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Co-optimization of oil recovery and CO₂ storage for cyclic CO₂ flooding in ultralow permeability reservoirs

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Abstract. Cyclic CO₂ flooding is an efficient method to enhance oil recovery in ultralow permeability reservoirs. As the demand for low carbon economy development, co-optimization of CO₂ storage and utilization should be considered. In this research, initially a comprehensive optimization method was proposed, which co-optimizes oil recovery and CO₂ storage by different weighting factors. Then, a series of core flooding experiments were performed using the core samples collected from Changqing oilfield, which is a ultralow permeability reservoir with heterogeneity and micro-cracks, CO₂ injection parameters of slug size and Injection-Soaking Time Ratio (ISR) were optimized. The results revealed that the optimal injection parameters changed for different optimization objectives. In the case where equal important to oil recovery and CO₂ storage were considered, the optimum CO₂ injection parameters in the ultralow permeability reservoirs were 0.03PV for slug size and 1:1 for ISR. Comparing the method of oil recovery optimization ($\omega_1 = 1$) to co-optimization of oil recovery and CO₂ storage ($\omega_1 = \omega_2 = 0.5$), oil recovery was reduced by 8.93%, CO₂ storage was significantly increased by 25.85%. The results provide an insight into parameter optimization of CO₂ enhanced oil recovery design.

1 Introduction

With advancement in the world petroleum industry, the development of low permeability oil fields has attracted more attention. However, conventional recovery methods are not effective in ultralow permeability reservoirs. Due to the nature of ultralow permeability reservoirs (poor physical properties, heavy heterogeneity and natural micro-fracture), water flooding recovery remains low even though long horizontal wells have been drilled and massively fractured (Christensen *et al.*, 2001; Song and Yang, 2017). As an enhanced oil recovery technology, CO₂-EOR (e.g. continuous CO₂ injection, carbonated water injection, water-alternating CO₂ injection, and cyclic CO₂ injection) have shown favorable recovery potential while offsetting the greenhouse gas emissions by CO₂ storage underground (Ma *et al.*, 2015). However, each CO₂ injection method has its merits and demerits (Murray *et al.*, 2001; Xu and Saeedi, 2017). Compared with other CO₂ injection methods, cyclic CO₂ injection is benefited from longer soaking period which enlarges the contact area between oil and CO₂, reduces oil viscosity and interfacial tension, vaporized lighter components of oil, additional it could alleviate CO₂ fingering,

gravity override and channeling effectively. It also has good field application in low permeability oil reservoir (Torabi and Asghari, 2010; Abedini and Torabi, 2014). Although the mechanisms of CO₂ flow and interaction with oil, water and rock are well understood by the scientific community, application and the distinction of these mechanisms in ultralow permeability reservoirs could be difficult (Yu *et al.*, 2015). In addition, the optimal operational parameters of cyclic CO₂ injection have not been recommended. It is therefore of practical significance to evaluate the performance of cyclic CO₂ injection process and optimize the injection parameters in ultralow permeability reservoirs.

In the process of cyclic CO₂ injection, slug size as well as Injection and Soaking time Ratio (ISR) are two major parameters which affect the results (Wolcott *et al.*, 1995). Unfavorable CO₂ injection parameters do not only lower the CO₂ microscopic displacement efficiency, but also aggravate CO₂ viscous fingering and breakthrough due to the large difference in density and viscosity between CO₂ and oil. The traditional approach for parameters optimization is pursuing maximum oil recovery by minimum CO₂ injection (Lv *et al.*, 2015; Liu *et al.*, 2016). However, CO₂ emission reduction has increasingly gained attention while CO₂ storage efficiency is very important in the current

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situation of climate change. It is therefore necessary to co-optimize both of oil production and CO₂ storage.

In order to investigate the viability of cyclic CO₂ injection processes in ultralow permeability reservoirs and to optimize the injection parameters based on the combination of oil recovery and CO₂ storage, a new objective function was proposed which includes two parts of oil recovery factor and CO₂ storage factor, every part has distinct weighting factors (ω_1 , ω_2), and the weighting factors are changed for different optimization objectives. In this paper, the cyclic CO₂ injection parameters were optimized with equal weighting factors. The result provides guidance for field design and operation of cyclic CO₂ flooding in ultralow permeability reservoirs.

