

Article

NMR Insights into Imbibition Flow During Shut-In Soaking in Fractured Tight Oil Reservoirs

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Abstract

Spontaneous imbibition plays a critical role in enhancing oil recovery. It also helps optimize fracturing fluid design in tight oil reservoirs. Conventional evaluation methods mainly rely on nuclear magnetic resonance (NMR) experiments on intact core samples. These methods can adequately characterize matrix imbibition behavior. However, they generally neglect the presence of artificial fractures. This limits their applicability for guiding hydraulic fracturing optimization in field development. To address this gap, this study introduces artificial fractures into tight sandstone cores from the Sichuan Basin. It integrates scanning electron microscopy (SEM) with online NMR technology. The imbibition performance of an oil-displacement slickwater system was systematically evaluated. The evaluation considered varying agent concentrations, injection rates, and initial oil saturation conditions. The results demonstrate that using a high-concentration oil-displacement fracturing fluid significantly enhances imbibition efficiency. For example, slickwater containing 0.3% oil-displacement agent increased oil recovery by 12.9%. This was compared with slickwater containing 0.1% agent. The high-concentration fluid also substantially improved oil mobilization from small pores. Furthermore, increasing the injection rate proved particularly beneficial for oil recovery across the micropore to mesopore range. The most pronounced improvement was observed in the micropore range. Initial oil saturation serves as another primary controlling factor for imbibition efficiency. As oil saturation increases, imbibition efficiency improves markedly. The optimized slickwater system developed in this study has been successfully applied in Well NC002. It achieved a tested oil production rate of 32 tonnes per day. This field application validates the effectiveness of the proposed approach. It also provides practical technical support for the efficient development of tight oil resources in the Sichuan Basin.

Keywords: tight oil; spontaneous imbibition; horizontal wells; fracturing; NMR



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1. Introduction

Tight oil is a strategic pillar of China's energy security [1–5]. Major accumulations exist in the Bohai Bay, Songliao, and Sichuan Basins. Production from these reservoirs relies on horizontal drilling and multi-stage fracturing [5–8]. Post-stimulation, a shut-in period (“soaking”) promotes spontaneous imbibition to mobilize matrix oil into fractures [9,10]. However, the dynamics of saturation redistribution, capillary-driven front propagation, and pressure–imbibition coupling remain poorly quantified. Rigorous experimental investigation of soaking imbibition is thus essential for rational shut-in design and post-fracturing startup in tight oil reservoirs.

The shut-in period following fracturing is increasingly recognized as a pivotal stage governing the initial productivity of tight oil wells. During shut-in, the retained fracturing fluid spontaneously imbibes into the matrix pores under capillary forces, displacing oil while simultaneously supplementing reservoir energy. This dual effect of “imbibition displacement and energy replenishment” renders the shut-in procedure an indispensable component of the integrated fracturing–production workflow. Nevertheless, the underlying micro-scale mechanisms governing imbibition flow during shut-in are remarkably complex, involving dynamic oil–water distribution and migration across multi-scale pores, coupled interactions between different imbibition modes, and the coupled influence of wettability, interfacial tension, and pore geometry. Elucidating these mechanisms to rationally evaluate shut-in effectiveness, optimize shut-in duration, and quantify oil mobilization from pores of varying sizes constitutes a critical scientific challenge for tight oil development.

Pioneering research on imbibition dates back to 1962, when Mattax and Kyte [11] introduced a dimensionless time-scaling model for spontaneous imbibition in fractured reservoirs, establishing the theoretical foundation for imbibition dynamics. Over subsequent decades, extensive investigations have advanced the understanding of imbibition mechanisms. Standnes [12] systematically examined the impact of boundary conditions on oil recovery by co-current and counter-current spontaneous imbibition, demonstrating the controlling role of face accessibility. Mason et al. [13] developed a theoretical model for counter-current spontaneous imbibition in cores with all faces open, providing a quantitative framework for describing imbibition kinetics. Traditional experimental methods, such as gravimetric and volumetric measurements, while capable of providing macroscopic imbibition recovery data, fall short of revealing pore-scale fluid distribution and migration characteristics. The advent of nuclear magnetic resonance (NMR) technology has revolutionized imbibition research by enabling non-destructive, quantitative characterization of fluid content variations within pores of different sizes through T_2 spectra, thereby visualizing pore-scale oil mobilization during imbibition. Cheng et al. [14] integrated NMR T_2 spectra with high-pressure mercury intrusion data to characterize oil distribution across pores of varying diameters during imbibition, revealing the influence of pore structure anisotropy. Xu et al. [15] further investigated forced imbibition in tight sandstones using low-field NMR, establishing correlations between pore-throat parameters and imbibition oil recovery. Wang et al. [16] comprehensively reviewed NMR applications in shale oil reservoir characterization and CO_2 -enhanced recovery, encompassing one-dimensional T_2 spectra, two-dimensional T_1 – T_2 mapping, magnetic resonance imaging (MRI), and depth-resolved T_2 techniques, highlighting the unique advantages of multi-dimensional NMR for fluid typing and occurrence state identification—yet systematic experimental investigations integrating these techniques for shut-in imbibition characterization remain limited.

