An experimental study to measure oil recovery factor by chemical agents and carbon dioxide after waterflooding

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Development of tight formations would be one of the main priorities for petroleum industries due to the enormous demand to the fossil fuels in various industries. In this paper, we provided a set of experiments on the generated foams by carbon dioxide (CO2) and nitrogen (N2), cyclic CO2 injection, water alternating gas injection (WAG), active carbonated water injection (coupling surfactant effects and carbonated water (CW)), and introducing the impact of active carbonated water alternating gas injection (combination of WAG and CW injection) after waterflooding. Carbon dioxide is more feasible than nitrogen, it can be mobilize more in the pore throats and provided higher oil recovery factor. Generated foam with CO2 has increased oil recovery factor about 32% while it’s about 28% for generated foam by N2. Moreover, according to the results of this study, the maximum oil recovery factor for active carbonated water alternating gas injection, active carbonated water injection, and water alternating gas injection measured 74%, 65%, and 48% respectively.

Increasing demand to energy which has been supplied by fossil fuels provide a straightforward way to invest more on tight hydrocarbon reservoirs regarding the less productivity from conventional reservoirs. Therefore, development of tight formations would be one of the main criteria for petroleum industries. Waterflooding can be widely used for oil recovery purposes, however, in tight reservoirs is not beneficial enough as the oil production will decrease sharply after the water breakthrough. Thereby, this method can’t be used as the main enhanced oil recovery techniques and additional chemical or thermal methods would be more demanding to increase the oil production after waterflooding. Wide applications of foams in enhanced oil recovery (EOR) techniques which can be applied as the blocking agent especially for high permeable pores to conduct the more feasible sweep efficiency for oil in low permeable pores is one of the main features of implementation of this chemical agent. Foams injection is one of the most appropriate chemical enhanced oil recovery methods especially in tight oil reservoirs1–3. Hu et al. (2020) experimentally investigated the coupling effects of foams and various saline brines on the enhanced oil recovery factor. It was observed that coupling injection of foams and KCl would be the optimum injectivity scenario. The reason for this oil recovery enhancement corresponds to the monovalent property of K+ on the wettability alteration. Another findings of this study related to its lowest interfacial tension which would be a good feature for oil recovery purposes4. Among chemically enhanced oil recovery techniques, surfactant has been always been an interesting topic among scientists and petroleum companies. It is corresponded to the useful characteristics of surfactants to alter the wettability and reduce the interfacial tension which has caused to increase the oil recovery factor in tight reservoirs. For example, Nguyen et al.5 observed that wettability alteration was the main phenomenon on the oil recovery increase in tight oil reservoirs.

Injection of carbon dioxide in tight oil reservoirs would be of important as it can cause oil swelling and subsequent oil viscosity reduction. It is led to increase oil recovery factor6,7. When the carbon dioxide (henceforth; CO2) has been injected under miscible condition, there is no interfacial tension between oil and CO2 that can be a useful method for enhanced oil recovery in tight reservoirs. On the other hand, cyclic injection of carbon

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dioxide in tight reservoirs would be a prominent technique to increase oil production as the CO₂ has the sufficient
time to soak the core samples and dissolve in oil. This method was used by previous scientists and the results of
this study would be consistent with the previous literature.

When CO₂ dissolved in formation brine (called carbonated water injection (CWI)) by the purpose of increas-
ing the sweep efficiency, CO₂ can transfer to the oil phase from formation brine. In this situation, CO₂ can cause
to decrease the oil viscosity and swelling. According to the observation of some researchers, addition of surf-
factants to the carbonated water can be a crucial role on the wettability alteration which provide better efficiencies
in oil recovery scenarios. It is called active carbonated water injection which couple the considerable effect of
surfactants and carbonated water injection to reduce the oil viscosity. Water alternating gas injection is one of the
effective EOR methods as it can inject both phases of water and gas in turn. However, Yu et al. (2019) observed
that carbonated water injection in tight reservoirs in provided better results than water alternating gas (WAG)
injection. Here, we compare the active carbonated water injection with WAG injection scenario to justify that
ACWAGI (active carbonated water alternating gas injection) would provide better results than WAG injection.

In this paper, we provide a set of experiments on the applications of foams (generated by CO₂ and N₂), cyclic
carbon dioxide (focused on the number of cycles due to more soaking time), water alternating gas injection,
active carbonated water injection (coupling surfactant effects and carbonated water), and introducing the impact
of active carbonated water alternating gas injection (combination of WAG and CW injection) after waterflood-
ing. In second section, the materials and experimental procedures has been explained in more detail and then
in third section, the experimental results of this paper were separately illustrated for each scenario. Finally, the
most notable features of this study is written in summary.