2 Methodology

Some researchers have studied optimization of CO₂ storage and oil recovery and the objective functions for parameter optimization were provided (Kovscek and Cakici, 2005; Jahangiri and Zhang, 2010; Kamali and Cinar, 2014). These functions, contain oil recovery factor and CO₂ storage factor, however each function has its method of computing CO₂ storage factor.

Initially, CO₂ storage factor was considered as the ratio of the volume of CO₂ stored to the total pore volume in a reservoir (Kovscek and Cakici, 2005). This ignored the geological limitations and this method assumed that the volume of CO₂ is constant without changing phase with changes in pressure and temperature.

In order to solve this problem, another storage factor was introduced as the ratio of CO₂ stored in reservoir to the total CO₂ storage capacity of the reservoir (Jahangiri and Zhang, 2010). However, the total capacity of CO₂ in reservoir is an uncertain parameter and CO₂ storage capacity in geological formations includes four levels: theoretical, effective, practical and matched storage capacities (Bachu and Shaw, 2003; Shen et al., 2009; DOE, 2010). The calculated results will be different for different level of storage capacities.

To fill this gap, a modified storage factor was proposed which is the ratio of CO₂ stored to the CO₂ injected in reservoir (Kamali and Cinar, 2014). The modified storage factor in this function only represents the injected CO₂ utilization factor rather than reservoir storage. In addition, CO₂ loss was not taken into account from the injector/producer system during EOR project.

In order to estimate the fraction of the CO₂ stored in reservoir accurately, a new CO₂ storage factor is proposed considering the operation loss of CO₂. The new storage factor is defined as the ratio of the cumulative injected CO₂ minus cumulative produced and loss of CO₂ to theoretical CO₂ storage capacity of the reservoir. The modified objective function is as follows:

$$f = w_1 \frac{N_P}{OIP} + w_2 \frac{M_{CO_2}^I - (M_{CO_2}^P + M_{CO_2}^L)}{M_{CO_2}^T} \quad (1)$$

$$\begin{aligned} M_{CO_2}^T &= M_{CO_2str_i} + M_{CO_2so_i} + M_{CO_2sw_i} \\ &= \rho_{CO_2} \times [E_R Ah \phi (1 - S_{wi}) + C_{ws} Ah \phi S_{wi} \\ &\quad + C_{os} (1 - E_R) Ah \phi (1 - S_{wi})], \end{aligned} \quad (2)$$

where, N_P is the net oil production, m³; and OIP is oil in place at the start of CO₂ injection, m³; $M_{CO_2}^P$ is the cumulative produced CO₂, t; $M_{CO_2}^I$ is the cumulative injected CO₂, t; $M_{CO_2}^L$ is the cumulative loss CO₂, t; $M_{CO_2}^T$ is the theoretical CO₂ storage capacity in reservoir which is calculated by Shen Pingping's method, t; the formula as shown in equation (2) (Shen et al., 2009; Sun et al., 2017); ω_1 and ω_2 are the weighting factors for oil recovery and CO₂ storage reflecting the extent of subjective intentions; $\omega_1 + \omega_2 = 1$. Selecting the appropriate weighting factor is very important and it is related to the revenue and policy of the producing country. If the goal is maximum oil recovery factor, then $\omega_1 = 1$. However, if the goal is maximum CO₂ storage factor, then $\omega_2 = 1$. In this paper, an equal weighting factor ($\omega_1 = \omega_2 = 0.5$) is assigned, indicating the equal importance of oil production and CO₂ storage.

There is no exact data on CO₂ loss in the Industry Data Set. CO₂ loss mainly includes surface loss and subsurface loss. Surface CO₂ loss is that part of CO₂ in pipe that is released to the atmosphere during the process of power outages or equipment repair. Subsurface CO₂ loss is that part of CO₂ that laterally migrates outside of the production wells or which is not captured by the recycling loop but remains in the subsurface. In this paper, according to industry experience, 5% of cumulative injected CO₂ is assumed to be the cumulative CO₂ loss (DOE, 2010; Azzolina et al., 2015).

