

Article

Mechanistic Investigation of CO₂-Soluble Compound Foaming Systems for Flow Blocking and Enhanced Oil Recovery

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Abstract

Carbon dioxide (CO₂) has been widely applied in gas flooding for reservoir development due to its remarkable oil recovery potential. However, because its viscosity is lower than that of water and most crude oils, severe channeling often occurs during the flooding process, resulting in a significant reduction in the sweep efficiency. To address this issue, foam flooding has attracted considerable attention as an effective method for controlling CO₂ mobility. In this study, a compound foam system was developed with alpha-olefin sulfonate (AOS) as the primary foaming agent, alcohol ethoxylate (AEO) and cetyltrimethylammonium bromide (CTAB) as co-surfactants, and partially hydrolyzed polyacrylamide (HPAM) as the stabilizer. The optimal system was screened through evaluations of comprehensive foam index, salt tolerance, oil resistance, and shear resistance. Results indicate that the AOS+AEO formulation exhibits superior foaming ability, salt tolerance, and foam stability compared with the AOS+CTAB system, with the best performance achieved at a mass ratio of 2:1 (AOS:AEO), balancing both adaptability and economic feasibility. A heterogeneous reservoir model was constructed using parallel core flooding to investigate the displacement performance and blocking capability of the system. Nuclear magnetic resonance (NMR) imaging was employed to monitor in situ oil phase migration and clarify the recovery mechanisms. Experimental results show that the compound foam system demonstrates excellent conformance control performance, achieving a blocking efficiency of 84.5% and improving the overall oil recovery by 4.6%. NMR imaging further reveals that the system effectively mobilizes low-permeability zones, with T₂ spectrum analysis indicating a 4.5% incremental recovery in low-permeability layers. Moreover, in reservoirs with larger permeability ratio, the system exhibits enhanced blocking efficiency (up to 86.5%), though the incremental recovery is not strictly proportional to the blocking effect. Compared with previous AOS-based CO₂ foam studies that primarily relied on pressure drop and effluent analyses, this work introduces NMR imaging and T₂ spectrum diagnostics to directly visualize pore-scale fluid redistribution and quantify sweep efficiency within heterogeneous cores. The NMR data provide mechanistic evidence that the enhanced recovery originates from selective foam propagation and the mobilization of residual oil in low-permeability channels, rather than merely from increased flow resistance. This integration of advanced pore-scale imaging with macroscopic displacement analysis represents a mechanistic advancement over conventional CO₂ foam evaluations, offering new insights into the conformance control behavior of AOS-based foam systems in heterogeneous reservoirs.



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Keywords: CO₂ foam flooding; compound foaming system; blocking efficiency; enhanced oil recovery

1. Introduction

Carbon dioxide (CO₂) has been widely applied in gas flooding for reservoir development due to its broad availability and excellent oil recovery performance [1,2]. Under reservoir temperature and pressure conditions, CO₂ can dissolve significantly in crude oil, reducing oil viscosity, causing oil swelling, and thereby improving its mobility. Under certain conditions, CO₂ can also achieve miscibility with some crude oil components, leading to efficient displacement [3–6]. However, the viscosity of CO₂ is lower than that of both water and most crude oils, resulting in unfavorable mobility ratios during flooding. This often leads to premature breakthrough and severe channeling, leaving large portions of the reservoir oil uncontacted [7,8].

To mitigate CO₂ channeling, extensive research has been conducted over the past decades. Strategies such as the use of CO₂ thickeners and water-alternating-gas (WAG) injection have been proposed. Among these, foam flooding has been recognized as a particularly promising technology due to its excellent CO₂ mobility control capability, effectively suppressing channeling and improving the sweep efficiency of CO₂ flooding [9–11].

The concept of foam flooding was first proposed by Bond and Holbrook in 1958, who also filed a patent. Later, Fred conducted extensive laboratory experiments to validate its feasibility [12]. Building on this foundation, Bernard and Holm (1967) introduced the idea of CO₂ foam flooding using CO₂-soluble surfactants, and carried out pioneering core-flooding experiments to investigate the underlying mechanisms, laying the groundwork for subsequent systematic studies [13]. The primary role of surfactants is to reduce interfacial tension between immiscible phases. Based on ionic characteristics, surfactants are generally categorized as anionic, cationic, or nonionic [14]. Anionic surfactants, such as alpha-olefin sulfonate (AOS), are widely employed in CO₂ foam flooding due to their strong foaming and foam-stabilizing capabilities, good thermal stability, and suitability for sandstone reservoirs with medium-to-low salinity. Cationic surfactants, represented by cetyltrimethylammonium bromide (CTAB), generate stable foam films and perform well in carbonate reservoirs, though their high adsorption in sandstone formations often results in large consumption and elevated costs. Nonionic surfactants, such as alcohol ethoxylates (AEO), exhibit outstanding salt and thermal resistance, making them suitable for high-salinity, high-temperature reservoirs. They are commonly blended with anionic surfactants as stabilizers or co-surfactants to improve overall foam stability [15–20].

For CO₂ foam flooding, foam volume and half-life are critical performance indicators. Madiyar et al. reported that increasing surfactant concentration improves foam volume and half-life, but only up to an optimum concentration, beyond which improvements become marginal [15]. Jawad et al. found that different salt types significantly affect foam performance, with foam half-life decreasing noticeably under high salinity [21]. Ahmed et al. demonstrated that CO₂ foam in porous media exhibits shear-thinning rheology, with viscosity dropping sharply as shear rate increases [22]. Furthermore, factors such as injection rate and gas–liquid ratio also strongly influence the effectiveness of foam flooding. In practice, single-surfactant systems face limitations: they often fail to simultaneously ensure foaming ability and stability, and exhibit insufficient resistance to high temperature or salinity. For instance, anionic surfactants may precipitate and lose effectiveness under high-salinity conditions. To overcome these limitations, compound surfactant systems—formulated by blending surfactants of the same or different types—are commonly employed. Through

synergistic effects, such systems significantly enhance foam stability under harsh reservoir conditions, while mitigating challenges such as high salinity, strong adsorption, and the presence of crude oil [23–27].

The objective of this work is to develop a CO₂-based compound foam system with strong resistance to crude oil, salinity, and shear, and to evaluate its oil recovery performance and conformance control efficiency using parallel-core flooding experiments combined with nuclear magnetic resonance (NMR) analysis. The study demonstrates that a formulation consisting of 0.6 wt% AOS as the primary agent, 0.3 wt% AEO as the co-surfactant, and 0.05 wt% HPAM as the stabilizer exhibits excellent oil, salt, and shear resistance. Moreover, this system provides effective blocking and enhanced oil recovery in heterogeneous reservoirs with permeability ratio, highlighting its promising potential for field applications.

2. Experimental Materials and Devices

The experimental cores were collected from the Huang 219 block, located in the western part of the mid-slope area of northern Shaanxi. The reservoir lithology is dominated by fine sandstone and medium-fine sandstone, with a low content of CO₂-sensitive minerals. Parallel-bedded cylindrical core plugs with a diameter of 25.0 mm were drilled using a standard coring bit. The cores were then subjected to Soxhlet extraction for oil removal, followed by drying at 105 °C for 48 h. Under a confining pressure of 10 MPa and a pore pressure of 8 MPa, porosity and permeability were measured using a helium porosimeter and a pulse-decay permeameter, respectively. This paper selected three different kinds of cores, totaling eight cores (three cores from fang67-132 with permeability of 0.212 mD, 0.219 mD, and 0.205 mD, respectively; one core from huang142 with permeability of 0.114 mD; and four cores from huang219 with permeability of 1.131 mD, 1.111 mD, 1.122 mD, and 1.115 mD, respectively), as summarized in Table 1. In the flooding experiment, the group with a permeability ratio of 5 in the pure CO₂ flooding experiment used cores with a permeability of 0.212 mD from fang67-132 and 1.131 mD from huang219. The group with a permeability ratio of 5 in the single AOS foam flooding experiment used cores with a permeability of 0.219 mD from fang67-132 and 1.111 mD from huang219. The group with a permeability ratio of 5 in the compound system foam flooding experiment used cores with a permeability of 0.205 mD from fang67-132 and 1.122 mD from huang219. The group with a permeability ratio of 10 in the compound system foam flooding experiment used cores with a permeability of 0.114 mD from huang142 and 1.115 mD from huang219.

Table 1. Physical property parameters of experimental core samples.

Core Kind	Length/cm	Diameter/cm	Porosity/%	Permeability/mD
Fang67-132	5.00	2.48	11.35	0.212
	5.00	2.50	10.92%	0.219
	4.99	2.49	11.12%	0.205
Huang142	4.97	2.49	9.67	0.114
	5.00	2.50	14.95	1.131
Huang 219	5.00	2.48	15.32%	1.111
	4.99	2.50	14.91%	1.122
	4.97	2.49	15.02%	1.115

2.1. Experimental Oil

The crude oil used in the experiments was obtained from the target reservoir in the study area. The surface oil properties are as follows: density of 0.8426 g/cm³, viscosity of 5.96 mPa·s, low sulfur and asphaltene content, pour point of 20.5 °C, and initial boiling point of 63.5 °C. The reservoir crude oil exhibits a saturation pressure of 7.03 MPa, viscosity

of 2.250 mPa·s, original gas–oil ratio of 80.8 m³/t, formation volume factor of 1.25, density of 0.7677 g/cm³, and associated natural gas relative density of 1.083.

2.2. Formation Water

The formation water in the reservoir has a total salinity of 29,180 mg/L, with a CaCl₂-type composition and a pH value of 6.25. The detailed ionic composition of the formation water is presented in Table 2.

Table 2. Composition of formation water.

Layer	Number of Wells	Cation			Anion			Total Salinity (mg/L)	Water Type	PH
		K ⁺ +Na ⁺	Ca ²⁺	Mg ²⁺	Cl [−]	SO ₄ ^{2−}	HCO ₃ [−]			
Chang9 ₁	8	0	2974	333	14,522	790	88	29,180	CaCl ₂	6.5

In the experiments, synthetic brines with salinities of 30,000 mg/L and 50,000 mg/L were prepared using the reservoir formation water and deionized water.

2.3. Surfactant

In this study, sodium alpha-olefin sulfonate (AOS) powder (produced by Linyi Yongtai Chemical, Linyi, China, Figure 1a) was employed as the primary foaming agent in the compound system. Alcohol ethoxylate-9 (AEO-9, fatty alcohol polyoxyethylene ether (9), Figure 1b) and cetyltrimethylammonium bromide (CTAB, Figure 1c), also supplied by Linyi Yongtai Chemical, Linyi, China, were used as secondary foaming agents. These three surfactants represent anionic, nonionic, and cationic types, respectively. In addition, partially hydrolyzed polyacrylamide (HPAM, produced by Linyi Yongtai Chemical, Linyi, China, Figure 1d) was applied as a foam stabilizer.

