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Research paper

On the application of surfactant and water alternating gas (SAG/WAG) injection to improve oil recovery in tight reservoirs

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A B S T R A C T

Tight reservoirs are considered one of the unconventional hydrocarbon reservoirs with low permeability and porosity, directly affecting the oil production rate rather than conventional reservoirs. Thereby, optimum enhanced oil recovery methods would help petroleum industries produce more oil volumes from these reservoirs. In this study, different chemical and thermal enhanced oil recoveries methods such as surfactant alternating gas (SAG), water alternating gas (WAG), surfactant and foam flooding, and carbon dioxide (continuous and cyclic) were experimentally investigated to measure oil recovery factor. According to the results of this study, 3.5% of surfactant concentration, 0.15 PV of surfactant slug size, and 0.75 PV was selected as the total surfactant injection volume was selected as the optimum concentration for the injectivity performances. SAG scenario provided the highest oil recovery factor among all injectivity scenarios. It is about 54% that indicated the best efficiency of enhanced oil recovery methods in tight reservoirs rather than conventional recovery methods. The second highest oil recovery factor is dedicated to the WAG injectivity scenario regarding the feasibility of CO_2 phase through porous media. It is about 46%. Moreover, due to the -gas phase in WAG and SAG, water cut had fluctuated as the water and gas had been alternatively injected into the core samples.

1. Introduction

Due to the global energy demand in recent decades, increasing the oil production from underground hydrocarbon fields has always been challenging for petroleum industries as natural drive mechanisms would not be efficient (Zhou and Davarpanah, 2020; Davarpanah and Mirshekari, 2019a; Davarpanah et al., 2018; Voleti et al., 2012; Pang et al., 2021; Cheng et al., 2016; Chen et al., 2018; Zuo et al., 2015; Kazemi and Yang, 2021, 2019; Mao et al., 2019). Therefore, enhanced oil recovery and improved oil recovery methods increase cumulative oil production (Chen et al., 2017, 2021a; Zuo et al., 2017; Liu et al., 2017; Yang and Sowmya, 2015; Jiang et al., 2018; Zhang et al., 2020c; Huang and Ge, 2020; Zheng et al., 2021a; Davarpanah, 2018b). Among various enhanced oil recovery methods, chemical recovery methods have been widely reported in the literature to enhance porous media's oil production rate (Druetta et al., 2019; Spildo et al., 2012; Cheraghian et al., 2013; Xu et al., 2020; Sun et al., 2020; Zheng et al., 2021b; Mazarei et al., 2019; Sepahvand et al., 2021; Jalali Sarvestani and Charehjou, 2021; Awan et al., 2020; Bafkar, 2020; Maina et al., 2020). Different mechanisms such as oil swelling, wettability changes, reduction of interfacial tension, and oil viscosity reduction would be influential (Zhang et al., 2020b; Alam et al., 2021; Zhang et al., 2020a; Davarpanah, 2018a; Nwankwo et al., 2020; Qayyum et al., 2020; Ebadi et al., 2020; Nnaemeka, 2020). Chemically enhanced oil recovery methods have revolutionized how petroleum industries have produced the oil from underground hydrocarbon reservoirs (Li et al., 2017; Jafari Behbahani et al., 2012; Arshadi et al., 2018; Abedini and Zhang, 2021; Li et al., 2020; Yang et al., 2020a; Haiyan and Davarpanah, 2020). Surfactant flooding is an efficient oil recovery method as it has provided efficient results due to its low costs and environmentally friendly features (Davarpanah, 2020; Davarpanah and Mirshekari, 2019d,c; Esfandyari et al., 2020a; Hu et al., 2020a; Jia et al., 2021). Surfactants have caused to reduce the interfacial tension and subsequent wettability alteration. Thereby, the capillary number has been increased and allows the oil phase to be more mobilized through the porous media (Esfandyari et al., 2020c,b; Saha et al., 2019; Pan et al., 2020; Huang et al., 2020; Yang et al., 2020b; Ebadati et al., 2018; Nesic et al., 2020; Lu and Davarpanah,