Although previous studies have significantly advanced the understanding of imbibition mechanisms, most existing work has focused on static spontaneous imbibition or single-phase dynamic displacement processes. Research on the dynamic seepage behavior during the shut-in period following hydraulic fracturing—particularly within

fracture–matrix coupled systems under realistic reservoir temperature and pressure conditions—remains scarce and lacks systematic experimental investigation. To address this gap, this study conducts integrated displacement–shut-in physical simulations using artificially fractured tight oil cores from the Shaximiao Formation in the Sichuan Basin. The cores were prepared with a single fracture to replicate fracture–matrix coupling, and experiments were performed under simulated in situ reservoir conditions. By incorporating real-time nuclear magnetic resonance (NMR) monitoring, we quantitatively evaluated the effects of key operational parameters—including surfactant concentration, injection rate, and initial oil saturation—on imbibition oil recovery. The findings were successfully applied in Well NC002, where the optimized shut-in imbibition strategy substantially enhanced post-fracturing production performance, thereby validating the engineering viability of this approach for tight oil reservoir development.

2. Introduction of Tight Oil Reservoir

The Jurassic succession in the central Sichuan Basin comprises a continental lacustrine–deltaic depositional system, which is subdivided, in ascending order, into the Zhenzhuchong, Dongyuemiao, Da’anzhai, Lianggaoshan, and Shaximiao formations. Among these, the Da’anzhai Member, Lianggaoshan Formation, and the first member of the Shaximiao Formation (Sha-1) represent the principal oil-bearing intervals in the region.

The Lianggaoshan Formation is further divided into the Liang-1, Liang-2, and Liang-3 members, whereas the Shaximiao Formation is subdivided into the Sha-1 and Sha-2 members. The reservoir lithology of the Lianggaoshan Formation primarily consists of siltstone to fine-grained sandstone, with quartz being the dominant mineral component, followed by feldspar.

Vertically, the Liang-2 Member exhibits a relatively stable sandstone unit with single-layer thicknesses ranging from 5 to 8 m. The high-quality reservoir intervals in this member display porosity of 5–8%, oil saturation of 60–70%, and movable oil saturation of 25–35%, characterizing a fracture-pore reservoir system. In contrast, the Liang-3 Member is dominated by sheet-like sandstones with thicknesses of 2–5 m, porosity of 3–6%, and oil saturation of 40–50%, representing a pore-fracture type reservoir. Sensitivity analysis indicates that the Lianggaoshan Formation reservoirs exhibit moderately strong water sensitivity and weak alkali sensitivity.

Currently, confirmed oil-bearing layers are mainly concentrated in the basal sheet sandstones of the Sha-1 Member and the No. 1, 2, and 3 subaqueous distributary channel sandstones in its middle–upper sections. The basal sheet sandstones of the Sha-1 Member were deposited in a shore-shallow lacustrine environment and share reservoir characteristics similar to those of the Liang-3 Member. The channel sandstones, however, are characterized by greater single-layer thickness (10–50 m) and superior physical properties, with porosity of 5–10% and permeability of 0.3–1.0 mD. Geomechanical analysis of the Sha-1 Member reservoir indicates a uniaxial compressive strength of 329.45 MPa, a Young’s modulus of 29.6 GPa, and a Poisson’s ratio of 0.187. The in situ stress field is characterized by a maximum horizontal principal stress of 53.0 MPa, a minimum horizontal principal stress of 43.6 MPa, and a vertical stress of 50.4 MPa, resulting in a horizontal stress difference of approximately 9.4 MPa. Sensitivity evaluation experiments further reveal that the reservoir exhibits weak water sensitivity and strong stress sensitivity.

