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# Optimization of Carbon Sequestration and Carbon Displacement in Fractured Horizontal Wells in Low Permeability Reservoirs

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**Abstract:** The increasing use of fossil fuels has raised concerns about rising greenhouse gas emissions. Carbon capture, utilization, and storage (CCUS) is one of the most important technologies for achieving net zero carbon emissions. In oil reservoirs, fully understanding their geological characteristics, fluid characteristics, and pressure distribution and injecting $CO_2$ in a reasonable scheme, some remaining oil can be recovered to improve oil recovery and even obtain certain economic benefits. In this paper, we investigate the effect of CCUS implementation in low-permeability reservoirs from both technical and economic aspects. First, based on the parameters of a low-permeability reservoir, a numerical simulation model of a reservoir with gas injection in a multi-stage fractured horizontal well at the top of the reservoir and oil recovery in a multi-stage fractured horizontal well at the bottom is established. Next, four cases of continuous $CO_2$ injection, intermittent $CO_2$ injection, $CO_2$ injection after water flooding, and water alternating gas drive (WAG) are designed to evaluate their effects on $CO_2$ storage and enhanced oil recovery. Finally, an economic evaluation model is developed to evaluate these four cases. The results show that fractured horizontal wells can improve the injection capacity, increase the swept volume of injected gas, cause $CO_2$ to fully contact the crude oil, greatly increase the contact area between the wellbore and crude oil, and greatly improve oil recovery. The WAG injection-production method can effectively inhibit gas channeling, reduce the production gas–oil ratio, improve oil recovery, and, at the same time, bury more $CO_2$ into the reservoir. Its economic benefit evaluation is also the best among the four cases. In addition, the remaining oil distribution and $CO_2$ buried distribution under different injection-production schemes are also analyzed. This study provides a scientific basis for the operation scheme design of CCUS in low-permeability reservoirs.

**Keywords:** fractured horizontal well; enhanced oil recovery; low-permeability reservoir

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## 1. Introduction

Under the background of the increasingly serious global greenhouse effect, governments of all countries are actively formulating response policies and major energy companies are also actively taking various measures. Excessive $CO_2$ emissions are the main culprit leading to the greenhouse effect, so reducing carbon emissions is the most critical [1–5]. Carbon capture, utilization, and sequestration (CCUS) is recognized as the most economical and effective measure to reduce carbon emissions. Its main principle is to transport captured $CO_2$ to oil fields and inject the $CO_2$ into oil reservoirs. When a large amount of $CO_2$ is buried in oil reservoirs, a large amount of crude oil can also be extracted, thus reducing carbon emissions and bringing certain economic benefits [6–8]. There are three main factors that affect its development: $CO_2$ capture cost, crude oil price, and carbon tax subsidy policy. If these three problems can be reasonably solved, its economic benefits will be considerable, and it will also greatly promote its development [9–11].

For the development of low-permeability sandstone reservoirs, there are many problems, such as swept volume of injected gas, low oil displacement efficiency, and low oil recovery. Therefore, the method of gas-assisted gravity drainage (GAGD) can be considered to solve the above problems. The concept of GAGD originated from the expansion of a gravity-stable gas injection project [12]. There are three-phase fluids of oil, gas, and water in most oil and gas reservoirs, which have different densities under the action of reservoir pressure. Gas is at the top, oil is in the middle, and water is at the bottom. In the field application, vertical wells are drilled at the top of the oil layer as gas injection wells and horizontal wells are drilled at the bottom of the oil layer as oil production wells [13,14]. GAGD technology mainly depends on the density difference caused by the low density of injected gas and the high density of reservoir fluid, which leads to gravity differentiation and makes the oil–gas interface move down steadily and inhibits viscous fingering, thus expanding the swept range and swept volume of injected gas and improving oil recovery [15]. The oil recovery ratio of GAGD technology is the highest among all immiscible flooding technologies and can even be twice as high as that of traditional water flooding [16–18]. With the continuous injection of $CO_2$, more and more crude oil is produced from production wells, and a large amount of injected $CO_2$ occupies the position of crude oil and is buried underground [19]. Therefore, GAGD meets the requirements of CCUS for enhancing oil recovery and geological storage of $CO_2$.

For low-permeability reservoirs, there will also be problems of low gas injection capacity and large oil and gas seepage resistance, etc. Research shows that water alternating gas drive (WAG) of fractured horizontal wells is the most effective for $CO_2$ sequestration and enhances oil recovery. $CO_2$ injection alone cannot significantly improve oil recovery because the injected gas migrates to the production well prematurely, resulting in gas channeling. WAG can effectively slow down gas channeling and make injected $CO_2$ fully in contact with crude oil, thus reducing crude oil's viscosity and seepage resistance and achieving better development effects. In addition, the interaction between $CO_2$ and rocks should also be considered when $CO_2$ is buried in oil reservoirs, and $CO_2$ is generally in a supercritical state. The content of feldspar, carbonate rock, and clay decreases after the interaction between supercritical $CO_2$ and the reservoir under medium- and high-pressure conditions, and this change can be ignored under low-pressure conditions [20]. The interaction of $CO_2$/brine/shale plays a decisive role in the sealing and burying effect. Mineral changes mainly occur during the burying period of 10 to 100 years, and some minerals dissolve during this period, reaching a state of equilibrium after 100 years [21]. Artificial intelligence can also be used to assist in the study of the interaction between $CO_2$ and crude oil or rocks [22].

Cardwell first put forward the theory of gravity flooding and the analytical model of gravity flooding [23]. Zhang Liehui [24] optimized and evaluated $CO_2$ storage and oil displacement effects under different injection production modes. The results showed that solvent flooding had a higher recovery ratio than pure $CO_2$ flooding but reduced $CO_2$ storage. Well control is the best method for $CO_2$ storage and enhanced oil recovery. Zhang Xinping [25] used a numerical simulation method to study the migration law of $CO_2$ after injection. $CO_2$ injected into the bottom of the oil layer will slowly gather upwards and reach the cap rock; it will be blocked by the cap rock, and $CO_2$ will spread out along the cap rock and form an inverted cone distribution under it. Rostami [26] fully considered the influence of reservoir parameters and reservoir heterogeneity on oil recovery and made relevant predictions by means of reservoir numerical simulation and nonlinear fitting. Li Bo [27] found that in the process of carbon dioxide flooding, the more light components in oil, the higher the recovery ratio. Mi Jianfeng [28] summarized the development of CCUS in China and the problems it faced. CCUS has great potential for emission reduction, but due to the constraints of the economy, technology, environment, and policies, the time for large-scale development of CCUS projects is not yet ripe. Hu Yongle [29] studied the economic cost of CCUS and found that the cost of storing carbon dioxide in most oil fields is higher than the benefit of oil recovery, which needs to be resolved by technology, policy, and market. Gao ran [30] found that in a CCUS scheme, if the effect of $CO_2$ geological storage is emphasized, the gas injection rate needs to be reduced in the middle of the project and increased again in the later stage of the project; if the oil displacement effect is emphasized, the gas injection rate should be greatly reduced in the middle and later stages of the project, and the flowing pressure at the bottom of the production well should be appropriately reduced, so as to increase the oil production. Xing Liren [31] analyzed the development status and prospects and suggested carrying out commercialized large-scale CCUS whole-process demonstration projects and industrial cluster construction in China and further increasing policy support and financial support.

