


Research Article

Imbibition Retention in the Process of Fluid Replacement in Tight Sandstone Reservoir

Xiong Liu,^{1,2} Yang Zhang,¹ Desheng Zhou,^{1,2} Le Yan ,¹ Hai Huang,^{1,2} and Xinru Li^{1,2}

¹College of Petroleum Engineering, Xi'an Shiyou University, Xi'an, Shaanxi 710065, China

²Shaanxi Key Laboratory of Advanced Stimulation Technology for Oil & Gas Reservoirs, Xi'an, Shaanxi 710065, China

Correspondence should be addressed to Le Yan; 2233128087@qq.com

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“Fracture network stimulation and oil-water infiltration and replacement” are recent attempts to effectively produce oil from tight reservoirs. On the one hand, the formation can be fractured by the fracturing fluid, which can carry proppant into fractures. On the other hand, the fracturing fluid can spontaneously infiltrate into the pores under the action of capillary pressure to displace the oil phase, thereby enhancing the oil recovery. To distinguish imbibition and displacement processes during fluid replacement in tight reservoirs is difficult, and the effect of these two processes is also vaguely defined. In this study, an experimental method that can visualize the imbibition and displacement process is proposed by combining the core slice displacement experiment. Based on this method, the process of imbibition and displacement can be effectively distinguished, and imbibition retention rate can be quantitatively characterized. The effectiveness of this method is proved by taking the core of Chang 7 tight sandstone reservoir in the Ordos Basin as the research object. The results show that the force direction of the fluid under imbibition is related to the wettability, and it is always from the wetting phase to the nonwetting phase, while the force direction of fluid under displacement is mainly related to the directivity of displacement pressure difference. Based on the difference of force action, imbibition and displacement can be quantitatively characterized, respectively. During the imbibition process, the peak value of the NMR curve corresponding to the small pore throat shifts to the left, and the signal amplitude increases. During the displacement process, the peak value of the NMR curve corresponding to the small pore throat has no obvious shift, nor signal amplitude change, but the peak value of the curve corresponding to the large pore throat shifts to the right. The results also indicate that there is an exponential negative correlation between imbibition retention rate and gas permeability. The greater the gas permeability is, the smaller the imbibition retention rate is.

1. Introduction

Imbibition refers to the process that the wetting fluid spontaneously sucks into the pores and displaces the nonwetting fluid under the action of capillary force [1–3]. The concept of displacement can be divided into broad sense and narrow sense. In a broad sense, displacement refers to the process of one fluid driving and replacing another fluid; that is to say, all fluid replacement can be called displacement (including imbibition process). In a narrow sense, displacement refers to the process of fluid replacement under the action of production pressure difference. The displacement described in this study refers to the displacement in a narrow sense [4, 5].

At present, the study of fluid replacement in tight oil reservoirs mainly depends on laboratory experimental. Arab et al. and Mai and Kantzas conducted core displacement experiments in the hydrophilic system and showed that the injection rate has different effects on the recovery under different oil-water viscosity [6, 7]. Li et al. conducted core imbibition experiments to show that chemical solutions can turn more remaining oil into movable oil to improve oil recovery [8]. Bertonecello et al. used NMR technology to study the influence factors on the imbibition [9–14]. Mason et al. and Li et al. showed that the fluid replacement in imbibition and displacement during the process of shut-in can improve the fracturing stimulation effect of tight oil reservoirs via the

imbibition experiment under pressure [15, 16]. Wang et al. studied the contribution of displacement and imbibition to the oil displacement rate via mathematical models [17–20]. Wang et al. carried out NMR tests, which showed that microfractures have little effect on improving spontaneous imbibition efficiency [21–24]. Wang Z. et al. and Gao et al. directly observed fluid replacement in the process of imbibition via the microfluidic pump, indicating that the chips with a larger average pore throat radius had a higher degree of imbibition recovery [25, 26]. Yao et al. and Li et al. studied the imbibition-displacement law in different reservoirs via capillary models [27, 28].

