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Research Article

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Analysis of Microscopic Flow Behavior and Main Controlling Factors of Water Huff-n-Puff in Tight Reservoirs under the Influence of Salinity

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Abstract

To address the unclear microscopic mechanisms of water huff-n-puff in tight reservoirs under the influence of salinity, a visual physical model for microscopic flow in fracturing fluid displacement was constructed. It was clarified that the fluid displacement mechanism during fracturing fluid displacement is jointly governed by three mechanisms: pressure differential displacement, capillary force imbibition, and ion osmosis, which breaks through the traditional understanding only considering "fracturing fluid displacement and imbibition for energy supplementation." Through multi-method and multi-scale approaches, the microscopic mobilization mechanism of fracturing fluid displacement under the influence of salinity was elucidated, and the main controlling factors were analyzed. The results indicate that reducing the salinity of injected water can enhance oil recovery, and the recovery factor increases with reservoir permeability, shut-in time, and injection pressure. Reservoir permeability and injected water salinity have a greater impact on the performance of water huff-n-puff, followed by shut-in time and injection pressure. Although low-salinity water flooding tends to induce viscous fingering, which reduces the sweep efficiency of the injected water, it enhances capillary imbibition, effectively stripping residual oil from low-permeability matrices and dead-end pores, thereby ultimately improving oil recovery. This study provides theoretical support for enhancing recovery in tight oil reservoirs using fracturing fluid displacement.

Keywords: Water Huff-n-Puff; Low-Salinity Water Flooding; Capillary Imbibition; Microfluidic Visualization

1 Introduction

Water huff-n-puff is a key technical means for achieving formation energy supplementation, efficient mobilization of remaining oil, and stable production and potential tapping of mature oilfields in tight reservoirs. Its core mechanism follows the cyclic working mode of injection for energy supplementation—shut-in for imbibition—opening for production. Field practices indicate that the effectiveness of water huff-n-puff exhibits a rapidly declining trend with increasing huff-n-puff cycles, and shows significant differences under varying reservoir physical properties, fluid characteristics, and development regimes. In recent years, research on low-salinity water flooding and smart water flooding for enhanced oil recovery by regulating rock wettability, interfacial electrical properties, and oil-water interfacial interactions has continued to deepen. A relatively comprehensive theoretical system has been established regarding the mechanisms of wettability alteration, ion exchange, and enhanced imbibition in carbonate reservoirs, providing an important theoretical basis for improving the development effectiveness of water huff-n-puff through optimizing injected water salinity (Liu et al., 2025; Shi et al., 2025; Xu et al., 2025; Zhang et al., 2025; Wang et al., 2025) .

From the perspectives of microscopic interface and multiphase flow mechanisms, reservoir wettability directly controls the oil-water distribution morphology, migration pathways, and residual oil mobilization conditions within pore throats. Changes in salinity can reconstruct the dominant mechanism of oil-water migration at the microscale by altering the electrical double layer structure on rock surfaces, oil-water interfacial tension, and oil film stability (Yang et al., 2025). In tight and shale reservoirs, spontaneous imbibition and pressure displacement exhibit strong coupling characteristics, resulting in obvious time-dependent and nonlinear features of imbibition contribution, which need to be characterized through numerical simulation under pore-fracture coupling conditions (Li et al., 2025).

In addition to low-salinity water flooding, displacement experiments under fluids such as CO₂ have shown that there is a synergistic control relationship among interfacial

tension, wettability evolution, and pore-throat structure. This understanding helps to expand the salinity effect from a single variable to a coupled issue of interface, structure, and dynamics (Yang et al., 2025). At the micro-nano pore scale, wettability alteration can directly affect oil film adsorption and oil droplet snap-off, revealing that salinity-induced wettability adjustment is the core microscopic mechanism determining the potential of huff-n-puff for enhancing oil recovery in tight reservoirs (Dou et al., 2024; Huang et al., 2024; Chen et al., 2025; David et al., 2025).

Spontaneous imbibition is the core oil displacement mechanism during the shut-in stage of water huff-n-puff. Phase-field model studies of fractured porous media have revealed the evolution laws of interface front advancement and pore occupancy, providing a computable theoretical framework for explaining the distribution of imbibition contribution between the shut-in and production periods (Tapanya et al., 2024; Liu et al., 2026). In situ observation techniques such as two-dimensional nuclear magnetic resonance and microfluidics have provided direct evidence of imbibition oil displacement in tight reservoirs from the perspective of pore fluid distribution, indicating that under the same injection scheme, salinity may alter oil recovery by changing fluid distribution and accessible space within pores (Gilavand, 2024).

International scholars have also focused on interfacial regulation of low-salinity water and its applicability for huff-n-puff as key issues. Studies on the impact of relative timing of low-salinity and polymer flooding on oil enhancement mechanisms indicate that water quality configuration at different stages alters the dominant mechanism of interfacial regulation, thereby affecting the distribution of final recovery contribution (Buriro et al., 2023). Research on the applicability of huff-n-puff in tight reservoirs under relative permeability constraints further suggests that the effectiveness of huff-n-puff is closely related to accessible space at the pore-throat scale, mobility conditions, and scheme matching (Kazemi et al., 2025).

From core to field studies, it has been pointed out that the effectiveness of low-salinity water injection is jointly influenced by mineral composition, ion composition, and injection scheme, and a single parameter cannot cover all responses (Alomair et al., 2023; Amiri et al., 2025; Liu et al., 2025; Mehranjani et al., 2025; Liu et al., 2026).

Microfluidic studies have directly observed the front morphology, oil droplet snap-off, and re-dispersion behavior during immiscible displacement under low-salinity conditions, providing visual evidence for establishing an explanatory chain from microscopic morphology to macroscopic response (Parvazdavani and Khorsand Movaghar, 2023; Dehaghani et al., 2024; Zahedi and Saeedi Dehaghani, 2025). In more complex chemical systems, mechanism evaluation of surfactant-assisted smart water indicates that anion type significantly alters interfacial interaction strength and oil enhancement effect, suggesting that salinity regulation in field applications needs to be considered together with ion compatibility and possible chemical synergy (Khormali et al., 2023). Experimental studies on low-salinity water flooding under different salt concentrations have also provided the influence laws of salinity boundaries on oil enhancement and flow stability, offering a methodological reference for setting up multi-level salinity comparison groups in this study (Quintella et al., 2025; Yonebayashi et al., 2025). Relevant conference papers further present microfluidic evaluation methods for mixed low-salinity water flooding and mechanistic evidence of wettability alteration under low-salinity conditions in sandstone systems, providing direct bases for the selection of microscopic experimental indicators and phenomenon interpretation in this study (Ma et al., 2023; Liu et al., 2026). This study adopts a combined approach of ultra-low permeability core water huff-n-puff experiments and microfluidic visualization experiments, systematically setting up controlled experiments with multiple levels of salinity, permeability, shut-in time, huff-n-puff cycles, and injection pressure. The influence laws and main controlling factors of water huff-n-puff experiments are clarified, and the microscopic mechanism of low-salinity enhanced imbibition for oil recovery is revealed, thereby establishing a testable chain of explanation linking microscopic evidence to macroscopic laws.

2 Experimental Methods

2.1 Experimental Materials

The experimental samples were natural cores from the Chang 8 reservoir of Zhenyuan Oilfield in the Ordos Basin. Their basic physical property parameters were measured

after oil cleaning and drying treatment, as shown in Table 1. The core porosity ranged from 5.54% to 11.78%, and the gas permeability ranged from 0.052 to 0.488 mD. The experimental oil was simulated oil with a density of 0.8 g/cm³. The experimental water was prepared as simulated formation water with salinities of 0, 5000, 10000, and 20000 mg/L according to the experimental scheme.

Table 1 Basic physical property parameters of cores

Core No.	Length (cm)	Diameter (cm)	Dry Weight (g)	Porosity (%)	Permeability (mD)
1	3.07	2.50	30.8567	6.09	0.052
2	3.52	2.50	38.9614	5.54	0.07
3	3.61	2.51	38.0047	6.98	0.24
4	3.18	2.51	31.957	6.01	0.08
5	3.12	2.51	29.6599	11.78	0.488
6	3.05	2.52	28.6253	6.43	0.061
7	3.54	2.51	37.8637	8.59	0.143
8	3.62	2.50	38.8869	6.17	0.084
9	3.59	2.51	38.7804	5.78	0.055

(1) Cast thin section analysis

Cores 3#, 4#, and 5# were selected for cast thin section analysis. As shown in Figure 1, Core 3# has a fine-grained structure, composed of fine-grained terrigenous detritus consisting of quartz, feldspar, and rock fragments. The interstitial materials are mainly flaky argillaceous matter, accompanied by a small amount of fine crystalline calcite, with heavy minerals and asphaltenes observed. The pore development structure is moderate, with intergranular pores, feldspar dissolution pores, and a small number of calcite intercrystalline pores filled with blue casting resin.

As shown in Figure 2, Core 4# has a fine-grained structure, composed of fine-grained terrigenous detritus consisting of quartz, feldspar, and rock fragments. The cements are mainly fine crystalline calcite, locally replacing individual feldspar grains, with asphaltenes observed between grains. The pore development structure is moderate, with

intergranular pores, feldspar dissolution pores, and a small number of calcite intercrystalline pores injected with blue casting resin.

As shown in Figure 3, Core 5# has a fine-grained structure, composed of terrigenous detritus consisting of quartz, feldspar, and rock fragments. The interstitial materials are mainly micritic argillaceous matter, with quartz overgrowths observed. The pore development structure is poor, with a small number of intergranular pores and feldspar dissolution pores injected with blue casting resin.

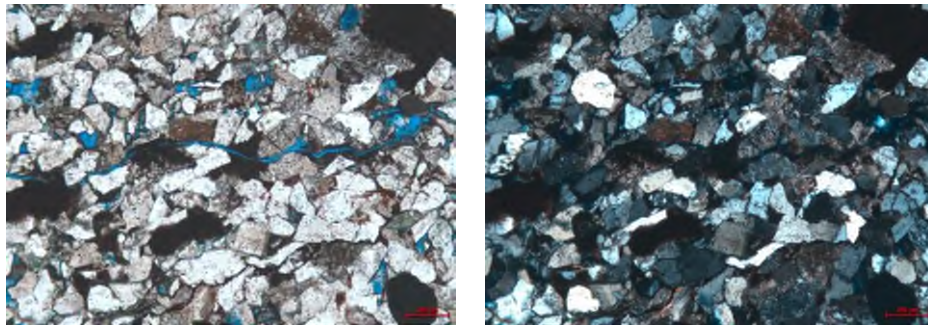


Figure 1 Cast thin section test results of Core 3#

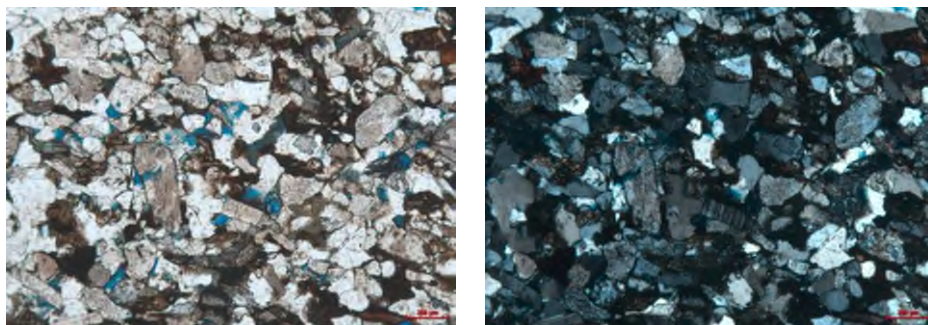


Figure 2 Cast thin section test results of Core 4#

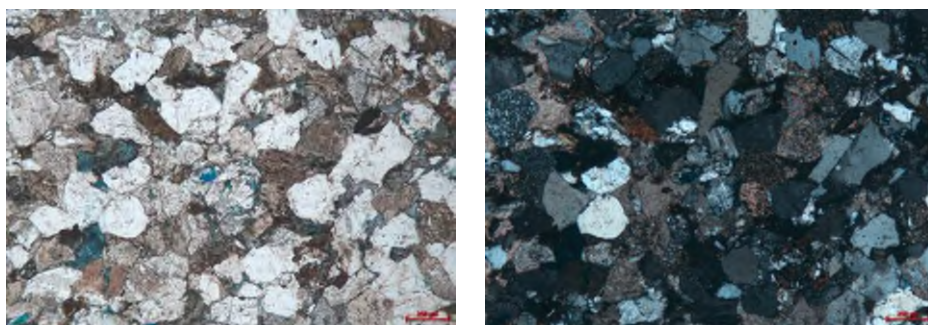


Figure 3 Cast thin section test results of Core 5#

(2) Scanning electron microscopy (SEM) analysis

Cores 3#, 4#, and 5# were selected for scanning electron microscopy analysis. As shown in Figure 4, Core 3# has a dense structure with elastic particles in mosaic contact. Filamentous and flaky illite attaches to the particle surfaces or fills intergranular spaces,

exhibiting slight directional alignment locally. The pores are mainly intergranular micropores and microfractures, filled with mica fragments, dolomite, siliceous crystals, and carbonaceous debris.

