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Influence of Heterogeneous Caprock on the Safety of Carbon Sequestration and Carbon Displacement

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Abstract: Carbon Capture, Utilization and Storage (CCUS) is a method of burying the captured CO_2 into the reservoir and displacement of crude oil from reservoirs, which considers both economy and environmental protection. At present, it is considered as an important means to deal with global climate change. To ensure the safety of the CCUS scheme, it is very important to study the invasion and migration of CO_2 in different types of caprocks. In this paper, we first choose the injection-production method of fixed gas injection rate at the top of the reservoir and constant pressure oil production at the bottom. Secondly, the distribution of porosity and permeability in the caprock is designed, and four types of caprock models are established: homogeneous caprock, layered homogeneous caprock, heterogeneous caprock, and layered heterogeneous caprock. Finally, the intrusion amount and migration characteristics of CO_2 in caprock of four schemes in injection-production stage and burial stage are studied, and comprehensive analysis and evaluation are made in combination with the pressure distribution of caprock. In addition, the oil recovery ratio, geological CO_2 storage, and amount of CO_2 intrusion in caprock under different injection-production parameters in this model are also analyzed. This study provides a scientific basis for the safe operation of CCUS and geological storage of CO_2.

Keywords: caprock safety; geological storage of carbon dioxide; CO_2 migration characteristic

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1. Introduction

Under the background of China's carbon neutrality, Carbon Capture, Utilization and Storage (CCUS) is the most economical and effective measure for China to reduce greenhouse gas emissions and deal with environmental problems [1,2]. CCUS refers to the process of burying the captured CO_2 into an oil reservoir and extracting crude oil. Because it can improve oil recovery, it has lower storage cost compared with pure carbon storage and can even bring economic benefits and has a better development prospect. CCUS will have great development prospects in the next few decades, but the key to promoting CCUS technology in China is to ensure the safety of CCUS projects and minimize risks [3,4].

In order to ensure the integrity and safety of the caprock in the process of CO_2 storage, there are certain requirements for the caprock (Figure 1): firstly, CO_2 should be in a supercritical state during the geological storage of CO_2, and its critical temperature and pressure should be 31.3 °C and 7.38 MPa, respectively, which requires the depth of the caprock to be at least below 800 m [5,6]; second, it is required that the caprock has certain compactness, that is, low permeability and porosity, so as to prevent a large amount of CO_2 from leaking to the caprock because the pressure difference between the wetting phase and the non-wetting phase is higher than the capillary displacement pressure of the cap layer; third, the caprock needs to have certain stability, which can withstand the reaction of CO_2-brine-minerals, which will produce dissolution or precipitation, which will change the permeability and porosity of the caprock, thus resulting in uncertain factors. The fourth caprock should have a certain bearing capacity to prevent cracks or fractures due to the increase in fluid pressure [7–10]; and fifth, the cap layer should have a certain thickness [11–14].

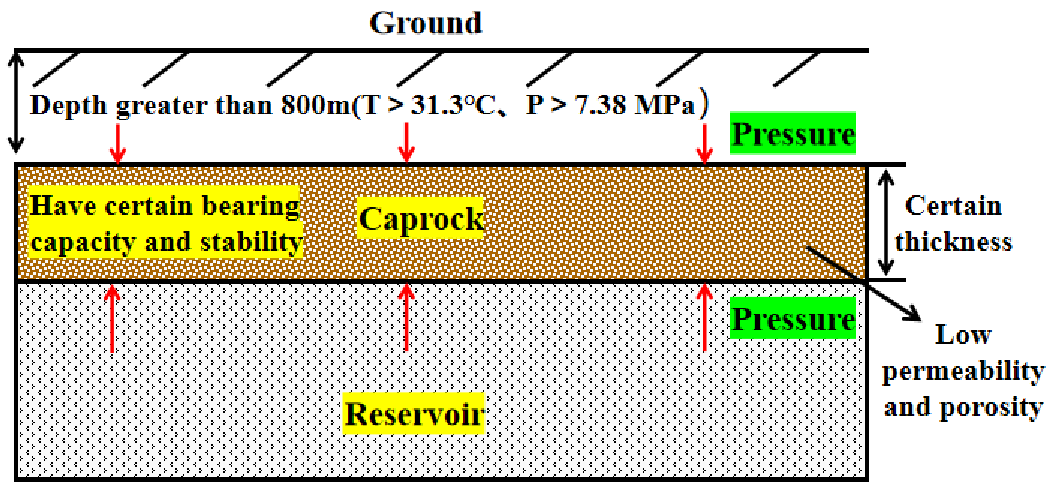

Figure 1. Certain requirements for the caprock.

There are three main leakage ways in the process of CO_2 storage: through unsealed or incomplete injection wells or abandoned wells; faults, fissures, or fault zones existing in buried bodies; and diffusion through the caprock. This paper focuses on whether CO_2 will leak through the caprock in the process of geological storage, and the migration characteristic of CO_2 in the caprock, which is one of the important steps for the safety evaluation of CCUS projects [15–18].

There are many studies on caprock by predecessors. Professor Lu Yanfang established a quantitative evaluation method of the sealing ability of caprock in the book "*Study on Sealing of Oil and Gas Reservoirs*" published in 1996, which laid a solid foundation for evaluating the integrity of caprock [19,20], and parameters of caprock were explained in detail. Additionally, a variety of methods were put forward to evaluate and judge the brittleness and plasticity of shale and gypsum rock, such as brittleness index (BRI) and overconsolidation ratio (OCR), Goetze's criterion, etc. [21–27]. He also found that there is a logarithmic linear relationship between the effective fracture thickness and the height of the maximum air column that can be closed, which provides an effective evaluation means for the safety evaluation of the caprock with fractures [28]. Yang Chen [29] summarized and sorted out the factors affecting the sealing property of caprock, which were mainly divided into two categories: macro factors and micro parameters. Microscopic parameters are porosity, permeability, breakthrough pressure, and specific surface area. Macroscopic parameters are lithology, thickness, diagenesis, and fracture of caprock. Comprehensive evaluation of various factors is used to achieve better results; Yuan Yusong [30] studied the sealing property of highly evolved mudstone, and found that it still had good sealing property if the tectonic action did not destroy the caprock in the later stage of production, and the height of the gas column that can be sealed by the caprock is positively correlated with the thickness of the caprock. Fu Xiaofei [31] undertook a detailed study on the present research situation and future development trend of oil and gas reservoir caprock sealing, pointing out that faults, structural fractures, and hydraulic fractures are the key factors for the integrity destruction of caprock, and defined the conditions for oil and gas migration through caprock. Lin [32] studied the influence of cap thickness on the sealing ability of natural gas. The cap thickness has no effect on the breakthrough pressure, but with the increase in cap thickness, its stability and the ability to prevent oil and gas diffusion gradually increase. Jiang Zhenhai [33] has studied the influence of vertical fractures in caprock on oil and gas sealing ability. The results show that the vertical sealing ability of mudstone caprock fractures is positively correlated with the displacement pressure of fault rocks and the thickness of mudstone caprock fractures, and negatively correlated with the residual pressure of oil and gas in underlying reservoirs. Song J [34] introduced in detail the factors that affect the sealing and integrity of cap rock in CO_2 capture and geological storage and gave the results of these mechanisms. Additionally, the leakage through faults and fractures is disastrous, but the CO_2 leakage caused by the diffusion mechanism usually accounts for a small proportion. Stéphanie Vialle [35] studied the strategy of mitigating CO_2 leakage when there are cracks in the caprock. Two methods are studied, namely, injecting desiccant under the damaged area of the cap layer and adding sealant to reduce the permeability of the fracture area. At the same time, knowing the leaked area to optimize the use position of the sealant.

