Experimental Analysis and Numerical Simulation of the Stability of Geological Storage of CO$_2$: A Case Study of Transforming a Depleted Gas Reservoir into a Carbon Sink Carrier

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ABSTRACT: Geological storage of CO$_2$ is one of the most economical, feasible, and effective measures to slow down global warming. In this study, a combined long core model was designed to study the seepage characteristics of supercritical CO$_2$ displacement. Moreover, the stability of permanent storage of cushion gas layers formed by supercritical CO$_2$ injection has been systematically studied. The research results showed that in the supercritical temperature and pressure range of CO$_2$, the front edge of CO$_2$ displacement can form a relatively stable seepage zone. Supercritical CO$_2$ displacement can achieve a high gas-storage rate and stable CO$_2$ storage. At the same time, the recovery rate of remaining natural gas has been significantly improved. As the injection pressure increased, supercritical CO$_2$ inhibited the reverse diffusion of natural gas molecules. Therefore, the breakthrough of the supercritical CO$_2$ displacement front under a high pressure lagged behind. However, due to the increase in the density difference of gas molecules, the forward diffusion of supercritical CO$_2$ has been enhanced. Temperature will not significantly affect the displacement and storage effects of supercritical CO$_2$ in gas reservoirs. The increase in injection pressure and reasonable control of the injection rate can delay the breakthrough of supercritical CO$_2$ displacement. These measures are conducive to the stable storage of CO$_2$ and the improvement of remaining natural gas recovery. The implementation of CO$_2$ geological storage is suitable for the later stage of gas reservoir depletion development. The high-density gravitational heterogeneity of supercritical CO$_2$ enables the injected CO$_2$ to form a stable high-density cushion gas layer in the gas reservoir, which can achieve stable CO$_2$ storage for more than 100 years.

1. INTRODUCTION

CO$_2$ storages include ocean storage, chemical storage, and geological storage.$^{1-10}$ Geological storage of CO$_2$ is one of the most economical, feasible, and effective measures to slow down global warming.$^{1-6}$ The concept “carbon neutral” that promotes low-carbon development has been widely accepted by people.$^{6-7}$ Carbon neutral is an ecosystem concept proposed to achieve the goal of zero net greenhouse gas emissions. The ways to achieve carbon neutral include afforestation, energy saving and emission reduction, and the development of low-carbon energy.$^{8-14}$ These measures can be used to balance the amount of carbon released and absorbed back to the earth, so that the “zero emission” of CO$_2$ can be achieved.$^{15-19}$ Broadly speaking, all geological structures with good sealing properties can be used as CO$_2$ storage sites,$^{1-3,10-24}$ such as oil reservoirs, gas reservoirs, brine beds, coal beds, and unconventional resource reservoirs (methane hydrate reservoirs, etc.).
The previous studies have successfully conducted some pilot experiments and demonstration projects for improving oil recovery through CO2 injection. These studies provided valuable experience for the implementation of CO2 geological storage. For example, the United Nations Agency for International Development has implemented a project in the Weyburn Oilfield to improve the recovery of remaining oil through CO2 injection and it realized the geological storage of CO2.

China’s Qinshui Basin used the CO2 injection technology to improve coal bed methane recovery and achieve CO2 storage. For CO2 storage in saltwater aquifers, the famous Norwegian Sleipner offshore CO2 capture and storage project was employed. In addition, some other research studies have also explored the storage of CO2 in unconventional reservoirs such as natural gas hydrates. Some studies have explored the prospects of using CO2 to recover natural gas from methane hydrate reservoirs.

This study, a candidate gas reservoir that was compatible with the CO2 supercritical temperature and pressure range was selected, so the depleted gas reservoir selected was an independent gas reservoir. The independent gas reservoir has good sealing properties, and the formation temperature and pressure can enable CO2 to be stored in the form of supercritical fluid. A combined long core model was designed to study the seepage characteristics of supercritical CO2 displacement. Moreover, the stability of permanent storage of cushion gas layers formed by supercritical CO2 injection has been systematically studied. This study can provide a reference for the implementation of CO2 geological storage in late-development stage or depleted mid-shallow buried gas reservoirs.

