Impact of water content on minimum miscibility pressure during CO_2 flooding in high water-cut reservoirs

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Abstract: This study focused on the X block stratum oil, specifically addressing the application of CO_2 displacement technology in enhancing oil recovery under high water content conditions. It systematically investigates the variation of the minimum miscibility pressure (MMP) between CO_2 and formation oil at water contents of 0%, 60%, 70%, 80%, and 90%. The research employed slim-tube model simulation experiments and theoretical analysis to explore the impact of different water contents on the physical properties of formation oil and the changes in the interaction mechanism between CO_2 and crude oil. The results indicate that the MMP of CO_2 flooding is the lowest at 31.11 MPa in the absence of water, reaching the highest value of 37.94 MPa at 90% water content. The MMP of the CO_2-formation oil system shows a significant upward trend with increasing water content in the formation, which is related to the stability of the water film, the solubility of CO_2, and the interfacial tension between oil and water. Meanwhile, high water content leads to the expansion of formation oil volume, increased viscosity, and compositional changes, collectively influencing the results. This study provides theoretical support for the field application of CO_2 flooding and offers critical references for optimizing the oil displacement process.

Key words: High water content, MMP, Slim-tube experiment, CO_2 flooding, Formation oil.

1. Introduction

In the global energy structure, oil still occupies an irreplaceable position. With the gradual depletion of traditional oil fields, improving the recovery rate of oil fields has become a significant challenge for the petroleum industry. Among the many enhanced oil recovery techniques, CO_2 flooding has attracted widespread attention due to its unique advantages [1]. CO_2 flooding not only can increase the recovery rate of crude oil but also achieve the geological sequestration of CO_2, combating global climate change [2]. However, the effectiveness of CO_2 flooding technology is influenced by various factors, among which the minimum miscibility pressure (MMP) between CO_2 and formation oil is a key parameter determining the feasibility and efficiency of CO_2 flooding [3].

The minimum miscibility pressure is the lowest pressure at which the injected CO_2 and formation oil form a single phase. At this pressure or higher, CO_2 can mix thoroughly with the crude oil, significantly improving the oil's flowability and, consequently, the recovery rate [4]. However, the conditions of underground reservoirs vary greatly, especially the water content, which significantly impacts the MMP of CO_2 flooding [5-7]. Under high water content conditions, the presence of the water phase not only dilutes the contact area between CO_2 and crude oil but may also alter the physicochemical environment of the reservoir, such as reducing interfacial tension, affecting the solubility and diffusivity of CO_2, and thus influencing the MMP.

Despite the deepening research on CO_2 flooding technology in recent years, the specific impact mechanism and pattern of MMP under high water content conditions are still not very clear. This paper focuses on the variation pattern of MMP between CO_2 and formation oil under high water content conditions, aiming to systematically investigate the MMP of CO_2 flooding at water contents of 60%, 70%, 80%, and 90% through slim-tube simulation experiments, explore the impact pattern of different water contents on MMP, and its underlying physicochemical mechanisms, providing a scientific basis for optimizing CO_2 flooding technology.

2. CO_2 Flooding Minimum Miscibility Pressure Slim-Tube Experiment

2.1 Experimental Samples

The crude oil samples were collected from the separator of the X block, while the associated gas samples were prepared by Dalian Dade based on the composition of the associated gas. According to the original formation pressure of 30 MPa, formation temperature of 127°C, and gas-oil ratio of 85.6 m³/m³, the formation fluids were reconstituted following the "Method for Analysis of Reservoir Fluid Physical Properties" (GBT 26981-2020). Based on the composition of the formation oil from the X field, the reconstitution of the formation oil samples was conducted using a PVT (Pressure Volume Temperature) analyzer, and the reconstituted samples were tested to ensure they met the standards [6]. The main assessment indicators were gas-oil ratio, saturation pressure, formation crude oil viscosity, and formation crude oil density.

According to the formation conditions of the target block, the dehydrated crude oil was prepared into formation oil samples. The conditions for preparing the formation oil samples are shown in Table 1.

Table 1. Conditions for oil sample preparation.

Block	Formation Temperature (℃)	Formation Pressure（MPa）	Formation Oil and Gas Ratio（m^3/m^3）
X	127	30	85.6

Table 2. Composition of compound formation oil.

Components	Mole Fraction (%)
CO_2	1.35
N_2	0
C_1	31.41
C_2	5.69
C_3	2.17
C_4	1.76
C_5	0.56
C_6	0.59
C_{7+}	56.46
Relative molecular mass of C_{7+} ($g{\cdot}mol^{-1}$)	220.9

2.2 Experimental Reagents and Equipment

Prepared according to oil and gas data in a high-temperature, high-pressure PVT analyzer. High-purity CO_2 (purity > 99.99%, Dalian Special Gases Co., Ltd., Dalian, China) serves as the experimental gas.

Experimental equipment: high temperature and high pressure PVT analyzer; The K-7000 Steam Pressure Permeability Analyze), Glass Piston Syringes supplied, ISCO-260D high precision displacement pump; HW-G high temperature two-phase displacement system; High precision pressure sensor; A thin tube with a length of 1 m (self-made);W-NK-0.5B Wet gas flowmeter; Injection piston container (capacity of the container is set at 2000 mL), pipeline, test tube, stopwatch and other necessary apparatus.

Table 3. Slim tube model parameters.

Length (m)	Outside Diameter (mm)	Inside Diameter (mm)	Filling Material	Gas Permeability (mD)	Porosity (%)
1	6	4	Micro glass beads	4026	40