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2020). One of the surfactant problems in porous media is its adsorption and retention, which might cause inefficiencies for further processing. It is essential to consider surfactant adsorption and which crucial parameters have affected this issue. Surfactant adsorption is defined as the adsorbing of surface-active molecules to rock surfaces (Ayoub et al., 2020; Porcelli and Bidner, 1994; Liu et al., 2019; Nowrouzi et al., 2020; Yang et al., 2015; Zhang et al., 2021; Yan et al., 2020; Yang et al., 2021). The adsorption mechanisms are contained ion association, electron polarization, ion exchange, and bonding of the hydrophobic parts. The influential parameters that have significantly impacted surfactant adsorption are salinity, temperature, polymer addition, interfacial tension, and surfactant concentration (Druetta and Picchioni, 2020; Paternina et al., 2020; Chen et al., 2021b; Ma et al., 2021; Xue et al., 2020; Zhang et al., 2019; Sun et al., 2019; Davarpanah et al., 2019; Daryayehsalameh et al., 2021).

Carbon dioxide injection is a thermally enhanced oil recovery method regarding its proper feasibility in porous media. Hu et al. (2020) experimentally investigated the profound impact of carbon dioxide injection in shale reservoirs as a cyclic injection. They concluded that increasing the number of cycles would be an essential parameter for the oil recovery enhancement in different temperatures and pressures (Hu et al., 2020b; Davarpanah and Mirshekari, 2019b). In this study, we compared the results of oil recovery factor for different scenarios with cyclic and continuous carbon dioxide injection that are in the same increasing pattern by the increase of cycles. Ebadati et al. (2018) experimentally investigated the water alternating gas injection scenario in low permeable reservoirs. This method has higher oil recovery than conventional oil recovery methods as gas can be mobilized more feasibly through fractures and pores. In this study, the WAG injection scenario's impact has been investigated, and it is compared with other injectivity scenarios (Ebadati et al., 2019). Surfactant alternating gas (SAG) injection is considered the efficient method to control mobility, especially in gas sequestration processes. Kamal et al. (2018) experimentally investigated the effect of different surfactants for SAG injection at various mineral types. They concluded that residual gas saturation had been increased regarding the surfactant concentration increase. The residual gas saturation had higher values in tight reservoirs due to the low permeability of these reservoirs (Kamal et al., 2018). In this paper, it is concluded that the SAG method has the highest recovery factor regarding the low permeability of tight reservoirs. Gong et al. (2020) investigated the SAG methods after a prolonged foam and gas injection. The water cut has been reduced regarding the presence of gas in the SAG process. This issue might be related to the capillary effects, pressure-driven flow, and liquid evaporation partially in the coreflooding system (Gong et al., 2020). The water cut reduction is experimentally investigated in this study to provide a proper justification for this water cut reduction in SAG processes.

In this study, we aimed to experimentally investigate the different injectivity scenarios of surfactant alternating gas (SAG), water alternating gas (WAG), surfactant and foam flooding, and carbon dioxide (continuous and cyclic) on the oil recovery factor for a tight reservoir. Due to the applicability of surfactant and carbon dioxide in terms of interfacial tension reduction and mobility control, combining these two methods would be significant to improve the oil recovery from tight reservoirs.

2. Materials and methods

2.1. Materials

– *Shale samples;* regarding previous literature, the size of samples are 1.5''*2'' in diameter and length, respectively. Samples compositions consisted of silica, Alumina, Fe_2O_3, $CaCl_2$, and Mg_2O_3 with the percentage of 92.5%, 4.5%, 1.75%, 0.55, and 0.7% respectively. The samples were selected from the Pazanan oilfield in the south of Iran. The core samples' average porosity is 23%–24.5%, and the average permeability is 32 mD. The total number of samples used in this paper is about 30 core samples, as some cores might be broken during the tests.

Table 1
Crude oil composition.

Composition	Mole%
C_1	79.4
C_2	8.51
C_3	4.6
C_4	3.54
C_5	1.2
C_6	0.35
C_{7+}	0
CO_2	0
H_2S	0
N_2	2.4

Table 2
Ions contained in synthetic brine.

Ions	Salinity (mg/L)
KCl	835.64
$H_2SO_4^-$	5.39
$MgCl_2$	18.73
$CaCl_2$	15.41
$H_2CO_3^{2-}$	701.25
NaCl	724.84
Total salinity	2301.26

– *Crude oil;* crude oil composition for this experiment is statistically depicted in Table 1.

– *Carbon dioxide;* to provide high purity for CO_2, a high-pressurized cylinder was administered. It can provide CO_2 with the purity of 99.9% that used in the experiments.

