processes

MDPI

Article

Enhanced Oil Recovery Mechanism and Parameter Optimization of Huff-and-Puff Flooding with Oil Displacement Agents in the Baikouquan Oilfield

Hui Tian [1], Jianye Mou [2,*], Kunlin Xue [1], Xingyu Yi [1], Hao Liu [2] and Budong Gao [2]

[1] Baikouquan Oil Plant, Xinjiang Oilfield Branch, PetroChina, Karamay 834000, China
[2] College of Petroleum Engineering, China University of Petroleum (Beijing), Beijing 102249, China
* Correspondence: moujianye@cup.edu.cn

Abstract

The Baikouquan Oilfield edge expansion wells suffer from poor reservoir properties and limited connectivity, leading to low waterflooding sweep efficiency and insufficient reservoir energy. While oil displacement agents (ODAs) are currently employed in huff-and-puff flooding to enhance recovery, there is a lack of a solid basis for selecting these ODAs, and the dominant mechanisms of enhanced oil recovery (EOR) remain unclear. To address this issue, this study combines experimental work and reservoir numerical simulation to investigate the mechanisms of EOR by ODAs, optimize the selection of ODAs, and fine-tune the huff-and-puff flooding parameters. The results show that the selected nanoemulsion ODA (Nano ODA) significantly reduces the oil–water interfacial tension (IFT) by 97%, thereby increasing capillary number. Additionally, the ODA induces a shift from water–wet to neutral–wet conditions on rock surfaces, reducing capillary forces and weakening spontaneous imbibition. The Nano ODA demonstrates strong emulsification and oil-carrying ability, with an emulsification efficiency of 75%. Overall, the ODA increases the relative permeability of the oil phase, reduces residual oil saturation, and achieves a recovery improvement of more than 10% compared with conventional waterflooding. The injection volume and shut-in time were optimized for the target well, and the recovery enhancement from multiple cycles of huff-and-puff flooding was predicted. The research in this paper is expected to provide guidance for the design of huff-and-puff flooding schemes in low-permeability reservoirs.

Keywords: huff-and-puff flooding; nanoemulsion ODA; imbibition; numerical simulation; parameter optimization

check for updates

Academic Editor: Vincenzo Russo

Received: 30 August 2025
Revised: 19 September 2025
Accepted: 25 September 2025
Published: 27 September 2025

Citation: Tian, H.; Mou, J.; Xue, K.; Yi, X.; Liu, H.; Gao, B. Enhanced Oil Recovery Mechanism and Parameter Optimization of Huff-and-Puff Flooding with Oil Displacement Agents in the Baikouquan Oilfield. *Processes* **2025**, *13*, 3098. https://doi.org/10.3390/pr13103098

Copyright: © 2025 by the authors. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license (https://creativecommons.org/licenses/by/4.0/).

1. Introduction

The Baikouquan Oilfield, particularly the Bai21 well area of the Kexia Formation, contains abundant unconventional oil and gas resources. The reservoir lithology is dominated by coarse-grained lithic sandstone with fine gravel, and vermicular kaolinite is the major clay mineral, accounting for 37.50% of the total clay content. Reservoir porosity is mainly distributed between 8% and 14%, with an average value of 11.40%, while permeability ranges from 1 mD to 30 mD, with an average of 23.71 mD. Due to the presence of a large number of nanoscale pores, conventional water flooding has limited sweep efficiency and cannot effectively mobilize residual oil [1–4]. To overcome these limitations, post-fracturing huff-and-puff flooding has been widely applied as an effective reservoir development strategy. This process involves injecting a large volume of water containing oil displacement

agents (ODAs) into the reservoir after fracturing, shutting in the well to allow the injected ODA to interact with the formation, and then resuming production to mobilize additional oil. Compared with conventional water flooding, huff-and-puff flooding can not only supplement formation energy and restore reservoir pressure but also improve crude oil mobility by altering interfacial properties [5].

During post-fracturing huff-and-puff flooding, ODAs play a crucial role in enhancing oil recovery. ODAs typically contain surfactants that can modify rock wettability and reduce oil–water interfacial tension (IFT). Numerous experimental and theoretical studies have confirmed the dual role of surfactants in wettability alteration and IFT reduction. Sheng et al. investigated the influence of surfactants on spontaneous imbibition through combined simulations, theoretical analysis, and experiments, and reported that surfactant molecules could change the initial wettability of the rock from oil-wet to water-wet, which significantly enhanced oil displacement [6,7]. Similarly, Standnes et al. demonstrated that cationic surfactants exhibit stronger wettability alteration ability than anionic surfactants in oil-wet limestone reservoirs [8], a conclusion that was further validated by the imbibition experiments conducted by Salehi et al. [9]. In parallel, surfactants also contribute to EOR by reducing oil–water IFT. Huang [10] showed that reservoirs with stronger hydrophilicity exhibit more pronounced flooding effects, while the reduction in IFT by surfactants further improved displacement efficiency. Hendraningrat et al. synthesized silica nanoparticles and confirmed that their addition to aqueous solutions reduced oil–water IFT with increasing nanofluid concentration, thereby enhancing oil recovery in low- and medium-permeability sandstone reservoirs [11]. Foster found that when the oil–water IFT is reduced to the level of 10^{-3} mN/m, the capillary number increases significantly, which in turn leads to a substantial improvement in recovery efficiency [12]. Youssif et al. reported that hydrophilic monodisperse silica nanoparticles with an average particle size of 22 nm enhanced oil recovery by 13.28% when used at 0.1% concentration in a three-stage recovery sequence following water flooding [13]. These results highlight that ODAs, through surfactant and nanoparticle action, can simultaneously alter wettability and reduce IFT, both of which are essential for improving recovery efficiency.

In addition to improving microscopic displacement efficiency, ODA flooding has also been demonstrated to replenish reservoir energy. Wellington and Richardson conducted displacement experiments using both cationic and anionic surfactants at 0.4% mass fraction and found that residual oil in the core was effectively displaced [14]. Field applications further confirmed that post-fracturing huff-and-puff flooding can significantly restore reservoir energy and production capacity, even enabling horizontal wells to recover to their initial production levels [15].

Beyond laboratory and field studies, numerical simulation has become an indispensable tool for understanding and optimizing huff-and-puff flooding processes. Liu developed a mathematical model for fractured reservoirs that considered spontaneous imbibition, and the results showed that oil recovery increased by 2.15% when imbibition was included in the simulation [16]. Similarly, Sandeep et al. and Viet Hoai Nguyen established mathematical models that also incorporated imbibition mechanisms, reinforcing the importance of accounting for capillary-driven flow in tight reservoirs [17,18]. Zhu applied the STARS simulator in CMG software to evaluate the effect of Nano ODA injection in tight reservoirs and concluded that oil production rates could be substantially enhanced with such treatments [19].

