Energy Reports 7 (2021) 1571–1580

Contents lists available at ScienceDirect

Energy Reports

journal homepage: www.elsevier.com/locate/egyr

A laboratory approach on the improvement of oil recovery and carbon dioxide storage capacity improvement by cyclic carbon dioxide injection

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ARTICLE INFO

Article history:
Received 19 December 2020
Received in revised form 3 March 2021
Accepted 14 March 2021
Available online 22 March 2021

Keywords:
Carbon dioxide storage capacity
Thermodynamic reservoir characteristics
Shale reservoirs
Cyclic carbon dioxide injection
Oil recovery factor
Soaking time

ABSTRACT

This paper experimentally investigated influential thermodynamic reservoir characteristics such as pressure, temperature, soaking time, core stimulation, number of cycles, shale particle size, and carbon dioxide phase during the cycling carbon dioxide injection. The carbon dioxide supercritical phase has reached the maximum recovery factor of 40%. When carbon dioxide is in the supercritical phase, its density will become lower than the liquid phase due to the high pressure. Therefore, the oil recovery factor has been increased in micro and nanopores. It is concluded that more than 12 h of carbon dioxide soaking would not play a significant role in oil recovery enhancement. It was observed that each shale particle size distribution would be a proper representative for the carbon dioxide adsorption calculation. Therefore, by doing this, the required time to equilibrate pressure for carbon dioxide adsorption would be decreased by pulverizing the shale cores into micro and nanoparticles. In higher temperatures, carbon dioxide helps to retrograde vaporize hydrocarbon liquid as carbon dioxide provided a higher gas–oil ratio (GOR), higher value of condensate oil density. Thereby, due to increased carbon dioxide content, oil recovery has been increased, indicating that carbon dioxide would be properly soluble. Therefore, at 120 °C, the oil recovery factor has the highest value of 64%. At 3000 psi, the oil recovery factor has the highest value, and it has reached 60% after 14 cycles of carbon dioxide injection. It would be related to the more surface area of carbon dioxide with shale matrixes. Finally, temperature increase would reduce the carbon dioxide absorption, which has a reverse pattern with oil recovery factor increase by the temperature increase.

1. Introduction

Most of the energy supply and demand has been provided by fossil fuels worldwide, associated with increased carbon content and its effect on climate change (Alvarado and Manrique, 2010; Ebadati et al., 2019; Xie et al., 2020; Nassabeh et al., 2019; Kazemi and Yang, 2019; Azamifard et al., 2014; Zhang et al., 2017; Davarpanah and Mirshekari, 2019b; Tcvetkov et al., 2019; Cherepovitsyn et al., 2018; Yang et al., 2020b; Han et al., 2019; Jiang et al., 2020). Thereby, the implementation of carbon dioxide capture and storage would be necessary for industrial purposes as carbon emissions are essentially vital (Bandilla, 2020; Cooney et al., 2015; Davarpanah et al., 2017; Davarpanah and Mirshekari, 2019; Enick et al., 2012; Ju et al., 2020; Mao et al., 2019; Mazarei et al., 2019; Pan et al., 2020; Wei et al., 2020; Yang et al., 2020c). Due to the dependency of carbon dioxide injectivity on the reservoir characteristics, sustainable carbon dioxide injection rates should be investigated to impact the volumetric and areal sweep efficiency (Ehyaei et al., 2020; Ebadati et al., 2018; De Silva and Ranjith, 2012; Edwards et al., 2015; Raza et al., 2018; Yang et al., 2020a, 2015; Liu et al., 2017; Li et al., 2020; Liu et al., 2020a). Hence, higher carbon dioxide saturation would be achieved by

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https://doi.org/10.1016/j.egyr.2021.03.012
2352-4847/

decreasing irreducible water saturation to increase the CO_2 injection rate (Wang et al., 2020b,a; Cui et al., 2021; Liu et al., 2020b; Huang and Ge, 2020; Jia et al., 2020; Kazemi and Yang, 2020; Petrakov et al., 2020; Tcvetkov, 2021; Wang et al., 2020c; Yu et al., 2021). Park et al. (2019) developed a numerical model to consider the impact of irreducible water saturation decrease on the enhancement of CO_2 relative permeability, which has caused the CO_2 storage and injectivity. They found that surfactant agent pre-injection would facilitate the bottom-hole pressure decrease, enhancing carbon dioxide injection capacity (Park et al., 2019; Korotenko et al., 2020; Korolev et al., 2020; Davarpanah, 2018; Davarpanah et al., 2018; Hu et al., 2020).

Zhao, F., et al. (2015) experimentally investigated oil recovery factors in the layered samples. They showed that pressure drop during the CO_2 displacement reduces drastically by the increase of the permeability ratio in the low permeable layers (Zhao et al., 2015). Shedid, S. (2009) proposed a core-flooding investigation that was conducted to consider the core-scale heterogeneity such as permeability sequence in the horizontal and vertical directions on the oil recovery during miscible CO_2 injection (Shedid, 2009). Hildenbrand et al. (2012) had experimentally investigated several different gas transportation mechanisms of adsorption, diffusion, desorption, and viscous flow in unconventional reservoirs. They concluded that the diffusion phenomenon could control gas transportation in the shale gas layers (Amann-Hildenbrand et al., 2012). Davarpanah, A. and B. Mirshekari (2019) proposed unipore diffusion and modified unipore diffusion mathematical model to compare the methane and carbon dioxide at different pressure ranges in two shale reservoirs (Davarpanah and Mirshekari, 2019a). Shi et al. (2019) investigated the considerable influence of pressure and temperature on the enhanced geothermal system during the carbon dioxide injection as heat transfer property would be crucial, especially in multilateral wells. They developed a mathematical model to predict the enhanced geothermal efficiency by considering the heat transfer and fluid flow properties. They concluded that working pressure of carbon dioxide could induce the temperature decrease that indicated that the dependency of pressure and temperature in multilateral wells (Shi et al., 2019). In this paper, we aimed to consider to the implementation of several number of cycles during the carbon dioxide injection to distinguish the required cycles for each pressure, temperature, soaking time, and core stimulation. The number of cycles for each parameter could be observed until the incremental oil recovery has been stopped during the injectivity processes.

