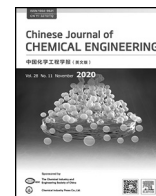




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Article

Activating solution gas drive as an extra oil production mechanism after carbonated water injection

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ABSTRACT

Enhanced oil recovery (EOR) methods are mostly based on different phenomena taking place at the interfaces between fluid–fluid and rock–fluid phases. Over the last decade, carbonated water injection (CWI) has been considered as one of the multi-objective EOR techniques to store CO₂ in the hydrocarbon bearing formations as well as improving oil recovery efficiency. During CWI process, as the reservoir pressure declines, the dissolved CO₂ in the oil phase evolves and gas nucleation phenomenon would occur. As a result, it can lead to oil saturation restoration and subsequently, oil displacement due to the hysteresis effect. At this condition, CO₂ would act as *in-situ* dissolved gas into the oil phase, and play the role of an artificial solution gas drive (SGD).

In this study, the effect of SGD as an extra oil recovery mechanism after secondary and tertiary CWI (SCWI–TCWI) modes has been experimentally investigated in carbonate rocks using coreflood tests. The depressurization tests resulted in more than 25% and 18% of original oil in place (OOIP) because of the SGD after SCWI and TCWI tests, respectively. From the ultimate enhanced oil recovery point of view, the efficiency of SGD was observed to be more than one-third of that of CWI itself. Furthermore, the pressure drop data revealed that the system pressure depends more on the oil production pattern than water production.

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1. Introduction

Over the past decades, the studies on enhanced oil recovery (EOR) methods were focused on determining the most effective mechanisms that alter the interfacial forces between the rock and the fluid phases in the oil reservoirs. In this regard, common mechanisms resulting in enhancing the oil recovery such as wettability alteration and interfacial tension (IFT) reduction, and emulsification have been widely studied [1–5]. Such mechanisms were mostly activated using chemicals and surface active agents (surfactants) [1–3]. However, the main point appeared here is that after each recovery stage, some residual oil saturation remains in the oil reservoir, which requires new EOR technique to unlock the remained oil in place. Therefore, after each stage of oil production including the EOR process, extra mechanisms could act consequently, which results in more oil recovery efficiency. Carbonated water injection (CWI) as an EOR technique could be considered as one of these methods that utilizes CO₂-enriched water as a single phase to be injected into reservoir. This new technique reduces the challenges associated with direct CO₂ injection. It is expected that CWI results in oil viscosity reduction and oil swelling due to CO₂ diffusion from the

water phase into the oil phase in the first stage followed by rock wettability alteration and IFT reduction [5]. These mechanisms would assist coalesce of trapped oil ganglia, to remove them from the capillary dominated traps in the pore spaces [5]. Besides, during the oil reservoir pressure reduction stage, an additional production mechanism (*i.e.* solution CO₂ drive) would come into the effect and assist the incremental oil recovery efficiency. Handy investigated enhanced oil recovery caused by SGD using sandstone core samples. It was concluded that oil recovery enhanced with rate at high production rates while it was independent at low rates. Moreover, at higher production rates, despite that the oil viscosity increases, the recovery efficiency is improved because of the movement of discrete gas bubbles through the pore spaces [6]. Holm and O'Brien presented the results of a CO₂-carbonated water–brine injection field experience. They reported that 50% more oil was produced compared to the conventional water flooding (WF) due to SGD mechanism during the five years field test [7]. Holm and Josendal studied the SGD scenario during CO₂ injection in sandstone reservoirs and observed that as pressure dropped from 6205 kPa to 2758 kPa, and then 1379 kPa, the oil recovery were increased by 14% and 18.5%, respectively [8]. Moulou calculated the critical gas saturation during SGD mechanism in limestone core samples at pressure and temperature of 2844 kPa and 37.78 °C, respectively. It was shown that the critical gas saturation decreased as the depletion rate was reduced [9]. Wong *et al.* investigated