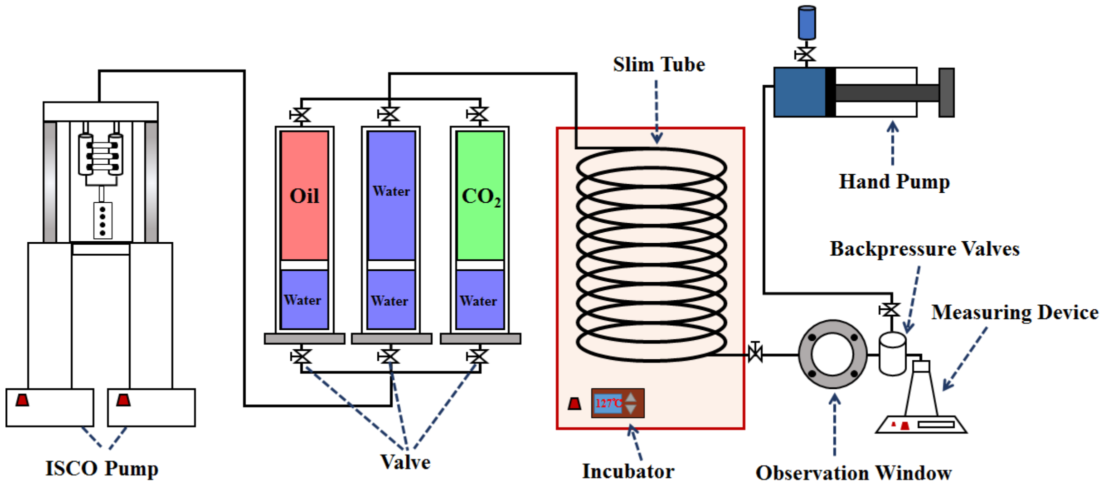

Figure 1. Flowchart of the slim tube experiment

2.3 Experimental methods

The main parameters of the miscible flooding physical simulation experiment device model used in this study are shown in Table 2. The flow process of the slim-tube experiment setup is illustrated in Figure 1. Multiple slim-tube oil displacement experiments were conducted according to the displacement scheme, obtaining oil recovery efficiencies at different displacement pressures. In the core flooding experiment, regardless of whether the phases are mixed or not, the recovery rate essentially ceases to increase when 1.2 pore volumes (PV) are injected. At this point, the recovery rate equals or is close to the total recovery rate. Therefore, the final recovery rate at 1.2 PV injection is generally used as the basis for comparison in different displacement experiments.

$$\text{Oil displacement efficiency} = \frac{\text{Volume of produced oil} \times \text{Volume coefficient}}{\text{Saturated oil volume}} \times 100\% \quad (1)$$

Formation crude oil samples and CO_2 injection gas were used to conduct seven different slim tube experiments under varying displacement pressures at a formation temperature of 127℃.

2.4 Experimental Procedure

In the experiment, special attention was paid to preventing leakage, especially gas leakage at high temperatures. The specific experimental steps are as follows:

(1) Pipeline Cleaning

Begin with flushing the pipeline using petroleum ether, maintaining the thermostat at the formation temperature of 127°C. After opening the pipeline valve, perform a constant-rate displacement at a low pressure with a flow rate of 0.45 mL/min, saturating the entire pipeline and displacing air and other impurities from the system. When a continuous flow of colorless, transparent liquid (petroleum ether) appears at the outlet, it indicates that the pipeline has been cleaned. Then, stop the pump and close the petroleum ether piston container.

(2) Saturating Dead Oil

Open the upstream and downstream valves of the dead oil container and saturate the dead oil under a pressure of 18 MPa, maintaining a constant displacement speed of 0.45 mL/min. To prevent degassing during the saturation of live oil, the process is carried out above the bubble point pressure. After saturating the dead oil (approximately 1.2 pore volumes), close the outlet of the dead oil piston container.

(3) Saturating Formation Oil

Gradually open the outlet valve of the crude oil piston container and the inlet valve of the slim tube, displacing at a constant rate of 0.45 mL/min. When the calculated oil-to-gas ratio reaches 85.6 m³/m³, the saturation of live oil is complete, and then close the outlet of the live oil piston container.

(4) Waterflooding Crude Oil

Slowly open the outlet valve of the water container and the inlet valve of the slim tube, and displace the crude oil with simulated formation water until the water content reaches 60%, 70%, 80%, and 90% respectively, ending the displacement. The displacement speed is 0.125 cm³/min. After completing the waterflooding, close the outlet of the formation water piston container.

(5) CO_2 Flooding Crude Oil

Gradually open the outlet valve of the CO_2 container and the inlet valve of the slim tube, and use CO_2 to displace the crude oil. The displacement speed is 0.125 cm³/min. Record the pressure, cumulative oil displacement volume, and the production of oil and gas approximately every 0.1 pore volume. When the displacement volume reaches 1.2 pore volumes, stop the displacement and close the inlet and outlet valves of the CO_2 container.

3. Experimental Results and Analysis

To investigate the minimum miscibility pressure (MMP) of CO_2 and reservoir oil under high water content conditions, experiments were conducted using a 1m-long slim tube at a constant temperature of 127°C, comprising seven sets under different injection pressure conditions. According to widely accepted standards, it is generally considered that miscibility between the injected gas and the crude oil is achieved when the final recovery rate exceeds 90%, at which point the interface between the two disappears and the recovery rate is maximized. Based on this, a recovery rate of 90% was used as the critical threshold for determining miscibility, and data processing was carried out accordingly.

For each set of experimental results, data points where the recovery rate reached 90% were used as inflection points for linear fitting. The intersection of the two lines represents the minimum miscibility pressure between the injected gas and the crude oil. Quantitative values of MMP for CO_2 and crude oil under different pressures were obtained from the experimental data, providing solid empirical evidence and analytical basis for revealing the influence patterns of miscible driving pressure in high water content environments.

3.1 Results of the CO_2 Flooding Experiment in the Slim Tube with 0% Water Content

Figure 2 presents the oil recovery efficiency graph of CO_2 flooding in a 1m Slim Tube under water-free conditions. From Figure 2, it is observed that under different displacement pressures, the oil recovery efficiency increases with the injection of multiple pore volumes and