As shown in Figure 5, Core 4# has a dense structure with intergranular pores containing residual intergranular pores developed. Hairy illite is extensively developed, attaching to the surfaces of detrital particles or filling in intergranular pores. Secondary quartz, secondary albite, and dolomite crystals are also commonly found filling the intergranular pores.

As shown in Figure 6, Core 5# has a dense structure with detrital particles in mosaic contact. Flaky and filamentous illite aggregates fill the intergranular spaces. The flaky and filamentous illite aggregates attach to the surfaces of detrital particles and fill between them, with occasional particle-attached microfractures observed.

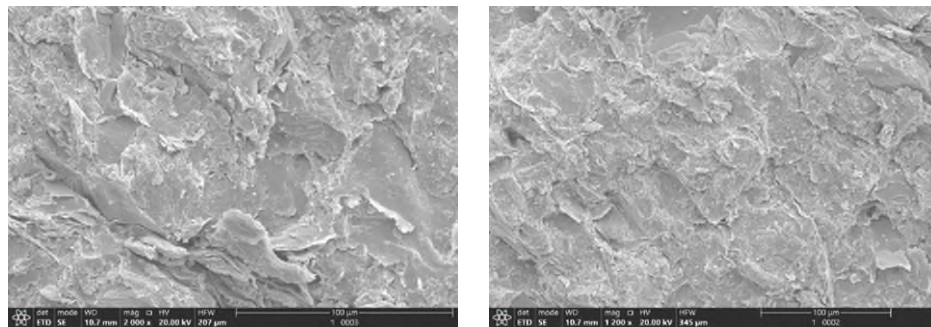


Figure 4 Scanning electron microscopy test results of Core 3#

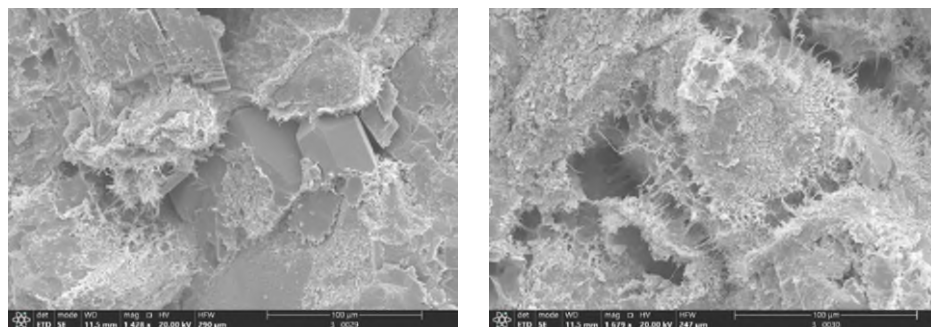


Figure 5 Scanning electron microscopy test results of Core 4#

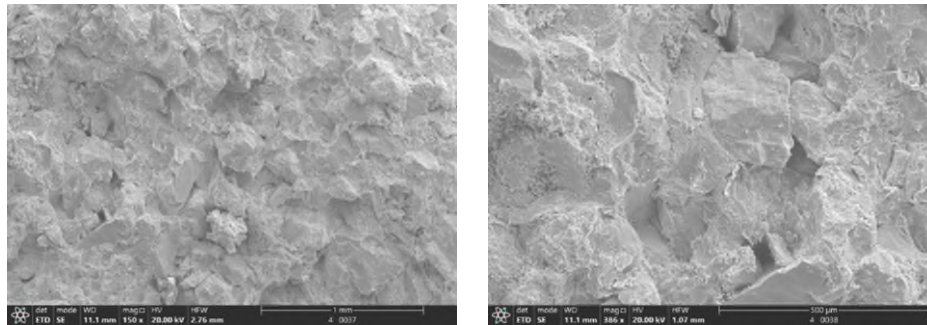


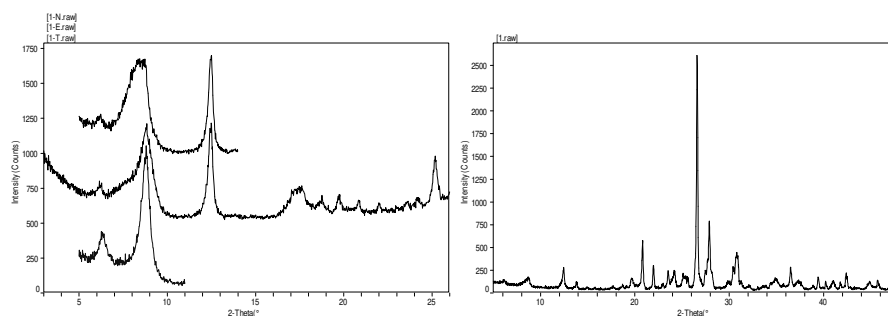
Figure 6 Scanning electron microscopy test results of Core 5#

(3) X-ray diffraction (XRD) whole-rock analysis

Cores 3#, 4#, and 5# were selected for X-ray diffraction whole-rock analysis (Figures 7-9). The experimental results show that for Core 3#, the quartz content is 34.2%, potassium feldspar content is 3.8%, plagioclase content is 26.5%, and absolute clay content is 27.7%. The relative clay mineral contents are: illite/smectite mixed layer: 18.9%, illite: 56.2%, kaolinite: 6.1%, chlorite: 18.8%.

For Core 4#, the quartz content is 42.0%, potassium feldspar content is 0.7%, plagioclase content is 39.6%, and absolute clay content is 14.6%. The relative clay mineral contents are: illite/smectite mixed layer: 23.3%, illite: 65.5%, kaolinite: 5.3%, chlorite: 5.8%.

For Core 5#, the quartz content is 57%, potassium feldspar content is 4.9%, plagioclase content is 16.3%, and absolute clay content is 21.3%. The relative clay mineral contents are: illite/smectite mixed layer: 24.4%, illite: 30.3%, kaolinite: 12.6%, chlorite: 32.7%.



(a) Whole-rock non-clay minerals

(b) Clay minerals

Figure 7 X-ray diffraction pattern of Core 3#

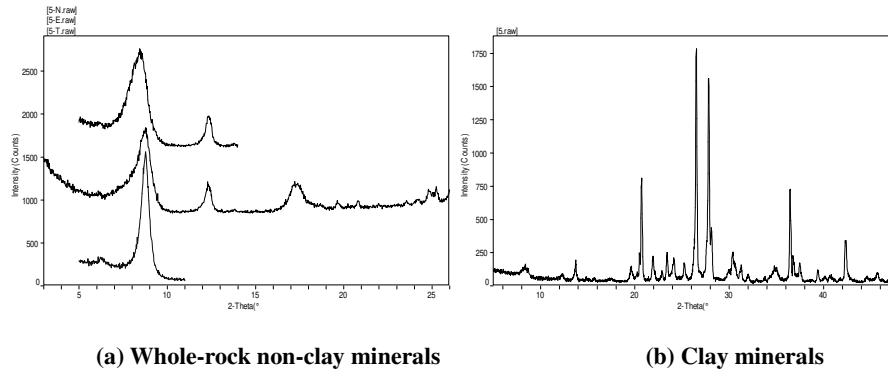


Figure 8 X-ray diffraction pattern of Core 4#

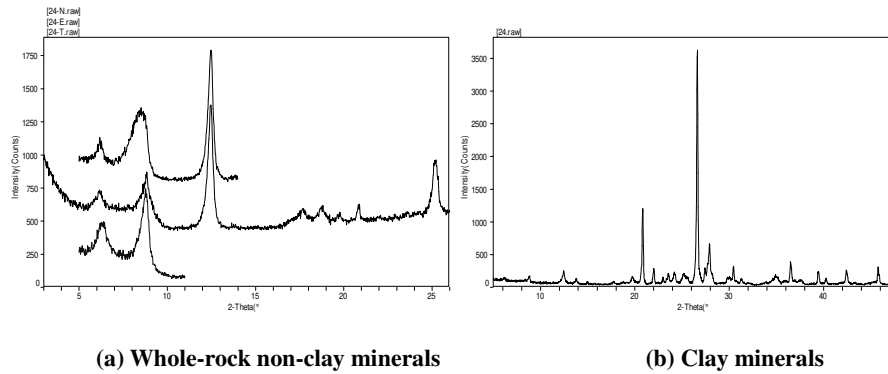


Figure 9 X-ray diffraction pattern of Core 5#

2.2 Microfluidic experiment

To observe microscopic displacement dynamics, a microfluidic model based on a glass-etched chip was designed. This model contains a high-permeability main channel and a low-permeability micro-network simulating the reservoir structure. The microfluidic experimental system consists of a micro-injection pump, an inverted fluorescence microscope, a high-speed CMOS camera, and an image acquisition workstation. The experiment was conducted under constant temperature conditions of 45°C. Three huff-n-puff cycles were set up. The injection rate was constant at 2 $\mu\text{L}/\text{min}$. The reservoir structure was set as a combination of high- and low-permeability zones. The water injection time was 10 min, the shut-in time was 10 min, and the oil production time was 10 min. The salinities of the injected water were set to 0 mg/L, 5000 mg/L, 20000 mg/L, and 100000 mg/L. The experimental setup is shown in Figure 10.

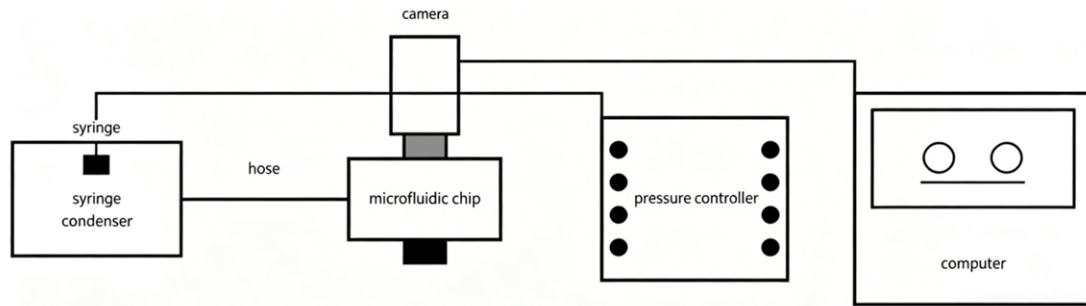


Figure 10 Schematic diagram of the microfluidic experimental setup

During the experiment, the model was first saturated with crude oil for 10 min, and the chip was allowed to stand for 5 min to reach pressure equilibrium. Subsequently, formation water with target salinities was injected at a rate of 2 $\mu\text{L}/\text{min}$ for the first displacement cycle, and real-time images of oil-water distribution in the pore-throat network were captured. During the shut-in stage, the inlet and outlet valves were closed, and images were recorded at 5 min and 10 min of standing. Finally, the needle at the water injection end was removed to start oil production for 10 min, and images were taken. The above steps were repeated to complete three huff-n-puff cycles. Image data were quantitatively analyzed for residual oil saturation using ImageJ software. Figure 11 shows the microscopic image of the rock after oil saturation.