To sum up, the ultimate goal of the CCUS scheme is to bury more $CO_2$ in the oil layer and extract more crude oil under the reasonable injection production mode to achieve the best economic benefit. Therefore, the design and economic evaluation of the injection-production scheme has always been the focus of CCUS technology. There are four main injection-production modes: continuous gas injection, intermittent gas injection, gas injection after water flooding, and water alternating gas drive.

For reservoirs in the later stages of development, the remaining oil still has certain development potential, and CCUS is a technical means that is vigorously promoted today. In this paper, a new GAGD method of top fracturing horizontal wells for gas injection and bottom fracturing horizontal wells for oil recovery is considered, which can not only increase the injection capacity of injection wells and the wave volume of injected gas but also increase the contact area between crude oil and production wells, thus improving the oil recovery [32–34].

## 2. Methodology

In this paper, the main objective is to investigate the effect of different injection-production methods on $CO_2$ sequestration and enhanced oil recovery in low-permeability sandstone reservoirs. There are four problems to be solved: oil recovery ratio of different injection-production methods, $CO_2$ storage, economic benefits, and $CO_2$ migration characteristics in low-permeability reservoirs [35,36].

On the premise of the above four questions, this paper establishes a numerical simulation model of an oil reservoir based on the parameters of a certain block. Considering the production mode of one production and one injection, that is, gas injection by horizontal wells at the top of the reservoir and oil production by horizontal wells at the bottom of the reservoir, this paper considers fracturing around the horizontal wells because of the low-permeability of the reservoir. To understand the migration law of carbon dioxide in the reservoir and the influencing parameters of enhancing oil recovery, based on the established reservoir numerical simulation model, four injection cases are analyzed to find the best injection model, and economic evaluation is conducted to obtain the best effect [37–39]. Figure 1 shows the workflow of this paper.


**Figure 1.** General workflow for a project of $CO_2$ sequestration and enhanced oil recovery in a low-permeability reservoir.

### 2.1. Establishment of Numerical Simulation Model

In this paper, we use tNavigator22.1 reservoir numerical simulation software to simulate and analyze $CO_2$ injection. The average reservoir thickness is 100 m, the top depth of the reservoir is 3700 m, the average horizontal permeability is 3 md, the ratio of average horizontal permeability to average vertical permeability is 10, the porosity is 0.2, the total pore volume of the reservoir is $2.3 \times 10^6$ $m^3$, and the initial oil saturation is 0.6. The gross ratio is 0.5. The model contains 61 × 41 × 10 grid blocks with 25,010 active blocks. The x, y, and z dimensions of each grid block are 10 m. Table 1 shows the main parameters of the model. The oil–water relative permeability curve and oil–gas relative permeability curve set in this model are shown in Figure 2. Reservoir fluid parameters are shown in Table 2. In this paper, the dissolution of $CO_2$ in crude oil and formation water is considered, but the capillary pressure among oil, gas, and water is not considered. In addition, the operation time of a single model is about 20 min.

**Table 1.** The reservoir model.

| Rock Properties Property/Parameter (Units) | Value | Fluid Properties Property/Parameter (Units) | Value |
|---|---|---|---|
| Reservoir dimensions | 61 × 41 × 10 | Water saturation, Sw (%) | 40 |
| Grid size | 10 × 10 × 10 | Initial oil saturation | 60 |
| Average Perm, K (μm$^2$) | 10 | Water density (kg/m$^3$) | 1014 |
| Porosity, (%) | 0.2 | Water viscosity (cp) | 0.3 |
| Perm.V/Perm.H, Kv/Kh | 0.1 | Oil specific gravity (kg/m$^3$) | 756 |
| Reservoir temperature, (°C) | 119 | | |
| Initial reservoir pressure (MPa) | 40 | | |
| Formation depth (m) | 3700 | | |
| Rock compressibility (1/bar) | 0.0003 | | |

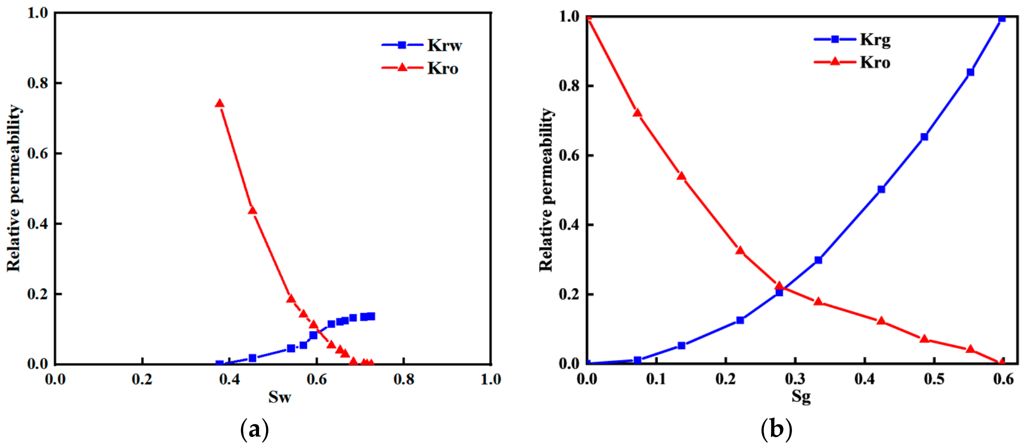


**Figure 2.** (**a**) Oil–water relative permeability curve; (**b**) Oil–gas relative permeability curve.

**Table 2.** Compositional reservoir parameters based on the reservoir system.

| Component | Molecular Weight | Tc (K) | Mole (%) | Acentric Factor | Pc (bar) | Omega A | Omega B |
|---|---|---|---|---|---|---|---|
| $CO_2$ | 44.01 | 304.70 | 0.07 | 0.2250 | 73.865 | 0.4572 | 0.0777 |
| C1, $N_2$ | 16.18 | 163.10 | 24.89 | 0.0133 | 45.901 | 0.4834 | 0.0558 |
| C2+ | 50.69 | 388.68 | 16.11 | 0.1722 | 43.121 | 0.4217 | 0.0887 |
| C7+ | 142.52 | 702.12 | 26.93 | 0.4041 | 19.106 | 0.4252 | 0.0949 |
| C16+ | 282.48 | 792.32 | 17.59 | 0.6996 | 14.344 | 0.4572 | 0.0673 |
| C27+ | 602.43 | 961.09 | 14.41 | 1.6552 | 6.122 | 0.5062 | 0.0696 |