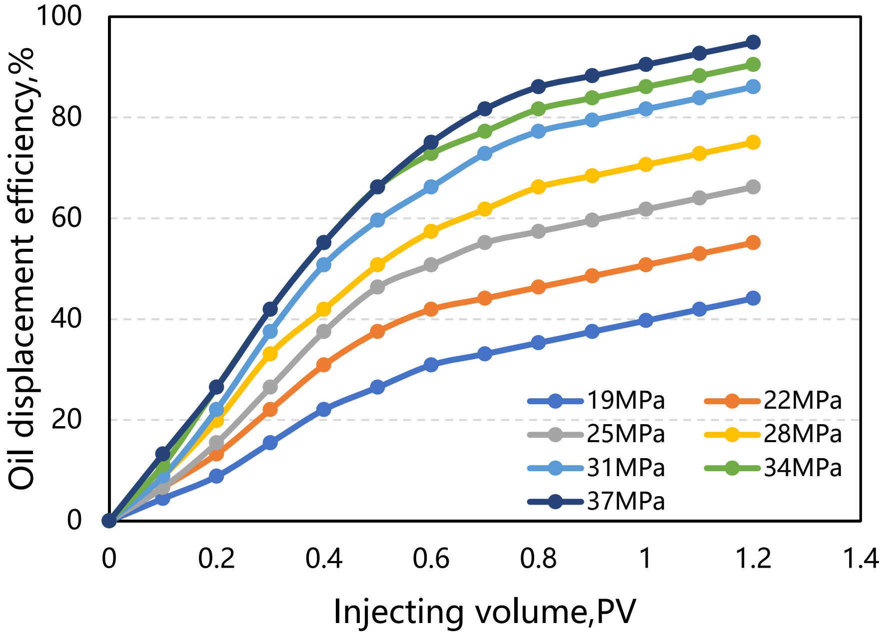

Figure 2. Oil displacement efficiency for CO_2 flooding in a slim tube at 0% water content

Table 4. Experimental results for CO_2 flooding in a slim tube at 0% water content

No.	Displacement pressure（MPa）	Temperature（℃）	Recovery rate when injecting 1.2PV（%）	Evaluation
1	19	127	44.14	immiscible
2	22	127	55.17	immiscible
3	25	127	66.21	immiscible
4	28	127	75.03	immiscible
5	31	127	86.07	immiscible
6	34	127	90.48	miscible
7	37	127	94.90	miscible

According to Table 4 and Figure 2, the displacement efficiency increases with the rise in displacement pressure. When the displacement pressure reaches 30 MPa, the curve of the relationship between recovery rate and displacement pressure shows a sudden change. Once the displacement pressure exceeds 34 MPa, the recovery rate is greater than 90%, indicating a miscible displacement phase. Even if the displacement pressure continues to increase, the growth of the recovery rate remains small, and the curve tends to level off.

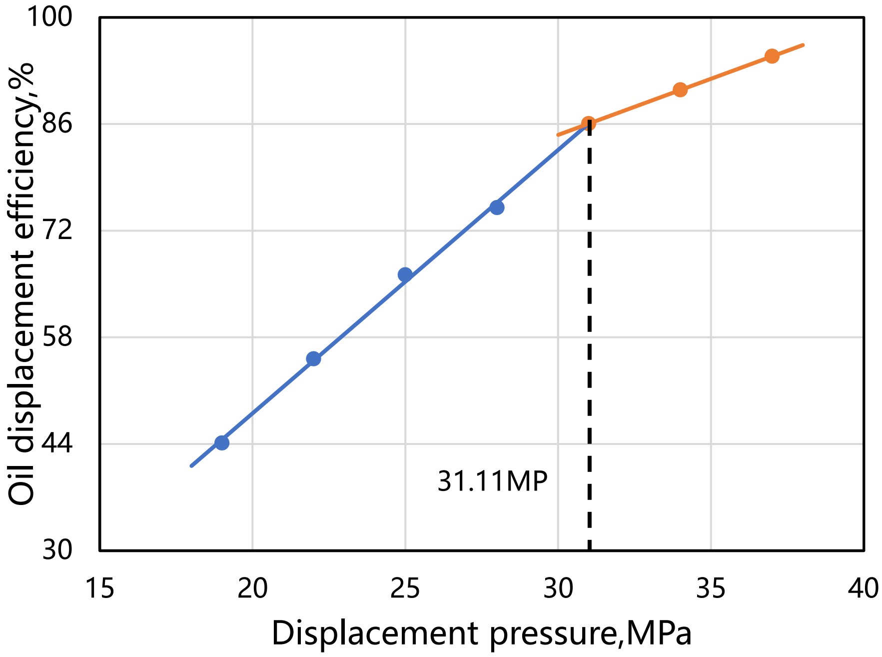

Figure 3. MMP for CO_2 flooding in a slim tube at 0% water content

By analyzing the slim tube experiment data and plotting the final crude oil recovery rates under each injection pressure, the corresponding curve is shown in Figure 3. The data before and after miscibility were linearly fitted and extended; the intersection point is the minimum miscibility pressure point. Therefore, the minimum miscibility pressure of CO_2 and crude oil measured from the slim tube experiment is 31.11 MPa.

3.2 Experimental Results for CO_2 Flooding in a Slim Tube at 60% Water Content

Figure 4 shows the CO_2 flooding oil recovery efficiency graph for a 1m slim tube with a water content of 60%. As depicted in Figure 4, under different displacement pressures, the crude oil recovery rate gradually increases with the increase of CO_2 injection volume and shows a turning point around 0.9 pore volumes (PV). When the injection volume reaches 1.2 PV, the oil displacement efficiency no longer changes. The final recovery rates are 50.27%, 61.87%, 75.40%, 85.07%, 90.87%, 92.80%, and 95.22%, respectively.

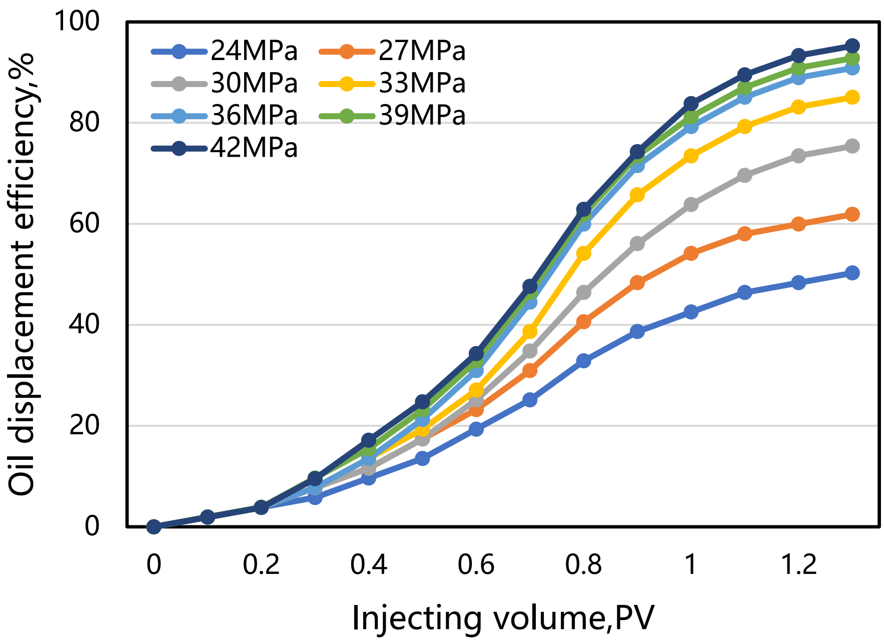

Figure 4. Oil Displacement efficiency for CO_2 flooding in a slim tube at 60% water content