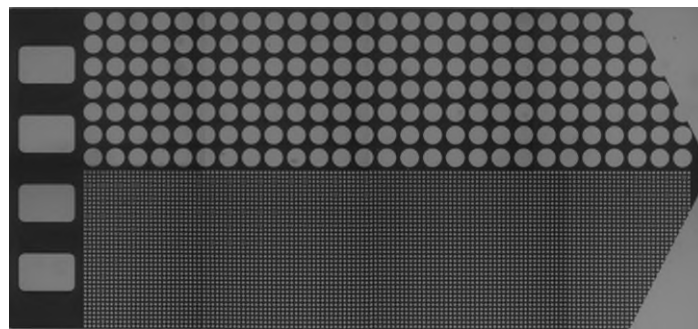


Figure 11 Microscopic image of the rock after oil saturation

2.3 Macroscopic core water huff-n-puff experiment

Water huff-n-puff refers to a development method in which water injection and oil production are carried out in the same well. The process mainly consists of an injection stage, a shut-in stage, and a flowback stage. The macroscopic displacement experiment uses a constant temperature and constant pressure dynamic huff-n-puff core

displacement experimental apparatus, which mainly includes a displacement system, a measurement system, and a temperature control system. It is composed of an ISCO 100DX constant-speed constant-pressure pump, a core holder, an overburden pressure tracking pump, intermediate containers, pressure sensors, and a high-precision oil-water measuring device. The experimental procedure is as follows: The experiment adopts a constant-pressure water injection mode and strictly follows the multi-cycle huff-n-puff operation procedure of water injection – shut-in – well opening for production – repeated cycles. A total of 3 huff-n-puff cycles were conducted in the experimental group, and a control group with 5 cycles was set to investigate the effect of the number of cycles. Comparative experiments were set up with different shut-in times, different salinities, and different permeability gradients. The calculation formula for oil displacement efficiency (η) is:

$$\eta = \frac{\text{Cumulative oil production}}{\text{Oil saturation volume}} \times 100\% \quad (2.1)$$

The specific operation steps are as follows:

(1) Water injection stage: Set the injection pump to constant pressure mode, and set the injection pressure according to the test conditions. Open the inlet valve of the core holder and inject formation water with different salinities into the core at a constant pressure.

(2) Shut-in stage: Close the inlet and outlet valves of the core holder, keep the confining pressure at the set value, and let it stand for the set duration. During this stage, the injected water is driven by capillary force, osmotic pressure, and rock wettability to imbibe from fractures and large pores into the micropores of the matrix, displacing the crude oil in the pores.

(3) Well opening for production stage: Open the outlet valve of the core holder, record the single-cycle oil production and water production. The production stage ends when the comprehensive water cut at the outlet reaches 98%. Close the outlet valve to complete a single huff-n-puff cycle.

(4) Cycle repetition: After completing the first cycle of production, immediately start the second cycle of water injection at the same injection pressure, and repeat the above

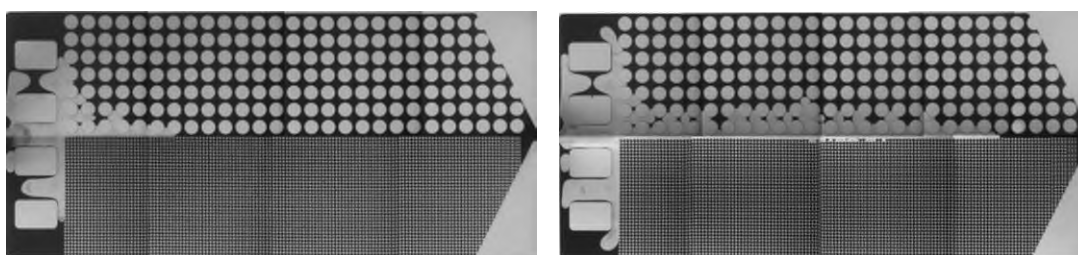
process until the preset number of huff-n-puff cycles is completed.

3. Results and Discussion

3.1 Analysis of microfluidic experiment results

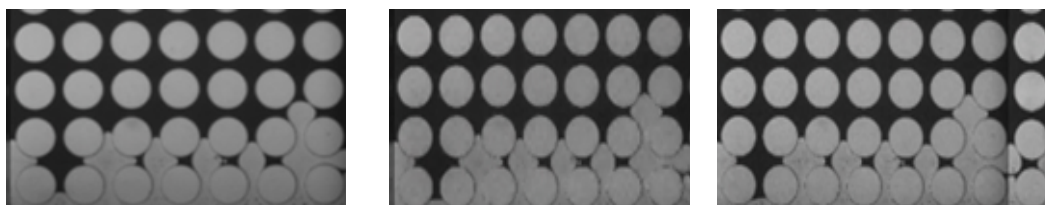
3.1.1 0 mg/L

Figure 12 shows the microscopic images of different stages of the first cycle when the injected water was deionized water. Under deionized water injection conditions, at 5 min of the first cycle water injection, the injected water preferentially advanced along the high-permeability main channel, exhibiting typical fingering phenomena, and the low-permeability micro-network showed no obvious sweep. After 10 min of water injection, the water phase further extended to the end of the high-permeability zone, while the low-permeability zone only showed sporadic seepage locally. After entering the shut-in stage, continuous fluid advancement was still observed in the high-permeability zone during the first 5 min, and the imbibition effect dominated by capillary force gradually appeared in the low-permeability zone. After 10 min of shut-in, the oil-water interface stabilized, and the imbibition effect weakened. During the flowback stage, the water phase preferentially retreated along the high-permeability channels, and the crude oil in the low-permeability zone was difficult to be effectively carried out, resulting in a low oil recovery of only 3.2% in the first cycle.

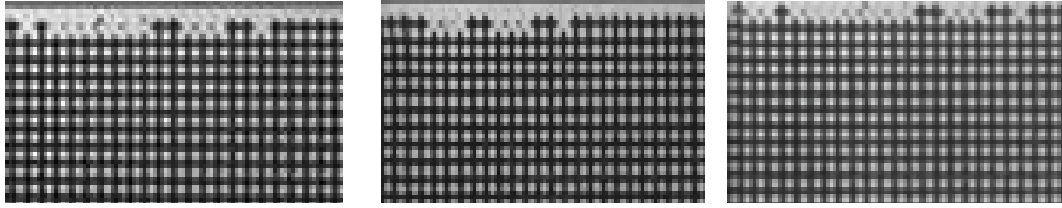


(a) First huff-n-puff cycle, injection for 5 min

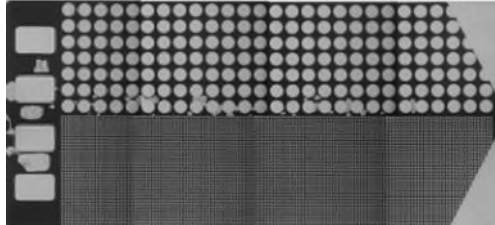
(b) First huff-n-puff cycle, injection for 10 min



(c) First cycle, fluid flow at 10 min injection, 5 min shut-in, and 10 min shut-in (high permeability)



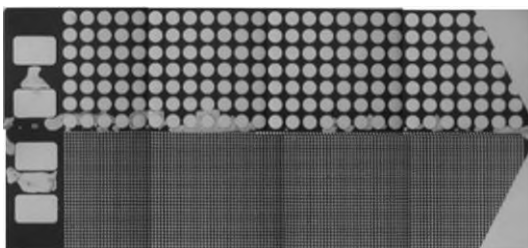
(d) First cycle, fluid flow at 10 min injection, 5 min shut-in, and 10 min shut-in (low permeability)



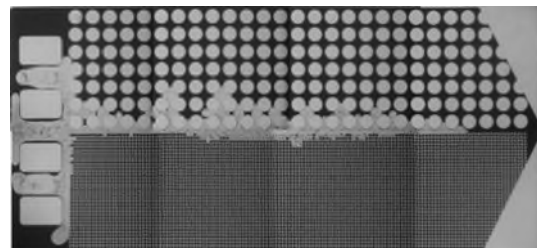
(e) First huff-n-puff cycle, oil production

Figure 12 The first huff-n-puff cycle process of the deionized water group

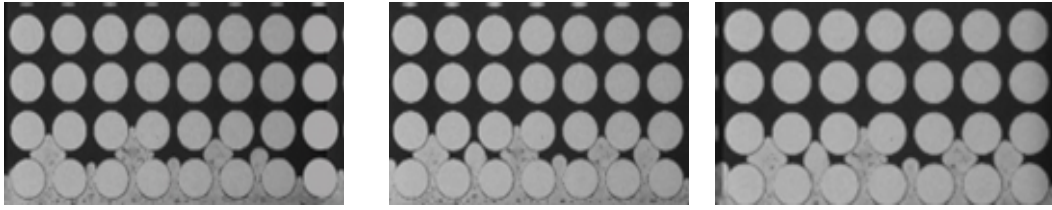
Figure 13 shows the microscopic images of different stages of the second cycle when the injected water was deionized water. During the second huff-n-puff cycle, at the initial stage of water injection, the ability to sweep the low-permeability zone was exhibited, and the advancement path of the water phase was significantly expanded. After 10 min of water injection, continuous oil phase breakage and localized mobilization appeared in the low-permeability zone. During the shut-in stage, the imbibition effect driven by capillary force in the low-permeability zone was significantly enhanced, the oil-water interface continued to advance, and some residual oil was displaced into the high-permeability channels. During the flowback stage, the crude oil at the end of the low-permeability zone was carried out, resulting in an oil recovery of 10.64%, an increase of 7.44%.



(a) Second huff-n-puff cycle, injection for 5 min



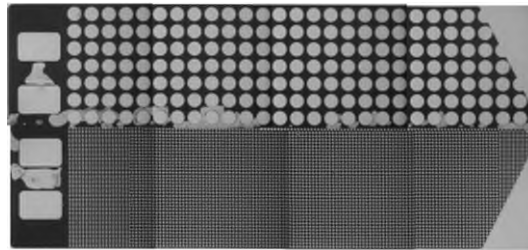
(b) Second huff-n-puff cycle, injection for 10 min



(c) Second cycle, fluid flow at 10 min injection, 5 min shut-in, and 10 min shut-in (high permeability)



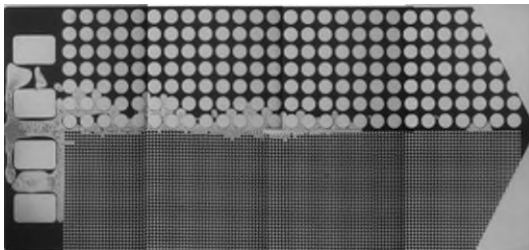
(d) Second cycle, fluid flow at 10 min injection, 5 min shut-in, and 10 min shut-in (low permeability)



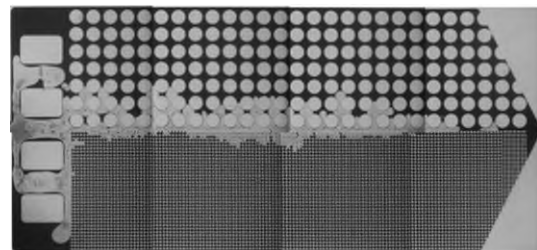
(e) Second huff-n-puff cycle, oil production

Figure 13 The second huff-n-puff cycle process of the deionized water group

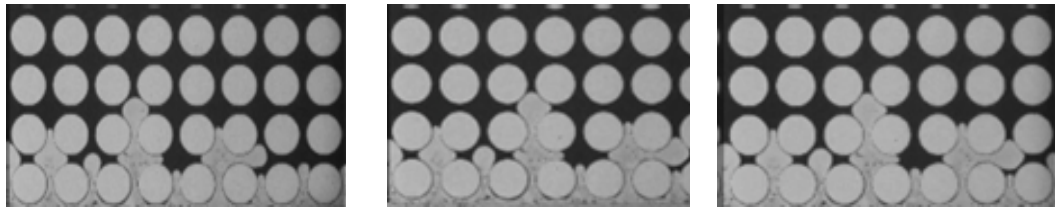
283 Figure 14 shows the microscopic images of different stages of the third cycle when the
 284 injected water was deionized water. During the third huff-n-puff cycle, the advancement
 285 path of the water phase tended to stabilize, the degree of mobilization in the low-
 286 permeability zone significantly improved, the penetration depth of the water phase
 287 increased, and oil phase breakage and redistribution occurred in local areas. During the
 288 flowback stage, the contribution of crude oil from the low-permeability zone increased
 289 significantly, and the oil recovery further increased to 14.52%.