Methodology

**Materials.** Core samples. In order to provide reliable results, we brought 10 core samples from one of the
tight reservoirs located in Daqing field (one of the unconventional oilfields in China). More information about
the sedimentology and lithology of this oilfield can be found. The properties of core samples are explained in
Table 1. The length of all the core samples are approximately 2 ±(ε = 0.01) with the diameter of 2 ft.

| No | Porosity (%) | Permeability (mD) |
|----|--------------|------------------|
| 1  | 4.62         | 0.056            |
| 2  | 4.86         | 0.094            |
| 3  | 4.25         | 0.015            |
| 4  | 4.67         | 0.065            |
| 5  | 5.07         | 0.131            |
| 6  | 4.92         | 0.115            |
| 7  | 5.28         | 0.143            |
| 8  | 5.16         | 0.14             |
| 9  | 5.65         | 0.156            |
| 10 | 4.38         | 0.022            |

Table 1. Rock characteristics of core sample properties.

Fluids. Crude oil composition and properties. The crude oil that is used in this experiment is mainly con-
tained heavy hydrocarbons (C₇+) which is measured in the room temperature of 25 °C and atmospheric pres-
sure. The content of C₇+ is 76.08 mol%, while lighter hydrocarbons only consisted less than 25% of the crude
oil (23.92 mol %) which is indicated that crude oil is heavy and needed secondary and tertiary enhanced oil
recovery techniques. The density and the viscosity of the crude oil were measured in the temperature of 120 °C
(reservoir temperature) 0.735 g/cm³ and 7.41 mPa.s respectively. Due to the higher viscosity of crude oil than
live oil (1.52 mPa.s), the heavy oil can’t be swept efficiency.

Synthetic brine. The synthetic which was used in this experiment has the total salinity of 5878.6 mg/L. The car-
bonated water is prepared with the 0.35*10⁻³ mol/cm³ concentration of purified carbon dioxide (99.9%) under
test situations.

Surfactant. Cetyltrimethylammonium bromide (henceforth; CTAB) is a quaternary ammonium surfactant
which was used to generate foaming agents. It was widely used in enhanced oil recovery methods in previous
literature. The surfactant solution was prepared in 30,000 ppm and Critical micelle concentration (CMC) was
obtained as 0.12 wt%. Therefore, to generate the foaming agent and prevent foam films, the surfactant concentra-
tion was kept at 0.1 wt%.

**Experiments and procedures.** Experimental apparatus. Figure 1 shows the experimental coreflooding
apparatus schematically. The chemical agents are stored in a separate vessel and connected to the core holder (the
place where tight core samples were fixed during the experiment) by some valves which was manually opened
and closed. The core holder system was put in an oven with the defined reservoir temperature of 120 °C. The
backpressure valve was used to control the pressure drop which was allocated to not allow the carbon dioxide liberation during the carbonated water injection. The liquid meter was defined in the system to measure the recovered flow which can be used to calculate oil recovery factor and water saturation.

**Coreflooding procedure.** The following procedure was done sequentially:

- To measure tight core samples' permeability, all the core samples were died and then weighed. Next, by the high purified nitrogen gas, the permeabilities of the tight core samples were measured (See Table 1).
- The tight core samples were put in the core holder system horizontally in the defined reservoir temperature of 120 °C and 25 MPa (confining pressure).
- The synthesized brine (to saturate core samples) and oil was injected sequentially with the flow rate of 0.02 cm³/min to measure the oil and water saturation.
- To calculate the oil recovery factor during the waterflooding, 2 PV of synthesized water was injected.
- Foams injection (generated by N₂ and CO₂), cyclic carbon dioxide injection, carbonated water injection, and active carbonated water injection scenarios were done separately at various pore volumes to measure oil recovery factor (Core samples 1 and 2).
- Finally, 1 PV of synthesized water was injected into the core samples to make sure that there is no remained oil in the core samples.
- Cyclic injection of carbon dioxide as a miscible phase for 1, 2, 5, 10, and 15 cycles has been performed (Core samples 3–7).
- Water alternating gas injection with the ratio of ½ (1 for water and 2 for gas) was performed after waterflooding on core sample 8.
- Carbonated water injection and active carbonated water alternating gas injection were done by core samples 9 and 10.

**Results and discussion**

**Enhanced oil recovery.** Waterflooding. First, we focused on the waterflooding scenario as enhanced oil recovery methods to compare with other recovery techniques. It is observed that the maximum value of oil recovery factor by waterflooding is approximately 24% after 2 PV of water injection. At this point, there is no progress on the oil recovery factor and we implemented other injectivity scenarios (see Fig. 2).

**Foams injection.** According to our experiments, it was observed that waterflooding can only be applied until 2 PV injection as it was reached a plateau on the oil recovery factor and it's not significant change on the oil...
production. Then, we shifted to other enhanced oil recovery (EOR) methods after waterflooding to observe the value of increasing oil recovery factor. Due to the enormous applications of foams in EOR techniques which can be applied as the blocking agent especially for high permeable pores to conduct the more feasible sweep efficiency for oil in low permeable pores, in this part, we injected to types of foams after waterflooding. One was generated by the carbon dioxide and the second one generated by nitrogen gas. As resistivity factor is one of essential issues on the selection of foaming agent to have higher efficiency in EOR methods. Therefore, we select foam qualities of 40%, 60%, and 80% to measure resistivity factor for various permeabilities. By the increase of permeability, foam resistivity factor has been increased and foam quality of 80% has the highest value which indicated the more efficient sweep efficiency by the foaming agent. Thereby, foam quality of 80% was selected for this experiment (see Fig. 3).