3 Experimental section

3.1 Experimental material and apparatus

In this study, coreflooding experiments were conducted with a 2.50 cm diameter, 85.03 cm long natural composite core from Changqing oilfields located in Ordos sedimentary basin, northwest China. The reservoirs in this basin generally feature ultralow porosity, ultralow permeability, microfracture and strong heterogeneity. The average porosity is 9.6%, and average permeability is 0.27 mD. The experimental oil and brine were obtained from the same area as the core. The viscosity of crude oil is 0.95 mPa s, the salinity of brine is 78 g/L. and the purity of CO₂ is 99.99%. CO₂ flooding can be classified as immiscible and miscible based on the reservoir pressure. In an earlier tubule experiment, the Minimum Miscible Pressure (MMP) was measured as 20.78 MPa, which is lower than the initial reservoir pressure of 21.9 MPa. Therefore under the current reservoir condition, the flooding is miscible flooding.

In cyclic CO₂ injection tests, the experimental apparatus consists of three parts: injection part, displacement part and metering part. Injection part includes three intermediate containers connected with a displacement pump to inject fluids. The displacement part includes a high pressure stainless steel core holder with a corrosion resistance of

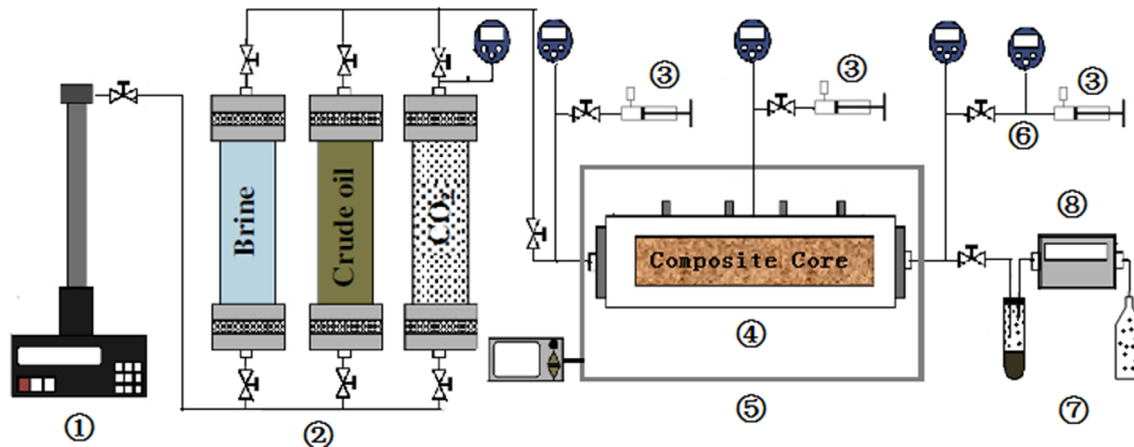


Fig. 1. Schematic diagram of the experimental apparatus used for cyclic CO₂ injection tests. Displacement pumps; intermediate container; manual pump; core holder; isothermal case; back pressure regulator; sample collector; gas flow meter.

synthetic rubber sleeve, a back pressure regulator connected to the end of the core holder maintaining the core pressure of 21.9 MPa, and two pressure gauges monitoring the core and the annulus pressure respectively. The annulus pressure was maintained at a value of around 2 MPa higher than the core pressure to avoid the core being ruptured. The metering part includes a three phase separator at ambient conditions used for metering the production of gas and oil. The entire apparatus excluding the displacement pump is housed in an isothermal case to maintain the experiment temperature at 84 °C. The schematic diagram of the experimental set up is shown in Figure 1.

3.2 Experimental procedure

Prior to the coreflooding experiments, the core samples were cleaned, vacuumed, and saturated with brine to obtain the pore volume and permeability at reservoir conditions. The pore volume obtained is 40.1 cm³. Thereafter, the core sample was saturated with live oil to establish the initial oil saturation and connate water saturation. The initial oil saturation is 54.4% while the irreducible water saturation is 45.6%. After the core sample was saturated with oil and kept in oil to re-establish its wettability. In addition, based the Shen Pingping's method, according to the condition of reservoirs, the value of basic parameters, such as initial water saturation E_R is 20%, CO₂ density in formation ρ_{CO_2} is 0.751 t/m³, CO₂ solubility in brine C_{ws} is 0.049, CO₂ solubility in oil is 0.35, the theoretical CO₂ storage capacity was calculated as 12.66×10^{-6} t (Shen et al., 2009; Sun et al., 2017).