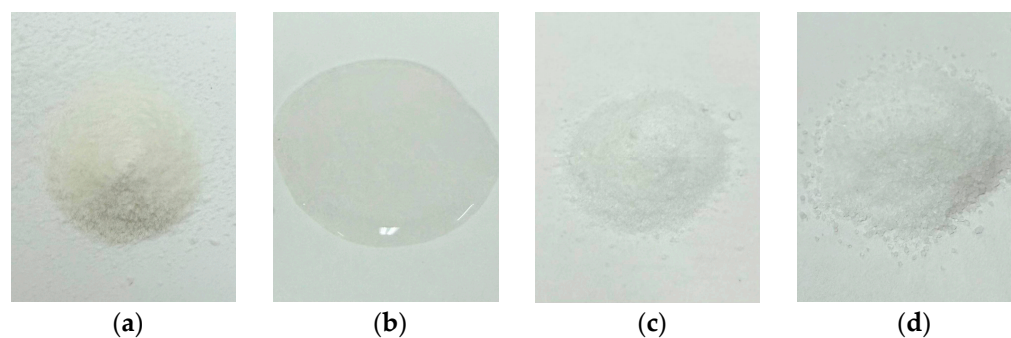


Figure 1. Surfactant reagent samples, (a) AOS, (b) AEO, (c) CTAB, (d) HPAM.

For the optimization of the primary surfactant concentration and the screening of the compound system, surfactant solutions were prepared using deionized water. In subsequent dual-core flooding experiments; however, surfactant solutions were prepared with heavy water to avoid interference with the oil signal during nuclear magnetic resonance (NMR) measurements.

2.4. Foam Evaluation Apparatus

The high-temperature and high-pressure foam stability tester, as shown in Figure 2, was manufactured by Hai'an Petroleum Scientific Instrument Co., Ltd, Haian, China. (Model SY-PMZZ-2). Its main functions include: (1) real-time microscopic observation of foam quality; (2) measurement of foam quality and density via the sampling device; and (3) evaluation of the performance of different foaming agents. The instrument operates

under a maximum working pressure of 30 MPa and a maximum working temperature of 300 °C.



Figure 2. High-temperature and high-pressure foam stability tester.

As shown in Figure 3, the high-temperature and high-pressure rheometer (Model Fann 50SL), manufactured by Fann Instrument Company (Houston, TX, USA), is primarily used to determine the viscosity, shear stress, and other parameters of drilling fluids under high-temperature and high-pressure conditions at various shear rates. The operating pressure is ≤ 30 MPa, and the operating temperature is ≤ 260 °C.



Figure 3. High-temperature and high-pressure rheometer.

2.5. Parallel-Core Displacement Apparatus

In this study, a parallel-core displacement apparatus, as shown in Figure 4, was employed. The apparatus consists of injection, displacement, and production systems. The injection system utilizes two high-precision plunger pumps to independently control the injection flow rates of CO₂ and surfactant solution. The intermediate containers are filled with surfactant solution and CO₂, respectively, which are connected through a sand-packed tube foam generator to the parallel-core holders. The displacement system is composed of two core holders, where confining pressure is applied via a hand-operated pump to simulate overburden pressure. In the production system, a back-pressure valve is used to simulate bottomhole pressure, while graduated cylinders and a gas meter are employed for real-time measurement of oil and gas production. Two pressure transducers are installed at both the inlet and outlet of the core holders, and the recorded pressures are subsequently used to calculate foam blocking efficiency.

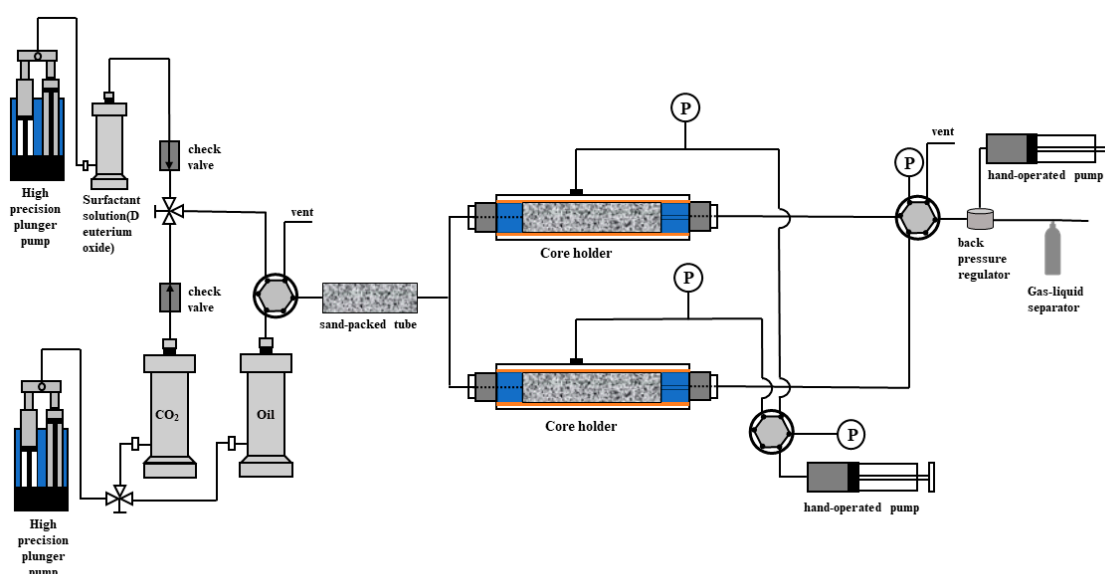


Figure 4. Parallel-core flooding apparatus.

2.6. Nuclear Magnetic Resonance (NMR) Technology

The experiment employed a medium-sized nuclear magnetic resonance imaging analyzer (MesoMR23-060H-I) manufactured by Niumag Corporation, Suzhou, China. The GR-HSE and CPMG sequences were utilized to obtain the axial 1D frequency encoding and T₂ spectra of the cores, respectively. The testing parameters are listed in Table 3.

Table 3. Key parameters of the nuclear magnetic resonance monitoring instrument.

Function	Pulse Sequence	Magnetic Field Intensity (MHZ)	Magnetic Field Gradient (T/m)	Echo Time (ms)
T ₂ spectrum	CPMG	12	0	0.1
Frequency encoding	GR-HSE	12	0.0487	3.7

3. Experimental Methods and Procedural Steps

In this study, a highly efficient CO₂-soluble compound foam system was selected based on performance tests of salt tolerance, oil resistance, and shear resistance. The blocking efficiency and oil recovery performance of the system were evaluated using parallel-core flooding experiments and nuclear magnetic resonance (NMR) techniques.

3.1. Calculation Methods

In this study, foam performance is primarily evaluated by calculating the comprehensive foam index. After measuring the initial foaming volume and foam half-life, the following equation is applied for the calculation [28]:

$$F_q = (3/4) * v_{max} * t_{1/2}$$

where F_q denotes the foam comprehensive index (mL·min), v_{max} represents the initial foaming volume (mL), and $t_{1/2}$ refers to the foam half-life (min).

The use of a comprehensive foam index is rational because a single foam property (such as initial volume or half-life alone) cannot fully describe the dynamic behavior of foam systems under reservoir-relevant conditions. Foam index effectively captures both the foam generation capacity and its persistence over time, offering a more representative evaluation of the system's overall stability and mobility control potential. This integrative parameter allows for straightforward comparison between formulations and provides a useful screening criterion for selecting optimal foaming systems for core-flood experiments.

The blocking efficiency during the flooding process with the foam compound system is calculated using the following equation [29]:

$$R = \left(1 - \frac{\Delta P_{before}}{\Delta P_{after}} \right)$$

Here, R denotes the blocking efficiency, ΔP_{before} represents the inlet–outlet pressure differential (MPa) prior to foam blocking (MPa), ΔP_{after} represents the inlet–outlet pressure differential (MPa) after foam blocking.

The accuracy of R is sensitive to baseline pressure stability and transient effects during foam buildup. If baseline drift occurs (e.g., due to pump fluctuations or temperature changes), the value of ΔP_{before} may deviate, leading to an overestimation or underestimation of R . Therefore, each test should be preceded by at least 30 min of steady-state flow to ensure stable baseline pressure. During the early stages of foam injection, transient pressure spikes can occur as lamellae form and coalesce. Using the average of the stabilized pressure plateau (rather than instantaneous peak values) can minimize this bias. Replicate experiments and consistent core cleaning procedures further improve the reproducibility of R measurements. Thus, the reported blocking efficiency values in this study reflect the steady-state behavior after foam establishment, ensuring comparability across formulations.

In the experiments, the one-dimensional frequency-encoding images display the axial distribution of the NMR signal of the oil phase within the core. By correlating the signal intensity with the corresponding oil volume, the signal profile is converted into the distribution of oil saturation in the core, thereby characterizing the migration of crude oil during the displacement process. The T_2 spectrum, on the other hand, represents the distribution of the oil phase across different pore sizes, with the relaxation time T_2 related to the pore radius as follows [25]:

$$\frac{1}{T_2} = \rho \frac{S}{V} = \rho \frac{C}{r}$$

In the equation, T_2 denotes the relaxation time (ms); ρ is the surface relaxivity (nm/ms); S is the pore surface area of the core (cm²); V is the pore volume (cm³); C is the geometrical shape factor; r is the pore radius (cm).

From the above equation, it can be inferred that the relaxation time is proportional to the pore radius of the fluid-bearing pores: short relaxation times correspond to fluids residing in small pores, whereas long relaxation times correspond to fluids in larger pores.

Therefore, by analyzing the variations in the dynamic T_2 spectra during the displacement process, the pore-scale microscopic migration behavior of the oil phase can be investigated, thereby elucidating the plugging and enhanced oil recovery effects of foam flooding. The method for characterizing core oil recovery using NMR T_2 spectra is as follows:

$$\text{Recovery factor} = \frac{I_{\text{Initial}} - I_{\text{Residual}}}{I_{\text{Initial}}}$$

There:

I_{Initial} represents the total integrated signal area before flooding; I_{Residual} represents the total integrated signal area after flooding.

3.2. Experimental Design and Procedures

The experimental work was divided into three parts: (1) optimization of the concentration of the primary CO_2 foaming agent (AOS); (2) optimization of the CO_2 blended foaming system; and (3) evaluation of the blocking efficiency and enhanced oil recovery performance of the optimized CO_2 blended foaming system. The first two parts focused on assessing foaming performance by calculating the comprehensive foam index from the measured initial foam volume and foam half-life, whereas the third part was conducted through parallel-core flooding tests combined with nuclear magnetic resonance (NMR) techniques.

The detailed experimental schemes are summarized in Tables 4–6.

Table 4. Optimization experiment on the concentration of the primary CO_2 foaming agent (AOS).