Although significant progress has been made in understanding oil recovery via post-fracturing huff-and-puff flooding, the selection of optimal ODAs for the Baikouquan Oilfield Kexia Formation remains a considerable challenge. This is due to its specific mineralogical composition, complex pore structure, and predominantly water-wet na-

ture, which collectively complicate displacement processes. Furthermore, most existing studies have concentrated on general surfactant-based EOR mechanisms, while limited attention has been given to the comparative performance of different ODAs under the unique petrophysical conditions of the Kexia Formation. Against this background, the present study systematically investigates the physicochemical properties and displacement performance of two ODAs: GPNR-2 Nano ODA, a nanoemulsion developed by GePeto Ltd., and KPS ODA, a petroleum sulfonate-based surfactant. Spontaneous imbibition tests, relative permeability measurements, and core flooding experiments were carried out on core samples from the Kexia Formation. Based on these experimental insights, a numerical huff-and-puff flooding model was constructed to optimize injection parameters.

Importantly, while many previous studies have reported that nanoemulsions reduce IFT and alter wettability, they seldom address reservoir-specific conditions or clarify the dominant recovery mechanisms in water-wet states. This study demonstrates that under the water-wet conditions of the Kexia Formation, emulsification and IFT reduction dominate oil recovery, whereas spontaneous imbibition plays only a minor role. By combining laboratory experiments with numerical huff-and-puff simulations, this work provides both mechanistic insights and practical guidance for reservoir-specific optimization. The findings not only provide theoretical support and technical guidance for efficient development of tight oil reservoirs in the Baikouquan Oilfield but also contribute to the broader understanding of surfactant–nanoparticle-assisted EOR processes in unconventional reservoirs worldwide.

2. Experiments on ODA Performance

Five kinds of experiments were conducted to clarify the mechanism of EOR of ODAs. They are (1) oil–water interface property tests, including oil–water IFT tests and wettability tests; (2) emulsion tests of different ODAs with oil; (3) relative permeability tests; (4) spontaneous imbibition tests; and (5) oil displacement tests. The overall performance of the two ODAs is systematically evaluated, and the dominant enhanced oil recovery (EOR) mechanisms are identified based on experimental results. It should be emphasized that in practical applications, flooding agents are selected based on their performance under reservoir conditions—such as interfacial tension reduction, emulsification efficiency, wettability alteration, and displacement efficiency. In this study, effective concentration ranges were therefore evaluated through interfacial tension, emulsification, contact angle, and core flooding tests, rather than by measuring the CMC (critical micelle concentration). The lack of direct measurement of CMC may introduce uncertainty in quantitatively distinguishing micellar versus sub-micellar effects, particularly with respect to interfacial tension reduction and wettability alteration, but it does not compromise the validity of the present findings. Future work will incorporate CMC measurements under representative reservoir conditions to enhance the rigor and completeness of the results. A numerical simulation is conducted to optimize the operational parameters of huff-and-puff flooding for the Kexia Formation. The complete research workflow is illustrated in Figure 1.

2.1. Experimental Materials and Instruments

The main equipment used in the experiments includes the following: TX-700C rotating oil–water IFT meter (produced by Beijing Pinzhi Chuangsi, Beijing, China), contact angle measurement instrument (LAUDA Scientific, Lauda-Königshofen, Germany), high-temperature and high-pressure displacement testing platform (Figure 2), Amott imbibition bottle (Beijing Sanjiao Trading, Beijing, China), A30 high-speed emulsifier (Shanghai Ouhe Machinery Equipment Co., Ltd., Shanghai, China), and a constant-temperature oven.

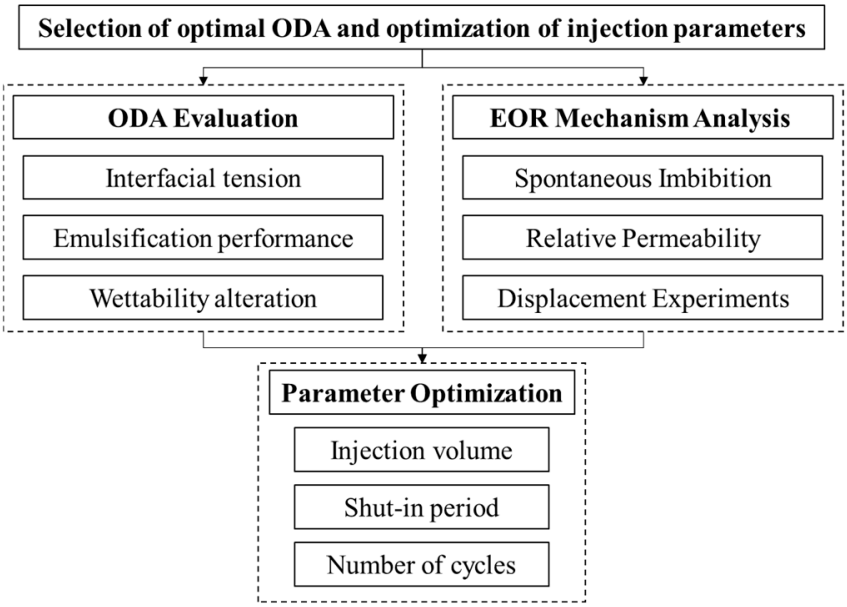


Figure 1. Workflow of ODA selection, EOR mechanism analysis, and injection parameter optimization.

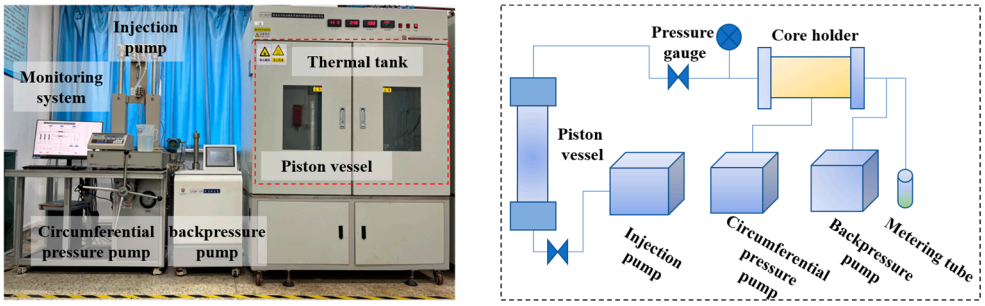


Figure 2. Oil displacement devices (**left**) and their schematic diagram (**right**).

The ODAs used in the experiments include a Nano ODA produced by Jiebeitong Petroleum Technology Co., Ltd., Chengdu, China, which primarily consists of organic solvents, diallylphenol ketone polyoxyethylene ether (surfactant), and water, with a surfactant content of 20–30%, and a KPS ODA provided by the Baikouquan Oil Plant, which mainly consists of petroleum sulfonate with an active content of 40%. The ODA concentration range of 0.1–0.3% was selected based on preliminary screening tests and literature evidence. Initial evaluations over a broader range (0.05–0.5 wt%) indicated that the most significant reduction in interfacial tension occurred up to 0.2%, beyond which further improvement was marginal, making this range both technically effective and economically practical. The water used in the experiment is the formation water from the Baikouquan Oil Plant, with a $NaHCO_3$ type composition and a salinity of 5276.9 mg/L. The crude oil used in the experiment is provided by the Baikouquan Oil Plant, Karamay, China, with a density of 0.833 g/cm^3 and a viscosity of 1.955 mPa·s. The core samples are also provided by the Baikouquan Oil Plant, with an average permeability of 1.18 mD and an average porosity of 14.8%. Table 1 shows the physical properties and purpose of each core sample.