On the basis of the above data, a numerical simulation model of an oil reservoir is established in this paper. In this model, a horizontal production well and a horizontal gas injection well are set, with the gas injection well in the first layer of the reservoir and the production well in the tenth layer of the reservoir. In a low-permeability sandstone reservoir, the seepage resistance of fluid migration is large, and there may be some problems, such as injection difficulty; therefore, hydraulic fracturing is considered in this paper. In this model, a total of 18 fractures are set up, and logarithmic local grid refinement is carried out to better understand the fluid flow state in the fractures (Figure 3). Parameters of horizontal well hydraulic fracturing are shown in Table 3.

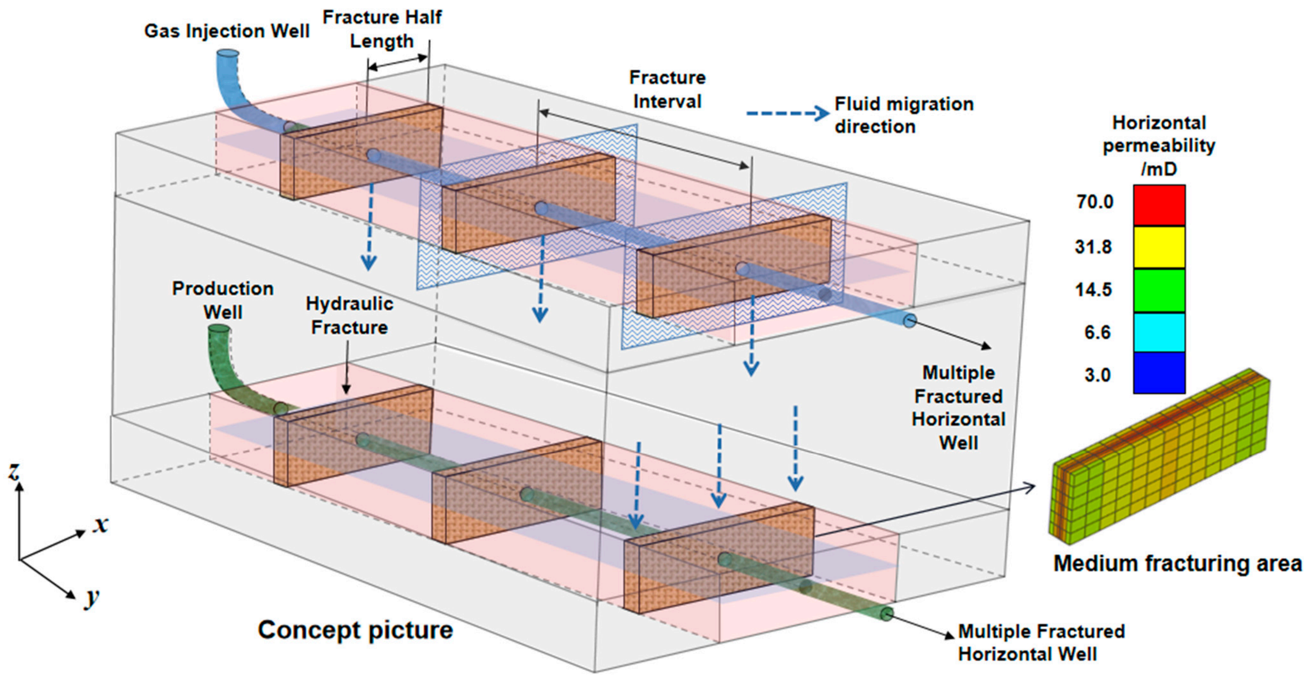


**Figure 3.** Low-permeability sandstone reservoir model with hydraulic fractures.

**Table 3.** Properties of hydraulic fractures used in the reservoir model.

| | |
|---|---|
| Fracture Half Length (m) | 65 |
| Average permeability (mD) | 29.45 |
| Maximum permeability (mD) | 70 |
| Minimum permeability (mD) | 10 |
| Fracture spacing (m) | 40 |

### *2.2. Scheme Design*

After the low-permeability sandstone reservoir model is established, four injection cases are designed in this paper. They are continuous $CO_2$ injection ($CO_2$ is injected continuously for 50 years), intermittent $CO_2$ injection ($CO_2$ is injected every other year for 50 years), $CO_2$ injection after water flooding (gas injection after 25 years of water injection), water alternating gas drive (one year of gas injection and one year of water injection) is used to study the oil displacement and $CO_2$ storage efficiency of each case and the migration characteristic after $CO_2$ injection, and to set the parameters of production well and gas injection well (water injection well) in the case (Table 4). The production wells are produced at a constant bottom pressure of 20 MPa, and the well control conditions are that the produced gas–oil ratio is not higher than 5000 $sm^3/sm^3$, and the water cut is not more than 95%. The gas injection rate of gas injection wells is constant at 10,000 $sm^3/d$, the water injection rate of water injection wells is constant at 40 $sm^3/d$, and the well control conditions are that the injection pressure does not exceed 60 MPa.

**Table 4.** Scenario design parameters.

| Case | Scenario | Gas Injection Rate (sm3/d) | Water Injection Rate (sm3/d) | Total Gas Injection Time/Years | Total Water Injection Time/Years | Years of Production |
|---|---|---|---|---|---|---|
| **1** | **Continuous $CO_2$ injection** | 10,000 | 0 | 50 | 0 | 50 |
| **2** | **Intermittent gas injection** | 20,000 | 0 | 25 | 0 | 50 |
| **3** | **$CO_2$ injection after water flooding** | 10,000 | 40 | 25 | 25 | 50 |
| **4** | **Water alternating gas drive (WAG)** | 10,000 | 40 | 25 | 25 | 50 |

*2.3. Establishment of Objective Function*

The ultimate goal of a CCUS project is to bury more $CO_2$ into the reservoir and extract more crude oil to maximize the economic benefits. However, the emphasis on oil displacement and $CO_2$ storage in each CCUS project may be different. Therefore, this paper introduces the objective function of reservoir utilization rate and oil recovery rate combined with $CO_2$ [40,41]:

$$f = w_1 \frac{N_p}{OOIP} + w_2 \frac{volume\ of\ CO_2\ stored}{pore\ volume} \tag{1}$$

where $w_1$ ($0 \leq w_1 \leq 1$), $w_2$ ($0 \leq w_2 \leq 1$), $w_1 + w_2 = 1$ and $N_p$ is the cumulative oil production, and OOIP is the original oil geological reserves. The biggest feature of this objective function is that it takes into account whether carbon dioxide is gas or liquid in the reservoir or dissolved in crude oil or formation water at the temperature and pressure of the reservoir; it can well show the reservoir utilization rate of $CO_2$, that is, the ratio of the mass of $CO_2$ buried in the reservoir to the reservoir capacity can be used to represent the reservoir utilization rate of $CO_2$. If the goal of the case is to extract as much crude oil from the reservoir as possible, then take $w_1 = 1$; if the goal of the case is to bury more $CO_2$ underground as much as possible, then take $w_2 = 1$; if the plan pays equal attention to enhancing oil recovery and geological storage of $CO_2$, then take $w_1 = w_2 = 0.5$.