Group Number	Foaming Agent	Concentration (wt%)	Total Salinity	Foam Stabilizer (wt%)	Assessment Criteria
1	AOS	0.3	30,000 mg/L	HPAM (0.05%)	Evaluation based on the foam composite index
2		0.5			
3		0.6			
4		0.7			
5		0.8			

Table 5. Optimization experiment on the CO_2 compound foaming system.

Group Number	Compound Formulation	Mass Ratio of the Formulation	Total Salinity	Foam Stabilizer (wt%)	Whether Oil Resistance and Shear Resistance Tests Were Conducted	Assessment Criteria
1	AOS+AEO	1:1	30,000	HPAM (0.05%)	NO	Evaluation based on the foam composite index
2	AOS+AEO	2:1				
3	AOS+AEO	3:1				
4	AOS+AEO	1:1	50,000		YES (The shear rate is 150 s ⁻¹ ; The temperature is 90 °C; The volume of crude oil is 40 mL)	
5	AOS+AEO	2:1				
6	AOS+CTAB	1:1				
7	AOS+CTAB	2:1	30,000		NO	
8	AOS+CTAB	3:1				
9	AOS+CTAB	1:1				
10	AOS+CTAB	2:1	50,000		YES (The shear rate is 150 s ⁻¹ ; The temperature is 90 °C; The volume of crude oil is 40 mL)	

Table 6. Evaluation experiment on the blocking and enhanced oil recovery performance of the CO_2 compound foaming system.

Group Number	Gas–Liquid Ratio (Volume Ratio of CO_2 to the Blended Solution)	Permeability Contrast	Inject Rate (mL/min)
1	Pure CO_2	5	0.2
2	Single AOS (0.6%wt) 2:1	5	
3	Compound System 2:1	5	
4	Compound System 2:1	10	

The detailed procedures for the CO₂ foaming agent primary surfactant (AOS) concentration optimization experiment and the CO₂ compound foaming system optimization experiment are as follows (taking the first group in the AOS concentration optimization experiment as an example):

- ① Preparation of formation water solution: Prepare the target salinity solution by mixing a measured volume of formation water and deionized water to obtain a solution with a salinity of 30,000 mg/L;
- ② Preparation of foaming solution: Dissolve 0.3 wt% AOS powder in the target salinity solution prepared in step 1 to obtain the foaming agent solution, then add 0.05 wt% HPAM as a foam stabilizer, followed by stirring and aging;
- ③ Pressurization and equilibration: Inject the solution into the reactor, seal it, heat to the target temperature, purge air with CO₂, pressurize to the target pressure, and maintain constant temperature for 30 min (for pre-aging, if an oil resistance test is to be conducted, add 40 mL of crude oil before injecting CO₂);
- ④ Foam generation and measurement: Start the high-speed stirrer and run for 30 s; after stopping, immediately record the maximum foam column height and calculate the foam volume based on the reactor diameter;
- ⑤ Foam stability test: Record the time required for the foam height to decrease to 0.5 of its initial value, and finally calculate the foam composite index using the designated formula.

The detailed procedures for the evaluation and optimization experiment of the blocking and enhanced oil recovery performance of the CO₂ compound foaming system are as follows (taking the first group as an example):

- ① Core preparation and setup: Place the two saturated cores into the parallel-core holder. After connecting all lines, apply a confining pressure of 10 MPa and set the back pressure to 5 MPa;
- ② System saturation with crude oil: Open the valves connecting the intermediate crude oil container to the experimental lines. Pump crude oil at a constant pressure of 5 MPa to fill the system and reach the target pressure. Once the outlet pressure reaches 5 MPa, indicating the system is fully saturated, close the relevant valves;
- ③ Primary CO₂ flooding: Open the valves connecting the CO₂ container to the system and inject CO₂ at a rate of 0.2 mL/min. Monitor the injection volume after CO₂ breakthrough. Stop the flooding after injecting 4 PV, record the inlet–outlet pressure differential, and remove the cores for NMR T₂ measurement;
- ④ Secondary CO₂ flooding: After NMR measurement, place the cores back into the holder and repeat the flooding procedure for another 4 PV. After completion, record the inlet–outlet pressure differential and conduct NMR T₂ measurement again;
- ⑤ Data analysis: Calculate the oil recovery using the changes in T₂ signal amplitude. Compare the recovery before and after foam injection, and compute the plugging efficiency to evaluate the performance of the CO₂-soluble foam system.

3.3. Core Oil Saturation Determination

A correlation between the total signal amplitude from one-dimensional (1D) frequency-encoding images, the cumulative envelope area of the T₂ spectrum (i.e., total accumulated signal), and the core oil content was established. The total signal measured by the two sequences was found to be essentially consistent. The procedure is described below using the T₂ spectrum as an example:

- (1) Measurement of dry core baseline: Measure the mass and NMR baseline signal of the washed and oven-dried core;

- (2) Saturation and measurement: After vacuum-saturating the core with crude oil, weigh the core and acquire the T_2 spectrum and 1D frequency-encoding image, as shown in Figure 5;
- (3) Centrifugation: Centrifuge the core at 2000, 4000, and 8000 rpm for 1 h each. After centrifugation, weigh the core and measure the T_2 spectrum again;
- (4) Correlation establishment: Calculate the mass difference before and after centrifugation and the corresponding difference in cumulative T_2 signal, and establish the conversion relationship between NMR signal amplitude and core oil content.

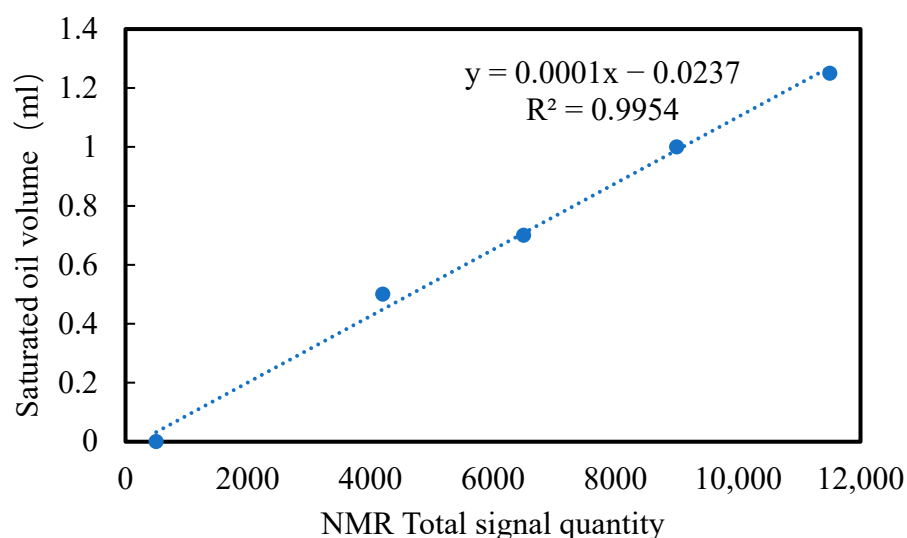


Figure 5. NMR signal-to-core oil content correlation.

4. Results and Discussion

4.1. Optimization Results and Analysis of the Primary Agent Concentration

To select a primary foaming agent concentration that is both effective and cost-efficient, five concentrations (0.3%, 0.5%, 0.6%, 0.7%, and 0.8%) were tested. The comprehensive foam index calculated for each concentration was used to construct the bar and line trend plots of foaming performance for AOS at different concentrations, as shown in Figure 6.

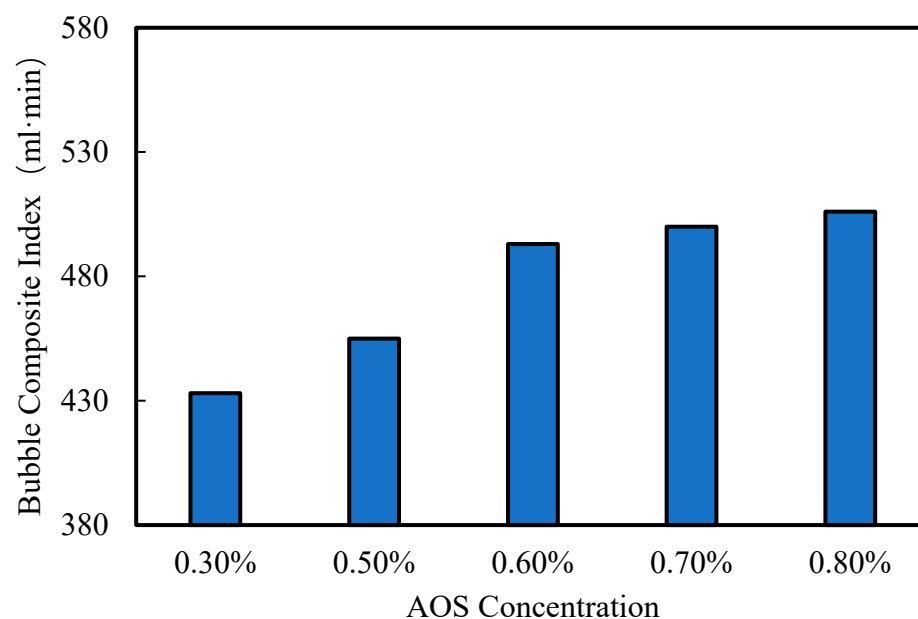


Figure 6. Foaming performance of AOS at different concentrations.

As shown in the figure, when the primary agent concentration increases from 0.3% to 0.6%, the comprehensive foam index rises rapidly, with the slope of the trend also increasing. At 0.6%, the foam index is 13.9% higher than that at 0.3%, indicating that low concentrations of the primary agent are insufficient to achieve good foaming performance, while an appropriate increase in concentration effectively optimizes the foaming capability. In the range of 0.6% to 0.8%, the increase in the foam index becomes much smaller, and the slope of the trend markedly decreases. Overall, 0.6% represents the inflection point of foaming performance. At 0.8%, the foam index increases by only 2.6% compared with 0.6%. Therefore, to achieve excellent foaming performance while maintaining economic efficiency, the concentration at the performance inflection point (0.6%) is considered optimal. Accordingly, in all subsequent experiments, the primary agent concentration was set at 0.6%.

4.2. Optimization Results and Analysis of the Compound Foaming System

To select an optimal compound foaming system, 0.6 wt% AOS was used as the primary surfactant, with AEO and CTAB as secondary surfactants for formulation. The optimization of the compound system was conducted by varying the type and mass ratio of the secondary surfactants, combined with performance evaluation tests. The comparison of foaming performance for the two compound systems using AEO or CTAB as the secondary surfactant at different mass ratios is shown in Figure 7.

