

# Characteristics of Crude Oil Mobilization and Displacement Mechanisms in Low-Permeability Conglomeratic Sandstone Reservoirs under Different Development Modes: An NMR-Based Study

Yuhui Zhou

Yangtze University

Yuchen Pei

1228847336@qq.com

Yangtze University

Xu Ren

Research Institute of Exploration and Development, PetroChina Xinjiang Oilfield Company

Chao Chen

Research Institute of Exploration and Development, PetroChina Xinjiang Oilfield Company

Shaoyang Geng

Yangtze University

Qi Zhang

China University of Geosciences

Shiyi Zheng

University of Portsmouth

---

## Article

**Keywords:** CO<sub>2</sub> flooding, Water flooding, Spontaneous imbibition, Pore-Scale oil mobilization, Oil displacement mechanism

**Posted Date:** September 25th, 2026

**DOI:** <https://doi.org/10.21203/rs.3.rs-10669567/v1>

**License:**  This work is licensed under a Creative Commons Attribution 4.0 International License.

[Read Full License](#)

**Additional Declarations:** No competing interests reported.

---

# Characteristics of Crude Oil Mobilization and Displacement Mechanisms in Low-Permeability Conglomeratic Sandstone Reservoirs under Different Development Modes: An NMR-Based Study

Yuhui Zhou<sup>a,b,c</sup>, Yuchen Pei<sup>a,c,\*</sup>, Xu Ren<sup>d</sup>, Chao Chen<sup>d</sup>,  
Shaoyang Geng<sup>a,b,c</sup>, Qi Zhang<sup>b,c</sup>, Shiyi Zheng<sup>e</sup>

<sup>a</sup> School of Petroleum Engineering, Yangtze University, WuHan, 430100, China

<sup>b</sup> Western Research Institute, Yangtze University, Karamay, 834000, China

<sup>c</sup> State Key Laboratory of Low Carbon Catalysis and Carbon Dioxide Utilization (Yangtze University)

<sup>d</sup> Exploration and Development Research Institute of Xinjiang Oilfield Company, Karamay, 834000, China

<sup>e</sup> School of Mechanical and Design Engineering, University of Portsmouth, Portsmouth, PO1 3DJ, United Kingdom

\*Corresponding author: 1228847336@qq.com (Yuchen Pei)

## Abstract

Oil recovery from ultra-low-permeability sandy conglomerate reservoirs is severely constrained by complex pore-throat structures and strong heterogeneity. In this study, low-field nuclear magnetic resonance (NMR)  $T_2$  spectra and  $T_1$ – $T_2$  maps were integrated with spontaneous imbibition, water flooding, supercritical  $\text{CO}_2$  flooding, and water flooding followed by  $\text{CO}_2$  flooding experiments to quantify oil mobilization in micropores, small pores, mesopores, and macropores. Spontaneous imbibition primarily recovered oil from micropores and small pores under capillary forces, whereas macropores mainly served as fluid-flow pathways. Water flooding preferentially displaced oil from mesopores and macropores but exhibited limited access to smaller pores because of high capillary resistance and threshold pressure gradients, resulting in final recovery factors of 31.2–46.7%. In contrast, supercritical  $\text{CO}_2$  flooding extended the lower pore-size limit of oil mobilization through molecular diffusion, hydrocarbon extraction, oil swelling, and viscosity reduction, achieving recovery factors of 61.6–79.4%. Subsequent  $\text{CO}_2$  injection after water flooding further recovered bypassed oil, particularly from small pores and mesopores, although micropores remained the principal residual-oil storage space. These results demonstrate that water flooding and  $\text{CO}_2$  flooding are complementary at the pore scale: water flooding provides effective pressure-driven displacement through larger pores, whereas  $\text{CO}_2$  enhances microscopic oil mobilization within finer pores. The findings provide an experimental basis for selecting and sequencing enhanced oil recovery methods in heterogeneous ultra-low-permeability sandy conglomerate reservoirs.

**Keywords:** CO<sub>2</sub> flooding; Water flooding; Spontaneous imbibition; Pore-Scale oil mobilization; Oil displacement mechanism

## 1 Introduction

Low- to ultra-low-permeability sandy conglomerate reservoirs constitute an important unconventional replacement resource in China's continental petroliferous basins and have become a major target for reserve growth and production enhancement in the Xinjiang Oilfield<sup>[1]</sup>. Compared with conventional sandstone reservoirs, sandy conglomerate reservoirs are characterized by rapid sedimentary facies variations, complex lithologic assemblages, and pore-throat systems jointly controlled by gravel-framework support and sandy-muddy infilling<sup>[2-4]</sup>. Consequently, these reservoirs commonly exhibit low porosity, low permeability, strong heterogeneity, and extensively developed micro- and fine-scale pore throats, resulting in limited sweep efficiency of injected fluids, high threshold pressure gradients, and considerable difficulty in mobilizing the original oil in place<sup>[5]</sup>. Publicly available information indicates that the Xinjiang Oilfield primarily operates oil and gas resources in the Junggar Basin. Among these resources, the Mahu Oilfield is a giant oilfield with geological reserves on the order of one billion tonnes and is widely recognized as the world's largest integrated conglomerate oilfield<sup>[6]</sup>. This highlights the importance of sandy conglomerate reservoirs as a fundamental resource base for large-scale production construction and long-term stable output in the Xinjiang Oilfield. At present, a series of development technologies have been applied to such reservoirs, including water flooding, horizontal wells combined with volumetric fracturing, well-pattern adjustment, cyclic water injection, gas injection for pressure maintenance, and CO<sub>2</sub> flooding for enhanced oil recovery. Water flooding remains the most widely used development method for low-permeability sandy conglomerate reservoirs because of its technical maturity, relatively low cost, and broad field applicability. CO<sub>2</sub> flooding can improve oil recovery through oil swelling, viscosity reduction, extraction of light hydrocarbon components, interfacial-tension reduction, and enhanced access to fine pore throats<sup>[7,8]</sup>. It also provides potential benefits for geological carbon storage and therefore shows considerable promise in low-permeability reservoirs. However, both field performance and laboratory experiments have demonstrated that water injection into low-permeability sandy conglomerate reservoirs is frequently associated with poor volumetric sweep despite acceptable injectivity, preferential breakthrough through large flow channels, and substantial residual-oil enrichment in micropores. Although CO<sub>2</sub> has stronger diffusion and extraction capacities, its displacement performance is also highly controlled by reservoir heterogeneity and is therefore vulnerable to gas channeling<sup>[9]</sup>. Accordingly, the selective mobilization characteristics of oil stored in micropores, small pores, medium pores, and large pores under different development methods remain insufficiently understood. In particular, whether spontaneous imbibition, water flooding, and CO<sub>2</sub> flooding exhibit complementary effects at the pore scale has not yet been systematically clarified.

Extensive studies have been conducted on the mechanisms governing oil mobilization in low-permeability and tight reservoirs. With respect to spontaneous imbibition, Qin et al<sup>[10,11]</sup> investigated the dynamic invasion of the wetting phase into pore networks from the pore scale to the Darcy scale<sup>[12]</sup>. They demonstrated that pore-scale heterogeneity significantly affects wetting-front propagation, non-wetting-phase trapping, and capillary-pressure transmission,

thereby providing a theoretical basis for understanding matrix-oil mobilization in tight reservoirs. Huang et al<sup>[13]</sup>. conducted dynamic imbibition experiments on Chang 6 tight-oil reservoir samples from the Jiyuan Oilfield in the Ordos Basin by integrating mercury intrusion porosimetry, NMR, and scanning electron microscopy<sup>[14]</sup>. They divided the dynamic imbibition process in fracture–matrix systems into three stages: rapid oil mobilization from large pores, gradual oil recovery from micro- and small pores, and eventual imbibition equilibrium<sup>[14]</sup>. Their results further indicated that, as reservoir quality deteriorates, the contribution of oil mobilized from micro- and small pores to the total recovery becomes increasingly important. Regarding water flooding, previous NMR studies have shown that injected water preferentially advances through well-connected medium and large pore throats in tight sandstone<sup>[15]</sup>. In contrast, oil stored in micro- and small pores is difficult to displace because of capillary resistance, bound-water films, and threshold pressure gradients. For CO<sub>2</sub> flooding, Li systematically reviewed CO<sub>2</sub>-enhanced oil recovery technologies in low-permeability reservoirs and concluded that CO<sub>2</sub> flooding is well suited to continental low-permeability reservoirs in China<sup>[16,17]</sup>. Its principal recovery mechanisms include dissolution-induced swelling, viscosity reduction, hydrocarbon extraction, interfacial-tension reduction, and improvement of microscopic displacement efficiency. Li et al<sup>[18,19]</sup>. investigated CO<sub>2</sub> flooding in tight sandstone reservoirs under different pressure conditions and demonstrated that pressure variations influence mass transfer and dissolution between CO<sub>2</sub> and crude oil, thereby controlling the extent of oil recovery from pores of different sizes. These studies have provided an important foundation for understanding water flooding, CO<sub>2</sub> flooding, and imbibition in low-permeability reservoirs. Nevertheless, most previous investigations have focused on tight sandstone, shale oil, ultra-low-permeability reservoirs in the Changqing Oilfield, or idealized porous media. Reservoir-specific studies on low-permeability sandy conglomerates in the Xinjiang Oilfield remain limited. Moreover, existing studies generally emphasize recovery evaluation under a single development method, whereas systematic comparisons among spontaneous imbibition, water flooding, CO<sub>2</sub> flooding, and water flooding followed by CO<sub>2</sub> flooding within a unified pore-scale framework are scarce. Consequently, several critical questions remain unanswered: which pore-size classes are preferentially mobilized by different displacement methods, where the remaining oil is predominantly retained, and whether subsequent CO<sub>2</sub> flooding can effectively recover residual oil left behind after water flooding<sup>[20]</sup>.

Based on these considerations, this study investigates representative ultra-low-permeability sandy conglomerate reservoir cores from the Xinjiang Oilfield<sup>[21,22]</sup>. Core samples with different petrophysical properties were collected from the Kexia and Baikouquan formations, and spontaneous imbibition, water flooding, supercritical CO<sub>2</sub> flooding, and water flooding followed by CO<sub>2</sub> flooding experiments were conducted in combination with NMR measurements<sup>[23]</sup>. A total of 28 core samples were selected for basic petrophysical characterization, among which 14 samples were further subjected to coupled nuclear magnetic resonance displacement experiments. The selected cores covered ultra-low-, low-, and medium-to-low-permeability intervals and therefore adequately represented the strong heterogeneity and pore-scale variations of the target sandy conglomerate reservoirs. NMR T<sub>2</sub> spectra and two-dimensional nuclear magnetic resonance maps were used to identify fluid occurrence states within different pore-size ranges. The pore system was classified into micropores, small pores, medium pores, and large pores, and the degree of oil mobilization and residual-oil distribution in each pore class were quantitatively evaluated under different development methods<sup>[24,25]</sup>. This study focuses on three objectives. First, it

determines the selective mobilization patterns of oil in different pore-size classes during spontaneous imbibition, water flooding, and CO<sub>2</sub> flooding. Second, it elucidates the microscopic mechanisms responsible for inefficient water flooding, residual-oil enrichment in micropores, and the extension of the lower pore-size limit of oil mobilization by CO<sub>2</sub> in low-permeability sandy conglomerate reservoirs. Third, it evaluates the supplementary recovery of water flood-bypassed residual oil by subsequent CO<sub>2</sub> flooding and clarifies the synergistic and complementary mechanisms of water and CO<sub>2</sub> displacement at the pore scale. The results provide a pore-scale experimental basis for selecting suitable development methods, evaluating the transition from water flooding to CO<sub>2</sub> flooding, identifying remaining-oil potential, and designing enhanced oil recovery strategies for low-permeability sandy conglomerate reservoirs in the Xinjiang Oilfield.

## 2 Materials and methods

### 2.1. Materials

#### 2.1.1 Experimental Materials

A total of 28 core samples were collected from two key cored wells (X9 and X65) in the study area. The sampled intervals included the Lower Kexia Formation (S<sub>7</sub><sup>4</sup> and S<sub>8</sub><sup>3</sup>) and the Baikouquan Formation (T<sub>1</sub>b<sub>2</sub><sup>1</sup> and T<sub>1</sub>b<sub>2</sub><sup>2</sup>). To ensure the representativeness of the experimental results, 28 core plugs with intact morphology and without obvious induced fractures were selected from the cored intervals. These samples comprehensively covered the typical lithological and petrophysical characteristics of the main reservoirs in the target area and were sufficient to support subsequent petrophysical characterization and fluid displacement mechanism investigations.

Based on the experimental objectives, 14 core samples were further selected for integrated NMR experiments. Specifically, the SI series was used for spontaneous imbibition experiments, the WF series for water flooding experiments, the GF series for CO<sub>2</sub> flooding experiments, and the TF series for water flooding followed by CO<sub>2</sub> flooding experiments. The selected cores covered different permeability levels, including ultra-low permeability, low permeability, and medium-low permeability reservoirs, thereby adequately reflecting the heterogeneity characteristics of the target reservoir and the oil mobilization behavior under different development methods. Detailed coring information and core sample identification numbers are presented in Table 1 and Figure 1.

