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Experimental Study of Influence of Core Wettability on Imbibition Properties

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Abstract: Through new core wettability simulation technology and the single-sided unidirectional imbibition experimental method, the influence of core wettability on oil imbibition characteristics was studied by using artificial cores with wettability index in the range of −0.9~0.95. Results show that for the cores with permeability from ultra-low to medium–high, the imbibition time shows a monotonically decreasing law with the increase in the wettability index. In the weak water-wet range, the imbibition time increases significantly with the weakening of water-wet. Oil imbibition rate goes up with the increase in wettability index. In the strong water-wet range, the imbibition rate will change significantly with wettability. In the water-wet zone, there is a positive correlation between imbibition oil limit recovery and wettability index, according to which a power exponent model of them is established. The imbibition–displacement ratio, which characterizes the contribution rate of oil recovery by imbibition to that by waterflooding, is also positively correlated with the wettability index. In addition, imbibition–displacement ratios of extra-low permeability cores are very close to that of medium–high permeability cores. According to the analysis of the research results, compared with the strongly water-wet oil layer, the weakly water-wet oil layer with a wettability index of 0–0.5 has a greater contribution to oil recovery by using the enhanced imbibition method.

Keywords: imbibition; wettability; imbibition oil recovery; imbibition rate; artificial core

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1. Introduction

Imbibition is a common fluid migration phenomenon in porous media, such as oil reservoirs. In tight low permeability reservoirs, the imbibition effect has a particularly important contribution to the recovery of crude oil in the matrix [1–3]. The study of imbibition in oil reservoirs has a long history; especially in recent years, the exploitation of tight low permeability reservoirs has received increased attention [4–7].

In recent years, the understanding of the influence of reservoir wettability on imbibition has gradually deepened. Experimental results show that many factors affect oil imbibition in tight low permeability reservoirs, and these factors can be generally divided into three types, such as rock properties, fluid properties, and environmental conditions [4,8–10]. The influence of rock properties on imbibition can be subdivided into rock wettability, rock pore structure, and rock mineral composition.

① Effect of rock wettability on imbibition

A large number of experiments and theories show that, generally, the imbibition rate and imbibition recovery go up with an increase in the water-wet of the reservoir rock [11–14]. The capillary force is the power source of imbibition. When the rock is more water-wet, the capillary force is greater, the imbibition effect is more intense, and the corresponding imbibition rate and imbibition recovery are also higher [15,16].

② Effect of rock pore structure on imbibition

The pore structure is usually characterized by permeability, porosity, and a pore-throat scale. Permeability and porosity are inherent properties of rocks. Generally speaking, the magnitude of permeability is proportional to porosity, and greater permeability means greater porosity and better pore connectivity [17]. A larger pore size and good pore connectivity means less resistance to fluid flow, which is favorable for water intrusion into pores to expel crude oil [18]. However, when the pores become larger, the capillary pressure becomes smaller, so the imbibition oil discharge rate will decrease. These two effects are opposite for imbibition and drainage, and in the actual imbibition process, one effect will prevail.

③ Effect of clay minerals on imbibition

Clay minerals resemble semi-permeable membranes. The brine intruding into the pores has a higher salinity due to the dissolution of clay minerals and exchange of cations, and has a lower osmotic pressure; while the brine outside the pores has a lower salinity and a higher osmotic pressure [19]. Therefore, the low salinity water enters the clay through the small pores, and the crude oil in the large pores is expelled due to the increase in the pore pressure [20].