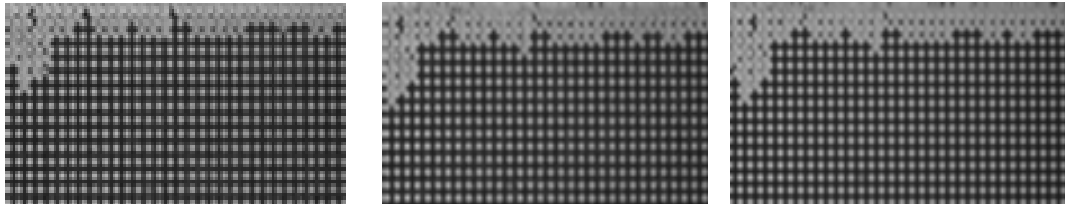
(a) 3rd huff-n-puff cycle, injection for 5 min



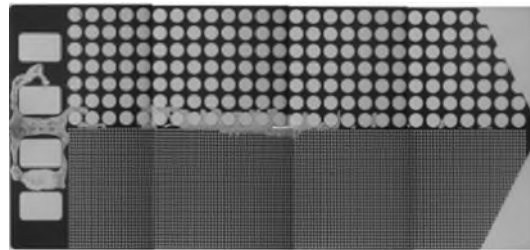
(b) 3rd huff-n-puff cycle, injection for 10 min



(c) 3rd cycle, fluid flow at 10 min injection, 5 min shut-in, and 10 min shut-in (high permeability)



(d) 3rd cycle, fluid flow at 10 min injection, 5 min shut-in, and 10 min shut-in (low permeability)



(e) 3rd huff-n-puff cycle, oil production

Figure 14 The third huff-n-puff cycle process of the deionized water group

3.1.2 5000 mg/L

Figure 15 shows the microscopic images of different stages of the first cycle when the injected water salinity was 5000 mg/L. At 5 min of water injection, the water phase advanced uniformly along the high-permeability main channel with weak fingering, and the sweep range was concentrated in the near-well high-permeability area, while the low-permeability zone was not obviously swept. After 10 min of water injection, the water phase extended further along the high-permeability channel and began to slowly penetrate into the surrounding low-permeability pores, with shallow penetration depth and no large-scale displacement formed. During the shut-in stage, slow seepage expansion of the water phase still existed in the high-permeability zone during the first 5 min, and weak imbibition driven by capillary force began to appear in the low-permeability zone. After 10 min of shut-in, the oil-water interface gradually stabilized, the advancement of the water phase in the high-permeability zone stagnated, and the imbibition range in the low-permeability zone did not further expand. During the flowback stage, the water phase flowed back along the injection channel, and the crude

oil in the low-permeability zone was difficult to be effectively carried out, resulting in a first-cycle oil recovery of 3.7%.

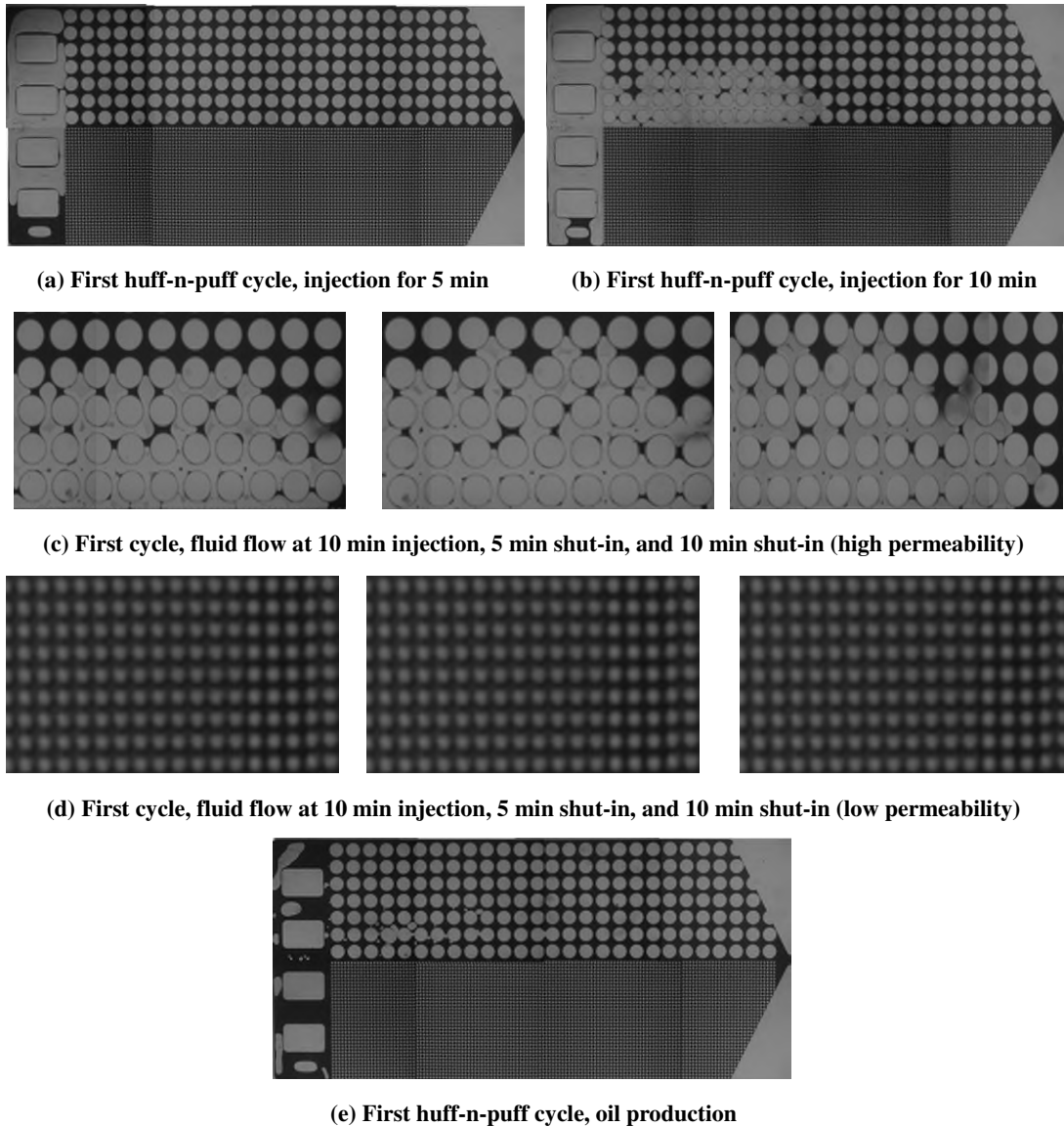


Figure 15 The first huff-n-puff cycle process when the injected water salinity is 5000 mg/L

Figure 16 shows the microscopic images of different stages of the second cycle when the injected water salinity was 5000 mg/L. At 5 min of water injection, the water phase advanced along the high-permeability preferential channel formed in the first cycle, with a slight increase in fingering degree, and the sweep range extended to the distal end of the high-permeability zone. After 10 min of water injection, the low-permeability zone was gradually swept under the induction of the high-permeability channel, and the penetration in the marginal areas became more obvious. During the shut-in stage, the imbibition effect driven by capillary force in the low-permeability zone was

315 significantly enhanced compared with the first cycle, and the oil phase underwent
 316 breakage and stripping under the displacement of the water phase. During the flowback
 317 stage, the water phase returning along the high-permeability zone carried out some
 318 crude oil, and the crude oil at the edge of the low-permeability zone was effectively
 319 produced. The oil recovery of this cycle was significantly higher than that of the first
 320 cycle, reaching 9.6%.

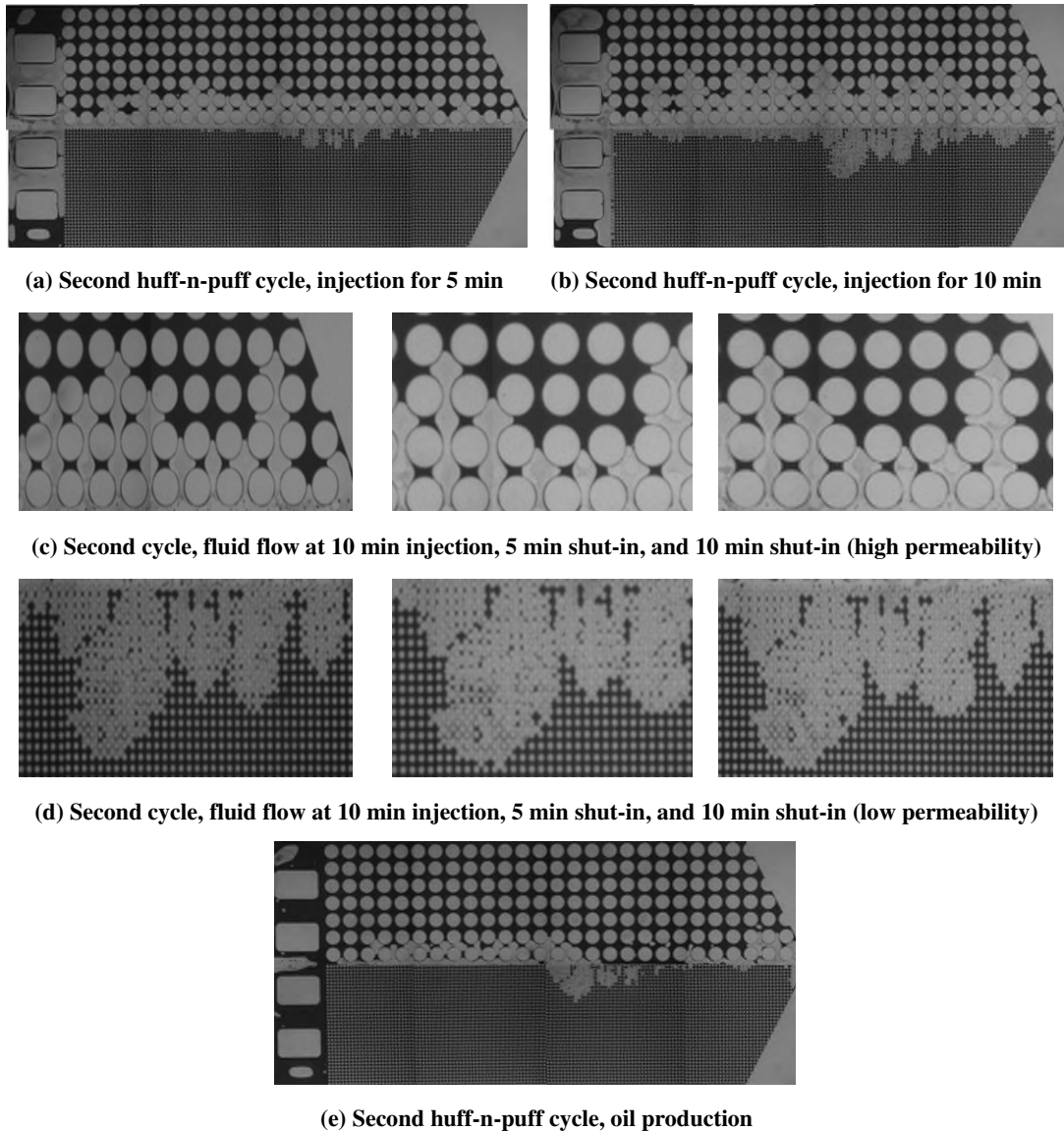
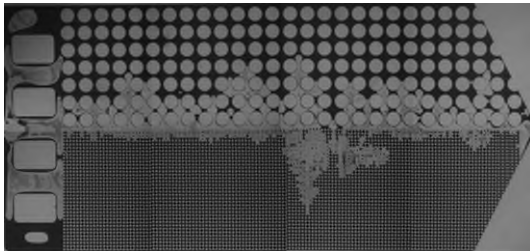


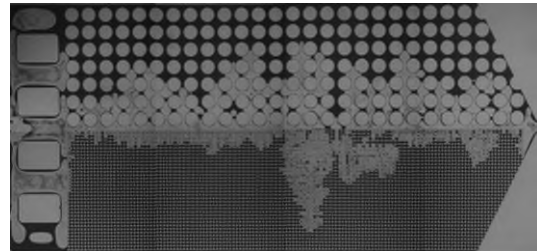
Figure 16 The second huff-n-puff cycle process when the injected water salinity is 5000 mg/L

321 Figure 17 shows the microscopic images of different stages of the third cycle when the
 322 injected water salinity was 5000 mg/L. At 5 min of water injection, the advancement
 323 path of the water phase tended to stabilize, still dominated by the high-permeability
 324 preferential channel, with further development of fingering, and the sweep range

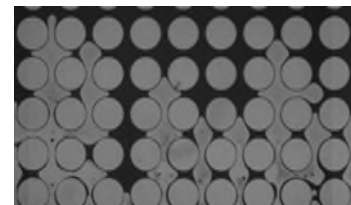
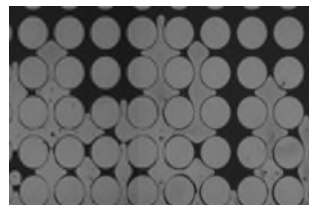
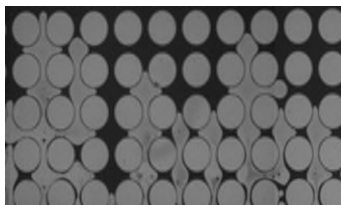
325 covered most of the high-permeability zone and part of the low-permeability zone.
 326 After 10 min of water injection, the degree of mobilization in the low-permeability zone
 327 significantly improved, and the penetration depth of the water phase obviously
 328 increased compared with the first two cycles. During the shut-in stage, the imbibition
 329 effect continued to strengthen, oil phase breakage and stripping occurred frequently, the
 330 crude oil in the pores of the low-permeability zone was gradually displaced by the water
 331 phase, and the advancement efficiency of the oil-water interface significantly increased.
 332 During the flowback stage, the contribution of the remaining water phase returning
 333 from the high-permeability zone was stable, the degree of crude oil mobilization in the
 334 low-permeability zone greatly increased, and the overall oil recovery was further
 335 improved compared with the second cycle, reaching 15.6%.