Table 1. Basic petrophysical properties of core samples used in different experiments

| No | Experimental type      | Core ID | Weight (g) | Diameter (cm) | Length (cm) | Permeability (mD) | Porosity (%) |
|----|------------------------|---------|------------|---------------|-------------|-------------------|--------------|
| 1  | Spontaneous imbibition | SI-1    | 72.22      | 2.45          | 6.96        | 0.33935           | 10.74        |
| 2  | Spontaneous imbibition | SI-2    | 39.47      | 2.45          | 3.58        | 0.06642           | 7.82         |
| 3  | Spontaneous imbibition | SI-3    | 62.00      | 2.45          | 5.46        | 0.01895           | 6.85         |
| 4  | Spontaneous imbibition | SI-4    | 53.85      | 2.45          | 4.90        | 0.10163           | 7.48         |
| 5  | Spontaneous imbibition | SI-5    | 40.71      | 2.45          | 3.69        | 1.19943           | 8.15         |
| 6  | Water flooding         | WF-1    | 91.95      | 2.45          | 8.58        | 0.04168           | 7.87         |

|    |                                                           |      |       |      |      |         |      |
|----|-----------------------------------------------------------|------|-------|------|------|---------|------|
| 7  | Water flooding                                            | WF-2 | 45.69 | 2.45 | 4.13 | 0.30326 | 8.52 |
| 8  | Water flooding                                            | WF-3 | 77.01 | 2.45 | 6.79 | 5.57430 | 7.42 |
| 9  | CO <sub>2</sub> flooding                                  | GF-1 | 58.54 | 2.45 | 5.34 | 0.02113 | 8.08 |
| 10 | CO <sub>2</sub> flooding                                  | GF-2 | 60.27 | 2.45 | 5.83 | 0.13372 | 8.96 |
| 11 | CO <sub>2</sub> flooding                                  | GF-3 | 69.81 | 2.45 | 6.70 | 1.40931 | 9.36 |
| 12 | Water flooding<br>followed by CO <sub>2</sub><br>flooding | TF-1 | 84.56 | 2.45 | 6.51 | 0.05721 | 7.88 |
| 13 | Water flooding<br>followed by CO <sub>2</sub><br>flooding | TF-2 | 78.30 | 2.45 | 5.83 | 0.28443 | 8.06 |
| 14 | Water flooding<br>followed by CO <sub>2</sub><br>flooding | TF-3 | 79.11 | 2.45 | 5.76 | 4.68395 | 7.61 |

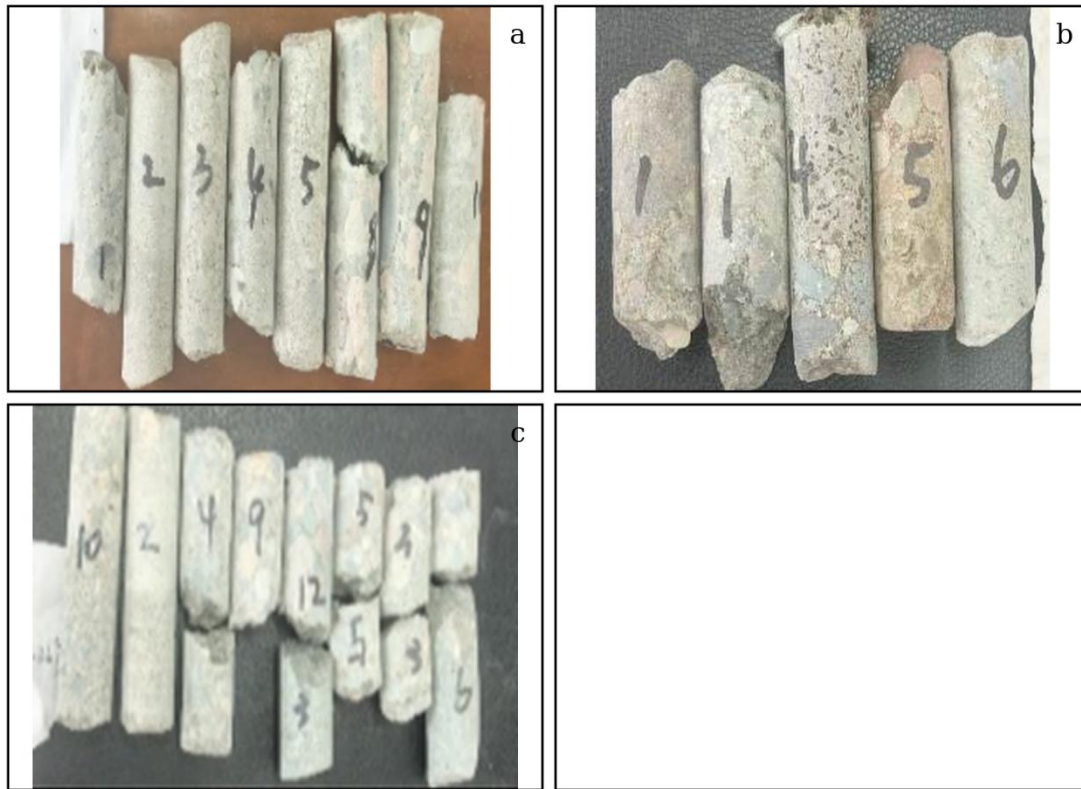


Figure 1. Photographs of the core samples

To ensure comparability among different experimental schemes, core samples with similar porosity and different permeability levels were selected for each experimental group. This approach allowed for a systematic assessment of the effects of various development methods on crude oil mobilization behavior in pores of different scales, as well as the corresponding recovery efficiency.

### 2.1.2 Experimental Apparatus

An integrated NMR experimental system was employed to conduct spontaneous imbibition, water flooding, CO<sub>2</sub> flooding, and water flooding followed by CO<sub>2</sub> flooding experiments. As shown in Figure 2, the system consists of a fluid supply system, a core holder system, a fluid measurement system, and an NMR measurement system, which can satisfy the requirements for investigating fluid migration behavior and residual oil distribution characteristics under different development methods.

The fluid supply system mainly comprises simulated formation fluid storage vessels, a CO<sub>2</sub> cylinder, pressure regulation devices, and connecting pipelines, which are used to provide the displacement media required for the experiments and ensure stable fluid delivery throughout the experimental process. The core holder system primarily consists of a core holder and its associated accessories, which are used to secure the core samples and simulate reservoir fluid flow conditions. The fluid measurement system includes a produced-fluid collection unit, oil–water metering devices, and a gas flow meter, enabling real-time monitoring and quantification of the produced oil, water, and gas during the experiments. The NMR measurement system employs a low-field NMR analyzer to determine the T<sub>2</sub> relaxation spectrum of the core samples, thereby characterizing pore structure properties and fluid occurrence states.

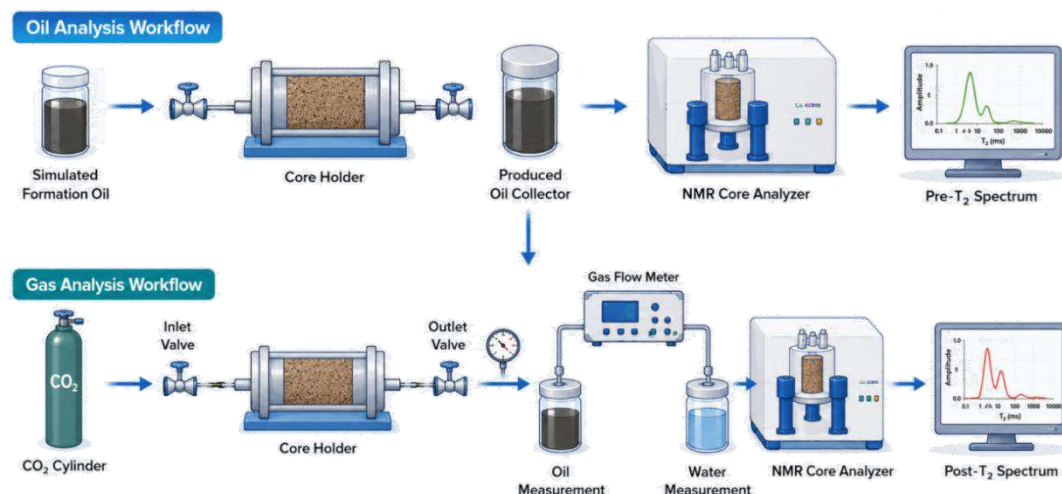


Figure 2. Schematic diagram of the experimental workflow

## 2.2. Methods

### 2.2.1 Spontaneous Imbibition Experiment

Core samples collected from the study area were used in this experiment. Deuterium oxide (D<sub>2</sub>O, heavy water) was selected as the imbibition medium, and an integrated spontaneous imbibition and two-dimensional 2D NMR experiment was conducted at a constant temperature of 60 °C for 12 days. The objective was to elucidate the pore-scale oil mobilization mechanisms of ultra-low permeability conglomerate reservoirs during water injection and CO<sub>2</sub> injection development.

The experimental procedures were as follows:

**(a) Core pretreatment and basic petrophysical measurements:** The core samples were cut,

polished, and labeled, followed by a 15-day solvent extraction process to remove residual oil. After drying to a constant weight, the basic parameters, including length, diameter, and dry weight, were measured, and the gas permeability and porosity were subsequently determined.

**(b) Initial-state characterization:** The NMR  $T_2$  spectrum of each dry core sample was measured to establish the baseline signal for subsequent analyses.

**(c) Fluid saturation and aging:** The core samples were first vacuumed and saturated with formation water. Subsequently, simulated crude oil was injected using a core holder until no water was produced at the outlet, thereby establishing the initial oil saturation. The cores were then subjected to an aging process to restore reservoir wettability conditions.

**(d) Spontaneous imbibition and dynamic monitoring:** The oil-saturated core samples were immersed in imbibition bottles filled with  $D_2O$  and placed in a constant-temperature oven at 60 °C to initiate spontaneous imbibition. NMR  $T_2$  measurements were performed on Days 1, 2, 4, 6, 8, and 12 to monitor the dynamic evolution of fluid distribution during the imbibition process.

**(e) Data processing and mechanism analysis:** After the experiments, the acquired NMR signals were inverted to generate  $T_2$  spectra at different imbibition stages. By comparing changes in signal amplitudes, the oil–water displacement efficiency within different pore-size intervals was quantitatively calculated, and the effectiveness of spontaneous imbibition in mobilizing microscopic residual oil was evaluated.

**(f) Parallel experiments:** To ensure the reliability and reproducibility of the experimental results, multiple core samples were selected, and the above procedures were repeated under identical conditions.

### *2.2.2 Water Flooding Experiment*

The detailed procedures of the water flooding experiment are described as follows:

**(a) Crude oil saturation:** After vacuuming, the outlet valve was closed, and prepared simulated crude oil was injected into the core sample mounted in the core holder using a constant-pressure displacement pump or a booster pump. Oil injection was continuously conducted under a constant pressure until no gas bubbles were observed at the outlet and the injected oil volume substantially exceeded the pore volume of the core, ensuring complete crude oil saturation.

**(b) NMR measurements after oil saturation:** The oil-saturated core samples were subjected to NMR  $T_2$  measurements while maintaining their original state to obtain the baseline spectra prior to flooding. These measurements were used to characterize the initial distribution of crude oil within the pore space and the corresponding pore structure characteristics.

**(c) Water flooding experiment:** The core sample remained in the core holder, and both the inlet and outlet valves were opened. Under predetermined temperature and confining pressure conditions, simulated formation water was injected into the core at a constant flow rate using a high-pressure constant-rate pump to perform the water flooding experiment. Throughout the experiment, the injection pressure was continuously recorded, while the volumes of produced oil and produced water at the outlet were periodically measured using precision metering devices.

**(d) Post-flooding microscopic mobilization evaluation:** Immediately after the flooding experiment, NMR  $T_2$  measurements were performed on the core samples. The  $T_2$  spectra obtained before and after flooding were superimposed and compared to identify signal attenuation intervals. Subsequently, the final oil recovery and the mobilization degree of different pore-size ranges (micropores, small pores, mesopores, and macropores) were quantitatively determined. Based on

these results, the effective lower pore-throat limit for water flooding and the preferential accumulation zones of microscopic residual oil were identified.

### 2.2.3 CO<sub>2</sub> Flooding Experiment

The detailed procedures of the CO<sub>2</sub> flooding experiment are described as follows:

**(a) Core saturation and aging:** The core sample was placed in a core holder and subjected to confining pressure. After vacuum treatment, simulated crude oil was injected into the core using a high-pressure constant-rate pump. Oil injection was continuously performed under constant pressure until stable oil production was observed at the outlet without gas bubbles, ensuring complete oil saturation of the core. Subsequently, the core was aged at the simulated reservoir temperature to restore the wettability characteristics of the rock surface.

**(b) Initial-state NMR measurements:** After oil saturation and aging, the core sample was removed and subjected to NMR T<sub>2</sub> measurements to obtain the baseline spectrum prior to flooding. These measurements were used to characterize the initial distribution of crude oil within micropores, small pores, mesopores, and macropores.

**(c) Experimental system setup and temperature–pressure equilibration:** The core sample was reinstalled in the core holder and connected to a back-pressure valve and a gas–liquid separation and metering system. The entire core holder assembly was then placed in a constant-temperature oven and heated to the reservoir temperature to ensure that CO<sub>2</sub> remained in the supercritical state. The back-pressure valve was adjusted to maintain a pressure higher than the minimum miscibility pressure (MMP) of the crude oil–CO<sub>2</sub> system. Meanwhile, the confining pressure conditions were maintained according to  $P_{\text{conf}} > P_{\text{in}} > P_{\text{out}}$ .

**(d) Supercritical CO<sub>2</sub> flooding experiment:** The valves between the intermediate vessel and the core holder were opened, and preheated supercritical CO<sub>2</sub> was injected into the core at a constant rate using a high-pressure displacement pump. The inlet and outlet pressures were continuously monitored throughout the experiment. The produced fluids passed through the back-pressure valve and entered a gas–liquid separator, where gas production was measured using a gas flow meter and oil production was recorded using a precision graduated cylinder. The experiment was terminated when the cumulative CO<sub>2</sub> injection reached the predetermined amount or when the gas–oil ratio increased sharply and no additional oil was produced.

**(e) Post-flooding microscopic mobilization evaluation:** After the experiment, the back pressure and confining pressure were gradually released, and the core sample was immediately subjected to post-flooding NMR T<sub>2</sub> measurements. The T<sub>2</sub> spectra obtained before and after flooding were normalized and superimposed for comparison. Differences in signal areas corresponding to micropores, small pores, mesopores, and macropores were calculated to quantify the recovery efficiency of CO<sub>2</sub> flooding at different pore scales. These results were further used to determine the lower pore-throat limit effectively mobilized by CO<sub>2</sub> flooding and to characterize the distribution patterns of residual oil.

### 2.2.4 Water Flooding Followed by CO<sub>2</sub> Flooding Experiment

The procedures of the water flooding followed by CO<sub>2</sub> flooding experiment are described as follows:

**(a) Core pretreatment and baseline NMR measurements:** The tight sandstone core samples were subjected to solvent extraction using toluene, petroleum ether, and ethanol for one week to

remove residual hydrocarbons. The cores were subsequently dried in an oven at 120 °C for 24 h. Basic petrophysical properties, including length, diameter, weight, porosity, and permeability, were measured. Thereafter, NMR  $T_2$  measurements were performed to obtain the baseline signal of the dry cores.