The existing researches have the following problems: (1) it is difficult to distinguish the processes of imbibition and displacement. During the process of fracturing or postfracturing production in tight reservoirs, the reservoir fluids are affected by many factors, such as pressure difference, capillary force, and gravity. The processes of displacement and imbibition are carried out at the same time and interact with each other. Especially for small pores ($25\text{ nm} < \text{pore diameter} \leq 100\text{ nm}$), whose capillary force and displacement pressure difference are relatively balanced, so it is difficult to distinguish the effects of imbibition and displacement [29–31]. (2) There is a big deviation in the definition of capillary force effect. Self-imbibition experiments are often used to study the effect of imbibition replacement in recent years. Many scholars have concluded that “the greater the permeability, the higher the imbibition replacement efficiency” and “the smaller the interfacial tension, the higher the imbibition replacement efficiency.” However, these conclusions are contrary to the effect of capillary force. The smaller the core permeability and the pore throat radius, the greater the capillary force and the more obvious the corresponding imbibition effect in general. Similarly, the smaller the interfacial tension, the smaller the capillary force effect and the worse the imbibition effect [32–34]. The reason why some contrary conclusions are drawn is that self-imbibition process is not only affected by capillary force, and the effect of which has not been clearly defined.

Based on the core slice displacement experiment, this study effectively distinguishes the imbibition and displacement effects, quantitatively characterizes the imbibition retention rate, and realizes the visual observation of imbibition and displacement processes.

2. Methodology

2.1. The Principle of Experiment. The force direction of the fluid under imbibition is related to wettability, and it is always from the wetting phase to the nonwetting phase. When the nonwetting phase is replaced with the wetting phase under the action of capillary force, the fluid replacement occurs spontaneously. When the wetting phase is replaced with the nonwetting phase, a larger external force is required to achieve fluid replacement. Different from capillary force, the direction of fluid flow under displacement is mainly related to the directivity of displacement pressure difference and has nothing to do with wettability. In a word, when the nonwetting phase is replaced with the wetting

phase, the direction of the force is from the wetting phase to the nonwetting phase. When the wetting phase is replaced with the nonwetting phase, the direction of the force is from the nonwetting phase to the wetting phase.

Assuming that the wettability of the core tends to be hydrophilic, the process of wetting phase displacing nonwetting phase is shown in Figure 1(a), where the blue area represents water phase, red area represents oil phase, and black area represents rock skeleton. Under the action of the production pressure difference, most of the water phase flows through the large pore throat to displace the oil phase. At the same time, spontaneous imbibition occurs in the small pore throat under the action of capillary force, the water phase is sucked into the small pore throats to displace the oil phase, and the water phase fills the affected pore throat areas.

After the wetting phase displaces the nonwetting phase to reach the displacement limit, the nonwetting phase is used to reversely displace the wetting phase (oil reverse displacement water), as shown in Figure 1(b). The water phase in the large pore throat is displaced by the oil phase under the action of the production pressure difference. Since the production pressure difference is much smaller than the capillary force of the small pore throat, the water phase in the small pore throat is retained. Comparing the two processes of the wetting phase displacing the nonwetting phase and the nonwetting phase displacing the wetting phase, we can effectively distinguish the imbibition and displacement in the process of fluid replacement in the tight reservoir.

2.2. The Process of Experiment. The six cores used in the experiment are from the tight sandstone reservoir of the Chang 7 Formation in the Ordos Basin. The basic physical parameters are shown in Table 1. The porosity distribution is 8.06%~10.86%, with an average of 9.33%. The permeability distribution is 0.144 mD~0.387 mD, with an average of 0.251 mD. The clay content is 3.28%~4.92%, with an average of 3.96%. In addition, the contents of illite, chlorite, and illite/montmorillonite in each core are similar. Since these cores come from the same block, there is little difference in physical properties between the cores. Core slices made from six cores are shown in Figure 2.

The detailed experimental procedures are as follows:

- (1) The core is made into a core slice sample with a length of 2 cm, a width of 2 cm, and a thickness of about 0.5 mm, which is sealed with glass. The experimental device is shown in Figure 3
- (2) Turn on the vacuum pump and evacuate the core slices for at least 5 hours. Turn off the evacuation pump to saturate the core with water, and end when there is no significant change in the color of the core (methyl blue is added to the water phase for easy identification). This process simulates the process of water filling the rock pores first under the original geological conditions
- (3) Displace the saturated simulated oil, which is added with oil red solution for easy identification. The ratio