To sum up, the main reason for CO_2 leakage in the caprock is that with the continuous injection of CO_2, the formation pressure gradually rises, and a large amount of CO_2 intrudes into the caprock due to the pressure difference between the reservoir and the caprock. Secondly, it is closely related to the size and distribution of porosity and permeability of caprock, that is, the heterogeneity of caprock. Therefore, this paper studies the heterogeneity of caprock in detail, considering four conditions of permeability and porosity distribution of caprock, namely homogeneous caprock, heterogeneous caprock, layered homogeneous caprock, and layered heterogeneous caprock, and studies the migration and leakage of CO_2 in caprock with different parameters.

2. Reservoir Modeling

In this paper, tNavigator numerical simulation software is used to study the leakage and migration characteristics of CO_2 in caprock, and a three-dimensional model is established (this software can simulate the process of CO_2 injection and consider miscibility). In this study, a cartesian coordinate system and single-hole and single-permeability model are used, and the reservoir parameters are similar to those of an oilfield (Table 1). Table 2 shows six pseudo-component fluid models, and Figure 2 shows oil–water relative permeability curves and oil–gas relative permeability curves, respectively. A Schematic view of the model geometry used is shown in Figure 3.

Table 1. Reservoir model parameters.

Cartesian reservoir grid (i,j,k)	50 × 1 × 15
Grid size (m)	20 × 20 × 10
Grid top (m)	3700
Layer thickness (m)	10
Reservoir temperature (°C)	119
Reference depth (m)	3700
Reference pressure (bar)	400
Rock compressibility (1/bar)	0.0003
Average permeability of oil layer (mD)	5
Average permeability of caprock (mD)	0.1
Average porosity of oil layer	0.2
Average porosity of caprock	0.03

Table 2. Composition description of oil.

Component	Molecular Weight (kg/mole)	Critical Temperature (K)	Critical Z-Factor	Mole Fraction	Critical Pressure (bar)	Critical Temperature (K)
CO_2	0.044	304.70	0.274	0.0007	73.86	304.7
C1, N_2	0.016	163.10	0.331	0.2489	45.90	163.1
C2+	0.051	388.68	0.303	0.1611	43.12	388.7
C7+	0.143	702.12	0.184	0.2692	19.11	702.1
C16+	0.282	792.32	0.219	0.1759	14.34	792.3
C27+	0.602	961.09	0.173	0.1442	6.12	961.0

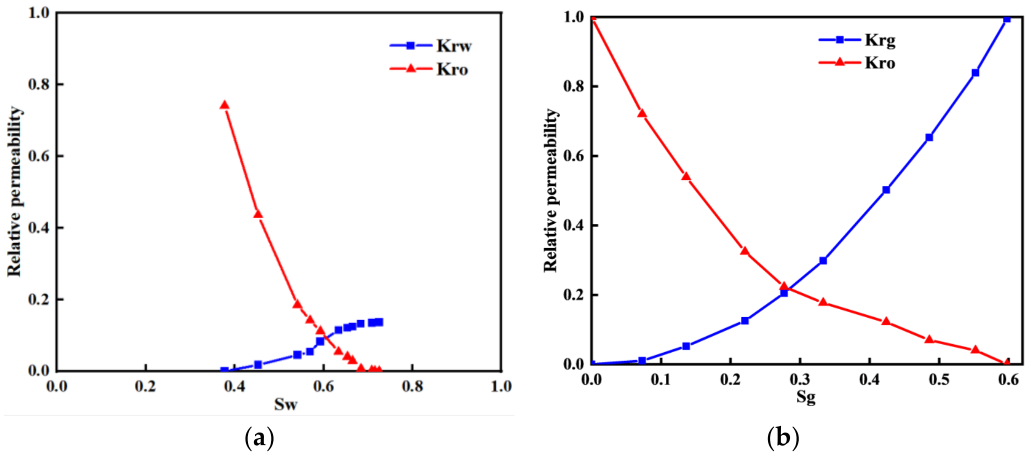

Figure 2. (**a**) Oil–water relative permeability curve; (**b**) oil–gas relative permeability curve.

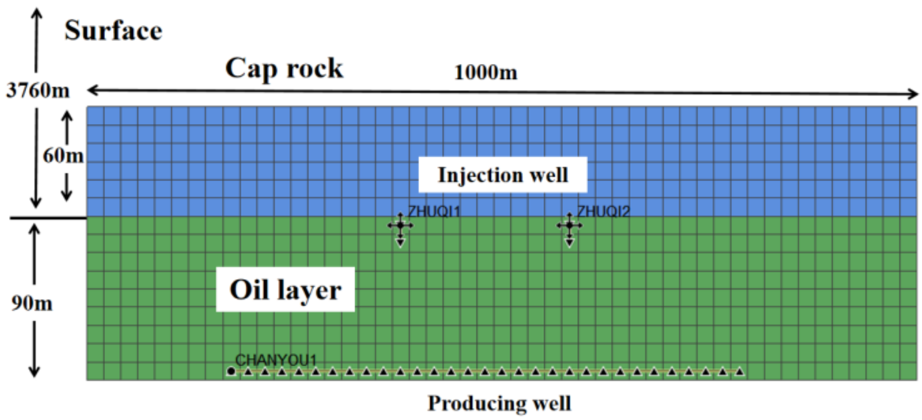

Figure 3. Schematic view of the model geometry used in the study.

In order to study the influence of heterogeneity on CO_2 migration and leakage in caprock, this paper considers designing four models for comparison. There are 15 layers in the model, the upper 6 layers are caprocks, the lower 9 layers are oil layers, and the oil layer is uniformly distributed.

In this paper, the Kozeny–Carman model is used to characterize the relationship between porosity and permeability [36], and the formula is as follows:

$$K = \frac{\varphi^3}{S(1-\varphi)^2} \quad (1)$$

where k is rock permeability; φ is rock porosity; and S is the coefficient related to the specific surface area of rock.

The Van Genuchten model is used for the capillary pressure curves of the oil layer and caprock [37], and the formula is as follows:

$$P_{cap} = -P_0\left([S^*]^{-\frac{1}{\lambda}} - 1\right)^{1-\lambda} \quad (2)$$

$$-P_{max} \ll P_{cap} \ll 0 \quad (3)$$

where $S^* = (S_l - S_{lr})(S_{ls} - S_{lr})$; P_{cap} is the capillary pressure of rock pore; P_0 is the rock intake value; and λ is a parameter related to the pore characteristics of rocks.