**(b) Formation water saturation:** After drying, the cores were placed in a core holder and subjected to a confining pressure of 3 MPa. Following vacuum treatment for 12 h, simulated formation water was injected into the cores at a constant flow rate of 0.1 mL min<sup>-1</sup> until full water saturation was achieved. NMR  $T_2$  measurements were then conducted under the water-saturated condition.

**(c) Heavy-water treatment:** The water-saturated cores were immersed in deuterium oxide (D<sub>2</sub>O, heavy water), followed by a second NMR measurement to reduce the hydrogen signal intensity to less than 1% of the original signal, thereby minimizing the interference from formation water during subsequent analyses.

**(d) Crude oil saturation:** Simulated formation crude oil was injected into the cores at a constant displacement pressure differential of 15 MPa to displace the formation water. Oil injection was terminated when no additional water was produced at the outlet. Subsequently, the wet weight of each core was measured, and NMR  $T_2$  measurements were performed under irreducible water conditions to obtain the NMR signal characteristics of the oil-saturated cores.

**(e) Water flooding experiment:** The tested cores were resealed in the core holder. Water flooding was then conducted under an injection pressure of 25 MPa, a back pressure of 20 MPa, and a confining pressure of 30 MPa. During the experiment, the injected volume, oil production, and water production were continuously recorded. The experiment was terminated when no additional oil was produced from the oil–water separator. Subsequently, three repeated NMR  $T_2$  measurements were performed on the water-flooded cores.

**(f) CO<sub>2</sub> flooding after water flooding:** After NMR testing, the cores were resealed in the core holder. CO<sub>2</sub> flooding was then performed under miscible flooding conditions with an injection pressure of 25 MPa, a back pressure of 20 MPa, and a confining pressure of 30 MPa. The injected CO<sub>2</sub> volume and oil production were continuously recorded throughout the experiment. Gas injection was terminated when no further oil was produced from the oil–water separator. Finally, three repeated NMR  $T_2$  measurements were conducted on the cores after CO<sub>2</sub> flooding.

## 3 Results

### 3.1 Oil Mobilization Characteristics during Spontaneous Imbibition

#### 3.1.1 Evolution characteristics of the $T_2$ spectra during spontaneous imbibition

According to the principles of NMR, different pore sizes exhibit different  $T_2$  relaxation times. Therefore, the distribution patterns of the  $T_2$  spectra directly reflect the size and distribution characteristics of the microscopic pore structure within the rock. As shown in **Figure 3**, the  $T_2$

spectra of the investigated core samples mainly exhibit two typical distribution patterns, namely bimodal and unimodal distributions, revealing the pronounced heterogeneity of ultra-low permeability conglomerate reservoirs.

For the bimodal distribution (**Figure 3(a)**), two distinct signal peaks separated by an obvious trough are observed. The left peak corresponds to shorter relaxation times, representing micropores or clay-bound water regions, whereas the right peak corresponds to longer relaxation times, indicating larger pores or macroscopic seepage channels. This bimodal pattern suggests the coexistence of two pore systems with different scales, including abundant micropores and a certain proportion of large pore throats. In addition, clear connectivity and transitional regions exist between small and large pores, indicating strong reservoir heterogeneity. In contrast, the unimodal distribution (**Figure 3(b)**) is characterized by a continuous dominant peak, indicating a relatively concentrated and continuous pore-size distribution without a distinct dual-porosity medium. In ultra-low permeability reservoirs, the unimodal peak is generally located in the left region of the  $T_2$  spectrum, implying that the storage space is mainly composed of micro- and nanoscale micropores and small pores, while large pores are poorly developed or account for only a small proportion. Consequently, pore-throat sorting is relatively poor, resulting in high fluid flow resistance.

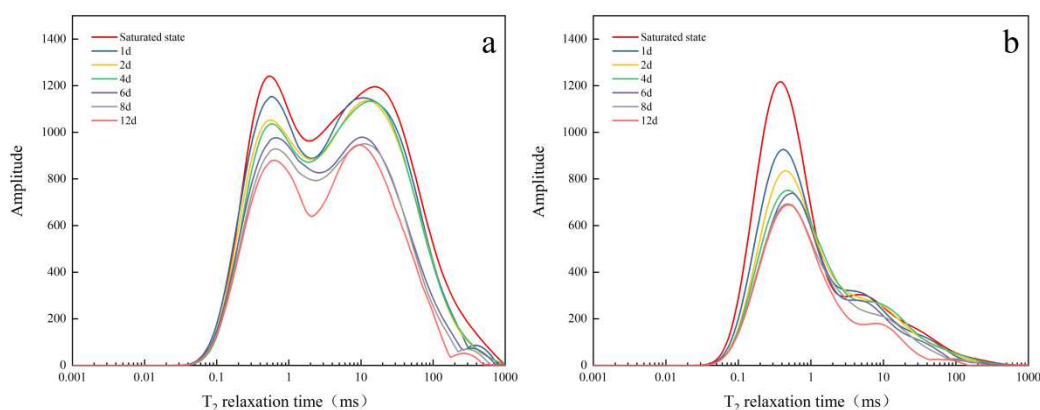


Figure 3. Typical  $T_2$  spectral distributions of different core samples

Three core samples with similar porosities but permeabilities spanning three orders of magnitude, namely SI-3 (0.019 mD), SI-4 (0.102 mD), and SI-5 (1.199 mD), were selected for analysis. Figures 4(a) – (c) illustrate the evolution of the NMR  $T_2$  spectra during spontaneous imbibition, objectively reflecting the controlling effect of permeability on pore-scale oil mobilization. The signal amplitudes of all three cores continuously decreased over time, indicating the spontaneous imbibition of water into the cores and confirming their water-wet characteristics.

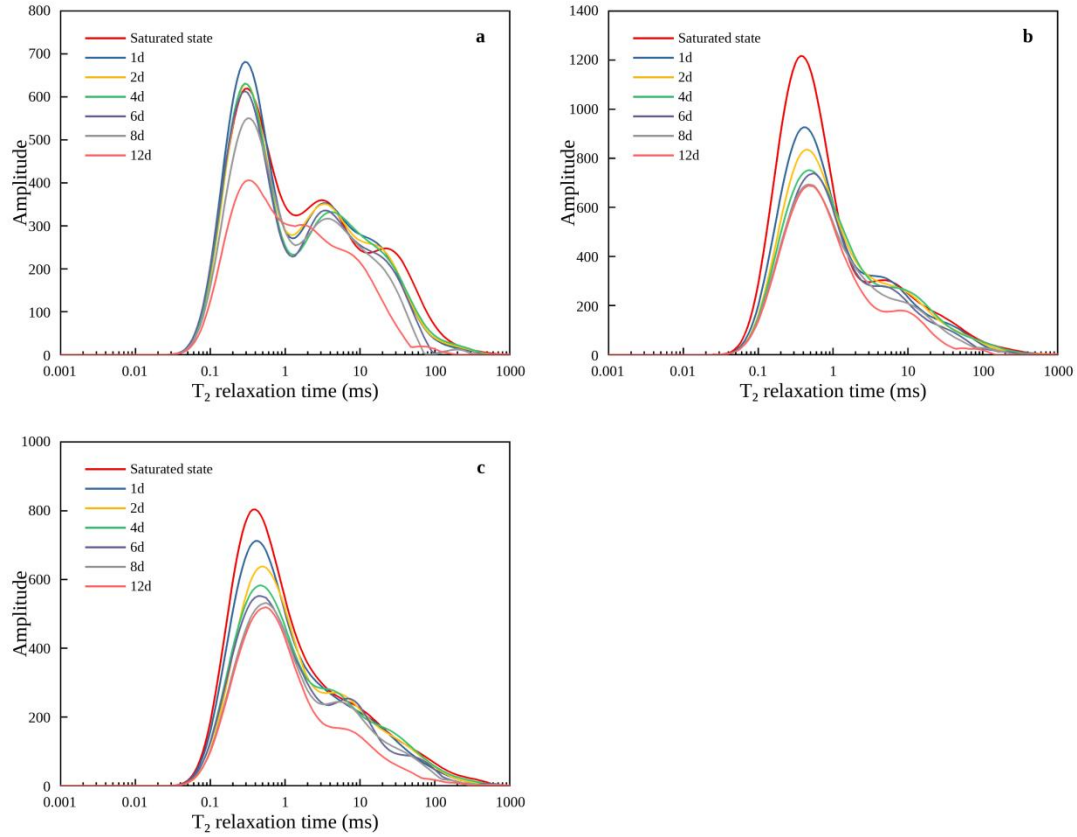


Figure 4. Evolution characteristics of the  $T_2$  spectra for core samples with different permeability levels

Comparison of the three cores indicates that the spectral peaks gradually shift toward longer relaxation times with increasing permeability, suggesting that the dominant storage space changes from micro- and nanoscale pores to micron-scale larger pores.

Regarding oil mobilization behavior, the signal amplitude within the left-side micropore region of the ultra-low permeability core SI-3 decreased significantly over time under strong capillary forces, indicating that capillary pressure is the primary driving force for overcoming flow resistance and displacing crude oil trapped in micropores (**Figure 4(a)**). In contrast, for the higher-permeability core SI-5, although oil saturation in the large-pore region decreased substantially, no obvious attenuation was observed in the left-side micropore region throughout the imbibition process (**Figure 4(c)**).

This difference indicates that in cores with relatively favorable petrophysical properties, the aqueous phase preferentially occupies large pores with lower flow resistance and forms dominant flow channels. Consequently, micropores remain in a water-blocked state because of insufficient capillary pressure gradients or the influence of the Jamin effect.

Overall, spontaneous imbibition exhibits strong pore-size selectivity. In ultra-low permeability tight zones, strong capillary forces facilitate oil recovery from micropores, whereas in higher-permeability regions, water tends to bypass the smaller pores, leading to residual oil accumulation within these pore spaces.

Table 2. Classification criteria for pore sizes in tight rocks

| T <sub>2</sub> relaxation time (ms) | Pore radius (μm) | Pore classification |
|-------------------------------------|------------------|---------------------|
| T <sub>2</sub> <1                   | r<0.02           | Micropores          |
| 1≤T <sub>2</sub> <10                | 0.02≤r<0.25      | Small pores         |
| 10≤T <sub>2</sub> <100              | 0.25≤r<1         | Mesopores           |
| T <sub>2</sub> ≥100                 | r≥2              | Macropores          |

### 3.1.2 Oil mobilization characteristics in different pore systems

As shown in **Table 3**, spontaneous imbibition exhibits different mobilization efficiencies for crude oil with different occurrence states, and adsorbed oil is the primary component mobilized during the imbibition process.

For the ultra-low permeability core SI-3, the proportion of adsorbed oil decreased from 59.44% to 44.02%, corresponding to a reduction of 15.42 percentage points, which is substantially greater than the 5.21 percentage-point reduction observed for free oil. This indicates that strong capillary forces within the tight matrix are the main mechanism for overcoming adsorption resistance and displacing trapped oil from micropores. This finding also explains why ultra-low permeability reservoirs often exhibit higher-than-expected matrix oil recovery after prolonged shut-in periods.

By comparison, core SI-4 exhibited the highest overall mobilization efficiency, reaching 31.94 percentage points, suggesting an optimal combination of capillary forces and pore connectivity within this petrophysical range.

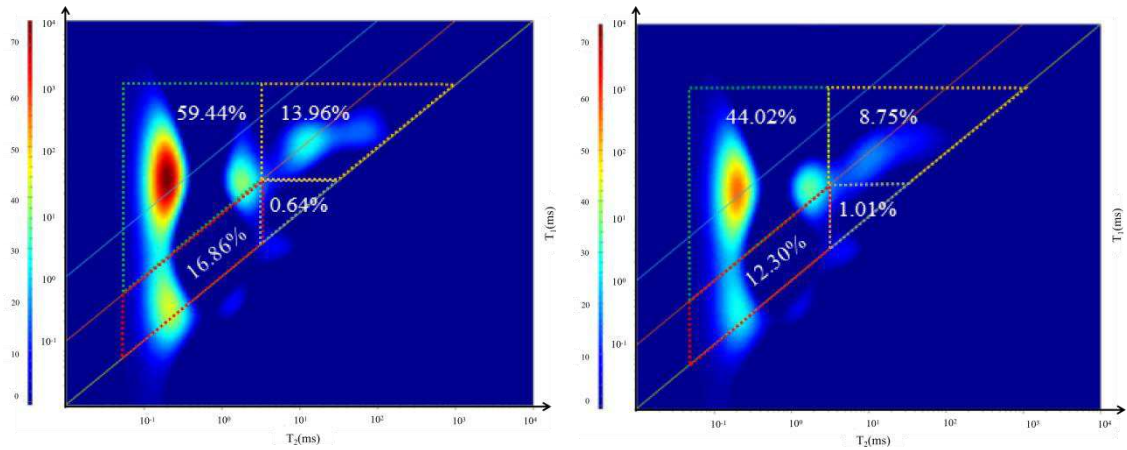
In contrast, the mobilization efficiency of free oil in the high-permeability core SI-5 did not improve with increasing permeability, with a reduction of only 3.16%, which was even lower than that observed for the ultra-low permeability core. This indicates that pore systems dominated by large pores exhibit relatively weak capillary forces. In the absence of external pressure gradients, oil–water displacement driven solely by gravity segregation is inefficient.

Overall, spontaneous imbibition can effectively mobilize adsorbed oil trapped within micropores<sup>[26]</sup>. Within a certain permeability range, stronger capillary forces are generated as the rock becomes tighter, thereby enhancing the mobilization of residual oil located deep within the reservoir matrix.