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the role of SGD on heavy oil flow using unconsolidated sandstone cores. They observed that as the rate of pressure depletion decreases, the ultimate oil recovery increases ranging from 35% to 50% suggesting that in the absence of foamy flow (*i.e.* dispersed gas-bubble flow) as a function of test duration, some other factors could likely lead to the higher oil recovery. According to their experiments below the bubble point, expansion of released gas plays the main role to preserve the reservoir pressure [10]. Kumar *et al.* carried out some experiments using sandpack to evaluate the amount of primary oil recovery under SGD. Besides, the tests were simulated with Eclipse 100 in order to match the experimental data. They observed that gas saturation into the sandpack would increase as the depletion rate increased as a consequence of very small gas bubbles appeared during the rapid depletion run. These tiny bubbles did not merge as fast as blowdown test. Simulation results were in good agreement with the experimental data [11]. Arora and Kovscek and Akin and Kovscek modeled SGD and accomplished some experiments in a sandpack using heavy mineral and crude oils. They reported that increasing the depletion rate could enhance bubbles production. The results of the tests indicated that oil viscosity, depletion rate, and solution gas–oil ratio would affect oil flow [12,13]. Tang *et al.* investigated the effect of oil composition and depletion rate on oil recovery efficiency for heavy oil reservoirs under SGD using crude and mineral oil samples. According to their results, for crude oils with low viscosity, as the depletion rate decreased, the possibility of forming a dispersed gas-bubble flow so-called foamy flow diminished. They reported that a higher depletion rate could increase the ultimate oil recovery for crude oil compared to mineral oil [14]. Sahni *et al.* studied the effects of oil viscosity, initial gas–oil ratio, and depletion rate on the growth of the gas phase during SGD using sandpack. They observed that the lowest gas–oil ratio leads to earlier critical gas saturation. They also concluded that a high depletion rate would result in more gas bubbles. Besides, an empirical correlation for predicting critical gas saturation was presented by them [15]. Shahvali and Pooladi-Darvish presented a model to predict the behavior of the tests at the desired conditions. Their results showed that during SGD, as depletion rate increased, non-equilibrium behavior would be more remarkable. Furthermore, they illustrated that gas mobility has a reverse proportion to viscous forces [16]. Lu *et al.* investigated the role of temperature on EOR during SGD mechanism using micromodel and sandpack tests. They showed that an optimum temperature could exist at which the highest oil recovery would be achieved. Outcomes also indicated that higher temperature had both favorable and adverse effects on oil recovery, oil viscosity reduction as a positive factor while lower stability of foamy oil flow at higher temperature conditions as the negative aspect [17]. The effect of different types of dissolved gas on oil recovery was studied by Bera and Babadagli [18]. They used CO₂, methane, and propane to prepare the live oil samples. The core flooding results reveal that CO₂ could lead to much more than three times incremental oil compared to two other gases because of its impressive effect on forming the foamy oil. Lu *et al.* surveyed enhanced oil recovery during conventional WF for an oil reservoir depleted under SGD. They determined the conversion pressure to be about 3516 kPa. As conversion pressure increased, the amount of oil recovered by SGD decreased while produced oil due to WF intensified [19]. Zhou *et al.* carried out some sandpack experiments to study the influence of depletion rate on oil production in the presence of different types of solvent (*i.e.* methane, propane, and a mixture of them). They observed that higher blowdown pressure would lead to lower critical pressure of foamy oil flow. Moreover, they reported that there is a critical depressurization rate for each system resulting in the highest oil recovery [20]. Abusahmin *et al.* investigated the impact of the type of dissolved gas and depletion rate using crude and mineral oil systems. They observed that the lighter dissolved gas resulted in much higher oil recovery. The direct relationship between oil recovery and depressurization rate was approved by them. In addition, they reported the same oil recovery efficiencies for mineral and crude oil types under similar operating circumstances [21]. Dong

et al. presented a new method to estimate the initial performance of oil reservoirs depleting under SGD. Their method can convert PDE (partial differential equation) equations into ODE (ordinary differential equation) ones, and subsequently, the problem could be solved more quickly compared to other methods using standard finite difference method. Besides, no pressure-saturation and gas–oil ratio data are required to estimate the reservoir pressure and fluids saturations [22]. Bagudu *et al.* modeled the depressurization process on a core sample from North Sea reservoir. They reported that the pressure drop rate had no remarkable influence on critical gas saturation. An increase in oil recovery was observed with connate water saturation enhancement. However, the higher the initial water saturation, the lower the critical gas saturation would be. In addition, they presented a general correlation in order to estimate the effective critical gas saturation as a function of initial water saturation, depletion rate, and system scale [23]. Zhang *et al.* conducted an experimental study using micromodel to survey the foamy oil flow in heavy oil reservoirs. They observed that gas nucleation was chiefly emerged at the pore surfaces. In addition, they indicated that a continuous gas phase would create in light oil, which can flow as a free phase while in foamy oil flow, gas bubbles move with oil phase [24].

Based on the literature, the impact of SGD after secondary and tertiary CWI has not been simultaneously investigated. Besides, the share of SGD compared to other EOR methods (for instance CWI in the current experimental research) on incremental oil production has not been studied. Thus, the main objective of this study is to evaluate the possibility of CWI as a two-stage method for more oil recovery in carbonate rocks and the proportion of SGD on ultimate EOR in both secondary and tertiary modes have been investigated. These stages consist of CWI, followed by depleting the oil reservoir through fluid production to activate the artificial SGD mechanism through core flooding tests. Such a mechanism has of great importance in the oil reservoirs with a low initial gas content.