Table 5. Experimental results for CO_2 flooding in a slim tube at 60% water content

No.	Displacement pressure（MPa）	Temperature（℃）	Recovery rate when injecting 1.2PV（%）	Evaluation
1	24	127	50.27	immiscible
2	27	127	61.87	immiscible
3	30	127	75.40	immiscible
4	33	127	85.07	immiscible
5	36	127	90.87	miscible
6	39	127	92.80	miscible
7	42	127	95.22	miscible

According to Table 5 and Figure 4, the displacement efficiency increases with the rise in displacement pressure. When the displacement pressure reaches 33 MPa, the relationship curve between recovery rate and displacement pressure shows a sudden inflection, indicating a change. At pressures greater than 36 MPa, the recovery rate exceeds 90%, exhibiting miscible displacement characteristics. Even with further increases in displacement pressure, the incremental rise in recovery rate remains small, and the curve tends to flatten.

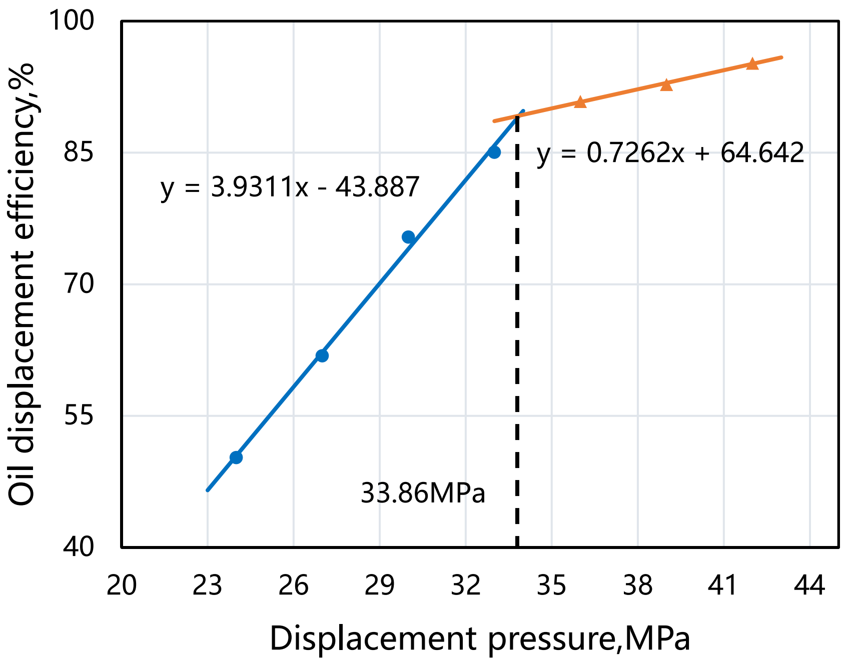

Figure 5. MMP for CO_2 flooding in a slim tube at 60% water content

By analyzing the data from the slim tube experiment and based on the final crude oil recovery rates at each injection pressure, the corresponding curve is illustrated in Figure 5. The data before and after miscibility were linearly fitted and extended, and the intersection point is identified as the minimum miscibility pressure point. Therefore, the minimum miscibility pressure of CO_2 and crude oil, as determined from the slim tube experiment, is 33.86 MPa.

3.3 Experimental Results for CO_2 Flooding in a Slim Tube at 70% Water Content

Figure 6 shows the CO_2 displacement efficiency graph in a 1m slim tube with a water content of 70%. According to Figure 6, under different displacement pressures, as the CO_2 injection volume increases, the crude oil recovery rate gradually rises and reaches an inflection point at around 0.9 pore volumes (PV). When the injection volume reaches 1.2 PV, the oil displacement efficiency no longer changes, with final recovery rates of 46.48%, 58.56%, 71.02%, 83.30%, 85.84%, 89.25%, and 93.22%, respectively.

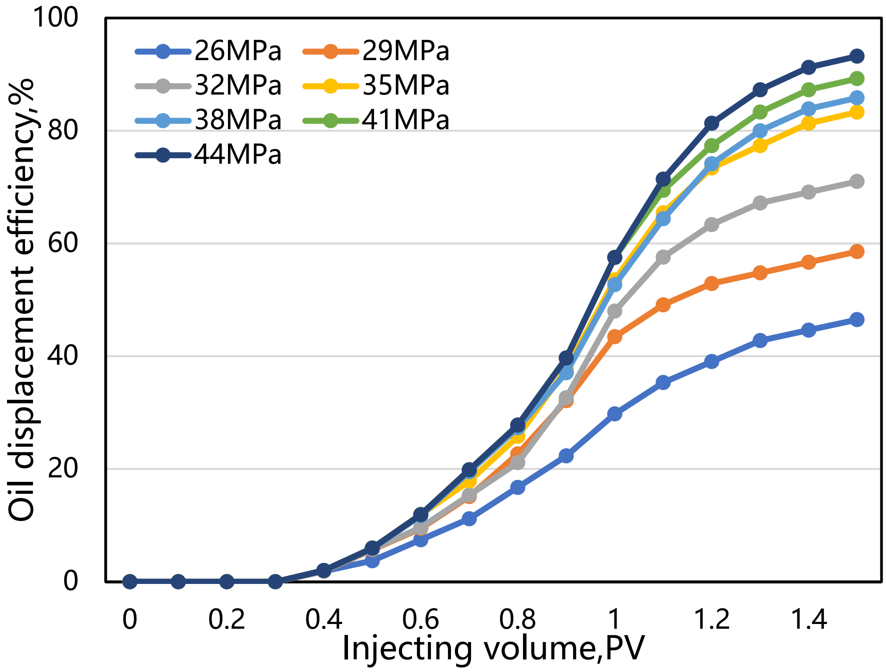

Figure 6. Oil displacement efficiency for CO_2 flooding in a slim tube at 70% water content

Table 6. Experimental results of slim tube CO_2 flooding at 70% water content

No.	Displacement pressure（MPa）	Temperature（℃）	Recovery rate when injecting 1.2PV（%）	Evaluation
1	26	127	46.48	immiscible
2	29	127	58.56	immiscible
3	32	127	71.02	immiscible
4	35	127	83.30	immiscible
5	38	127	85.84	miscible
6	41	127	89.25	miscible
7	44	127	93.22	miscible

As shown in Table 6 and Figure 6, the displacement efficiency increases with the rising displacement pressure. A sudden inflection in the curve relating recovery rate and displacement pressure occurs when the pressure reaches 35 MPa. At pressures greater than 41 MPa, the recovery rate exceeds 90%, indicating miscible displacement. Even with continued increases in displacement pressure, the gain in recovery rate remains small, and the curve becomes flat.