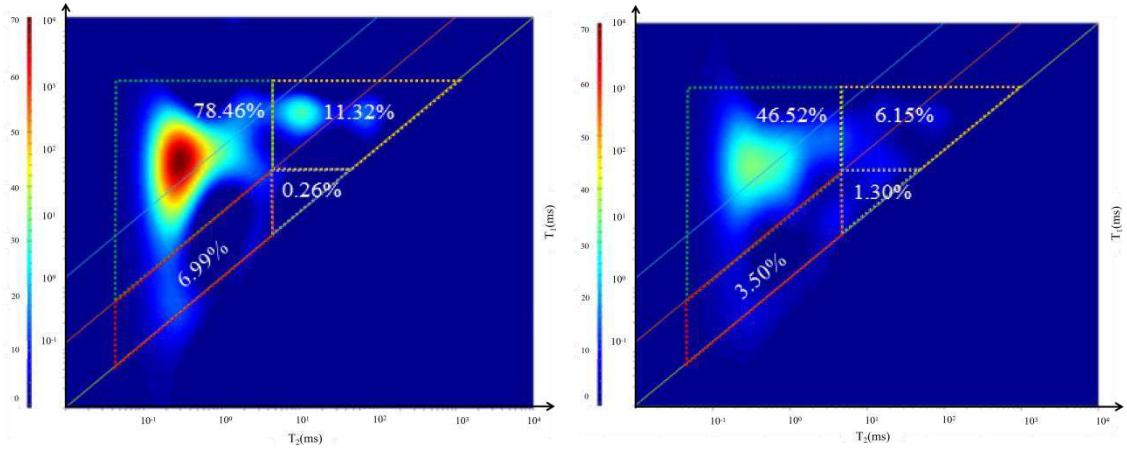
Table 3. Statistics of oil mobilization efficiency during spontaneous imbibition

| Core sample | Free oil (%)      |                  | Adsorbed oil (%)  |                  | Movable water (%) |                  | Bound water (%)   |                  |
|-------------|-------------------|------------------|-------------------|------------------|-------------------|------------------|-------------------|------------------|
|             | Before imbibition | After imbibition | Before imbibition | After imbibition | Before imbibition | After imbibition | Before imbibition | After imbibition |
| SI-3        | 13.96             | 8.75             | 59.44             | 44.02            | 0.64              | 1.01             | 16.86             | 12.30            |
| SI-4        | 11.32             | 6.15             | 78.46             | 46.52            | 0.26              | 1.30             | 6.99              | 3.50             |
| SI-5        | 11.28             | 8.12             | 75.33             | 56.68            | 0.27              | 0.54             | 7.84              | 5.10             |

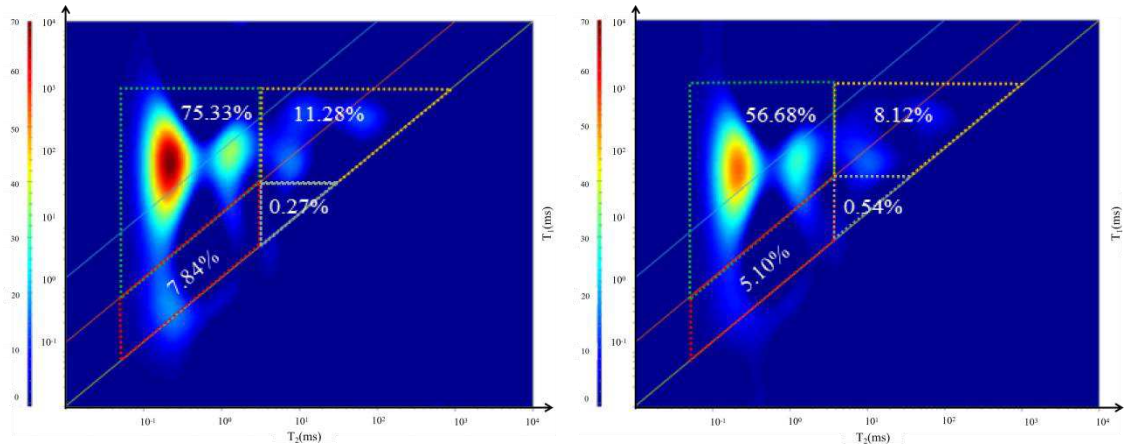
Comparison of Figures 5(a)–(c) indicates that the contribution of micropores to oil recovery increases as permeability decreases,<sup>[27]</sup> whereas macropores mainly function as preferential flow pathways and contribute only marginally to incremental oil production.



(a)  $T_1$ – $T_2$  maps of core SI-3 before and after spontaneous imbibition



(b)  $T_1$ – $T_2$  maps of core SI-4 before and after spontaneous imbibition



(c)  $T_1$ – $T_2$  maps of core SI-5 before and after spontaneous imbibition

Figure 5.  $T_1$ – $T_2$  two-dimensional NMR maps of core samples with different permeability levels before and after spontaneous imbibition

The above analyses demonstrate that spontaneous imbibition in the studied reservoir cores predominantly occurs within micropores and small pores, whereas macropores mainly constitute the macroscopic flow channels for fluid transport. The imbibition process is primarily governed by capillary pressure, allowing fluids to overcome flow resistance and penetrate into small pore throats with limited dependence on externally applied pressure gradients.

During the displacement of a non-wetting phase by a wetting phase (e.g., water displacing oil), pressure-driven displacement in large flow channels and capillary imbibition within small pore throats often act synergistically, making spontaneous imbibition a critical mechanism for mobilizing residual oil trapped deep within the reservoir matrix. In contrast, during non-wetting phase displacement, fluids residing in micropores are more susceptible to capillary hysteresis and tend to become trapped.

Figure 6 presents the variation in spontaneous imbibition recovery efficiency over a 12-day period for core samples with different permeability levels. Core SI-4 achieved the highest final recovery factor of 40.8%, followed by SI-5 (38.5%), whereas the lowest-permeability core SI-3 exhibited the lowest recovery factor of only 32.2%.

These results indicate that spontaneous imbibition efficiency does not exhibit a simple monotonic relationship with permeability<sup>[28]</sup>. In general, lower permeability is associated with stronger capillary forces, which enhance the imbibition driving force and improve oil recovery in water-wet reservoirs. However, SI-3, characterized by a bimodal  $T_2$  spectrum, exhibits poorer pore distribution characteristics than the other two cores with unimodal  $T_2$  spectra, resulting in lower oil mobilization efficiency and slower displacement rates.

This finding suggests that crude oil mobility is controlled not only by the overall permeability of the core but also by the pore-scale distribution of crude oil and the intrinsic pore structure characteristics<sup>[29]</sup>. Furthermore, the results confirm that for tight ultra-low permeability reservoirs represented by SI-3, spontaneous imbibition alone is insufficient to overcome the substantial flow resistance within the matrix, leading to a pronounced oil mobilization bottleneck.

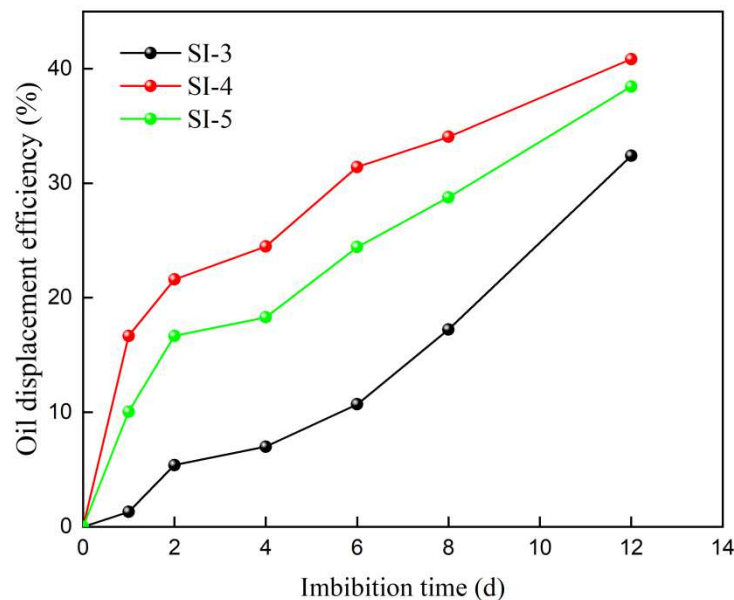


Figure 6. Comparison of spontaneous imbibition recovery efficiency for core samples with different permeability levels

### 3.2 Oil Mobilization Characteristics during Water Flooding

**Figures 7(a), (c), and (e)** compare the NMR  $T_2$  spectra of core samples with different permeability levels before and after water flooding. The results indicate that water flooding exhibits distinct oil mobilization behavior across different pore-size ranges. Signal attenuation is mainly concentrated in the mesopore and macropore regions ( $T_2 > 10$  ms), as evidenced by the substantial reduction of the right-side spectral peaks. In contrast, little attenuation is observed in the micropore and small-pore regions ( $T_2 < 10$  ms), where the post-flooding  $T_2$  spectra remain similar to those under the initial oil-saturated condition. This phenomenon is consistently observed in all core samples and becomes more pronounced with increasing permeability, as reflected by the greater reduction in the right-side peak amplitudes. These observations indicate that under pressure-driven conditions, the injected water preferentially propagates through mesopore and macropore channels with lower flow resistance<sup>[30]</sup>. However, due to the high capillary resistance and threshold pressure gradients associated with the solid-liquid interface, injected water cannot effectively penetrate into smaller pores, resulting in poor mobilization of the oil trapped within these pore systems.

**Figures 7(b), (d), and (f)** further quantify the oil mobilization behavior under water flooding at different pore scales. The results demonstrate that water flooding recovery is primarily controlled by mesopores and macropores, whereas oil recovery from micropores and small pores remains limited. For example, in the relatively high-permeability core WF-3, oil mobilization in mesopores and macropores is significantly greater than that in other pore-size intervals. This can be attributed to the well-developed large flow channels, superior pore connectivity, and higher sweep efficiency of the injected water. Notably, in WF-3, the oil mobilization efficiencies of micropores and small pores are only 3.2% and 7.0%, respectively, indicating that a considerable amount of residual oil remains trapped within these smaller pores.

By comparison, the low-permeability core WF-1 is characterized by a generally tighter pore structure and poorly developed macropores, resulting in an overall lower mobilization efficiency. Therefore, the effective pore-throat mobilization limit of conventional water flooding is generally restricted to mesopores, whereas effective displacement within the extensively developed micro- and nanoscale pores of ultra-low permeability reservoirs is difficult to achieve.

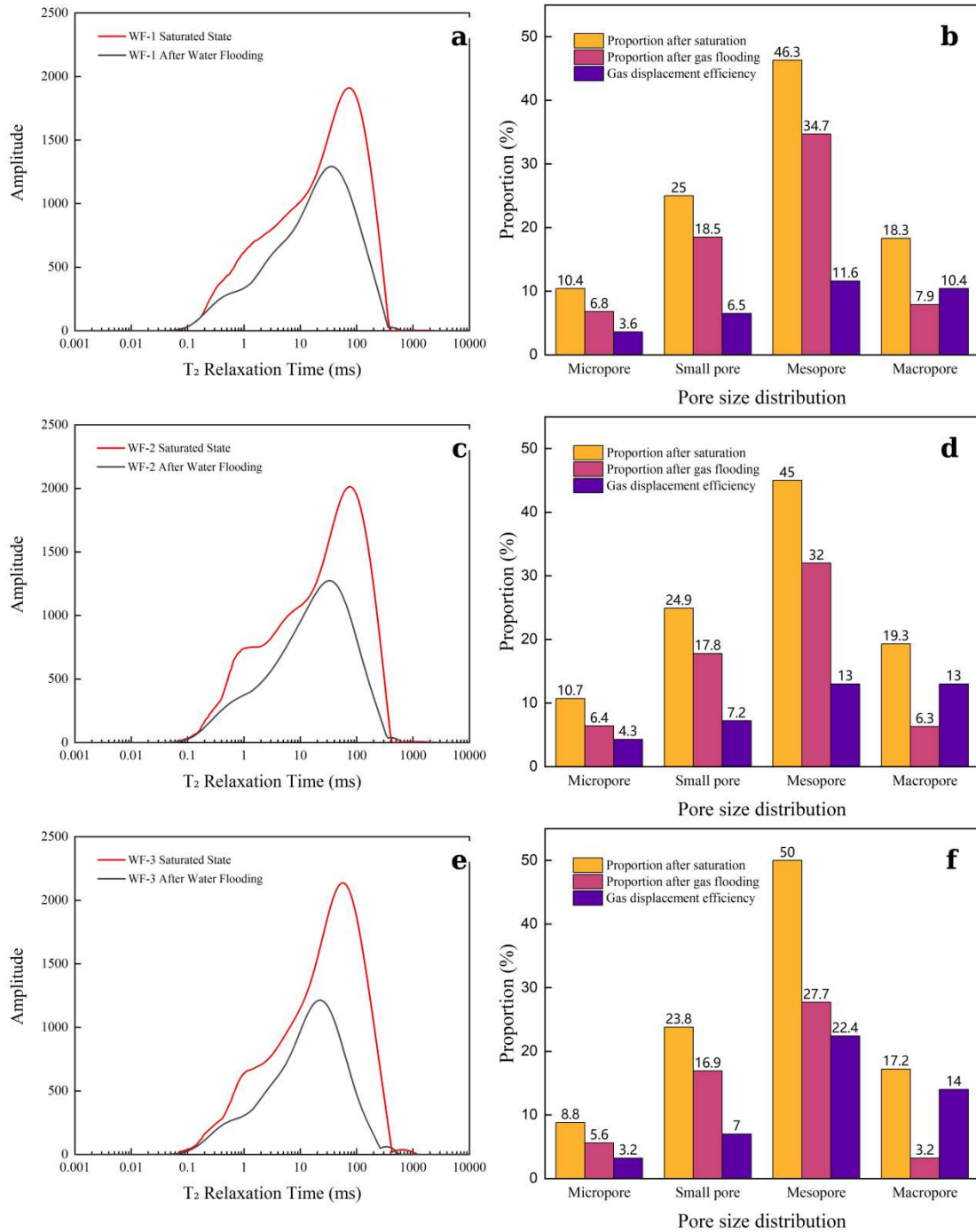


Figure 7. T<sub>2</sub> spectra and pore-scale oil mobilization characteristics during water flooding for core samples with different permeability levels

Figure 8 presents the variations in oil recovery and water cut as a function of injected pore volumes (PV) under constant-rate water flooding conditions for core samples with different permeability levels. The results demonstrate that permeability strongly controls water flooding performance. The relatively high-permeability cores WF-2 (0.30 mD) and WF-3 (5.57 mD) achieved final recovery factors of 46.7% and 38.0%, respectively, both exceeding that of the ultra-low permeability core WF-1 (31.2%)

For the ultra-low permeability core WF-1, the dense pore structure and high threshold pressure gradient hinder the penetration of injected water into the deep matrix. Consequently, the recovery

curve rapidly reaches a plateau at an injection volume of approximately 0.4 PV. Furthermore, the water cut curve reveals that once water breakthrough occurs at the outlet, the water cut increases abruptly from 0% to 80% within a very small injection volume interval. This rapid increase following water breakthrough indicates the widespread occurrence of viscous fingering and water channeling in ultra-low permeability conglomerate reservoirs. Under such conditions, the injected water cannot effectively spread laterally into adjacent micropores.