2. Experimental

2.1. Fluid (formation brine, CW brine, and crude oil)

The composition of the formation brine as the connate water and the brine used for CW are given in Table 1. To prepare the CW, carbon dioxide (CO₂) was mixed with a low salinity brine (*i.e.* flooding brine). During the tertiary carbonated water injection (TCWI) test, the core sample was first conventionally flooded using a CO₂ free brine with the same composition and salinity as CW brine as the secondary stage, then it was followed by CWI for tertiary oil recovery purposes.

Carbon dioxide and flooding brine were combined in a rocking cell apparatus at temperature and pressure of 40 °C and 13,790 kPa, respectively. Based on the available information in the literature, CO₂ solubility in distilled water remarkably depends on pressure. Chang *et al.* and Wiebe have investigated the CO₂ solubility in distilled water at a wide range of pressure [25,26]. According to their results, the pressure of 13,790 kPa could be considered as an optimum pressure for CO₂

Table 1
The composition of the flooding and formation brines

Salt	Flooding brine	Formation brine
	Concentration/mg·L ⁻¹	Concentration/mg·L ⁻¹
NaCl	8000	24,000
KCl	2000	740
Na ₂ SO ₄	–	4010
CaCl ₂ ·2H ₂ O	–	1520
MgCl ₂ ·6H ₂ O	–	10,900
TDS	10,000	41,170

Note: TDS = total dissolved solid.

dissolution in deionized water. In order to take into account the impact of different salinity on CO_2 dissolution at different pressure and temperature conditions, a model has been presented by Duan and Sun and Duan *et al.* [27,28]. In this study, CO_2 solubility into the flooding brine was calculated to be 31 (Standard cm^3 of gas) per 1 (Standard cm^3 of brine) based on the model presented by Duan *et al.* [28]. The quantities of dissolved gas for brines used in secondary carbonated water injection (SCWI) and TCWI tests are shown in Fig. 1 [28].

The precise solubility of CO_2 in crude oil has not been measured but based on the results obtained in our previous study, it is postulated that CO_2 solubility in the oil phase is higher than that in the water phase [29]. In this research, all the experiments were performed using dead crude oil from one of the Iranian carbonate oil reservoirs with the viscosity and density of $0.062 \text{ Pa}\cdot\text{s}$ and 28° API , respectively, at 40°C . According to the literature, CWI could be basically recognized as an efficient method in enhancing oil recovery for heavy crude oils. It should be noted that viscosity reduction is one of the main mechanisms during this EOR technique [5,17]. In our research group, the IFTs of crude oil–water and crude oil–CW systems were measured to be $29.92 \text{ mN}\cdot\text{m}^{-1}$ and $22.29 \text{ mN}\cdot\text{m}^{-1}$, respectively at temperature of 40°C and pressure of $13,790 \text{ kPa}$ [30].

2.2. Core sample

An intact outcrop of an Iranian southern carbonate oil reservoirs has been provided for preparing two core samples used in this study. The physical properties of the core samples are given in Table 2.

2.3. Rocking cell apparatus

Carbonated water used in the tests has been prepared using a rocking cell apparatus. The rocking cell consists of a cell coated by a thermal jacket that can be rocked to prepare mixture of water and CO_2 at desired conditions. Then, the CW is transferred into one of the core flood accumulators placed in the core flooding set-up to be injected into the core samples.

2.4. Gasometer

In order to activate SGD, it needs to decrease whole system pressure. As system pressure declines, both oil and water phases initially expand, and consequently, CO_2 could be released from the CW throughout the core afterward. At this condition, CO_2 as free phase moves easily through the core sample because of its high mobility compared to oil and water phases. In order to precisely monitor and record the amount of produced gas, a gasometer from Vinci Technologies was mounted on the core holder outlet.

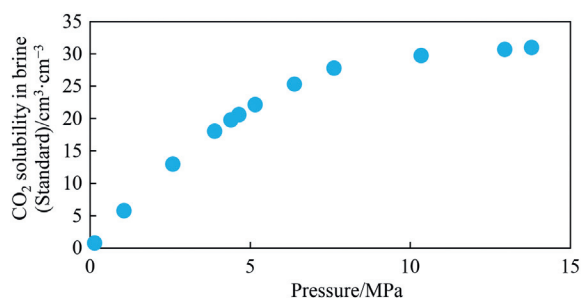


Fig. 1. CO_2 solubility in brine versus pressure [28].

Table 2

Physical properties of core samples used in this study

Sample	Properties					
	D/mm	L/mm	$\Phi/\%$	K/mD	PV/ cm^3	$S_{wi}/\%$
S ₁	37.8	78.3	23.80	11.26	20.90	35
S ₂	37.8	77.2	18.30	10.31	15.87	50

2.5. System set-up

During core flooding trials, outlet pressure has been retained using a back pressure regulator (BPR). Required pressure applied to BPR is supplied using a nitrogen cylinder. After core flooding experiments, inlet and outlet of the system have been shut for about 12 h so that the pressure distribution could be stable across the core sample. To mimic the solution gas drive condition, the system pressure has been decreased at a constant depletion rate of $1241 \text{ kPa}\cdot\text{h}^{-1}$ via a vent valve set between the nitrogen cylinder and BPR. It should be noted that the pressure data recorded here is the pressure between the core outlet and the BPR delineated as downstream pressure in Fig. 2. As the pressure of the system dropped, different fluids (*i.e.* oil, water, and gas) are produced. Produced oil and water have been accumulated using a collector. A glass separator has been set at the core holder outlet to segregate the liquid and gas phases. The top section of the separator has been connected to the gasometer. The system set-up is schematically shown in Fig. 2.