When the preparation was completed, the cyclic CO₂ flooding experiment was started by injecting supercritical CO₂ with a constant flow rate of 0.05 mL/min. In each cycle, supercritical CO₂ was injected into the core with injection slug of 0.03–0.1 PV and injection time of 2–6.5 h after which the injection end closes for a soaking period of 1–13 h. During the entire process, the production end opens. The injection-soaking process described above is one cycle. The cycle process continues until there is no

considerable oil production. In each cycle, cumulative produced oil, injected and produced CO₂ were measured, oil recovery factor, CO₂ storage factor and the objective function were calculated and complex drive and storage mechanisms were analyzed. Finally the optimal injection parameters were determined by co-optimizing oil recovery and CO₂ storage. Detailed experimental design is shown in Table 1. All these operations were carried out at reservoir conditions (21.9 MPa and 84 °C).

4 Experimental results and discussion

4.1 The objective function

In this section, a total of nine cyclic CO₂ injection tests were carried out at different injection scenarios under miscible conditions. Figure 2 depicts objective function versus cumulative injected CO₂ at different injection scenarios. It was observed that the objective function increases with cumulative CO₂ injection, and the value increased rapidly during the initial stage. It was mainly attributed to a faster and strong CO₂ drive and storage mechanism (Cao and Gu, 2013; Vahid et al., 2017). Some of the injected CO₂ dissolved in oil and improved the oil mobility by oil volume expansion and viscosity reduction. Some of the injected CO₂ displaced and occupied the pore space of produced oil to store CO₂. However, with increase of cumulative injected CO₂, the curve became gradually flatter. This is because CO₂ viscous fingering and gravity segregation reduced the CO₂ sweep volume and resulted in CO₂ breakthrough which drastically declined oil production and CO₂ storage.

Table 2 shows cyclic CO₂ injection test results conducted at different injection scenarios. As can be seen from the table, with increase in CO₂ slug size, objective function decreased from 54.18% for 0.03 PV (run 2) to 27.85% for 0.1 PV (run 9). In addition, the injection process of each run before gas breakthrough contributed the majority of the ultimate value. The objective function only increased by 6%–10% after gas breakthrough. The same trend could

Table 1. Experiment scenarios of cyclic CO₂ injection.

Run	CO ₂ slug size (PV)	ISR	Injection rate (mL/min)
1	0.03	2:1	0.05
2	0.03	1:1	0.05
3	0.03	1:2	0.05
4	0.06	2:1	0.05
5	0.06	1:1	0.05
6	0.06	1:2	0.05
7	0.1	2:1	0.05
8	0.1	1:1	0.05
9	0.1	1:2	0.05

also be observed for oil recovery factor and CO₂ storage factor. Gas breakthrough is a key factor which affects oil recovery and CO₂ storage. The later CO₂ breakthrough occurred, the more oil produced and CO₂ stored. Therefore, in order to achieve more oil production and CO₂ storage, the injection parameters should be optimized to delay gas breakthrough (Bachu *et al.*, 2007).