In this paper, the relative permeability curve of the oil layer is based on the relative permeability data of an oil field, and the relative permeability curve of caprock is described by the Grant [38] model, whose formula is:

$$K_{rl} = \hat{s}^4 \quad (4)$$

$$K_{rg} = 1 - K_{rl} \quad (5)$$

where K_{rg} is the relative permeability of the gas phase; $\hat{s} = (S - S_{lr}) \div (1 - S_{lr} - S_{gr})$; K_{rl} is the relative permeability of the liquid phase; S_l is liquid saturation; S_{lr} is the residual saturation of the liquid phase; and S_{gr} is the residual saturation of the gas phase.

Case 1: homogeneous caprock model; Case 2: layered homogeneous caprock model, that is, the permeability and porosity of caprock are distributed in layers, and the permeability and porosity of each layer are fixed values; Case 3: heterogeneous caprock model, in which permeability and porosity are completely randomly distributed in a certain range; Case 4: layered heterogeneous caprock model, permeability and porosity are completely randomly distributed among layers, and the distribution range of different layers has different values.

The average porosity and average permeability of the four models are the same, but the spatial distribution is different, and the conditions of gas injection wells and oil production wells in the four schemes are the same. In the first five years of the model operation, the gas injection rate of two gas injection wells was 10,000 sm^3/d, and the production wells were produced at a constant pressure of 15 mPa. After five years, the production wells were closed, and gas injection continued for two years. After that, the production wells were closed and buried for 1000 years to observe the variation in CO_2 leakage and migration law in the caprock with time. The distribution of porosity and permeability of caprock in four schemes is shown in Figure 4. Table 3 shows the interaction coefficient of each component in the reservoir. The parameters of permeability and porosity in the four models are set as shown in Table 4. The well control condition of production wells is that the ratio of production gas to oil is more than 8000 sm^3/sm^3, and that of gas injection wells is that the gas injection pressure is more than 60 MPa.

Table 3. Interaction coefficient of each component.

HC Interaction Coefficients						
Component	**CO_2**	**C1N2**	**C2+**	**C7+**	**C16+**	**C27+**
CO_2	0	0.098695058	0.1	0.1	0.1	0.1
C1N2	0.098695058	0	0.003116425	0.041740203	0.053395059	0.062798992
C2+	0.1	0.003116425	0	0.005481068	0.005481068	0.005481068
C7+	0.1	0.041740203	0.005481068	0	0	0
C16+	0.1	0.053395059	0.005481068	0	0	0
C27+	0.1	0.062798992	0.005481068	0	0	0

Table 4. Four cases' parameter settings.

Scheme	Average Permeability of Caprock (mD)	Average Porosity of Caprock	Maximum Permeability (mD)	Minimum Permeability (mD)	Maximum Porosity	Minimum Porosity
Case 1	0.1	0.03	0.1	0.100	0.030	0.030
Case 2	0.1	0.0	0.2	0.050	0.015	0.060
Case 3	0.1	0.0	0.2	0.001	0.060	0.001
Case 4	0.1	0.0	0.3	0.001	0.090	0.001

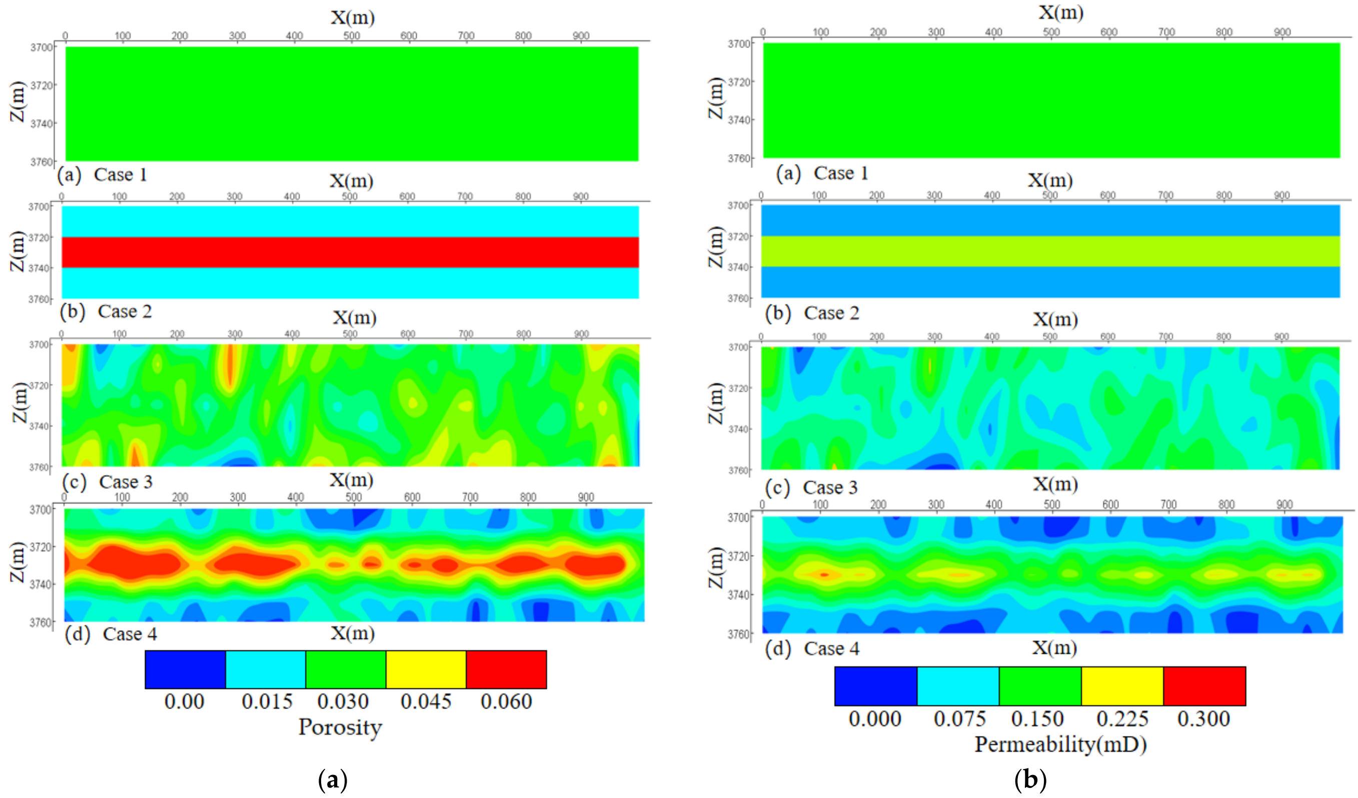

Figure 4. (**a**) Comparison of permeability distribution of caprock in four schemes; (**b**) comparison of permeability distribution of caprock in four schemes.

3. Analysis and Discussion

In the four schemes set in this paper, the gas injection wells are all injected at a fixed gas injection rate, and the production wells are produced at a fixed pressure, with a production pressure of 15 mPa. In order to study the leakage and migration of CO_2 injected into the reservoir into the caprock, the model is simulated and operated for 1000 years, and the CO_2 saturation, CO_2 leakage, and other parameters are compared and analyzed. Due to the long time span and slow reflection of CO_2-formation water–rock interaction, various possible chemical reactions are not considered in this paper.