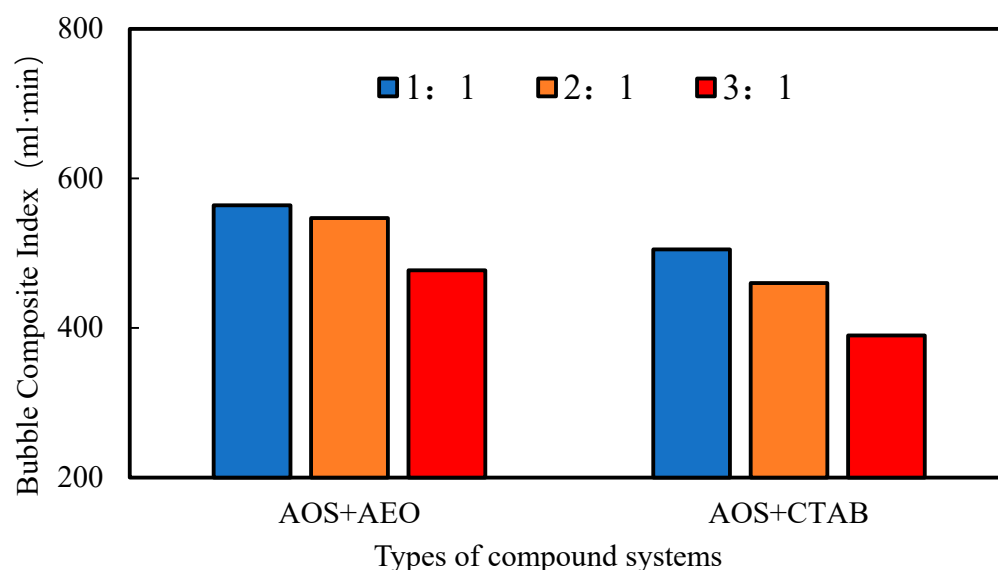


Figure 7. Comparison of foaming performance for two compound systems at different mass ratios.

As shown in the figure, the AOS+AEO compound system exhibits superior foaming performance compared with the AOS+CTAB system across different surfactant mass ratios. In both systems, the foaming performance decreases as the mass ratio of primary to secondary surfactant increases. For the better-performing AOS+AEO system, although the foaming performance slightly decreases at a 2:1 mass ratio, it still reaches 97% of the performance observed at a 1:1 ratio.

The comparison of salt tolerance for the two compound systems with AEO or CTAB as the secondary surfactant is shown in Figure 8.

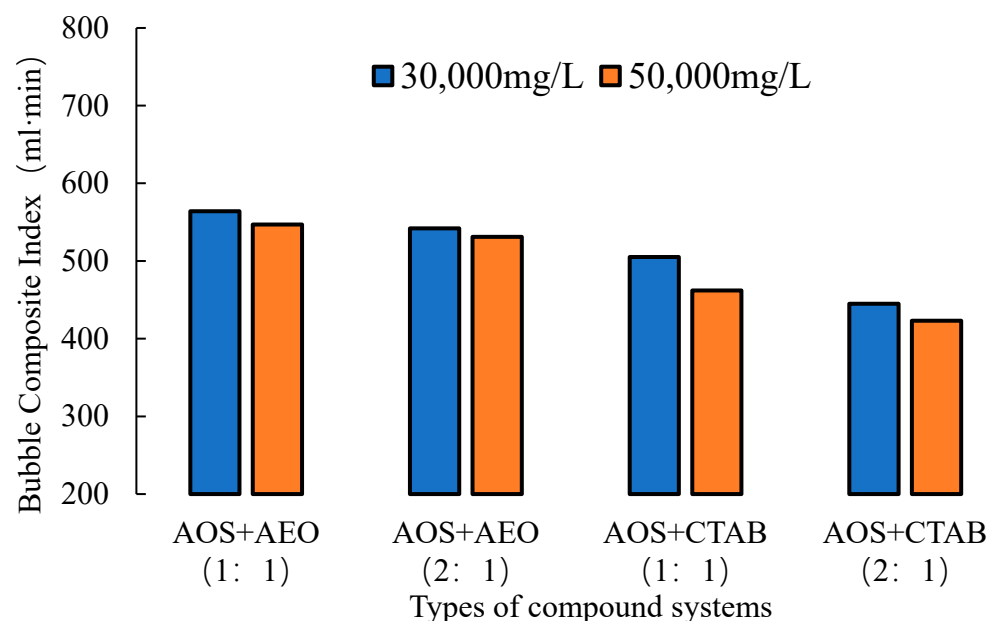


Figure 8. Comparison of salt tolerance for the two compound systems.

As shown in the figure, the AOS+AEO compound system exhibits superior salt tolerance compared with the AOS+CTAB system across different mass ratios. When the salinity increases from 30,000 mg/L to 50,000 mg/L, the foaming performance of the AOS+AEO system at both mass ratios retains 97% and 98% of the original level, whereas the AOS+CTAB system retains only 91.5% and 95.1%, respectively. This indicates that the foaming performance of the AOS+AEO system is less affected by increasing salinity and demonstrates better salt resistance.

The comparison of oil tolerance and shear resistance for the two compound systems is shown in Figure 9.

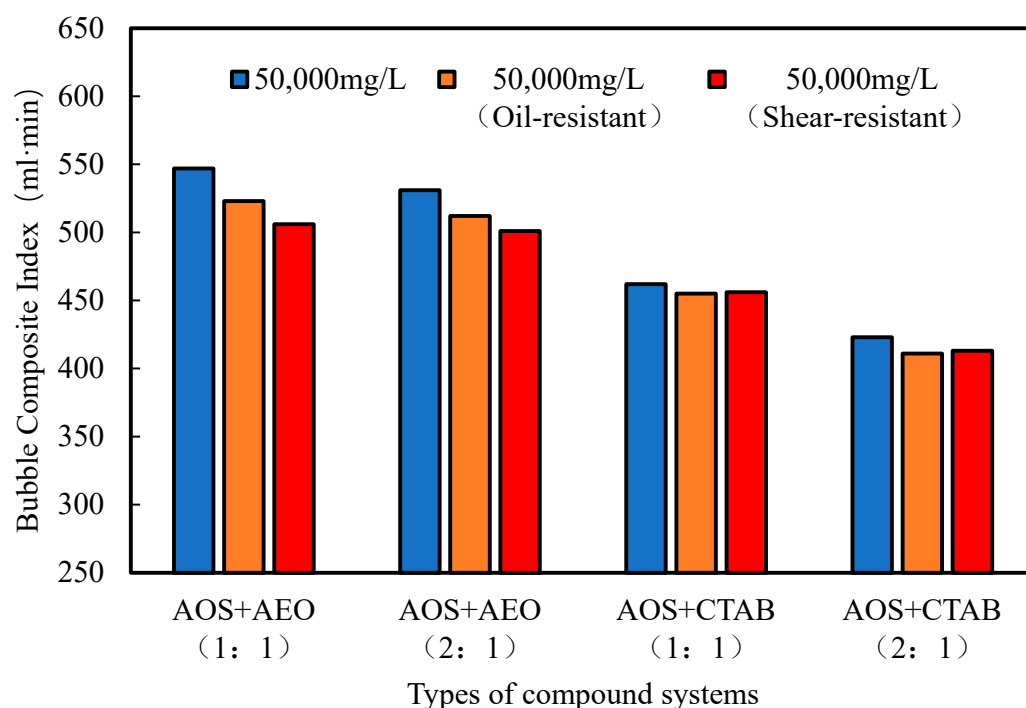


Figure 9. Comparison of oil tolerance and shear resistance for the two compound systems.

As shown in the figure, the AOS+AEO compound system at a 2:1 mass ratio exhibits excellent oil tolerance and shear resistance. Its foaming performance shows no significant decline after the addition of crude oil and shear treatment. Although slightly lower than that of the 1:1 AOS+AEO system, the difference is minimal. The AOS+CTAB system demonstrates even less reduction in foaming performance under oil addition and shear, indicating better oil tolerance and shear resistance; however, its overall foam index is substantially lower than that of the AOS+AEO system.

Considering all the above experiments, the AOS+AEO system outperforms the AOS+CTAB system in foaming performance across different surfactant mass ratios and exhibits excellent salt tolerance, oil tolerance, and shear resistance. The 2:1 AOS+AEO system provides both superior foaming performance and economic efficiency (industrial-grade prices of approximately 15,000 CNY t⁻¹ for AOS and 25,000 CNY t⁻¹ for AEO, if maintain a constant AOS dosage while reducing the AEO proportion by half decreases, it could make an overall cost reduction of approximately 31%), and is therefore selected as the optimal system for subsequent experiments.

4.3. Core Flooding Experiments and NMR Measurement Analysis

This part of the experiment employed NMR imaging to provide a direct qualitative assessment of the foaming performance of the compound system, while NMR T₂ spectra were used for quantitative evaluation of oil recovery. The blocking performance of the foam system was quantified based on the inlet–outlet pressure differential.

For the first group (permeability ratio = 5, injection rate = 0.2 mL/min), a heterogeneous reservoir was subjected to pure CO₂ flooding as the control. The variation in inlet pressure with time is shown in Figure 10. The injected PV count was calculated starting from CO₂ breakthrough. After injecting 4 PV of CO₂, the system stabilized, followed by an additional 4 PV injection. At this point, the inlet pressure reached 5.24 MPa, and the difference from the outlet back pressure of 5 MPa, $\Delta P_{before} = 0.24$ MPa, was used to calculate the blocking efficiency for the subsequent CO₂ foam flooding experiments.

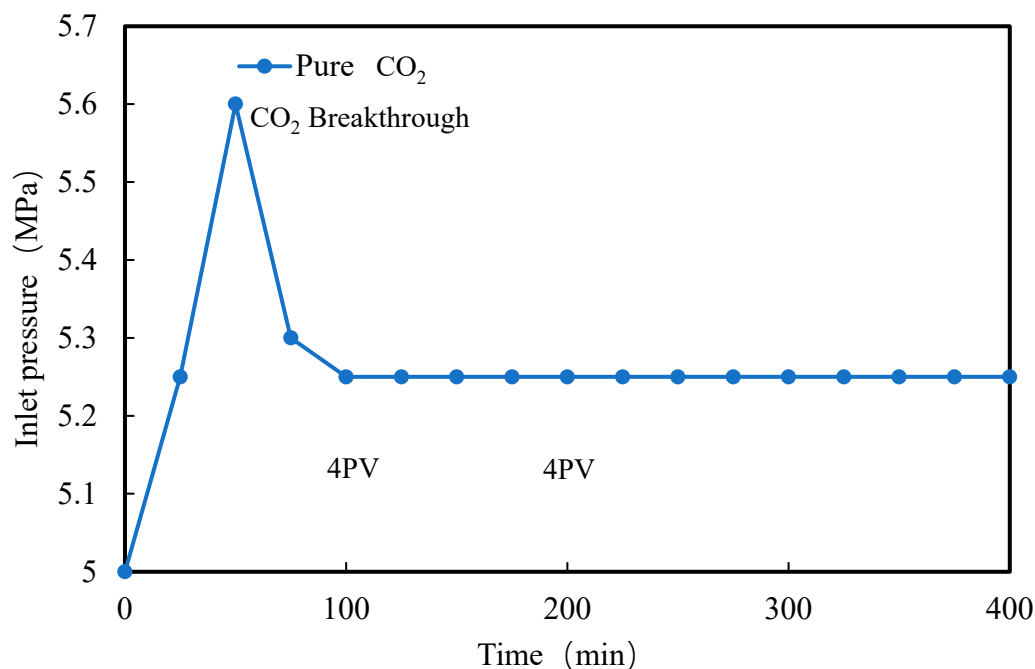


Figure 10. Inlet pressure versus time curve for the control group.

