



Article Effect of Confining Pressure on CO₂-Brine Relative Permeability Characteristics of Sandstone in Ordos Basin

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Abstract: CO₂-brine relative permeability significantly impacts CO₂ injection and is a key parameter for carbon dioxide storage simulation in saline aquifers. In the study of relative permeability, factors such as temperature, pressure, and reservoir rock physical properties play a crucial role. To better understand the impact of confining pressure on the CO₂-brine relative permeability characteristics of sandstone in the Ordos Basin, five sets of CO₂-brine relative permeability data were obtained through unsteady-state displacement tests conducted at various confining pressures ranging from 12 to 20 MPa. The research findings indicate that with an increase in confining pressure there is a slight decrease in irreducible brine saturation. Furthermore, the CO₂ relative permeability in the irreducible brine state decreased by 57% as the pressure increased from 12 MPa to 20 MPa. The study demonstrates notable differences in the CO₂-brine relative permeability curves under varying confining pressure conditions. As the confining pressure increases, the CO₂ relative permeability is not as pronounced as that of CO₂. These experimental results offer essential support for subsequent numerical calculations and practical applications in engineering. Experimental research holds significant importance in the assessment of storage potential and the prediction of the evolutionary patterns of CO₂ migration.

Keywords: CO₂-brine relative permeability; confining pressure; unsteady-state experiment; Carbon Capture and Storage

1. Introduction

Climate change has been identified as one of the most significant global environmental issues due to the continuous increase in carbon dioxide (CO_2) and other greenhouse gas emissions in recent years. Consequently, reducing atmospheric CO_2 content has become a critical area of research within the international scientific community [1]. Carbon Capture and Storage (CCS) technology has emerged as a highly effective method for reducing significant CO_2 emissions into the atmosphere [2]. One of the potential sites for large-scale CO_2 storage is deep saline aquifers. This is because the rocks in saline aquifers are often permeable sandstones, and the depth of the reservoir allows CO_2 to be maintained in a dense supercritical state. In these deep saline aquifers, supercritical CO_2 can be permanently stored through structural, solubility, mineral, and residual trapping mechanisms [3].

The flow and distribution of CO_2 in saline aquifers are highly complex processes influenced by reservoir characteristics, interactions between CO_2 and brine, as well as flow and transport properties [4]. Relative permeability (RP) is an important basic parameter for predicting CO_2 reserves in deep saline aquifers; it significantly affects the CO_2 injection capacity and transportation capacity [5]. Currently, the primary method of obtaining RP is laboratory testing, usually using steady-state and unsteady-state methods [6].



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Copyright: © 2023 by the authors. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license (https:// creativecommons.org/licenses/by/ 4.0/). Several studies have reported data on the CO₂-brine RP in common sedimentary formations, including Berea sandstone, carbonate rocks, and other rock types [7–21]. Most of these studies discussed the impacts of temperature, injection pressure, and porosity on RP. Apart from the aforementioned influencing factors, confining pressure (CP) is also an important parameter. Given that the stress state can influence the rock physical properties of the reservoir [22], studying the impact of alterations in CP on RP is essential. In previous studies, research efforts have explored the influence of CP on absolute permeability, and these studies typically arrive at consistent conclusions [23–26]. However, there is limited research focusing on RP, and the existing studies have presented conflicting conclusions regarding the impact of CP on RP.