Here, we used CO₂ and N₂ to generate foams. Then, we started the experiments after 2 PV of waterflooding to see the maximum value of oil recovery increase. In the first pore volumes of foams injection, oil recovery factor has increased slightly through the core samples indicated that foams were moving through the higher permeable areas to block them. Then, oil recovery has increased rapidly due to the blocking of high permeable areas and remained oils in low permeable areas displaced more feasible. It is corresponded to the foams efficiency to block the high permeable pores and pore throats. This point (PV = 4) is the commencement of oil recovery enhancement by generated foams. Carbon dioxide is more feasible than nitrogen, it can be mobilize more in the
pore throats and provided higher oil recovery factor. Generated foam with CO$_2$ has increased oil recovery factor about 32% while it’s about 28% for generated foam by N$_2$ (see Fig. 4). It is corresponded to the weak solubility of N$_2$ in crude oil due to the weak mass transfer capacity. It is caused to decrease the oil recovery factor which was discussed in previous literature$^{15}$.

Pressure profile for foam injection with CO$_2$ and N$_2$ is shown in Fig. 5. As it can be seen, before starting the foams injection, the pressure drop has not changed enough and it was observed about 246 kPa when the highest oil recovery was achieved by water flooding. Then, it has slowly increased as the foaming agent should block the high permeable throats first and then push oil from low permeable areas. It has its maximum pressure drop at 4.4 PV and after that it was reached a plateau which indicated that there is no increase on the oil recovery factor.

Cyclic CO$_2$ injection. In this part, we experimentally investigated on the cyclic injection of carbon dioxide as a miscible phase for 1, 2, 5, 10, and 15 cycles. Performing carbon dioxide experiments after 2 PV of waterflooding for different cycles would allow core samples to soak properly and then oil can be produced from the end of the core holder. This process is called huff-n-puff which was previously studied in literature$^{16-19}$. Carbon dioxide injection is enhanced oil recovery slightly as it needs be solved as a miscible phase in the crude oil to reduce the oil viscosity. The minimum miscible pressure is recorded 8.14 MPa. This is corresponded to low oil recovery factor in the first stages of pore volume injection. Cyclic carbon dioxide injection can help to reach the minimum miscible pressure in a short time and this is why it can be trusted for enhanced oil recovery processes. By the increase of cycle’s number, oil recovery has improved, however, it is observed that this increase in the number of cycles would have a limit and after 15 cycles, there is no significant changes in the oil recovery factor. It would be an important guide for petroleum companies to test and distinguish the proper number of cycles as it needs high expenditures too in field applications (see Fig. 6).

Pressure profile for Cyclic CO$_2$ injection is shown in Fig. 7. As it can be seen, before starting the Cyclic CO$_2$ injection, the pressure drop has not changed enough and it was observed about 246 kPa when the highest oil recovery was achieved by water flooding. Then, it has slowly increased as the Cyclic CO$_2$ injection and then dispalce oil from low permeable areas. It has its maximum pressure drop at 4 PV and after that it was reached.
a plateau which indicated that there is no increase on the oil recovery factor. By the increase of cycles number, pressure drop has been increased, which in cycles more than 10, the pressure drop is not changed a lot.

**Surfactant-based methods.** In this part, we experimentally investigated the effect of active carbonated water injection (which was made by CTAB as surfactant agent) and active carbonated water alternating gas injection (a mixture of water alternating gas injection and carbonated water which is made by CTAB. The rock-injected fluid interactions was one of the main features of carbonated water injection that caused to wettability alteration. Therefore, it is necessary to perform each test individually and compare the results of each test together to select the optimum injectivity scenario. Figure 8 shows combination of water alternating gas and active carbonated water injection would be a more appropriate scenario on the oil recovery enhancement. Active carbonated water alternating gas injection has witnessed the highest oil recovery of 74%. The second highest oil recovery factor is allocated for active carbonated water injection. It is reported of 65%, while water alternating gas injection has improved the oil recovery factor to 48%.

Pressure profile for these injectivity scenarios is shown in Fig. 9.

**Conclusions**

- Active carbonated water alternating gas injection has the highest oil recovery factor of 74%. The second highest oil recovery factor is allocated for active carbonated water injection. It is reported of 65%.
- By the increase of cycle's number, oil recovery has enhanced, however, it is observed that this increase in the number of cycles would have a limit and after 15 cycles, it's not economically beneficial to continue the process.
- In the first pore volumes of foams injection, oil recovery factor has increased slightly through the core samples. It is corresponded to the foams efficiency to block the high permeable pores and pore throats.
Carbon dioxide is more feasible than nitrogen, it can be mobilize more in the pore throats and provided higher oil recovery factor.

Generated foam with CO₂ has increased oil recovery factor about 32% while it's about 28% for generated foam by N₂. It should be noted that the observed data were normalized to provide more feasible results.

**Data availability**

All the data were used in this paper are included in the text.

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**Author contributions**

All authors have the same contribution.

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**Competing interests**

The authors declare no competing interests.

**Additional information**

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