(a) Third huff-n-puff cycle, injection for 5 min



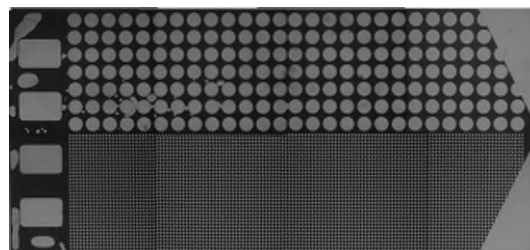
(b) Third huff-n-puff cycle, injection for 10 min



(c) Third cycle, fluid flow at 10 min injection, 5 min shut-in, and 10 min shut-in (high permeability)



(d) Third cycle, fluid flow at 10 min injection, 5 min shut-in, and 10 min shut-in (low permeability)

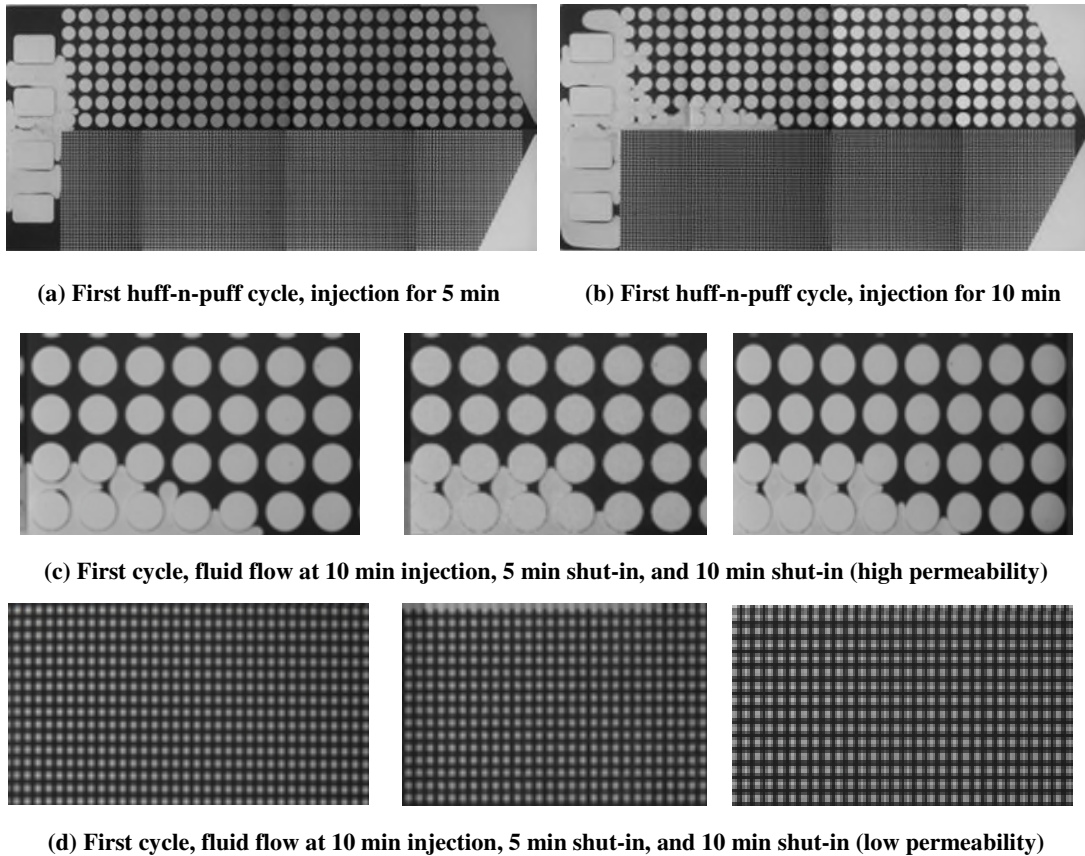


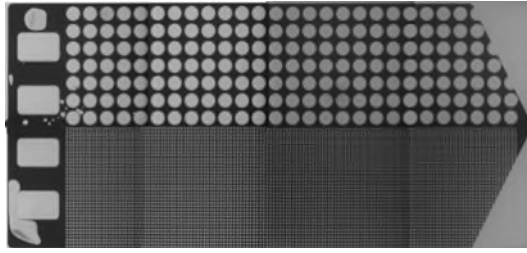
(e) Third huff-n-puff cycle, oil production

Figure 17 The third huff-n-puff cycle process when the injected water salinity is 5000 mg/L

3.1.3 20000mg/L

Figure 18 shows the microscopic images of different stages of the first cycle when the injected water salinity was 20000 mg/L. The results indicate that under the condition of injected water with a salinity of 20000 mg/L, at 5 min of the first cycle water injection, the water phase advanced along the high-permeability main channel, with weakened fingering and a more uniform sweep range. After 10 min of water injection, the water phase gradually expanded into the low-permeability zone, but the overall sweep depth was limited. During the shut-in stage, obvious seepage expansion still existed in the high-permeability zone during the first 5 min, while the imbibition effect in the low-permeability zone was weak. After 10 min of shut-in, the oil-water interface tended to stabilize, with no significant advancement observed. During the flowback stage, significant water phase backflow occurred, and the crude oil in the low-permeability zone was difficult to be effectively carried out, resulting in a low first-cycle oil recovery of 5.2%.

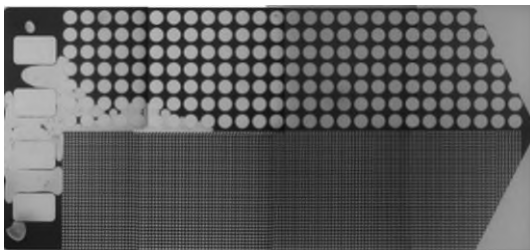




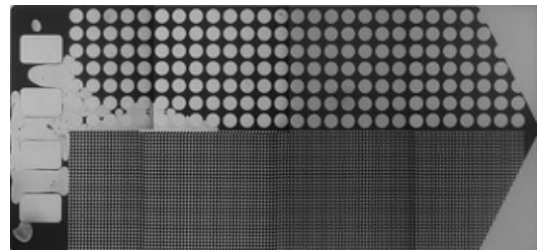
(e) First huff-n-puff cycle, oil production

Figure 18 The first huff-n-puff cycle process when the injected water salinity is 20000 mg/L

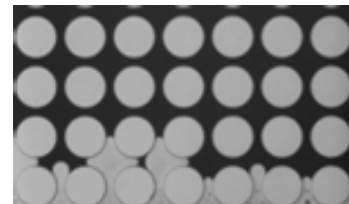
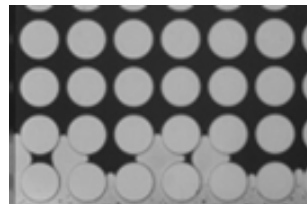
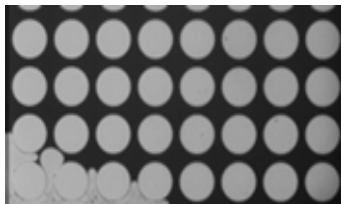
350 Figure 19 shows the microscopic images of different stages of the second cycle when
 351 the injected water salinity was 20000 mg/L. The results indicate that during the second
 352 huff-n-puff cycle, the advancement path of the injected water was still dominated by
 353 the high-permeability channels, and the low-permeability zone was gradually swept in
 354 the later stage of water injection, but the overall degree of mobilization remained low.
 355 During the shut-in stage, the imbibition effect driven by capillary force in the low-
 356 permeability zone was somewhat enhanced, but limited by the enhanced stability of the
 357 oil-water interface under high salinity, the efficiency of oil phase breakage and
 358 displacement was inhibited. During the flowback stage, the recovery of crude oil from
 359 the end of the low-permeability zone was limited, with an oil recovery of 12.9%.



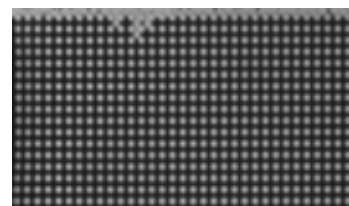
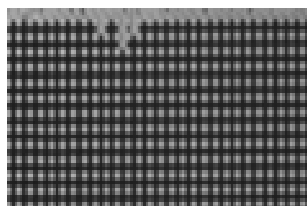
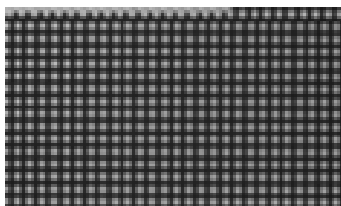
(a) Second huff-n-puff cycle, injection for 5 min



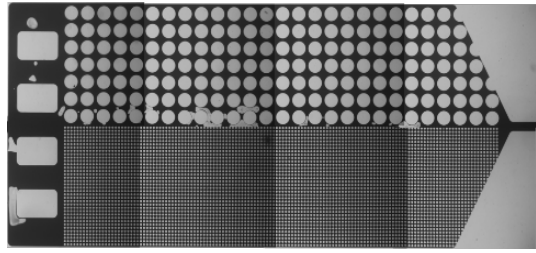
(b) Second huff-n-puff cycle, injection for 10 min



(c) Second cycle, fluid flow at 10 min injection, 5 min shut-in, and 10 min shut-in (high permeability)



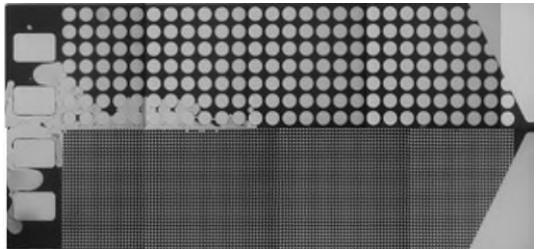
(d) Second cycle, fluid flow at 10 min injection, 5 min shut-in, and 10 min shut-in (low permeability)



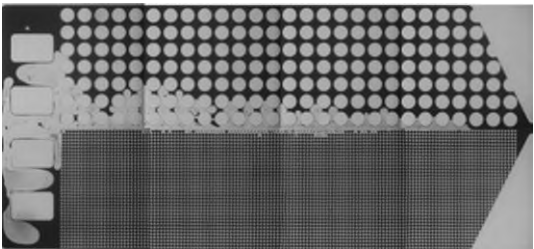
(e) Second huff-n-puff cycle, oil production

Figure 19 The second huff-n-puff cycle process when the injected water salinity is 20000 mg/L

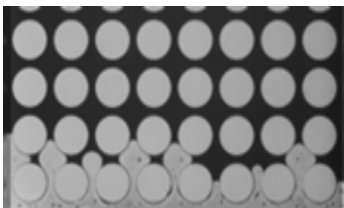
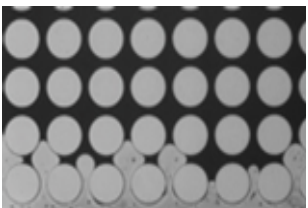
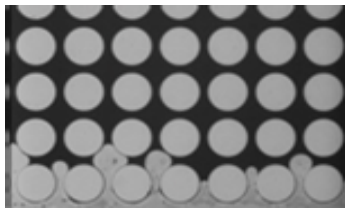
Figure 20 shows the microscopic images of different stages of the third cycle when the injected water salinity was 20000 mg/L. It can be observed that during the third huff-n-puff cycle, the advancement path of the water phase tended to stabilize, the degree of mobilization in the low-permeability zone slightly increased, but the advancement efficiency of the oil-water interface was still lower than that of the deionized water group. During the shut-in stage, the imbibition effect continued but with reduced efficiency, and the occurrence of oil phase breakage decreased. During the flowback stage, the contribution to recovery was limited, and the overall oil recovery was 18.2%.