Synthetic brine; to ensure that the results would match the reservoir condition, synthetic brine was used with the following properties in Table 2.

– *Surfactant;* Cetyl trimethyl ammonium bromide with the chemical formula of $(C_{16}H_{33})N(CH_3)_3)Br$ were used in this experiment to reduce the interfacial tension.

2.2. Methods

The Coreflooding apparatus is schematically depicted in Fig. 1. A tight percolation tester is defined in the system to hold the shale core samples. To provide field application of the studied reservoir, a tight percolation tester was held in an oven to ensure that the reservoir temperature is induced to the system. The temperature in this system is about 60 °C. Three constant pressure injection pump were put in the system to maintain the pressure with the accurate injection rate of 0.001 ml/min. These pumps can provide constant fluid flow through the system and saturate the oil and water phases steadily. Confining pressure is defined as 2600 psi to maintain the system in a proper condition. It is 500 psi more than the required pressure in the system. A gas pressure transmitter was used to provide the pressurized gaseous phase for the system during the injection performances. To observe the oil recovery factor, water cut, and pressure drop in the system, we implemented different injectivity scenarios. The injectivity scenarios contained water flooding, carbon dioxide injection (continuous injection and cyclic injection), foam flooding, surfactant flooding, surfactant alternating gas injection, and water alternating gas injection. To ensure that the results were done appropriately and confidentially, each test were repeated

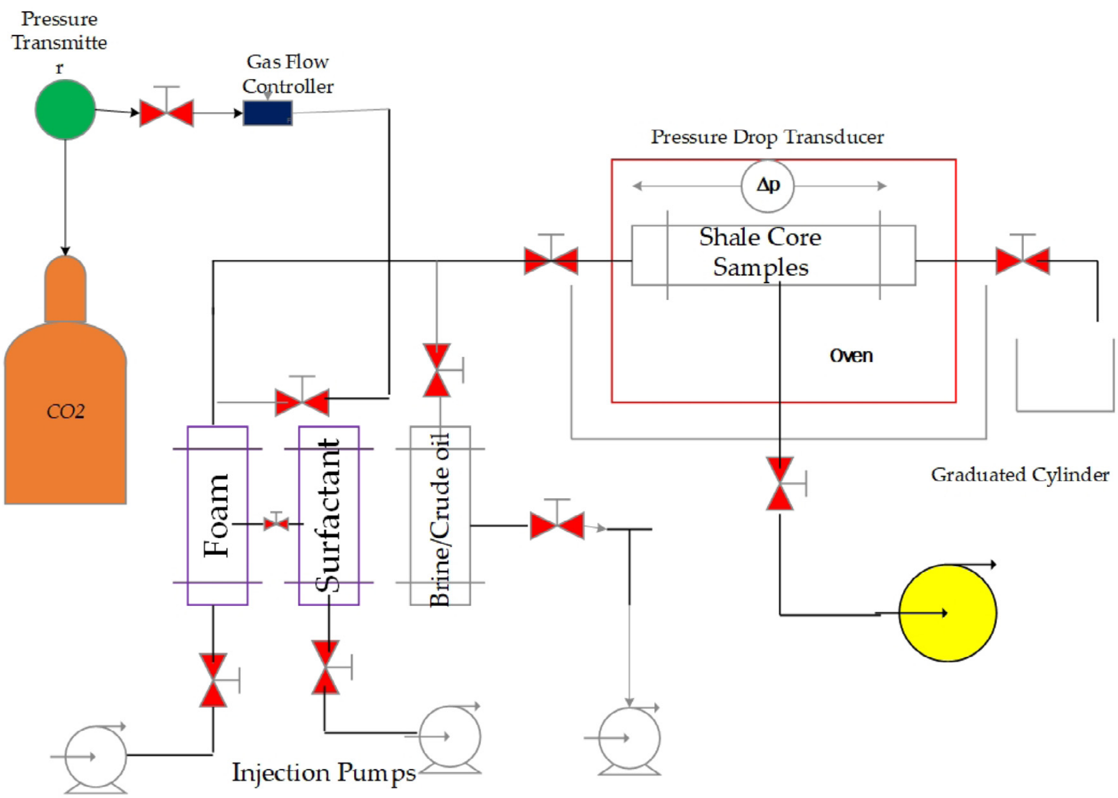

Fig. 1. Schematic of coreflooding apparatus.