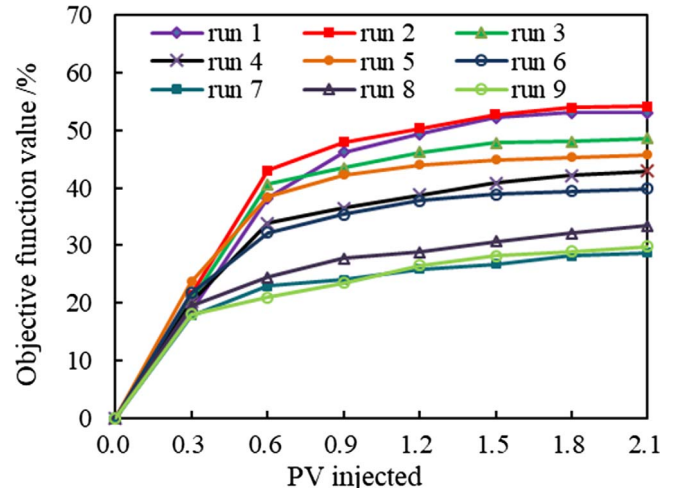
4.2 Effects of slug size

CO₂ slug size is an important factor affecting the effect of cyclic CO₂ injection (Wang *et al.*, 2013). In order to study the effects of CO₂ slug on oil recovery factor and CO₂ storage factor, three groups of cyclic CO₂ injection experiments were carried out with different CO₂ slug sizes (0.03, 0.06 and 0.1 PV). The ultimate oil recovery factor of all cyclic CO₂ injection tests *versus* CO₂ slug size are illustrated in Figure 3. As can be seen from this figure, the ultimate oil recovery increases firstly and then decreases with the increase in CO₂ slug size. The main reason is that a large CO₂ slug (0.1 PV) might have larger contact areas between the oil and CO₂ phases than a small CO₂ slug (0.03 PV), resulting in a greater reduced oil viscosity. However, a large slug size is easy to induce CO₂ breakthrough, decreasing oil recovery drastically after breakthrough. In this paper, the peak of ultimate oil recovery is 57.86% when CO₂ slug is 0.06 PV.

Figure 4 shows CO₂ storage factor *versus* CO₂ slug size in different injection tests. Comparison of CO₂ storage factor among 0.03 PV, 0.06 PV, and 0.1 PV suggests that when injected CO₂ slugs increase, CO₂ storage factor decreases from 61.35% for 0.03 PV to 29.46% for 0.1 PV. A small CO₂ slug seems to be more favorable for CO₂ storage, because it is helpful for controlling and delaying gas breakthrough.

4.3 Effect of injection-soaking time ratio

Injection-soaking time ratio, defined as the ratio of injection time to soaking time, is another major operating parameter in cyclic CO₂ injection. For a long period of time, the

**Fig. 2.** Objective function value *vs.* PV CO₂ injected for $\omega_1 = \omega_2 = 0.5$.

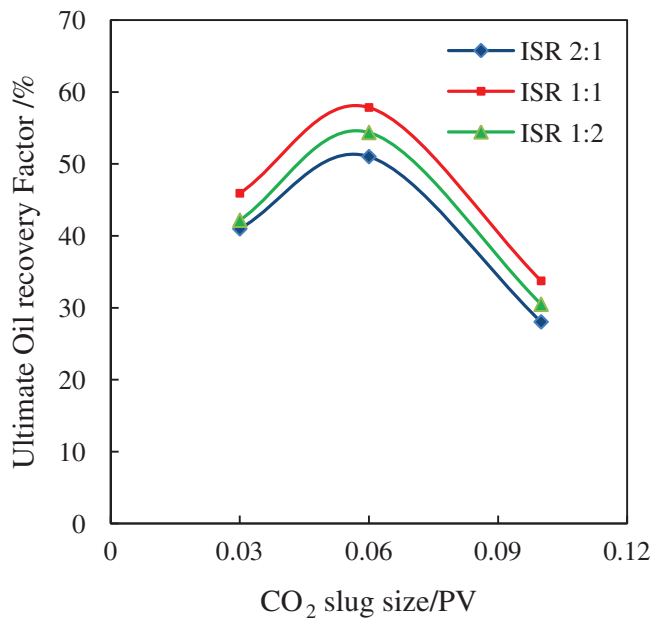
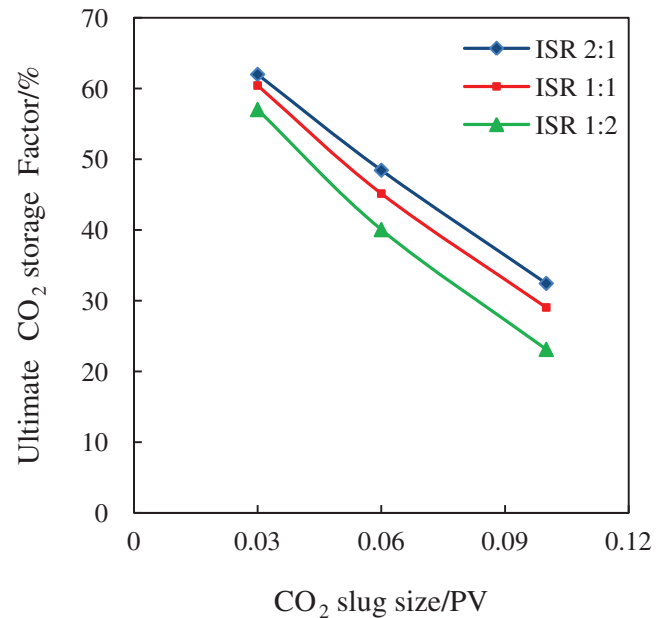
determination of soaking time relies on field experiences without theoretic basis. In this paper, three group of ISR (2:1, 1:1 and 1:2) were implemented to investigate its effect on cyclic CO₂ injection. Figure 5 shows the ultimate oil recovery factor *versus* ISR in different injection tests. The results indicated that the maximum oil recovery factor of 57.86% is obtained at ISR of 1:1. This is higher than the oil recovery obtained from ISR 2:1 and 1:2, because the soaking time mainly affects the amount of CO₂ dissolved in the oil phase. If the ISR is too high, CO₂ cannot spread into the deep formation and a large amount of CO₂ will gather around the wellbore, which increases injection-production pressure difference. This results in the reduction of CO₂ sweep areas and the ultimate oil recovery factor. If the ISR is too low, CO₂ can be fully dissolved in crude oil but the longer soaking time has little contribution to improve oil recovery and the amount of CO₂ injection is small in each cycle. This weakens the ability of CO₂ to expand the crude oil and reduce viscosity, thus reducing the oil recovery factor.