Wu et al. (2019) investigated the profound impact of capillarity and confinement effect during carbon dioxide injection in tight reservoirs that can be applied for phase equilibria. They concluded that as the carbon dioxide solubility and mass transfer have higher values in small pores (especially in tight and shale reservoirs), the confinement effect would be of significance in determining phase equilibria. Moreover, they found that gas-phase saturation has smaller values, and minimum miscible pressure has decreased with pore size. This phenomenon would be of importance during carbon dioxide injection. Carbon dioxide soaking time impact on the oil recovery enhancement would be one of the crucial parameters that should be considered. Under the immiscible condition, the pressure would be of importance during carbon dioxide injection (Wu et al., 2020). According to Gamdi et al. (2013) and Gamdi et al. (2014), the considerable influence of soaking time and pressure had been experimentally investigated for one cycle. In this paper, we set aside to investigate these thermodynamic parameters in different cycles to permeate the significance of increasing cycles to observe what has happened for the shale core samples.

Moreover, it can result that an increasing number of cycles would be one of the crucial factors in carbon dioxide injectivity as it might be challenged by creating fractures on the shale core samples. Another comparison between our paper and the following papers is that we used carbon dioxide for cycling carbon injection, while nitrogen was used in the following papers (Gamadi et al., 2013, 2014). Davarpanah A. and Mirshekari B. (2019) investigated the carbon dioxide solubility on the thermodynamics properties of crude oil such as viscosity, density, and oil recovery factor for different temperatures and pressures. Different temperatures and pressures were taken into an investigation to compare the considerable influence of carbon dioxide solubility. They concluded that carbon dioxide dissolution resulted in heavy oil viscosity reduction for higher pressures and temperatures. This issue has caused to improve oil recovery factor (Davarpanah and Mirshekari, 2020). Hou et al. (2020) experimentally investigated phase flow behavior characteristics during carbon dioxide injectivity in a gas condensate well. They have used constant volume depletion (CVD), and constant composition expansion (CCE) tests to observe phase flow behavior, especially carbon dioxide content in gas condensate wells. It is found that the higher value of carbon dioxide has caused to provide a higher gas–oil ratio (GOR), higher value of condensate oil density, and a small amount of retrograde condensate oil. Thereby, due to the increase of carbon dioxide content in the condensate gas wells, condensate oil recovery has been increased, indicating that carbon dioxide would be a proper soluble (Hou et al., 2020). Moreover, due to the proper capacity extraction of the carbon dioxide, lighter condensate gas compositions have been released, and more volume of retrograded oil has been produced with natural gas on the surface. Another reason for enhancing retrograded oil production is condensate oil reverse evaporation property (Chen et al., 2019; Davarpanah and Mirshekari, 2019a, 2020; Gamadi et al., 2013, 2014; Su et al., 2017; Zhong et al., 2020).

However, having said this, different experimental investigation has been performed to consider the profound impact of carbon dioxide injectivity on the oil recovery enhancement in both conventional and unconventional reservoirs, we aimed to investigate influential reservoir characteristics such as pressure, temperature, soaking time, core stimulation, number of cycles, shale particle size, and carbon dioxide phase during the cycling carbon dioxide injection. To do this, we consider different ranges for each parameter and investigate how they can improve the oil recovery factor. Moreover, each parameter's effect has been investigated to measure carbon dioxide adsorption that can be applied as proper insights for industrial and field purposes. It is concluded that more than 12 h of carbon dioxide soaking would not play a significant role in oil recovery enhancement. Therefore, it can result that instead high carbon dioxide soaking time to provide pressure equilibrium, 12 h soaking time is recommended. Shale particle size distribution is another parameter that was taken into an investigation on carbon dioxide adsorption. It was observed that each shale particle size distribution would be a proper representative for the carbon dioxide adsorption calculation. Therefore, by doing this, the required time to equilibrate pressure for carbon dioxide adsorption would be decreased by pulverizing the shale cores into micro and nanoparticles. Another finding of this study is to perform various carbon dioxide injectivity cycles to observe the necessary cycles needed for different temperatures, pressure, and soaking times. The number of cycles for each parameter could be observed until the incremental oil recovery has been stopped during the injectivity processes.