These observations are highly consistent with the microscopic mechanisms identified in the previous spontaneous imbibition–NMR experiments<sup>[31]</sup>, namely, preferential water channeling through large pores and water blockage within micropores.

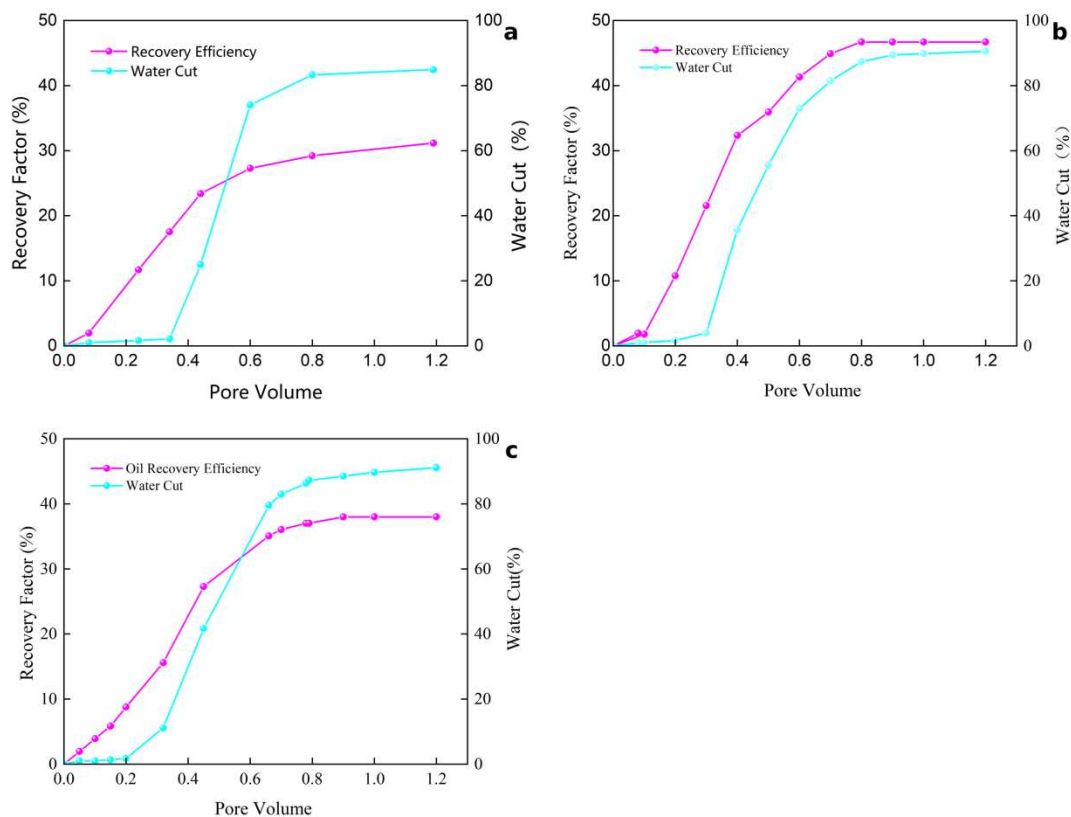


Figure 8. Oil recovery and water cut during water flooding for core samples with different permeability levels

### 3.3 Oil Mobilization Characteristics during CO<sub>2</sub> Flooding

Figures 9(a), (c), and (e) present the NMR T<sub>2</sub> spectra of the GF-series core samples before and after supercritical CO<sub>2</sub> flooding. In contrast to the displacement behavior observed during water flooding, which is characterized by preferential channeling through macropores and water blockage in micropores, supercritical CO<sub>2</sub> exhibits high microscopic displacement efficiency across cores with different permeability levels and effectively overcomes the mobilization limitations of micropores and small pores. In the micropore and small-pore regions (T<sub>2</sub> < 10 ms), which are generally inaccessible to water flooding, a pronounced reduction in T<sub>2</sub> signal intensity is observed after CO<sub>2</sub> flooding. This result indicates that supercritical CO<sub>2</sub>, owing to its extremely low interfacial tension and gas-like diffusivity, can overcome the Jamin effect and capillary

476 resistance within fine pore throats. Through mechanisms such as dissolution, oil swelling, and  
477 extraction, supercritical CO<sub>2</sub> effectively displaces previously trapped residual oil thereby  
478 improving sweep efficiency and enhancing oil recovery from small pore spaces<sup>[32]</sup>.

479 Based on the changes in the T<sub>2</sub> spectral area, oil mobilization efficiencies at different pore  
480 scales were quantitatively determined, as shown in **Figures 9(b), (d), and (f)**. For the  
481 low-permeability core GF-1 with fine pore throats, supercritical CO<sub>2</sub> effectively mobilizes crude  
482 oil from micropores and small pores. However, due to its low viscosity, supercritical CO<sub>2</sub> readily  
483 forms preferential high-permeability flow channels within well-connected macropores, resulting in  
484 relatively lower oil mobilization efficiency in these regions. This observation suggests that  
485 operational parameters, particularly the CO<sub>2</sub> injection rate, should be carefully controlled to  
486 mitigate the risk of gas channeling during CO<sub>2</sub> flooding. Overall, supercritical CO<sub>2</sub> substantially  
487 expands the lower pore-throat mobilization limit in ultra-low permeability reservoirs and provides  
488 an effective approach for converting geological reserves into recoverable reserves<sup>[33]</sup>.

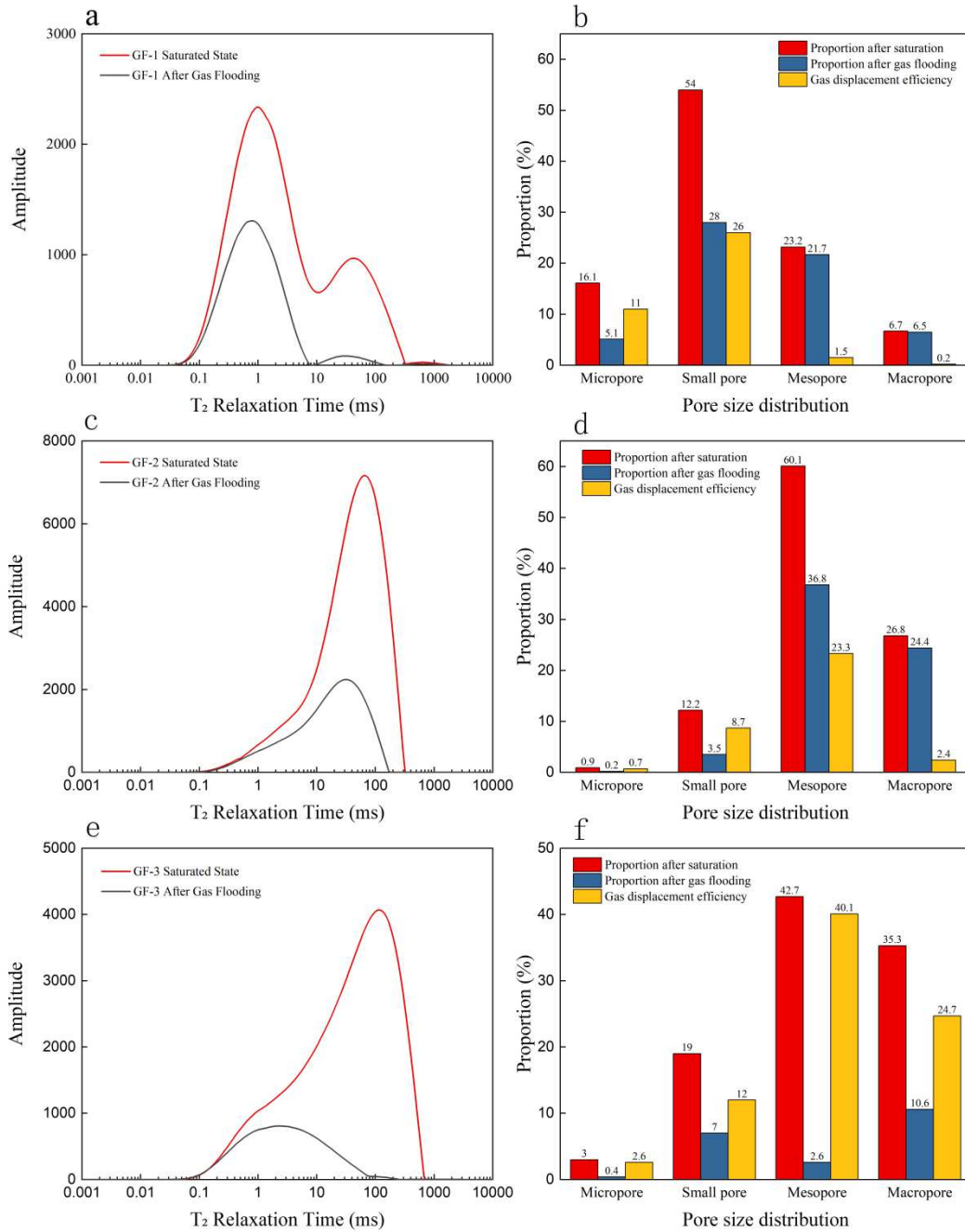


Figure 9. T<sub>2</sub> spectra and pore-scale oil mobilization characteristics during CO<sub>2</sub> flooding for core samples with different permeability levels

Although the actual time required for the three core samples to reach the same injected pore volume (PV) differs because of permeability variations, using PV as a normalized displacement scale does not affect the characterization of dynamic flooding behavior. Figure 10 illustrates the variations in oil recovery and gas-oil ratio (GOR) as a function of injected pore volumes during CO<sub>2</sub> flooding.

The oil recovery curve of core GF-1 exhibits a gradual upward trend, indicating that the high capillary resistance associated with fine pore throats in low-permeability reservoirs delays gas breakthrough and results in a slow increase in GOR. Under these conditions, CO<sub>2</sub> mainly migrates

in the dissolved phase and continuously enhances oil recovery through diffusion-driven mass transfer<sup>[34]</sup>, in situ viscosity reduction, and oil swelling effects, as shown in Figure 10(a).

In contrast, the high-permeability core GF-3 exhibits a rapid increase in oil recovery during the early flooding stage, followed by a quick transition to a plateau. This behavior indicates the occurrence of gas channeling at higher permeability levels, where a substantial portion of the injected CO<sub>2</sub> rapidly traverses the core as a continuous free-gas phase without sufficient contact with crude oil, thereby reducing gas utilization efficiency, as shown in Figure 10(c)

Overall, lower-permeability cores exhibit a more gradual increase in oil recovery, while the sharp increase in GOR occurs at later stages of the flooding process.

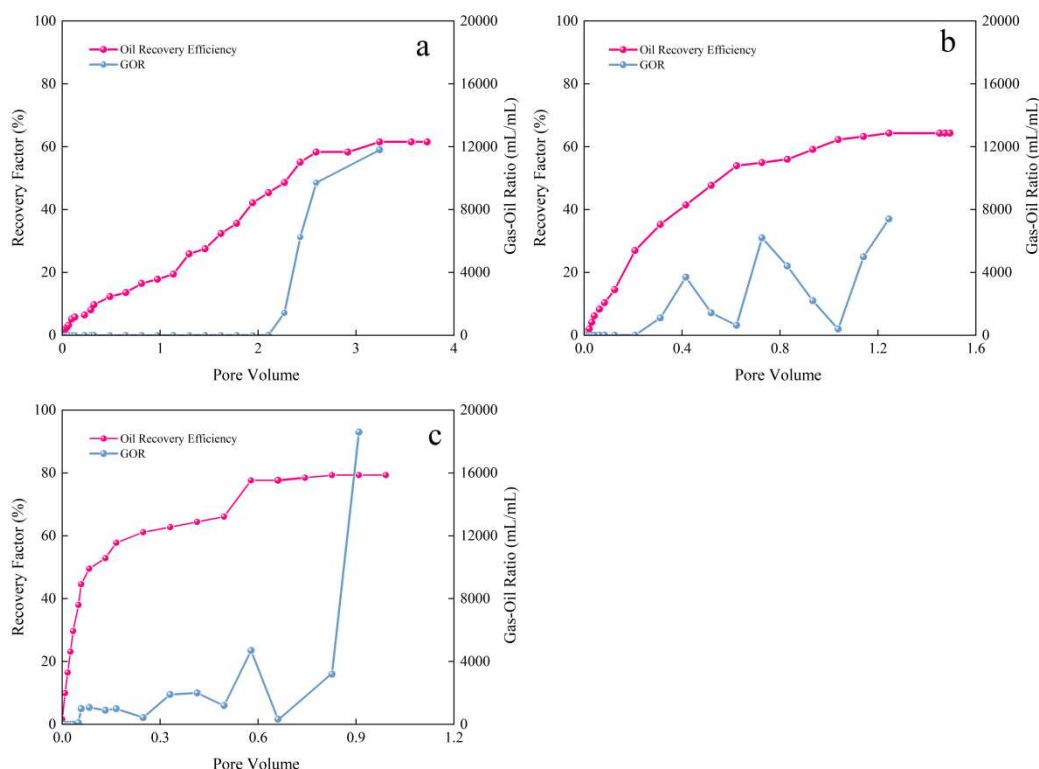


Figure 10. Oil recovery and gas–oil ratio during CO<sub>2</sub> flooding for core samples with different permeability levels

As shown in Figure 11, the final recovery factors of GF-1, GF-2, and GF-3 are 61.6%, 64.3%, and 79.4%, respectively. In general, oil recovery increases with permeability in low-permeability cores<sup>[35]</sup>.

Although early gas channeling occurs in the relatively high-permeability core GF-3, its superior petrophysical properties result in a higher proportion of oil stored in mesopores and macropores. Moreover, CO<sub>2</sub> exhibits particularly high mobilization efficiency within mesopores (Figure 9(f)), ultimately leading to the highest recovery factor among the three core samples.