3. Experimental Apparatus and Methods

The experiments were performed using a custom-built online NMR imbibition monitoring system (Southwest Petroleum University in Chengdu, Chengdu, China). The apparatus integrates an NMR spectrometer, a constant-temperature and constant-pressure

circulation unit, a fluid imbibition simulation module, and a specialized core holder. Precise pressure control was achieved using auxiliary components, including back-pressure pumps, confining pressure pumps, and a constant-rate/constant-pressure displacement pump. The system is capable of operating at temperatures up to 110 °C and pressures up to 50 MPa. The NMR instrument operates at a magnetic field strength of 0.3 T with a resonant frequency of 12 MHz, providing a spatial resolution of 0.01 mm and a magnetic field homogeneity of greater than 50 ppm.

To ensure the reliability of the measurements, calibration of the NMR instrument in terms of frequency and magnetic field homogeneity was performed prior to experiments using a standard oil sample. Repeatability was validated by three independent measurements of the T_2 distributions on the same core plug. The relative standard deviation (RSD) of the peak relaxation times was less than 2%. The NMR acquisition parameters were set as follows: a CPMG spin-echo sequence with an echo spacing τ of 0.2 ms, 64 scans, a repetition delay of 3 s, and 2048 echoes. These parameters provide a sufficient signal-to-noise ratio and complete acquisition of relaxation information.

The core samples used in this experiment were extracted from Well NC002 in the Sichuan Basin. The cylindrical plugs measure 2.5 cm in diameter and 5.6 cm in length, with an average porosity of 5.3%. An artificial fracture was created along the core axis using a wire-cutting technique, extending over 70% of the total core length. Figure 1 illustrates the core samples before and after the notching process.



Figure 1. Photograph of the core sample from Well NC002. (a) The core sample from Well NC002, (b) The core from Well NC002 with an artificial fracture.

The slickwater system employed in the tests was provided by the Natural Gas Research Institute of Southwest Oil & Gasfield Company (Chengdu, China). The formulation consists of 0.1–0.3% oil-displacing agent, 0.3% drag reducer, and 0.1% demulsifier.

The experimental workflow was conducted as follows:

1. Sample selection and characterization: Core samples with similar porosity were selected. Their pore structure and size distribution were characterized using scanning electron microscopy (SEM) (Japan Electronics).
2. Initial state establishment: The cores were cleaned, dried, and scanned via NMR to obtain baseline T_2 spectra. They were then vacuum-saturated with crude oil to simulate initial reservoir fluid distribution.
3. Effect of oil-displacing agent concentration: Each core was placed in a core holder under the experimental conditions of 70 °C and 25 MPa, and injected with two pore volumes (PV) of slickwater at a displacement rate of 20 m³/min, simulating field fracturing operations. Two slickwater formulations with oil-displacing agent concentrations of 0.1% and 0.3% were tested separately. After injection, a 75 h shut-in period was simulated. Throughout the shut-in process, an online low-field NMR system was used to continuously monitor the evolution of T_2 spectra.
4. Effect of injection rate: Using the 0.3% oil-displacing agent slickwater formulation under the same conditions of 70 °C and 25 MPa, injection experiments were performed at rates of 16 m³/min and 20 m³/min, each with 2 PV injected volume. A 59 h shut-in

period followed each injection, during which T_2 spectra were acquired in real time via the online NMR system.

5. **Effect of Initial Oil Saturation:** Using the slickwater formulation containing 0.3% oil-displacing agent, displacement experiments were conducted on cores with varying initial oil saturations under identical conditions (70 °C and 25 MPa) and at the same injection rate. Each core was injected with 2 PV of slickwater, followed by a sufficient shut-in period. During shut-in, T_2 spectra were acquired in real time using the online NMR system to monitor imbibition dynamics. To investigate the effect of varying initial oil saturations on imbibition efficiency following slickwater treatment containing an oil-displacement agent, three core plugs with similar porosity and permeability were selected from the Shaximiao Formation in the Sichuan Basin. Prior to the experiment, the initial oil saturations of the three plugs were measured using nuclear magnetic resonance (NMR), yielding values of 69.2%, 32.5%, and 13.3%, respectively. Each core was then flooded with an equal volume of slickwater containing 0.3% oil-displacement agent, followed by a shut-in period of identical duration to simulate field soaking conditions. After shut-in, the imbibition efficiency for each core was determined using NMR measurements. This procedure allows for a comparative assessment of how initial oil saturation influences the effectiveness of surfactant-assisted imbibition under simulated reservoir conditions.