2. Materials and methods

2.1. Materials

Shale core samples extracted from Pazanan oilfield from Iranian oilfields. Shale core samples with an approximate length

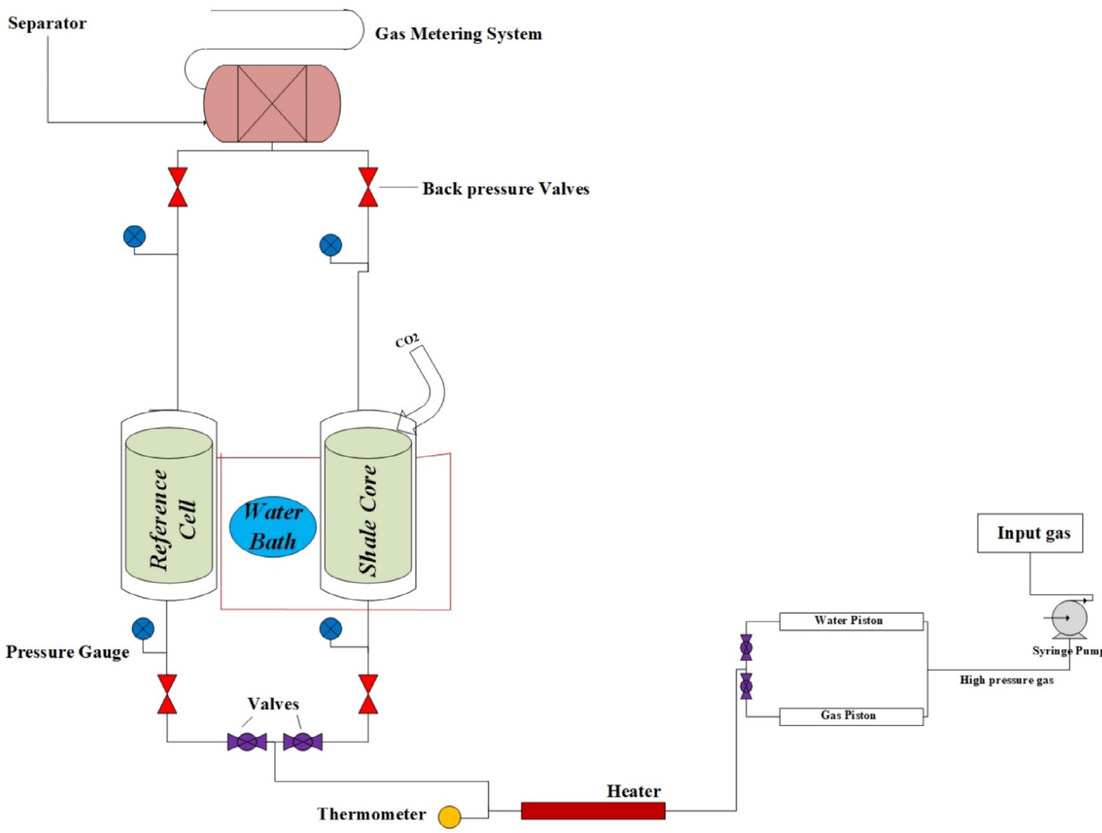

Fig. 1. Experimental apparatus for cyclic carbon dioxide injection and adsorption.

of 2″ and the same diameter of 1.5″ were selected according to previous studies on carbon dioxide injectivity (Gamdi et al.. (2014)). A high pressurized cylinder was utilized to purify the carbon dioxide and helium to 99.9%. Composition of crude oil is contained 12.3% C_1–C_6, 18.46% C_7–C_{12}, 29.84% C_{13}–C_{20}, and 39.4% C_{20+}. High-pressure valves (maximum pressure capacity of 5000 psia) and gauges (maximum pressure capacity of 5000 psia). As this experiment had performed at high temperatures, gauges should be resistant to this condition. A water bath was used to maintain the temperature during the injectivity procedure; however, if the temperature alterations would be about 0.3 C, the experiments were repeated to control the errors properly. The total number of samples used in this paper is about 50 core samples, as some cores might be broken during the tests.

2.2. Methods

We define the experimental investigation in two different sections of cyclic carbon dioxide injection and carbon dioxide adsorption. In this paper, we concentrated on the miscible oil displacement by carbon dioxide injection. The apparatus for this experiment is shown in Fig. 1.

2.2.1. Cyclic carbon dioxide injection

Firstly, to observe the accurate pore volume, shale cores were placed in a vessel with high pressure in the presence of crude oil. The vessels were put in an oven with high temperatures for seven months to be fully saturated with crude oil. After this period, cores were weighted, and it was compared with the situation before saturation with crude oil started to determine the pore volume accurately. Therefore, all the core samples were thoroughly saturated with crude oil to obtain the same condition for each experiment. Then, the provided vessels were put in the water bath to be sealed and vacuumed for 12 h. In this stage, the pressurized carbon dioxide (syringe pumps did it to pressurize the carbon dioxide before injecting it into the system) was injected into the vessel. It should be left in the vessel to be soaked to reach the designated temperature and pressure. The soaking time for each step was observed. When the soaking time had reached the designated soaking time, the current vessel was depressurized. After retrieving the core samples, the oil recovery factor was measured by measuring the core weights alteration. To continue the carbon dioxide injection as new cycles, to eliminate the experimental errors and possible alterations, vessels were vacuumed again, and the experiments were done three times. It can provide an appropriate sensitivity analysis for each measurement to have more reliable results. Carbon dioxide injection processes in different cycles had continued when incremental oil recovery reached under 1%.