At present, some basic understanding of oil imbibition has been formed. For example, among the many influencing factors, reservoir wettability is the most important main controlling factor. The more water-wet the reservoir, the stronger the imbibition effect. In the oil-wet reservoir, the imbibition effect will not be formed [21,22]. For oil-wet reservoirs, such as some carbonate rocks or shale, the use of appropriate surfactants can significantly improve wettability [23–26]. The hydrophobic part of the surfactant can be adsorbed on the rock surface, making the rock change from oil-wet to water-wet [27], so water or fluid in fractures will enter into the matrix spontaneously, and the oil recovery by imbibition will be improved. Some researchers believe that surfactants can enhance and improve imbibition through emulsification and solubilization [21]. According to current research reports, cores with 2 to 3 wettability indices were often used to carry out experimental studies on imbibition, and a qualitative understanding of the effect of wettability on imbibition was obtained [15,28]. Obviously, in order to obtain the correlation law between oil imbibition and wettability, the first technical bottleneck to be broken is that the experimental cores need precise quantitative control of wettability. At present, the commonly used core wettability control methods are mainly adsorption methods soaked in surfactants, silicone oil, and asphalt. Wettability alteration by adsorbing the polar components from the crude oil is a complex process, which is affected by components of crude oil and aging time [29]. Actually, since the components of crude oil are complex, the wettability alteration can be caused by a combination of different adsorption mechanisms, which include polar interaction, surface precipitation, acid/base interactions, and ion binding or specific interactions [30]. Using this adsorption method, the experimental results of the imbibition characteristics of cores under three wettability conditions, namely water-wet, medium-wet, and oil-wet, can be obtained [31,32]. Some researchers have obtained a series of core wettability changes to different oil-wet cores by treating water-wet cores with crude oil with different aging times and aging temperatures in the cores [33]. However, changing the wettability of the core by the adsorption method faces three key problems. Firstly, the core wettability index value cannot be designed and accurately controlled according to the research requirements. Secondly, the range of core wettability changes is usually small, generally 0.4~0.8 [15], and quantitative and regular experimental results are difficult to obtain in a wide-enough range of WI. Thirdly, the core whose wetting reversal is realized by the adsorption principle inevitably will desorb some wetting chemical agent during the experiment, and the wettability changes accordingly. Thus, the experimental results at stable wettability are difficult to obtain.

In the imbibition experiment, the length of the core, the contact area with imbibition fluid, and the effect of gravity greatly influence the experimental results [34–36]. Zhu [4] and

Gao [35] found that the imbibition rate of short cores is faster than that of long cores, and the measured imbibition oil recovery is quite different due to different imbibition contact areas. Morrow [3] and Meng [37] analyzed the results of imbibition boundary conditions and concluded that different oil–water contact conditions result in different imbibition results. These research results imply that the differences in core size, imbibition area, and oil–water contact mode will inevitably lead to deviations in imbibition experimental results.

In addition, imbibition is a special oil–water and liquid–solid interface phenomenon, and the influence of other driving forces, such as pressure difference and gravity, must be excluded or reduced as much as possible in the oil imbibition experiment. Therefore, the experimental method of imbibition should be improved and standardized urgently.

In view of these problems, the simulation method of core wettability is improved, the experimental method of imbibition is optimized, and the influence of core wettability on the characteristics of imbibition is studied in the wettability index range of −0.9~0.95. The results can be used as a reference for analyzing the characteristics of imbibition in actual reservoirs.

2. Imbibition Experiment

2.1. Experimental Cores

In the past imbibition experiment, natural cores were often used. The natural core has the real physical properties of the specific oil layer, but its amount is very small, and it is impossible to obtain cores with a series of physical properties required for regularity research. In order to study the influence of wettability on imbibition, this paper uses artificial cores whose main physical properties (permeability, porosity, wettability, etc.) can be quantitatively controlled within a wide enough range to carry out imbibition experiments.

The imbibition experiments were carried out using artificial cores with strong oil-wetness to strong water-wetness. Different from the previous cores whose wettability were changed by the adsorption principle, the artificial cores used in this experiment were fabricated by adding the wettability control agent to the quartz sand, mixing it with the core cement agent evenly, and then pressing, curing reaction, and drilling. By adjusting the type and amount of wettability control agent, cores with different wettability are produced. Its production process can be briefly introduced as followed:

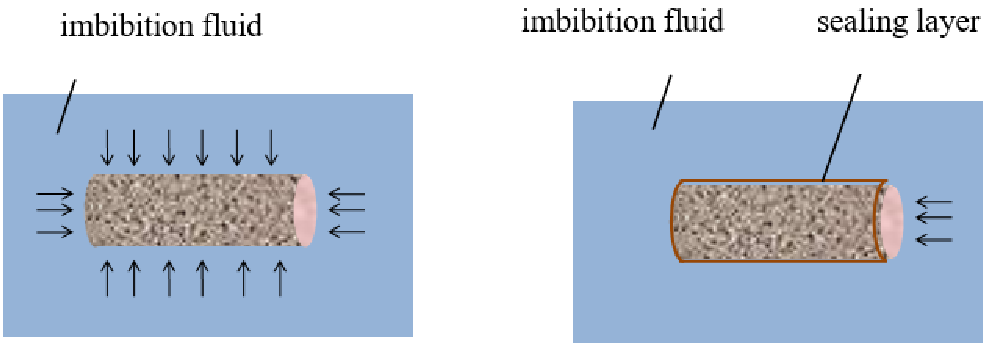
(1) Choose the size and mass of quartz sands and clay minerals according to the needed experimental core permeability;
(2) Choose type and proportion of the wetting control agent and sands according to experiment need;
(3) Mix the sands, clay minerals, and wetting control agent well;
(4) Put the mixed material into the mold and press it with a hydraulic press;
(5) Heat curing;
(6) Test the permeability and *WI* of the core.