4. Results and Discussion

4.1. Effect of Slickwater Concentration on Oil Imbibition Efficiency

The concentration of the oil-displacement agent is a critical parameter governing imbibition efficiency [17–19]. An optimal concentration improves surfactant adsorption at oil–water–rock interfaces, effectively reducing capillary resistance and displacing oil films. Conversely, excessively high concentrations may induce micelle formation or adsorption saturation, diminishing interfacial activity, while overly low concentrations fail to sufficiently modify interfacial properties. Both scenarios can lead to suboptimal displacement performance.

Therefore, systematic investigation and optimization of surfactant concentration in slickwater are essential to synergize hydraulic fracturing with chemical displacement, thereby maximizing oil recovery within the stimulated reservoir volume.

Figure 2 presents the T_2 spectra obtained during the imbibition-soaking process following displacement with slickwater containing 0.3% oil-displacing agent. The spectra clearly exhibit a “stepwise mobilization” pattern, in which oil recovery progresses sequentially from small to large pores. Based on the established correspondence between relaxation time and pore structure—small pores ($T_2 < 10$ ms), mesopores ($T_2 = 10$ –100 ms), and large pores ($T_2 = 100$ –1000 ms)—the oil-mobilization behavior in pores of different scales can be further elucidated. The above T_2 thresholds have been calibrated specifically for the tested reservoir.

The NMR signal intensity from small pores ($T_2 < 10$ ms) continuously decreases with soaking time, indicating significant fluid exchange and changes in fluid occupancy within pores of this size range. This phenomenon is primarily attributed to the replacement of crude oil, which exhibits a higher hydrogen index, by the invading slickwater, resulting in a reduction in the detectable number of hydrogen nuclei per unit pore volume [20,21]. The sustained decline in signal intensity directly confirms that slickwater effectively penetrates the dense small-pore network and initiates the mobilization of crude oil.

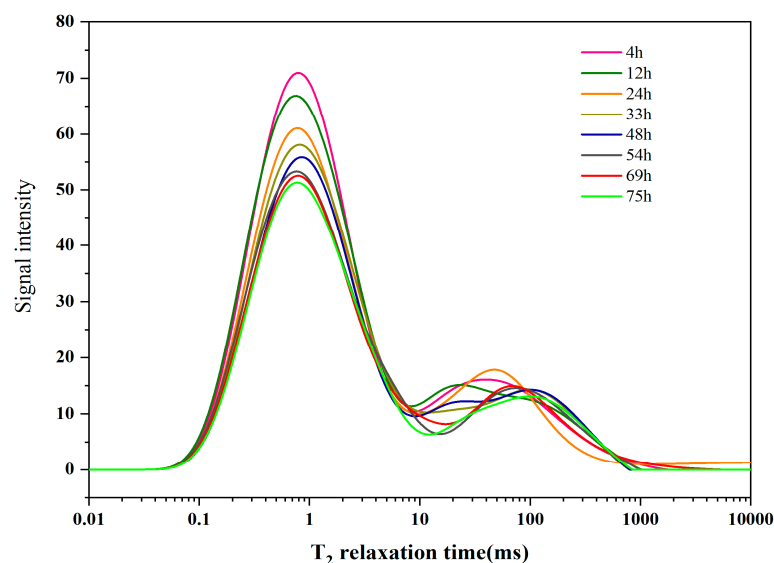


Figure 2. T_2 spectra at different soaking times.