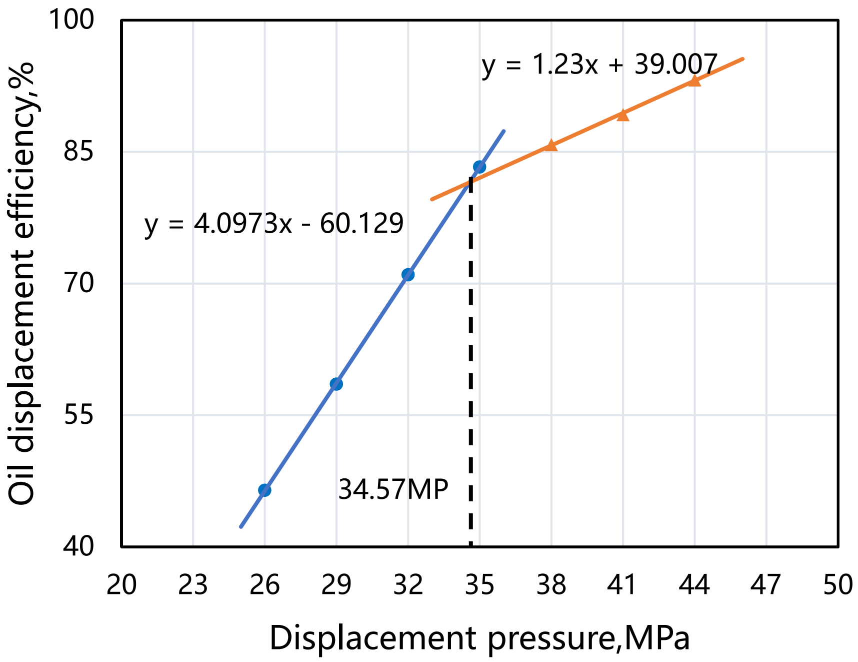

Figure 7. MMP for CO_2 flooding in a slim tube at 70% water content

By analyzing the slim tube experiment data and based on the final crude oil recovery rates under each injection pressure, the corresponding curve is plotted as shown in Figure 7. The data before and after miscibility were linearly fitted and extended, and the intersection point is the minimum miscibility pressure point. Hence, the minimum miscibility pressure of CO_2 and crude oil determined from the slim tube experiment is 34.57 MPa.

3.4 Experimental Results for CO Flooding in a Slim Tube at 80% Water Content

Figure 8 is the CO_2 flooding oil recovery efficiency graph in the slim tube. According to Figure 8, under different displacement pressures, the crude oil recovery rate gradually increases with the increase in CO_2 injection volume and reaches a turning point at about 0.9 pore volumes (PV). When the injection volume reaches 1.2 PV, the oil displacement efficiency no longer changes. The final recovery rates are 42.23%, 51.82%, 64.22%, 78.66%, 84.12%, 87.68%, and 89.77%, respectively.

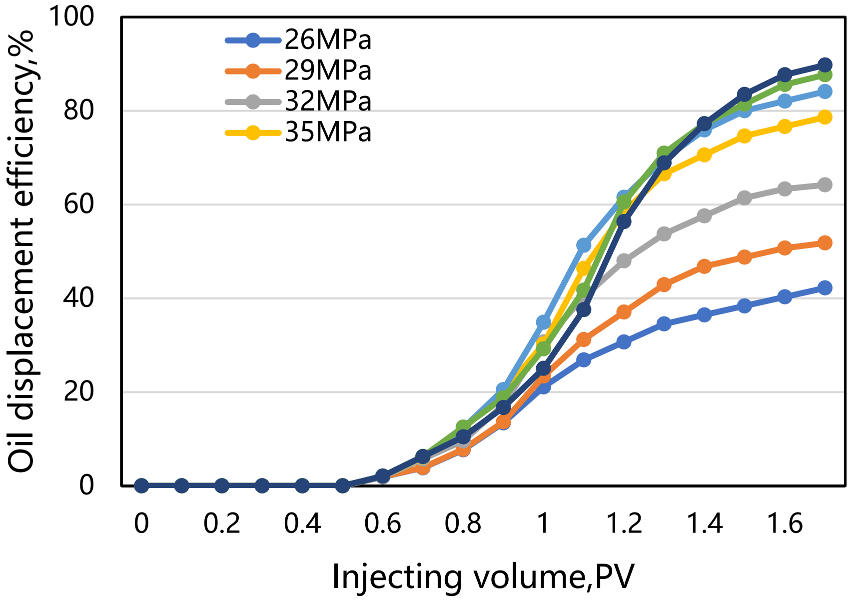

Figure 8. Oil displacement efficiency for CO_2 flooding in a slim tube at 80% water content

Table 7. Experimental results of slim tube CO_2 flooding at 80% water content

No.	Displacement pressure（MPa）	Temperature（℃）	Recovery rate when injecting 1.2PV（%）	Evaluation
1	26	127	42.23	immiscible
2	29	127	51.82	immiscible
3	32	127	64.22	immiscible
4	35	127	78.66	immiscible
5	38	127	84.12	miscible
6	41	127	87.68	miscible
7	44	127	89.77	miscible

According to Table 7 and Figure 8, the displacement efficiency increases with increasing displacement pressure. At a displacement pressure of 36 MPa, the relationship curve between recovery rate and displacement pressure exhibits a sudden change. When the displacement pressure exceeds 41 MPa, the recovery rate is greater than 85%, indicating a miscible displacement phase. Further increases in displacement pressure lead to only small increases in recovery rate, and the curve flattens out.