Since the cost of $CO_2$ was not considered in the above formula, a new objective function was introduced for economic analysis and evaluation to gain a detailed understanding of the economic benefits of $CO_2$ geological sequestration and enhanced oil recovery in low-permeability sandstone reservoirs. In the CCUS case, the cost of $CO_2$ is mainly sourced from five aspects, namely, $CO_2$ capture, $CO_2$ compression, $CO_2$ transportation, $CO_2$ injection, $CO_2$ burial, and long-term monitoring. The storage cost per ton of $CO_2$ is usually in the range of USD 40–USD 60, depending on transportation distance, $CO_2$ capture technology, and well pattern design. The crude oil price is USD 90/barrel, and the water injection cost is USD 1/t. In this paper, the storage cost per ton of $CO_2$ is USD 40. The economic benefit can be represented by the ratio of the added value of crude oil production income to the cost of $CO_2$ storage. In addition, in 2008, the United States enacted the 45Q Act [42], which provided tax incentives for the capture, storage, and utilization of carbon dioxide emissions, including injecting $CO_2$ into reservoirs to enhance oil recovery. From 2017 to 2026, the tax relief was increased proportionally, and the carbon tax subsidy in 2022 was USD 25.15/t. In order to simplify the calculation, this value is used to calculate the carbon tax subsidy. The formula is as follows [43–45]:

$$R = \frac{Revenue\ of\ oil\ production}{Cost\ of\ CO_2\ sequestration\ and\ water\ injection} = \frac{\frac{\$110}{barrel} * Total\ oil\ production + \frac{45Q\ tax\ credit\ in\ \$25.15}{tCO_2} * CO_2\ storage\ quantity}{\frac{\$40}{tCO_2} * Total\ CO_2\ injection + \frac{\$4}{tWater} * Total\ water\ injection} \tag{2}$$

## 3. Analysis and Discussion

### *3.1. Effects of Four Cases on $CO_2$ Storage and Oil Displacement*

It can be seen from Figure 4 that there are obvious differences in $CO_2$ distribution characteristics under different injection-production cases.

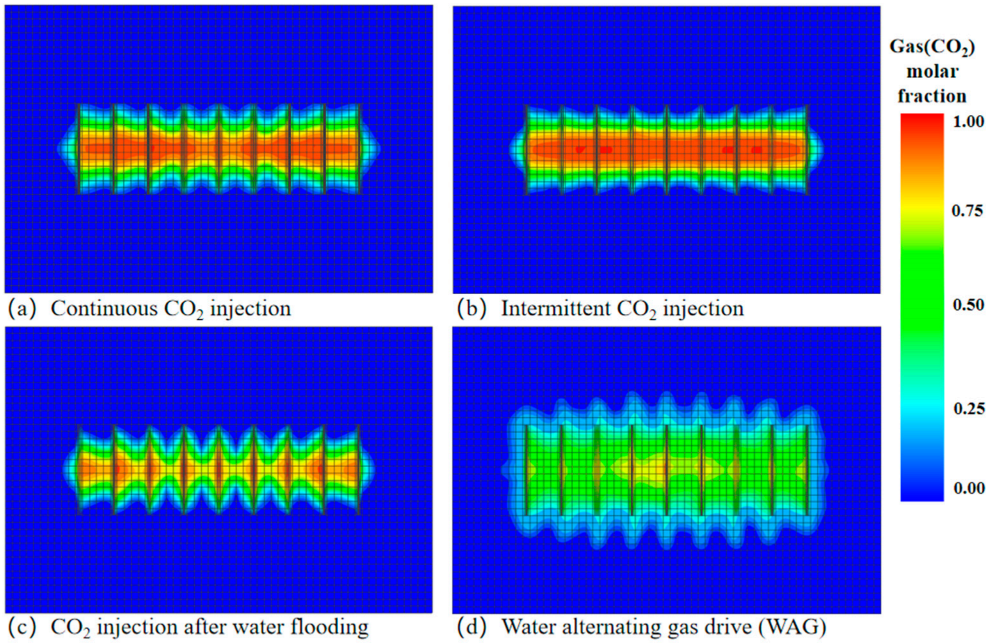


**Figure 4.** Plane distribution of $CO_2$ mole fraction in four cases after 50 years of operation of the model (K = 10).

After the model runs for 50 years, the total injection amount of $CO_2$ in Case 1 and Case 2 is $1.83 \times 10^8$ sm$^3$, and the gas injection amount and water injection amount in Case 3 and Case 4 are $9.13 \times 10^8$ sm$^3$ and $3.65 \times 10^5$ sm$^3$, respectively. Although the injection amount of $CO_2$ in Case 4 is less, it has the widest distribution range at the bottom of the reservoir, and its distribution outside the fracturing area is obviously higher than that of the other three cases (Figure 4). Case 1 and Case 2 have the highest $CO_2$ mole fraction at the bottom of the reservoir, and they are all distributed among the fracturing areas, which indicates that a large amount of $CO_2$ migrated to the bottom of the reservoir prematurely and was produced by the production wells. Of course, this is also the reason for the high total gas injection amount in these two cases. Compared with Case 3 and Case 4, certain characteristics can also be found. The distribution range of $CO_2$ at the bottom of the reservoir in Case 3 is the least among the four cases, and the areas with a high molar fraction of $CO_2$ are all near the oil wells. However, the injection-production mode of water–gas alternation is the opposite result, which shows that the rational use of water injection can not only slow down gas channeling but also make the injected $CO_2$ have a wider spread range so as to achieve better oil displacement and $CO_2$ storage effects.