For mesopores ($T_2 = 10\text{--}100\text{ ms}$) and macropores ($T_2 = 100\text{--}1000\text{ ms}$), the signal intensity generally shows a progressive weakening trend with prolonged soaking time. This clearly demonstrates that the imbibition front driven by slickwater has advanced from small pores into the meso- and macro-pore systems, continuously displacing movable oil therein. It is worth noting that the evolution of signal intensity within these pore ranges exhibits a certain degree of irregularity. Analysis in the context of the experimental design suggests that this is mainly due to the presence of artificial fractures, which disrupt the typical, orderly imbibition signal response pattern characteristic of homogeneous porous media.

Figure 3 illustrates the evolution of crude oil recovery factor as a function of soaking time. As the soaking process continues and the readily recoverable oil within fractures and the near-fracture zone is rapidly produced, the imbibition mechanism transitions to being dominated by microscopic fluid exchange within the matrix. Due to the ultralow permeability, high capillary entry pressure, and complex pore-throat structure typical of tight sandstone matrices, the driving force for imbibition weakens significantly. Concurrently, the effective diffusion distance increases and mass-transfer resistance rises sharply, leading to a marked slowdown in the oil recovery rate and its eventual approach to a dynamic equilibrium state.

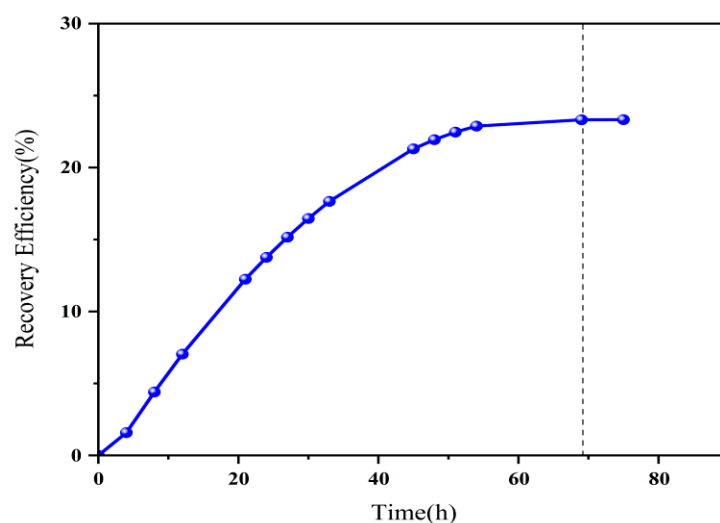


Figure 3. Relationship between oil recovery factor and soaking time.

The dynamic imbibition equilibrium time characterizes the behavior and migration of crude oil during imbibition between fractures and the matrix. Using online nuclear magnetic resonance technology, the real-time displacement process—encompassing oil expulsion from matrix pores, migration into fractures, and subsequent production—can be monitored continuously throughout the well-soaking period. This study defines the dynamic imbibition equilibrium time as the inflection point at which the incremental recovery factor per unit time stabilizes and reaches its minimum (i.e., the rate of recovery change ceases to decrease significantly). As illustrated in Figure 3, the oil recovery factor exhibits a characteristic nonlinear increase with prolonged shut-in time, marked by an initial rapid ascent followed by a pronounced deceleration in the incremental rate. In this study, the dynamic imbibition equilibrium time is defined as the critical inflection point at which the rate of recovery factor increment—i.e., the variation in recovery factor per unit time—approaches a stable value. This temporal threshold signifies the transition of the imbibition displacement process within the matrix–fracture system from a dynamically dominated regime to a quasi-steady-state stage. Based on curve analysis, this equilibrium time is approximately 69 h. Beyond this point, further soaking contributes only marginally to ultimate recovery, indicating that the imbibition displacement process has reached a dynamic equilibrium under the current fluid–rock interactions.

Following displacement with 0.3% slickwater and subsequent 69 h of soaking, imbibition equilibrium was reached, yielding an ultimate oil recovery of 24.3%. In terms of pore-scale contributions, the oil mobilization degree—defined as the percentage of recoverable oil within a specific pore-size range relative to its original oil content—was 19.01% in small pores ($T_2 < 10$ ms), 21.03% in mesopores ($T_2 = 10$ –100 ms), and highest in large pores ($T_2 = 100$ –1000 ms) at 22.93%. This distribution clearly demonstrates that during the imbibition-soaking process in the Sichuan Basin shale oil reservoirs, large pores constitute the dominant contributor to oil recovery, followed by mesopores, whereas oil within small pores remains the most challenging to mobilize effectively.