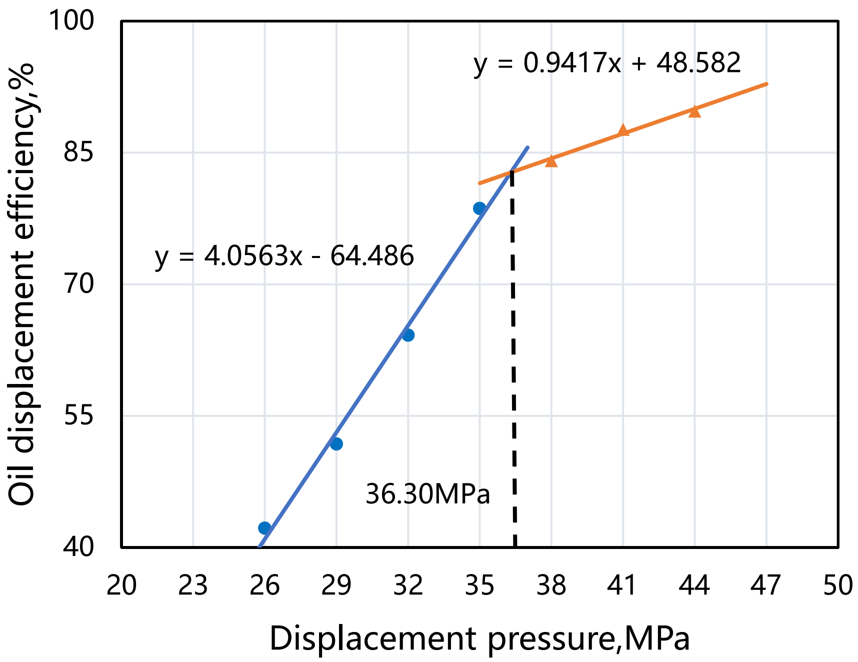

Figure 9. MMP for CO_2 flooding in a slim tube at 80% water content

By analyzing the slim tube experiment data and calculating the final crude oil recovery rates under each injection pressure, the relevant curve was drawn as shown in Figure 9. The data before and after reaching miscibility were linearly fitted and extended, and the intersection point represents the minimum miscibility pressure. Therefore, the minimum miscibility pressure of CO_2 and crude oil, as determined from the slim tube experiment, is 36.30 MPa.

3.5 Experimental Results for CO_2 Flooding in a Slim Tube at 90% Water Content

Figure 10 is a graph showing the efficiency of CO_2 flooding oil recovery in a slim tube. As depicted in Figure 10, under different displacement pressures, the crude oil recovery rate gradually increases with the rise in CO_2 injection volume and shows a turning point around 0.9 pore volumes (PV). When the injection volume reaches 1.2 PV, the efficiency of oil recovery no longer changes. The final recovery rates are 37.68%, 49.58%, 58.49%, 68.89%, 79.33%, 81.54%, and 84.81%, respectively.

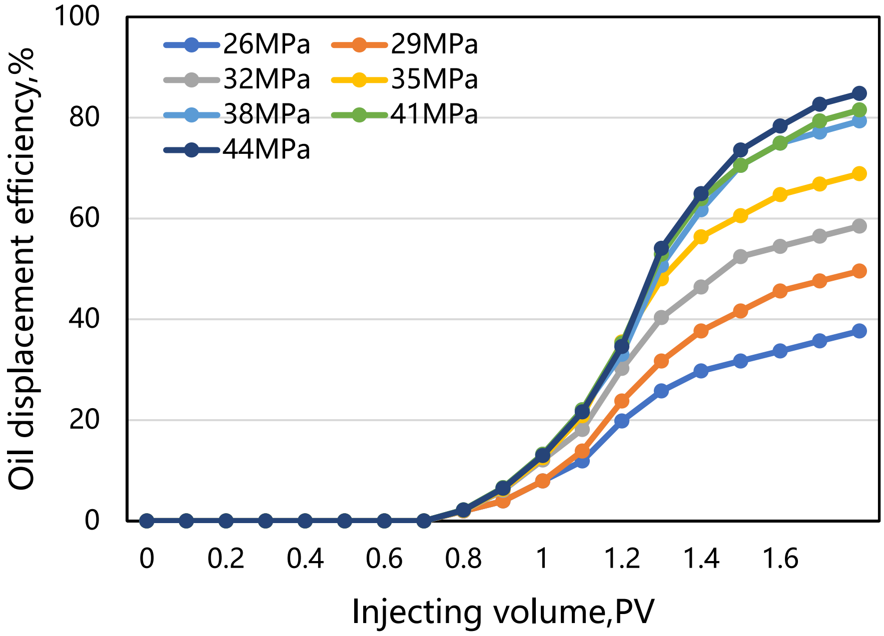

Figure 10: Oil displacement efficiency for CO_2 flooding in a slim tube at 90% water content

Table 8. Experimental results for CO_2 flooding in a slim tube at 90% water content

No.	Displacement pressure（MPa）	Temperature（℃）	Recovery rate when injecting 1.2PV（%）	Evaluation
1	26	127	37.68	immiscible
2	29	127	49.58	immiscible
3	32	127	58.49	immiscible
4	35	127	68.89	immiscible
5	38	127	79.33	miscible
6	41	127	81.54	miscible
7	44	127	84.81	miscible

As indicated by Table 8 and Figure 10, the displacement efficiency increases with rising displacement pressure. A sudden change in the curve relating recovery rate to displacement pressure occurs when the pressure reaches 38 MPa. With pressures greater than 41 MPa, the recovery rate exceeds 85%, characterizing the process as miscible displacement. Further increases in displacement pressure result in only minor improvements in recovery rate, leading to a flattening of the curve. Above 35 MPa, partial miscibility occurs in the reservoir, and as the displacement pressure approaches the minimum miscibility pressure (MMP), the higher the recovery rate becomes. This implies that at higher pressures, closer to miscibility, the pressure region is considered to be within the range of near-miscible displacement.