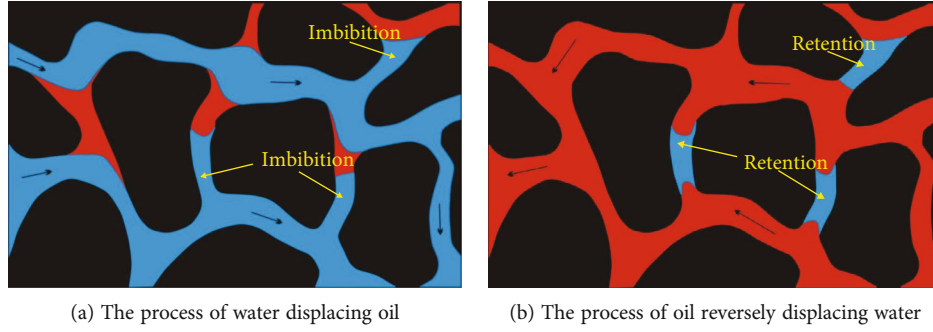


FIGURE 1: Schematic diagram of fluid displacing and reversely displacing (the blue area represents water phase, the red area represents oil phase, and the black area represents the rock skeleton).

TABLE 1: Basic physical parameters of cores.

Number	Length (cm)	Diameter (cm)	Dry weight (g)	Porosity (%)	Average of gas permeability ($10^{-3} \mu\text{m}^2$)	Clay content (%)	Mineral types and relative content (%)		
							Illite	Chlorite	Illite/montmorillonite
A12	4.342	2.51	49.49	10.86	0.387	3.57	15.42	5.11	13.47
B17	4.328	2.52	51.63	8.06	0.181	3.28	16.18	5.09	15.73
B30	4.358	2.51	52.83	9.61	0.313	4.92	13.06	4.83	14.11
B33	4.364	2.52	52.23	8.48	0.144	3.71	13.27	6.65	15.08
C35	4.306	2.52	50.24	8.69	0.199	4.41	15.99	6.57	15.85
C37	4.406	2.52	50.54	10.28	0.284	3.86	15.26	6.27	14.47

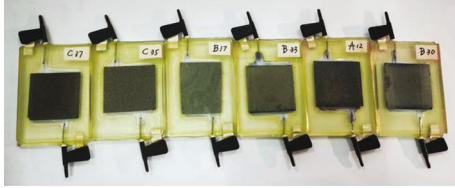


FIGURE 2: Core slices.

of crude oil and kerosene in the target reservoir is 1 : 2, and the viscosity of the simulated oil phase is 1.87 mPa·s. This process simulates the accumulation process of the reservoir, and the first NMR scan is performed after displacement until no water phase is produced at the output end

- (4) In the process of water displacing oil, the core slices are observed in real time by a microscope. When there is no oil phase produced at the production end, stand still for a period of time to allow the water phase to be fully imbibed. Then, record the oil-water distribution at the moment, and conduct the second NMR scan
- (5) In the process of oil reversely displacing water, the core slices are observed in real time by a microscope. When there is no water phase produced at the production end, stand still for a period of time. Then, record the oil-water distribution at the moment, and conduct the third NMR scan

- (6) Analyze the experimental data. Compare the processes of displacing saturation simulation oil, water displacing oil, and oil reverse displacing water. The Nikon NIS-Elements Documentation software was used to identify and quantify the displacement range of water and oil phases, and the measuring cylinder was used to calculate the water phase imbibition retention rate of core slices

The specific measurement process is as follows: when measured using conventional measuring cylinder, the injection and production flow rates of the core slices can be measured after the oil and water collected in the measuring cylinder are separated, and the physical parameters of the core slices can be used to calculate the volume of each fluid in the core slices. When calculated using microscopic image recognition software, the water phase containing methyl blue and the oil phase containing oil red solution were mixed, and the corresponding mixed colors under different water saturation were calibrated. During the experiment, a microscope was used to observe the core slices in real time, and the images of the fluid color in the core slices observed by the microscope corresponded to the calibrated saturation values. Then, the control ranges of different saturation were calculated to obtain the fluid volumes in the core slices at different times. The formula for calculating the imbibition retention rate is