3. Results and Discussion

3.1. Produced gas

Using CWI technique both in SCWI and TCWI modes, the properties between fluid–fluid and rock–fluid are changed. After CWI process, during SGD mechanism, the main mechanisms of oil production are oil shrinkage, oil saturation redistribution and gas expansion. On one hand, at the early times above saturation pressure, both oil and water phases would be swollen and no free gas is present in the core sample. As system pressure declines on a continuous trend, the pressure of oil and water phases progressively reach the gas saturation pressure and as a result, gas bubbles could be gradually released from oil and water phases. It is worth mentioning that as the depletion process continues, the gas phase tends to transfer from the water phase toward the gas bubbles in the oil phase and no gas nucleation would occur in the water phase [31]. As a consequence, the gas phase movement can result in the oil saturation restoration and accordingly, it can help the oil displacement due to the hysteresis effect. However, the volume of the oil bank decreases due to gas expulsion, it can flow through the pore paths because of its continuity. On the other hand, as CO_2 expands and reaches critical gas saturation, it can displace easily due to its high mobility. Moreover, it may help with oil production as a result of the viscous forces formed by its motion. Fig. 3 illustrates schematically the oil bank formed during this process.

Different parameters such as oil viscosity, oil composition, permeability, and depletion rate can influence critical gas saturation [15,32, 33]. When the depletion process started, some oil and water phases were immediately produced. Besides, gasometer apparatus indicated the amounts of gas production. The volumes of produced oil and water phases show the space occupied by the released gas (*i.e.* free gas). Critical gas saturations for secondary carbonated water depletion (SCWD) and tertiary carbonated water depletion (TCWD) processes are determined to be 11% and 10%, respectively. At the end of each hour elapsed of both tests, gas saturations have been recorded and depicted in Fig. 4.

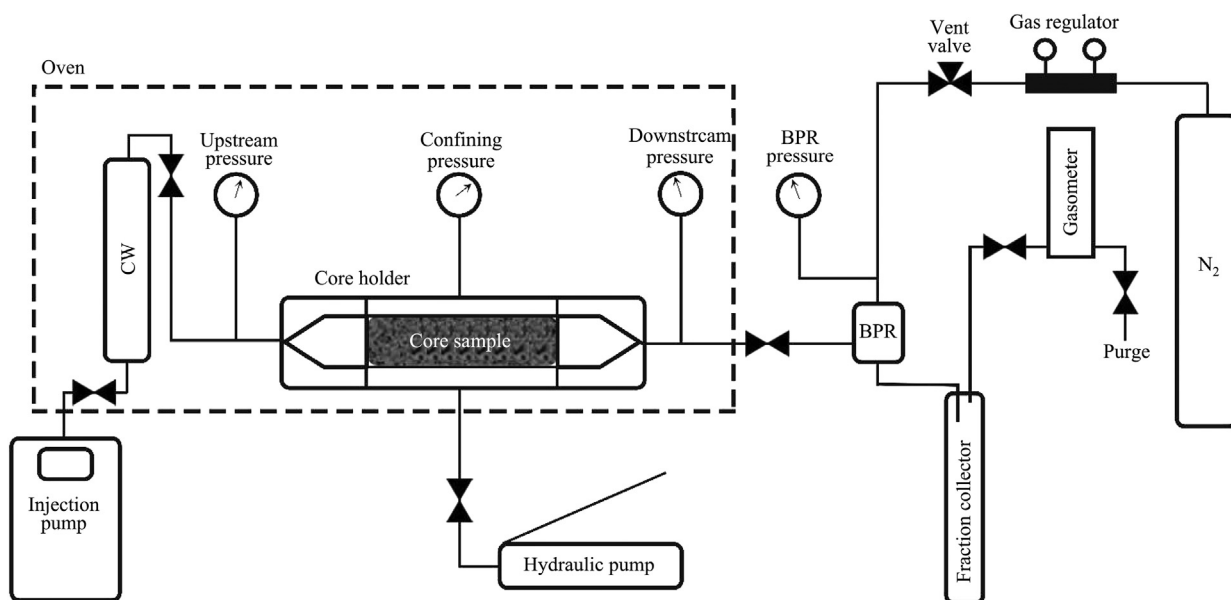


Fig. 2. Schematic of the system set-up.