2. MATERIALS AND METHODS

2.1. Natural Gas Displacement Experiments by Supercritical CO2 (SCCO2). The one-dimensional composite long core model was composed of 14 gas reservoir cores with a diameter of 2.5 cm and a length of 5.0–7.0 cm with a total length of 92.42 cm. In theory, the core of the core displacement experiment can be as long as possible. However, the long core displacement device developed by the American company Rusta used in this experiment was limited by the size of the oven and the length of the long core holder, and the total length of the combined long core cannot exceed 100 cm. All cores were taken from actual depleted gas reservoirs. The combination order of each short core was determined by the length-weighted average; and two adjacent cores were connected with a filter paper to eliminate "end effects." The long core model has a total pore volume of 65.674 cm3, an average porosity of 14.72%, and an average rock permeability of $1.05 \times 10^{-3}$ μm². The device for the long core gas displacement experiment is shown in Figure 1. A constant pressure and constant speed pump was used for gas injection and displacement, while pressure sensors and back...
pressure valves were used for production fluid control and metering.

The natural gas used in the displacement experiment was taken from the middle-shallow buried gas reservoir M in the Sichuan Basin, China. The original parameters of the target reservoir were as follows: a buried depth of 1000 m, a formation temperature of 35 °C, an initial formation pressure of 10 MPa, a water saturation of 30%, and an original natural gas reserve of 20.45 × 10⁸ m³. In addition, the mol % composition of CO₂, N₂, C₁, C₂, C₃, I C₄, N C₄, I C₅, N C₅, and FC₆ in natural gas was 4.528, 4.303, 90.014, 1.057, 0.083, 0.007, 0.008, 0.004, 0.002, and 0.004, respectively. The experimental CO₂ was industrially pure CO₂.

The procedures of long core gas displacement experiments are as follows:

(1) The temperature set in the experiment was consistent with the actual temperature of the formation, which was 35 °C. In addition, the formation pressure of the depleted gas reservoir was 10 MPa, and the overlying formation pressure was 25 MPa. Afterward, the confining pressure of the core was set to be consistent with the overlying formation pressure. In order to compare the relationship between supercritical CO₂ and natural gas storage in actual gas reservoirs in the early and late stages of gas injection, the experimental pressures were set to 10 and 20 MPa, respectively. When the injection pressure was 10 MPa, the outlet pressure was controlled at about 8 MPa; and when the injection pressure was 20 MPa, the outlet pressure was controlled at about 18 MPa.

(2) Supercritical CO₂ injection and continuous dry gas displacement were performed under the conditions of a temperature of 35 °C and pressures of 10 and 20 MPa, respectively. Furthermore, the extent and stability of the front-edge displacement of supercritical CO₂ injection were evaluated by testing the composition of CO₂ and its displacement efficiency changes at the outlet.

(3) First, 0.2 PV supercritical CO₂ was injected for dry gas displacement at a temperature of 35 °C and pressures of 10 and 20 MPa. Then, the production end valve was closed and the constant pressure “simmering well” was maintained for 8–12 h. Finally, dry gas displacement with supercritical CO₂ injection under a constant pressure was conducted, and the composition of CO₂ and its displacement efficiency changes were measured at the outlet end. The test results can be used to evaluate the degree of convection and diffusion of the displacement front in the “simmering” stage. In addition, the test can also provide basic data (data on changes in CO₂ composition, breakthrough time, and displacement efficiency at the outlet) for the numerical simulation of the stability of CO₂ geological storage.

In actual operation, the pipelines used to connect different devices were very short, thereby reducing the influence of dead volume and ineffective volume.

2.2. One-Dimensional Interwell Gas Displacement and Seepage Model Considering Convection and Diffusion. In order to further understand the seepage mechanism of supercritical CO₂ displacement, the Computer Modelling Group (CMG) component diffusion equation of the multiphase multicomponent system suitable for describing the multiphase flow and viscous fingering phenomenon of CO₂ displacement was introduced. This method was used to evaluate the percolation properties and storage stability of supercritical CO₂ displacement in interwell reservoirs. The constructed one-dimensional interwell reservoir core model had a total length of 500 m, and the grid was divided into J × K × X = 30 × 1 × 1. Since there is no drastic phase change in the supercritical CO₂ displacement process, therefore, the mesh size is not sensitive to the results. That is, the solution of equally dividing the grids is reasonable. The average porosity was 14.72%, the horizontal permeability was 11.05 × 10⁻³ μm², and the rock compressibility was 10⁻⁶ MPa⁻¹. The natural gas used in the model was collected from the M natural gas reservoir in the Sichuan Basin, and the injection medium was industrially pure CO₂. A constant pressure injection well and a constant pressure production well were arranged at the first grid block and the last grid block, respectively. They were used to simulate a supercritical CO₂ injection well and a natural gas production well in the gas displacement experiment.