Fatt [27] was the first to investigate the correlation between RP and CP in sandstone. There are no effects on non-wetting RP at all considering CP. Zhang et al. [28] employed the unsteady-state method and identified significant variations in gas-water two-phase RP curves under various CP conditions. With an increase in CP, the water RP experiences a significant decrease. Additionally, when the water saturation is below 80%, the gas RP exhibits a discernible increasing trend. Liu et al. [29], through experiments, demonstrated that with an increase in CP the gas RP increases while the water RP decreases. Lai and Miskimins [30] observed the influence of CP on the gas–water RP curve through experiments. With an increase in CP, the gas RP decreases significantly, whereas the water RP shows minimal change. Thomas and Ward [31] believed that the RP of both the gas and water phases would remain unaffected by changes in CP. It is evident that researchers hold varying opinions on the impact of CP on RP, and there are very limited studies on the effect of CP on CO_2 -brine RP. There are numerous factors influencing the RP of two-phase fluids, encompassing temperature, pressure, rock type, wettability, and interfacial tension [32–34]. Changes in CP can modify pore properties, wettability, and interfacial tension within rocks, thereby inducing notable correlations in the two-phase fluid flow characteristics and varying CPs [35,36]. Adenutsi et al. [37] and others conducted comparisons of NMR T2 spectra before and after applying CP, revealing a decrease in pore volume with increasing CP. This corresponding reduction in the local pore throat radius heightens the capillary resistance of the oil phase through the pores, resulting in a diminished RP of the oil phase as CP rises. Lei et al. [38] and Zhang et al. [28] applied fractal theory to investigate the pressure correlation with the RP. The pressure correlation was expounded by analyzing the relationship between fractal dimensions, pore radius ratios, wettability, and RP. Existing studies generally concentrate on a singular factor, and observing changes in pore properties, wettability, and interfacial tension in rocks is challenging. This results in a lack of clarity regarding the potential causes of changes in RP due to variations in CP. Therefore, in the absence of CO₂-brine RP CP correlation data, it is imperative to conduct CO₂-brine RP tests on cores under various CPs. This is crucial for enhancing our understanding of CO₂ storage in saline aquifers, particularly in the geographical locations where the cores are obtained.

This article explores the influence of CP on the CO_2 -brine RP characteristics of sandstone in the Ordos Basin. Unsteady-state drainage experiments were performed in five sets under varying CP conditions (12, 14, 16, 18, 20 MPa). The 'J.B.N' method was employed to calculate CO_2 -brine RP. The study analyzed the impacts of CP on irreducible brine saturation, CO_2 RP in the irreducible brine state, and CO_2 -brine RP curves. The results of the experiments provide necessary data support for numerical calculations of CO_2 storage in saline aquifers.

2. Materials and Methods

2.1. Experimental Sample and Conditions

The experiment was conducted using a natural sandstone core extracted from the Yi-Shan slope in the eastern Ordos Basin. Five cores are shown in Figure 1. These were all drilled from the same original full-diameter core. Each core is approximately 2.5 cm in diameter and 6.0 cm in length. The five cores were tested for their porosity and single-phase

gas permeability. Detailed information on the size, porosity, and permeability of each core sample is given in Table 1.



Figure 1. Five cores for CO₂-brine relative permeability experiments, numbered as 1-1, 1-2, 1-3, 1-4, and 1-5, respectively.

Core Number	Length/cm	Diameter/cm	Porosity/%	Dry Weight/g	Permeability/mD
1-1	5.965	2.502	8.9	69.89	97
1-2	5.977	2.506	8.4	70.95	101
1-3	5.965	2.502	8.4	70.28	103
1-4	5.965	2.502	8.1	70.33	97
1-5	5.977	2.506	8.4	70.95	101

Table 1. Detailed information on experimental cores.

An incubator was used in the experiment to maintain a constant temperature of 70 °C, representing the formation temperature. The core holder's inlet pressure was kept at 10 MPa by a constant speed and constant pressure pump. Meanwhile, the back pressure pump maintained the outlet pressure at 8 MPa. The pressure difference between the core's inlet and outlet was always maintained at 2 MPa. Therefore, the physical properties of brine and CO₂ were determined based on the temperature and average core pressure (9 MPa). The salinity of brine is 23.5 g/L, density is 0.984 g·cm⁻³, and viscosity is 0.415 mpa·s at 70 °C [39,40]. For temperatures (T) and pressures (P) exceeding the critical point (Tc = 31.1 °C and Pc = 7.38 MPa), CO₂ exists in the supercritical phase, exhibiting gaslike behavior while possessing the density of a liquid. Therefore, CO₂ is in a supercritical state at a temperature of 70 °C and a pressure of 9 MPa, with a density of 0.208 g·cm⁻³ and a viscosity of 0.021 mpa·s. Five sets of CP conditions were established, namely 12 MPa, 14 MPa, 16 MPa, 18 MPa, and 20 MPa.