Figure 6 shows CO₂ storage factor *versus* ISR in different injection tests. The results revealed that ultimate CO₂ storage factor increases with ISR and the maximum CO₂ storage factor is 61.35% for ISR of 2:1. The higher the ISR, the more CO₂ injected and although CO₂ production and loss may be increased, CO₂ storage will also be increased. Under the action of buoyancy, some injected CO₂ is left behind as disconnected or residual droplets in rock interstices and seals and some migrates and dissolves into formation fluid. Those are the two main storage mechanisms (residual and solubility trapping) which take a significant percentage of total CO₂ stored (Ampomah *et al.*, 2016; Liang *et al.*, 2016).

Because oil recovery and CO₂ storage factor exhibit different trends with CO₂ injection parameters, for low permeability reservoirs, injection parameter optimization is a complicated process, which depends on specific field conditions with balances between oil recovery factor and CO₂ storage factor. The objective function established in

Table 2. summary of cyclic CO₂ injection experiment results.

Runs	PV		Function value/%		Oil recovery factor/%		CO ₂ storage factor/%	
	Breakthrough		Breakthrough	Ultimate	Breakthrough	Ultimate	Breakthrough	Ultimate
1	0.84		46.22	53.09	36.73	44.83	55.71	61.35
2	0.66		45.48	54.18	41.98	48.93	48.98	59.43
3	0.57		40.56	48.6	34.38	40.17	46.74	57.03
4	0.78		34.45	42.93	37.29	53.02	31.61	32.84
5	0.54		35.49	45.72	47.20	57.86	23.78	33.58
6	0.42		30.71	39.9	29.71	54.38	31.71	25.42
7	0.6		22.44	28.75	24.23	28.04	20.65	29.46
8	0.4		20.57	33.4	20.57	33.74	20.57	33.06
9	0.3		18.01	27.85	16.98	27.49	19.04	28.21

**Fig. 3.** Oil recovery factor *vs.* CO₂ slug size.**Fig. 4.** CO₂ storage factor *vs.* CO₂ slug size.

Section 2 can be provided for co-optimization of oil production and CO₂ storage.

4.4 Results comparison and analysis

As mentioned above, due to the different mechanisms of CO₂ drive and storage, CO₂ injection parameters have different influences on oil recovery factor and CO₂ storage factor. In order to investigate the effect of the co-optimization method on different scenarios, three optimization goals were used for comparison and analysis (only for oil recovery factor, $\omega_1 = 1$; only for CO₂ storage factor, $\omega_2 = 1$; co-optimization of oil recovery and CO₂ storage, $\omega_1 = \omega_2 = 0.5$).