Figures 5 and 6 show the distribution of $CO_2$ mole fraction in a reservoir full and a half model after the four cases run for 50 years, which can further prove the conclusion obtained in Figure 4. Although the injection amount of $CO_2$ in Case 4 is half that of Case 1 and Case 2, the migration range of $CO_2$ in Case 4 is the highest among the four cases, and the mole fraction of $CO_2$ in the bottom of the reservoir can be seen to be significantly lower than that in the other three cases. The further proven WAG case can not only alleviate gas channeling but also make it contact with more crude oil, thus achieving a better development effect. Compared with Case 1, Case 2 has a better-swept volume of $CO_2$, which is mainly due to intermittent gas injection, which can alleviate gas channeling. During the shutdown period, due to the reduction in production pressure difference, more $CO_2$ migrates on the plane than in Case 1, which makes the swept volume of $CO_2$ in Case 2 higher.

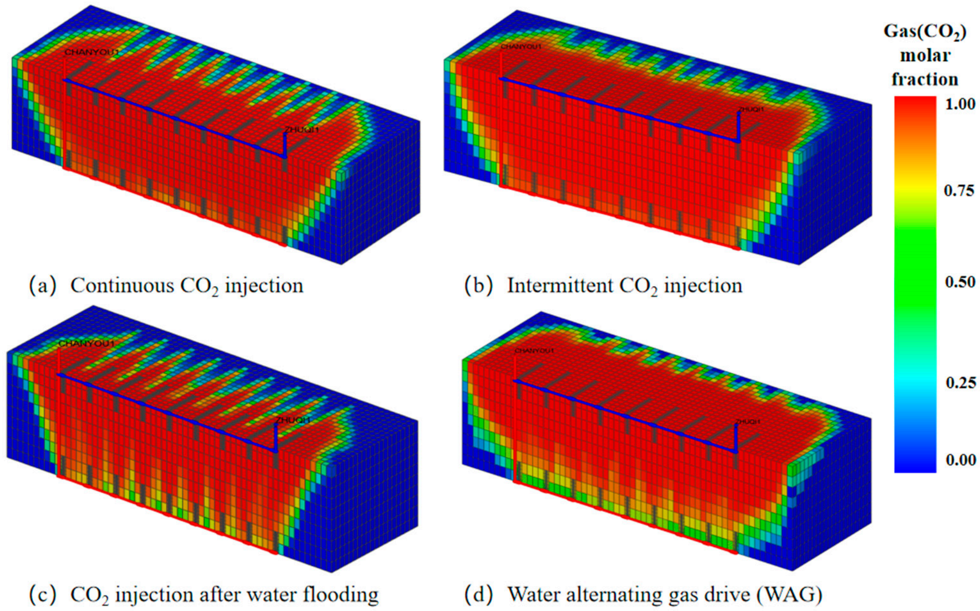


**Figure 5.** Reservoir a half model showing $CO_2$ mole fraction distribution, 50 years after shut-in.

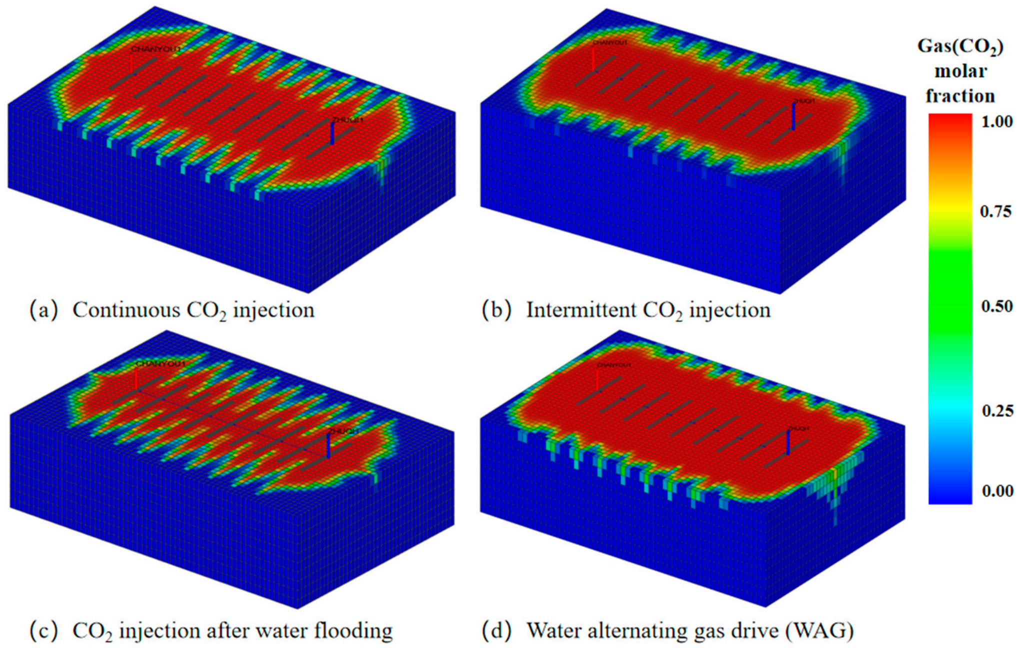


**Figure 6.** Reservoir full model showing $CO_2$ mole fraction distribution 50 years after shut-in.

The application of horizontal well injection-production in a low-permeability reservoir can greatly increase the contact area between the wellbore and reservoir, and the development effect of WAG is much higher than that of the other three cases. As shown in Figure 7, after 50 years of model operation, the cumulative oil production of Case 4 is $1.52 \times 10^5$ sm$^3$, $1.41 \times 10^5$ sm$^3$, and $6.84 \times 10^4$ sm$^3$ higher than that of the other three cases, respectively. After 50 years of model operation, the oil saturation of Case 4 is 39.493%, and the gas saturation is only 1.705% lower than that of Case 1. It should be known that the gas injection rate of Case 1 is twice that of Case 4. It can also be found that Case 4 has higher water saturation, lower gas saturation, and higher gas saturation under the same total gas injection and water injection, which indicates that more crude oil is produced and more $CO_2$ is buried in the reservoir, which is of great significance to CCUS's case design.