Based on data in Fig. 4, at the pressure of 13,790 kPa, no free gas could exist in the core sample. As pressure declines, CO_2 saturation would increase in the core samples. At the end of TCWD and SCWD scenarios, the total volume of pore space occupied by oil and water

(including connate water) were 9.2 cm^3 and 9.07 cm^3 , respectively. Based on the initial pore volume of the core samples, the free pore spaces that could be engaged by gas phase are 11.7 cm^3 and 6.8 cm^3 in TCWD and SCWD, respectively. Hence, it is expected that the last

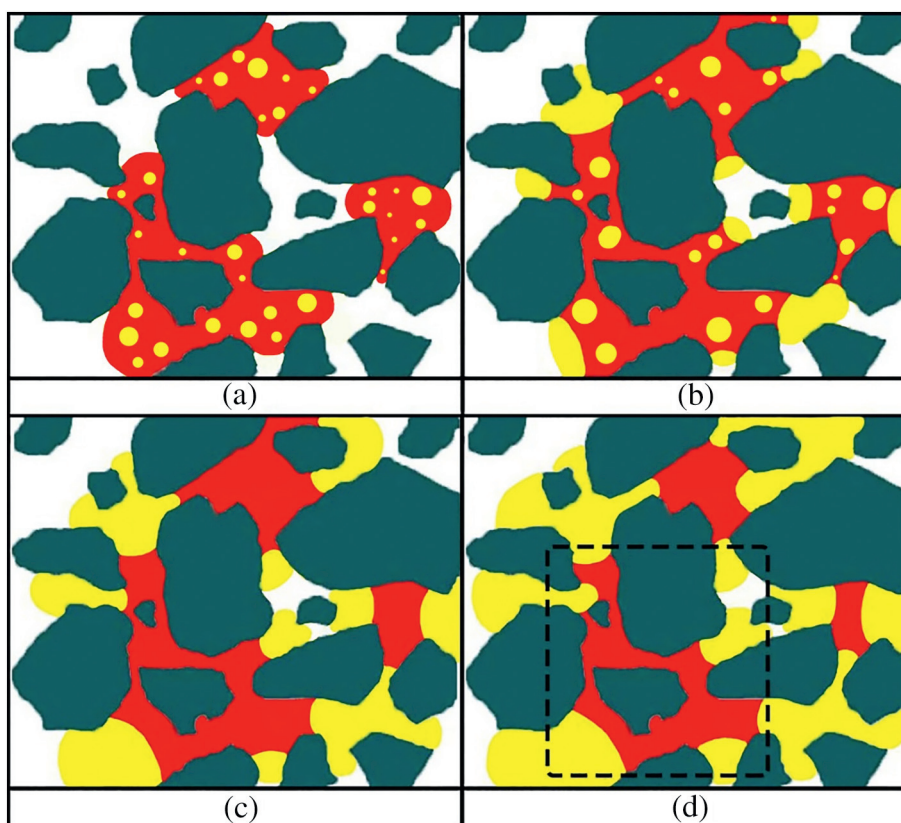


Fig. 3. (a) As system pressure is declined and reached the saturation pressure, gas bubbles are progressively nucleating in the oil phase (oil, water, and gas phases are in red, white, and yellow colors, respectively), (b) pressure decline causes further expansion of gas bubbles and oil drop shrinkage, (c) more pressure drop results in more gas bubbles expansion, and gas movement toward the oil–water edge makes more diminution of oil volume, (d) gas bubbles movement would lead to a new arrangement of oil saturation (i.e. oil saturation restoration) and hysteresis effect during displacement. Eventually, oil phase can flow through pore paths due to hysteresis effect emerged during the gas phase movement (highlighted by a dashed-rectangle).

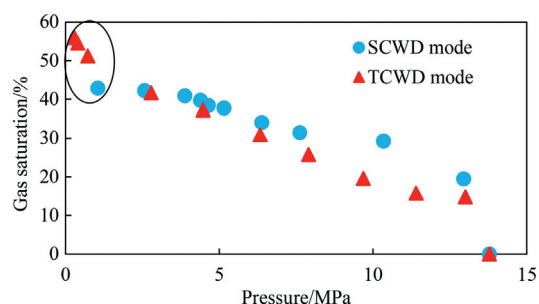


Fig. 4. Gas saturation during depletion period in both SCWD and TCWD processes.

gas saturation values in TCWD are higher compared to SCWD test. As shown in Fig. 4, for the pressure lower than 1379 kPa, CO_2 saturation in TCWD scenario is more than that of SCWD test (highlighted by an oval). The volumes of sequestered CO_2 into the core samples should be around 961 cm^3 and 1743 cm^3 (i.e. the difference between injected and produced CO_2 during SCWI and TCWI tests) for SCWI and TCWI, respectively [29,34]. Figs. 5 and 6 illustrate gas/oil/water production and system pressure data over the test time during SCWD and TCWD, respectively. It should be noted that the produced gas has a dramatic high volume compared to that of the oil and water phases. Hence, in order to depict all the fluids production in one figure (i.e. Figs. 5 and

