SW+LSW	17	CFW+FW+SW+LSW	26	CLSW+LSW+SW
10		21		19		14	
						4	

C. Experimental Setup

Core flooding system, which operates under reservoir conditions module XRFS-150, was used in this project. The system is configured for liquid/liquid displacements under unsteady state or steady state conditions. The system features automated data acquisition, manual and semi-automated operation via Windows-based graphical interface as shown in Figure 2. Composite core experiments were conducted in this project. All tests were conducted at reservoir conditions of 250 °F and 3200-psia pressure. An overburden pressure of 4000 psia and a constant flooding rate of 1 cc/sec were used in all the runs. During the sequential water flooding, the injected fluid volumes, the pressure drop across the core, and the produced oil/water volumes were continuously measured. In addition to that oil recovery, residual oil saturation, displacement efficiency was measured for the studied system. CO_2 was mixed with the specified water in a high pressure and temperature cell at reservoir condition and the cell was agitated for 24 hours to make sure that the water was saturated with the CO_2prior to injection. Three runs were repeated to check for data reliability and the results indicated that no significant difference was observed between the runs that affect our conclusions.

III. Results and Discussion

The objectives of the proposed flooding runs were to determine the effects of the carbonated FW, SW, LSW in different sequential form on the displacement efficiency of low permeability oil reservoir and to introduce a new approach for estimating the amount of carbon dioxide that can be stored in a safe place as a result of the proposed process. Interfacial tensions and contact angles of the studied fluids were measured at high temperature to provide additional information that can be used to better understand the possible mechanism of the oil displacement process.

Figure 3. A photograph of the core flooding system.

A. Interfacial Tension and Contact Angle Studies

The values of interfacial tension (IFT) between oil and water and the contact angle (CA) (at 90 °C) for various brines were measured during the first stage of this project. Figures 4 and 5 presents a summary of these findings. The results of IFT measurements have shown that CLSW is the best brine in terms of lowest measured IFT value. Low salinity water also exhibited relatively low IFT value comparing to formation brine. The amount of reduction in IFT between CLSW and FW is estimated to be around 28%, which might contribute to the difference in the displacement efficiency (DE) between the two processes. To assess the possibility of wettability alteration from contact angle measurements, Anderson's criteria of wettability reigns was employed in this study as follows: from 0 to 75° referred to as water-wet, from 75 to 115° as neutral, and from 115 to 180° as oil-wet. Figure 5 shows the changes in contact angle values for carbonated and non-carbonated brines. Based on adopted criteria, LSW and CLSW can be classified as neutral wettability, and other brines used in this project showed oil wet behavior as presented in Figure 5. Therefore, CLWS water shifted the system wettability from oil wet to neutral wettability and that could have an effect on the DE. Wettability alteration was reported as one of the mechanisms contributing to the incremental oil recovery by CWF, Riazi (2011) and Dong (2011). Mosavat and Torabi (2016) and Sohrabi et al. (2015) arrived at the same conclusion that CWF tends to shift the wettability of the studied system toward water wet as observed during micro model study of CWF. Soleimania et al. (2020) reported that when the concentration of carbonic acid increases in the system, wettability changes to more intermediate wet. They have indicated that the change in wettability is due to the diffusion of CO2 from the water phase into the oil phase then diffuses to rock surface removing the oil heavier components which results in wettability alteration. Ruidiaz et al. (2018) evaluated oil recovery from carbonate rock flooded with SW, FW, CSW, and CFW. They concluded that Wettability alteration took place as the system wettability shifted from oil-wet to neutral-wet, which is in line with our findings.

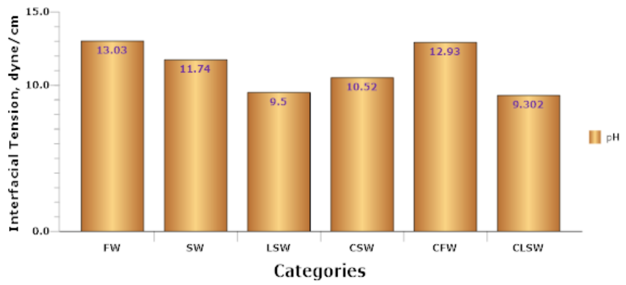


Figure 4. IFT of non-C-Brines and C-Brines.