Table 3
Injectivity scenarios for different injection patterns.

Scenario No.	Injectivity pattern	Procedure
1	Water flooding	Water with the flow rate of 0.2 cm^3/min injected continuously in the system to reach the water cut of 98%
2	Foam flooding	Foam flooding (0.75 PV) + Water with a flow rate of 0.2 cm^3/min.
3	Surfactant flooding	Surfactant flooding (0.75 PV) + Water with a flow rate of 0.2 cm^3/min.
4	Carbon Dioxide (Continuous)	CO_2 injection continuously (0.75 PV) + Water with the flow rate of 0.2 cm^3/min.
5	Carbon Dioxide (Cyclic)	3 Cycles of CO_2 injection 3 Cycles (0.75 PV) + Water with the flow rate of 0.2 cm^3/min.
6	WAG	Water (0.3 PV) + CO_2 (0.4 PV) + Water with the flow rate of 0.2 cm^3/min.
7	SAG	3.5% of surfactant (0.3 PV) + CO_2 (0.4 PV) + Water with the flow rate of 0.2 cm^3/min.

three times, and an average value was considered in the results. Synthetic brine with a constant flow rate of 0.2 cm^3/min was injected continuously in the system to reach the water cut of 98%. At this point, synthetic brine injection was stopped as the pressure drop reached a plateau. Injectivity scenarios pattern was defined as the following scenarios in Table 3.

3. Results and discussion

As surfactant concentration, injected volume and slug sizes should be optimized before any injectivity scenarios. Therefore, these parameter's were optimized, and the optimum one is chosen for the injectivity scenarios in the coreflooding system.

3.1. Optimum surfactant concentration

To observe and select the optimum surfactant concentration for injectivity scenarios, 0.1 PV of slug size and 0.75 PV of the fluid mixture contained carbon dioxide and surfactant solution in the water phase was considered in the system. As shown in Fig. 2, by the increase of surfactant concentration, the oil recovery factor increased. This increase was incrementally crucial for the increase from 0.5% to 2.5%. There are no significant changes in the oil recovery by the increase of surfactant concentration from 3.5% to 5%. Thereby, 3.5% of surfactant concentration was selected as the optimum concentration for the injectivity performances.

3.2. Optimum surfactant slug size

To observe and select the optimum surfactant slug size for injectivity scenarios, 3.5% of surfactant concentration and 0.75 PV of the fluid mixture contained carbon dioxide and surfactant solution in the water phase was considered in the system. As shown in Fig. 3, the oil recovery factor has increased by increasing surfactant slug sizes from 0.05 PV to 0.15 PV. As the increasing pattern for 0.15 PV to 0.2 is not significant enough, 0.15 PV was selected as the optimal surfactant slug size for injectivity scenarios was not significant enough.

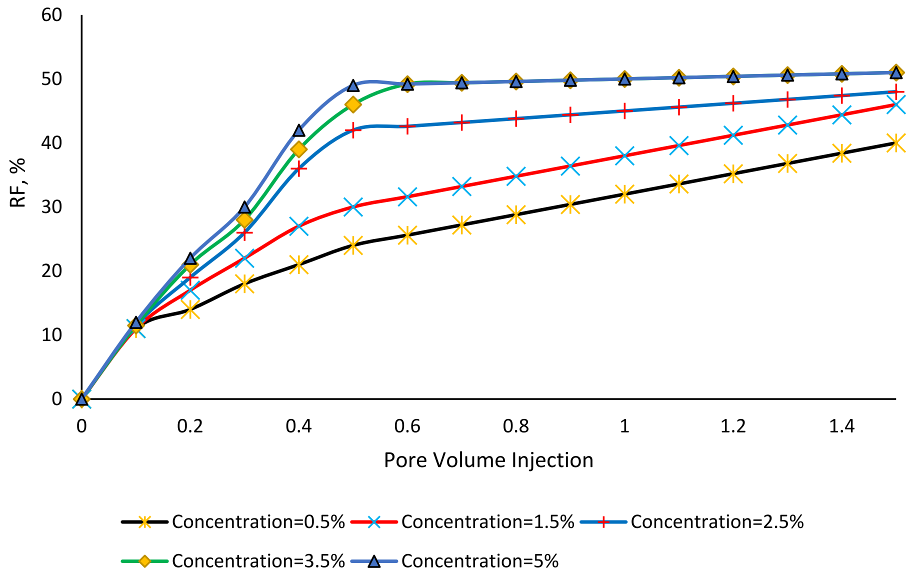

Fig. 2. Oil recovery factor in the presence of different surfactant concentration.