The NMR images of the two cores in the control group before and after flooding are shown in Figure 11. From the images, it can be observed that after injecting 4 PV of

pure CO₂, the oil saturation in the low-permeability core decreases only slightly. After an additional 4 PV injections of pure CO₂, the oil saturation in the low-permeability core remains nearly unchanged, indicating that a large amount of oil remains in the low-permeability core, and the recovery potential is significant. For the high-permeability core, a substantial amount of oil is produced after the first 4 PV of pure CO₂ flooding; however, after a subsequent 4 PV injection, the oil saturation in the high-permeability core shows little further change. This behavior is likely due to the formation of CO₂ preferential flow channels in the high-permeability core after breakthrough, causing subsequent CO₂ injection to bypass the low-permeability core and the remaining oil in the high-permeability core, thereby limiting further recovery. Qualitatively, the NMR images demonstrate that the development of high-permeability CO₂ channels is unfavorable for subsequent oil recovery, highlighting the importance of foam-based blocking.

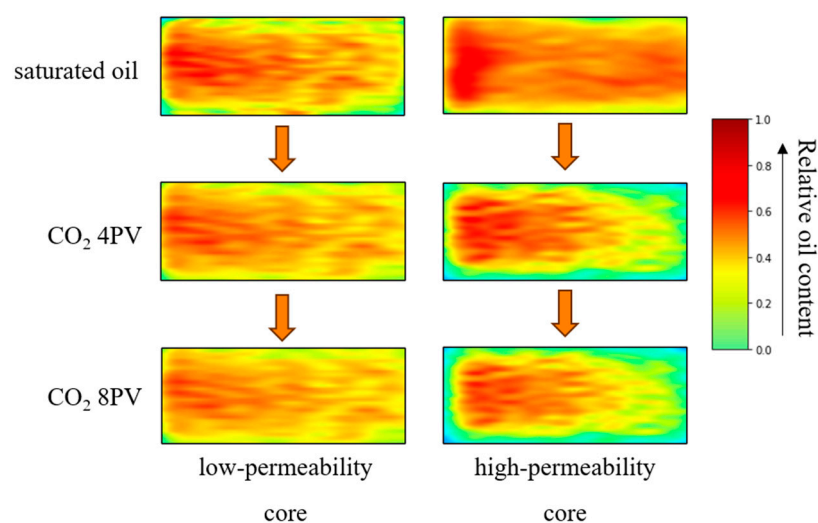


Figure 11. NMR images of high- and low-permeability cores in the control group after pure CO₂ flooding.

The T₂ spectra of the two cores in the control group before and after flooding, along with the corresponding recovery calculated from peak areas, are shown in Figures 12 and 16. It can be seen that after pure CO₂ flooding, the peak area of the T₂ spectrum for the high-permeability core decreases significantly, whereas the low-permeability core shows only a slight decrease. This indicates that most of the oil is produced from the high-permeability core, while oil mobilization in the low-permeability core is minimal. Furthermore, the oil produced from the high-permeability core mainly originates from the larger pores. After 8 PV of pure CO₂ flooding, the overall recovery of the two cores is 21.0%, with 33.5% from the high-permeability core and only 7.1% from the low-permeability core. These results quantitatively confirm that the high-permeability core contributes the majority of oil production during pure CO₂ flooding, while the low-permeability core retains substantial recovery potential.

To visually demonstrate the performance improvement of the subsequent compound system compared to the single system surfactant, we conducted a parallel core flooding experiment with the single AOS (0.6%wt). The gas–liquid ratio of the surfactant solution to CO₂ was 2:1, the injection rate was 0.2 mL/min, and the permeability ratio was 5. The curve of the inlet pressure varying with time is shown in Figure 13. It can be seen that the foam flooding of the AOS single system can effectively block the high-permeability layer. Through calculation, the blocking rate reaches 79.1%.

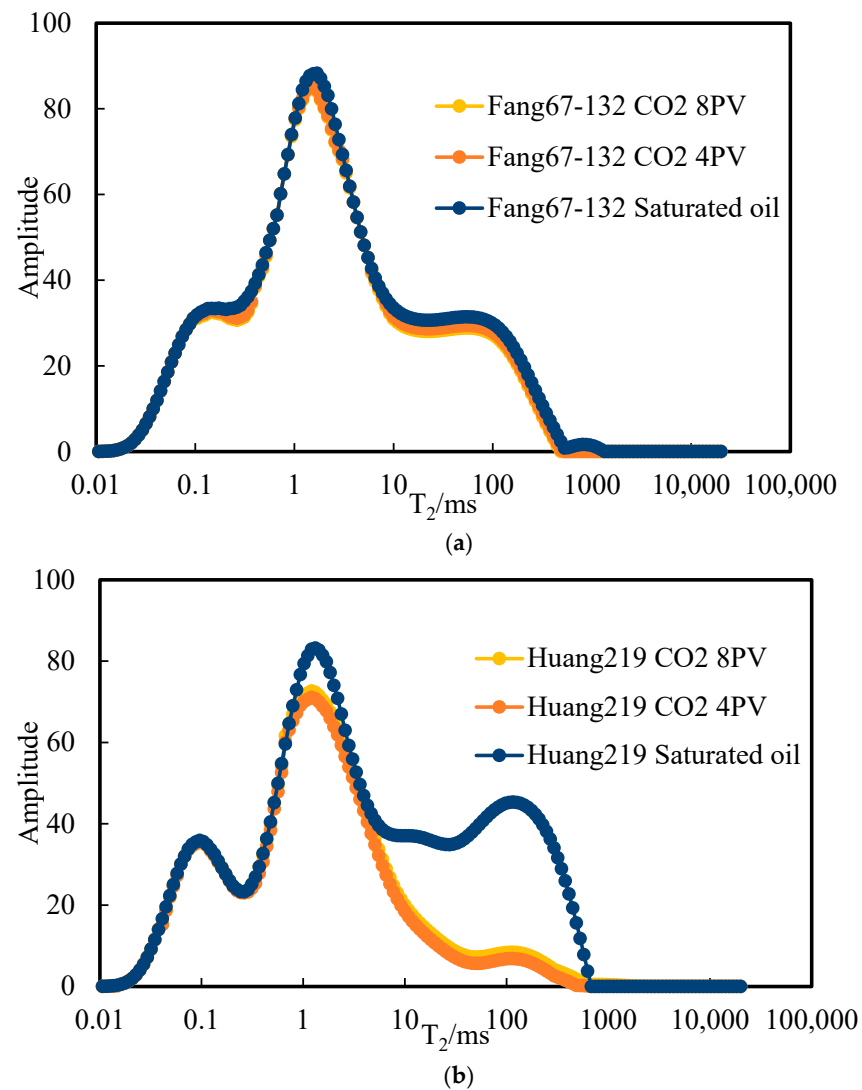


Figure 12. T_2 spectra of low-permeability core (a) and high-permeability core (b) in the control group after pure CO₂ flooding.

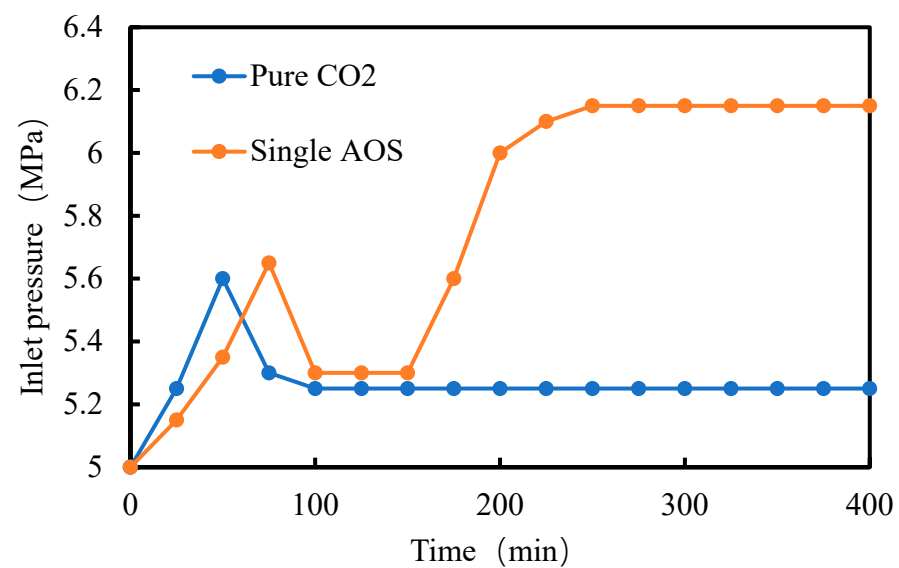


Figure 13. Inlet pressure versus time curves for foam flooding and the control group.

The nuclear magnetic resonance images of the AOS single system foam flooding before and after are shown in Figure 14. It can be seen from the figure that after 4PV pure CO₂ flooding, the oil saturation of the low-permeability core remains basically unchanged. After the AOS single system foam flooding for 4PV, the oil utilization in the low-permeability core was enhanced, and the oil saturation decreased. Qualitative analysis indicates that the AOS single system foam flooding effectively blocks high-permeability channels and improves crude oil utilization of low-permeability cores.

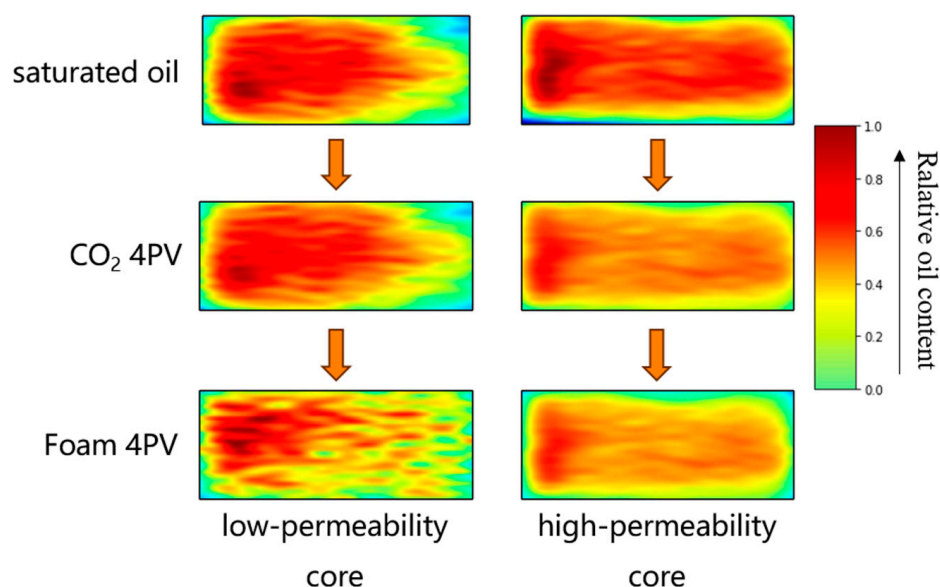


Figure 14. NMR images of high- and low-permeability cores before and after foam flooding.