2.3. Numerical Simulation of the Stability of Supercritical CO₂ Storage. In order to further verify the reliability
of implementing supercritical CO₂ stable storage in actual gas reservoirs, in this study, taking the M gas reservoir in the Sichuan Basin as an example, a three-dimensional well group model of the gas reservoir was constructed. In the model, two gas injection wells, three gas production wells, and a nonuniform 5-point well pattern were used, and all the wells were vertical wells. The selected gas reservoir was located in a complete anticline structure, which was covered by tight mudstone cap rocks. The average reservoir depth was 1000 m, the formation temperature was 35 °C, and the initial formation pressure was 10 MPa; the water saturation was 30% and the original geological reserve of natural gas was 20.45 × 10⁸ m³. The pressure parameters were automatically adjusted with the gas density according to the designed base surface pressure. In addition, the constructed heterogeneous geological model used corner grids, the total number of grids was 50 × 60 × 6 = 18,000, and the plane grid size was 50 m × 50 m.

3. RESULTS AND DISCUSSION

3.1. Seepage Stability of the Front Edge of Supercritical CO₂ Displacement. Supercritical CO₂ has high-density properties, which makes both the diffusion of supercritical CO₂ in natural gas and the diffusion of natural gas in supercritical CO₂ weakened. Furthermore, this enables supercritical CO₂ to have strong piston-type gas displacement and stable gas-storage capabilities.

3.1.1. Comparison of Seepage Characteristics of Displacement Front by Continuous Supercritical CO₂ Injection. Figure 2a shows the relationship between the concentration of CO₂ and the injection volume multiples at the outlet in the first experimental procedure. When the displacement pressure was 10 MPa, the gas injection volume at the CO₂ breakthrough point was close to 0.8 PV, and when the gas injection volume reached 1.1 PV, the concentration of CO₂ in the outlet gas reached 100%. Therefore, the transition zone formed by the displacement front edge was about 0.3 PV. Similarly, when the displacement pressure was 20 MPa, the breakthrough point of continuous natural gas displacement by supercritical CO₂ was slightly lagging behind 10 MPa, which was about 0.85 PV. When the supercritical CO₂ injection volume reached 1.2 PV, the outlet gas CO₂ concentration reached 100% and the displacement front transition zone was close to 0.3 PV.

According to the above results, a stable displacement front and a transition zone can be formed in the supercritical CO₂ displacement process. Although the shapes of the transition zone curves after the breakthrough of supercritical CO₂ under different displacement pressures were different, the widths of the transition zones did not change significantly. This showed that the CO₂ displacement process was similar to the displacement of oil by water, both of which had relatively stable displacement fronts. In addition, it can be seen from Figure 2b that when the supercritical CO₂ injection reached 1.2 PV, the natural gas production in the two groups of experiments reached 100%. This showed that supercritical CO₂ displacement can achieve high gas-storage rate and stable CO₂ storage. At the same time, the recovery rate of the remaining natural gas has been significantly improved.

3.1.2. Convection and Diffusion Degree of the Displacement Front. Figure 3 shows the relationship between the CO₂ concentration in the produced gas and the injection volume multiples of CO₂ at different injection pressures. When the supercritical CO₂ injection volume reached 1.2 PV, the natural gas production in the two groups of experiments reached 100%. This showed that supercritical CO₂ displacement can achieve high gas-storage rate and stable CO₂ storage. At the same time, the recovery rate of the remaining natural gas has been significantly improved.

3.2. Analysis of Controlling Factors for Stable Storage of Supercritical CO₂. When CO₂ geological storage was implemented in an abandoned or late-development stage gas reservoir, the main factors affecting the stability of CO₂ storage could be the temperature and pressure of the gas reservoir and the migration speed of supercritical CO₂ in the reservoir. Changes in temperature and pressure may affect the supercritical properties of CO₂ and in turn affect the percolation behavior of the process of CO₂ displacement. However, the rate of CO₂ injection may affect the dynamic...
dispersion process between the supercritical CO₂ zone and the natural gas zone.

The basic conditions for calculation of the 500 m one-dimensional displacement model are listed in Table 1.

In Table 1, the first case was conducted at the current formation pressure of 10 MPa. The influence of temperature changes on underground gas migration was studied by changing the temperature to 20, 35, and 60 °C. Changing the temperature is not to heat the formation but to consider that the conditions for underground supercritical CO₂ storage are within the temperature and pressure range. This study is an expanded study for the selection of other possible potential storage sites.