The Amott–Harvey method was used to measure the wettability index *WI*, which characterizes the wettability of the core.

This new type of core [38] has two characteristics, one is that a core with a series of wettability index (*WI*) can be designed and fabricated according to experimental requirements, and the core wettability index can be precisely controlled within the range of $-1.0 < WI < 1.0$; the second is that the wetting agent is solidified on the surface of the mineral particles by the binder. The wettability is very stable; it can eliminate the deviation of experimental results caused by the change in wettability during the experiment. According to the experimental design, ultra-low permeability (2 mD) to medium–high permeability (200 mD) cores are fabricated, and each permeability core group has seven types of Amott wettability index (−0.9–0.95).

2.2. Experimental Method

The traditional imbibition experiment immerses the core in the imbibition liquid (Figure 1a) [9,16]. The two end faces and cylinder faces of the core are imbibition faces, and oil discharged from the cylinder area dominates in the experiment. This experimental method has two deficiencies, as follows: first, the experimental results will have great deviations due to the non-uniform core length; second, the imbibition effect and its effective distance is difficult to objectively reflect due to the dominant radial imbibition in the cylinder face. In response to these problems, the traditional multifaceted and multidirectional oil imbibition experiment method is improved to a one-face and one-way approach (Figure 1b). The cylindrical surface and one-end surface of the core is sealed, and only the other one end surface is used as the oil discharge surface to contact the imbibition liquid. Thus, the imbibition area and the oil discharge direction are easy to standardize. Using the method shown in Figure 1b, the deviation and uncertainty of the experimental results of oil discharge caused by the difference in core size, morphology, and multidirectional imbibition among different experiments can be effectively eliminated. When the size of the core in the oil discharge direction is sufficiently large, the contribution of effective imbibition distances of different cores to oil discharge can be truly reflected.



(**a**) (**b**)

Figure 1. Schematic of oil imbibition: (**a**) traditional imbibition and (**b**) improved imbibition.

The imbibition oil recovery (E_{io}) is defined as the ratio of the amount of crude oil discharged from the imbibition end face (Q_{oe}) to the original amount of oil (Q_{oo}) to objectively characterize the effect of imbibition.

$$E_{io} = \frac{Q_{oe}}{Q_{oo}} \tag{1}$$

The experimental procedure of imbibition and oil drainage is as follows: ① the core is vacuumed for 4–6 h, the simulated formation water is saturated, and the pore volume and porosity are measured; ② the experimental oil and core are heated in a constant temperature box at 50 °C; ③ core is saturated with crude oil, and the oil content is calculated; ④ the core cylinder and one end face are sealed; ⑤ the sealed core is placed into the imbibition bottle for the imbibition and oil drainage experiment; and ⑥ time and oil volume expelled from the core are recorded.

2.3. Experimental Condition

The oil for experiment was the mix of degassed kerosene and dehydrated crude oil from an oilfield in China. The simulated oil viscosity was 1.8 mPa·s at 50 °C. The asphaltene content of the simulated oil was 1.14%, the gum content was 6.02%, and the wax content was 14.56%. The total salinity of the experimental water was 12875 mg/L; the mass concentrations of Mg^{2+}, Ca^{2+}, Na^{+}, and Cl^{-} ions were 201.31, 334.26, 4526.75, and 7813.34 mg/L, respectively. The pH value of the water was 6.8. The experimental temperature was 50 °C.

3. Results and Discussion

3.1. Dynamic Characteristics and Characteristic Parameters of Imbibition

As a typical example of a large number of oil imbibition experiments, Figure 2 shows dynamic curves of imbibition oil recovery of cores with wettability index WI = 0.5 and permeability of 2, 50, and 200 mD, according to which the basic characteristics of the oil imbibition process can be observed.