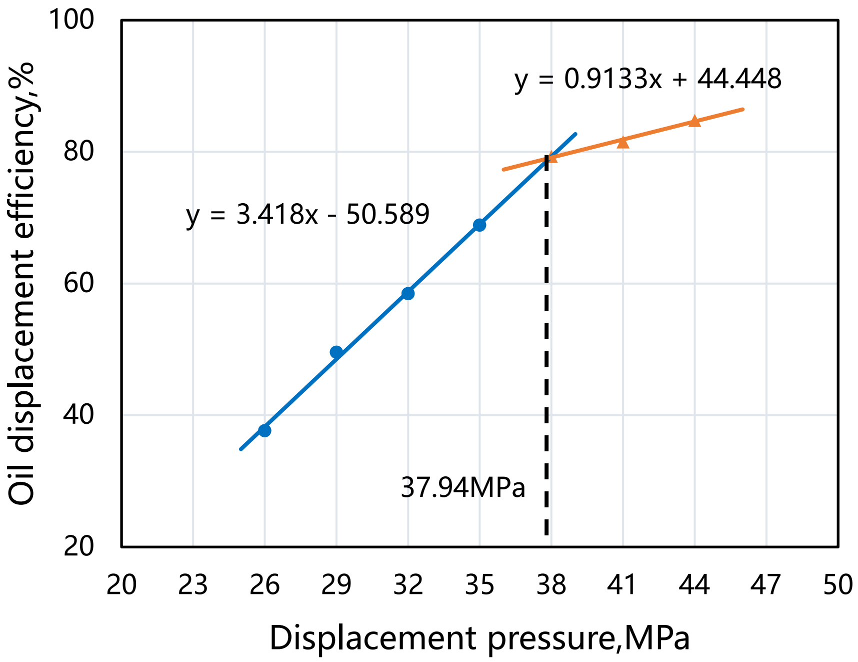

Figure 11. MMP for CO_2 flooding in a slim tube at 90% water content

By analyzing the slim tube experiment data and based on the final crude oil recovery rates under each injection pressure, the corresponding curve was plotted as shown in Figure 11. The data before and after miscibility were linearly fitted and extended, with the intersection point indicating the minimum miscibility pressure. Consequently, the minimum miscibility pressure of CO_2 and crude oil, as determined from the slim tube experiment, is 37.94 MPa.

3.6 Analysis of the Impact of Different Water Content Conditions on CO_2 Flooding MMP

MMP (Minimum Miscibility Pressure) refers to the minimum pressure under certain temperature and pressure conditions, at which the injected gas and crude oil can form a single-phase state. If the injection pressure is lower than the MMP, then the gas cannot effectively displace the crude oil; if it is higher than the MMP, a mixed phase can be formed, thereby improving the recovery rate. Figure 12 shows the minimum miscibility pressure graph of CO_2 flooding under different water content conditions, obtained from the results of a 1m long slim tube CO_2 flooding experiment. It has been found that with the increase in water content, the CO_2 − crude oil minimum miscibility pressure gradually increases. The increase in water content means that injecting CO_2 needs to overcome more slim tube forces and resistance from the water phase, therefore requiring higher pressure to achieve miscibility.

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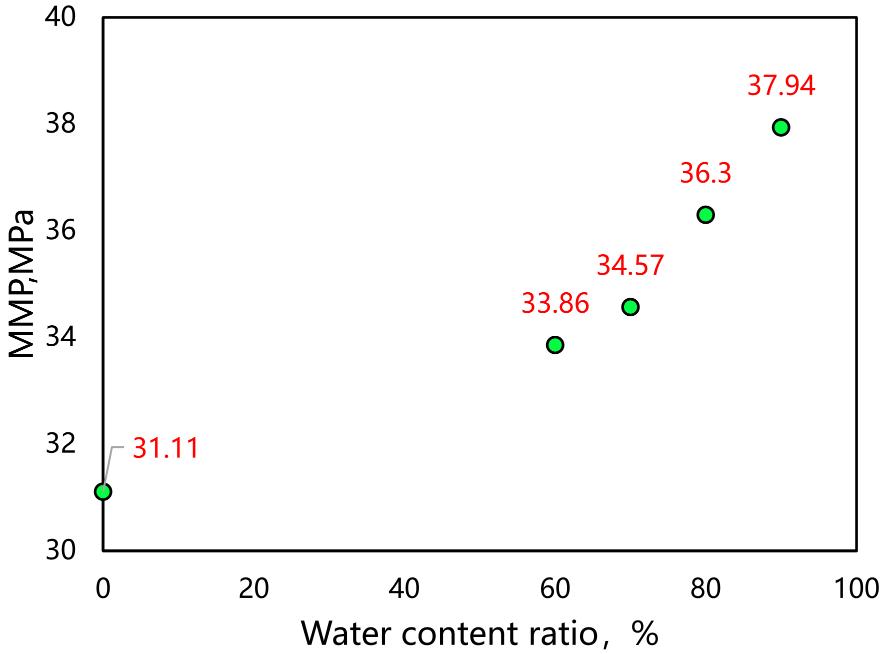

Figure 12. MMP for CO_2 flooding in a slim tube under different water content conditions

In the absence of water (0% water content), the MMP is the lowest at 31.11 MPa. This indicates that in the case of pure oil, CO_2 can form a miscible phase with oil at relatively lower pressures.

As the water content increases to 60%, the MMP rises to about 33.86 MPa. This demonstrates that the presence of water increases the pressure required to form a miscible phase. When the water content further increases to 70% and 80%, the MMP continues to rise, reaching 34.57 MPa and 36.3 MPa, respectively. This suggests that as the water content increases, CO_2 molecules require greater pressure to penetrate the interface between the water and oil phases, facilitating miscibility with hydrocarbons. At the highest water content of 90%, the MMP reaches its maximum at 37.94 MPa, indicating that forming a miscible phase is most difficult under high water content conditions [7].

From the experimental data, it can be inferred that the presence of water significantly increases the minimum pressure required to achieve a miscible phase between CO_2 and crude oil. This may be because water adds complexity to the system, including altering the interfacial tension between fluids, increasing fluid viscosity, or affecting solubility, among other factors. In the presence of a water phase, CO_2 may find it more difficult to dissolve in the oil phase, thus raising the pressure threshold for forming a single miscible phase. Moreover, an increase in water content might affect the interactions between the oil phase and CO_2, especially the mechanisms of micro-dispersion and dissolution at the oil-water interface. These factors could lead to the need for higher MMP under higher water content conditions. Water adds complexity to the fluid system, affecting CO_2 phase behavior, thereby requiring higher pressure to overcome the resistance of water to miscibility, to achieve effective mixing of CO_2 and crude oil [8-10].