2.2.2. Carbon dioxide adsorption

To measure the carbon dioxide adsorption in fewer periods, we utilize pestle and mortar to pulverize shale core samples into nano and micro-sized particles. It can simplify the carbon dioxide diffusion performances in the matrixes of shale particles that can easily be absorbed. To cells were used to observe the carbon dioxide adsorption. Reference cell was used to contain pressurized carbon dioxide that is required for the adsorption process. Another utilization of this cell is to maintain reference pressure for the adsorption process. The sample cell is another cell used for placing the shale particles, and some screen meshes were put in the sample cell to avoid the shale particle suctions. Then both of the cells were vacuumed for 12 h. After the injection of carbon dioxide to the reference cell to obtain the designated pressure, it was expanded to the sample cell. When the pressures in both cells were equilibrated (it was measure continuously),

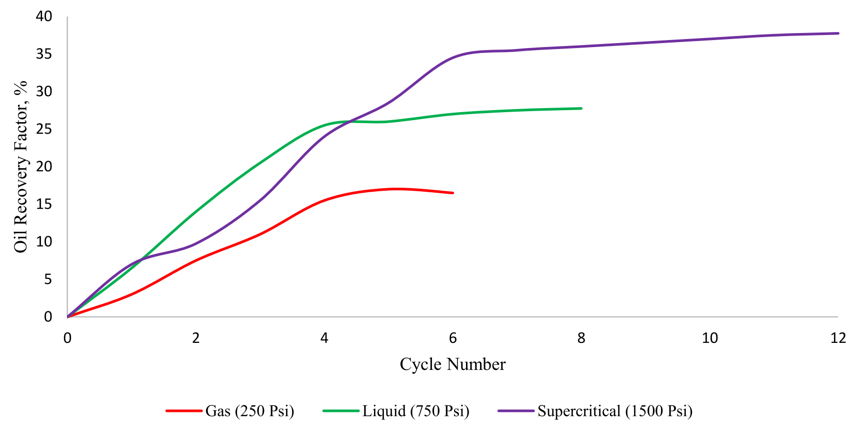

Fig. 2. Carbon dioxide phase impact on the oil recovery factor.

the adsorption was measured by calculating void spaces occupied with helium.

3. Results and discussion

3.1. Impact of carbon dioxide phase on the oil recovery factor

As the carbon dioxide phase is one of the essential issues in oil recovery processes, in this part, the significant influence of the carbon dioxide phase is experimentally investigated in the supercritical, liquid, and gas phases. Thereby, experiments were done during the carbon dioxide soaking time for 6 h at 60 °C and 250 psi (gas phase), 750 psi (liquid phase), and 1500 psi (supercritical phase) for three different phases. As shown in Fig. 1, the carbon dioxide supercritical phase has reached the maximum recovery factor of 40%. The liquid and gas phase has an approximately oil recovery factor of 28% and 17%, respectively. This indicated that the carbon dioxide phase could play a significant role in oil recovery enhancement as carbon dioxide might have had different behaviors at different phases. As carbon dioxide density is low enough in the gas phase, its extrusion through the pores and pore throats is rugged at low pressures. Therefore, carbon dioxide injectivity in low pressures when it is a gas phase is not suitable for oil recovery enhancement. When the gas is in the liquid phase, due to the denser property of carbon dioxide, large oil volumes have been mobilized in the pores. However, oil recovery would decrease regarding the remains of large oil volumes in the micro and nanopores. When carbon dioxide is in the supercritical phase, its density will become lower than the liquid phase due to the high pressure. Therefore, the oil recovery factor has been increased in micro and nanopores. It is elaborated that the liquid phase has more oil recovery factor than a supercritical phase in the first cycles (see Fig. 2).

3.2. Effect of temperature on the oil recovery factor

As reservoir temperature is one of the uncontrolled properties due to the reservoir characteristics, reservoir depth, and so on, it is essential to consider different temperature ranges (low to high temperatures) on the oil recovery enhancement. In this part, we aimed to investigate temperature ranges from 20–120 °C on the oil recovery enhancement. Cycling carbon dioxide injectivity was done at the 1500 psi confining pressure and 6 h of soaking time. In Fig. 3, it is depicted that temperature increase has resulted in having higher oil recovery factor. It would correspond to the decrease of oil viscosity and pore size increase regarding the rock-shale grain expansion. However, in higher temperatures, carbon dioxide helps to retrograde vaporize hydrocarbon liquid as carbon dioxide provided a higher gas–oil ratio (GOR), higher value of condensate oil density. Thereby, due to the increase of carbon dioxide content, oil recovery has been increased, indicating that carbon dioxide would be properly soluble. Therefore, at 120 °C, the oil recovery factor has the highest value of 64%. Since then, at temperatures of 100 °C and 60 °C, oil recovery has the second and third highest value of 47% and 38%, respectively. Moreover, it is concluded that the number of carbon dioxide injectivity cycles would depend on the temperatures. When the oil recovery factor has reached a stable value, an increase in carbon dioxide cycles would not be crucial as there is no amendment on the oil recovery factor.

3.3. Effect of pressure on the oil recovery factor

Due to the considerable influence of the carbon dioxide phase on the oil recovery performances, it is essential to consider different pressure ranges and see what happened by increasing cycles. We observe the oil recovery factor for pressure ranges of 250–3000 psi by assuming a soaking time of 6 h and a temperature of 60 °C. At higher pressures, due to the lower density of carbon dioxide (as carbon dioxide changed to supercritical phase), the recovery factor has been increased due to the convenient mobilization of carbon dioxide through the pore networks. At 3000 psi, the oil recovery factor has the highest value, and it has reached 60% after 14 cycles of carbon dioxide injection. It would be related to the more surface area of carbon dioxide with shale matrixes.

3.4. Effect of soaking time

Soaking time is defined as the required time for the formation of fluid-carbon dioxide interaction in which the increase of carbon dioxide soaking time would be an essential item on the oil recovery enhancement. We assumed a confining pressure of 1500 psi and a temperature of 60 °C. As is shown in Fig. 4, an increase in soaking time has resulted in an oil recovery increase after 14 cycles of carbon dioxide injectivity. It is due to the more interaction between carbon dioxide and formation fluids. Furthermore, as shown in Fig. 4, the increase of soaking time from 12 h to 24 h and 48 h would not be large enough. Therefore, it can be used as an industrial point of view for field production operations to reduce the soaking time, resulting in virtually eliminating unnecessary expenses. After 48, 24, and 12 h of carbon dioxide soaking time, the maximum oil recovery factor has reached approximately 63%, 61%, and 59%, respectively.