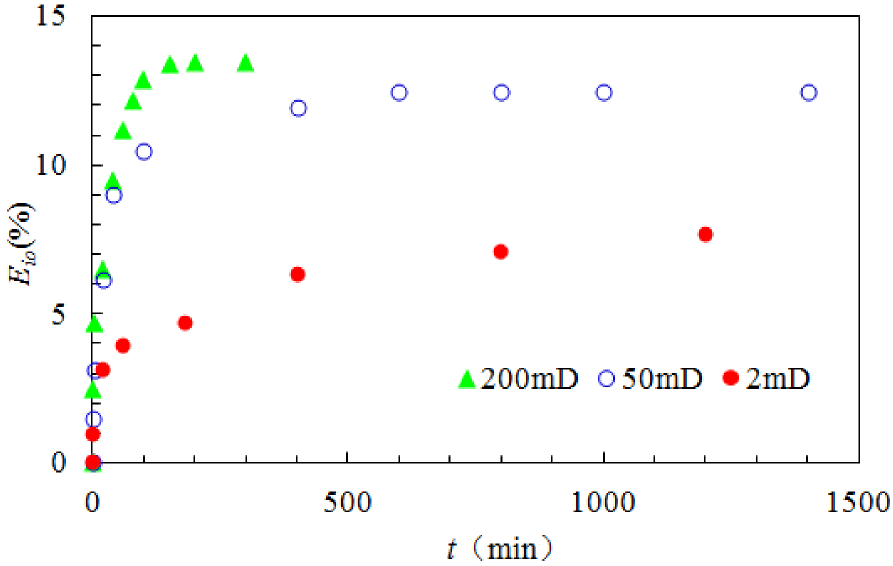


Figure 2. Imbibition oil recovery dynamics (WI = 0.5).

Figure 2 shows that ultra-low permeability and medium–high permeability cores have the same dynamic characteristics; the imbibition oil recovery E_{io} increases monotonically with imbibition time t increasing. The main feature of the dynamic curve is that the entire process of oil imbibition is clearly divided into two intervals, namely, the initial high-speed oil discharge and the latter low-speed oil discharge. The imbibition oil recovery increases rapidly at first, and then goes up significantly slowly after reaching a certain characteristic time. Eventually, it reaches a limit value, and then imbibition ends.

As shown in Figure 3, the dynamic curve of oil imbibition has four important characteristic parameters. The first one is the boundary time between high-speed and low-speed oil discharge areas, which is called the critical time T_h for high-speed oil discharge. The second one is the time T_t, called the critical time for the termination of oil imbibition. The third one is the imbibition rate V_{io}, which characterizes the speed of imbibition. The fourth one is the oil imbibition limit recovery, which is the imbibition recovery when the oil discharge process ends. For example, in the dynamic curve of oil imbibition with permeability k = 50 mD and wettability index WI = 0.5, the methods for determining the critical time T_h for high-speed oil imbibition, the critical time T_t for termination of oil imbibition, and the oil imbibition rate V_{io} are introduced.

Taking the measured imbibition oil limit recovery E_{iol} = 12.48% as a straight line, the initial time when the experimental curve of imbibition oil recovery intersects with this straight line is the critical time for terminating oil discharge T_t = 600 min.

In the initial stage of oil imbibition, the imbibition oil recovery increases quasi-linearly with time. In the E_{io}-t diagram, the quasi-linearly increasing experimental points are selected to draw a straight line, which intersects with the E_{iol} = 12.48% line at (T_h, E_{iol}), where T_h is the high-speed oil imbibition critical time (50 min) of the experiment.