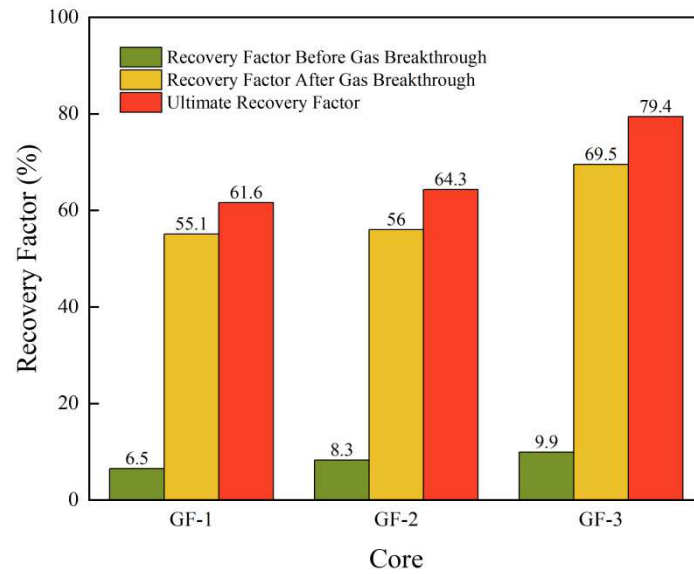


Figure 11. Oil recovery performance before gas breakthrough, after gas breakthrough, and at the end of CO<sub>2</sub> flooding

### 3.4 Oil Mobilization Characteristics during Water Flooding Followed by CO<sub>2</sub> Flooding

#### 3.4.1 Core TF-1

Core TF-1 has a porosity of 7.88% and a gas permeability of 0.05721 mD. As shown in **Figure 12(c)**, crude oil after oil saturation is mainly distributed within mesopores, accounting for 50.1% of the total oil saturation.

During the water flooding stage, oil production mainly originated from macropores, with a displacement efficiency reaching 81.40%, whereas the recovery efficiencies of mesopores, small pores, and micropores remained relatively low. Overall, water flooding improved the recovery efficiency by approximately 30 percentage points.

After switching to CO<sub>2</sub> flooding, the mobilization efficiencies of crude oil stored in mesopores and small pores increased substantially<sup>[36]</sup>, exhibiting approximately 1.9-fold improvements compared with those achieved by water flooding alone. However, the final recovery efficiencies of small pores and micropores were only 55.52% and 46.07%, respectively, indicating that these pore systems remained the primary storage spaces for residual oil.

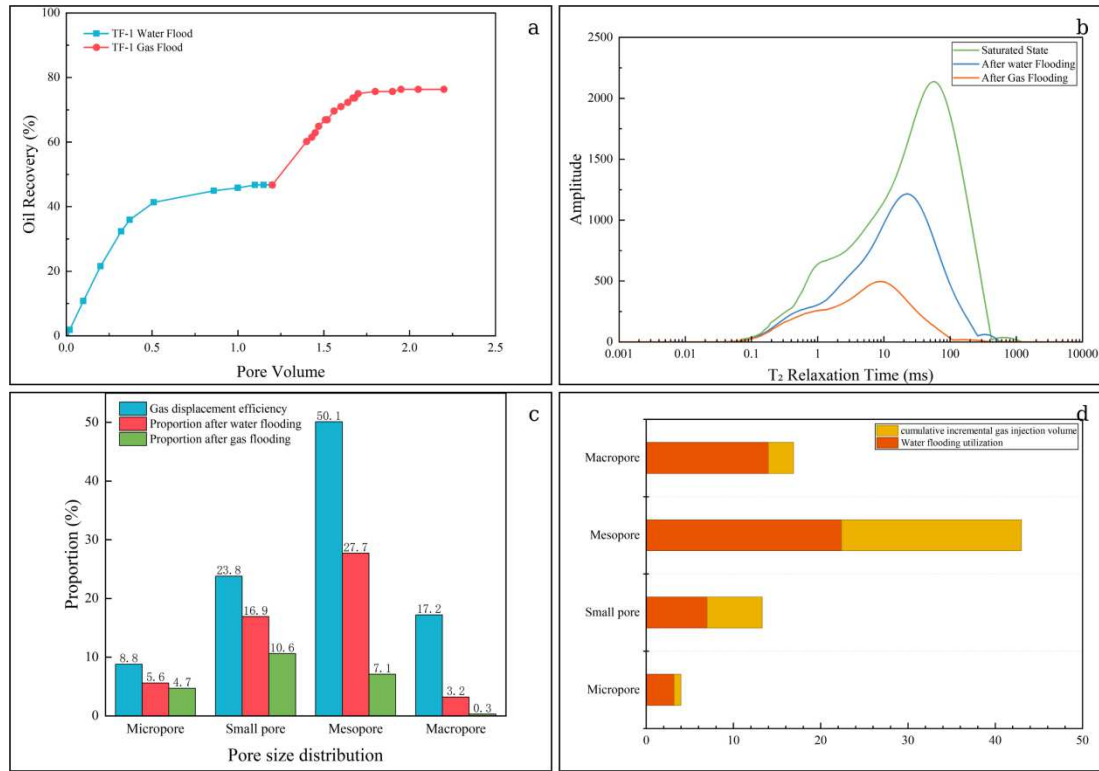


Figure 12. Experimental results of core TF-1

### 3.4.2 Core TF-2

Core TF-2 has a porosity of 8.06% and a gas permeability of 0.28443 mD. The recovery efficiency obtained by water flooding alone was 27.98%, which increased to 66.51% after subsequent CO<sub>2</sub> flooding, representing an overall improvement of approximately 38 percentage points.

Water flooding followed by CO<sub>2</sub> flooding enhanced the oil mobilization efficiency of mesopores by a factor of 4.2, representing the greatest improvement among all investigated cores<sup>[37]</sup>. Oil recovery from small pores also increased by approximately 20 percentage points. However, the improvement in oil mobilization within micropores was relatively limited, with recovery increasing by only 4.43%, resulting in a final micropore recovery efficiency of 43.86%.

The observed differences in pore-scale mobilization behavior may be associated with the unique microscopic pore structure characteristics of this core sample.

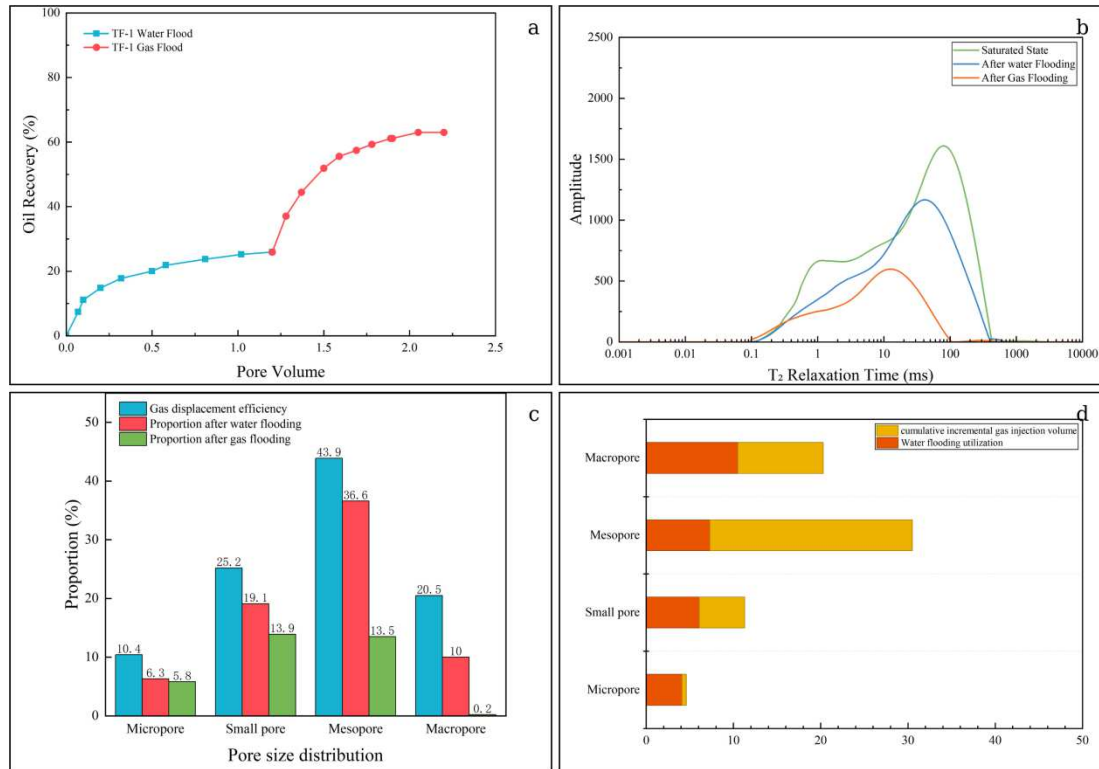


Figure 13. Experimental results of core TF-2

### 3.4.3 Core TF-3

Core TF-3 has a porosity of 7.61% and a gas permeability of 4.68395 mD. The recovery efficiency obtained by water flooding was 34.25%, which further increased to 69.83% after subsequent CO<sub>2</sub> flooding, corresponding to an overall improvement of approximately 35 percentage points.

The greatest enhancement in oil mobilization occurred within mesopores, where recovery increased by approximately 2.6 times. In contrast, oil recovery from small pores increased by only about 3 percentage points, reaching a final value of 32.92%, which was the lowest among the three cores.

This behavior suggests that in higher-permeability cores, the injected fluids preferentially propagate through dominant flow channels, thereby reducing the sweep efficiency of CO<sub>2</sub> within smaller pore systems.

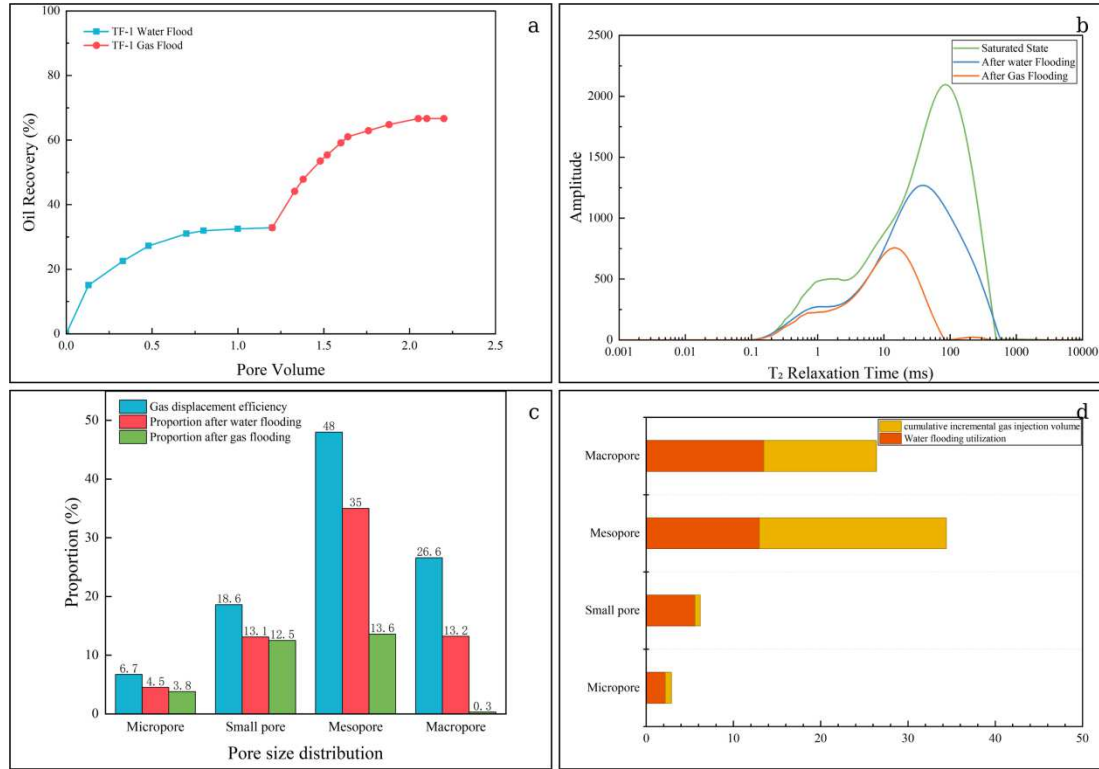


Figure 14. Experimental results of core TF-3

## 4 Discussion

### 4.1 Controlling Effects of Pore Structure on Oil Mobilization

#### Characteristics under Different Displacement Methods

The experimental results demonstrate that oil mobilization in ultra-low permeability conglomerate reservoirs is not governed solely by permeability but is jointly controlled by pore structure and pore-throat size distribution. Although permeability reflects the overall flow capacity of a reservoir, it is essentially a macroscopic parameter integrating the effects of multiscale pore systems and therefore cannot fully elucidate the underlying microscopic fluid transport mechanisms.

NMR  $T_2$  spectral analysis indicates that the core samples from the study area can be broadly classified into two pore structure types: unimodal and bimodal distributions. Unimodal cores exhibit relatively continuous pore-size distributions, resulting in lower flow resistance within the pore network and facilitating the uniform propagation of displacement fluids throughout the reservoir. In contrast, bimodal cores contain two relatively independent pore systems composed of micropores and macropores. Under these conditions, fluids preferentially migrate through highly connected dominant flow channels, weakening hydraulic coupling among pores of different scales and ultimately leading to pronounced residual oil segregation.

It is noteworthy that spontaneous imbibition recovery does not exhibit a simple positive correlation with permeability. For example, core SI-3, which has the lowest permeability, did not

achieve the highest final recovery, whereas core SI-4, with intermediate permeability, exhibited the best oil displacement performance. This observation suggests that pore structure heterogeneity has become a key factor controlling development performance in ultra-low permeability reservoirs, and its influence may even exceed that of permeability alone.

Furthermore, the dominant fluid transport mechanisms evolve as reservoir tightness increases. Conventional Darcy flow gradually diminishes, whereas capillary forces and interfacial interactions become increasingly important. Consequently, reservoir development transitions from a pressure-driven regime toward a capillary-controlled regime.

Therefore, evaluating the development potential of ultra-low permeability conglomerate reservoirs solely based on permeability has inherent limitations. A reservoir evaluation framework centered on pore structure and pore-throat size distribution<sup>[38]</sup>, as illustrated in **Figure 15**, should be established to more accurately characterize reservoir quality and predict oil mobilization potential.