Table 1. Core physical properties and its experimental purpose.

Core Number	Length (cm)	Diameter (cm)	Permeability (mD)	Porosity (%)	Experimental Purpose	
1-1	1.24	2.49	1.15	15.32	Wettability test	Oil saturated
1-2	1.25	2.50	1.15	15.32		Water flooded
1-3	1.24	2.50	1.15	15.32		Nano ODA flooded
1-4	1.23	2.50	1.15	15.32		KPS ODA flooded
2	5.01	2.49	1.24	15.61	Relative permeability test	Water
3	5.00	2.50	0.98	13.12		Nano ODA
4	4.99	2.50	1.42	15.28		KPS ODA
5	5.00	2.49	0.98	14.62		Water+ Nano ODA
6	5.01	2.49	1.15	16.15	Imbibition test	Nano ODA
7	5.00	2.50	1.02	14.24		Water + KPS ODA
8	4.98	2.49	0.90	12.49		KPS ODA
9	4.97	2.50	1.12	13.82		Water
10	4.99	2.49	1.25	14.53		0.1% Nano ODA
11	5.01	2.49	1.32	15.10		0.2% Nano ODA
12	5.00	2.49	1.28	13.94	Displacement test	0.3% Nano ODA
13	4.98	2.49	1.25	14.25		0.1% KPS ODA
14	4.99	2.50	1.38	16.18		0.2% KPS ODA
15	5.00	2.49	1.32	15.47		0.3% KPS ODA

Note: core disks 1-1 to 1-4 are cut from the same core plug.

2.2. Experimental Method

2.2.1. The IFT Test

The IFT test and wettability test are performed to measure the oil–water interface property. The IFT between oil and injected fluid acts as flow resistance when flooding the oil by injected fluid. The interfacial tensiometer was used to test the oil–water IFT between oil and ODA solution. Before the test, 2 μL of crude oil was injected into the quartz tube, which is filled with ODA solution. The quartz tube was carefully placed in the interfacial tensiometer. Then the interfacial tensiometer is started, and the IFT is measured according to the national standard of SY/T 5370—2018 [20].

2.2.2. Wettability Test

A 5 cm-long core sample (Core #1) saturated with crude oil was cut into four equal slices. Three slices were displaced with water, 0.2% Nano ODA, and 0.2% KPS ODA, respectively, until the water cut reached 98%. The slices were then polished, immersed in formation water, and crude oil droplets (1–2 mm in diameter) were applied to the mineral surface. Using an optical system, light was projected onto the droplets, magnified, and projected onto a screen to directly measure the contact angle. The experiment followed the "SY/T5153-2017 Method for Determining the Wettability of Reservoir Rocks" [21].

2.2.3. Emulsion Test

The emulsification performance of an ODA has a promotion effect on the oil displacement effect. The ODA to be tested was mixed with crude oil in an 8:2 volume ratio and added to a 10 mL stoppered graduated test tube. The mixture was then heated in a 40 °C constant-temperature oven for 20 min. After removal, the mixture was emulsified for 90 s at 20,000 r/min using a high-speed emulsifier to form a uniform system. The formation of water, oil, and emulsion layers was observed and quantified, and the emulsification rate was calculated as the emulsified oil volume divided by the total crude oil volume. The experiment followed the "Q/SY17583-2018 Technical Specification for Surfactants Used in Binary Composite Flooding" [22].

2.2.4. Relative Permeability Test

The distribution of oil–water saturation in porous media is a function of distance and time, and the relative permeability of oil and water saturation can be obtained by recording the production and pressure difference in each fluid according to the change in time. The

relative permeability was measured through the constant velocity method. The testing procedures include (1) drying and vacuuming the core (2#, 3#, 4# core sample) for 8 h, (2) saturating the core with formation water and calculating the porosity, (3) displacing the core with oil until no water comes out from the outlet and calculating the relative permeability of the oil phase, and (4) displacing the oil-saturated core with formation water and calculating the relative permeability of the water phase. The relative permeability test follows the national standard of GB/T28912-2012 for the determination of the relative permeability of two-phase fluids in rocks [23].

2.2.5. The Imbibition Experiment

The wetting phase can imbibe into the core under the capillary pressure to displace the non-wetting phase. Thus, to evaluate the imbibition ability of different ODA solutions, imbibition experiments have been performed. The saturated core samples (Core #5, #7) were placed in imbibition bottles and immersed in formation water at reservoir temperature, with oil production observed over time. The core mass was measured at intervals. After no oil was produced under formation water conditions for 4 days, the cores were weighed again and then replaced with Nano ODA solution (Core #5) and KPS ODA solution (Core #7), continuing the immersion until day 8. Oil displacement was observed, and mass measurements were taken at intervals. Core samples soaked for 8 days in Nano ODA (Core #6) and KPS ODA solution (Core #8) served as control groups, analyzing the effect of Nano ODA and KPS ODA solutions on spontaneous imbibition displacement. The oil displacement volume and oil recovery rate were calculated by measuring the mass difference in the cores under different solutions and soaking times.

2.2.6. Oil Displacement Experiment

Oil displacement experiments were conducted to evaluate the performance of different oil displacement agents (ODAs) under controlled laboratory conditions, simulating the fluid flow behavior in the Kexia Formation. The detailed procedure is as follows:

(1) Core preparation: Cylindrical core plugs were dried in an oven at 80 °C until a constant weight was reached, then cooled to room temperature in a desiccator.
(2) Vacuum saturation: The dried cores were placed in a vacuum chamber and evacuated to a pressure below −0.08 MPa for at least 4 h to remove air from the pore spaces. Subsequently, formation brine was slowly introduced to saturate the cores under vacuum conditions, ensuring complete brine saturation.
(3) Establishing initial oil saturation: After brine saturation, the cores were mounted in a core holder. Crude oil was injected at a constant flow rate of 0.02 mL/min until no more water was produced from the outlet.
(4) Water/ODA flooding: The injection flow rate was maintained at 0.02 mL/min. Injection continued until the water cut reached 99% or 30 pore volumes (PV) were injected, whichever came first.
(5) Backpressure and confining pressure: A backpressure of 1 MPa was applied at the outlet to stabilize flow and maintain liquid-phase continuity. A confining pressure of 12 MPa was maintained to mimic in situ stress and avoid bypass.
(6) Pressure and production monitoring: Differential pressure across the core was continuously monitored using a precision pressure transducer. Oil and water production were recorded periodically throughout the flooding process.
(7) Post-flooding analysis: At the end of the displacement test, the final oil recovery factor and residual oil saturation were calculated based on cumulative oil production [24].