The second case was conducted by changing the pressure at the formation temperature. The purpose is to study the impact of formation pressure recovery on gas migration as CO₂ continues to be injected.

In the third case, the influence of the injection rate on gas migration in the formation was studied by continuously changing the CO₂ injection rate under the formation pressure and temperature. The simulation data in this study were obtained based on the gas displacement experiments. The displacement experiments adopted the method of constant pressure injection, and the injection rates of supercritical CO₂ were uncertain values. After CMG software was used to correct the 92 cm one-dimensional displacement model with the same length of the core according to the core displacement experimental data, the constant pressure average injection rates were calculated: 4.8 mL/h without holding pressure and 3.8 mL/h with holding pressure. There is a certain simulation calculation error here. Then, all the data were enlarged to 10⁸ times, and the gas displacement rates of the 500 m one-dimensional model were obtained, which were 1.16 and 0.92 m³/d, respectively.

3.2.1. Gas Reservoir Temperature. Figures 4 and 5 show the stability characteristics of the supercritical CO₂ displacement front at three temperature points of 20, 35, and 60 °C under a 10 MPa injection pressure. It could be found that the breakthrough point of liquid CO₂ at 20 °C was 0.9 PV, while the breakthrough point of supercritical CO₂ displacement at 35 and 60 °C was 0.8 PV (Figure 4). The range of the transition zone tested at different temperatures was similar, which was 0.3 PV. However, the changing trends of the CO₂ content in the produced gas in different tests had a certain difference (Figures 4 and 5). On the whole, temperature will not significantly affect the displacement and storage effects of supercritical CO₂ in gas reservoirs.

3.2.2. Gas Reservoir Pressure. Figures 6 and 7 show the stability characteristics of the supercritical CO₂ displacement front at four injection pressure points of 3, 5, 10, and 20 MPa at a temperature of 35 °C. From the CO₂ concentration curves in the produced gas, it can be found that the injection pressure had a certain impact on the stable seepage effect of CO₂ displacement (Figure 6). In the low pressure range of 3 and 5 MPa in the nonsupercritical region, the breakthrough point of CO₂ displacement with gaseous characteristics was about 0.65 PV, and the transition zone from gaseous CO₂ to natural gas was long. Especially when the injection pressure was 3 MPa and only when the CO₂ injection reached 1.2 PV, the CO₂ concentration in the produced gas reached 99%. This showed that the gaseous CO₂ at the displacement front diffused violently in natural gas, and its seepage stability was weakened. However, in the injection pressure range of 5–20 MPa, that is, in the near-critical region of CO₂, especially in the supercritical

Table 1. Basic Conditions for Calculation of the 500 m One-Dimensional Displacement Model

| calculation model | design conditions | goal |
|-------------------|-------------------|------|
| 500 m one-dimensional displacement model simulation corrected by displacement experimental data (the calculation results were magnified 108 times). | 20, 35, and 60 °C under 10 MPa. | influence of temperature on the gas migration process under the current formation pressure. |
| 3, 5, 10, and 20 MPa at a temperature of 35 °C. | 1.16 and 0.92 m³/d displacement rates at a temperature of 35 °C. | influence of pressure on the gas migration process under the formation temperature. |
| Influence of different injection rates on the displacement process under the formation temperature. | | |
region, the emergence of the CO₂ breakthrough point will lag significantly, and the transition zone will also become shorter. This indicated that the diffusion degree of supercritical CO₂ in natural gas was weakened, while its seepage stability was enhanced. The gas-storage rates of supercritical CO₂ in different injection pressure tests were high and there were little differences. This showed that even if long-distance displacement was implemented in the gas reservoir, CO₂ can still effectively displace natural gas.

3.2.3. Gas Injection Speed. Figures 8 and 9 show the supercritical CO₂ displacement curves of a 500 m-long one-dimensional homogeneous model at 35 °C and different displacement speeds.

The comparison results showed that as the injection rate increased, the CO₂ breakthrough point appeared in advance, and the transition zone became wider (Figure 8). In addition, as the injection rate increases, the displacement efficiency and the gas-storage rate of supercritical CO₂ will also decrease (Figure 9). However, for the one-dimensional homogeneous model, the effect of speed changes on the percolation stability of supercritical CO₂ displacement was not particularly obvious.