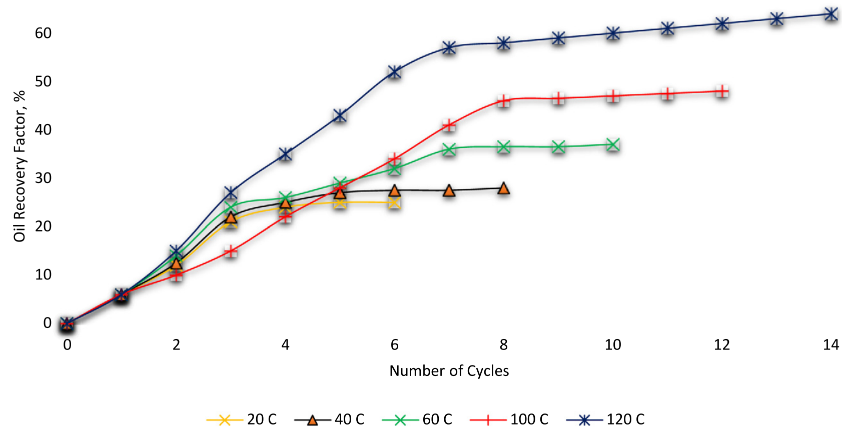

Fig. 3. Effect of temperature on the oil recovery factor.

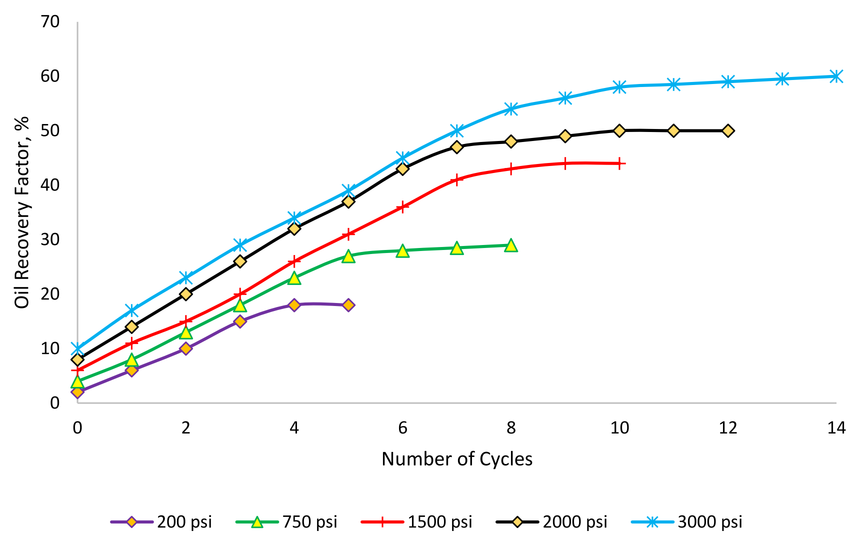

Fig. 4. Effect of pressure on the oil recovery factor.

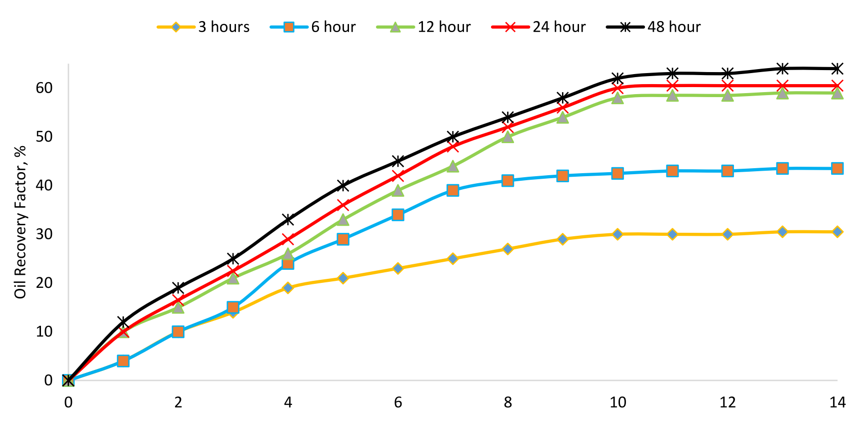

Fig. 5. Effect of soaking on the oil recovery factor.

3.5. Number of carbon dioxide cycles

It is essential to compare different cycles during carbon dioxide injection as it might be considered non-productive for some temperatures and pressures. Thereby, it is observed that cycling carbon dioxide injection would be discontinued when there was no incremental oil production. It is concluded that the increase in temperature and pressure would increase the number of cycles. It is statistically explained in Table 1.

3.6. Effect of core stimulation

One of the crucial factors during cyclic carbon dioxide injectivity is the core stimulation to observe the core fractures and how it would affect the oil recovery factor. Experiments were

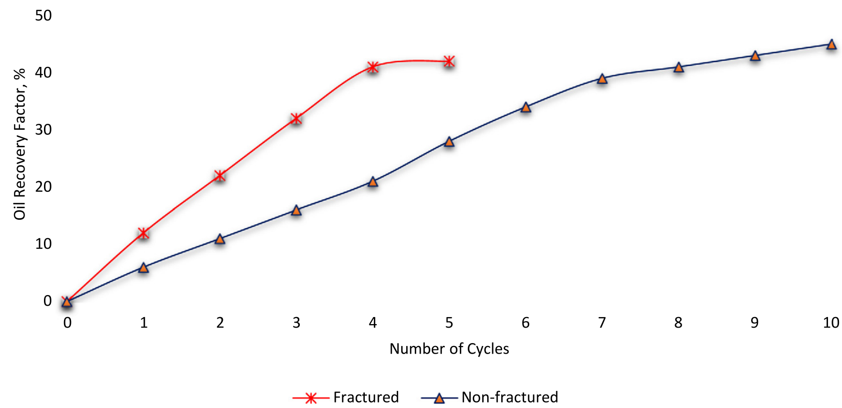

Fig. 6. Effect of core stimulation on the oil recovery factor.