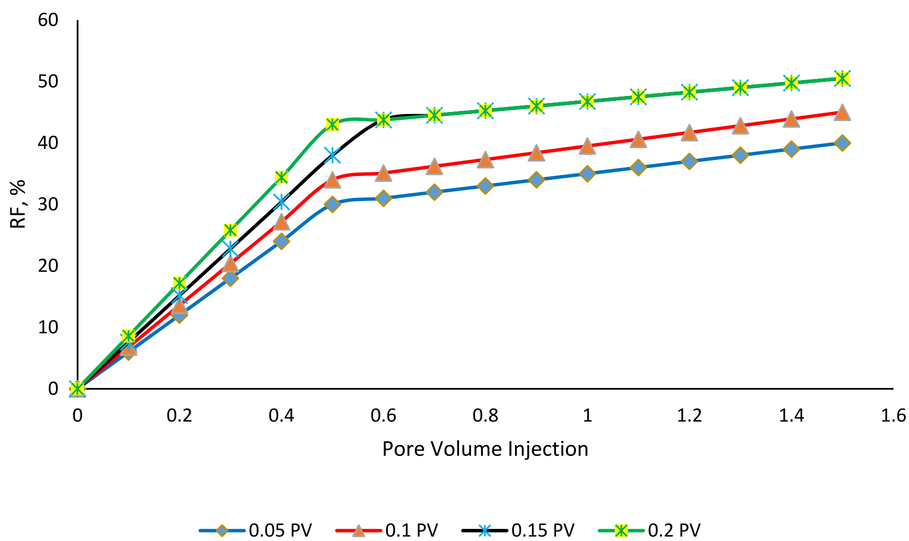

Fig. 3. Oil recovery factor in the presence of different surfactant slug sizes.

3.3. Optimum total surfactant injection volume

To observe and select the optimum total surfactant injection volume for injectivity scenarios, 3.5% of surfactant concentration and 0.15 PV of surfactant slug size was considered in the system. As shown in Fig. 4, the oil recovery factor has increased by increasing total surfactant injection volume from 0.25 PV to 0.1 PV. As the increasing pattern for 0.75 PV to 1 PV is not significant enough, 0.75 PV was selected as the optimum total surfactant injection volume for injectivity scenarios.

3.4. Oil recovery factor

According to Table 3, different injectivity scenarios with the provided pore volume was injected into the system to measure the oil recovery factor. As shown in Fig. 5, water flooding had the lowest oil recovery factor among other injectivity scenarios. Since then, foam flooding and surfactant flooding has the next lowest oil recovery factor. It is about 36% and 38% for surfactant and foam flooding, respectively, in the optimum mode. Carbon dioxide injection had performed in two different situations of continuous and cyclic injection (3 cycles). As shown in Fig. 5, cyclic injection provided better oil recovery than continuous injection. It is about 40% and 43% for continuous and cyclic injection, respectively. This concept was experimentally investigated by Hu et al. (2020a,b) that indicated that the increase of cyclic injection had provided better results than continuous injection in one cycle. SAG scenario provided the highest oil recovery factor among all injectivity scenarios. It is about 54%, indicating the best efficiency of enhanced oil recovery methods in tight reservoirs rather than conventional recovery methods. The second highest oil recovery factor is dedicated to the WAG injectivity scenario regarding the feasibility of CO_2 phase through porous media. It is about 46%.