The numerical simulation model has been corrected based on experimental data. According to the simulation results, it can be known that in the supercritical temperature and pressure range, the displacement front of supercritical CO₂ can form relatively stable seepage, which can meet the requirements of stable storage of supercritical CO₂. Moreover, the increase in the injection pressure and reasonable control of the injection rate can delay the breakthrough of supercritical CO₂ displacement. These measures can strengthen the stability of the supercritical CO₂–natural gas transition zone and are conducive to the stable storage of CO₂ and the improvement of remaining natural gas recovery.

3.3. Stability Analysis of Supercritical CO₂ Storage Based on Injection–Production Well Group Simulation. The gas reservoir used in this study had a complete anticline structure, and the upper and lower parts of the gas reservoir were sealed by tight layers. It is a closed antirhythm gas...
reservoir, and this study ignores the possibility of gas leakage in the periphery of the gas reservoir.

3.3.1. Injection−Production Design Model for Supercritical CO2 Storage in Gas Reservoirs. In this study, CMG software was used for the modeling of the target layer and the numerical simulation of supercritical carbon dioxide displacement. The porosity and permeability distributions of gas reservoirs are shown in Figure 10. The central part of the gas reservoir structure has good porosity and permeability, while the porosity and permeability at the edges become poor. The target layer has an antirhythmic geological structure with fine grains in the upper part and coarse grains in the lower part. Figure 11 shows the porosity and permeability profiles of the three-dimensional geological model with antirhythmic structures of the target layer. Supercritical CO2 displacement is similar to piston displacement, and its relative permeability curve satisfies a diagonal relationship.

In the gas reservoir model, two CO2 injection wells were designed at the lower part on both sides of the long-axis direction, and three gas production wells were designed along the short-axis direction at the upper part of the gas reservoir structure (Figure 12). The lower quarter of the production horizon in the long-axis direction was opened for CO2 injection, while the upper quarter of the production horizon in the short-axis direction was opened for natural gas production. The adoption of this method of well deployment can reduce the mixing degree of CO2 and natural gas, thereby better improving the displacement effect of supercritical CO2.

In this study, the M gas reservoir used a depletion development method from the original pressure of 10 to 3 MPa, and then CO2 was injected to increase the recovery rate of the remaining natural gas and achieve CO2 storage. In the depletion development stage, all five wells produced gas and all layers were opened. The initial single well gas production rate

Figure 10. Planar distribution of porosity and permeability of the target layer of the M gas reservoir. (a) Porosity distribution and (b) permeability distribution.

Figure 11. Porosity and permeability profiles in the target layer of the M gas reservoir. The target layer has an antirhythmic geological structure with fine grains in the upper part and coarse grains in the lower part. (a) Porosity profile and (b) permeability profile.

Figure 12. Geological model of the M gas reservoir and its 5-point well pattern. IN1 and IN2 are the injection wells, and PR1, PR2, and PR3 are the production wells.
was 15 × 10⁴ m³/d. When the formation pressure was reduced to 5 MPa using the depletion development method, the two production wells on the side of the long axis were subjected to critical CO₂ injection, which opened the lower part of the production horizon. The results showed that the initial daily CO₂ injection volume of the injection well was 15 × 10⁴ m³, and the initial daily gas production volume of the production well was 10 × 10⁴ m³. When CO₂ breakthroughs (the CO₂ concentration of the production well reached 10%), the production wells were closed. Then, the daily CO₂ injection volume of the two injection wells was increased to 50 × 10⁴ m³. When the formation pressure returned to the original formation pressure, the supercritical CO₂ injection from the injection wells was stopped. Thus, permanent storage of supercritical CO₂ can be realized. The calculations in this simulation were continued for 100 years after the wells were closed. The continuous injection time of supercritical CO₂ was 13.5 years, and the total duration of storage stability prediction was 100 years.

### 3.3.2. Enhanced Oil Recovery, Breakthrough Time, and Storage Effect of Supercritical CO₂ Injection

This study showed that the time from the start of supercritical CO₂ injection to the breakthrough of CO₂ in the production well was 3 years and 8 months. This indicated that after supercritical CO₂ was injected for the formation, it will not rapidly mix with the formation natural gas to form a supercritical CO₂ channeling effect. The prediction results of the natural gas recovery factor during the supercritical CO₂ displacement process are shown in Table 2. The results showed that when supercritical CO₂ storage was implemented in depleted gas reservoirs, the remaining natural gas recovery rate could reach 12.65% and the CO₂ storage capacity could reach 9.02 million tons. For depleted gas reservoirs, most of the natural gas in the formation was recovered, and the potential effective remaining pore space for supercritical CO₂ storage was increased. Therefore, the effect of CO₂ storage in depleted gas reservoirs will be enhanced, and the total amount of CO₂ storage will be large. The lower the abandonment pressure of the gas reservoir, the greater the total amount of supercritical CO₂ stored.