6) and get an appropriate comparative view, gas volume has been divided by one hundred for both scenarios. It is worth mentioning that some pressure fluctuation occurred during depressurization process is concerned with the progressive gas nucleation [20]. The existent gas in the core sample mainly controls the system pressure as solution gas drive. Based on Figs. 5 and 6, until the middle times, the oil production was higher in SCWD compared to that in TCWD. During this period, gas production in SCWD test was also much more than that in TCWD scenario. Hence, it is postulated that the system pressure for SCWD declines more than that in TCWD. After that, until the end of the tests, residual oil saturation in SCWD would lessen compared to TCWD and as a result, less oil could be produced in SCWD. This means that the system pressure drop in TCWD can be more than that in SCWD at the end of the tests. Free gas phase would play the role of an artificial gas cap so that it can compensate the pressure decline. Pressure change throughout the core sample could appear as a pressure shock and showed an up-and-down behavior. Besides, among oil and water phases within the core sample, the oil phase can further affect the system pressure drop. In a core sample after CWI, more pore spaces would be occupied by the water phase. According to the previous studies, CWI could change the wettability from oil wet toward more water wetness [5,29]. At these conditions, water and oil phases would be considered as continuous and trapped phases, respectively. As system pressure declines, the water phase would be produced due to its continuity and subsequently, a great deal of dissolved gas could be nucleated and

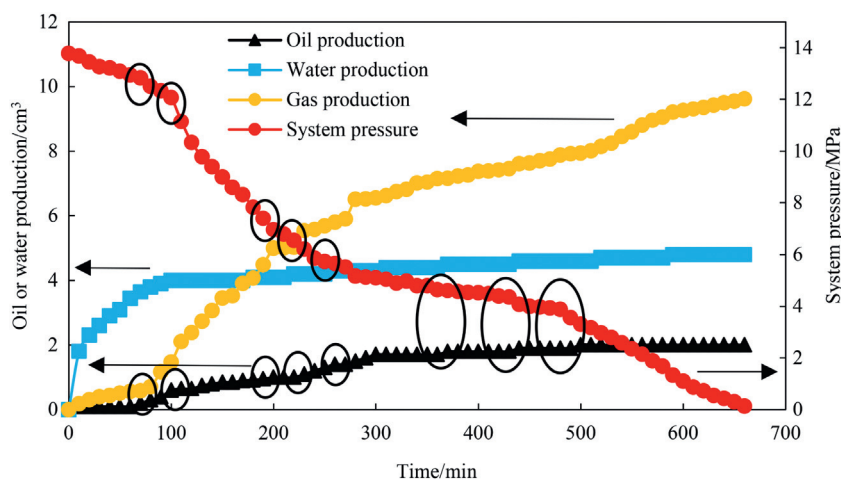


Fig. 5. Oil and water production and pressure drop history for SCWD (to better demonstrate, the volume of gas phase has been divided by one hundred).

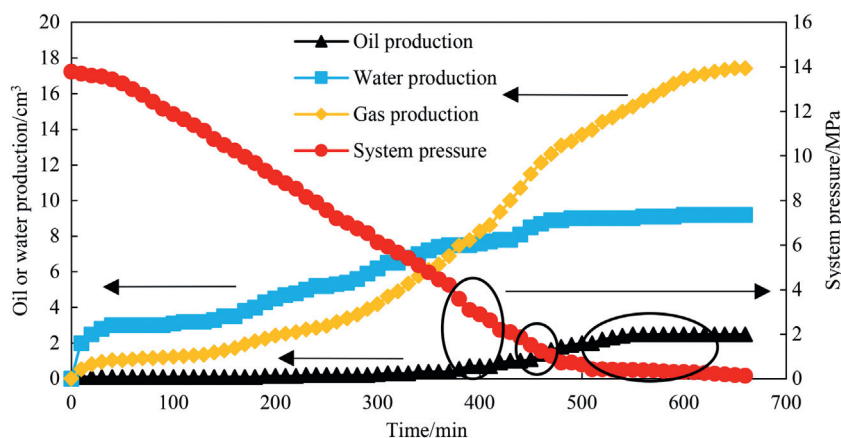


Fig. 6. Oil and water production and pressure drop history for TCWD (to better demonstrate, the volume of gas phase has been divided by one hundred).

Table 3
Oil and water volume in core samples

Test	PV/cm ³	S_{oi}	S_{or}	V_{gi}/cm^3	$S_{w(i+cw)}$	$S_{wi}/\%$
SCWD	15.87	0.16	0.034	961	0.84	50
TCWD	20.90	0.18	0.061	1743	0.82	35

then produced, as well. On the other hand, during a depressurization period, CO₂ bubbles would remain in the oil phase instead of the water phase due to interfacial tension (IFT) difference between oil–CO₂ and water–CO₂ [31]. In other words, gas bubbles would rather stay in the oil phase than in the water phase in order to reach more stable conditions of the minimum Gibbs energy level [31]. At these conditions, it is presumed that the rate of the produced gas is controlled by the oil phase production history.