The results are illustrated in Figures 2, 7, 8. As can be seen from these figures, the highest oil recovery with $\omega_1 = 1$ is 57.86% and was obtained from run 5 (0.06PV for CO₂ slug, 1:1 for ISR). The highest CO₂ storage

efficiency with $\omega_2 = 1$ is 61.35% and was obtained from run 1 (0.03 PV for CO₂ slug, 2:1 for ISR). However, run 2 (0.03 PV for CO₂ slug, 1:1 for ISR) gave the maximum value of the objective function for the co-optimization method (as shown from Fig. 2).

Table 3 shows the maximum value of the objective function for different optimization methods. The results revealed that the oil recovery factor is 48.93% and CO₂ storage factor is 59.43% when the objective function value is maximum for co-optimization method ($\omega_1 = \omega_2 = 0.5$). Although the oil recovery is lower than the maximum oil recovery (57.86% for oil recovery optimization method $\omega_1 = 1$), CO₂ storage factor increases from 33.58% to 59.43%. The co-optimization method which combines the oil recovery with CO₂ storage factor is better, especially in the context of global warming. It provides a win-win solution to achieve economic and social benefits.

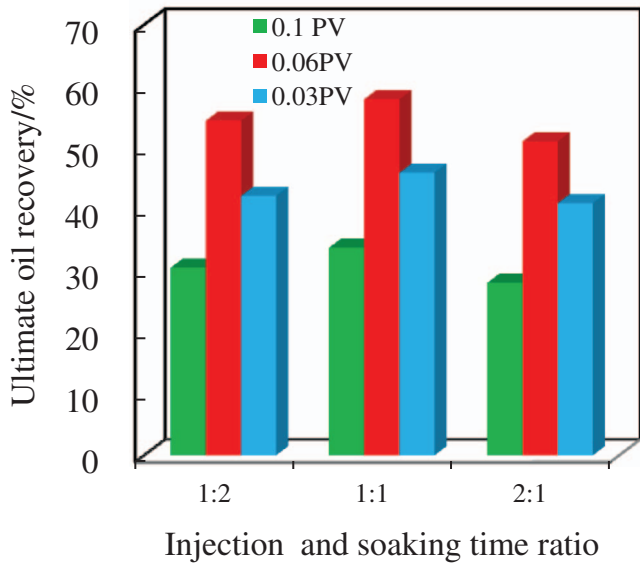


Fig. 5. Oil recovery factor vs. ISR.

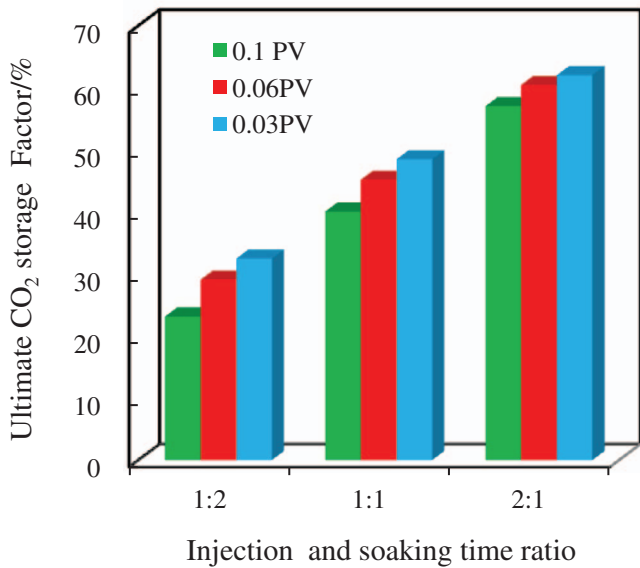


Fig. 6. CO₂ storage factor vs. ISR.