### 3.3.3. Stability Analysis after 100 years of Supercritical CO₂ Storage

In order to better understand the stability of supercritical CO₂ storage in the long-term storage process, the

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**Table 2. Natural Gas Recovery of Supercritical CO₂ Displacement in Different Stages**

| Injection−production scheme | Recovery factor in depletion stage | Recovery factor of CO₂ displacement | Total recovery of depletion + CO₂ displacement | Final storage of supercritical CO₂ (t) |
|-----------------------------|-----------------------------------|------------------------------------|-----------------------------------------------|---------------------------------------|
| CO₂ injection implementation at a depletion pressure of 3 MPa | 72.83%                            | 12.65%                             | 85.48%                                        | 9,021,276                             |

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**Figure 13.** CO₂ mole fraction and formation gas density distribution in the target layer at the end of supercritical CO₂ injection. (a) CO₂ mole fraction and (b) formation gas density.

**Figure 14.** CO₂ mole fraction and formation gas density distribution in the target layer when supercritical CO₂ was stored in a gas reservoir for 100 years. (a) CO₂ mole fraction and (b) formation gas density.
influences of the gravity differentiation and density difference of the gas reservoir on the migration of supercritical CO₂ at the end of supercritical CO₂ injection and at the end of 100 years were analyzed. Figures 13–15 show the simulation results of the CO₂ molar fraction, formation gas density, and fluid flow vector after the supercritical CO₂ injection was completed and after 100 years of CO₂ storage, respectively.

It can be seen from Figure 13 that the gravity differentiation and convection diffusion between supercritical CO₂ and natural gas occurred under the influence of density difference. Furthermore, supercritical CO₂ migrated to the lower and bottom of the gas reservoir, spontaneously and gradually, to form a “cushion gas layer”. At the same time, the remaining natural gas migrated to the top of the upper central zone of the gas reservoir, forming a relatively stable “gas cap.” It can be seen from Figure 13b that the supercritical CO₂ cushion layer and the natural gas top layer were formed due to gravity differentiation.

According to the calculation results in Figures 14 and 15, when CO₂ has been stored for 100 years, the supercritical CO₂ and remaining natural gas in the formation will not reach a completely miscible mixed state. The cushion gas layer formed by supercritical CO₂ at the edge and bottom of the gas reservoir can still be very stable, and the fluids in the middle and lower parts of the cushion gas layer do not flow to the top of the gas reservoir. In addition, the transition zone between the supercritical CO₂ and the remaining natural gas in the upper and middle parts of the gas reservoir also remain stable. This showed that the gas flow caused by gravity differentiation and convection diffusion between supercritical CO₂ and natural gas will become slower and slower as the storage time increased. Therefore, the migration of supercritical CO₂ to the top cover of the structure was finally transformed into molecular diffusion, which made the diffusion much more slower. Then, the possibility that the supercritical CO₂ cushion gas layer “impacts” upward into the gas reservoir became less. Ultimately, the time for the stable storage of supercritical CO₂ will be extended to a great extent.

4. CONCLUSIONS

(1) In this study, a combined long core model was designed to study the seepage characteristics of supercritical CO₂ displacement. The results showed that in the supercritical temperature and pressure range of CO₂, the front edge of CO₂ displacement can form a relatively stable seepage zone.

(2) Supercritical CO₂ displacement can achieve a high gas-storage rate and stable CO₂ storage. At the same time, the recovery rate of the remaining natural gas has been significantly improved. As the injection pressure increased, supercritical CO₂ inhibited the reverse diffusion of natural gas molecules. Therefore, the breakthrough of the supercritical CO₂ displacement front under a high pressure lagged behind. However, due to the increased in the density difference of gas molecules, the forward diffusion of supercritical CO₂ has been enhanced.

(3) Temperature will not significantly affect the displacement and storage effects of supercritical CO₂ in gas reservoirs. The increase in the injection pressure and reasonable control of the injection rate can delay the breakthrough of supercritical CO₂ displacement. These measures are conducive to the stable storage of CO₂ and the improvement of the remaining natural gas recovery.

(4) The implementation of the CO₂ geological storage is suitable for the later stage of gas reservoir depletion development. The high-density gravitational heterogeneity of supercritical CO₂ enables the injected CO₂ to form a stable high-density cushion gas layer in the gas reservoir, which can achieve stable CO₂ storage for more than 100 years.
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