3.1. Carbon Dioxide Leakage in Caprock

CO_2 injected into the reservoir is mainly buried in the reservoir in free state, i.e., supercritical state and dissolved state, and the leakage of CO_2 injected into the reservoir into the caprock can effectively reflect the CO_2 storage capacity of different caprocks. Figure 5a shows the variation curve of CO_2 intrusion in the caprock with time in the first seven years (1–5 years of gas injection at a fixed gas injection rate, oil production at a fixed bottom-hole pressure, and only gas injection in the sixth to seventh years) before the operation of the four schemes, and Figure 5b shows the CO_2 intrusion in the caprock in 1000 years after the model operation.

It can be seen from Figure 5a that in the first five years of production, that is, when the gas injection well and the production well are running simultaneously, the leakage of CO_2 in the caprock is relatively small and basically unchanged, and in the first two years of operation, the leakage of CO_2 first rises and then falls, which is mainly due to the gas injection at the top of the reservoir that leads to the pressure rise at the top of the reservoir, and the reservoir pressure is higher than the caprock pressure, resulting in some CO_2 entering the caprock. However, with the rapid decrease in reservoir pressure, the caprock pressure is higher than the reservoir pressure, resulting in CO_2 in the caprock entering the reservoir again. After a few years, the amount of CO_2 intrusion in the caprock returned to normal gradually, and in the fifth year of operation, the order of CO_2 intrusion in the caprock from large to small was Case 1, Case 3, Case 2, and Case 4, respectively.

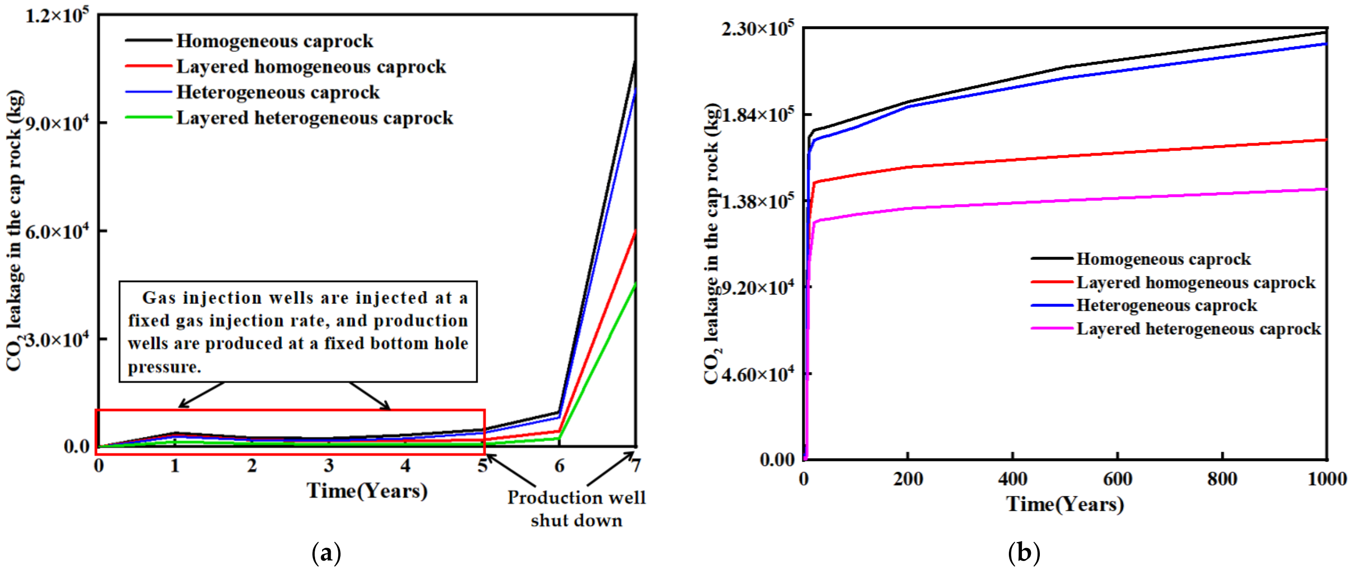

Figure 5. (**a**) Curves of CO_2 leakage in caprock for seven years before the four schemes; (**b**) curves of CO_2 leakage in caprock for 1000 years in four schemes.

In the sixth and seventh years of operation of the model, the production wells were closed for pure gas injection for two years, and the leakage of CO_2 into the caprock of the four schemes all increased greatly, which was mainly due to the rapid increase in CO_2 leakage into the caprock as the CO_2 was continuously injected into the reservoir, and the leakage of CO_2 into the caprock of the four schemes was Case 1: 108,339 kg; Case 2: 60,239 kg; Case 3: 99,656 kg; and Case 4: 45,523 kg (Table 5).

Table 5. Scheme running result.

Operation Scheme	CO_2 Intrusion in Caprock (kg)		
	5 Years	7 Years	1000 Years
Case1	4826	108,339	227,829
Case2	2009	60,240	170,641
Case3	3865	99,657	221,748
Case4	800	45,524	144,335

First of all, it can be clearly seen from the figure that the formation pressure is an important factor affecting the safety of the caprock. During the scheme design, special attention should be paid to the change in the formation pressure, so as to prevent the CO_2 leakage in the caprock from rising greatly due to the increase in the formation pressure; thus, leading to a series of potential safety accidents. Secondly, it can be found from the figure that the leakage of CO_2 in homogeneous caprock is the largest, mainly because the permeability and porosity in homogeneous caprock are both constant, and CO_2 migrates to the caprock uniformly, while in heterogeneous caprock, due to the heterogeneous distribution of permeability, most of CO_2 migrates to the middle and high permeability area of caprock, which accounts for a small proportion in caprock, so the leakage of CO_2 in homogeneous caprock is larger than that in heterogeneous caprock.

The leakage of CO_2 in the caprocks of Cases 2 and 4 is much lower than that of Cases 1 and 3. This is mainly because when the caprocks are layered, three layers are set in this paper, and the permeability of the middle layer will be relatively high, while the permeability of the top and bottom reservoirs will be relatively low, which increases the difficulty of CO_2 migration to the caprocks; thus, greatly reducing the leakage of CO_2. The leakage of CO_2 in layered heterogeneous caprock is the lowest, which is mainly due to the fact that banded high permeability zones are cut off by banded low permeability zones, which reduces the probability of high permeability zones being connected with each other, so that there are fewer dominant paths; thus, reducing the leakage of CO_2.

It can be seen from Figure 5b that after the production wells and gas injection wells are closed, the rate of CO_2 entering the caprock obviously decreases, but the rate of CO_2 intrusion into the caprock in Cases 1 and 3 is still higher than that in Cases 2 and 4. The layered characteristics of Case 4 not only slow down the migration rate of CO_2 in the caprock, but also reduce the overall leakage rate and total amount, which is mainly due to the layered characteristics that reduce the number of dominant paths and increase the migration distance of CO_2 along the main dominant paths. With the continuous invasion of CO_2 into the caprock, after the model runs for 1000 years, the amount of CO_2 leaked into the caprock by the four schemes is, respectively (Table 5), Case 1: 227,828 kg; Case 2: 170,641 kg; Case 3: 221,747 kg; and Case 4: 14,435 kg.