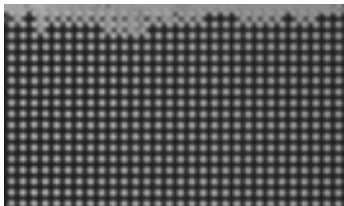
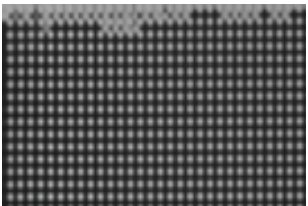
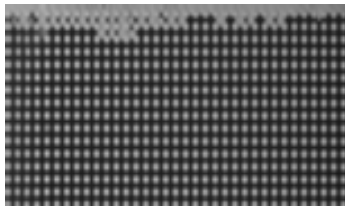
(a) Third huff-n-puff cycle, injection for 5 min



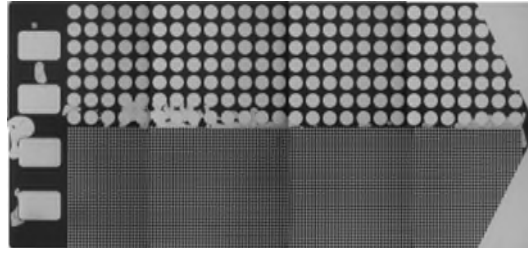
(b) Third huff-n-puff cycle, injection for 10 min



(c) Third cycle, fluid flow at 10 min injection, 5 min shut-in, and 10 min shut-in (high permeability)



(d) Third cycle, fluid flow at 10 min injection, 5 min shut-in, and 10 min shut-in (low permeability)



(e) Third huff-n-puff cycle, oil production

Figure 20 The third huff-n-puff cycle process when the injected water salinity is 20000 mg/L

368 Figure 21 shows the crude oil recovery degree of cores in different cycles when the
 369 injected water salinity varies. In general, as the salinity of the injected water increases,
 370 the fingering phenomenon at the advancing front of the water phase is gradually
 371 suppressed, and the displacement interface tends to become smooth and stable. Under
 372 the same salinity condition, the fingering phenomenon is more significant at the initial
 373 stage of water injection; as the injection process proceeds, the capillary force gradually
 374 strengthens, and the displacement interface morphology gradually becomes moderate
 375 and stable. During multi-cycle water huff-n-puff, although low-salinity water and
 376 deionized water can enhance flow instability, leading to intensified fingering and thus
 377 reducing macroscopic sweep uniformity to some extent, they can significantly enhance
 378 capillary imbibition, promoting the mobilization of crude oil in low-permeability zones
 379 and dead-end pores. In contrast, although high-salinity water can effectively suppress
 380 fingering and improve macroscopic sweep characteristics, it weakens the capillary
 381 imbibition drive, resulting in insufficient mobilization of crude oil in low-permeability
 382 and disconnected areas, thereby limiting further improvement of overall recovery
 383 efficiency. Therefore, the recovery effect during water huff-n-puff is jointly influenced
 384 by the competitive mechanism between the sweep volume controlled by flow instability
 385 and the microscopic mobilization efficiency controlled by capillary imbibition.

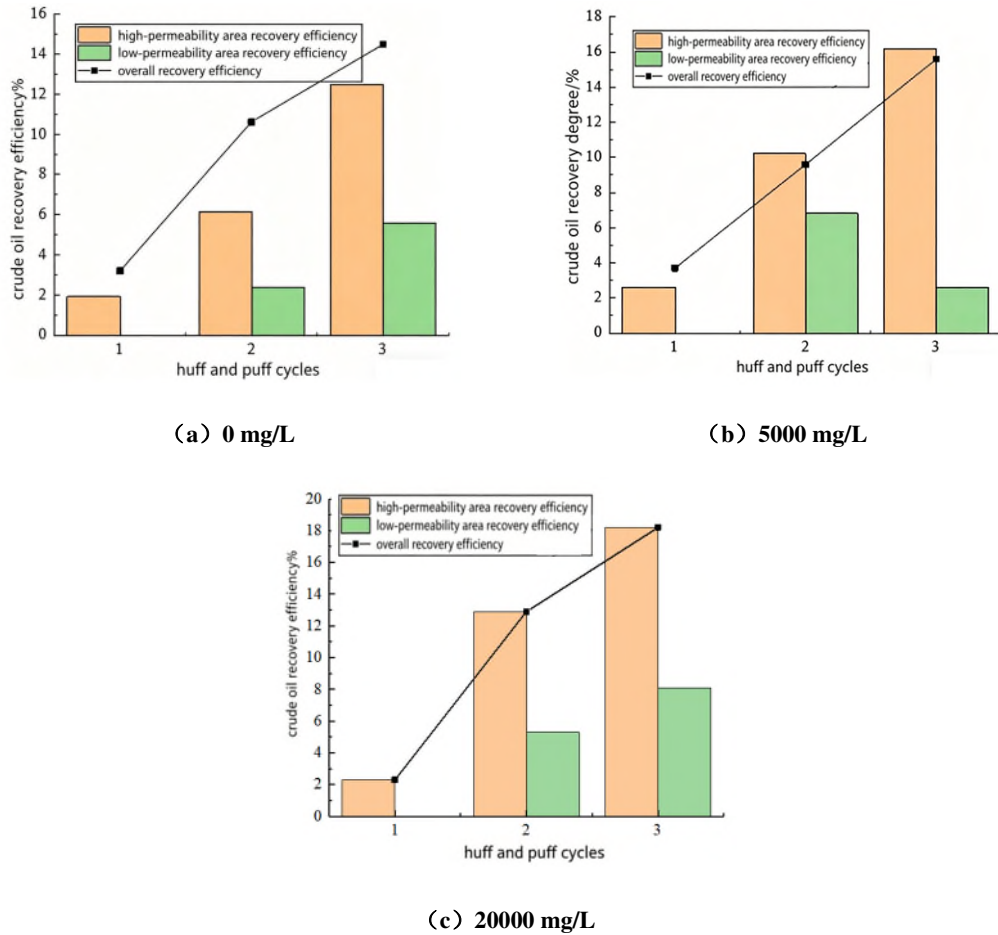


Figure 21 Crude oil recovery degree of cores

3.2 Analysis of macroscopic core water huff-n-puff experiment results

3.2.1 Effect of salinity

Using the same base core block, under the same injection pressure and shut-in time conditions, comparative experiments of fracturing fluid displacement with different salinities were carried out, with three huff-n-puff cycles for each. Figure 22 shows the change in cumulative oil production of three cycles of huff-n-puff under different injected water salinities. The experimental results indicate that the relationship between salinity and oil displacement efficiency is not a simple monotonic linear one. The oil displacement efficiency was highest when the injected water salinity was 5000 mg/L, with a cumulative oil displacement efficiency of 40.2% over three cycles; the 0 mg/L group was next, at 35.6%; the 10000 mg/L group was 23.8%; and the 20000 mg/L group was the lowest, at only 18.9%.

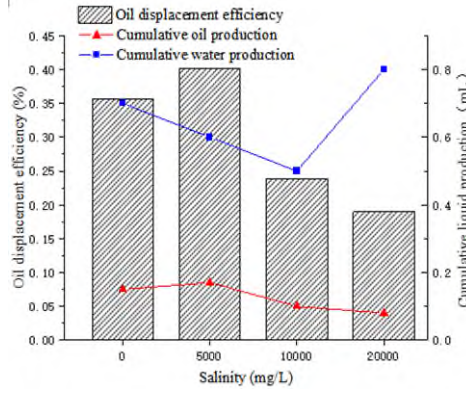


Figure 22 Crude oil recovery degree under different salinities

Table 2 lists the oil saturation volume, cumulative oil production over three cycles, and oil displacement efficiency corresponding to each salinity group. At 5000 mg/L, the cumulative oil production of the core reached the highest value of 0.17 mL, with an oil displacement efficiency of 40.22%. For a tight core of 0.052 mD, moderately reducing the salinity of the injected water can effectively expand the electrical double layer at the oil-water-rock interface. This expansion breaks the original electrostatic balance, promoting the transformation of the rock surface to a strongly water-wet state. During the shut-in stage, the enhanced water wettability greatly increases the positive capillary force. Driven by capillary force, spontaneous imbibition is significantly enhanced, thereby displacing more crude oil from the matrix pores. When the injected water salinity was reduced to 0 mg/L, the oil displacement efficiency was 35.58%, and the cumulative water production increased from 0.6 mL to 0.7 mL. Under the condition of 20000 mg/L, the oil displacement efficiency was only 18.99%, while the cumulative water production reached a peak value of 0.8 mL.

Table 2 Oil saturation volume, cumulative oil production over three cycles, and oil displacement efficiency corresponding to different salinities

No.	Injected			Oil saturation volume (mL)	Cumulative oil production (mL)	Cumulative water production (mL)	Cumulative liquid production (mL)	Oil displacement efficiency (%)
	water salinity (mg/L)	Porosity (%)	permeability (mD)					
1	20000	6.09	0.052	0.4213	0.08	0.8	0.88	18.99%
2	10000	6.09	0.052	0.4198	0.11	0.52	0.63	23.82%

3	5000	6.09	0.052	0.4227	0.17	0.6	0.77	40.22%
4	0	6.09	0.052	0.4216	0.15	0.7	0.85	35.58%

Figure 23 shows the composition of cumulative liquid production over three cycles of huff-n-puff for each salinity group. The experimental data indicate that the first cycle contributes the majority of the recovery. Taking the 5000 mg/L group as an example, the first-cycle oil production reached 0.15 mL, accounting for 88.2% of the total oil production, with a relatively low water cut of only 40%. The first-cycle oil production proportion for the other groups was also above 60%. This indicates that the first huff-n-puff cycle efficiently mobilizes the crude oil in pores with good connectivity.

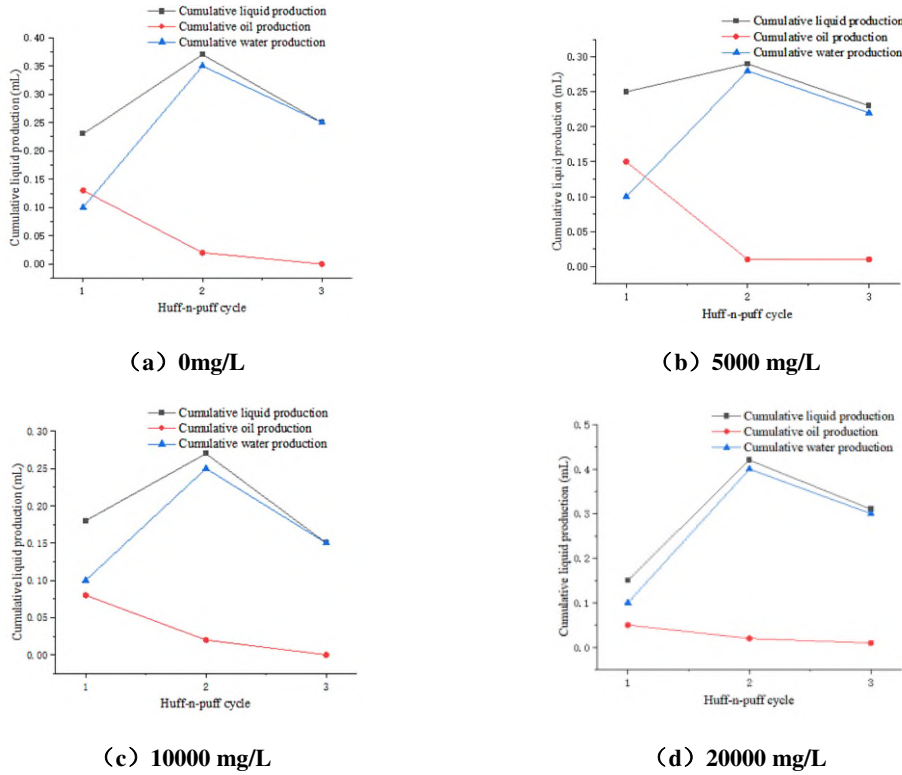


Figure 23 Production curves under the influence of different salinities

Starting from the second cycle, the efficiency of water huff-n-puff decreased. The single-cycle oil production of each group dropped to between 0 and 0.02 mL. The water cut of the 20000 mg/L group reached as high as 95.2% in the second cycle; the oil production of the 0 mg/L and 10000 mg/L groups was zero in the third cycle. After the first cycle of flushing, fixed preferential water flow channels have formed inside the tight core, making it difficult for the injected water in subsequent cycles to imbibe into the deep matrix, mainly manifesting as ineffective water circulation along the already

formed channels.