As can be seen from Figs. 5 and 6, the pressure drop of the system severely depends on the oil production trend. After Shakiba *et al.*, the ultimate oil recoveries of SCWI and TCWI were 68.1% and 72.16%, respectively [29,34]. Hence, less residual oil saturation existed in the core sample of TCWD test. Coalescence of disconnected oil ganglia due to swelling and viscous forces is more considerable in SCWD compared to that in TCWD test. That is, the oil production trend is slower in TCWD than that in SCWD. Besides, TCWI resulted in more erratic oil saturation distribution in the core sample compared to SCWI mode [29,34]. At this condition, disconnected oil droplets during TCWD test could not rejoin as quickly as those during SCWD, thus, they need more time to be reunited. Table 3 presents more details about oil and water volumes for both experiments.

It should be noted that in Table 3, initial oil saturations at the beginning of depletion scenarios are equal to residual oil saturation after CWI tests [29,34].

3.2. Oil recovery

During oil recovery, the continuity of the oil phase is the most effective parameter that influences the oil movement. During the depletion process, as gas bubbles move through the pore paths, they can cause oil saturation restoration that results in hysteresis effect. Therefore, oil phase would flow easily in the porous medium. Besides, viscous forces due to gas dissolution could be considered as an effective mechanisms leading to additional oil production. Figs. 7 and 8 demonstrate the cumulative oil recovery efficiency and water production for four sections of the test time for both SCWD and TCWD tests, respectively.

As discussed in Section 3.1, coalescence of oil droplets requires more time in TCWD compared to that in SCWD and subsequently, the amount of water production was shown to be much more than that of SCWD scenario as demonstrated in Figs. 5 and 6. The results presented in Fig. 7 indicate that the oil recovery factor for TCWD is measured to be only about 2% of the original oil in place for half of the test time period.

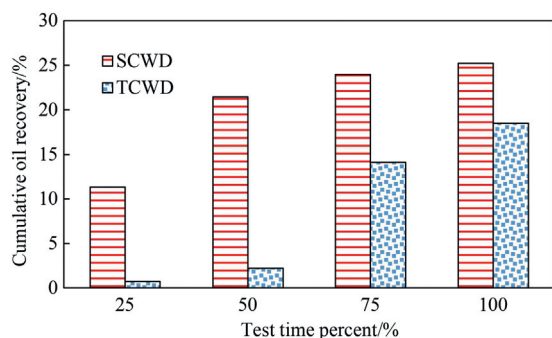


Fig. 7. Oil recovery during the test time in both SCWD and TCWD cases.

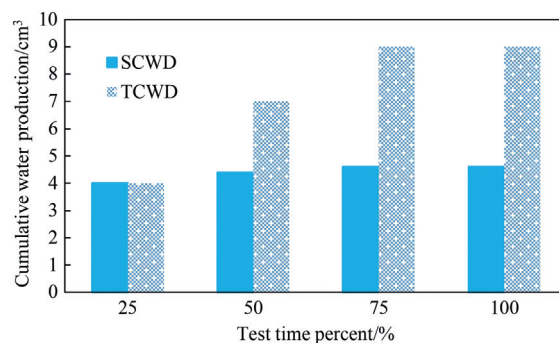


Fig. 8. Water production during the test time in both SCWD and TCWD scenarios.

As the test continued, reconnecting the trapped oil droplets enhanced oil recovery up to more than six times for the next quarter of the test period. In TCWD scenario, the results indicated that the oil production during the second half of the test grew about 88% compared to that of the first half. Similarly for SCWD, as shown in Fig. 7, the oil recovery factor was increased progressively. However, the amount of oil recovery enhancement did not approach the same amount noticed for TCWD case. At this condition for SCWD, the enhanced oil recovery was 15% at the end of the second half of the test in comparison with that of the first half. Conventional WF and TCWI in the core sample would result in more irregular saturation distribution of the oil phase relative to that in SCWI case. Besides, hysteresis effect as a result of rearrangement of the oil saturation could control the oil phase movement. This indicates that SGD mechanism requires more time for TCWI test compared to that of SCWI case in order for its effectiveness to be revealed. As demonstrated in Fig. 8, the amount of water production in TCWD is remarkable compared to that in SCWD test. This is due to the fact that new oil saturation distribution after TCWI requires more times to be affected by SGD and consequently to be produced. At this condition, water phase would have higher relative permeability compared to the oil phase and as a result, it could pass easily through the pore paths. In order to clearly report the amount of liquids at the effluent stream, water cut data has been shown in Fig. 9.