After the production well and gas injection well are shut down, until the model runs to 1000 years, the increment of CO_2 intrusion in the caprock of each scheme is 119,490, 110,401, 122,091, and 98,811 kg, respectively. From this data, it can be clearly seen that the CO_2 intrusion of layered heterogeneous caprock is the lowest, indicating that the distribution of layered caprock is more conducive to sealing CO_2 and making the caprock safer.

The average pressure of caprock in different schemes can be seen in Figure 6. Under the condition of constant gas injection and constant pressure production in the first five years of model operation, the average pressure of caprock decreased rapidly in the first year, then slowly in the next four years, and the cap pressure reached the lowest of 180 bar in the fifth year. In the next two years, the production wells were closed, the gas injection wells continued, and the average pressure of the caprock increased rapidly. In the seventh year, the average pressure of the caprock in the four schemes was: Case 1: 336 bar; Case 2: 316 bar; Case 3: 335 bar; and Case 4: 321 bar. Another problem can be reflected from the seventh year average caprock pressure of the model. The pressure appreciation of homogeneous caprock and heterogeneous caprock is higher than that of the other two schemes. I think it is mainly due to the seepage resistance. Because the permeability of the two caprocks close to the reservoir in the layered model set in this paper is low, if you want to enter the caprock, the seepage resistance is high, and the propagation speed of the pressure wave is lower than that of Cases 1 and 3, resulting in the lower average caprock pressure in the seventh year. However, the average caprock pressure of Cases 2 and 4 continued to rise in the next two years, and finally the caprock pressure of the four schemes remained basically the same in the tenth year of model operation, and the average caprock pressure remained unchanged until the model operated for 1000 years, so the average caprock pressure after the model operated for 20 years was not drawn in this paper.

Considering the gas injection process and the burial process, the layered heterogeneous caprock is more conducive to preventing CO_2 from invading the caprock, that is, it has fewer dominant paths; thus, slowing down the migration of CO_2 in the caprock. Moreover, the formation pressure is a key point to be considered in the CCUS scheme design. No matter what type of caprock, when the oil layer pressure increases, the CO_2 leaked into the caprock will also increase with it.

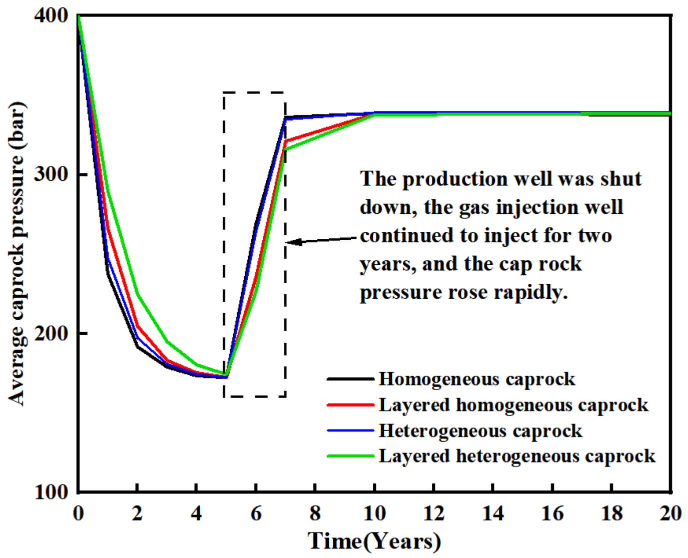

Figure 6. Caprock pressure variation curves of four schemes.

3.2. Migration Characteristic of CO_2 in Caprock

Figure 7 shows the pressure distribution of reservoir and caprock after the operation of Case 1 for five years. Figure 8 shows the changes in CO_2 mole fraction in caprock at different times, respectively, which are 5, 7, 500, and 1000 years of operation. The distribution of the CO_2 mole fraction is basically consistent with that of permeability.

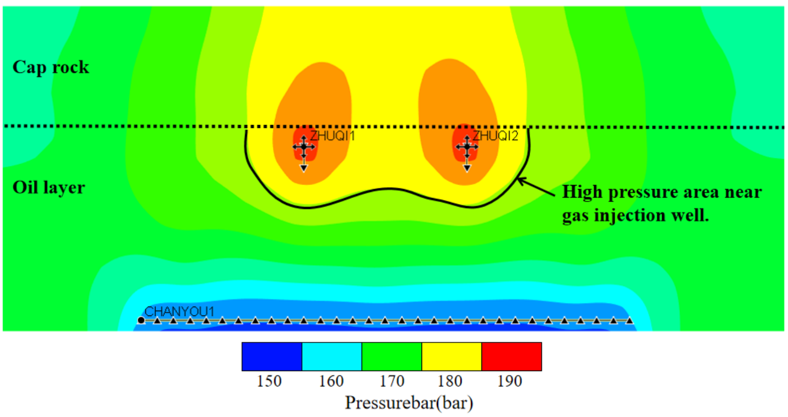

Figure 7. Case 1 pressure distribution in the fifth year of operation.

It can be seen from Figure 7 that there are obvious differences in CO_2 saturation distribution maps of different types of caprocks. Case 1 is similar to Case 3, because the permeability and saturation are homogeneous. In the fifth year of the model operation, all four schemes have a small amount of CO_2 distribution on the gas injection wells, and the migration distance of CO_2 in Cases 1 and 3 is larger than that in Cases 2 and 4. In the case of gas injection wells, the reservoir pressure is kept at a low level, and in this case, the average pressure of the caprock is higher than that of the oil layer (taking Case 1 as an example, the average pressure of the oil layer is 168 bar and the average pressure of the caprock is 173 bar). Due to gravity differentiation, a small amount of CO_2 still enters the caprock. Figure 7 (taking Case 1 as an example) shows the pressure distribution of the model in the fifth year of operation. It can be seen intuitively that there is a high-pressure area around the gas injection well, and the mole fraction of CO_2 in this area is high. When the reservoir pressure is higher than the caprock pressure, some CO_2 in this area enters the caprock.