3.2.2 Effect of permeability

Figure 24 compares the oil displacement efficiency of cores with different permeabilities under the same salinity, injection pressure, shut-in time, and number of huff-n-puff cycles. Core permeability essentially determines the degree of matrix mobilization and the upper limit of ultimate recovery. As core permeability increases, oil displacement efficiency steadily improves. When the permeability was 0.052 mD, limited by the capillary resistance and threshold pressure caused by extremely fine pore throats, the oil displacement efficiency was only 23.82%, with a cumulative oil production of only 0.1 mL. When the permeability increased nearly 10 times to 0.488 mD, the oil displacement efficiency rose to 58.15%, and cumulative oil production increased to 0.6 mL. From the perspective of physical mechanisms, for tight reservoirs, physical properties are the core boundary conditions constraining fluid exchange. The higher the permeability, the more developed the pore-throat network and the smaller the capillary resistance. Good pore connectivity allows the injected water to overcome resistance during the pressure buildup stage and sweep deeper into the matrix.

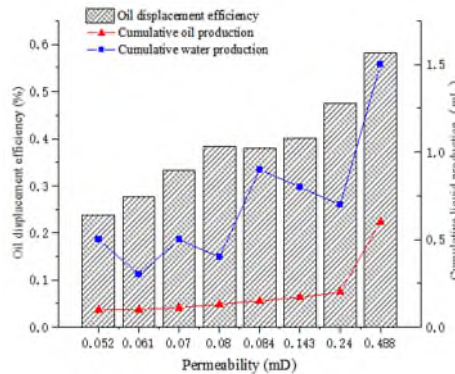


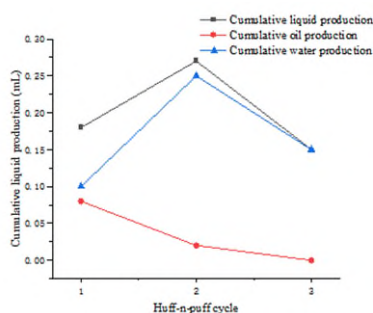
Figure 24 Crude oil recovery degree under different permeabilities

Table 3 lists the oil saturation volume, cumulative oil production over three cycles, and oil displacement efficiency corresponding to different permeabilities. The data indicate that the increase in permeability not only enhances oil production capacity but also significantly increases water production characteristics. In the low permeability range from 0.052 mD to 0.08 mD, fluid activity is limited, and cumulative water production remains at a relatively low level of 0.3–0.5 mL. In cores with relatively high

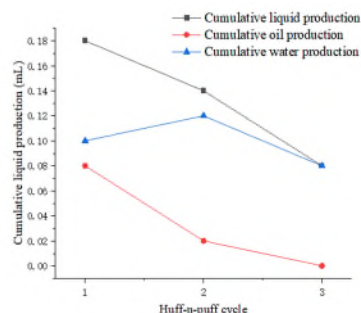
permeability, the frictional resistance to water phase entry and exit is greatly reduced, which greatly promotes oil-water displacement in the matrix pores, but also causes the injected water to flow out more easily along the 畅通的 pore network during the production stage, manifested as an increase in cumulative liquid production and water production.

Table 3 Oil saturation volume, cumulative oil production over three cycles, and oil displacement efficiency corresponding to different permeabilities

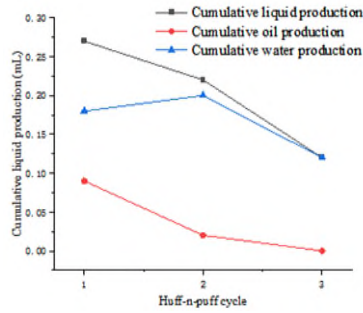
No.	Injected water salinity (mg/L)	Porosity (%)	permeability (mD)	Oil saturation volume (mL)	Cumulative oil production (mL)	Cumulative water production (mL)	Cumulative liquid production (mL)	Oil displacement efficiency (%)
1	10000	6.09	0.052	0.4198	0.10	0.5	0.60	23.82%
2	10000	6.43	0.061	0.3625	0.10	0.3	0.40	27.59%
3	10000	5.54	0.070	0.3302	0.11	0.5	0.61	33.31%
4	10000	6.01	0.080	0.3389	0.13	0.4	0.53	38.36%
5	10000	6.17	0.084	0.3945	0.15	0.9	1.05	38.02%
6	10000	8.59	0.143	0.4231	0.17	0.8	0.97	40.18%
7	10000	6.98	0.240	0.4209	0.20	0.7	0.90	47.52%
8	10000	11.78	0.488	1.0319	0.60	1.5	2.10	58.15%



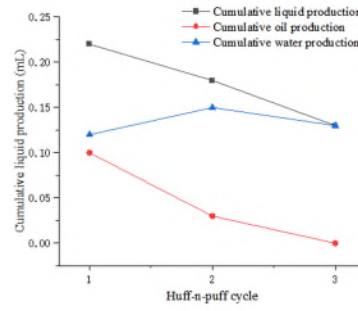
(a) Permeability 0.052 mD



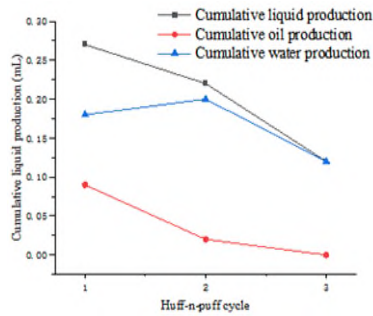
(b) Permeability 0.061 mD



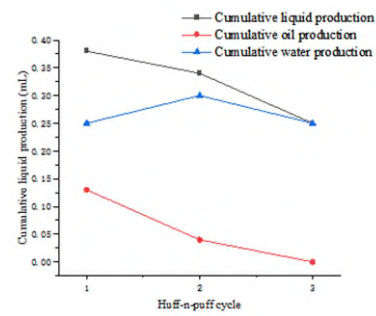
(c) Permeability 0.07 mD



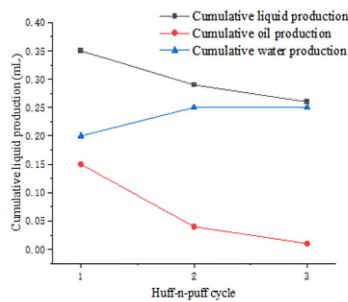
(d) Permeability 0.08 mD



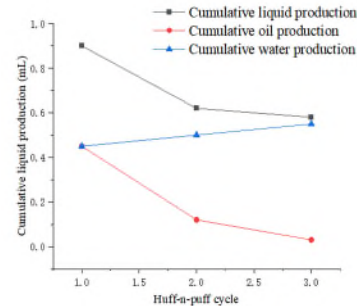
(e) Permeability 0.084 mD



(f) Permeability 0.143 mD



(g) Permeability 0.24 mD



(h) Permeability 0.488 mD

Figure 25 Influence curve of reservoir permeability

458 Figure 25 shows the variation of liquid production per cycle for cores with different
 459 permeabilities. Comparing the oil phase dynamic curves of each group, it can be seen
 460 that the single-cycle oil production of cores with all permeabilities exhibits an
 461 exponential nonlinear decreasing characteristic. The first-cycle oil production accounts
 462 for 80% of the total production. From the second cycle onward, the mobilization
 463 capacity of the oil phase declines sharply, and by the third cycle, the oil production
 464 generally approaches the lower limit of mobility. The high-pressure water injection in
 465 the first cycle preferentially mobilizes the high-mobility crude oil in the connected large
 466 pores. As the fluid alternates in cycles, a strong relative permeability hysteresis effect
 467 occurs inside the core. Due to the tight matrix, within the limited shut-in time, the crude

oil in the deep matrix pores cannot overcome the capillary resistance to imbibe and supply into the main fracture network or large pores, resulting in the movable oil saturation in the pore network rapidly dropping below the critical value, and the oil phase basically loses its macroscopic flowability in subsequent cycles.

3.2.3 Effect of shut-in time

Figure 26 compares the oil displacement efficiency of cores under different shut-in times, with the same salinity, injection pressure, permeability, and number of huff-n-puff cycles. The data indicate that extending shut-in time can improve the ultimate recovery, but is accompanied by significant diminishing marginal returns. As the single shut-in time increased from 12 h to 36 h, the oil displacement efficiency of the core increased from 23.82% to 31.27%. From the perspective of physical processes, for low-permeability tight cores, the entry of the water phase into the matrix pores driven by capillary force is a slow kinetic process. Extending the shut-in time provides sufficient time for spontaneous imbibition, allowing the injected water to sweep and displace crude oil from deeper tiny pores.

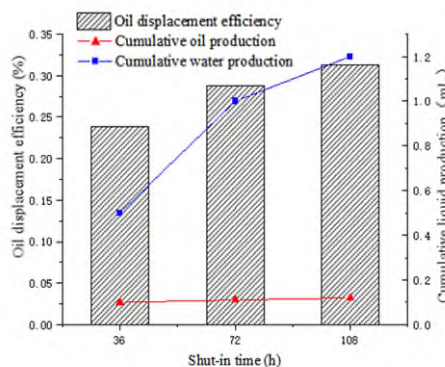


Figure 26 Crude oil recovery degree under different shut-in times

Table 4 lists the oil saturation volume, cumulative oil production over three cycles, and oil displacement efficiency corresponding to different shut-in times. When the single shut-in time was increased from 12 h to 36 h (a two-fold increase), the cumulative oil production increased by only 0.02 mL, but the cumulative water production increased from 0.50 mL to 1.20 mL, an increase of up to 140%. This phenomenon reveals the attenuation mechanism of imbibition: the spontaneous imbibition rate is highest at the initial stage and then decreases rapidly.

Table 4 Oil saturation volume, cumulative oil production over three cycles, and oil displacement efficiency corresponding to different shut-in durations

No.	Shut-in time (h)	Porosity (%)	permeability (mD)	Oil saturation volume (mL)	Cumulative oil production (mL)	Cumulative water production (mL)	Cumulative liquid production (mL)	Oil displacement efficiency (%)
1	12	6.09	0.052	0.4198	0.1	0.5	0.6	23.82%
2	24	5.78	0.055	0.3825	0.11	1.0	1.11	28.76%
3	36	5.78	0.055	0.3837	0.12	1.2	1.32	31.27%

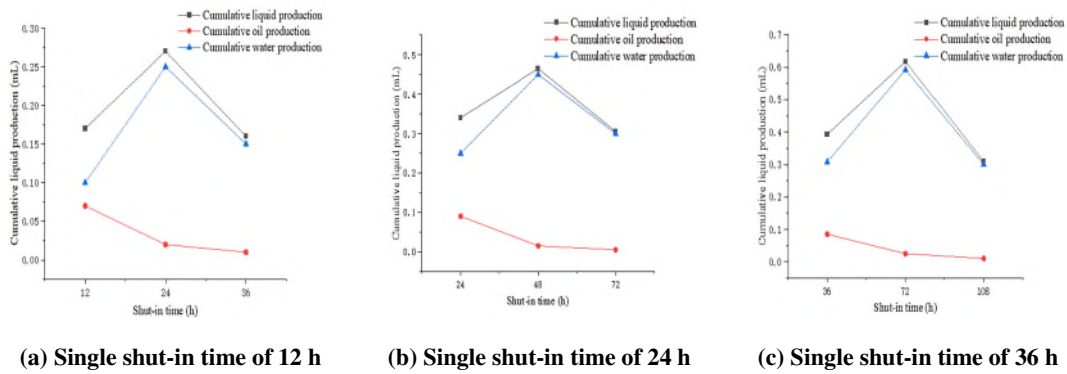


Figure 27 Production curves under different shut-in times

The data by cycle indicate that changing the shut-in time follows the cycle decline law of huff-n-puff production. Regardless of whether the single shut-in time is 12 h or 36 h, the oil production of the first cycle accounts for more than 70% of the total oil production. Starting from the second cycle, all groups quickly enter a state of high water cut. This further proves that in tight cores, once water flow channels are formed in the first cycle, simply extending the shut-in time cannot reverse the water channeling trend in subsequent cycles. Extending the shut-in time has an enhancing effect on the liquid production of each cycle, but the magnitude of increase in liquid production in later cycles weakens. Extending the shut-in time mainly strengthens the imbibition effect of the first and second cycles, with limited contribution to oil increase in the third cycle.