2.2. Experimental Equipment and Process

2.2.1. Experimental Setup

Figure 2 illustrates the experimental setup for unsteady CO_2 -brine RP testing. The system comprises a CO_2 storage tank, constant speed and constant pressure pump, pressure

gauge, incubator, core holder, CP pump, back pressure valve, back pressure pump, gasliquid separator, and gas-water metering device. The main equipment for the experiment is divided into a core holder, various pressurization devices, and experimental measurement instruments. The core holder fixes the core through the clamping heads at both ends and the rubber sleeve in the middle. The inlet is connected to a CO_2 storage tank and a constant speed and constant pressure pump to provide CO_2 injection pressure, set at 10 MPa for this experiment. The outlet is connected to a back pressure valve and a back pressure pump to maintain the outlet pressure. In the middle of the core holder, there is a connection for a CP pump, which supplies CP by injecting water into the rubber sleeve's outer periphery, simulating the reservoir pressure of the saline aquifer. It can provide five sets of CP conditions from 12 MPa to 20 MPa. After the back pressure valve, the experimental measurement instruments are connected, including a gas-liquid separator, a graduated cylinder, and a gas flow meter, used to measure fluid flow rate.



Figure 2. CO₂-brine relative permeability test flow chart.

2.2.2. Experimental Process

In this study, the CO_2 -brine RP was measured using the unsteady-state method. Compared with the steady-state method, which is more accurate but also more timeconsuming and expensive, the unsteady-state method allows for a significantly shorter experimental time frame. To generate RP curves, different ratios of fluid injection were used to obtain multiple data points [41]. The steady-state method involves the simultaneous injection of CO_2 and brine into the core, which does not reflect the actual injection scenario for CO_2 saline aquifer storage [42]. In contrast, the unsteady-state method displaces one fluid with another, allowing for continuous changes in fluid saturation. This approach better simulates the actual flow conditions of reservoir storage in saline aquifers.

Two types of RP affect CO_2 migration, namely drainage and imbibition RP [43]. This article focuses on the RP of drainage, which corresponds to the injection stage of the geological storage project. The design method of this experiment only obtains the RP of CO_2 -displaced brine at irreducible water saturation, that is, the drainage RP.

- (a) Dry the core at 60 °C for 24 h and weigh it. Pump to vacuum, then saturate the core with brine. Weigh the rock samples saturated with brine to calculate the effective pore volume of the core.
- (b) Before experimenting, CO₂ needs to be pressurized. Open the outlet valve of the CO₂ cylinder to allow CO₂ to enter the piston container. Close the inlet valve of the container and utilize a booster pump to pressurize the CO₂ to the required pressure for the displacement experiment.
- (c) Load the rock sample saturated with brine into the core holder. Utilize the CP and back pressure device to apply the necessary back pressure and CP to both ends and to the middle section of the core holder. After completing the pressurization, activate the heating device and maintain the instrument at the experiment's required temperature conditions for 2 h before commencing the experiment.
- (d) Activate the booster pump and apply a specific injection pressure to enable the formation brine to pass through the rock sample. Once the pressure difference and

flow rate at both ends of the inlet and outlet of the rock sample stabilize, record the flow value.

(e) Utilize the CO_2 displacement brine method and record the time, cumulative brine production, CO_2 production, and pressure conditions at both ends of the rock sample until no brine is produced (visual observation). Reach the irreducible brine state, establish the irreducible brine saturation of the core sample, and measure the effective permeability of the CO_2 in this irreducible brine state.

2.3. Experimental Data Processing Methods

The experiment uses the unsteady-state method to conduct a constant pressure drop CO_2 displacement brine test on the core. Record the flow rate of each fluid at the core outlet. The CO_2 -brine RP is calculated using the 'J.B.N' method [44,45]. The method is as follows.

Due to compressibility, the average volume flow rate needs to be used to correct the total fluid production according to Equation (1):

$$V_t = \Delta V_w + V_{t-1} + \frac{2P_a}{\Delta P + 2P_a} \Delta V_g$$
(1)

where V_t denotes the cumulative flow rate of each fluid at time t, mL; V_{t-1} is the cumulative flow rate of each fluid at time t – 1, mL; ΔV_w is the increased flow rate of brine from t – 1 to time t, mL; P_a is the value of atmospheric pressure; ΔP is the value of the displacement pressure difference; and ΔV_g represents the measured increase in CO₂ flow rate over a specific time interval under atmospheric pressure, expressed in mL.