$$\eta = \frac{V_r}{V_\phi}, \tag{1}$$

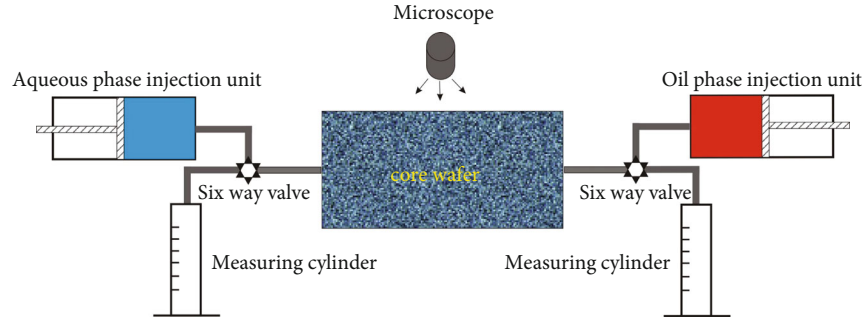


FIGURE 3: The experimental device.

where η is the imbibition retention rate, %; V_r is the imbibition retention volume of water phase, m^3 ; and V_ϕ is the total pore volume of core slices, m^3 .

Compared with the core self-imbibition experiment and the core displacement imbibition experiment, the experimental method provided in this study can effectively define the imbibition and displacement effects, quantitatively characterize the imbibition retention rate, and realize the visual observation of the imbibition and displacement process. However, this method also has certain limitations. When using microscopic images to identify fluids, only one surface of the core slice can be observed, and the measurement accuracy will be affected by the thickness of the core slice and the accuracy of color calibration. At the same time, due to the total displacement volume flow is small, the error of flow measurement increases. Compared with the calculation of displacement flow rate method, the average relative error of the six cores calculated by the microscopic image recognition method is about 6.8%. The average value of the two methods is taken in this experiment.

3. Results and Discussion

Based on the experimental principle, most of the pore throat areas in the core slices will be filled with simulated oil after the process of saturating simulated oil, which makes the core slices dyed red. After the process of water displacing oil, whether in the displacement area or the imbibition area, the water phase will replace the oil phase under the action of displacement or imbibition, which makes the core slices dyed blue. After the process of oil reversely displacing water, the water phase in the displacement area will be displaced by the oil phase under the action of pressure difference, which makes this area dyed red. In the imbibition area, the displacement pressure difference is less than the capillary force, resulting in the water phase being retained. This area appears as a blue area. This study takes B17 and C37 core slices as examples to illustrate.

3.1. The Displacement Experiment of the B17 Core Slice. The observation image of the B17 core slice saturated with simulated oil is shown in Figure 4(a), the observation image of the B17 core slice after water displacing oil is shown in Figure 4(b), and the observation image of the B17 core slice

after the process of oil reversely displacing water is shown in Figure 4(c).

Comparing the core slice images of the three stages of the B17 core, three small areas were selected, which are enclosed by the dotted circle in Figures 4(a)–4(c). The area 1 and area 2 appear red after the process of saturating simulated oil, blue after the process of water displacing oil, and remain blue after the process of oil reversely displacing water. This phenomenon indicates that these areas are mainly controlled by imbibition. The blue area after oil reversely displacing water is the water phase left by imbibition. The area 3 appears red after the process of saturating simulated oil, blue after the process of water displacing oil, and red after the process of oil reversely displacing water. This phenomenon indicates that this area is mainly controlled by the effect of displacement. The experiment results indirectly verify the correctness of the experimental principle.

The NMR curve of the B17 core slice after positive and negative displacement is shown in Figure 5. The abscissa is the relaxation time, which corresponds to the pore throat size. The larger the relaxation time is, the larger the pore throat diameter is. The ordinate is the amplitude of NMR signal. Through the experimental calibration, the NMR signal of the water phase is much stronger than that of the oil phase, so the signal amplitude of the NMR curve mainly reflects the amount of the water phase. By comparing the changes of the curves, it can be seen that after the process of saturating simulated oil, the NMR curve of the core slice shows a double hump shape. The peak signal intensity of the curve corresponding to the small pore throat is higher than that corresponding to the large pore throat, indicating that the small pore throat accounts for a large proportion of the core. After the process of water displacing oil, the peak of the curve corresponding to the small pore throat has a slight left deviation, and the NMR signal amplitude has little change. The peak of the curve corresponding to the large pore throat deviates significantly to the left, and the signal amplitude decreases. The range of the hump across the pore throat increases. This is due to fluid displacement; the water phase is more likely to enter from larger pore throat and invade into smaller pore throat under the action of pressure difference and capillary force, which affects the area that was not affected by the process of saturating simulated oil. After the process of oil reversely displacing water, the peak value