Table 1
Effect of different parameters on the number of carbon dioxide cycles.

Pressure	Temperature	Soaking time	Number of cycles
200 psi	60 °C	6 h	5
750 psi	60 °C	6 h	8
1500 psi	20 °C	6 h	6
1500 psi	40 °C	6 h	8
1500 psi	60 °C	6 h	10
1500 psi	100 °C	6 h	12
1500 psi	120 °C	6 h	14
2000 psi	60 °C	6 h	12
3000 psi	60 °C	6 h	14

done under 1500 psi and 60 °C for the 6 h of soaking time. According to Fig. 5, fractured cores have provided a higher oil recovery factor in the initial cycles. However, the results might be encountered some errors as fractured cores might be broken. Therefore, sensitivity analysis would be explained in the following sections. The reason for the oil recovery enhancement in stimulated core samples corresponds to the fracture's high conductivity, especially in the initial injectivity cycles.

3.7. Effect of shale particle size on the carbon dioxide adsorption

To measure the carbon dioxide adsorption, a pestle and mortar were used to pulverize the shale cores into smaller particles, explained in more detail in Section 2.2.2. In this part, we consider different shale particle sizes to observe that it has influenced carbon dioxide adsorption or not. Experiments were performed under 1500 psi and 60 °C for the 6 h of soaking time. It is observed that the increase of shale particle size would have a small impact on the carbon dioxide adsorption, which indicated that shale particles would be an appropriate representative of shale core samples. Thereby, it is elaborated that pulverizing shale cores into small particles would be necessary for field applications as it would eliminate the required time for pressure equilibrium during the carbon dioxide injectivity for both reference and sample cells. It is schematically depicted in Fig. 6.

3.8. Effect of pressure on the carbon dioxide adsorption

Experiments were performed under 60 °C for the 6 h of soaking time with 40 μ particle size for different pressures. As shown in Fig. 7, by increasing pressure during carbon dioxide injection, carbon dioxide adsorption has been increased, indicating a higher volume of carbon dioxide storage capacity. However, fracturing issues should be analyzed and controlled in field applications as it might alter the reservoir heterogeneity, which has resulted in the carbon dioxide adsorption reduction. The highest adsorption volume is for the pressure of 3000 psi. It is about 94%.

3.9. Effect of temperature on the carbon dioxide adsorption

Experiments were performed under 1500 psi for the 6 h of soaking time with 40 μ particle size for different temperatures. As shown in Fig. 8, the temperature increase would reduce the carbon dioxide absorption, which has a reverse pattern with oil recovery factor increase. Therefore, it would be a significant factor to consider shale reservoirs even if there will be a right choice for oil recovery enhancement as carbon dioxide adsorption would not be beneficial in high temperatures.

3.10. Sensitivity analysis

We repeated each test about 3–5 times to provide reliable results as reservoir conditions might be changed during the field operational performances due to the discrepancies and experimental errors. Therefore, to provide a reliability that can be more applicable for field purposes, a sensitivity analysis was performed to observe the approximate domain for each parameter. According to the results of this part, for temperature and pressure impact on the oil recovery factor, the error domain is observed between (−2%; the lowest domain and 2%; the highest domain from the average value depicted in Figs. 9 and 10. For soaking time impact on the oil recovery factor, the error domain is observed between (−1%; the lowest domain and 1%; the highest domain from the average value depicted in Fig. 11 (see Fig. 12).

4. Conclusion

Shale reservoirs are considered as one the most important reservoirs for petroleum industries as production from conventional reservoirs will be reduced, and it should be taken into consideration to improve the oil recovery factor from these reservoirs. Carbon dioxide injectivity is one of the thermal enhanced oil recovery methods that has improved cumulative oil production. Due to the dependency of carbon dioxide injectivity on the reservoir characteristics, sustainable carbon dioxide injection rates should be investigated to impact the volumetric and areal sweep efficiency. Cyclic injection of carbon dioxide can enhance the oil recovery factor due to carbon dioxide mobilization feasibility through porous media. Furthermore, carbon dioxide adsorption would be another critical parameter to determine the carbon dioxide storage capacity. In this paper, the main findings are as follows;

– The carbon dioxide supercritical phase has reached the maximum recovery factor of 40%. The liquid and gas phase has an approximately oil recovery factor of 28% and 17%,