3. Experimental Results and Discussion

3.1. Effect of ODAs on Oil–Water IFT

The IFT test results are shown in Figure 3. The experiments demonstrate that both Nano ODA and KPS ODA reduce the oil–water IFT by over 97%. This is due to the presence of a large amount of surfactant in the displacement agent, which reduces direct contact between the two fluids and reduces the interfacial energy between oil and water, thereby lowering the IFT [25,26]. A comparison reveals that the Nano ODA is more effective in lowering the IFT than the KPS ODA. This could be attributed to nanoemulsion structure. The smaller particle size and larger specific surface area of the nanoemulsion allow it to disperse rapidly at the oil–water interface, forming multiple fine thin-layer structures that more significantly reduce the IFT [27]. Additionally, when the ODA concentration exceeds 0.2%, the rate of IFT reduction slows. The potential reason is that once the ODA concentration approaches a critical value, the interfacial sites become nearly saturated. Further increasing the surfactant concentration predominantly promotes micelle formation in the bulk solution rather than additional interfacial adsorption. Consequently, the rate at which the IFT decreases slows down beyond this critical concentration [28]. As the IFT decreases, the adhesion of crude oil to the rock surface also diminishes, converting more residual oil in the reservoir into movable oil, thereby enhancing recovery [29–31].

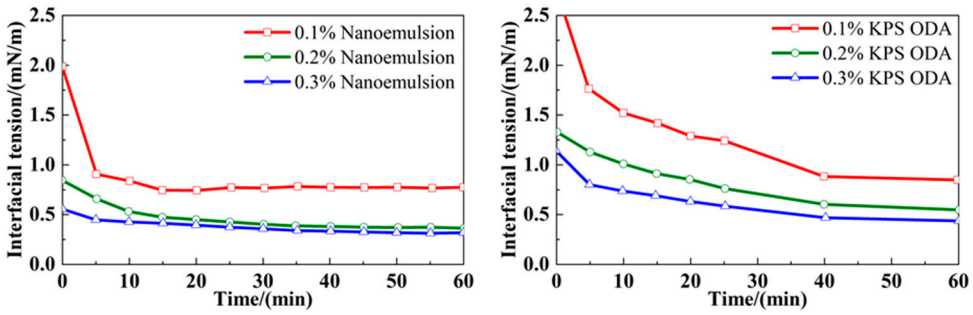


Figure 3. Nano ODA significantly reduces IFT, and when its concentration is beyond 0.2%, the IFT reduction rate decreases (**left**); KPS ODA reduces the IFT slowly, and compared with Nano ODA, the effect of KPS ODA in reducing IFT is slightly weaker (**right**).

3.2. Effect of ODAs on Wettability

During the development of low-permeability reservoirs, the wettability of the rock affects the imbibition process. When the reservoir is hydrophilic, capillary forces act as the driving force for imbibition. Displacement agents can alter the wettability of the rock, mainly through surfactant adsorption, which affects the surface affinity to water [32]. However, for strongly hydrophilic reservoirs, further increasing hydrophilicity is not always beneficial. Cui found that oil recovery is most effective when the rock exhibits weak hydrophilicity, close to neutral wettability [33]. To evaluate the effect of displacement agents on rock wettability in this study, core samples were prepared, including saturated oil core slices (Core 1-1), water-flooded core slices (Core 1-2), Nano ODA-flooded core slices (Core 1-3), and KPS ODA-flooded core slices (Core 1-4), for contact angle measurement. As shown in Figure 4, the contact angle for all four core samples was less than 90°, indicating that the cores were initially water-wet. After water flooding, the change in wettability was minimal. Following flooding with the ODAs, the measured contact angles increased slightly, demonstrating that the water-wetness weakened and shifted closer to a neutral condition. The Nano ODA exhibited a more pronounced effect in increasing the contact angle than the KPS ODA, indicating a greater tendency to weaken strong water-wetness. This change is directly evidenced by the measured contact angle data presented in Figure 4. The mention of surfactant adsorption explains the possible mechanism: surfactant molecules in the

ODAs can adsorb onto the rock surface and partially block hydrophilic mineral sites, thereby reducing the affinity between the rock and water. However, it should be noted that no direct adsorption measurements were conducted in this work; the inference is supported by the contact angle results and existing literature [34]. This moderate shift in wettability helps balance capillary and viscous forces, which is favorable for improving oil mobilization in low-permeability pore networks.

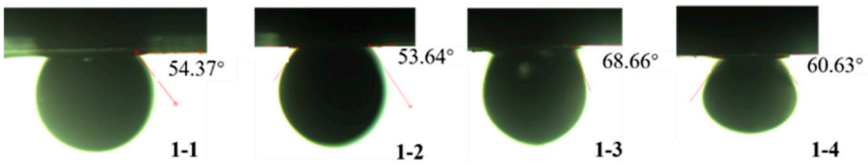


Figure 4. The contact angles after ODA flooding increased slightly, demonstrating that the water-wetness weakened and shifted closer to a neutral condition.

3.3. Emulsifying Efficiency of ODAs

By adding a displacement agent to the crude oil, a relatively stable water-in-oil (W/O) emulsion droplet is formed, which reduces the binding force of the reservoir on the released oil droplets. In addition, emulsification makes large oil clusters break into smaller droplets, reducing their adhesion to pore surfaces and lowering local capillary resistance. As a result, oil droplets become more mobile and can be more easily displaced by the injected fluid, thus improving oil recovery [35,36]. The changing process of the emulsified mixture is shown in Figure 5. The two mixed liquids, from top to bottom, include the pure oil phase (black), high oil-content phase (dark brown), and low oil-content phase (light brown), with the color gradually becoming lighter from top to bottom. The volume of emulsified crude oil can be determined by subtracting the amount of pure oil phase from the initial amount of crude oil added.

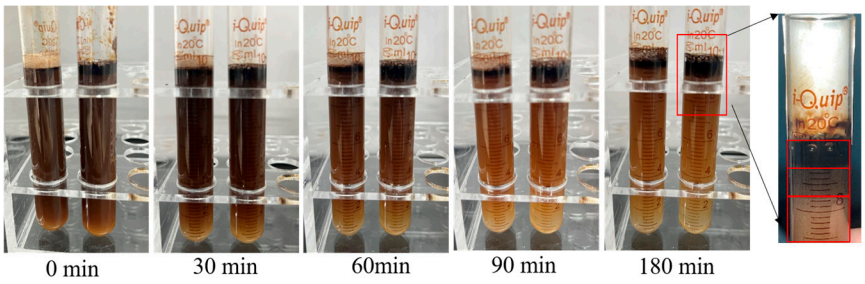


Figure 5. Emulsifying processes of Nano ODA (**left**) and KPS ODA (**right**).