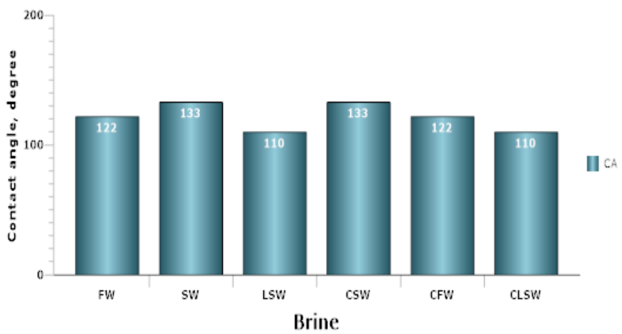


Figure 5. Contact angle of non-C-Brines and C-Brines.

B. Displacement efficiency for different Carbonated and non-Carbonated brines

Four different secondary water flooding runs employing FW, CFW, CSW, CLSW and composite cores 1,2,3, and 4 respectively were preformed in this task. The objective of this work is to evaluate the DE of carbonated and non-carbonated FW, SW, and LSW. As displayed in Fig. 6, the DE for CSW injection is nearly about 59.3% and for CLSW is about 64.2%. Therefore, coupling dilution and carbonation of SW resulted in an incremental improvement in DE about 4.9%. The reason for the improvement is the coupling effect of dilution and carbonation. The obtained value of DE for CLSW injection (0.642) is quite significant for the low permeability system of≈ 0.7 mD. Results indicated that carbonation of high salinity system 157,622 ppm had a negative impact on the DE. Examining the pH, total dissolved solids, contact angle, and interfacial tension measurements for both fluids before and post flooding did not provide a clear explanation of this result. An important conclusion can be drawn from the purpose of of discussion is that coupling of dilution and carbonation of seawater had a significant effect on the DE for low permeability oil reservoir employed in this study.

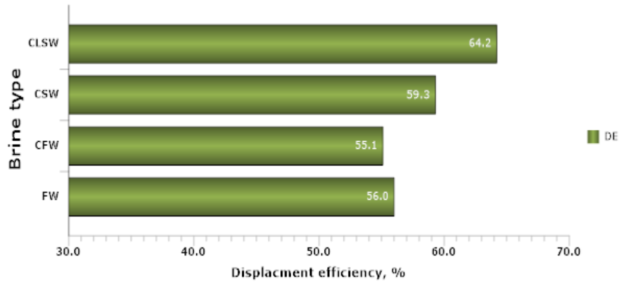


Figure 6. Displacement efficiency for different Carbonated and non-Carbonated brines.

C. Sequential flooding of composite core group 1

Composite core Group no. 1 (CCG1) was flooded with different waters as follows: formation brine (FW) followed by seawater (SW), then the system switched to low salinity water (LSW), at the end carbonated low salinity water (CLSW) was injected. The composite core no. 1 was set at irreducible water saturation at the start of the flood, and that represents secondary injection mode. Figure 7 presents the results of the displacement efficiency for different brines in a sequential order. The FW with salinity of 157,662-ppm targets mobile oil in the composite core no. 1 and produced DE equal to around 56.0% of original oil-in-place OOIP. The majority of the DE was achieved during the first eight pore volumes of FW injecting. Injection of FW was continued until no more oil displaced from the CCGI and in most of the injection systems oil seized to reach the outlet of the composite core after around 10-pore volume. This injection practice was employed for all injection waters and all composite runs. The second stage of this task was the injection of seawater with a relatively lower salinity of 62,522 ppm followed FW injection. After injection about 10-pore volume an increase of DE was observed, equivalent to 5.35% beyond FW flooding. The incremental improvement in DE due to LSW is around 4.33 of OOIP. At the end, CLSW (6252) was injected, and a small improvement in DE ≈1.53 percentage of OOIP was observed. The lower improvement in DE obtained by CLSW is due to a lower oil saturation in the composite core 34.3% at the start of that water injection. The total incremental improvement in DE, beyond FW flooding, is equal to 11.2% by SW, LSW, and CLSW sequential flooding.