3.5. Water cut

According to Table 3, different injectivity scenarios with the provided pore volume was injected into the system to measure water cut. As shown in Fig. 6, water cut had the highest value in the first period of pore volume injection. It has reached about 90% after only 0.4 pore volume injection. It is quickly reached 98% as the pressure has been stable, and there are no specific

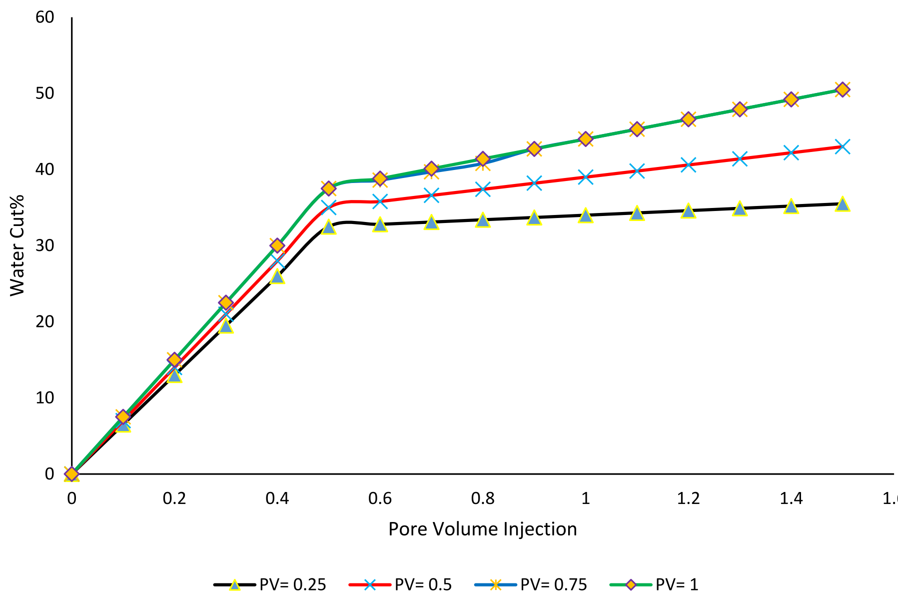

Fig. 4. Oil recovery factor in the presence of different total surfactant injection volume.

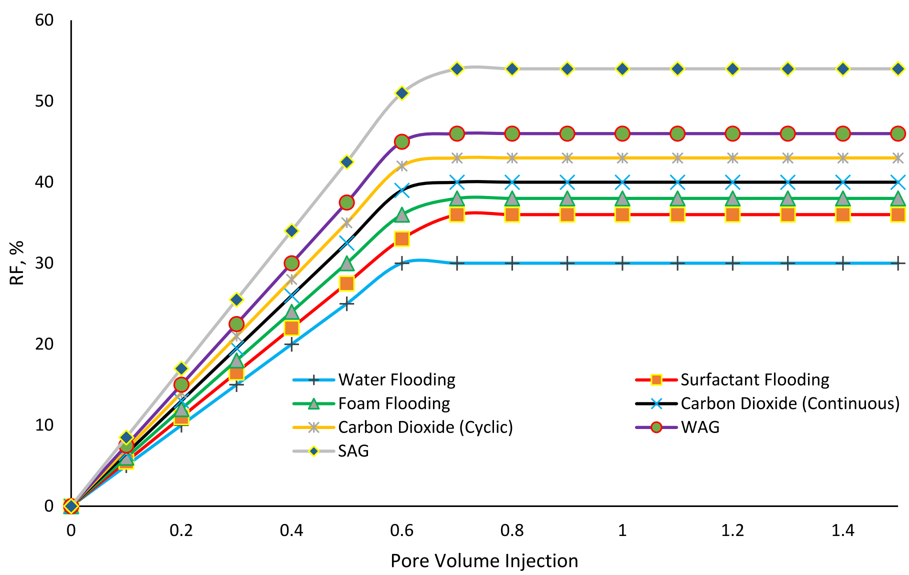

Fig. 5. Oil recovery factor for different injectivity scenarios.

changes through the system. In foam and surfactant flooding, water cut increased slightly in the first period of pore volume injection. After 0.4 PV, water cut increased dramatically, and it reached its maximum value in 1 PV. Due to the gas phase in WAG and SAG, the water cut had fluctuated as the water and gas had been alternatively injected into the core samples. On the other hand, when the alternative injection of gas and water has finished at 0.8 PV, the water cut started to increase in a slight pattern and reached its maximum value after 1.2 PV. For cycling and continuous injection of carbon dioxide, there is no water production in the first period of injection due to the supercritical property of carbon dioxide, improving oil recovery and reducing water cut.