The non-emulsified oil gradually rises to the top of the mixture due to buoyancy. After approximately 60 min, the separation process nearly ceases, and the volume of emulsified oil stabilizes. It is found that as the concentration of the displacement agent increases, the emulsification efficiency improves significantly (Figure 6). The emulsification efficiency for different concentrations and types of displacement agents is shown in Table 2. At the same concentration, the Nano ODA exhibits higher emulsification efficiency than the KPS ODA. The potential mechanism behind this phenomenon is that the Nano ODA produces finer droplets and denser surfactant coverage, improving emulsification performance beyond what petroleum sulfonate alone can achieve [37].

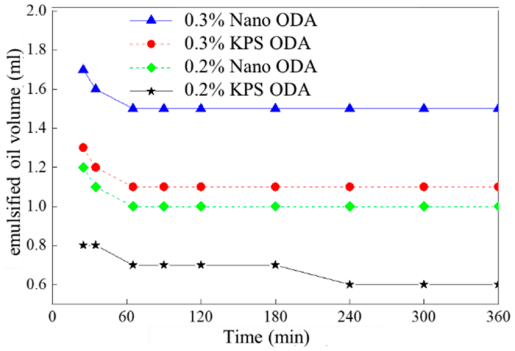


Figure 6. Variation in emulsified oil volume with time: as the concentration of the displacement agent increases, the emulsification efficiency improves significantly, and the Nano ODA exhibits higher emulsification efficiency than the KPS ODA.

Table 2. Emulsifying efficiency of ODAs of different concentrations.

Number	1	2	3	4
ODA type	Nano ODA	Nano ODA	KPS ODA	KPS ODA
Concentration	0.2%	0.3%	0.2%	0.3%
Emulsifying efficiency	53.0%	68%	32%	57%

3.4. Effect of ODAs on Oil–Water Relative Permeability

The relative permeability results are shown in Table 3 and Figure 7. A comparison reveals that the oil-phase relative permeability of the cores displaced by the ODAs increased, and the residual oil saturation was lower. Furthermore, the Nano ODA was more effective than the KPS ODA. This is because the smaller particle size of the nanoemulsion allows it to enter smaller pores, thereby displacing more crude oil from the narrow pore spaces. Meanwhile, the Nano ODA exhibits enhanced emulsification performance and generates stable, fine droplets, as confirmed by the emulsion tests. These droplets improve oil mobilization and contribute to increased oil-phase relative permeability. Additionally, the ODAs alter the rock surface wettability toward more neutral or oil-wet conditions, facilitating oil-phase flow. By reducing IFT and capillary forces, ODAs enable more efficient oil displacement and lower residual oil saturation. Therefore, the observed improvement in oil-phase relative permeability is attributed to the combined effects of emulsification, wettability alteration, and IFT reduction. This experimental result is also supported by other researchers' findings [38,39].

Table 3. Results of the relative permeability test.

Injected Fluid (Core Number)	Oil Relative Permeability Under Water Saturation of 0.5	Residual Oil Saturation (%)
Water (2#)	0.222	0.378
0.2% Nano ODA (3#)	0.369	0.325
0.2% KPS ODA (4#)	0.285	0.346

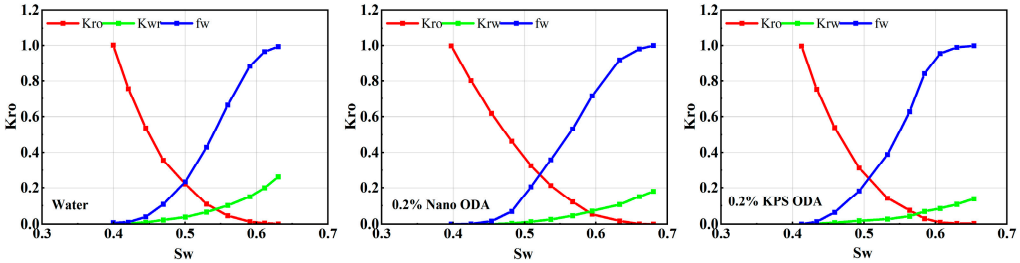


Figure 7. Relative permeability curve under different flooding fluids: the oil-phase permeability increased when ODA solution was used for displacement.

3.5. Effect of ODAs on Imbibition

In water-wet reservoirs, capillary forces are the main driving force for spontaneous imbibition. The surfactants in the ODA can influence both the oil–water IFT and the rock wettability, so it is essential to clarify the effect of the ODA on imbibition and displacement efficiency and subsequently determine its impact on the oil recovery mechanism of the target reservoir. Table 4 shows that the imbibition effect of formation water is better than that of the ODA, with a higher imbibition displacement efficiency of 27%, while the displacement efficiency of the ODA is less than 25%. Upon further comparison, the imbibition effect of the Nano ODA is weaker than that of the KPS ODA, with both Nano ODA and KPS ODA having a negative effect on imbibition displacement. A comprehensive analysis suggests that while the ODA can improve the mobility of crude oil in the pore spaces by emulsifying and lowering IFT, it also causes the originally water-wet rock to transition towards a neutral-wet state, and the reduction in IFT weakens the capillary forces driving imbibition. Overall, for water-wet reservoirs, the displacement agent has a certain negative effect on imbibition displacement, which contrasts with its positive effect in oil-wet reservoirs [40,41].

Table 4. Imbibition test results.

Core Number	Fluid Type	Core Mass (g)	Saturated Oil Mass (g)	Core Mass After Imbibition (g)	Imbibition Efficiency (%)
5#	Water + 0.2% Nano ODA	49.61	2.37	51.34 (4 d) 51.31 (5 d–8 d)	26.98 28.00
6#	0.2% Nano ODA	48.77	2.68	50.79 (8 d)	24.55
7#	Water + 0.2% KPS ODA	49.22	2.25	50.83 (4 d) 50.82 (5 d–8 d)	28.01 28.91
8#	0.2% KPS ODA	48.15	2.07	49.68 (8 d)	25.96

3.6. Effect of ODAs on Oil Recovery

To simulate the enhanced oil recovery effect of the ODA, core flooding experiments were conducted using formation water, Nano ODA, and KPS ODA. Various concentrations of the ODAs were tested to determine the optimal ODA concentration. Results (Figure 8) show that both Nano ODA and KPS ODA significantly improved the oil recovery, exceeding 60%, with lower residual oil saturation. The oil recovery increased with the ODA concentration, but the improvement slowed when the concentration exceeded 0.2%. Compared to KPS ODA, Nano ODA showed a stronger ability to enhance oil recovery. Based on the previous test results, the optimal ODA for the Baikouquan Oilfield Kexia Formation, is the Nano ODA with a concentration of 0.2%.