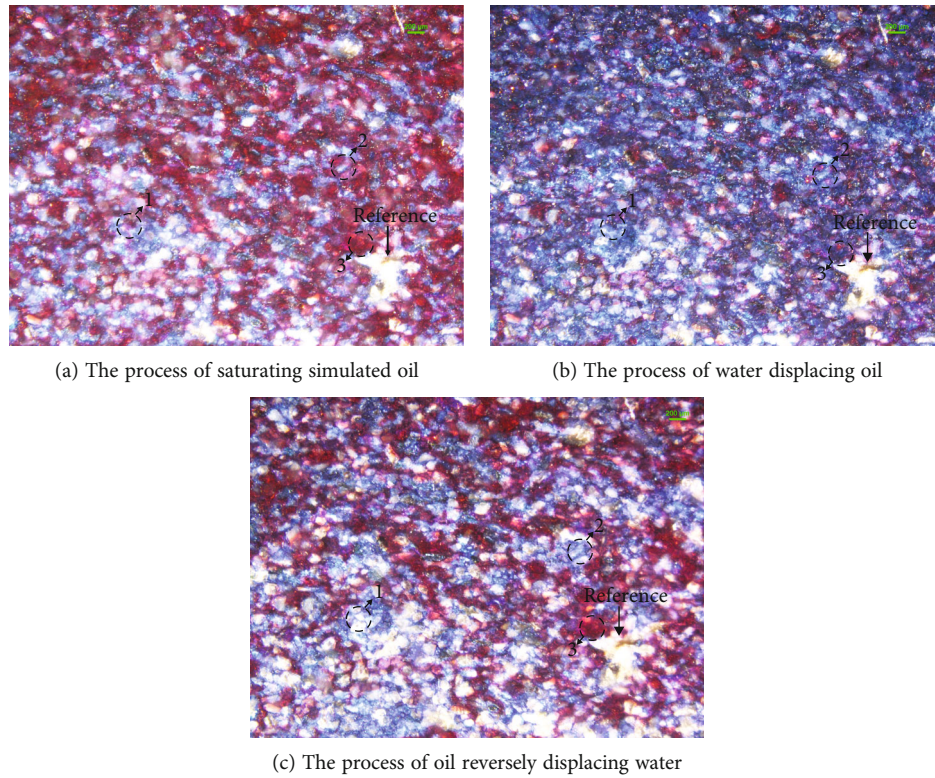


FIGURE 4: Observation images of B17 core slices at different displacement stages.

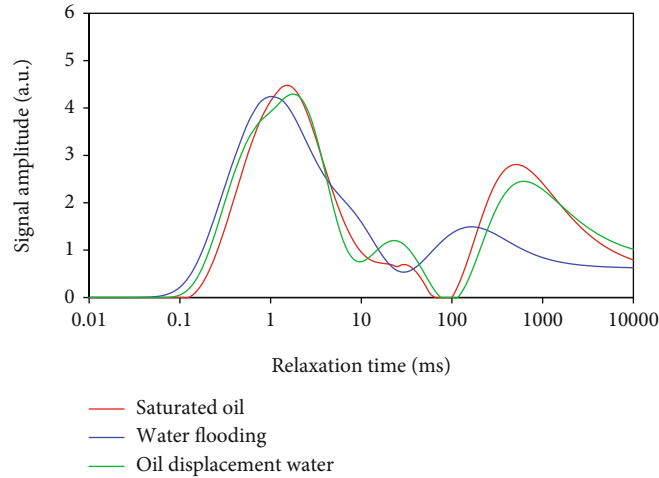


FIGURE 5: The NMR curve of B17 core slice after positive and negative displacement.

of the curve corresponding to the small pore throat has no obvious lateral shift, and the signal amplitude has little change. This is because the water phase in the small pore throat is retained by the capillary force. The peak value of the curve corresponding to the large pore throat deviates significantly to the right, and the peak signal amplitude increases greatly. We can conclude that the displacement process makes more fluid flow in the larger pore throat, and the fluid flow direction is the migration from the larger pore throat to the largest pore throat.