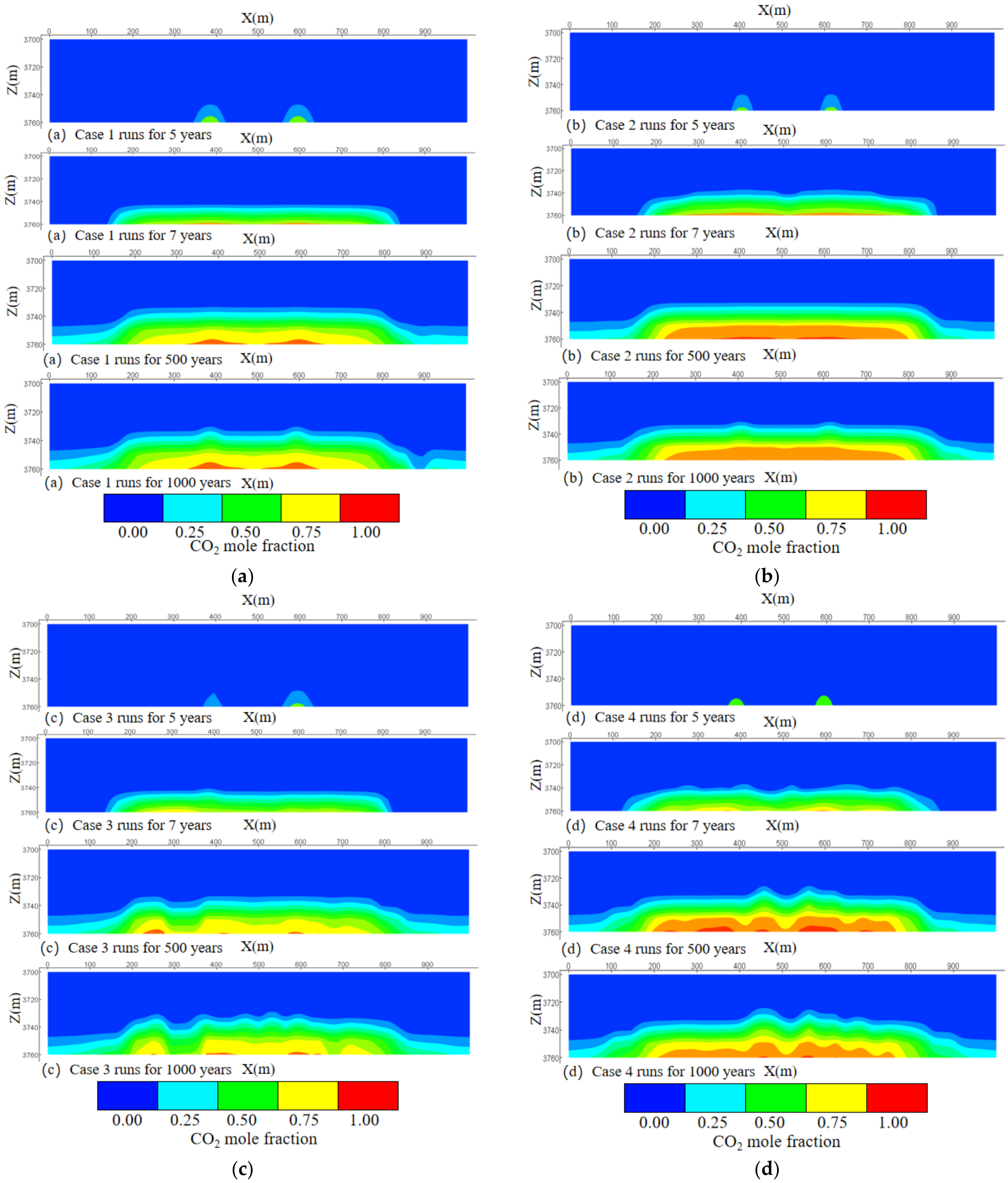

Figure 8. Profile of CO_2 mole fraction in caprock under four schemes at different times: (**a**) homogeneous caprock model; (**b**) layered homogeneous caprock model; (**c**) heterogeneous caprock model; (**d**) layered heterogeneous caprock model.

Figure 8a shows that CO_2 migrates upward uniformly in the caprock, and the migration distance of CO_2 in the caprock around the gas injection well is far away, and the migration distance of CO_2 gradually decreases with the increase in the distance. Figure 8b shows that CO_2 liquid migrates into the caprock in a homogeneous way, but the migration distance of CO_2 in the caprock is shorter than that of Case 1 because of the low permeability of the caprock adjacent to the reservoir. Figure 8c shows that in the heterogeneous caprock model, CO_2 migrates in the caprock in a finger shape and along the high permeability area. Figure 8d shows that in the layered heterogeneous caprock, CO_2 also shows finger migration characteristics in the caprock.

After the fifth year, the production wells were closed, and the gas injection wells were closed after two years of gas injection. It can be clearly seen from the CO_2 mole fraction distribution diagram of the four schemes in the seventh year that a large amount of CO_2 entered the caprock, which changed obviously from that in the fifth year. The CO_2 in Cases and 3 pushed uniformly into the caprock, while the CO_2 in Cases 2 and 4 pushed unevenly, with a long penetration distance in some areas. Compared with the heterogeneous caprock, the migration distance of CO_2 in homogeneous caprock was shorter, but the CO_2 intrusion was higher. In the two years of pure gas injection, both the reservoir pressure and the caprock pressure increased greatly.

In the seventh year (Figure 9), the average pressure of the caprock was lower than that of the reservoir (taking Case 1 as an example, the average pressure of the reservoir was 338 bar and the average pressure of the caprock was 268 bar). Under the double effects of this pressure difference and the gravity differentiation of CO_2, a large amount of CO_2 invaded the caprock.

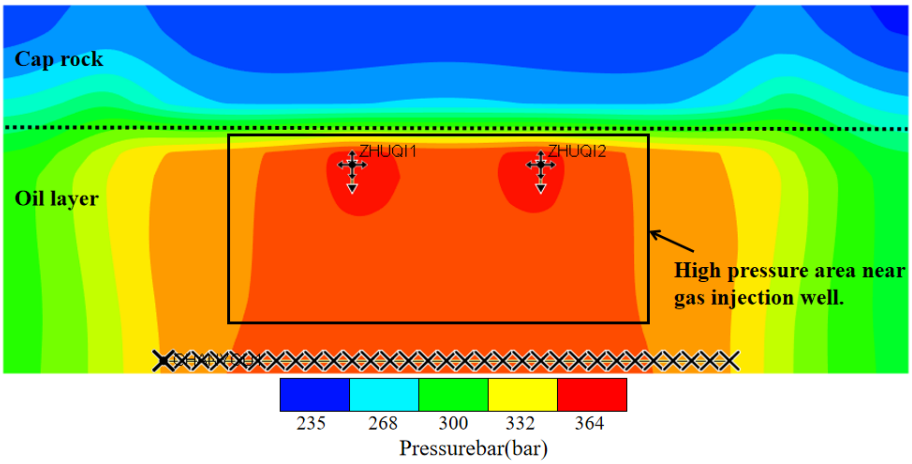

Figure 9. Case 1 pressure distribution in the seventh year of operation.

To sum up, during gas injection, due to the influence of gravity differentiation, CO_2 injected into the top of the oil layer migrates at the high part of the oil layer, and a large amount of CO_2 accumulates at the top of the oil layer. The mole fraction and pressure of CO_2 around the production well are obviously higher than those in other areas. This makes CO_2 overcome the seepage resistance and enter the caprock with low oil layer pressure and low CO_2 mole fraction. When the production well is closed, with the continuous injection of CO_2, the area in the caprock that has not been invaded by CO_2 also begins to invade, and the spread range is rapidly expanded. The area with the highest mole fraction of CO_2 is still the bottom area of the cap rock, and the higher the caprock level, the lower the mole fraction of CO_2. Moreover, the mole fraction of CO_2 in the caprock near the gas injection well is high, so it is necessary to focus on monitoring.

When the distribution of CO_2 in the invaded caprock is stable in the later stage of burial, the CO_2 mole fraction in the lower part of the caprock is still higher than that in the upper part of the caprock, which is mainly due to the great resistance of migration and seepage in the caprock, and most of the CO_2 invading the caprock can only enter the bottom of the caprock.