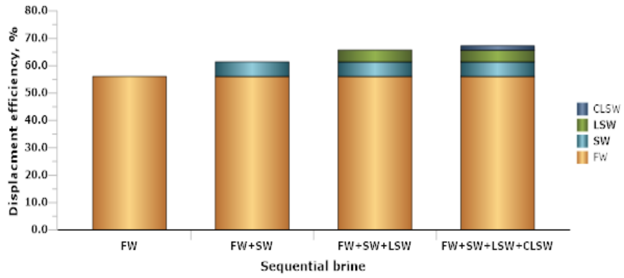


Figure 7. Sequential flooding of composite core group 1.

D. Sequential flooding of composite core group 2

Composite core Group no. 2 (CCG2) was flooded with different waters as follows: carbonated seawater CSW followed by seawater (SW), then the system switched to low salinity water (LSW). Figure 8 presents the results of the displacement efficiency for different seawater brines in sequential order. The CSW with salinity of 6,662-ppm targets mobile oil in the composite core no. 2 and produced DE equal to around 59.32% of original oil-in-place OOIP. At the end of CSW, the composite core residual oil saturation estimated to be around 40.8% PV. The injection of seawater with a relatively lower salinity of 6,662 ppm was followed and after injection about 10-pore volume a significant increase of DE was observed, equivalent to7.75 percentage beyond CSW flooding. SW injection following CSW injection seems to produce a relatively significant more DE due probably to a lower IFT associated with SW as compared to the value of CSW. Then the system switched to the injecting LSW with a salinity of 6,252 ppm. The incremental improvement in DE due to LSW is around 0.97 of OOIP. Again, similar argument could be used regarding the reason for lower displacement at the end of the sequential flooding which lower oil remains in the core after two segments of flooding. The total incremental improvement in DE, beyond CSW injection, is equal to 8.72% by SW followed by LSW sequential flooding.

E. Sequential flooding of composite core group 3

Third sequential coreflood experiment was also conducted at reservoir conditions using composite core group no. 3 to investigate the potential of increasing oil recovery during secondary mode by employing CFW, FW, SW, and LSW in the sequential process. Figures 8 present the displacement efficiency in terms of OOIP versus stage of the sequential flooding. The results show that the displacement efficiency of CFW is around 55.13% of OOIP. At the end of CFW injection, the composite core residual oil saturation estimated to be around 44.9% PV.

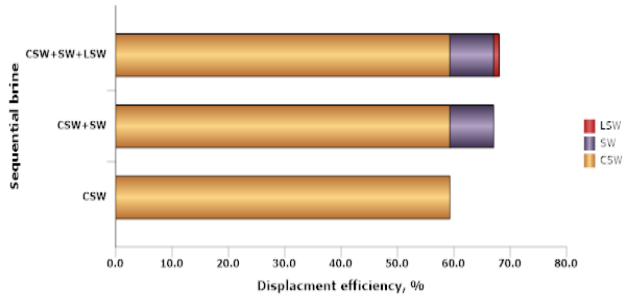


Figure 8. Sequential flooding of composite core group 2.

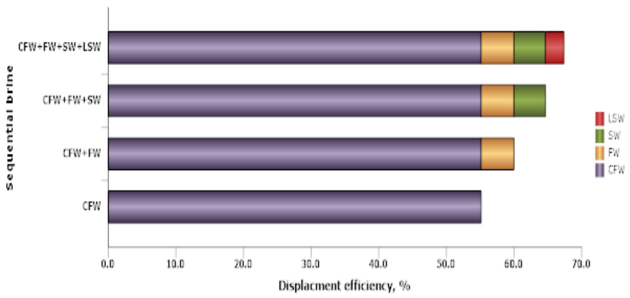


Figure 7. Sequential flooding of composite core group 3.