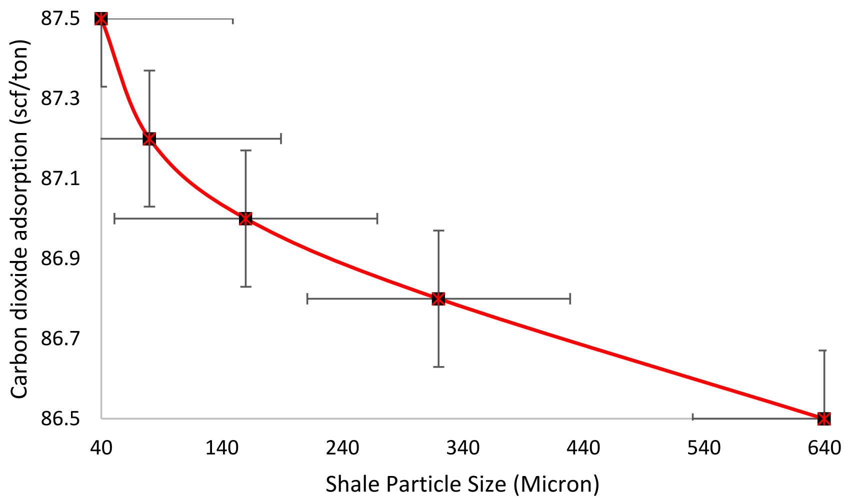

Fig. 7. Effect of shale particle size on the carbon dioxide adsorption.

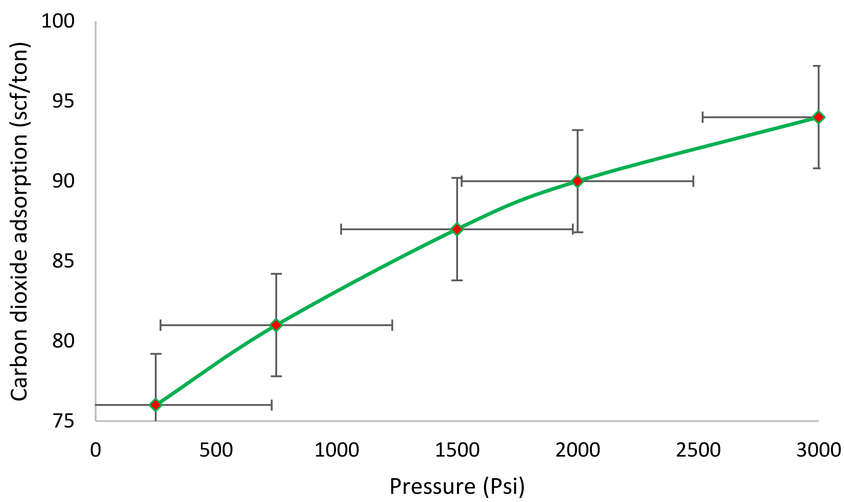

Fig. 8. Effect of pressure on the carbon dioxide adsorption.

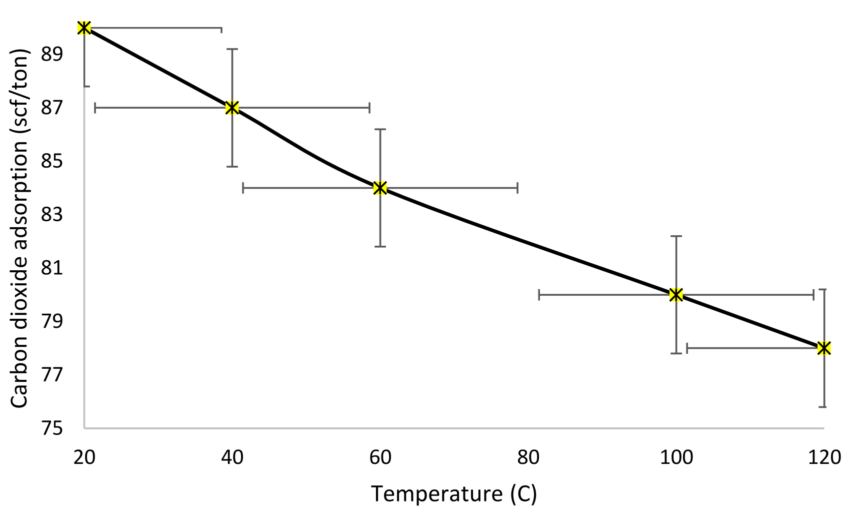

Fig. 9. Effect of temperature on the carbon dioxide adsorption.

respectively. This indicated that the carbon dioxide phase could play a significant role in oil recovery enhancement as carbon dioxide might have had different behaviors at different phases. When carbon dioxide is in the supercritical phase, its density will become lower than the liquid phase due to the high pressure. Therefore, the oil recovery factor has been increased in micro and nanopores.

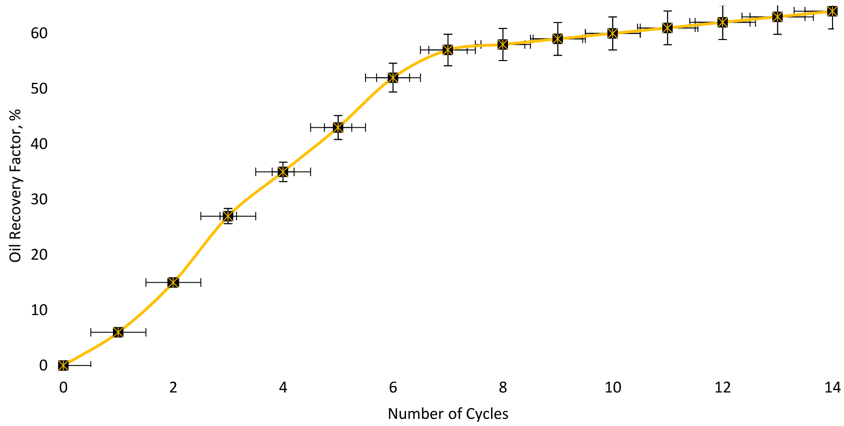

Fig. 10. Temperature sensitivity analysis (120 °C).