3.2.4 Effect of huff-n-puff cycles

Figure 28 compares the oil displacement efficiency of cores under different numbers of

huff-n-puff cycles, with the same salinity, injection pressure, permeability, and shut-in conditions. The data indicate that increasing the number of huff-n-puff cycles can improve the ultimate recovery to a certain extent. When the number of cycles increased from 3 to 5, the total oil displacement efficiency increased from 23.82% to 28.43%, and the cumulative oil production increased from 0.10 mL to 0.12 mL. This indicates that after the initial three cycles, a small amount of movable oil still remains in the matrix. By increasing the number of injection-depressurization cycles, the weak alternating pressure difference and imbibition can still barely strip some residual oil. In the initial state, the oil saturation inside the tight matrix is high, and there is a huge capillary pressure difference and concentration gradient between the injected water and the crude oil.

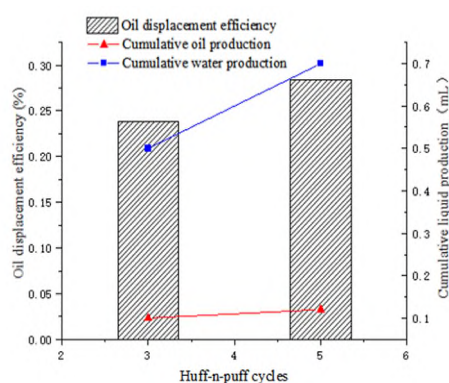


Figure 28 Crude oil recovery degree under different huff-n-puff cycles

Table 5 lists the oil saturation volume, cumulative oil production over three cycles, and oil displacement efficiency corresponding to different numbers of huff-n-puff cycles. In the complete cycle of five huff-n-puff cycles, the crude oil was mainly produced in the first cycle, with the first-cycle oil production reaching as high as 0.08 mL, accounting for 66.7% of the total cumulative oil production of 0.12 mL over the five cycles.

Table 5 Oil saturation volume, cumulative oil production over three cycles, and oil displacement efficiency corresponding to different numbers of huff-n-puff cycles

No.	Huff-n-puff	Porosity (%)	permeability (mD)	Oil saturation volume	Cumulative oil production	Cumulative water production	Cumulative liquid production	Oil displacement efficiency (%)
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	cycles			(mL)	(mL)	(mL)	(mL)	
1	3	6.09	0.052	0.4198	0.1	0.5	0.6	23.82%
2	5	6.09	0.052	0.4221	0.12	0.7	0.82	28.43%

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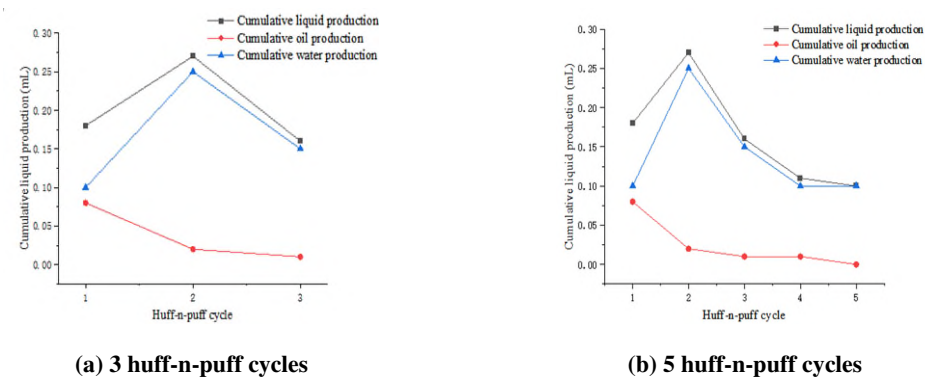


Figure 29 Cumulative production under different huff-n-puff cycles

525 During the shut-in period, the injected water enters the matrix through spontaneous

526 imbibition, displacing crude oil into large pores or microfractures, and is then efficiently

527 produced under the pressure difference during well opening. At this stage, capillary

528 force is the main driving force for oil increase. In the 2nd and 3rd cycles, after the initial

529 fluid displacement is completed, the larger pores and microfractures in the core have

530 been occupied by the water phase. Due to the certain hydrophilicity of the core, the

531 subsequently injected water tends to flow along the low-resistance pores, causing

532 microscopic fingering and forming stable preferential water flow channels. As a result,

533 water production peaks in the second cycle. The total oil production of the first two

534 cycles reaches 0.10 mL, accounting for 83.3% of the total oil production of 0.12 mL.

535 The single-cycle oil production of the third and fourth cycles is only 0.01 mL, while

536 the single-cycle water production is as high as 0.10–0.15 mL. By the fifth cycle, oil

537 production is zero, and all 0.10 mL of produced liquid is injected water, indicating that

538 the core has reached a state of complete water flooding. In the later stage of huff-n-puff,

539 the remaining oil mainly occurs in nanoscale dead-end pores or extremely narrow

540 throats. The capillary force at the entrance of tiny pores reverses from the initial

541 imbibition driving force to the Jamin resistance that prevents water from entering. The

542 cyclic pressure alone is no longer able to overcome the huge capillary threshold

pressure to strip the deep crude oil. Multi-cycle water injection completely evolves into ineffective circulation along the existing water phase channels, resulting in zero oil production in the fifth cycle.

3.2.5 Effect of injection pressure

Figure 30 compares the oil displacement efficiency of cores under different injection pressures, with the same salinity, number of huff-n-puff cycles, permeability, and shut-in conditions. The data indicate that increasing injection pressure enhances oil displacement efficiency. As the injection pressure increased from 15 MPa to 25 MPa, the ultimate oil displacement efficiency steadily rose, and the cumulative oil production increased from 0.10 mL to 0.13 mL. For a tight core with a permeability of 0.052 mD, increasing the injection pressure directly enhances the driving force for fluid entry into the matrix. This high pressure difference overcomes the capillary resistance in tiny pore throats, forcing the injected water to sweep deeper, previously unutilized pores.

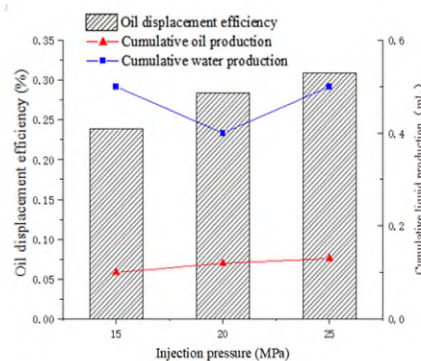


Figure 30 Cumulative liquid production under different injection pressures

Table 6 lists the oil saturation volume, cumulative oil production, and oil displacement efficiency corresponding to different injection pressures. The positive benefit brought by pressure increase is not linearly increasing. A quantitative comparison of the increase shows that when the pressure increased from 15 MPa to 20 MPa, the oil displacement efficiency increased by 4.54%; however, when the pressure increased from 20 MPa to 25 MPa, the oil displacement efficiency increased only slightly by 2.48%. The cumulative water production rebounded at 25 MPa, reaching 0.50 mL, indicating that when the pressure exceeds a certain critical value, the excessively high fluid pressure easily opens microfractures or weakly cemented surfaces in the tight core. The injected

water undergoes microscopic short-circuiting along these newly opened fractures, resulting in inefficient production of subsequent injected water and diminishing marginal oil increase benefits.

Table 6 Oil saturation volume, cumulative oil production over three cycles, and oil displacement efficiency corresponding to different injection pressures

No.	Injection pressure (MPa)	Porosity (%)	permeability (mD)	Oil saturation volume (mL)	Cumulative oil production (mL)	Cumulative water production (mL)	Cumulative liquid production (mL)	Oil displacement efficiency (%)
1	15	6.09	0.052	0.4198	0.1	0.5	0.6	23.82%
2	20	6.09	0.052	0.4231	0.12	0.4	0.52	28.36%
3	25	6.09	0.052	0.4215	0.13	0.5	0.63	30.84%

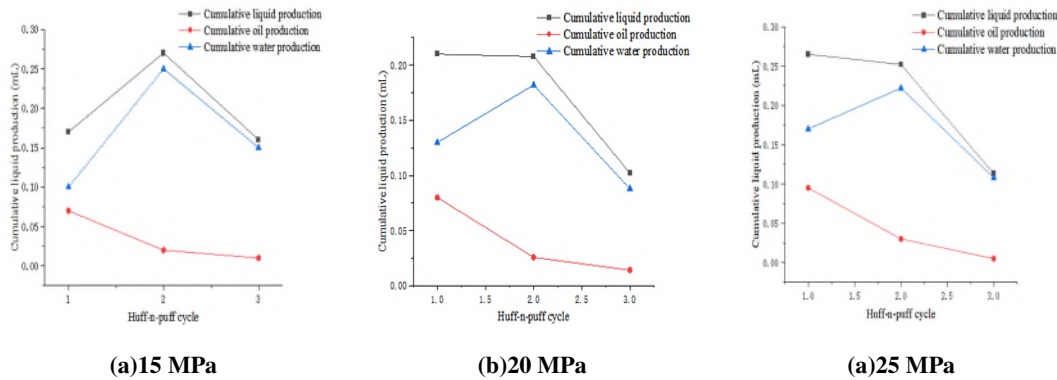


Figure 31 Liquid production under different injection pressures

When the injection pressure was 25 MPa, the first-cycle oil production was 0.095 mL, accounting for 73% of the total oil production of 0.13 mL. Due to the high-pressure displacement in the first cycle, a large amount of easily movable oil and formation energy were rapidly consumed. In this group, the oil production decreased to 0.005 mL in the third cycle, and the water cut rose to 95.6%. This indicates that although excessively high injection pressure can improve early-stage productivity, it also significantly shortens the effective life cycle of huff-n-puff, causing the reservoir to enter the stage of complete water flooding prematurely.

3.2.6 Analysis of main controlling factors

Through range analysis, the range values of injected water salinity, core permeability, huff-n-puff cycles, shut-in time, and injection pressure were compared, and the relative influence degree of each factor on oil recovery was systematically evaluated. The analysis results are shown in Figure 32. The results indicate that core permeability and injected water salinity have a greater impact on oil recovery, accounting for 45.9% and 28.4%, respectively, while the influence of huff-n-puff cycles is the smallest, only 6.2%.

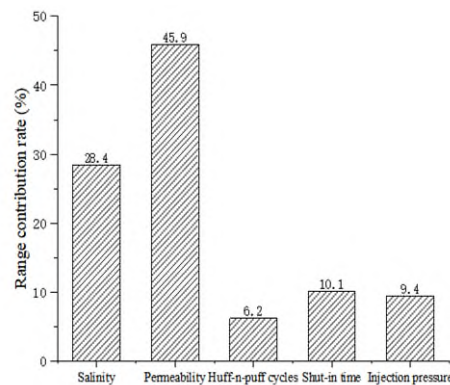


Figure 32 Influence degree of different factors on oil recovery

4. Conclusions

In this paper, microfluidic experiments were conducted to analyze the microscopic characteristics of the displacement process under different salinities, and huff-n-puff experiments were performed to investigate the effects of injected water salinity, core permeability, shut-in time, huff-n-puff cycles, and injection pressure on oil recovery efficiency. The main conclusions are as follows:

- (1) Low-salinity fluid can effectively improve fracturing fluid displacement efficiency. Core experiments show that when the injected water salinity is 5000 mg/L, the oil displacement efficiency reaches 40.22%. Reservoir permeability is positively correlated with oil displacement efficiency. High-permeability cores have better pore-throat connectivity and larger sweep volume.
- (2) Increasing injection pressure can overcome the threshold resistance of tiny pore throats. When the injection pressure increases from 15 MPa to 25 MPa, the oil displacement efficiency increases from 23.82% to 30.84%. However, excessively high

injection pressure can easily induce water channeling. Extending the shut-in time from 12 h to 36 h increases the oil displacement efficiency from 23.82% to 31.27%. The first cycle of fracturing fluid displacement contributes more than 70% of the total oil production, and the effect of multi-cycle huff-n-puff on increasing production is not significant.

(3) The order of main controlling factors for fracturing fluid displacement is: reservoir permeability > salinity > shut-in time > injection pressure > huff-n-puff cycles.

CRedit authorship contribution statement

Xiong Liu: Writing – review & editing, Writing – original draft, Supervision, Investigation, Funding acquisition. Yirui Ren: Writing – original draft. Yueqi Cui: Writing – Data curation. Tuanqi Yao: Supervision. Yuchan Cheng: Methodology.

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.

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