After correcting the cumulative CO_2 and brine flow rate according to Equation (1), use Equations (2)–(6) to calculate the unsteady gas-water RP:

$$f_w(S_g) = \frac{d\overline{V_w}(t)}{d\overline{V}(t)}$$
(2)

$$K_{rw} = f_w(S_g) \frac{d[1/\overline{V}(t)]}{d\{1/[I \cdot \overline{V}(t)]\}}$$
(3)

$$K_{rg} = K_{rw} \frac{\mu_g}{\mu_w} \frac{1 - f_w(S_g)}{f_w(S_g)}$$
(4)

$$I = (Q(t)/Q_0)(\Delta P_0/\Delta P_t)$$
(5)

$$S_g = \overline{V_w}(t) - \overline{V}(t) f_w(S_g) \tag{6}$$

where $f_w(S_g)$ denotes the moisture content; $\overline{V_w}(t)$ represents the dimensionless cumulative brine flow rate, expressed as pore volume fraction; $\overline{V}(t)$ is the dimensionless cumulative CO₂ and brine flow rate; K_{rw} and K_{rg} are the RP of CO₂ and brine, respectively; *I* is the relative injection capability; Q_0 and Q(t) are the brine flow rate at the core outlet at the initial time and time *t*, respectively, cm³/s; ΔP_0 and ΔP_t are the driving pressure drop at the initial time and time *t*, respectively, MPa. In constant pressure drop displacement experiments, ΔP_0 and ΔP_t are equal. S_g is the CO₂ saturation at the core outlet.

3. Results and Discussion

3.1. Relative Permeability Results for Five Sets of Confining Pressure Conditions

Five sets of CO_2 -brine RP were obtained through unsteady-state displacement tests conducted at various CPs ranging from 12 to 20 MPa. The experimental data of CO_2 -brine RP at various CPs were calculated using the 'J.B.N' method.

The experimental data were fitted using the Corey model and the Van Genuchten modified model. The basic expression of the Corey model is as follows [46,47]:

$$K_{rw} = K_{rw} (S_{gr}) \left(\frac{S_w - S_{wr}}{1 - S_{wr} - S_{gr}} \right)^a, \tag{7}$$

$$K_{rg} = K_{rg}(S_{wr}) \left(\frac{1 - S_w - S_{gr}}{1 - S_{wr} - S_{gr}}\right)^b \tag{8}$$

where S_{gr} is the irreducible CO₂ saturation and $K_{rw}(S_{gr})$ is the RP of brine in the irreducible CO₂ state; similarly, S_{wr} is the irreducible brine saturation, and $K_{rg}(S_{wr})$ is the CO₂ RP in the irreducible brine state. Since the experiment is a drainage process, $S_{gr} = 0$ and $K_{rw}(S_{gr}) = 1$ are taken.

The expression of the Van Genuchten modified model is as follows [48]:

$$S^* = (S_w - S_{wr}) / (1 - S_{wr}), \tag{9}$$

$$K_{rw} = \sqrt{S^*} [1 - (1 - S^{*1/\lambda})^{\lambda}]^2$$
(10)

$$K_{rg} = K_{rg}(S_{wr})(1 - S^*)^{\gamma}(1 - S^{*1/\lambda})^{2\lambda},$$
(11)

Core 1-1 was used for a displacement experiment under a CP of 12 MPa. After processing the experimental data, the irreducible brine saturation was 0.171, and the CO₂ RP under irreducible brine saturation was 0.258. Figure 3 shows the experimental results of CO₂-brine RP, which were fitted using the Corey model—with parameters *a* = 7.661, *b* = 3.251—and plotted as the black curve. The Van Genuchten modified model was also used for fitting with parameters of γ = 2.761 and λ = 0.591. The resulting curve is shown in red in Figure 3.



Figure 3. Results from experiments and model-fitting for relative permeability under a confining pressure of 12 MPa.

Core 1-2 was used for a displacement experiment under a CP of 14 MPa. The irreducible brine saturation was 0.143, with the CO₂ RP under irreducible brine saturation measured at 0.230. Corey model parameters were found to be a = 5.959 and b = 3.280. Additionally, the Van Genuchten parameters were determined as $\gamma = 2.704$ and $\lambda = 0.632$. Experimental and model-fitting results are depicted in Figure 4.



Figure 4. Results from experiments and model-fitting for relative permeability under a confining pressure of 14 MPa.

Core 1-3 was used for a displacement experiment under a CP of 16 MPa. Irreducible brine saturation was 0.138 and CO₂ RP under irreducible brine saturation was 0.166. Corey model parameters were a = 5.979 and b = 2.887. Van Genuchten parameters were $\gamma = 2.267$ and $\lambda = 0.635$. The results from experiments and model-fitting for RP are shown in Figure 5.