3.3. Comparison of Program Results under Different Injection-Production Parameters

After studying the CO_2 intrusion and migration characteristic in four different types of caprocks, this section further analyzes the oil recovery ratio, CO_2 storage, and CO_2 intrusion in caprocks under different injection-production parameters. Nine schemes are designed as shown in Table 6.

Table 6. Design table of the injection-production scheme.

Scheme	Bottom-Hole Pressure of the Production Well (MPa)	Gas Injection Rate of the Gas Injection Well (sm^3/d)
Case 5	13	5000
Case 6	13	10,000
Case 7	13	15,000
Case 8	15	5000
Case 9	15	10,000
Case 10	15	15,000
Case 11	17	5000
Case 12	17	10,000
Case 13	17	15,000

The well control conditions of production wells are consistent with the above, the caprock is layered heterogeneous caprock, and all parameters of the oil layer are consistent with the above. In this section, it is set as the operation of gas injection wells and production wells in the first 10 years. After 10 years, both gas injection wells and production wells will be closed, and the model will run for 1000 years in total.

From Figure 10, we can see the changes in CO_2 geological storage with time in nine schemes. Because gas injection and oil production were carried out in the first 10 years of this scheme design, the production wells and gas injection wells were closed 10 years later, and the model results showed that the CO_2 geological storage remained basically unchanged after 10 years of operation. Therefore, this paper only drew the CO_2 geological storage curve in the first 10 years and undertook a selective analysis. It can be seen from the figure that Case 13 has the largest CO_2 geological storage in the tenth year of model operation, while Case 5 has the smallest CO_2 geological storage in the tenth year of model operation.

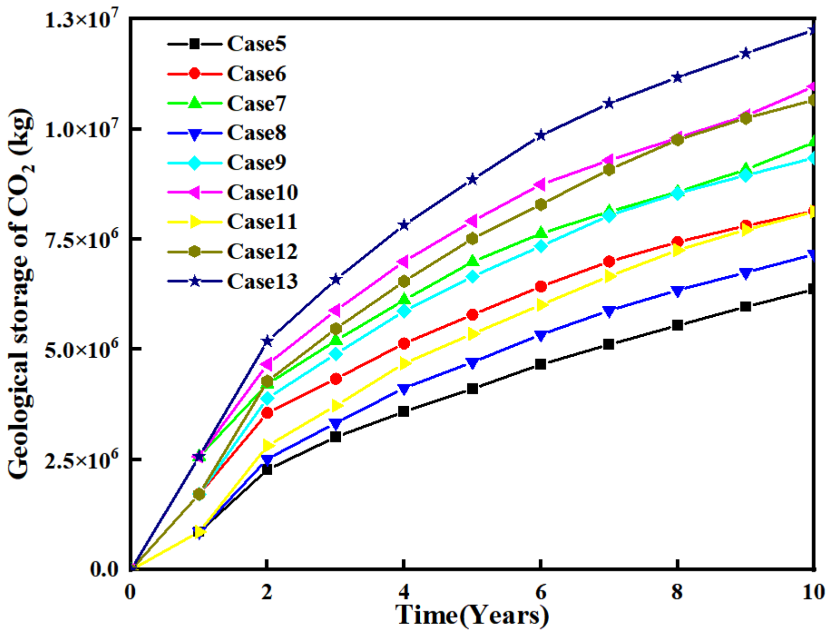

Figure 10. CO_2 geological storage curve of each scheme.

It can also be seen from the figure that with the increase in bottom-hole pressure of production wells and CO_2 injection rate, the geological burial of CO_2 gradually increases. If you want to increase the geological storage of CO_2 at a constant CO_2 injection rate, you can appropriately increase the bottom-hole pressure of production wells. Taking Cases 5, 8, and 11 as examples, the gas injection rate is 5000 sm^3/d, and the bottom-hole pressure of production wells gradually increases. In the 10th year of model operation, the geological storage of CO_2 is 6.4×10^6 kg, 7.1×10^6 kg, and 8.1×10^6 kg, respectively.

If you want to increase the geological storage of CO_2 under a fixed bottom pressure of production wells, the gas injection rate needs to be increased appropriately. Taking Cases 5, 6, and 7 as examples, the bottom pressure of production wells is 13 MPa, and the gas injection rates are 5000, 10,000, and 15,000 sm^3/d, respectively. In the 10th year of model operation, the geological storage of CO_2 is 6.4×10^6 kg, 8.1×10^6 kg, and 9.6×10^6 kg, respectively. It can be seen that increasing the gas injection rate will greatly increase the geological storage of CO_2, but the production gas–oil ratio will also greatly increase, resulting in unnecessary and ineffective circulation of CO_2 injection (in the 10th year, the production gas–oil ratio was 1891, 4295, and 6209 sm^3/sm^3, respectively). Therefore, the gas injection rate should not be too high in design. When the production gas–oil ratio reaches a certain value, the gas injection rate should be appropriately reduced, so as to achieve a better economic benefit.

From Figure 11, it can be seen that the oil recovery ratio of nine schemes changes with time. The oil recovery ratio curves of Cases 7, 10, and 13 are basically the same, and the oil recovery ratio in the tenth year is about 36%. The oil recovery curves of Cases 6, 9, and 12 are basically the same, and the oil recovery in the tenth year is about 34%; the oil recovery curves of Cases 5, 8, and 11 are basically the same, and the oil recovery in the tenth year is about 30%.

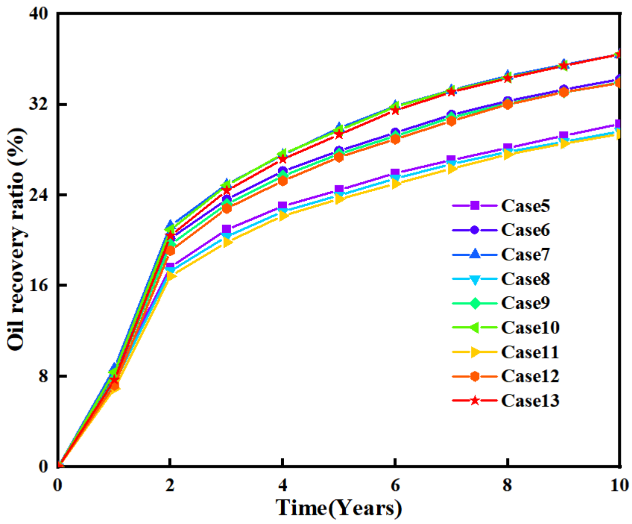

Figure 11. Oil recovery curves of each scheme.

In this model, the influence of bottom-hole pressure of production wells on oil recovery is lower than that of CO_2 injection rate, that is, the oil recovery is basically the same under different bottom-hole pressures of production wells at the same gas injection rate. Taking Cases 7, 10, and 13 as examples, at the same gas injection rate (15,000 sm^3/d), the oil recovery rates in the 10th year are 36.43%, 36.45%, and 36.45%, respectively, which are almost the same. I think it is mainly due to the fact that with the decrease in bottom-hole pressure of production wells under the same gas injection rate, the produced gas–oil ratio gradually increases, and a large amount of gas produced from production wells does not increase the oil recovery. It can be seen from Figure 12 that the 10-year produced gas–oil ratios of the above three schemes are 6209, 5754, and 5543 sm^3/sm^3, respectively. From the situation of production gas–oil ratio, it can also be proved that more injected gas is produced with the decrease in bottom-hole pressure of production wells, and from the aspect of crude oil viscosity, with the decrease in formation pressure, crude oil degasses, crude oil viscosity gradually increases, seepage resistance increases, resulting in no increase in oil recovery.