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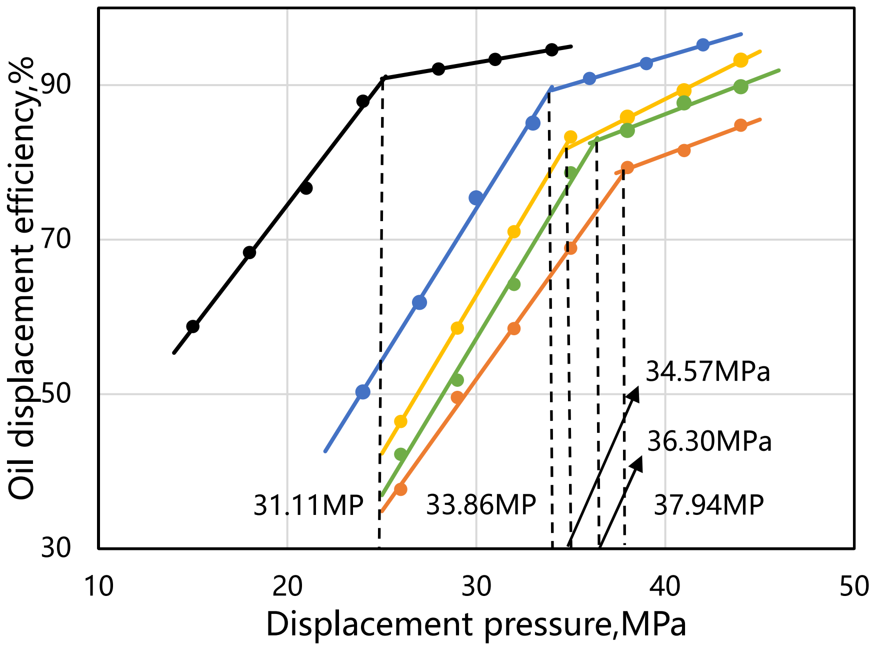

Figure 13. MMP for CO_2 flooding in a slim tube under different water content

Figure 13 is a comparison graph of the minimum miscibility pressures under different water content conditions. As shown in Figure 13, at a 0% water content (i.e., in a pure oil state), the MMP is 25.12 MPa, which is the lowest MMP value among all curves. This indicates that under anhydrous conditions, CO_2 can more easily mix with the oil phase. When the water content increases to 60%, the MMP rises to 33.86 MPa, and the slope change of the curve suggests that under this water content condition, the oil displacement rate gradually accelerates with increasing pressure. At a 70% water content, the MMP further increases to 34.57 MPa. At this point, the curve becomes flatter compared to the 60% water content, showing a slower increase in oil displacement efficiency with the initial increase in pressure. For an 80% water content, the MMP rises to 36.30 MPa, with the curve's slope becoming even flatter initially, meaning higher pressure is required to achieve the same oil displacement efficiency [11]. Finally, at a 90% water content, the MMP reaches the highest at 37.94 MPa, with the initial part of the curve showing almost no oil displacement before reaching the MMP, indicating that water significantly impedes oil extraction.
The impact of MMP under different water content conditions can be primarily determined by the following factors [12-15]:
(1) Hindrance of water: The presence of water may lead to an increase in the interfacial tension between fluids, impeding CO_2 molecules from entering the oil phase, thus elevating the pressure required to form a miscible phase.
(2) Physical properties of water: Water increases the complexity of the fluid system, including potentially altering the viscosity and flow properties of the oil-water mixture, which can affect the interaction between CO_2 and oil as well as the mixing process.
(3) Solubility and diffusion: The solubility of CO_2 in water may be lower than in oil, implying that with an increase in water content, more CO_2 remains in the gas phase or supercritical phase, reducing its efficiency in entering the oil phase and mixing with it.
(4) Impact of pore structure: Water might occupy space in the rock pores, restricting the pathways for CO_2 molecules to reach the oil phase, especially in porous media such as reservoir rocks.
As the water content increases, the pressure requirement for effective CO_2 miscibility significantly rises. This must be considered when designing CO_2 flooding projects, especially in reservoirs with high water content, where higher injection pressures may be required, or other enhanced recovery measures such as water management, modification of the injection fluid, etc., should be considered to improve the efficiency of CO_2 flooding.

4. Conclusions

(1) As the water content increases, the minimum miscibility pressure (MMP) generally shows an upward trend. In the absence of water, the MMP is at its lowest at 31.11 MPa. In a pure oil phase, the pressure required for CO_2 to mix with crude oil is relatively lower. When the water content reaches 90%, the MMP hits its highest value at 37.94 MPa. Under high water conditions, the pressure needed for CO_2 to mix with crude oil significantly increases due to the substantial impediment of CO_2's diffusion and dissolution caused by the presence of water.
(2) Based on these research findings, the increase in water content significantly impacts the MMP during the CO_2

flooding process, showing a positive correlation trend. As the water content increases, the MMP gradually rises, indicating that higher pressure is required to achieve a mix between CO_2 and the oil phase. This result underscores the importance of controlling water content in optimizing oil displacement efficiency and cost control during the CO_2 flooding process.

(3) With the increase in water content, the solubility and diffusion capability of CO_2 are affected, leading to changes in the minimum miscibility pressure. Additionally, the stability of the water film significantly impacts CO_2 breakthrough and the interfacial tension between oil and water. Under high water content conditions, accurate prediction and control of the minimum miscibility pressure are required for effective CO_2 flooding, providing a theoretical basis for the application of CO_2 flooding technology in complex reservoir conditions and helping to guide the development strategy of actual oil fields to improve recovery rates and economic benefits. Future research should further consider the effects of CO_2 flooding under different reservoir conditions and how to optimize operational parameters to adapt to high water environments.

(4) When designing and optimizing CO_2 displacement schemes, it is essential to fully consider the actual formation water content to develop more accurate and effective injection strategies, overcome the challenges brought by high water content, and maximize crude oil recovery benefits. Additionally, this study indicates that through targeted technical improvements, such as using surfactants to reduce oil-water interfacial tension or improving formation wettability, it may be possible to lower the pressure threshold required to reach the minimum miscibility pressure under high water conditions, thus providing new ideas and technical support for solving the development challenges of high water content reservoirs.

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