Figure 5. Results from experiments and model-fitting for relative permeability under a confining pressure of 16 MPa.

Core 1-4 was used for a displacement experiment under a CP of 18 MPa. Irreducible brine saturation was 0.136 and CO₂ RP under irreducible brine saturation was 0.117. Corey model parameters were a = 5.591 and b = 2.796. Van Genuchten parameters were $\gamma = 2.199$ and $\lambda = 0.644$. The results from experiments and model-fitting for RP are shown in Figure 6.



Figure 6. Results from experiments and model-fitting for relative permeability under a confining pressure of 18 MPa.

Core 1-5 was used for a displacement experiment under a CP of 20 MPa. Irreducible brine saturation was 0.133 and CO₂ RP under irreducible brine saturation was 0.110. Corey model parameters were a = 5.494 and b = 2.814. Van Genuchten parameters were $\gamma = 2.124$ and $\lambda = 0.668$. Experimental and model-fitting results are shown in Figure 7.



Figure 7. Results from experiments and model-fitting for relative permeability under a confining pressure of 20 MPa.

Based on the images of the results, differences were found in the accuracy of the models used to determine the RP of CO₂ and brine. Both fitting models agree with the experimental results of CO₂ RP. The Van Genuchten modified model was found to be more consistent with experimental results when calculating brine RP. As the CP increased, the coefficient λ in the model also increased, while γ decreased gradually.

The resulting curve in the study clearly shows the process of core drainage, where CO_2 gradually replaces brine in the saturated core, resulting in a decrease in brine saturation. With the decrease in brine saturation, CO_2 RP increases while brine RP decreases gradually. On the left side of the isotonic point, as brine saturation decreases, CO_2 RP increases rapidly. Conversely, on the right side of the isotonic point, as brine saturation increases, brine RP

increases rapidly. When brine saturation decreases to the irreducible state, CO_2 RP reaches the maximum while brine RP decreases to 0.

3.2. Effects of Confining Pressures on Irreducible Water Saturation

Irreducible brine refers to the immobile water adsorbed on rock surfaces and trapped in rock pores and throats [49]. Irreducible brine saturation (S_{wr}) is a crucial parameter in reservoir evaluation, directly influencing permeability prediction models and reserve estimations [50]. In the displacement experiment, irreducible brine saturation is reached when the core stops producing brine. The core is weighed, and irreducible brine saturation is calculated.

This study investigates the impact of various CP conditions on irreducible brine saturation. Figure 8 depicts the irreducible brine saturation under varying CP conditions. It can be observed that with the increase in CP, there is a slight decrease in irreducible brine saturation. The elevated CP can alter the rock pore structure [51,52]. Higher pressure may compress larger pores, forming smaller capillary pores, thereby reducing the retention of irreducible brine [53]. This alteration in pore structure might be a primary reason for the decrease in irreducible brine saturation.



Figure 8. Relationship between irreducible water saturation and confining pressure.

3.3. Effect of Confining Pressure on CO₂ Relative Permeability in the Irreducible Water State

The relationship between CO_2 RP and CP in the irreducible brine state was studied and the results are presented in Figure 9. The experimental findings indicated that as the CP increased from 12 MPa to 14 MPa while in the irreducible water state, the CO_2 RP decreased considerably. However, as the CP was further increased to 20 MPa, the decrease in the CO_2 RP was relatively small.

This phenomenon may be due to alterations in the rock pore structure induced by CP, involving a decrease in pore size and the development of capillary pores [54,55]. Certain larger pores transform into capillary pores with water-binding potential [37]. This shift in pore structure hinders CO_2 flow, causing a decline in CO_2 RP. Simultaneously, the reduction in the pore throat radius results in increased capillary forces. This augmented capillary force hinders CO_2 from displacing bound water, further diminishing the CO_2 RP. The effect of pore structure compression might have been significant under the 14 MPa CP. Consequently, under the 20 MPa CP the alteration in pore structure has a relatively minor impact on CO_2 RP.



Figure 9. Relationship between CO₂ relative permeability and confining pressure in the irreducible water state.