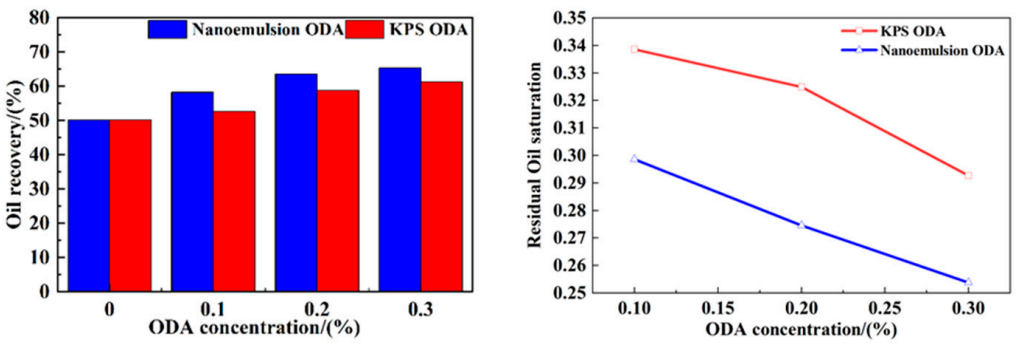


Figure 8. Oil recovery (**left**) and residual oil saturation (**right**) achieved by Nano ODA and KPS ODA flooding: both Nano ODA and KPS ODA can increase oil recovery and reduce residual oil saturation, but the effect of Nano ODA is superior.

4. Optimization of Huff-and-Puff Flooding Parameters

4.1. Model Setup

In the optimization of huff-and-puff flooding parameters, well 1090 in the Baikouquan Oilfield is selected as the target well. A geological model is established (1320 m × 750 m) based on the average reservoir physical properties of the Baikouquan Oilfield Kexia Formation, and numerical simulations are conducted using the CMG software (Version 2021). The reservoir pressure is set at 20.77 MPa, with a thickness of 19.7 m. The porosity ranges from 8% to 14%, with an average of 11.40%, and the permeability mainly ranges from 4 mD to 7 mD, with an average of 5.32 mD. The oil saturation ranges from 26.3% to 38.9%, with an average of 35.2%. The fracture length is 220 m, the fracture width is 0.01 m, and the fracture conductivity is 50.6 mD·m. In the simulation, relative permeability data for 0.2% Nano ODA is used as input, with an injection rate of 2 m^3/min.

4.2. Simulation Results

4.2.1. Injection Volume

The huff-and-puff flooding process replenishes reservoir energy and restores formation pressure, with injection volume directly influencing both. A higher injection volume increases reservoir pressure but also extends injection time under a constant injection rate. As injection volume rises, more water is retained in the reservoir, leading to higher water cut in the produced fluids and thus reducing oil production efficiency. To determine the optimal injection volume, simulations were conducted for 2000 m^3, 3000 m^3, 4000 m^3, 5000 m^3, and 6000 m^3 with a shut-in time of 20 days. The results (Figure 9) show that while both cumulative and daily oil production initially increase with injection volume, the incremental gains diminish significantly at higher volumes. A distinct plateau is observed around 4000 m^3, indicating this as the optimal injection volume.

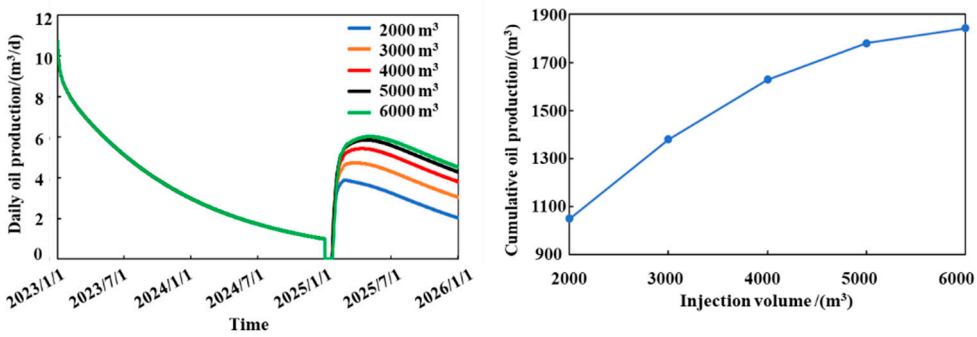


Figure 9. Daily production rate curves (**left**) and the cumulative production curve (**right**) under different injection volumes: both cumulative and daily oil production initially increase with injection volume; the incremental gains diminish significantly at higher volumes.

This trend is consistent with the concept of diminishing marginal returns, where each additional unit of injected fluid yields less additional oil due to reduced displacement efficiency and increasing water production. As Zhang et al. point out, beyond a certain injection threshold, further volume fails to proportionally increase the sweep area or oil mobility and instead leads to premature water breakthrough and inefficient use of injection energy [42,43]. Therefore, excessive injection not only offers limited production benefits but may also adversely affect economic and operational efficiency. Optimizing injection volume is thus essential to maximize recovery while minimizing unnecessary water handling and operational costs.

4.2.2. Shut-In Period

Well shut-in leverages the hydrophilicity of the reservoir, enhancing imbibition and oil displacement, redistributing oil–water saturation, and restoring pressure to facilitate oil recovery. The shut-in period significantly impacts the huff-and-puff flooding efficiency and ultimate oil recovery. To determine the optimal shut-in period, simulations were conducted with shut-in periods of 5, 10, 15, 20, 25, and 30 days under an injection volume of 4000 m^3. The results (Figure 10) show that both cumulative and daily oil production increase with shut-in time, exhibiting a roughly positive correlation. However, the growth rate slows after 15 days, with a clear plateau, indicating that the optimal shut-in time is around 15–20 days.

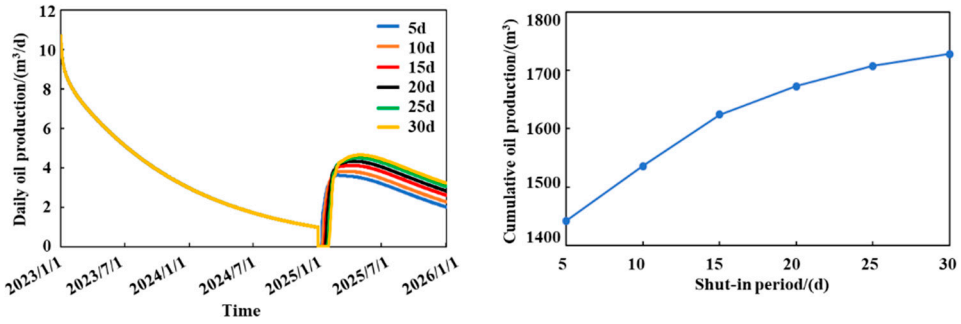


Figure 10. Daily production rate curves (**left**) and the cumulative production curve (**right**) under different shut-in periods: both cumulative and daily oil production increase with shut-in time, exhibiting a roughly positive correlation.