Water cut data presented in Fig. 9 indicates that water production was decreased as the production approached the last quarter of time period in TCWD case (highlighted by a rectangle in Fig. 9). Prior to this, the water cut was approximately constant and above 90%. Based on the results of secondary, tertiary carbonated water injection, and depressurization process, the total oil recovery history has been plotted in Fig. 10. It should be noted that since the data recorded during the depletion process were based on the test time, thus ultimate oil recovery efficiency illustrated in Fig. 10 has been shown based on the injection time instead of the pore volume.

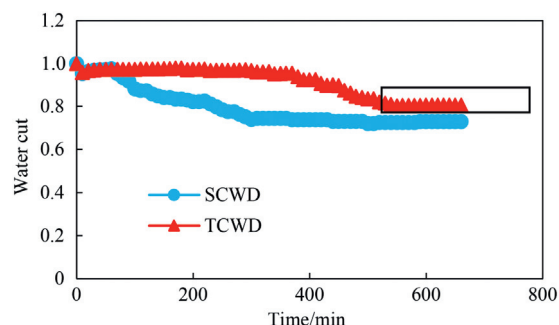


Fig. 9. Water cut for SCWD and TCWD tests.

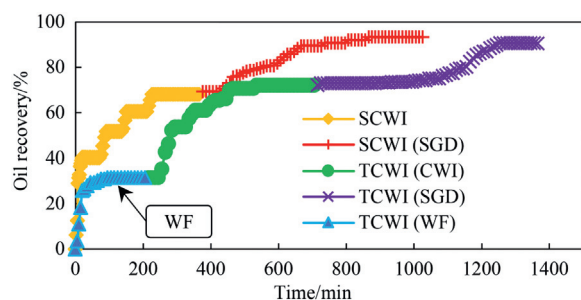


Fig. 10. Cumulative oil recovery in terms of test time [29,34].

The results indicate that at the end of depletion scenarios, the oil recovery efficiencies of SCWD and TCWD tests are approached 79% and 66% of residual oil saturation within the core samples before beginning the depletion process, respectively. The depressurization process was allowed to be extended for 11 h in both cases. A conventional WF test has been performed before CWI in TCWI scenario, thus as shown in Fig. 10, the total test time of TCWI is more than that of the SCWI case. Fig. 11 reveals the effectiveness of each process on the oil recovery efficiencies for both cases.

As can be seen in Fig. 11, although CWI has led to more oil recovery efficiency, the SGD mechanism could assist more oil recovery as its share is more than 30% of the CWI share in both cases.

4. Conclusions

According to the outcomes of this laboratory research work, the following results can be concluded:

- After CWI process in an oil reservoir, artificial SGD as a secondary EOR technique could be activated due to the reservoir depletion, which could result in more incremental oil recovery. The results of coreflood tests conducted in this study indicated 25.22% and 18.5% incremental oil production after SCWI and TCWI, respectively, as initial EOR technique.
- In both SCWD and TCWD scenarios, the system pressure decreases due to simultaneous production of oil and water phases. However, the results indicated that the system pressure drop severely depends on the oil production trend while produced water pattern showed no phenomenal impact on it.
- The results of the depressurization tests revealed that the ultimate oil recovery efficiencies due to SGD activation for SCWD and TCWD modes were 79% and 66% of residual oil saturation within the core samples, respectively. However, the effect of SGD mechanism is more than 30% of the incremental oil recovered during CWI both in secondary and tertiary cases.
- After half of TCWD process, enhanced oil recovery remarkably promoted likely due to more oil ganglia coalescence phenomenon. It is worth mentioning that in TCWD test, the more fraction of core sample PV has been occupied by the water phase compared to the oil phase.

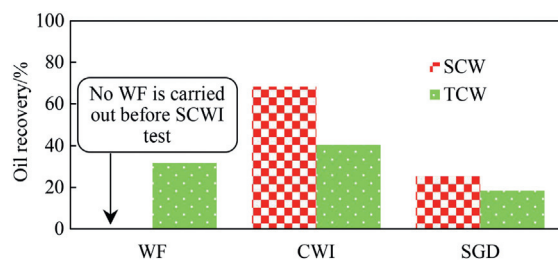


Fig. 11. Ration of different processes on enhanced oil recovery.

This means that more time is needed for the SGD to be activated in TCWI case compared to that of SCWI scenario.

Acknowledgements

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Nomenclature

D	Core sample diameter, mm
K	Permeability, mD
L	Core sample length, mm
PV	Pore volume, cm^3
S_{oi}	Initial oil saturation
S_{or}	Residual oil saturation
$S_{w(i+cw)}$	Total saturation of water (initial and carbonated water)
S_{wi}	Initial water saturation
S_1	Core sample 1
S_2	Core sample 2
TDS	Total dissolved solid, $\text{mg} \cdot \text{L}^{-1}$
V_{gr}	Residual gas volume, cm^3
ϕ	Porosity, %

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