3.4. Effect of Confining Pressure on CO₂-Brine Relative Permeability Curve

Figure 10 illustrates the CO_2 -brine RP curves fitted by five sets of Van Genuchten modified models. The results show significant variations in the CO_2 -brine RP curves depending on the CP. The CO_2 RP curve decreases as the CP increases, while the brine RP increases. Specifically, as the pressure was raised from 12 MPa to 20 MPa, the CO_2 RP in the irreducible brine state decreased by 57%. However, the change in brine RP is not as noticeable as that of CO_2 . The reduction in CO_2 RP is more apparent when the brine saturation is below the isotonic point saturation. Figure 10's right image provides an enlarged view of the isotonic point area of the RP curve. The isotonic point shifts progressively to the left with increasing CP, while the brine saturation corresponding to the isotonic point decrease significantly hampers CO_2 flow.



Figure 10. CO₂-brine relative permeability under different confining pressures.

The observed results may be attributed to changes in CP altering rock properties, thereby influencing the RP magnitude [9,56]. These rock properties encompass wettability and pore characteristics. Wettability plays a pivotal role in RP; a shift in rock wettability from strongly water-wetting to gas-wetting leads to a decrease in the RP of gas and an increase in the RP of water [57]. Research on wettability in saline aquifers indicates

that increased pressure enhances the wettability of CO_2 [58,59]. Wettability governs the distribution and flow of CO_2 and brine in rock pores. An escalation in CP transforms wettability from water-wetting to mixed-wetting to CO2-wetting, ultimately resulting in a decrease in the RP of CO_2 . Beyond altering wettability, CP may also impact the pore properties of the rock, including porosity, pore size distribution, pore geometry, and pore connectivity. Investigations into CO₂-brine two-phase RP reveal a significant decrease in the RP of CO₂ with decreasing porosity [60]. An increase in CP compacts sand grains, leading to a denser core structure, reduced pore volumes, smaller pore throat sizes, and diminished porosity [61,62]. Small pores are occupied by the wetting phase, forming a thin film on rock particle surfaces. The non-wetting phase occupies larger pores' central region [63,64]. With rising CP, core pore volume decreases, causing pore fluids to redistribute. Some larger pores that originally allowed the unrestricted flow of the non-wetting phase gradually shrink, becoming pores bound by the wetting phase [65]. As the number of pores capable of binding the wetting phase increases, the number of pores permitting non-wetting phase flow decreases. As the CP increases, the local pore throat size decreases, resulting in higher capillary resistance when the non-wetting phase passes through the pore throat. This makes it more challenging for the non-wetting phase to traverse the pores. Consequently, with the increase in CP, the RP of CO_2 decreases. Pore connectivity similarly influences RP [66–68], as fluid can efficiently flow only through connected pores. An increase in CP may isolate pores that were previously interconnected, disrupting fluid flow and decreasing the RP of the terminal gas, even as the final gas saturation increases.

Figure 11 demonstrates that when water saturation is below 80% the ratio of gas RP to water RP (K_{rg}/K_{rw}) decreases as CP increases. The intersection point between the horizontal line and the curve in the figure represents the isotonic point. The brine saturation corresponding to the isotonic point decreases. This suggests that the increase in CP has a more significant impact on gas RP than it does on brine RP.



Figure 11. Relationship between relative permeability ratio K_{rg}/K_{rw} and brine saturation under different confining pressures.

Compared with CO_2 , the mobility of brine within the core is less influenced by CP. Water molecules may interact with the solid particle surfaces in the formation, and they are more prone to forming water films within the formation pores [69]. At low CP, water molecules can already flow relatively freely in the pores, and increasing the CP has little effect on brine RP.

4. Conclusions

Five sets of unsteady-state drainage experiments were conducted using natural sandstone cores in the Ordos Basin under different CP conditions (12, 14, 16, 18, 20 MPa). The 'J.B.N' method was used to calculate the relative permeability of CO₂-brine. Relative permeability curves for the CO₂-brine system at various confining pressures were plotted. Analyses of confining pressure effects on irreducible brine saturation, CO₂ relative permeability in the irreducible brine state, and CO₂-brine relative permeability curves were conducted.

The research results show that for the sandstone in the Ordos Basin in this study, as the confining pressure increases irreducible brine saturation slightly decreases. As the confining pressure was raised from 12 MPa to 20 MPa, the CO_2 relative permeability in the irreducible brine state decreased by 57%. The results reveal notable differences in the CO_2 -brine relative permeability curves at various confining pressures. As the confining pressure increases, the CO_2 relative permeability curve decreases, while the brine relative permeability in treases. The change in brine relative permeability is not as pronounced as that of CO_2 .

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