The injection of formation water with a high salinity of 157622 ppm was followed and after injection about 8.8-pore volume a slight increase of DE was observed, equivalent to 4.85 percentage beyond CFW flooding. Then the water injection scheme switched to SW followed by LSW, which resulted in additional in DE around 4.64 and 2.74% of OOIP respectively. At the end of the third sequential water injection, around 67.36 of the oil in place was displaced and the oil saturation dropped from 83.34% at the start of the water injection to 32.60 at the end of the scheme.

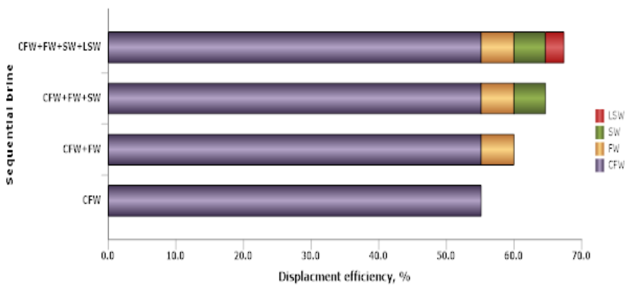


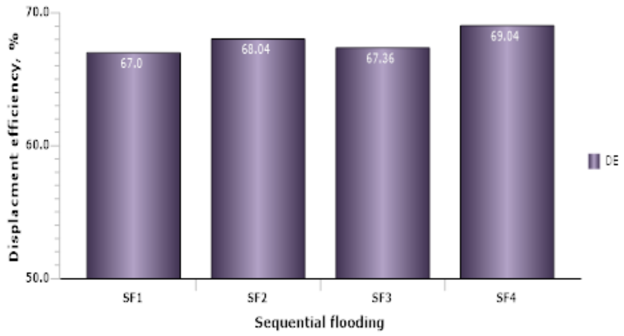
Figure 8. Sequential flooding of composite core group 4.

F. Sequential flooding of composite core group 4

The last sequential coreflood experiment (SCCG4) was also conducted at reservoir conditions using composite core group no. 4 to investigate the potential of increasing oil recovery during secondary mode by employing CLSW, LSW, and SW in the sequential process. The CLSW injection was stopped after 7.6 PV of the fluid injected as no addition oil displaced from the composite core 4 was observed. At this stage, the DE and the residual oil saturation S_{orCLSW} of the system were 64.19% of OOIP and 35.8% PV respectively. The DE at this point is very significant because of the very low permeability of the studied system. Switching the injection mode from CLSW to LSW resulted in additional DE equal to 3.86% of OOIP and reduction of residual oil saturation to 31.8% PV. During the last phase of the CCG4 injection, SW was injected which added a DE equal to 1.35% of OOIP and further reduction of remaining oil saturation to 30.4% of PV. The overall DE of CCG4 is equal to 69.4%. Therefor sequential coreflood CCG4 is the optimum sequential system in this project.

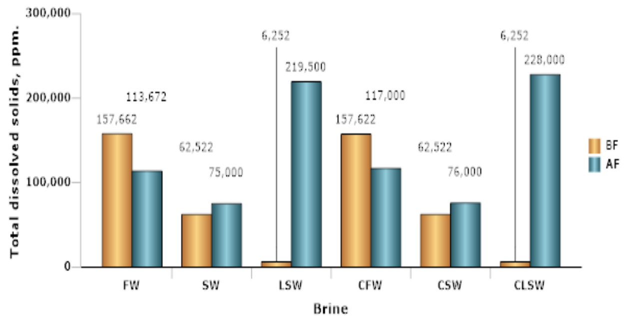
G. Comparison of sequential flooding

The displacement efficiency of the four-employed sequential water injection in this project presented in Figure 9. The priority of different sequential of injection for the composite core systems are SF4 (69.04%), SF2 (69.04%), SF3 (67.36%), SF1 (67%). The results clearly indicated that starting the water injection using CLSW injection would result in a higher displacement efficiency as compared to the studied systems.