Three core plugs with comparable porosity and permeability were selected from Well NC002 to conduct oil displacement and imbibition experiments, comparing the performance of slickwater containing an oil-displacement agent at concentrations of 0.1%, 0.2%, and 0.3%. The data presented in Table 1 are single measurements obtained from three independent core plugs, each tested at one concentration. Owing to the limited availability of core plugs from Well NC002, replicate experiments could not be performed. As shown in Table 1, the oil recovery factor exhibited an overall increasing trend with the rising concentration of the oil-displacement agent in slickwater. Notably, at an agent concentration of 0.3%, the oil recovery reached 24.3%. Concurrently, the increase in agent concentration led to a marked improvement in oil mobilization from small pores ($T_2 < 10$ ms): the oil mobilization degree rose from 10.63% at 0.1% concentration to 19.01% at 0.3%. In contrast, although the mobilization degree in mesopores and large pores also increased with higher agent concentrations, the extent of improvement was comparatively limited.

The significant improvement in oil mobilization from small pores ($T_2 < 10$ ms) with increasing concentration of the displacement agent is primarily attributed to the dominant role of capillary forces within these pore systems. In shale reservoirs, oil displacement in small pores is largely controlled by high capillary pressure, which follows the Young–Laplace equation and is inversely proportional to the pore radius. Acting as a surfactant, the displacement agent effectively reduces the oil–water interfacial tension (IFT) [22]. When the concentration approaches or reaches the critical micelle concentration, the reduction in IFT becomes more pronounced, substantially lowering the capillary entry pressure required to mobilize the oil trapped in narrow pore throats. In contrast, although larger pores also

benefit from IFT reduction, their flow dynamics are less influenced by capillary forces; thus, the improvement resulting from increased agent concentration remains relatively limited.

Table 1. Oil recovery performance of slickwater at varying concentrations of the oil-displacement agent.

Core Number	Oil-Displacement Agent Concentration	Oil Mobilization Degree in Small Pores ($T_2 < 10$ ms)	Oil Mobilization Degree in Mesopores ($T_2 = 10\text{--}100$ ms)	Oil Mobilization Degree in Large Pores ($T_2 = 100\text{--}1000$ ms)	Overall Core Oil Recovery Factor
1	0.1%	10.63%	20.65%	21.62%	21.51%
2	0.2%	15.31%	21.03%	22.41%	22.32%
3	0.3%	19.01%	21.03%	22.93%	24.30%

4.2. Effect of Injection Rate on Oil Imbibition Efficiency

To evaluate the effect of fracturing fluid injection rate on imbibition efficiency, two core plugs with comparable petrophysical and lithological properties were selected for comparative experiments. The fracturing fluid used was slickwater incorporating an oil-displacement agent. The injection rates were designed to simulate field-scale fracturing operations, corresponding to $16\text{ m}^3/\text{min}$ and $20\text{ m}^3/\text{min}$, respectively.

Figures 4 and 5 present the evolution of NMR T_2 spectra with soaking time at slickwater injection rates of $16\text{ m}^3/\text{min}$ and $20\text{ m}^3/\text{min}$, respectively. As illustrated in both figures, regardless of the injection rate, the NMR signal intensity in small pores ($T_2 < 10$ ms) exhibits a continuous decline with prolonged soaking time. Similarly, the signal intensities in mesopores ($T_2 = 10\text{--}100$ ms) and macropores ($T_2 = 100\text{--}1000$ ms) generally show a progressive weakening trend as soaking time increases. This systematic signal attenuation across all pore scales clearly demonstrates the sequential nature of the imbibition process, wherein oil displacement initiates in small pores and progressively propagates into mesopores and macropores over time.