In the imbibition experiment, the total oil discharge amount is closely related to the imbibition area of the core. For the sake of unified specification and comparability, the oil discharge volume per unit imbibition area q_{io} (mL/cm^2) is considered the characterization parameter of the oil discharge in the imbibition experiment, and the limit oil discharge volume of imbibition is q_{iol}. Accordingly, the oil imbibition rate is defined as follows:

$$V_{io} = \frac{q_{iol}}{T_t} \tag{2}$$

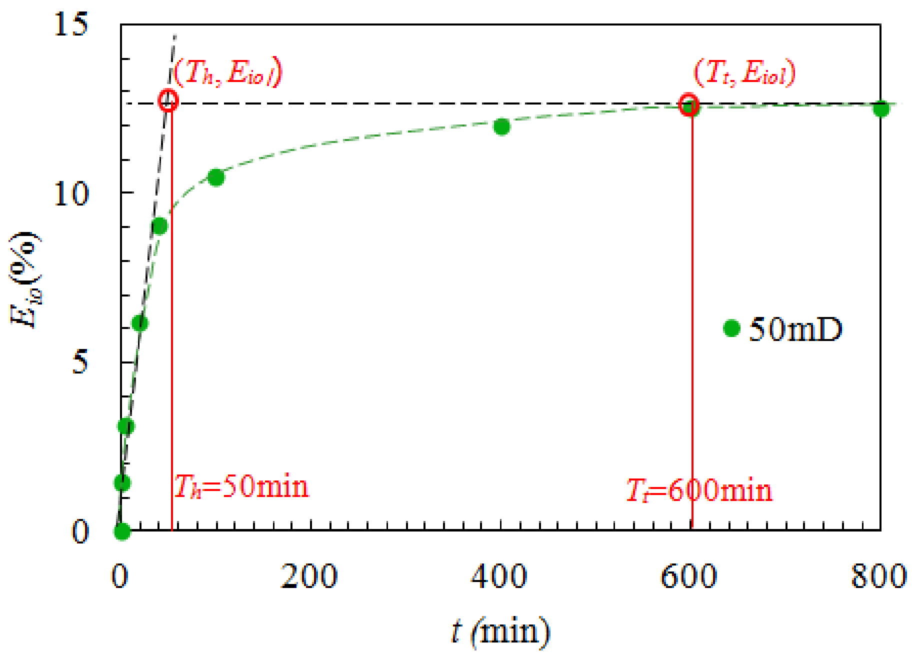


Figure 3. Characteristic parameters of oil imbibition.

Tables 1 and 2 shows the repeated imbibition experiment data, which can be used to test the repeatability and homogeneity. In Table 1, each permeability level of the core has three measurements of E_{iol}. The calculated average value is close to the experiment results, and relative standard deviation (RSD) is small. The RSD of 2, 50, and 200 mD cores is 1.20%, 0.79%, and 0.4%. These results indicate that the imbibition experiments can be repeated well. In Table 2, each wettability level of the core has four measurements of E_{iol}. The variance ratio between them is 0.0052/0.0047, approximately equal to 1.1. The results show there is good homogeneity between the group data.

Table 1. Repeated imbibition experiments (WI = 0.5).

Permeability of Core (mD)	Measurement of E_{iol} (%)			Average (%)	Relative Standard Deviation (RSD, %)
	#1	#2	#3		
2	7.82	7.92	8.01	7.92	1.20
50	12.54	12.56	12.35	12.48	0.79
200	17.46	17.38	17.52	17.45	0.40

3.2. Relationship between the Characteristic Time of Imbibition and Core Wettability

The two main characteristic times of the oil imbibition experiment are the critical time of high-rate imbibition (T_h) and the critical time of terminal imbibition (T_t). These characteristic times are greatly important in actual reservoir development. In the production of oil reservoirs (especially ultra-low permeability reservoirs), T_h is the production period during which the imbibition effect may have application value; T_t can be used as an important parameter for evaluating the limit of the imbibition effect.

Table 2. Repeated imbibition experiments (k = 2 mD).

Wettability of Core (WI)	Measurement of E_{iol} (%)				Average (%)	Variance
	#1	#2	#3	#4		
0.12	3.18	3.28	3.24	3.26	3.22	0.0052
0.35	5.42	5.38	5.26	5.34	5.35	0.0047

Figure 4 shows the correlation law between the critical time T_h and the wettability index WI of the cores with permeabilities of 2, 50, and 200 mD. Figure 4 shows that the critical time T_h for high-speed oil drainage of ultra-low permeability and high permeability cores decreases linearly with the wettability index WI increasing. The T_h (165.4 min) of cores with ultra-low permeability and weak water wetness (WI = 0.12) is nearly three times the T_h (55 min) of the core with ultra-low permeability and strong water wetness (WI = 0.95).