Figures 9. Displacement efficiency of different sequential flooding.

The reason behind this phenomenon is a combination of rock dissolution associated with the low salinity and oil swelling and viscosity reduction which are due to the diffusion of CO2 from the water phase into the oil phase then diffuses to rock surface removing the oil heavier components which results in wettability alteration, Soleimani et al. (2020). In addition to that, a lower pore volume of water injection is required to reach the displacement efficiency. The TDS of different brines presented in Figure 10. Data clearly confirms the dissolution mechanism contributing to the improvement of DE for the low salinity systems. The TDS of CLSW after flooding (AF) jumped by 3500% as compared to before flooding (PRF). The highest increase in TDS AF as compared to TDS BF is correlate excellently with the improvement in DE for the studied systems.



Figures 9. Total dissolved solids versus before and after flooding brines.

H. Optimizing CO2 Storage and CO2 EOR

Figure 10 presents a flow diagram of the steps needed to estimate the amount of the CO_2 in standard cubic feet (SCF) retention in the porous media after carbonated injection completion and the produced oil during that period in stock tank barrel (STB).

The CO_2 retention values were estimated when the oil stopped flowing out of the core for each CWF test. The objective is to estimate the amount of CO_2 retention per STB produced to compare between different CWF systems. In the studied cases the oil produced data was available for each test in milliliter (ml) and the volumetric sweep efficiency was estimated by subtracted the remaining oil from the pore volume and divided by the pore volume. The calculation value of the Ev is an excellent estimation because we flooded the reservoir with over 30 PV of water, displacing all the oil and the connate water. Keeping in mine that the injected carbonated water is miscible with the connate water, therefore it's capable of removing it completely from the porous media. The CO_2 solubility in water was estimated from Figure 11 using reservoir pressure and temperature, Wei et al. 2011. The solubility of CO_2 in brine was calculated using Kechut et al. (2011) equation. Figure 12 shows two columns diagram of the CO_2 retention in SCF per STB production and the total displacement efficiency for different CWF tests conducted in this study. As presented in Figure 12, the CO_2 retention per gross oil production in STB values ranged from 1.03 to 1.34 for all CWF tests conducted. Results indicated that LSCW in secondary mode resulted in more CO_2 storage per oil recovery in the cores than CFW and CSW. Results also highlighted the fact that CLSW provided the highest DE among the tested carbonated systems. Therefore, CLSW is the optimum system in terms of DE and CO_2 storage on the bases of total DE. Looking at the DE and retention in terms of incremental oil recovery produced slightly different picture. The incremental DE is determined by subtracting DE for carbonated system from DE of formation brine to obtain the additional (ΔDE) due to dissolving of CO2 in the injection water.

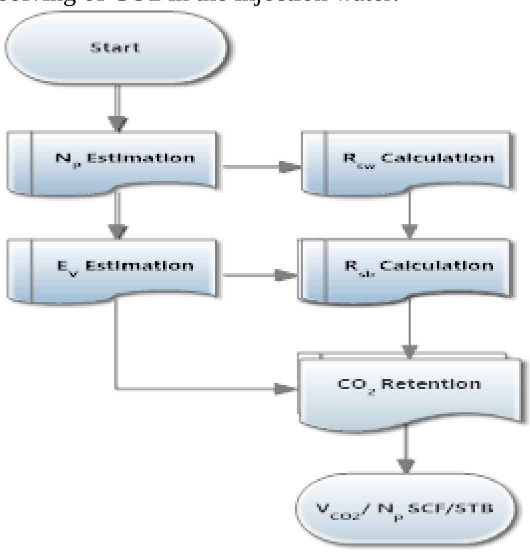


Figure 10. Flow diagram Of estimating CO2 retention per 1 stb production.