4. Conclusion

In this study, different chemical and thermal enhanced oil recoveries methods such as surfactant alternating gas (SAG), water alternating gas (WAG), surfactant and foam flooding, and carbon dioxide (continuous and cyclic) were experimentally investigated to measure oil recovery factor. The main findings of this study are as follows;

- There are no significant changes in the oil recovery by the increase of surfactant concentration from 3.5% to 5%. Thereby, 3.5% of surfactant concentration was selected as the optimum concentration for the injectivity performances.
- Oil recovery factor has increased by the increase of surfactant slug sizes from 0.05 PV to 0.15 PV. As the increasing pattern for 0.15 PV to 0.2 is not significant enough, 0.15 PV was selected as the optimal surfactant slug size for injectivity scenarios was not significant enough.
- The oil recovery factor has increased by increasing total surfactant injection volume from 0.25 PV to 0.1 PV. As the increasing pattern for 0.75 PV to 1 PV is not significant enough, 0.75 PV was selected as the optimum total surfactant injection volume for injectivity scenarios.

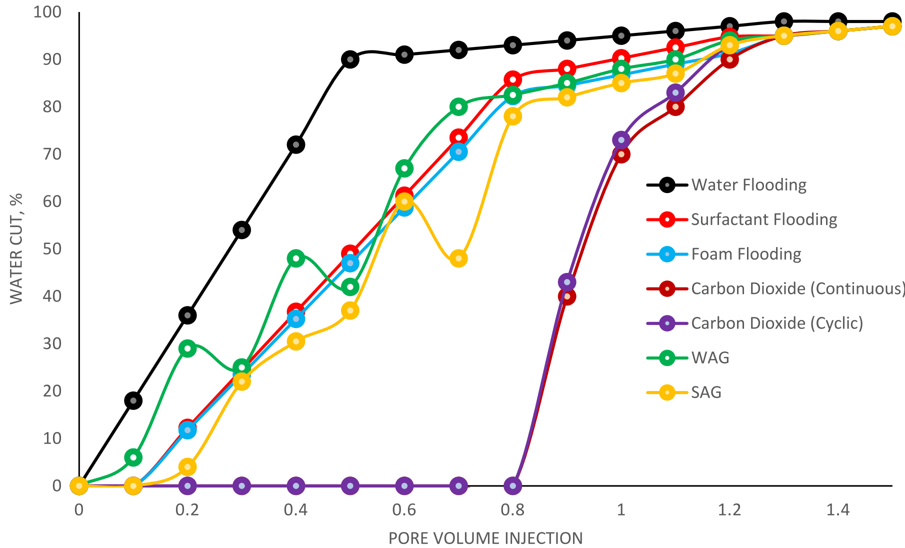

Fig. 6. Water cut for different injectivity scenarios.

– SAG scenario provided the highest oil recovery factor among all injectivity scenarios. It is about 54%, indicating the best efficiency of enhanced oil recovery methods in tight reservoirs rather than conventional recovery methods.
– The second highest oil recovery factor is dedicated to the WAG injectivity scenario regarding the feasibility of CO_2 phase through porous media. It is about 46%.
– Water cut had the highest value in the first period of pore volume injection. It has reached about 90% after only 0.4 pore volume injection. It is quickly reached 98% as the pressure has been stable, and there are no specific changes through the system.
– Due to the gas phase in WAG and SAG, the water cut had fluctuated as the water and gas had been alternatively injected into the core samples.

Abbreviations;

WAG;	Water alternating gas
SAG;	Surfactant alternating gas
PV;	Pore volume
CO_2;	Carbon Dioxide
Fe_2O_3;	Iron(III) oxide
$CaCl_2$;	Calcium chloride
Mg_2O_3;	Magnesium oxide
(C16H33)N(CH3)3)Br;	Cetyl trimethyl ammonium bromide
KCl,	Potassium chloride
$H_2SO_4^-$;	Sulfuric acid
$MgCl_2$;	Magnesium chloride
$H_2CO_3^{2-}$;	Carbonic acid
NaCl;	Sodium Chloride

CRediT authorship contribution statement

Xiao Sun: Methodology, Writing - original draft. **Jia Liu:** Investigation, Software, Writing - original draft. **Xiaodong Dai:** Investigation. **Xuewu Wang:** Investigation, Validation. **Lis M. Yapanto:** Writing - reviewing and editing. **Angelina Olegovna Zekiy:** Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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– Study on the production limits of different injection media in typical ultra-low permeability reservoirs, China.

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