3.2. *The Displacement Experiment of the C37 Core Slice.* The observation image of the C37 core slice after the oil simulation saturating process is shown in Figure 6(a), the observation image of the C37 core slice after the water displacing oil process is shown in Figure 6(b), and the observation image of the C37 core slice after the oil reversely displacing water process is shown in Figure 6(c).

Comparing the core slice images of the three stages of the C37 core, three small areas were selected, which are enclosed by the dotted circle in Figures 6(a)–6(c). The area

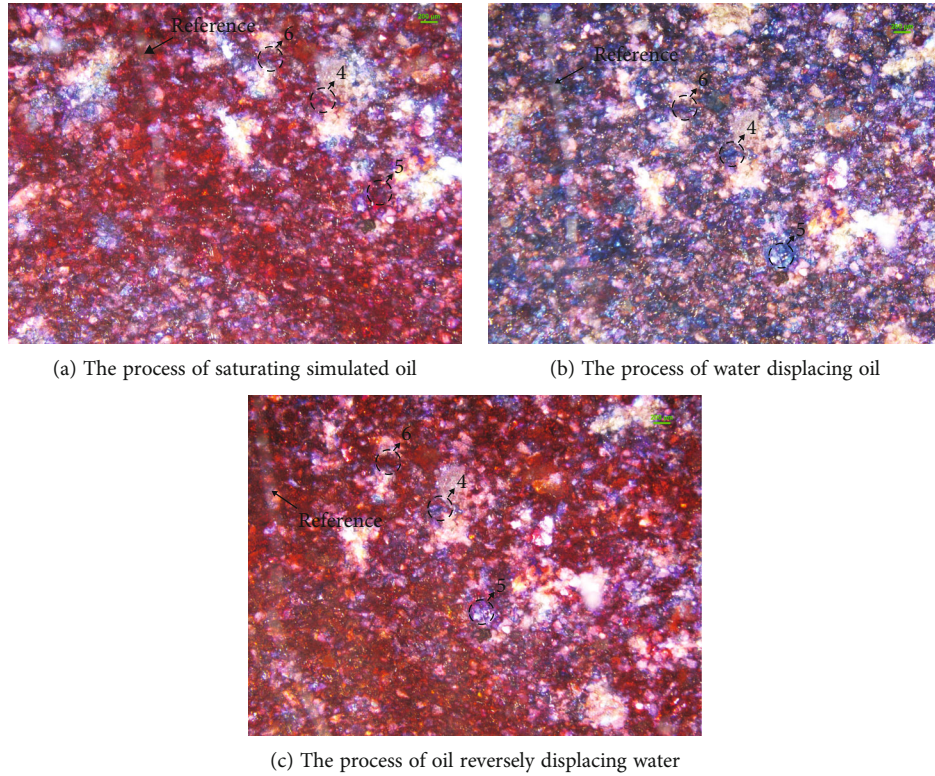


FIGURE 6: Observation images of C37 core slices at different displacement stages.

4 and area 5 appear red after the process of saturating simulated oil, blue after the process of water displacing oil, and remain blue after the process of oil reversely displacing water. This phenomenon indicates that these areas are mainly controlled by imbibition, and the blue area is the water phase left behind by imbibition retention. The area 6 will be dyed red after the process of saturating simulated oil, blue after the process of water displacing oil, and red after the process of oil reversely displacing water, which indicates that the pore throat in this area is larger and is mainly controlled by the action of displacement.

The NMR curve of the C37 core slice after positive and negative displacement is shown in Figure 7. By comparing the changes of the curves, it can be seen that after the process of saturating simulated oil, the NMR curve of the core slice is in the shape of a double hump. The peak value of the curve corresponding to the large pore throat is higher than the peak value of the curve corresponding to the small pore throat, which indicates that the core has a high proportion of large pore throats. After the process of water displacing oil, the peak value of the curve corresponding to the small pore throat shifted significantly to the left, and the amplitude of NMR signal increased. This is due to the imbibition of the small pore throat; the water phase enters into the small pore throat under the action of capillary force, which affects the area not affected by the simulated oil. At the same time, the NMR signal is enhanced because of a large amount of water phase imbibition. The peak value of the curve corresponding to the large pore throat has no obvious shift from left to right. However, the signal amplitude decreases and the