In addition to that, ΔNp was calculated by subtraction-carbonated system Np from formation water injection Np. Figure 13 presents two columns of Volume of stored CO2/ ΔNp in scf/stb and incremental DE (ΔNp). As presented in Figure 13, the CO2 retention per incremental oil production in STB values ranged from 4.13 to 11.9 SCF/STB for all CWF tests. The optimum retention system in this case is CSW with a value of 11.9 SCF/STB. On the other hand, the CLSW displayed the highest incremental oil recovery. Since LSCW flooding resulted in the optimum DE, therefore that will translate to higher oil recovery. Higher oil recovery by carbonated water flooding means higher CO2 storage. In terms of incremental oil recovery, economic analysis is required to determine the optimum system. Technically CLSW flooding displayed excellent ΔDE of 21.4% and CSW exhibited the best retention per incremental ΔNp.

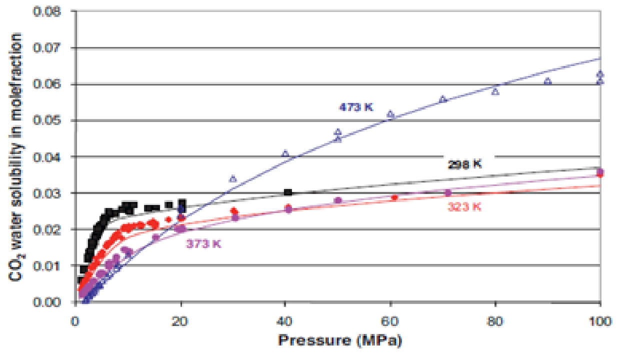


Figure 11. Solubility of CO2 in water, after Wei et al. 2011.

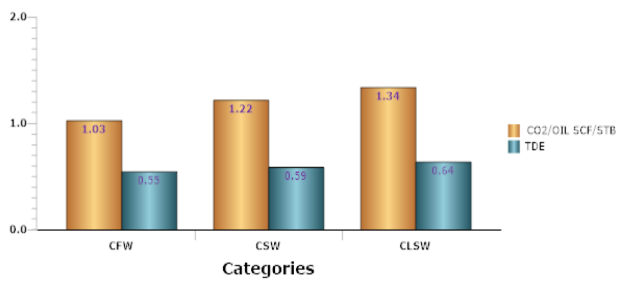


Figure 12. Carbon dioxide retention SCF per oil production in stb, and DE for all CWF tests.

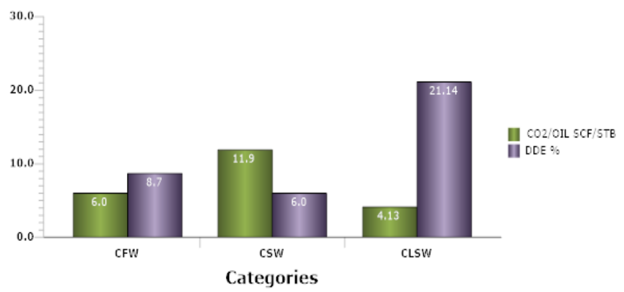


Figure 13. Carbon dioxide retention SCF per ΔN_p in stb, and ΔDE for all CWF tests.

IV. CONCLUSIONS

Based on the results obtained from this study, the following conclusions can be drawn:

1. Under the same conditions, CWF displayed an improvement on DE over FW in carbonate rocks.
2. Carbonated low salinity water flooding results in the highest DE as compared to FW, LSW, CLSW, CFW.
3. A new technique is presented to estimate CO2 retention based on the oil recovery of the carbonated water flooding system.
4. Combination of dilution and carbon dioxide dissolving in seawater resulted in substantial improvement in the DE of low permeability oil reservoir.

5. Technically, CLSW flooding displayed an excellent ΔDE of 21.4% and CSW exhibited the best retention per incremental ΔNp.
6. Carbonated low salinity water flooding can serve both enhanced oil recovery and CO2 retention.
7. Sequential water injection consists of CLSW, LSW, and SW produced the best DE (69.4%) as compared to CFW+ FW+ SW+ LSW, CW.
8. Brine salinity is the major factor effecting the performance of CW EOR and Storage, therefore CO2 solubility assessment with injection brine at reservoir conditions is strongly recommended prior to core flooding.

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