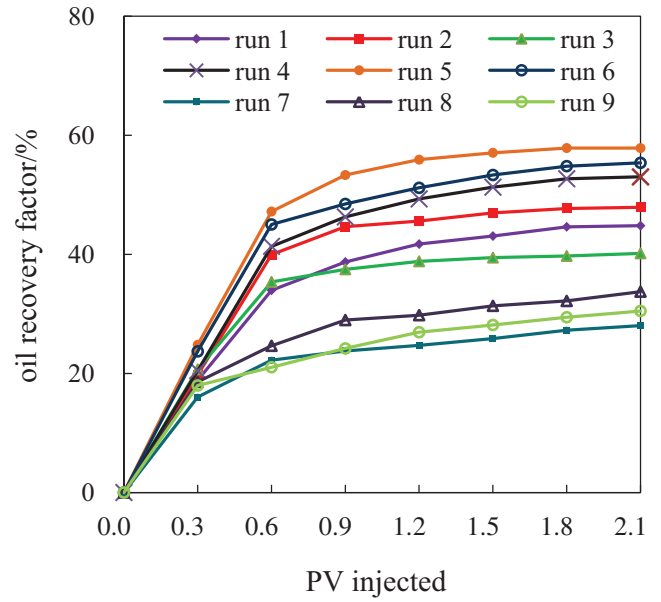


Fig. 7. Oil recovery factor vs. CO₂ injected PV for ω₁ = 1.

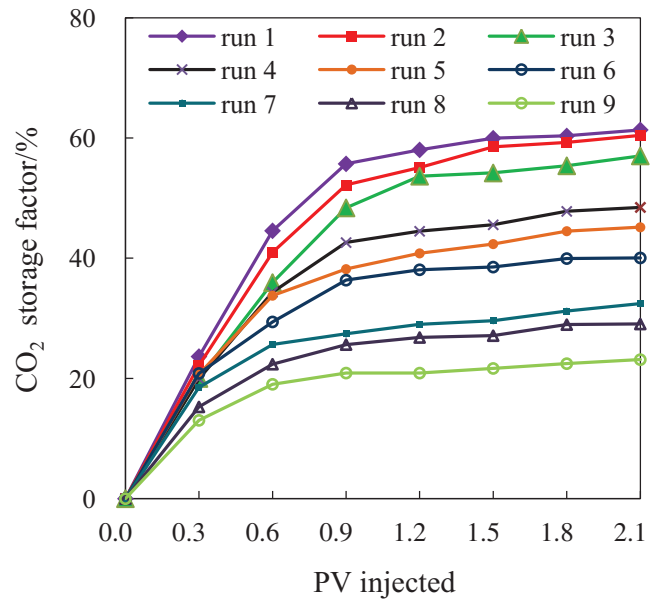


Fig. 8. CO₂ storage factor vs. CO₂ injected PV for ω₂ = 1.

Table 3. Maximum objective function values comparison for different optimization methods.

Method	Slug size	ISR	Objective function value	Oil recovery factor	CO ₂ storage factor
Oil recovery, ω ₁ = 1	0.06	1:1	57.86	57.86	33.58
CO ₂ storage, ω ₂ = 1	0.03	2:1	61.35	44.83	61.35
Co-optimization, ω ₁ = ω ₂ = 0.5	0.03	1:1	54.18	48.93	59.43

5 Conclusion

Cyclic CO₂ injection is an effective method for enhanced oil recovery and CO₂ storage in ultralow permeability oil reservoirs. Through the optimization of injection parameters, a more economically profitable, as well as environmentally friendly enhanced oil recovery/CO₂ storage can be achieved.

1. A co-optimization method was established which coupled the oil recovery and CO₂ storage and considered the loss of CO₂ in actual operation. It gives a guidance on the optimization of CO₂-EOR reservoir engineering design.
2. The injection parameters are important factors which affect oil recovery and CO₂ storage. For equal weight factor, the optimal injection slug size was 0.03 PV and ISR was 1:1, while slug size was 0.03 PV and ISR was 2:1 for the highest oil recovery, and slug size was 0.06 PV and ISR was 1:1 for the highest CO₂ storage. The most important thing is to delay gas breakthrough in reservoirs.
3. Comparing the three optimization goals, the co-optimization function which considered equal weight factors ($\omega_1 = \omega_2 = 0.5$) gave the best results with economic and environmental benefits with a reasonable oil recovery factor of 48.93% and CO₂ storage factor of 59.43%.

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