4.2.3. Huff-and-Puff Flooding Cycle

In the huff-and-puff flooding oil recovery process, the oil production increment from a single huff-and-puff flooding cycle is limited, necessitating multiple huff-and-puff flooding rounds. To evaluate the impact of huff-and-puff flooding cycles on oil recovery, simulations were conducted with an injection volume of 4000 m^3, shut-in period of 15 days, and a single cycle duration of 20 months. The oil production per cycle and cumulative oil production for three huff-and-puff flooding cycles were calculated. As shown in Figure 11, multiple huff-and-puff flooding cycles increase cumulative oil production. However, with each additional cycle, the oil increment per cycle decreases, primarily due to the reduction in oil saturation and diminishing effectiveness of each successive cycle.

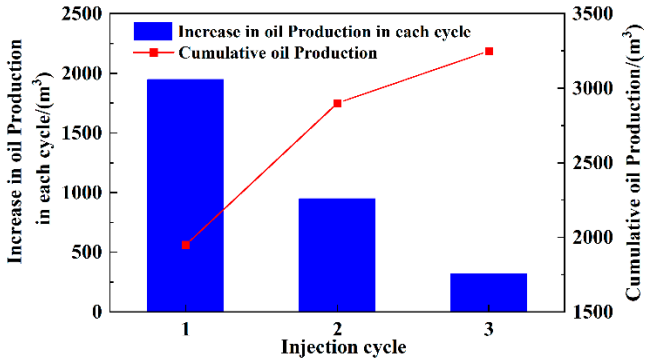


Figure 11. Increase in oil production in each huff-and-puff flooding cycle and cumulative oil production: the cumulative oil production increases with the number of huff-and-puff cycles, but the oil production per individual cycle shows a decreasing trend.

5. Discussions

While our study provides optimized injection volumes and shut-in periods for Nano ODA in the Kexia Formation, it is important to acknowledge several practical limitations

for field implementation. Long-term injectivity may be affected by formation heterogeneity, pore-throat clogging, or potential adsorption of the nanoemulsion on rock surfaces. Chemical loss through adsorption or emulsification breakdown could reduce effective concentration in the reservoir. Moreover, operational challenges such as maintaining stable injection rates and handling large volumes of chemical agents must be considered. Environmental aspects, including potential toxicity, disposal of produced fluids, and regulatory compliance, also need to be addressed in large-scale applications. Future work should incorporate pilot-scale field tests and environmental risk assessments to ensure safe and effective deployment of Nano ODA.

6. Conclusions

This study investigated the huff-and-puff flooding mechanism in the Baikouquan Oilfield Kexia Formation through laboratory experiments and numerical simulations. Results show that in this water-wet, low-porosity lithic sandstone, ODAs enhance recovery via a synergistic mechanism of reservoir energy replenishment, significant IFT reduction (up to 97% for the nanoemulsion-based ODA), and strong emulsification (up to 75% efficiency) that mobilizes residual oil clusters and shifts relative permeability. Unlike most previous studies that attribute recovery mainly to wettability alteration and spontaneous imbibition, our findings reveal that in strongly water-wet formations, emulsification and IFT reduction dominate, with the nanoemulsion providing a particularly effective oil mobilization mechanism in nanoscale pores. Numerical simulations further indicate that 4000 m^3 injection with a 15–20 day shut-in is the optimal design for well 1090. Overall, this work not only provides a reservoir-specific flooding strategy for the Kexia Formation but also highlights a distinct recovery mechanism where nanoemulsion-driven emulsification plays the dominant role, advancing the understanding of surfactant–nanoparticle-assisted EOR in unconventional reservoirs.

Author Contributions: Conceptualization, J.M. and H.T.; methodology, J.M. and K.X.; software, H.L.; validation, B.G.; formal analysis, X.Y. and H.T.; investigation, H.L. and K.X.; writing—original draft preparation, H.L. and B.G.; writing—review and editing, J.M. and H.T. All authors have read and agreed to the published version of the manuscript.

Funding: This research received no external funding.

Data Availability Statement: The original contributions presented in this study are included in the article. Further inquiries can be directed to the corresponding author.

Conflicts of Interest: Hui Tian, Kunlin Xue and Xingyu Yi were employed by the PetroChina. The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

References

1. Sun, W.; Zhi, H.; Li, J. Analysis of water flooding mechanism and development effect after water breakthrough in Ansete low permeability oilfield. *Exp. Petr. Geol.* **1999**, *3*, 256–260.
2. Thomas, A.; Kumar, A.; Rodrigues, K.; Sinclair, R.; Lackie, C.; Galipeault, A.; Blair, M. Understanding water flood response in tight oil formations: A case study of the lower Shaunavon. In Proceedings of the SPE/CSUR Unconventional Resources Conference, Calgary, AB, Canada, 30 September–2 October 2014; SPE-171671-MS. [CrossRef]
3. Wang, T. Influencing factors and analysis of carbon dioxide flooding effect. *China Petrol. Chem. Ind.* **2008**, *24*, 30–33.
4. Shang, Q. Sensitivity analysis of CO_2 flooding oil well productivity and influencing factors. *Petr. Dril. Tech.* **2011**, *39*, 83–88.
5. Wang, H.; Chen, Z.; Zhang, L. Discussion on injection huff and puff development model of water-wet sandstone reservoir. *Petrol. Explor. Dev.* **2004**, *5*, 86–88.
6. Li, G.; Zhang, S. Study on capillary imbibition effect of low permeability sandstone simulated by quartz glass. *J. Chongqing Univ. Sci. Technol. (Nat. Sci.)* **2010**, *12*, 1–3+7.