range of the hump across the pore throat increases, indicating that the fluid flows to the larger pore throat under the joint action of displacement and imbibition. After the process of oil reversely displacing water, the peak value of the curve corresponding to the small pore throat has no obvious lateral shift, and the signal amplitude changes little, which is because the water phase in the small pore throat is bound and retained by the capillary force. The peak value of the curve corresponding to the large pore throat deviates significantly to the right. This illustrates that the displacement process makes more fluid flow in the larger pore throat, and the flow direction of the fluid is the migration from the larger pore throat to the larger pore throat.

3.3. Relationship between Imbibition Retention Rate and Permeability. On the basis of the displacement experiments of six core slices, combined with the recognition software of microscope images and the calculation of displacement flow rate, the amount of fluid controlled by displacement and imbibition can be effectively quantified, and the rate of imbibition retained also can be measured.

The statistical data after the displacement experiment is shown in Figure 8. It is not difficult to see from the curve shape that the imbibition retention rate decreases exponentially with the increase of permeability, and the fitting relationship is as follows:

$$\eta = 5.2047 \times K^{-1.176}, \quad (2)$$

where K is the gas permeability, $10^{-3} \mu\text{m}^2$.

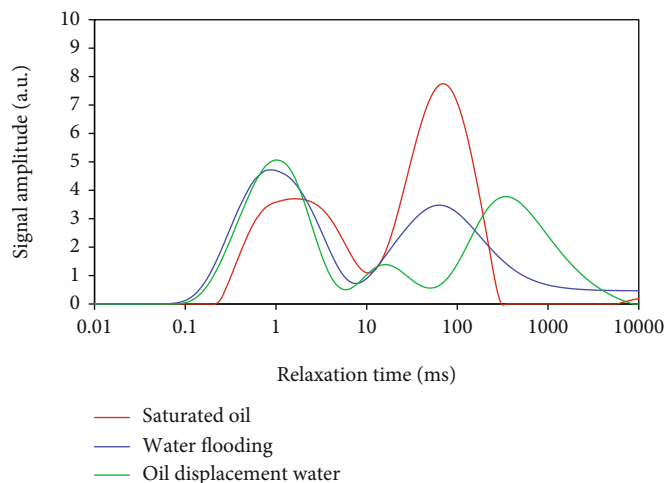


FIGURE 7: The NMR curve of C37 core slice after positive and negative displacement.

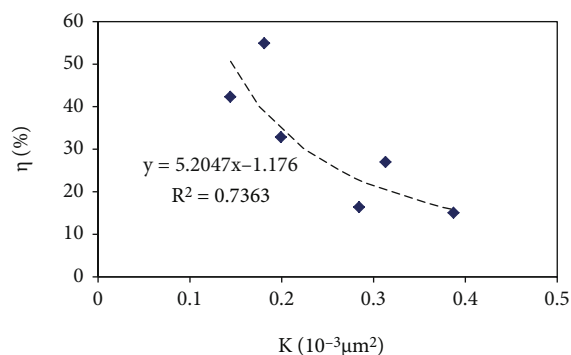


FIGURE 8: The relationship between the imbibition retention rate and the permeability.

4. Conclusions

- (1) According to the difference between imbibition and displacement, an experimental method that can visualize the imbibition and displacement process is proposed by combining the core slice displacement experiment. Based on this method, the process of imbibition and displacement can be effectively distinguished, and imbibition retention rate can be quantitatively characterized
- (2) During the imbibition process, the peak value of the NMR curve corresponding to the small pore throat shifted to the left, and the signal amplitude increased. During the displacement process, the peak value of the NMR curve corresponding to the small pore throat has no obvious shift and signal amplitude change, but the peak value of the curve corresponding to the large pore throat is shifted to the right
- (3) There is an exponential negative correlation between imbibition retention rate and gas permeability. The larger the gas permeability is, the smaller the imbibition retention rate is

Data Availability

Raw data and derived data supporting the findings of this study are available from the author Xiong Liu (email: liuxiong2016@xsyu.edu.cn) on request.

Conflicts of Interest

The authors declare no competing interest.

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