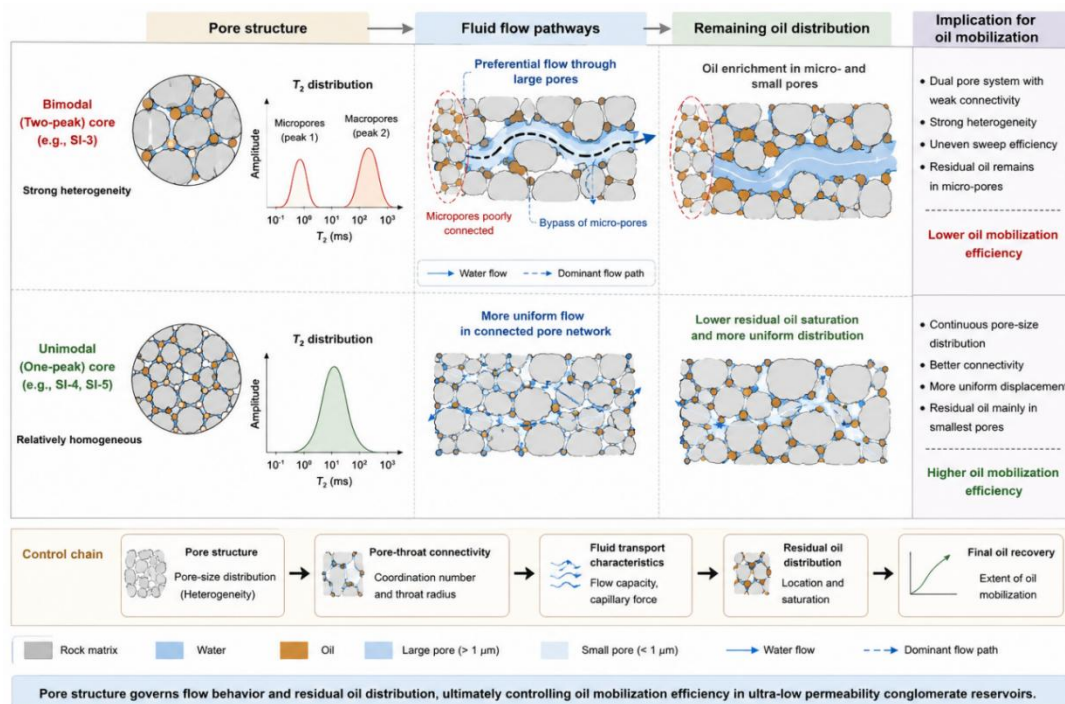


Figure 15. Schematic illustration of the pore structure-controlled oil mobilization mechanisms

## 4.2 Comparison between Water Flooding and CO<sub>2</sub> Flooding

Compared with water flooding, the flow and displacement mechanisms involved in CO<sub>2</sub> flooding are considerably more complex. Conventional water flooding mainly relies on the injection of water to displace crude oil. However, owing to the large viscosity contrast between oil and water, viscous fingering readily occurs in low-permeability reservoirs, resulting in substantial residual oil retention and relatively low displacement efficiency.

In contrast, CO<sub>2</sub> flooding not only improves crude oil mobility through physical mechanisms such as viscosity reduction and oil swelling but can also alleviate flow restrictions in low-permeability reservoirs through additional mechanisms, including mineral dissolution and wettability alteration. Under appropriate temperature and pressure conditions, the development of

miscibility between CO<sub>2</sub> and crude oil can significantly reduce interfacial tension and consequently enhance reservoir flow capacity. Nevertheless, CO<sub>2</sub> flooding is also associated with challenges such as gas channeling and nonlinear flow behavior, making its operational requirements more demanding than those of conventional water flooding. A schematic comparison of the microscopic flow mechanisms during water flooding and CO<sub>2</sub> flooding is presented in **Figure 16**.

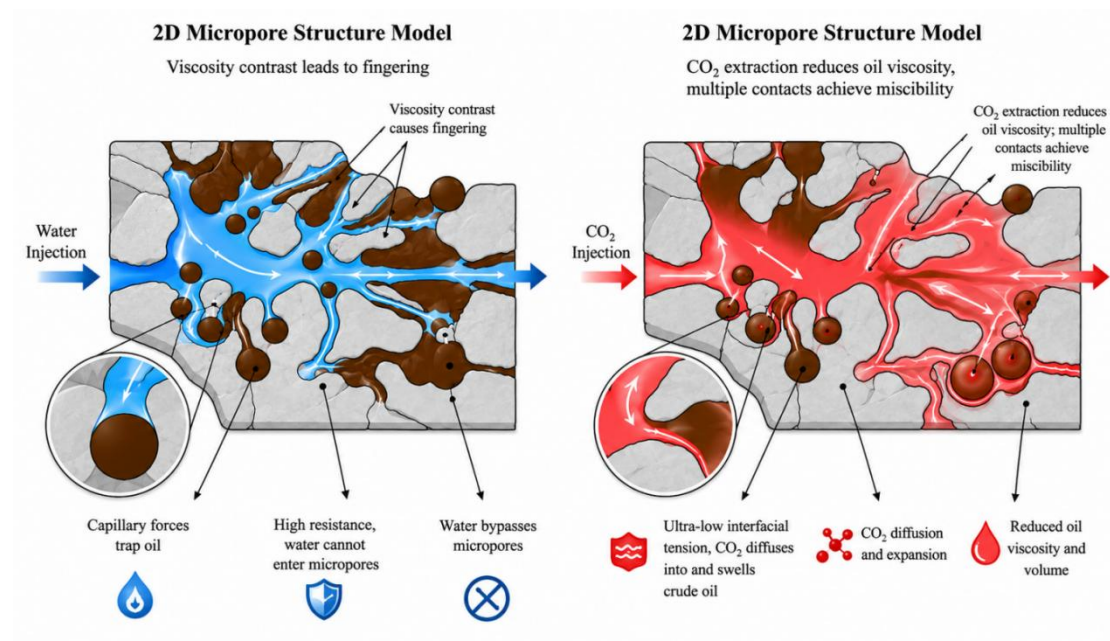


Figure 16. Schematic illustration of the microscopic flow mechanisms during water flooding and CO<sub>2</sub> flooding

Based on the experimental results, the displacement performance of water flooding and CO<sub>2</sub> flooding is comprehensively compared in **Figure 17**. Water flooding predominantly mobilizes crude oil stored in mesopores and macropores, whereas CO<sub>2</sub> flooding preferentially recovers crude oil trapped within micropores and small pores. Moreover, the advantage of CO<sub>2</sub> flooding in mobilizing oil from these smaller pore systems becomes increasingly pronounced as permeability decreases.

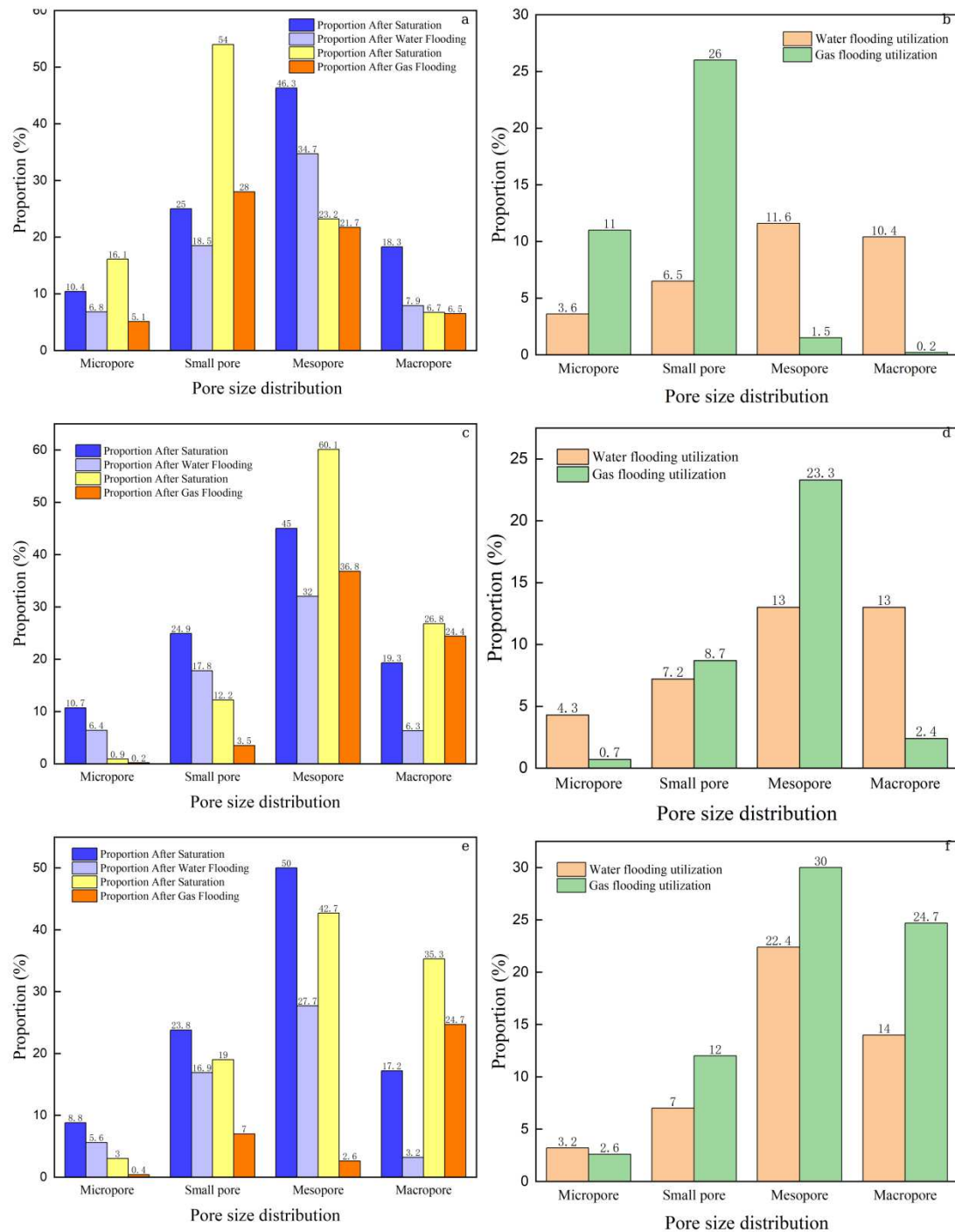


Figure 17. Comprehensive comparison of water flooding and CO<sub>2</sub> flooding at different permeability levels

**Figure 18** compares the oil recovery curves of water flooding and CO<sub>2</sub> flooding as a function of injected pore volumes (PV). Supercritical CO<sub>2</sub> flooding exhibits a clear advantage in enhancing oil recovery. Under comparable reservoir conditions, the final recovery factors of the GF-series cores are generally 20–50 percentage points higher than those of the WF-series cores.

In particular, the high-permeability core GF-3 exhibits a steep recovery curve, reaching nearly 80% recovery within a very small injection volume (<0.5 PV), after which the recovery factor remains relatively unchanged.

Furthermore, comparison of the ultra-low permeability cores WF-1 and GF-1 reveals distinct displacement behaviors. Owing to the high threshold pressure gradient, oil production from WF-1 nearly ceased after injecting approximately 1.2 PV, resulting in a final recovery factor of only about 30%. In contrast, GF-1 exhibited a continuously increasing recovery trend, and the recovery curve did not reach a plateau until approximately 2.5 PV had been injected.

These observations indicate that within tight reservoir matrices, supercritical CO<sub>2</sub> not only displaces crude oil through pressure-driven mechanisms but also continuously extracts deeply trapped oil from micro- and nanoscale pores through long-term molecular diffusion and mass transfer processes. Consequently, oil recovery continues to increase during the later stages of injection, resulting in substantially better displacement performance than that achieved by conventional water flooding.

Overall, CO<sub>2</sub> flooding represents a more promising EOR technique for improving oil recovery in ultra-low permeability reservoirs.

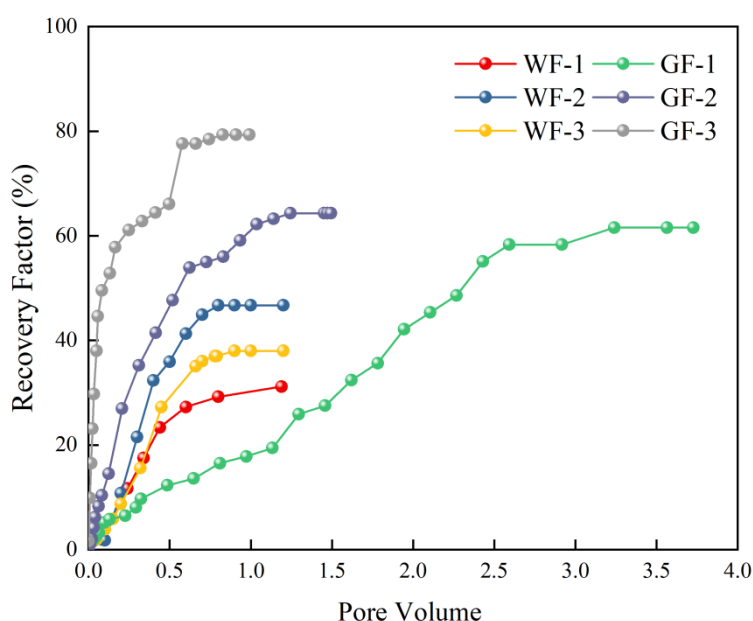


Figure 18. Comparison of oil recovery performance between water flooding and CO<sub>2</sub> flooding

## 5 Conclusions

In this study, spontaneous imbibition, water flooding, CO<sub>2</sub> flooding, and water flooding followed by CO<sub>2</sub> flooding experiments were conducted using NMR technology to characterize fluid distribution patterns at different pore scales in low-permeability conglomerate reservoirs. The oil mobilization characteristics within different pore systems were systematically investigated, and the recovery efficiencies of micropores, small pores, mesopores, and macropores were quantitatively evaluated. The main conclusions are summarized as follows:

(a) Core permeability significantly influences the distribution of oil and water among different pore systems during spontaneous imbibition. As permeability decreases, capillary forces become stronger, thereby enhancing the imbibition effect. Spontaneous imbibition predominantly occurs in micropores and small pores, whereas macropores mainly serve as fluid flow channels and contribute only marginally to incremental oil recovery.