7. Sheng, J. What type of surfactants should be used to enhance spontaneous imbibition in shale and tight reservoirs? *J. Petrol. Sci. Eng.* **2017**, *159*, 635–643. [CrossRef]
8. Standnes, D.; Austad, T. Wettability alteration in chalk: Mechanism for wettability alteration from oil-wet to water-wet using surfactants. *J. Petrol. Sci. Eng.* **2000**, *28*, 123–143. [CrossRef]
9. Salehi, M.; Johnson, S.; Liang, J. Mechanistic study of wettability alteration using surfactants with applications in naturally fractured reservoirs. *Langmuir* **2008**, *24*, 14099–14107. [CrossRef] [PubMed]
10. Huang, D.; Xiang, D. Study on the mechanism of injection huff and puff oil recovery. *Petrol. Geol. Rec. Effi.* **2004**, *5*, 39–40+43.
11. Hendraningrat, L.; Torsæter, O. A study of water chemistry extends the benefits of using silica-based nanoparticles on enhanced oil recovery. *Appl. Nanosci.* **2016**, *6*, 83–95. [CrossRef]
12. Foster, W. A low-tension waterflooding process. *J. Petrol. Technol.* **1973**, *25*, 205–210. [CrossRef]
13. Youssif, M.; El-Maghraby, R.; Saleh, S.; Elgibaly, A. Silica nanofluid flooding for enhanced oil recovery in sandstone rocks. *Egypt J. Pet.* **2018**, *27*, 105–110. [CrossRef]
14. Wellington, S.; Richardson, E. Low surfactant concentration enhanced waterflooding. *SPE J.* **1997**, *2*, 389–405. [CrossRef]
15. Gao, T. Injection huff mechanism and application of tight reservoir in Yanchang Oilfield. *Spec. Oil Gas Res.* **2018**, *25*, 134–137.
16. Liu, L. Numerical Simulation of Imbibition Production in Fractured Reservoirs. Master's Thesis, Southwest Petroleum University, Chengdu, China, 2006.
17. Kaul, S.; Putra, E.; Schechter, D. Simulation of spontaneous imbibition using Rayleigh-Ritz finite element method—A discrete fracture approach. In Proceedings of the Canadian International Petroleum Conference, Calgary, AB, Canada, 8–10 June 2004; PETSOC-2004-228.
18. Nguyen, V. A dynamic network model for imbibition. In Proceedings of the SPE Annual Technical Conference and Exhibition, Houston, TX, USA, 26 September 2004; SPE-90365-MS. [CrossRef]
19. Zhu, Y. Study on Oil Recovery by Nano-Active Water Huff and Puff After Fracturing in Tight Reservoirs. Master's Thesis, China University of Petroleum, Beijing, China, 2022.
20. *SY/T 5370-2018*; Test Method for Surface Tension and Interfacial Tension. China Petroleum Industry Publishing House: Beijing, China, 2019.
21. *SY/T 5153-2017*; Test Method of Reservoir Rock Wettability. China Petroleum Industry Publishing House: Beijing, China, 2017.
22. *Q/SY17583-2018*; Technical Specification for Surfactants Used in Binary Composite Flooding. China Petroleum Industry Publishing House: Beijing, China, 2018.
23. *GB/T 28912-2012*; Test Method for Two Phase Relative Permeability in Rock. China Standards Press: Beijing, China, 2012.
24. Green, D.W.; Willhite, G.P. *Enhanced Oil Recovery*; Society of Petroleum Engineers: Richardson, TX, USA, 2018. [CrossRef]
25. Bui, T.; Frampton, H.; Huang, S.; Collins, I.; Striolo, A.; Michaelides, A. Water/oil interfacial tension reduction—An interfacial entropy driven process. *Phys. Chem. Chem. Phys.* **2021**, *44*, 25075–25085. [CrossRef] [PubMed]
26. Najimi, S.; Nowrouzi, I.; Khaksar, A.; Mohammadi, A. Experimental study of the performances of commercial surfactants in reducing interfacial tension and wettability alteration in the process of chemical water injection into carbonate reservoirs. *J. Pet. Explor. Prod. Technol.* **2020**, *10*, 1551–1563. [CrossRef]
27. Liang, T.; Hou, J.; Qu, M.; Xi, J.; Raj, I. Application of nanomaterial for enhanced oil recovery. *Petrol. Sci.* **2022**, *19*, 882–899. [CrossRef]
28. Rosen, M.; Kunjappu, J. *Surfactants and Interfacial Phenomena*, 4th ed.; Wiley: Hoboken, NJ, USA, 2012.
29. Dang, H.; Wang, X.; Duan, W. Research on imbibition displacement of fractured low permeability reservoir in Ordos Basin. *Fault Block Oil Gas Field* **2017**, *24*, 687–690.
30. Li, Y.; Li, M.; Xu, H.; Yang, F.; Yan, M.; Tao, T. Surfactant flooding technology in ultra-low permeability reservoir. *Liaoning Chem. Ind.* **2020**, *49*, 804–806.
31. Zhang, J.; Wang, M.; Wu, J. Study on synthesis and pressure flooding technology of a new nano imbibition agent. *Appl. Chem. Ind.* **2021**, *50*, 1239–1244.
32. Liu, C.; Wang, Y.; Yu, H. Laboratory study on surfactant flooding system in low permeability reservoir. *Oil Gas Chem. Ind.* **2011**, *40*, 486–489.
33. Cui, Z. Research on the Influence of Wettability of Low Permeability Reservoir on oil Recovery. Master's Thesis, Daqing Petrol. Inst., Daqing, China, 2009.
34. Phukan, R.; Saha, R.; Mazumdar, P. Adsorption behavior of surfactants on sandstone reservoir rocks with carbonate cements and its influence on wettability alteration. *J. Surfactants Deterg.* **2024**, *27*, 392–408. [CrossRef]
35. Li, N.; Wang, H.; Li, J. Research status and development trend of surfactants for oil displacement. *Guangdong Chem. Ind.* **2012**, *39*, 98–99+127.
36. Ratanpara, A.; Kim, M. Wettability alteration mechanisms in enhanced oil recovery with surfactants and nanofluids: A review with microfluidic applications. *Energies* **2023**, *16*, 8003. [CrossRef]

37. Malode, G.; Ande, S.; Chavhan, S.; Bartare, S.; Malode, L.; Manwar, J.; Bakal, R. A critical review on nanoemulsion: Advantages, techniques and characterization. *World J. Adv. Res. Rev.* **2021**, *11*, 462–473. [CrossRef]
38. Jalilian, M.; Tabzar, A.; Ghasemi, V.; Mohammadzadeh, O.; Pourafshary, P.; Rezaei, N.; Zendehboudi, S. An experimental investigation of nanoemulsion enhanced oil recovery: Use of unconsolidated porous systems. *Fuel* **2019**, *251*, 754–762. [CrossRef]
39. Xu, H.; Li, Y.; Wu, H.; Ding, Z.; Yuan, S.; Bai, H.; Yao, E.; Zhou, F. Development and performance evaluation of nonionic surfactant-stabilized nanoemulsion for enhanced oil recovery applications in tight reservoir. *Phys. Fluids* **2024**, *36*, 032015. [CrossRef]
40. Ding, X.; Zhou, D.; Wu, K.; Li, S.; He, Y.; Yu, B.; Chen, L. Performance evaluation and application of nanoemulsion imbibition oil-displacing agent. *Oilfield Chem.* **2022**, *39*, 651–657.
41. Morrow, N.R.; Mason, G. Recovery of oil by spontaneous imbibition. *Curr. Opin. Colloid Interface Sci.* **2001**, *6*, 321–337. [CrossRef]
42. Zhang, L.; Wang, J.; Liu, H. Optimization of cyclic water injection parameters in low-permeability reservoirs: Understanding the marginal returns of injection volume. *J. Pet. Sci. Eng.* **2021**, *198*, 108209.
43. Kukharova, T.; Maltsev, P.; Novozhilov, I. Development of a control system for pressure distribution during gas production in a structurally complex field. *Appl. Syst. Innov.* **2025**, *8*, 51. [CrossRef]

Disclaimer/Publisher's Note: The statements, opinions and data contained in all publications are solely those of the individual author(s) and contributor(s) and not of MDPI and/or the editor(s). MDPI and/or the editor(s) disclaim responsibility for any injury to people or property resulting from any ideas, methods, instructions or products referred to in the content.