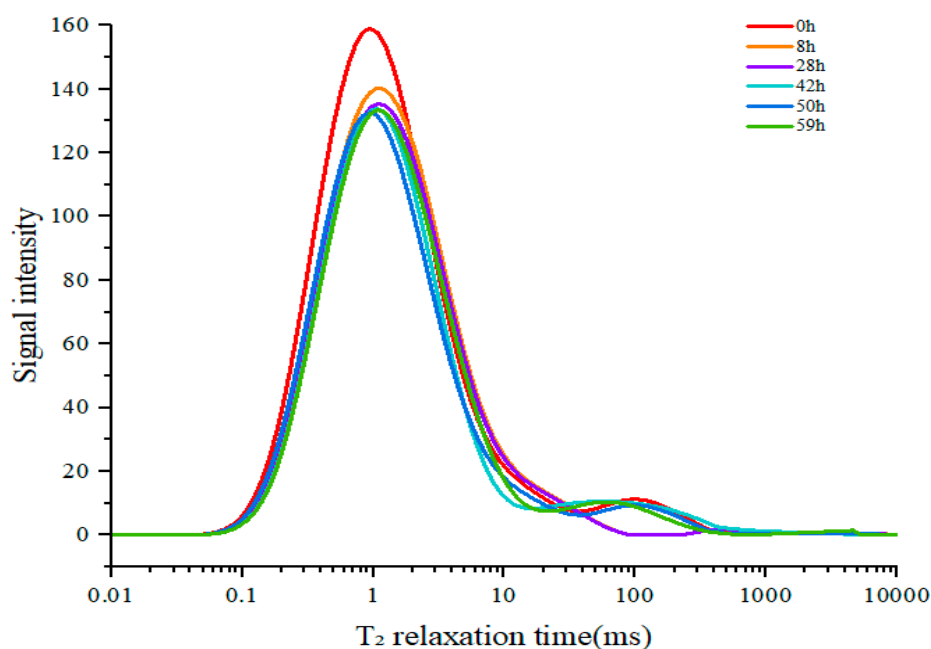


Figure 4. T_2 spectra at different soaking times under an injection rate of $16\text{ m}^3/\text{min}$.

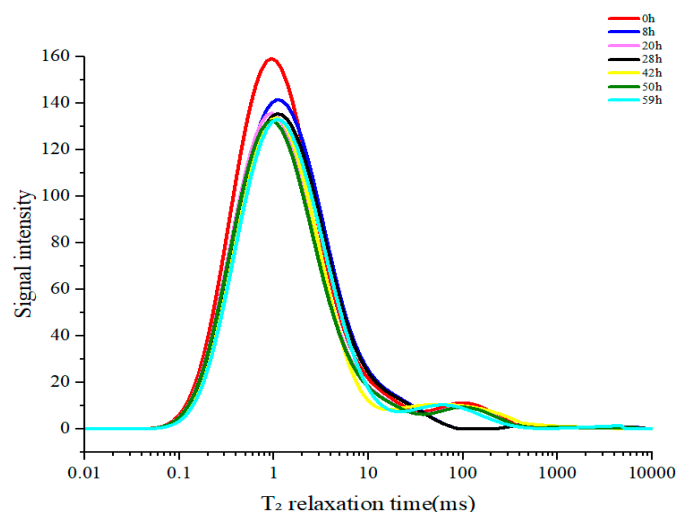


Figure 5. T_2 spectra at different soaking times under an injection rate of $20 \text{ m}^3/\text{min}$.

Table 2 summarizes the imbibition efficiency for pores of different scales at imbibition equilibrium under slickwater injection rates of $16 \text{ m}^3/\text{min}$ and $20 \text{ m}^3/\text{min}$. As shown in the table, increasing the injection rate enhances imbibition efficiency in both small and mesopores. Specifically, when the injection rate is raised from $16 \text{ m}^3/\text{min}$ to $20 \text{ m}^3/\text{min}$, the imbibition efficiency in small pores ($T_2 < 10 \text{ ms}$) increases from 5.1% to 8.7%, while that in mesopores ($T_2 = 10\text{--}100 \text{ ms}$) rises from 16.6% to 19.3%. Nevertheless, it should be explicitly noted that the present experimental program covers only two injection-rate conditions, which inherently defines the valid applicability boundary of the observed trends. Robust extrapolation of these findings to a broader range of injection rates would require supplementary experiments that incorporate a more comprehensive set of rate gradients to provide systematic data support and validation.

Table 2. Oil recovery performance of slickwater at varying concentrations of the oil-displacement agent.