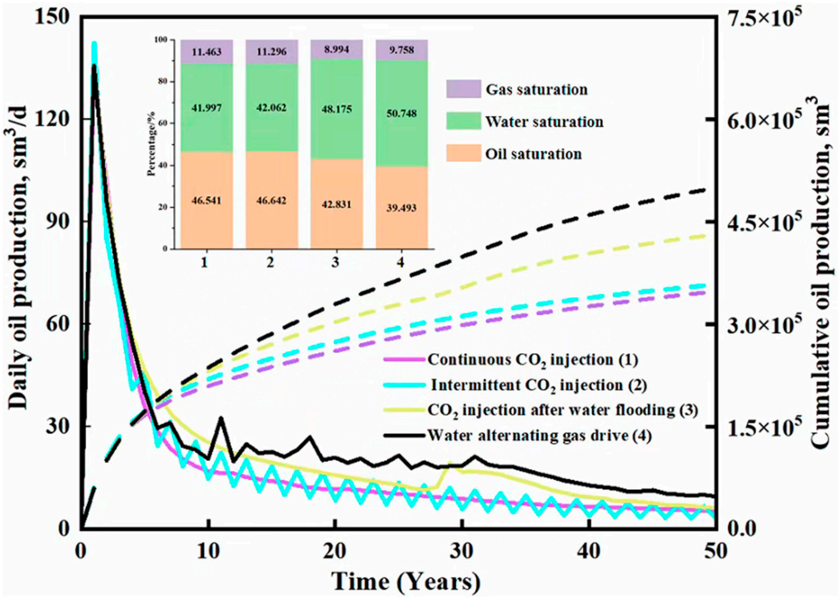


**Figure 7.** Daily oil production and cumulative oil production curves of four cases. The illustration shows the distribution of oil, gas, and water saturation of four cases after the model runs for 50 years.

After 50 years of operation of the model, the plane average oil saturation and crude oil streamline distribution of four cases are shown in Figure 8. It can be seen from the figure that fracturing is very helpful to increase oil production. Crude oil streamline is concentrated in the fracturing area, and also, there are more streamline distributions outside the fracturing area in Case 4. For the oil saturation distribution of the four cases, Case 2 has the lowest oil saturation in the fracturing area, and Case 1 has the highest oil saturation in the fracturing area, which indicates that compared with continuous gas injection, intermittent gas injection can produce more crude oil around the fractured section of horizontal wells. The average oil saturation of Case 4 is the lowest, and the area not affected by injected fluid is the smallest. This shows that the WAG injection-production method can effectively increase the spread range of injected fluid and produce more remaining oil. Multi-stage fracturing in horizontal wells can greatly increase the contact area between production wells and crude oil and greatly improve oil recovery. $CO_2$ injection will occupy the original pore volume of the produced crude oil, and the more remaining oil is produced, the greater the $CO_2$ storage capacity.

According to the simulation results, after the model runs for 50 years, the highest oil recovery rate of Case 4 is 37.56%, the lowest oil recovery rate of Case 1 is 26.17%, the highest $CO_2$ storage rate of Case 2 is $1.26 \times 10^8$ sm$^3$, and the lowest $CO_2$ storage rate of Case 3 is $9.40 \times 10^7$ sm$^3$ (Figure 9).

Compared with continuous gas injection, intermittent gas injection has certain advantages in both oil recovery rate and $CO_2$ storage rate. However, as mentioned earlier, when the gas injection volume of Case 1 and Case 2 is twice as high as that of Case 4, the $CO_2$ storage volume does not increase exponentially. The reason can also be clearly seen from the produced gas–oil ratio. The produced gas–oil ratio of Case 1 and Case 2 after the model runs for 50 years is more than four times that of Case 4, which indicates that a large amount of $CO_2$ injected into the reservoir quickly migrates to the bottom of the well to be produced, and the produced gas–oil ratio increases in proportion with the running time of the model, in other words, the production efficiency becomes lower and lower. On the other hand, it also shows that water injection can better inhibit gas channeling and has a great effect on reducing the gas–oil ratio of production, especially the water–gas alternate injection mode. Moreover, during water injection, it can not only restrain the increase in the production gas–oil ratio but also maintain the reservoir pressure to produce an objective amount of crude oil, which can be said to kill two birds with one stone (Figure 10).

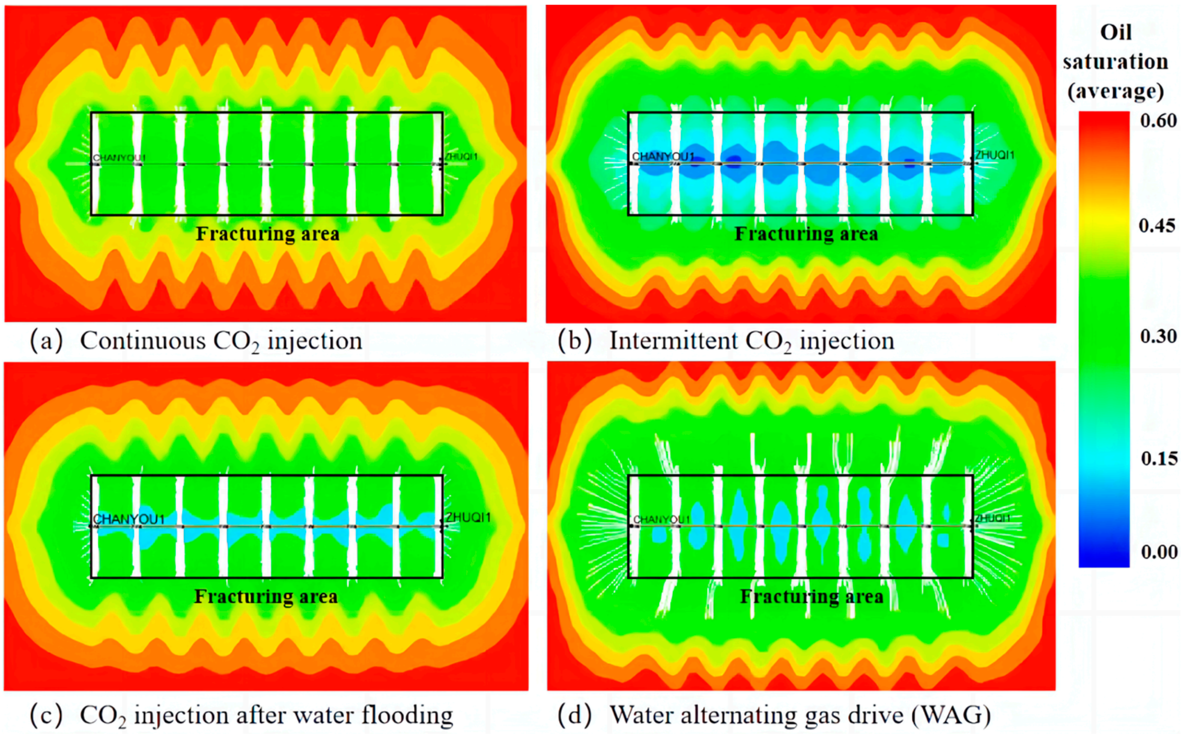


**Figure 8.** Plane average oil saturation and oil streamline distribution map of four cases after 50 years of operation.