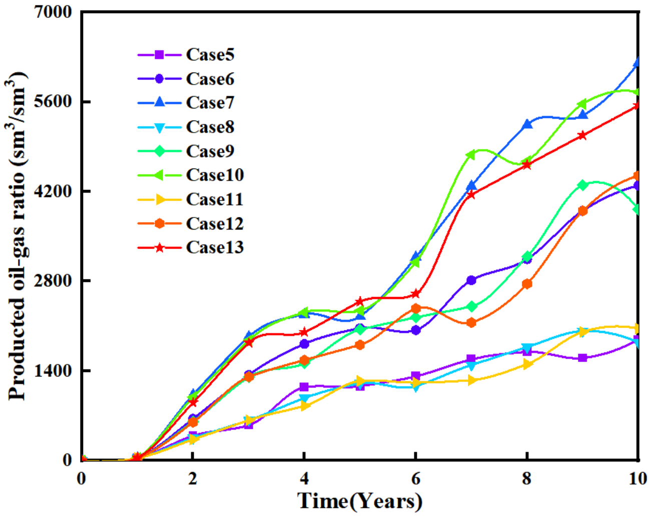

Figure 12. Production gas–oil ratio curves of each scheme.

For oil recovery, the effect of reducing the bottom-hole pressure of production wells is not ideal, so if you want to improve oil recovery, you should increase the gas injection rate properly under the condition of ensuring a certain formation pressure, so as to achieve the purpose of improving oil recovery.

It can be seen from Figure 13 that CO_2 invasion curves in the caprock of nine cases. When the model runs to 1000 years, the CO_2 intrusion in the caprock of Case 5 is the lowest and that in Case 13 is the highest, which are 6.3 × 10^4 and 7.7 × 10^4 kg, respectively. With the increase in gas injection rate or bottom pressure of production wells, the leakage of CO_2 in caprock gradually increases. In this model, under the condition of the largest amount of CO_2 intrusion in the caprock, CO_2 did not migrate to the top of the caprock after being buried for 1000 years. In the design of the scheme, the safety of the caprock should be considered first. Only when the time scale of burial is large enough (for example, 1000 years) and CO_2 does not migrate to the highest point in the caprock can the scheme be further designed.

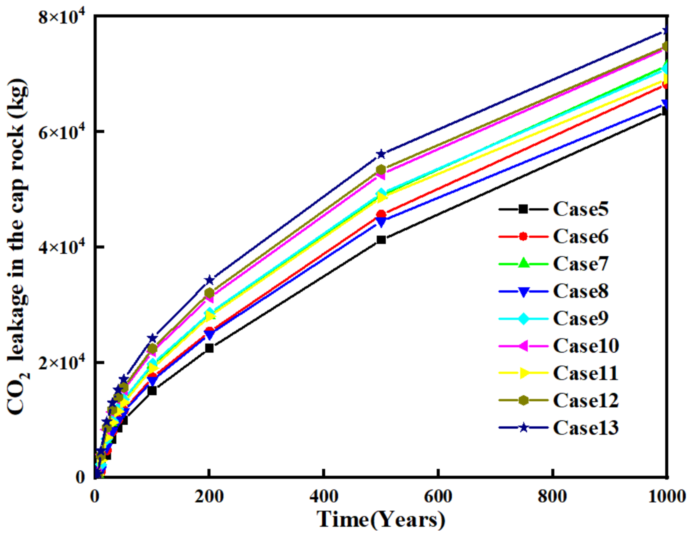

Figure 13. CO_2 invasion curve.

To sum up, the safety of caprock should be considered first when designing the scheme, and the influence of different schemes on oil recovery ratio or geological storage of CO_2 can be further discussed only when CO_2 is not leaked in the caprock for a long time. If you want to improve oil recovery, you should properly increase the rate of gas injection (CO_2) on the premise of ensuring a certain formation pressure, and the rate of gas injection should not be too high, which will lead to the invalid cycle of CO_2 injection due to the high ratio of production gas to oil. If we want to increase the geological storage of CO_2, we should appropriately increase the bottom-hole pressure or gas injection rate of production wells. Considering the oil recovery and CO_2 storage comprehensively, it is necessary to ensure a certain formation pressure, that is, a higher bottom pressure of production wells, and increase the gas injection rate appropriately, which can achieve ideal results.

4. Conclusions

Through numerical simulation, it was shown that among the four kinds of caprocks with different permeability and porosity distribution, the CO_2 migration law and intrusion amount are quite different, which is mainly due to the influence of heterogeneity. CO_2 preferentially migrates from the dominant channel in the caprock, but no matter what type of caprock, the mole fraction of CO_2 at the bottom of the caprock is the highest. With the increase in caprock layers, the mole fraction of CO_2 decreases gradually.

The simulation results of CO_2 storage after 1000 years show that the highest CO_2 intrusion in homogeneous caprock is 227,829 kg, and the lowest CO_2 intrusion in layered heterogeneous caprock is 144,335 kg. From the above results, it can be seen that the CO_2 intrusion in layered heterogeneous caprock is obviously reduced, which is 36.65% lower than that in homogeneous caprock. The layered heterogeneous caprock has fewer dominant paths and a lower CO_2 migration rate, which hinders CO_2 migration in caprock.

Compared with homogeneous caprock, heterogeneous caprock will increase the migration distance of CO_2 in caprock due to the heterogeneity of porosity and permeability distribution.

If the plan is constant pressure production of production wells, the formation pressure will be slightly higher than the bottom pressure of production wells after a period of production, and only less CO_2 intrudes into the caprock in this case. However, when the gas injection is continued after the production well is closed, the formation pressure rises rapidly and a large amount of CO_2 intrudes into the caprock, which may lead to a series of safety problems, that is, we should pay close attention to the change in oil layer pressure in the process of burial. In this paper, for example, after the production well has been shut down for two years (continuous gas injection from the gas injection well), the CO_2 intrusion of caprock in the four schemes will increase by 103,513, 58,231, 95,792, and 44,724 kg, respectively.

As for oil recovery and CO_2 geological storage, higher bottom-hole pressure and gas injection rate of production wells can bring better results, but we should also pay attention to the change in production gas–oil ratio and appropriately reduce the gas injection rate when it reaches a certain value.

There are still many problems in the simulation of CO_2 intrusion and migration in the caprock: first, as far as the current technology is concerned, there is no detection method that can accurately characterize the parameters of the caprock due to the low thickness of the caprock. Accurately describing the distribution of permeability and porosity in caprock has great influence on the simulation study of caprock safety. Second, the relative permeability curve in the caprock is difficult to obtain, and its parameters can only be taken within the approximate range, which reduces the accuracy. Third, the thickness of the caprock is different at different positions, which should be considered in the actual model.

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