Core Number	Simulated Field Pumping Rates (m^3/min)	Oil Mobilization Degree in Small Pores ($T_2 < 10 \text{ ms}$)	Oil Mobilization Degree in Mesopores ($T_2 = 10\text{--}100 \text{ ms}$)	Oil Mobilization Degree in Large Pores ($T_2 = 100\text{--}1000 \text{ ms}$)
4	16	5.1	16.6	15.2
5	20	8.7	19.3	14.9

This improvement can be attributed to the enhanced imbibition dynamics under higher injection rates. The elevated injection pressure associated with higher flow rates helps overcome the capillary entry pressure of smaller pores, facilitating more effective invasion of slickwater into micro- and mesopore networks [23–25]. Consequently, the displacement efficiency of oil from these tighter pore spaces is significantly improved, leading to higher ultimate recovery from the pore fractions that are otherwise less accessible.

4.3. Effect of Initial Oil Saturation on Oil Imbibition Efficiency

As presented in Table 3, the imbibition efficiency of crude oil after the flooding and shut-in sequence increased substantially with higher initial oil saturation in the core plugs under identical shut-in durations. This trend is primarily attributed to the dominant role of capillary force in the imbibition process. A higher oil saturation corresponds to a lower initial water saturation. According to capillary pressure theory, a lower initial water saturation generates a higher capillary force, thereby providing a stronger driving

mechanism for the spontaneous imbibition of slickwater into the micropores and the subsequent displacement of crude oil [26,27].

Table 3. Oil recovery performance of slickwater at varying concentrations of the oil-displacement agent.

Core Number	Porosity (%)	Oil Saturation (%)	Oil Mobilization Degree in Large Pores ($T_2 = 100\text{--}1000\text{ ms}$)
5	6.82	69.2	53.2
6	6.79	32.5	31.6
7	6.80	13.3	10.6

5. Field Application

Well NC002 is a tight oil horizontal well located in Sichuan Basin, China, with a lateral length of 1370 m. Log interpretation indicates a reservoir thickness of 10 m. The lithology is predominantly medium-fine to coarse-grained sandstone. The pore system is dominated by primary intergranular and intragranular pores, with an average porosity of 7.6%, average permeability of 0.3 mD, and average oil saturation of 58.5%. Natural fractures are not developed in this reservoir.

The well was successfully fractured in 28 stages. In each stage, slickwater containing 0.3% oil-displacement agent was injected at a rate of $18\text{ m}^3/\text{min}$. A mixture of 40/70-mesh and 30/50-mesh quartz sand was used as proppant. The average cluster spacing ranged from 11 to 12 m, with 36 to 48 perforations per stage. Microseismic monitoring revealed that the fracture half-length (or fracture length, as the original reports) ranged from 328 to 376 m, fracture height from 24.8 to 27.3 m, and the total stimulated reservoir volume (SRV) reached $1.405 \times 10^7\text{ m}^3$.

To facilitate full imbibition and oil displacement, the well was shut in for 28 days after fracturing. Upon flowback, the initial oil production rate reached 32 tons per day. Microseismic monitoring further indicated a fracture complexity index of 1.19, suggesting distinctly multi-stranded fracture geometries. No natural fractures were observed in the reservoir, implying that the observed complexity is primarily induced by the stimulation treatment.

6. Conclusions

- (1) Imbibition in tight oil reservoirs of the Sichuan Basin follows a dynamic pore-filling sequence, progressing from micropores to mesopores and finally to macropores. This process is constrained by a characteristic imbibition equilibrium time; once this equilibrium is reached, further extending the shut-in period does not substantially improve imbibition efficiency.
- (2) Owing to the limited availability of core samples, the imbibition experiments in this study were confined to two injection rates and three concentration levels of the displacing agent in the fracturing fluid. The results demonstrate that an increase in either the displacing-agent concentration or the injection rate contributes to a higher overall imbibition efficiency. Notably, this enhancement is more pronounced in micropores and mesopores, where it substantially facilitates the mobilization of trapped oil that would otherwise remain difficult to recover.
- (3) Initial oil saturation significantly influences imbibition oil recovery. Therefore, for tight oil reservoirs in the Sichuan Basin, it is recommended to select zones with favorable petrophysical properties and high oil saturation for fracturing treatments to optimize stimulation effectiveness.

- (4) The findings of this study are applicable to pore-type tight sandstone reservoirs; however, their extension to naturally fractured reservoirs requires further validation. Future research should incorporate numerical simulation techniques to develop an optimization module for shut-in time, thereby guiding fracturing design.

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Data Availability Statement: Data is contained within the article.

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