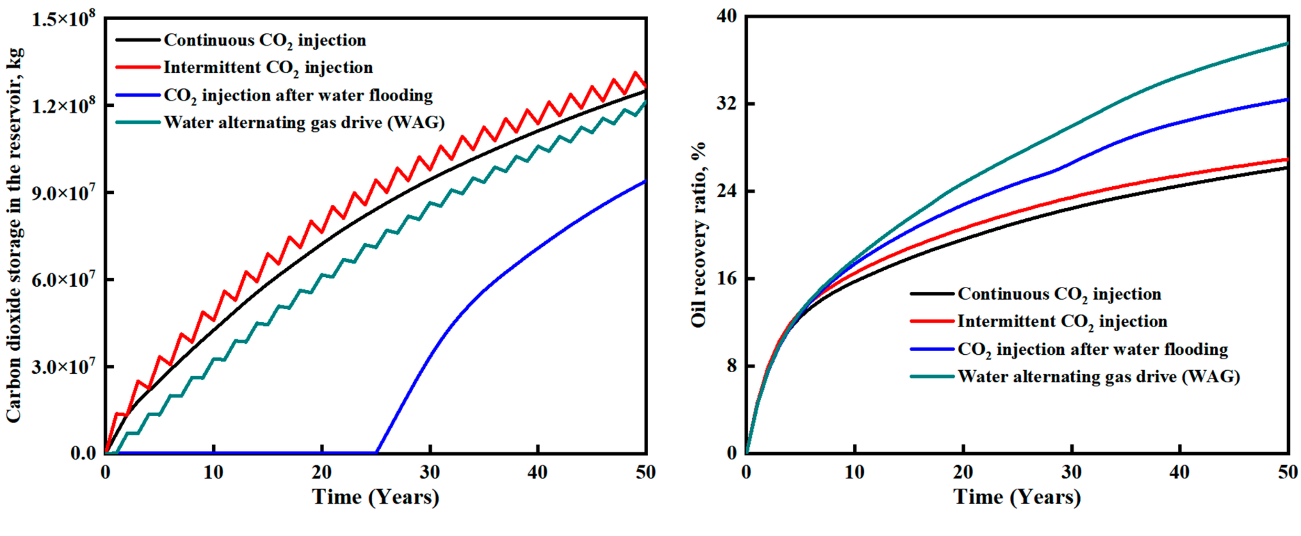


**Figure 9.** $CO_2$ storage curve (**left**) and oil recovery curve (**right**) of four cases.

For reservoir development, the watercut in the production process is also an important index. Because of water injection in Case 3 and Case 4, the watercut is much higher than that in the other two cases. Among them, the watercut of Case 3 reached 68.77% after the model was operated for 25 years, and then the watercut gradually decreased in 25 years, which was mainly due to the change of injection-production mode (Figure 11). The watercut of Case 4 reached 61.94% in the 50th year after the model operation, fluctuated greatly in the early stage of production, and then rose steadily. However, the watercut of Case 1 and Case 2 has been kept at a low level, with the watercut of 9.06% and 10.77%, respectively, after 50 years of production.

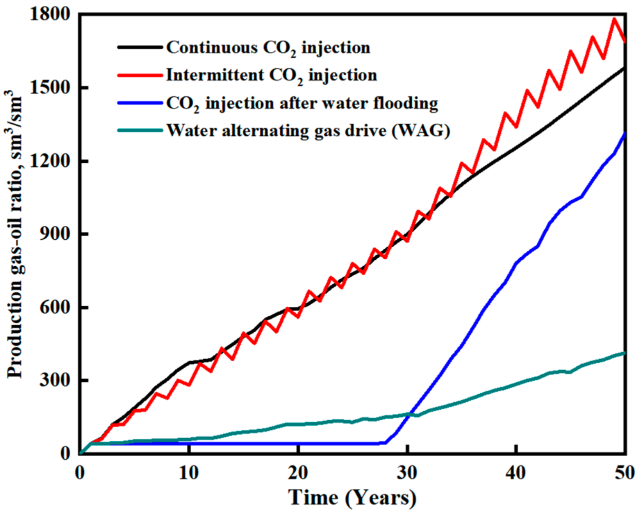


**Figure 10.** Production gas–oil ratio curves of four cases.

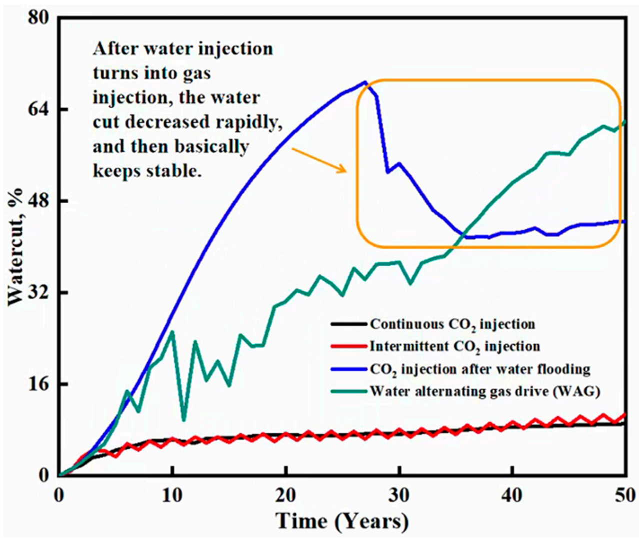


**Figure 11.** Watercut curves of four cases.

### *3.2. Economic Analysis*

The objectives of different CCUS cases are not completely the same, but the main objective is to find the injection-production case with the maximum oil recovery rate and, at the same time, to bury $CO_2$ into the reservoir to the greatest extent. In this paper, we consider setting $w_1 = w_2 = 0.5$; that is, the oil recovery ratio and $CO_2$ storage have equal weights. As shown in Figure 12, WAG's injection-production case is the best, with a score 20% higher than that of the continuous gas injection case. In Case 3, the objective function value was the lowest in the first 25 years, and the objective function value of gas injection increased rapidly. The objective function value of Case 2 is slightly higher than that of Case 1.

After evaluating the four cases by using the objective function in order to understand the economic benefits of $CO_2$ injection in low-permeability reservoirs, economic analysis is continued. In the CCUS case, the cost of $CO_2$ injection is set at USD 40/t, the cost of water injection at USD 1/t, and the oil price at USD 90/barrel. The tax credit for carbon dioxide capture and storage stipulated in 45Q regulations increased from USD 22.68/t to USD 35/t of carbon dioxide stored through EOR geology from 2017 to 2026. Beyond 2026, the tax credit is adjusted for inflation. According to the statistics of the U.S. Department of Labor, the average inflation rate in the United States was 1.75% from 2011 to 2020. Therefore, this paper assumes that the carbon tax subsidy after 2026 will rise year by year according to this inflation rate.