The T₂ spectra of the cores before and after the AOS single system foam flooding, as well as the recovery rates calculated by peak area, are compared, as shown in Figures 15 and 16. It can be seen that the peak areas of both low-permeability and high-permeability cores after foam flooding are significantly lower than those after pure CO₂ flooding, indicating that crude oil has been effectively further utilized during the AOS single system foam flooding process. The extracted oil mainly comes from larger pores. The total recovery rate of the two cores after foam flooding was 22.9%, which was 1.9% higher than that of pure CO₂ flooding. Foam flooding enhanced the recovery rate of low-permeability cores by 1.6% compared to CO₂ flooding and further increased the crude oil utilization of high-permeability cores by 2.7%.

The comparative experiment between AOS+AEO foam flooding and pure CO₂ flooding was conducted with the compound system at an AOS–AEO mass ratio of 2:1. The gas–liquid ratio of the system to CO₂ was set at 2:1, the injection rate was 0.2 mL/min, and the permeability ratio between the high- and low-permeability cores was 5. The inlet pressure versus time curves are shown in Figure 17. It can be seen that foam flooding with the AOS+AEO system effectively blocks the high-permeability layer, achieving a blocking rate of 84.5% through calculation. This is superior to the 79.1% blocking rate of the single-system AOS. This indicates that the system significantly reduces CO₂ channeling through high-permeability zones, allowing the displacing fluid to sweep a larger portion of the core and thereby providing the potential to further enhance oil recovery.

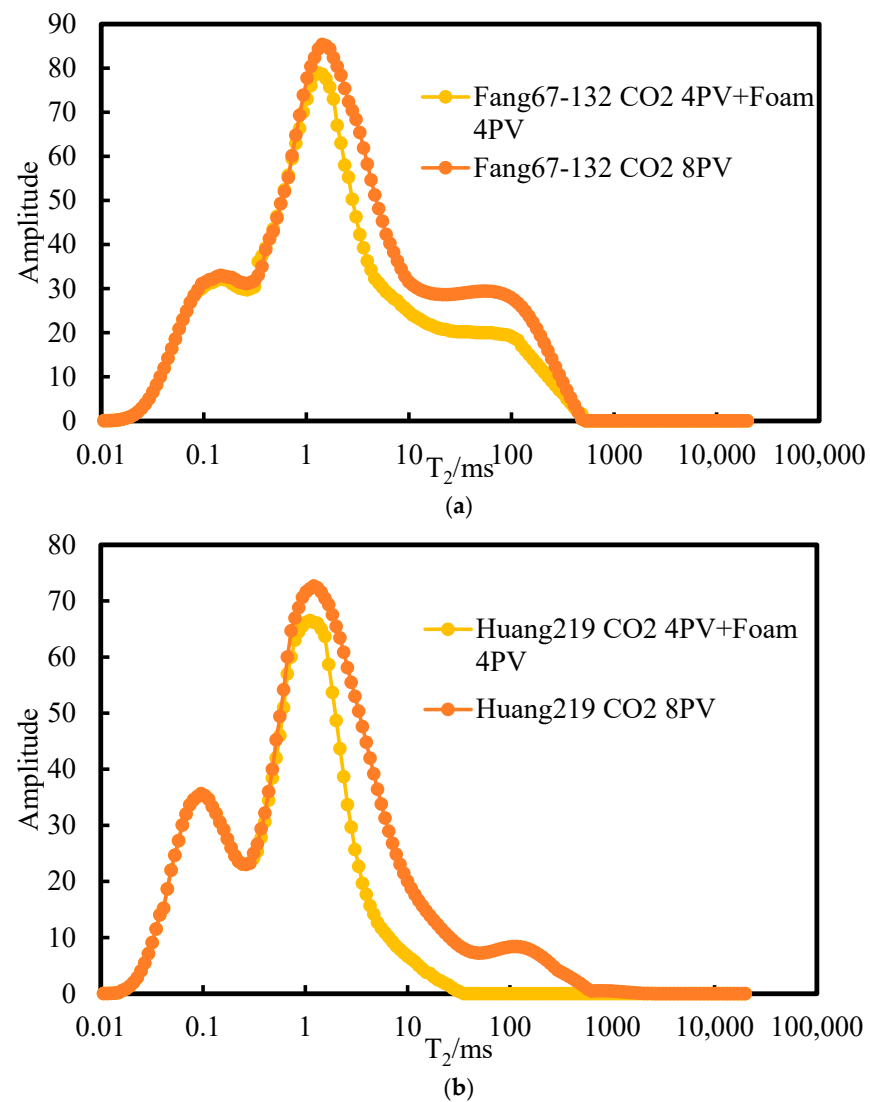


Figure 15. Comparison of T_2 spectra for low-permeability core (a) and high-permeability core (b) between single AOS foam flooding and the control group.

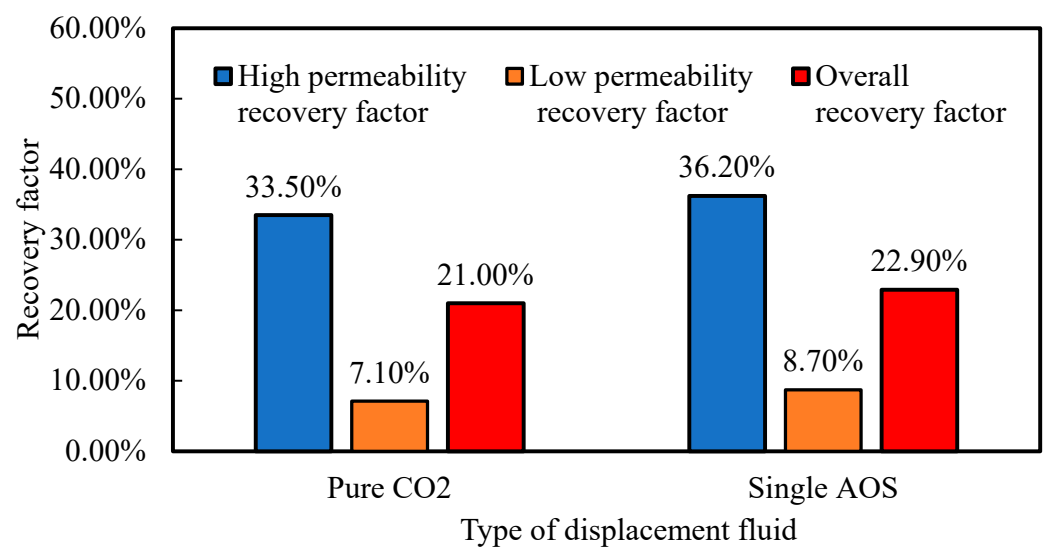


Figure 16. Comparison of oil recovery between foam flooding and the control group.

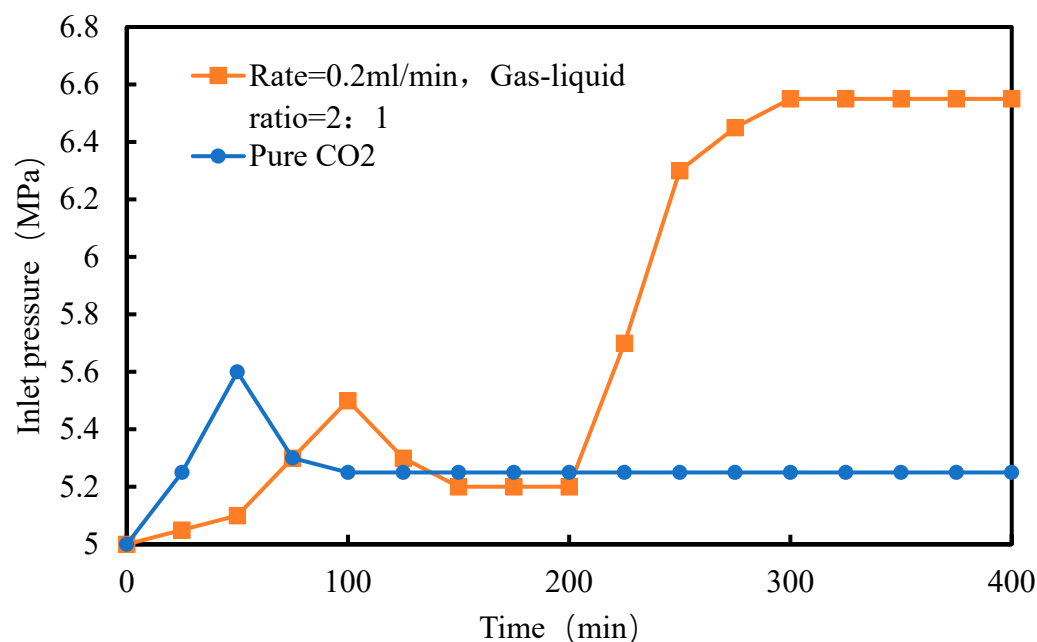


Figure 17. Inlet pressure versus time curves for compound foam flooding and the control group.

The NMR images before and after foam flooding with the AOS+AEO system are shown in Figure 18. From the images, it can be observed that after 4 PV of pure CO₂ flooding, the oil saturation in the low-permeability core remains nearly unchanged. However, after 4 PV of foam flooding with the compound system, oil mobilization in the low-permeability core is significantly enhanced, with a noticeable decrease in oil saturation. The high-permeability core remains the primary contributor to oil production. Compared with the control group, not only does it produce a large amount of oil after the initial 4 PV of pure CO₂ flooding, but additional oil is also mobilized during the subsequent foam flooding. Qualitatively, the NMR images demonstrate that the compound foam system effectively blocks high-permeability channels, improves oil mobilization in the low-permeability core, and further enhances recovery from the remaining oil in the high-permeability core, indicating that this system is effective for improving overall oil recovery.