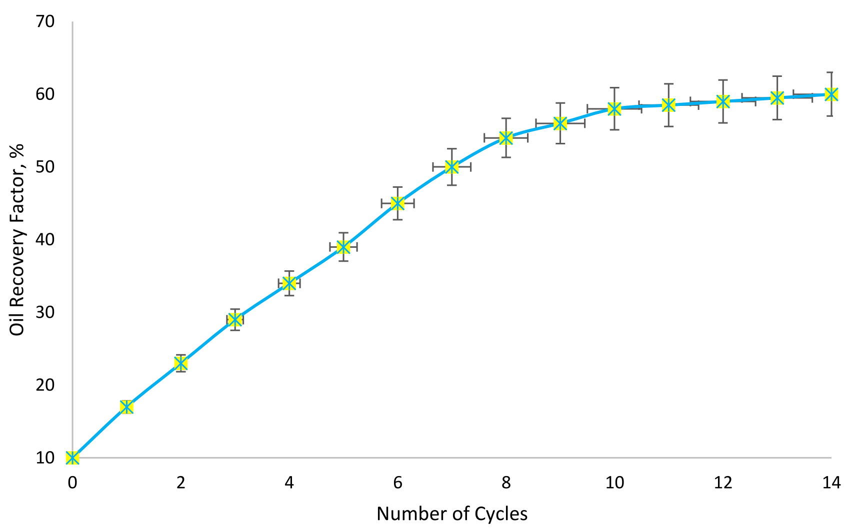

Fig. 11. Pressure sensitivity analysis (3000 psi).

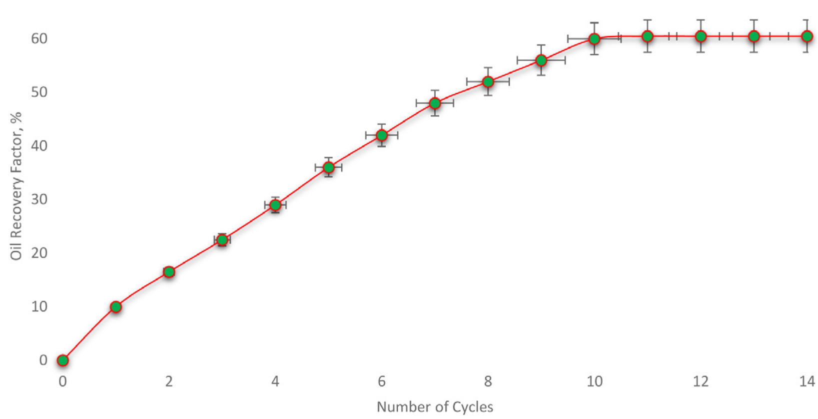

Fig. 12. Soaking time sensitivity analysis (48 h).

– The temperature increase has resulted in having a higher oil recovery factor. It would correspond to the decrease of oil viscosity and pore size increase regarding the rock-shale grain expansion. However, in higher temperatures, carbon dioxide helps to retrograde vaporize hydrocarbon liquid as carbon dioxide provided a higher gas–oil ratio (GOR), higher value of condensate oil density. Thereby, due to increased carbon dioxide content, oil recovery has been increased, indicating that carbon dioxide would be properly soluble. Therefore, at 120 °C, the oil recovery factor has the highest value of 64%.

– At higher pressures, due to the lower density of carbon dioxide (as carbon dioxide changed to supercritical phase), the recovery factor has been increased due to the convenient mobilization of carbon dioxide through the pore networks. At 3000 psi, the oil recovery factor has the highest value, and it has reached 60% after 14 cycles of carbon dioxide injection. It would be related to the more surface area of carbon dioxide with shale matrixes.

- The socking period is the period of thermodynamic equilibrium CO2 with reservoir fluid, or it is time for CO2 to penetrate through tiny pores of the core. An increase of soaking time from 12 h to 24 h and 48 h would not be large enough. Therefore, it can be used as an industrial point of view for field production operations to reduce the soaking time that virtually eliminated unnecessary expenses. After 48, 24, and 12 h of carbon dioxide soaking time, the maximum oil recovery factor has reached approximately 63%, 61%, and 59%, respectively.
- Fractured cores have provided a higher oil recovery factor in the initial cycles. However, the results might be encountered some errors as fractured cores might be broken. The reason for the oil recovery enhancement in stimulated core samples corresponds to the fracture's high conductivity, especially in the initial injectivity cycles.
- An increase in shale particle size would have a small impact on the carbon dioxide adsorption, which indicated that shale particles would be an appropriate representative of shale core samples. This reduction is due to eliminating the required time for pressure equilibrium during the carbon dioxide injectivity for both reference and sample cells.
- The increase of pressure during carbon dioxide injection and carbon dioxide adsorption has been increased, indicating a higher volume of carbon dioxide storage capacity.
- Temperature increase would reduce the carbon dioxide absorption, which has a reverse pattern with oil recovery factor increase by the temperature increase.

CRediT authorship contribution statement

Qing Guo: Conceptualization, Writing - original draft. **Mohammad Hossein Ahmadi:** Investigation, Software, Writing - original draft. **Mohammad Lahafdoozian:** Conceptualization, Software. **Aleksandra Palyanitsina:** Investigation, Validation, Writing - review & editing. **Oleg R. Kuzichkin:** Writing - review & editing. **S.M. Alizadeh:** Writing - review & editing. **Seyed Mohammad Mehdi Nassabeh:** Methodology, Writing - original draft.

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.

Acknowledgments

The article was prepared as part of the state task "Research and development of complex energy-saving and thermoelectric regenerative systems" application number 2019-1497, subject number FZWG-2020 -0034.

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