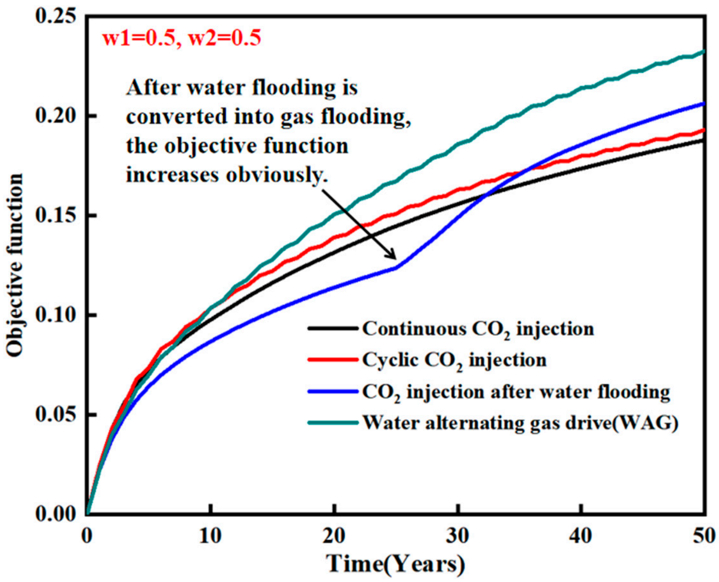


**Figure 12.** Curve of objective function.

This case assumes compliance with the tax subsidy regulations. After the model runs for 50 years, the ratio of CCUS cost and enhanced oil production revenue of four cases is shown in Formulas (3)–(6).

For the continuous $CO_2$ injection case:

$$R = \frac{Revenme\ of\ oil\ production}{cost\ of\ CO_2\ sequestration\ and\ water\ injection} = \frac{\frac{\$90}{barrel} * 2.24 \times 10^3 + \frac{45Q\ tax\ credit\ in\ \$25.15}{tCO_2} * 1.25 \times 10^5}{\frac{\$40}{tCO_2} * 3.59 \times 10^5 + \frac{\$1}{tWater} * 0} = 0.23 \quad (3)$$

For the intermittent $CO_2$ injection case:

$$R = \frac{Revenme\ of\ oil\ production}{cost\ of\ CO_2\ sequestration\ and\ water\ injection} = \frac{\frac{\$90}{barrel} * 2.25 \times 10^3 + \frac{45Q\ tax\ credit\ in\ \$25.15}{tCO_2} * 1.26 \times 10^5}{\frac{\$40}{tCO_2} * 3.59 \times 10^5 + \frac{\$4}{tWater} * 0} = 0.24 \quad (4)$$

For the $CO_2$ injection after water flooding case:

$$R = \frac{Revenme\ of\ oil\ production}{cost\ of\ CO_2\ sequestration\ and\ water\ injection} = \frac{\frac{\$90}{barrel} * 2.55 \times 10^3 + \frac{45Q\ tax\ credit\ in\ \$25.15}{tCO_2} * 1.06 \times 10^5}{\frac{\$40}{tCO_2} * 1.79 \times 10^5 + \frac{\$1}{tWater} * 3.65 \times 10^5} = 0.38 \quad (5)$$

For the water alternating gas drive case (WAG):

$$R = \frac{Revenme\ of\ oil\ production}{cost\ of\ CO_2\ sequestration\ and\ water\ injection} = \frac{\frac{\$90}{barrel} * 2.91 \times 10^3 + \frac{45Q\ tax\ credit\ in\ \$25.15}{tCO_2} * 1.23 \times 10^5}{\frac{\$40}{tCO_2} * 1.79 \times 10^5 + \frac{\$1}{tWater} * 3.65 \times 10^5} = 0.45 \quad (6)$$

## 4. Conclusions

By combining the conclusions obtained in this paper with references, it is clear that it is technically and economically feasible to use the GAGD method for carbon flooding and carbon burial for low-permeability reservoirs with multi-stage fractured horizontal wells.

Through a series of numerical simulation studies, it is found that there are great differences in $CO_2$ migration characteristics, $CO_2$ storage and oil recovery ratio under different injection-production modes. In the absence of water injection, both continuous and intermittent gas injection will result in earlier gas channeling, injected gas quickly into the production well, and rapid increase in the production gas–oil ratio, resulting in poorer development results. However, no matter what kind of injection-production method, the mole fraction of $CO_2$ at the top of the oil layer is the highest, and the spread range is the largest, which gradually decreases with the increase in oil layer depth.

The results show that after the model runs for 50 years, the oil recovery rate of WAG is the highest at 37.56%, which is 11.39% higher than that of continuous gas injection mode. Even if the $CO_2$ injection amount is half of that of continuous gas injection and intermittent gas injection, the $CO_2$ storage amount is only slightly lower than in the two cases, and there is no obvious difference. Therefore, WAG is the best choice among the four injection-production methods considered in this paper, regardless of oil production or $CO_2$ storage.

WAG can effectively restrain the increase in the gas–oil ratio. After 50 years of operation, the gas–oil ratio of the first three injection-production methods is 382%, 407%, and 317% higher than that of WAG. It also shows that WAG can not only slow down gas channeling but also make $CO_2$ fully in contact with crude oil, reduce crude oil viscosity, and greatly improve oil recovery.

Under the condition that oil displacement and $CO_2$ storage are equally important by using the objective function, that is, $w_1 = w_2 = 0.5$, the objective function value of WAG is the highest, followed by gas injection after water flooding and intermittent gas injection, and the objective function value of continuous gas injection is the lowest.

Considering the carbon tax subsidy, the economic evaluation of four cases is carried out. WAG has the best economic benefit, followed by gas injection after water injection, intermittent gas injection, and continuous gas injection. For low-permeability reservoirs, if there are reasonable carbon tax subsidies, lower $CO_2$ capture costs, and higher oil prices, the benefits will be considerable. Compared with pure $CO_2$ storage of CCS, the economic benefit of CCUS is obviously superior. However, this paper only makes a simplified calculation. The fluctuation in oil prices, the cost of $CO_2$ capture, and the carbon tax are the key factors that determine the economic benefits of CCUS.

There are still many problems in the design of injection-production cases and the evaluation of the economic benefits of CCUS. First, the homogeneous model is established in this paper. If further research is needed, a heterogeneous numerical simulation model can be established according to the specific conditions of the oilfield. Second, the evaluation of the economic scheme is relatively simple, without considering the fluctuation in oil price, the difference in $CO_2$ capture cost, and the change in the carbon tax subsidy with the year, which can be further analyzed. Third, the injection-production mode can be further analyzed in detail, such as selecting different gas injection rates and bottom pressure of production wells in different periods.

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