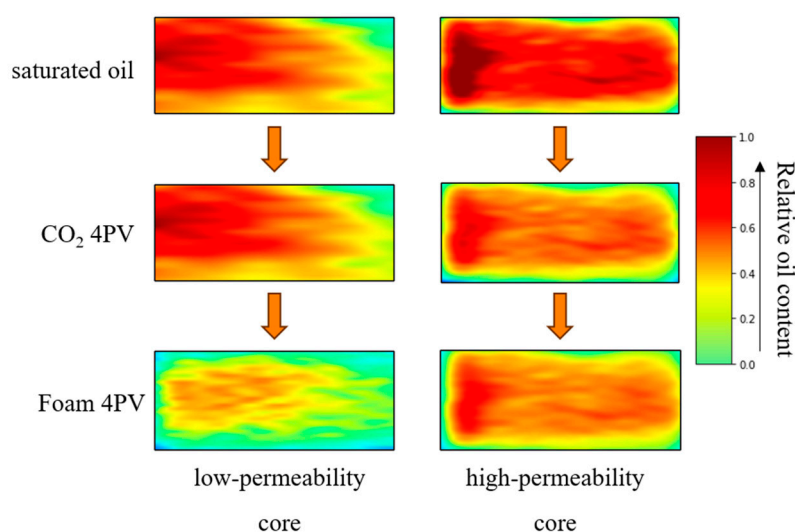


Figure 18. NMR images of high- and low-permeability cores before and after foam flooding.

The T₂ spectra of the cores before and after foam flooding, along with the corresponding recovery calculated from peak areas, are compared in Figures 19 and 20. It can be

seen that the peak areas for both the low- and high-permeability cores after foam flooding are noticeably lower than those after pure CO₂ flooding, indicating that oil is effectively further mobilized during foam flooding. The produced oil mainly originates from the larger pores. The overall recovery of the two cores after foam flooding is 25.6%, representing an increase of 4.6% compared to pure CO₂ flooding. Compound foam flooding significantly improves oil recovery in the low-permeability core, with a 4.5% increase over CO₂ flooding, and further enhances oil mobilization in the high-permeability core, with a 4.6% increase. All these performances are superior to those of a single system AOS. These quantitative results demonstrate that the compound foam system effectively improves recovery in low-permeability zones while further mobilizing oil in high-permeability zones, highlighting its practical significance for optimizing recovery in heterogeneous reservoirs.

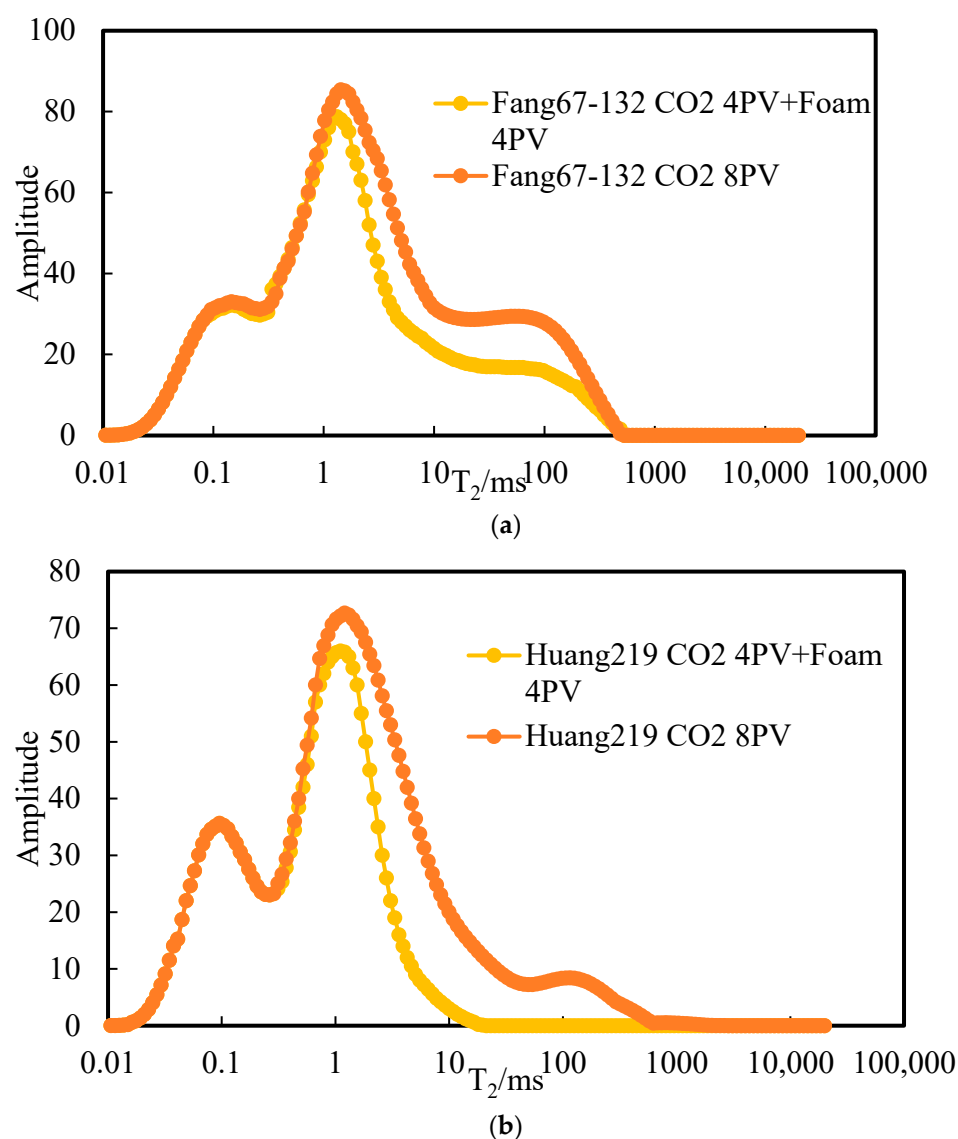


Figure 19. Comparison of T₂ spectra for low-permeability core (a) and high-permeability core (b) between compound foam flooding and the control group.

To investigate the blocking and recovery performance of the AOS+AEO compound system in heterogeneous reservoirs with different permeability contrasts, cores with a permeability ratio of 10 were selected and compared with the previously tested cores with a permeability ratio of 5. In both experiments, the high-permeability cores had identical permeability, while only the low-permeability cores differed; all other experimental param-

eters were kept constant. The injection pressure versus time curves and the corresponding blocking rate comparisons for this set of experiments are shown in Figure 21a,b. It can be observed that the AOS+AEO compound system achieves even better blocking performance in cores with a permeability ratio of 10, with a blocking rate reaching 86.5%, which is 2% higher than that of the cores with a permeability ratio of 5.

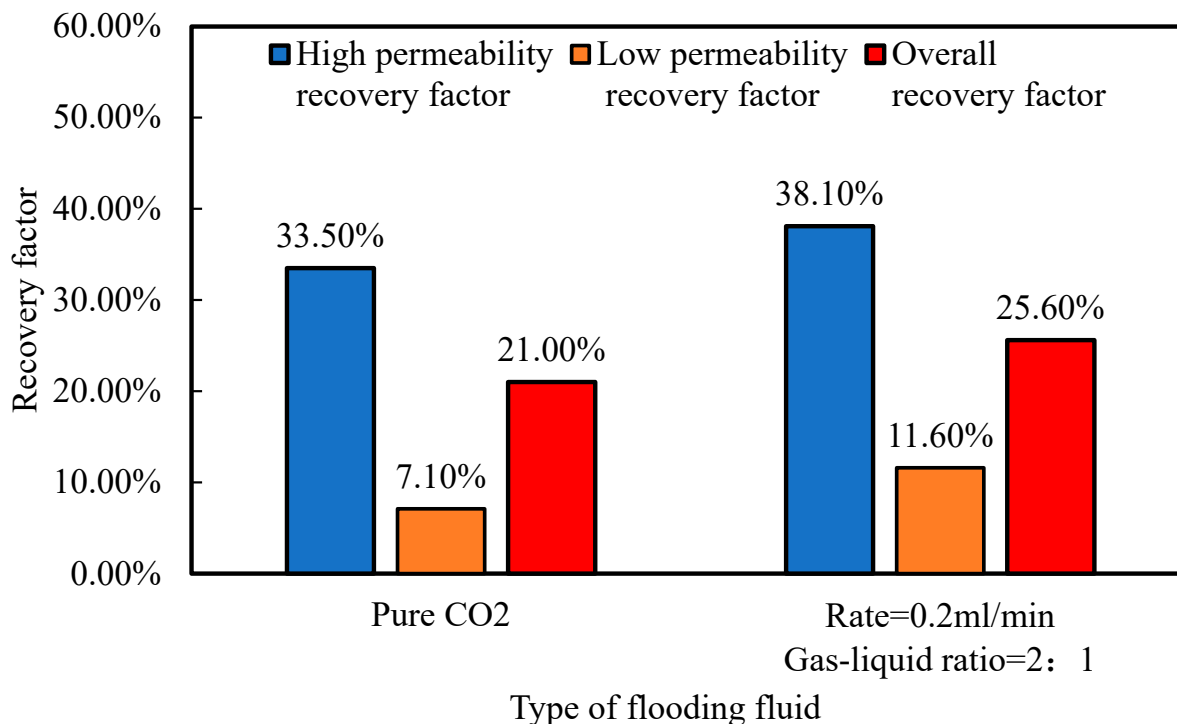


Figure 20. Comparison of oil recovery between compound foam flooding and the control group.

Figure 22 shows the NMR images of cores with a permeability ratio of 10 before and after foam flooding. It can be observed that the oil saturation changes in both the low- and high-permeability cores are similar to those in the control group. The AOS+AEO compound foam system has only a minor effect on oil recovery for this permeability-contrast core, with the low-permeability core still exhibiting poor oil mobilization.

Figures 23 and 24 present the T2 spectra before and after foam flooding, along with the corresponding oil recovery calculated from the peak areas for cores with different permeability contrasts. It can be observed that for the experiment with a permeability ratio of 10, the overall recovery was only 22.5%, 3.1% lower than that for the permeability ratio of 5. The oil recovery of the low-permeability core decreased by 6.4%, approximately half of that observed in the low-permeability core of the permeability ratio 5 experiment, while the high-permeability core recovery decreased by 1.6% to 36.5%. This may be attributed to the fact that, although a higher permeability ratio effectively increases the blocking efficiency, the extremely low permeability of the low-permeability layer still limits oil mobilization during displacement, resulting in a persistently low recovery. Therefore, while the foam system can achieve effective blocking in reservoirs with a large permeability ratio, its incremental effect on oil recovery is limited.