(b) Under the laboratory conditions of this study, CO<sub>2</sub> flooding achieved higher final oil recovery than water flooding for the tested cores. Water flooding mainly mobilized oil from mesopores and macropores, whereas CO<sub>2</sub> also enhanced oil mobilization from finer pore systems through diffusion, extraction, oil swelling, and viscosity reduction. The magnitude of this advantage varied among cores and should not be directly extrapolated to reservoir scale without considering heterogeneity, injectivity, gas channeling, and operating conditions.

(c) For the three cores subjected to water flooding followed by CO<sub>2</sub> flooding, subsequent CO<sub>2</sub> injection provided substantial incremental recovery and mainly mobilized residual oil in mesopores and small pores. Micropores remained an important residual-oil storage space after the combined process. These plug-scale results indicate a complementary effect between water flooding and subsequent CO<sub>2</sub> flooding, rather than establishing a universal reservoir-scale synergistic response.

## Data Availability

The datasets generated and/or analysed during the current study are available from the corresponding author on reasonable request.

## Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

## Acknowledgement

This research was funded by the Science and Technology Innovation Team Project of Xinjiang Uygur Autonomous Region (Grant number: 2024TSYCTD0018); Western Research Institute, Yangtze University, Karamay 834000, China; Sponsored by the Natural Science Foundation of Xinjiang Uygur Autonomous Region (No. 2023D01A54).

## References

- [1] Lv, J., Liao, G., Ma, C., Du, M., Wang, X., & Tan, F. (2023). Difference in step-wise production rules of SP binary flooding for conglomerate reservoirs with different lithologies. *Polymers*, 15(14), 3119. <https://doi.org/10.3390/polym15143119>.
- [2] Hu, Y., Li, B., Wu, Z., Hou, J., Li, Y., & Peng, H. (2020). Microscopic oil displacement characteristics of low permeability glutenite reservoir in Qaidam Basin. In *Springer series in geomechanics and geoengineering* (pp. 175–182). [https://doi.org/10.1007/978-981-15-2485-1\\_19](https://doi.org/10.1007/978-981-15-2485-1_19).
- [3] Lu, Y. (2023). Visual outcrops model combined with nmr to study the oil utilization situation and displacement behavior of CO<sub>2</sub> flooding in a tight conglomerate. SSRN El

- electronic Journal. <https://doi.org/10.2139/ssrn.4523188>.
- [4] Luo, Q., Li, M., Liang, B., Liu, J., Shi, G., Wang, M., ... & Li, L. (2025). Experimental investigation on the mechanism of CO<sub>2</sub>-enhanced oil recovery in tight conglomerate reservoirs with surfactant assistance. *ACS Omega*, 10(42), 50077–50087. <https://doi.org/10.1021/acsomega.5c06519>.
- [5] Xu, L., Li, Q., Myers, M., & Cao, X. (2023). Investigation of the enhanced oil recovery mechanism of CO<sub>2</sub> synergistically with nanofluid in tight glutenite. *Energy*, 273, 127275. <https://doi.org/10.1016/j.energy.2023.127275>.
- [6] Wang, L., Zhang, H., Peng, X., Wang, P., Zhao, N., Chu, S., ... & Ling-hui, K. (2019). Water-sensitive damage mechanism and the injection water source optimization of low permeability sandy conglomerate reservoirs. *Petroleum Exploration and Development*, 46(6), 1218–1230. [https://doi.org/10.1016/s1876-3804\(19\)60275-2](https://doi.org/10.1016/s1876-3804(19)60275-2).
- [7] Zhang, D. F., Liu, J., Liu, S., Gong, R., & Li, H. (2025). EOR mechanisms and influencing factors of CO<sub>2</sub>-WAG immiscible displacement in heterogeneous sandy conglomerate reservoirs using nuclear magnetic resonance technology. *Energy Proceedings*.
- [8] Wang, Y., Chang, T., Zhou, J., Wu, J., & Liu, S. (2025). Remaining oil distribution characteristics in sandy conglomerate reservoirs during CO<sub>2</sub>-WAG flooding: Insights from nuclear magnetic resonance (NMR) technology. *Processes*, 13(9), 2872–2872. <https://doi.org/10.3390/pr13092872>.
- [9] Hu, Y., Wu, Z., Hu, S., Zhu, J., Zhu, Y., Huang, L., & He, H. (2024). Stimulation Mechanism and Development Method Optimization of CO<sub>2</sub> Injection After Water Flooding in Low Permeability Glutenite Reservoir. *Springer series in geomechanics and geoen지니어링*. [https://doi.org/10.1007/978-981-97-0264-0\\_43](https://doi.org/10.1007/978-981-97-0264-0_43).
- [10] Khan, M. A. I., Strand, S., Puntervold, T., & Mamonov, A. (2023). Positive capillary forces: The key for optimized oil recovery in low-permeable cores. *Zenodo (CERN European Organization for Nuclear Research)*. <https://doi.org/10.5281/zenodo.15900658>.
- [11] Qin, C.-Z., Wang, X., Hefny, M., Zhao, J., Chen, S., & Guo, B. (2022). Wetting dynamics of spontaneous imbibition in porous media: From pore scale to Darcy scale. *Geophysical Research Letters*, 49, e2021GL097269. <https://doi.org/10.1029/2021GL097269>.
- [12] Kathel, P., & Mohanty, K. K. (2013). EOR in tight oil reservoirs through wettability alteration. *SPE Annual Technical Conference and Exhibition*. <https://doi.org/10.2118/166281-ms>.
- [13] Huang Xing, Dou Liangbin, Zuo Xiongdi, Gao Hui, Li Tiantai. Dynamic imbibition and drainage laws of fractures in tight reservoirs[J]. *Acta Petrolei Sinica*, 2021, 42(7): 924-935.
- [14] Wang, D., & Zhang, J. (2018). Surfactant drive process in ultra-tight fractured reservoirs for EOR. *Proceedings*. <https://doi.org/10.3997/2214-4609.201801113>.
- [15] Yubin Yang, Wenlian Xiao, Yves Bernabe, Qichao Xie, Jin Wang, Youan He, Min Li, Meng Chen, Jitian Ren, Jinzhou Zhao, Lingli Zheng, Effect of pore structure and injection pressure on waterflooding in tight oil sandstone cores using NMR technique and pore network simulation, *Journal of Petroleum Science and Engineering*, Volume 217, 2022, 110886, ISSN 0920-4105, <https://doi.org/10.1016/j.petrol.2022.110886>.
- [16] WANG Xiang-zeng, ZHAO Xi-sen, DANG Hai-long, WANG Xiao-feng, CUI Peng-xin, HOU Fen-chi, LI Teng. Research on the characteristics of spontaneous imbibition a

- nd displacement of the tight reservoir with the NMR method[J]. *Progress in Geophysics*, 2020, 35(5): 1870-1877. doi: 10.6038/pg2020DD0386.
- [17] Li Yang. (2020). Advances and prospects of CO<sub>2</sub> flooding enhanced oil recovery technology in low-permeability reservoirs. *Petroleum Geology and Recovery Efficiency*, 27(1), 1-10. <https://doi.org/10.13673/j.cnki.cn37-1359/te.2020.01.001..>
- [18] Tang, Y., Wang, R., Li, Z., Cui, M., Lun, Z., & Lu, Y. (2019). Experimental study on spontaneous imbibition of CO<sub>2</sub>-rich brine in tight oil reservoirs. *Energy & Fuels*, 33(8), 7604–7613. <https://doi.org/10.1021/acs.energyfuels.9b01621>.
- [19] Xiang Li, Junjie Xue, Yanqing Wang, Weipeng Yang, Jun Lu, Experimental study of oil recovery from pore of different sizes in tight sandstone reservoirs during CO<sub>2</sub> flooding, *Journal of Petroleum Science and Engineering*, Volume 208, Part E, 2022, 109740, ISSN 0920-4105, <https://doi.org/10.1016/j.petrol.2021.109740>. <https://www.sciencedirect.com/science/article/pii/S0920410521013644>.
- [20] Tian, W., Lu, S., Zhang, J., Gao, Y., Huang, W., Wen, Z., ... & Li, J. (2022). NMR characterization of fluid mobility in low-permeability conglomerates: An experimental investigation of spontaneous imbibition and flooding. *Journal of Petroleum Science and Engineering*, 214, 110483. <https://doi.org/10.1016/j.petrol.2022.110483>.
- [21] Zhu, Y., Shi, Y., Yang, B., Shi, J., & Hu, Z. (2022). Permeability characteristics and influencing factors of fracturing fluid in glutenite reservoir based on NMR. *Chemistry and Technology of Fuels and Oils*, 58(5), 815–819. <https://doi.org/10.1007/s10553-022-01455-8>.
- [22] Zhu, D., Lu, J., Zhang, J., Gao, Y., Guo, S. Y., Yang, Y., ... & Tan, H. (2025). N<sub>2</sub> and CO<sub>2</sub> nanobubble enhanced oil recovery in conglomerate reservoirs based on NMR technology. *Energy & Fuels*. <https://doi.org/10.1021/acs.energyfuels.5c02717>.
- [23] Cheng, X.-q. (2013). Experimental research of spontaneous imbibition in low-permeability glutenite reservoir. *Science Technology and Engineering*.
- [24] Liu, J., Zhang, D., Liu, S., Gong, R., & Wang, L. (2025). Multiscale investigation into EOR mechanisms and influencing factors for CO<sub>2</sub>-WAG injection in heterogeneous sandy conglomerate reservoirs using NMR technology. *Petroleum Science*, 22(7), 2977–2991. <https://doi.org/10.1016/j.petsci.2025.04.004>.
- [25] Lu, Y., Wang, J., Luo, X., Xu, T., Wang, D., & Wei, H. (2026). Enhanced oil recovery in tight conglomerate reservoirs using CO<sub>2</sub> flooding: A visual model with fractal-based zoning. *Petroleum*, 12(1), 154–166. <https://doi.org/10.1016/j.petlm.2025.12.004>.
- [26] Fuyong Wang, Lu Wang, Liang Jiao, Zhichao Liu, and Kun Yang, Experimental Mechanism for Enhancing Oil Recovery by Spontaneous Imbibition with Surfactants in a Tight Sandstone Oil Reservoir, *Energy & Fuels* 2023 37 (12), 8180-8189.
- [27] Wang M, Wang R, Yuan S and Zhou F (2023) A pore-scale study on the dynamics of spontaneous imbibition for heterogeneous sandstone gas reservoirs. *Front. Energy Res.* 11:1135903. doi: 10.3389/fenrg.2023.1135903.
- [28] Li Z (2023) Comprehensive analysis of influencing factors and mechanism of nanoe emulsion spontaneous imbibition oil displacement in tight sandstone reservoir. *Front. Energy Res.* 11:1332484. doi: 10.3389/fenrg.2023.1332484.
- [29] Yang, C., Yang, E. Mineral composition and pore structure on spontaneous imbibition in tight sandstone reservoirs. *Sci Rep* 15, 7504 (2025). <https://doi.org/10.1038/s41598-0>

- 25-89676-9.
- [30] Gao, H., Jing-le, G., & Yong, L. (2008). The influences of microscopic pore structure on waterflooding effectiveness in Xifeng Oilfield. *Journal Name*, Volume(Issue), Page s. DOI or URL.
- [31] Zhihao Jiang, Gaoren Li, Peiqiang Zhao, You Zhou, Zhiqiang Mao, Zhidi Liu, Study on spontaneous imbibition and displacement characteristics of mixed-wet tight sandstone reservoir based on high-precision balance and NMR method, *Fuel*, Volume 345, 2023, 128247, ISSN 0016-2361, <https://doi.org/10.1016/j.fuel.2023.128247>.
- [32] Tan, X. (2017). Nanosilica-stabilised supercritical carbon dioxide foam for enhanced oil recovery application (Doctoral dissertation, Universiti Teknologi Malaysia). <http://eprints.utm.my/id/eprint/77954/>.
- [33] Liu, M., Song, K., Wang, L., Fu, H., & Wang, T. (2024). Characteristics of supercritical CO<sub>2</sub> non-mixed phase replacement in intraformational inhomogeneous low-permeability reservoirs. *Energies*, 17(22), 5608. <https://doi.org/10.3390/en17225608>.
- [34] Xiaoyi Zhang, Rui Xu, Qing Zhao, Qian Cheng, Rui Shen, Yanbiao Gan; Enhanced oil recovery in reservoirs via diffusion-driven flooding: Experimental insights and material balance modeling. *Physics of Fluids* 1 August 2025; 37 (8): 083111.
- [35] Dachao Qi, Weiqun Liu, Chaobin Guo, Tianran Ma, Zeng Wang, Chen Song, Dongya Wei, Rui Yang; Experimental investigation on CO<sub>2</sub> flooding for enhanced light oil recovery in low-permeability sandstones under multiple controlling factors by online nuclear magnetic resonance testing. *Physics of Fluids* 1 December 2024; 36 (12): 126616.
- [36] Wang X, Zheng J, Li S, et al. Pore-scale study on interfacial characteristic of CO<sub>2</sub>-oil-glass beads during CO<sub>2</sub>-EOR[J]. *Energy Proceedings*, 2023. DOI:10.46855/energy-proceedings-10590.
- [37] Zheng, L., Bai, X., Xiao, W., Zhu, B., Shi, J., Ren, J., ... & Wang, J. (2025). Advanced CO<sub>2</sub> injection in tight oil reservoirs: Pore-scale mechanisms from high-temperature, high-pressure visualization and NMR. *Energy & Fuels*, 39(42), 20315–20329. <https://doi.org/10.1021/acs.energyfuels.5c04001>.
- [38] Xiaobo Guo, Zhilong Huang, Libin Zhao, Wei Han, Chao Ding, Xiongwei Sun, Ruitao Yan, Tonghui Zhang, Xuejun Yang, Ruomei Wang, Pore structure and multi-fractal analysis of tight sandstone using MIP, NMR and NMRC methods: A case study from the Kuqa depression, China, *Journal of Petroleum Science and Engineering*, Volume 178, 2019, Pages 544-558, ISSN 0920-4105, <https://doi.org/10.1016/j.petrol.2019.03.069>.