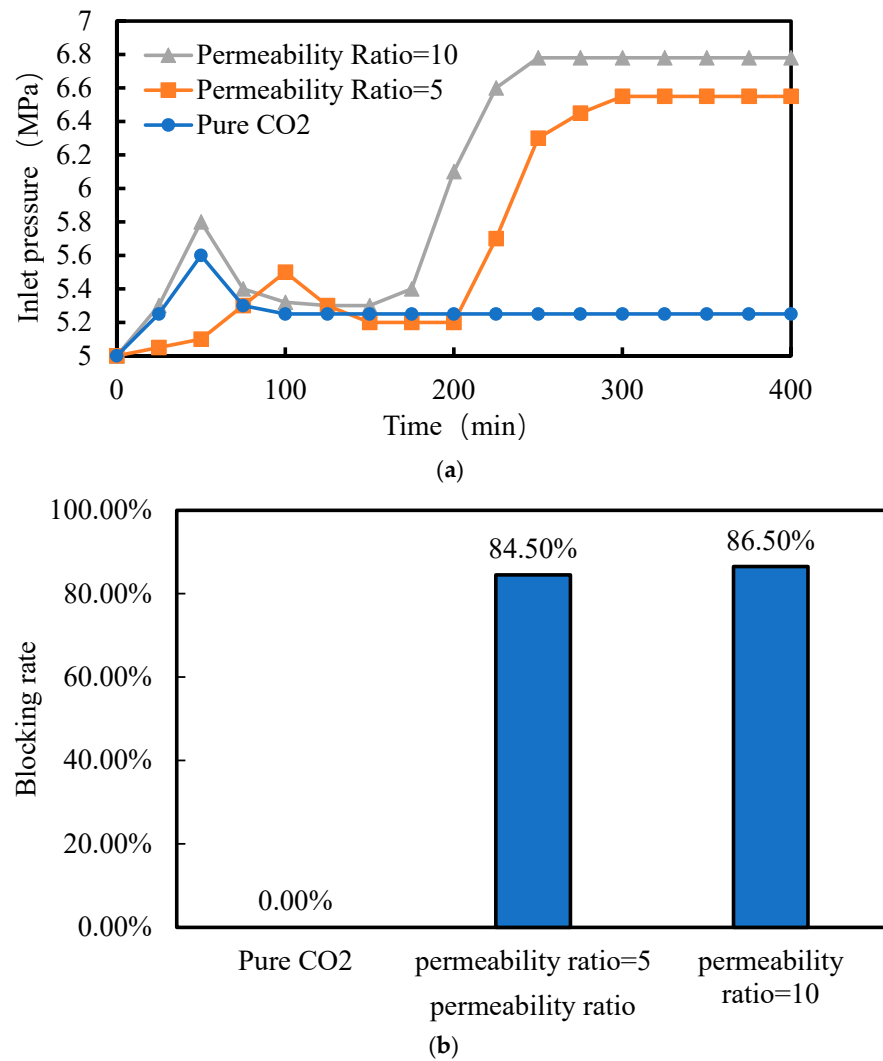


Figure 21. Injection pressure versus time curves (a) and blocking rate comparison (b) for cores with different permeability ratios and the control group.

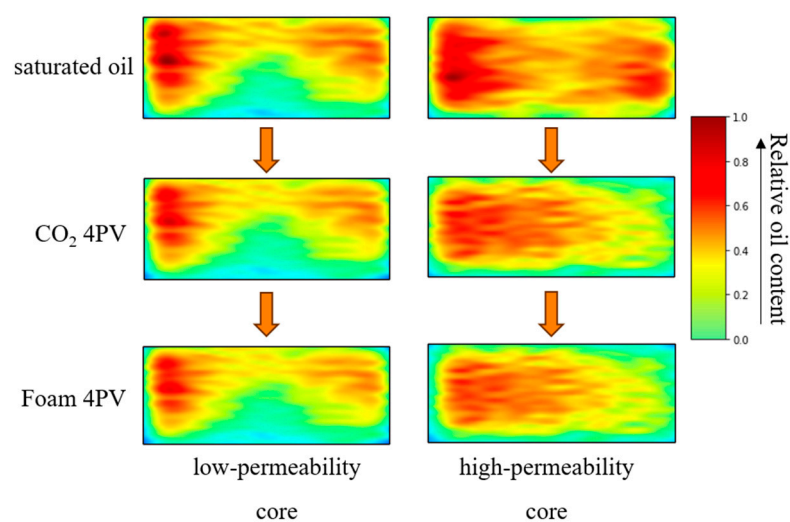


Figure 22. NMR images of high- and low-permeability cores with a permeability ratio of 10.

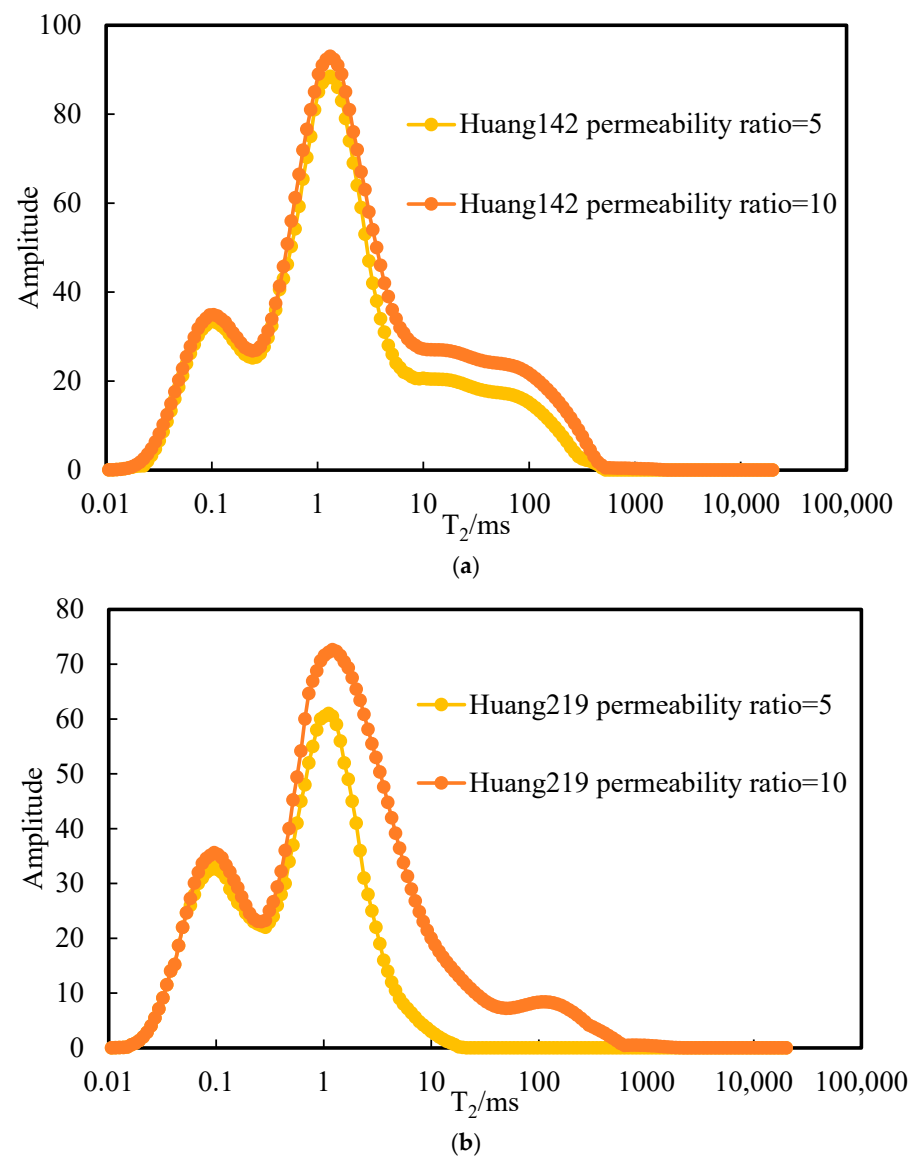


Figure 23. Comparison of T2 spectra for low-permeability (a) and high-permeability (b) cores under foam flooding with different permeability ratios.

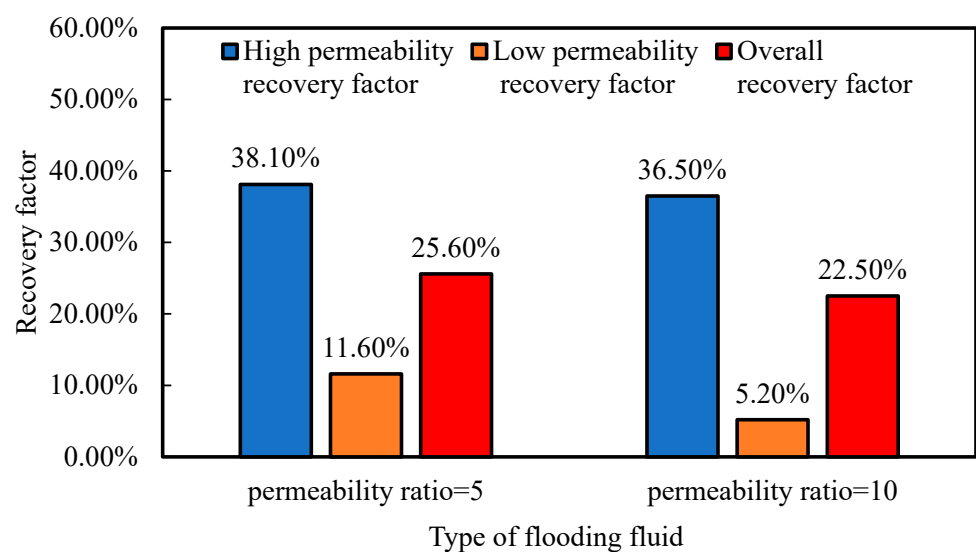


Figure 24. Comparison of oil recovery for foam flooding under different permeability ratios.

5. Conclusions

- (1) An optimized CO₂-foam system comprising 0.6 wt% AOS (primary foaming agent), 0.3 wt% AEO (auxiliary agent), and 0.05 wt% HPAM (stabilizer) was developed, exhibiting excellent foaming performance, stability (thermal, salt, shear), and cost-effectiveness.
- (2) Core-flooding experiments coupled with NMR analysis demonstrated that this AOS+AEO foam system can effectively block high-permeability channels in heterogeneous reservoirs, and its effect is superior to that of the AOS single system.
- (3) The compound foam system significantly increased the overall oil recovery versus pure CO₂ flooding, particularly in low-permeability zones, whose effect is better than that of the AOS single system as well.
- (4) Permeability ratio has a dual impact on foam-based blocking experiments. With increasing contrast, the foam's blocking efficiency improves, but oil mobilization in low-permeability layers becomes more challenging, leading to a decline in overall recovery. This highlights the inherent trade-off between blocking performance and oil recovery under different degrees of reservoir heterogeneity.
- (5) HPAM may undergo partial hydrolysis or chain scission at elevated temperatures (>90 °C), leading to viscosity loss and reduced foam stability over prolonged injection periods. To mitigate this, future work will focus on screening temperature-resistant copolymers and optimizing formulation pH and salinity to improve polymer stability.

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