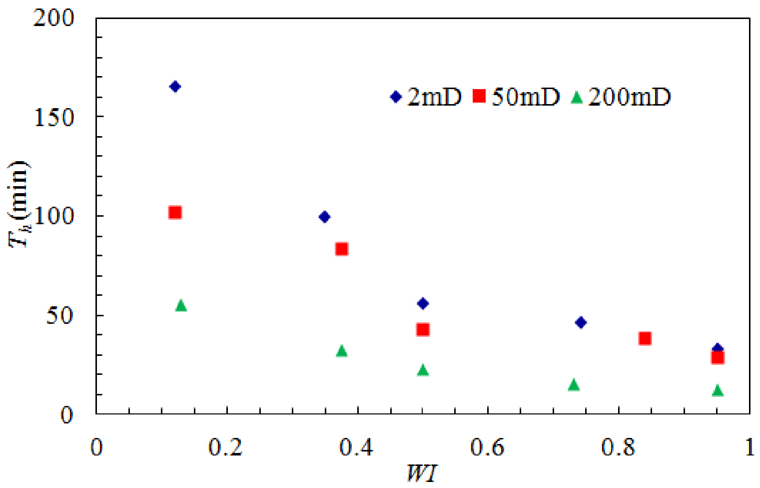


Figure 4. Relationship between high-speed imbibition time and wettability index.

Figure 5 shows the correlation law between the critical time T_t and the wettability index WI of the cores with permeabilities of 2, 50, and 200 mD. Figure 5 shows that the law and main characteristics of T_t changing with wetting index WI are consistent with T_h, and the difference is mainly that the influence of wetting index on T_t is more sensitive than that of T_h. For example, the critical time for terminal imbibition for ultra-low permeability and weak water-wet cores (WI = 0.12) is 10 times that of strong water-wet cores (WI = 0.95).

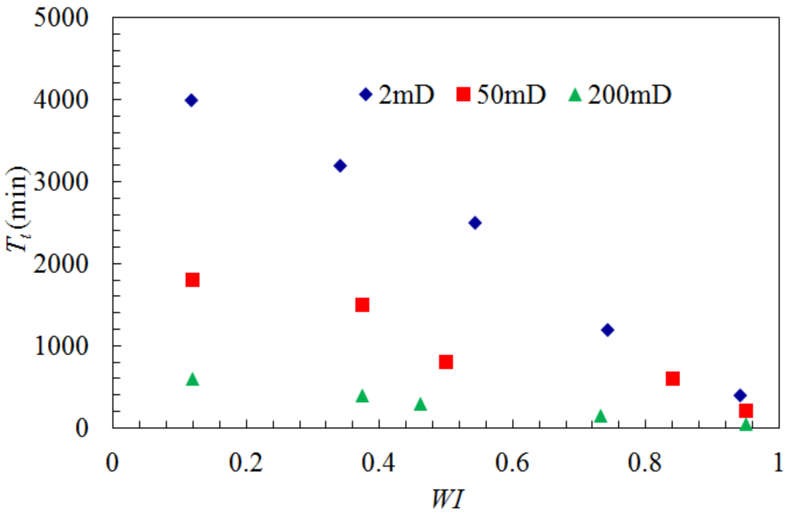


Figure 5. Relationship between the termination time of imbibition and wettability index.

Table 3 shows the calculated linear correlation value between imbibition time (T_h and T_t) and core wettability. It can be seen in Table 3 that the values are negative and their absolute values are close to 1. These data indicate that there is a negative linear relationship between imbibition time (T_h and T_t) and core wettability.

Table 3. Linear correlation coefficient calculation.

Permeability (mD)	Linear Correlation Coefficient between Time and Wettability Index	
	T_h	T_t
2	−0.92	−0.99
50	−0.93	−0.96
200	−0.94	−0.99

In the experiment of Zhu [4], T_h of medium water-wet core is 800 min, corresponding T_t is 3000 min, T_h of weak water-wet core is 1200 min, and corresponding T_t is 5000 min. In Zhou's experiment [15], it could be found that the T_t of cores without crude oil soaking (strong water-wet) was 1000 min, and the T_t of cores soaked in crude oil for 240 h (weak water-wet) was 20,000 min. Compared to these findings, this paper is not limited to the comparison of the imbibition results of two different wettability cores, but concludes related rules between imbibition and wettability. For Figures 4 and 5, in the range of WI from 0 to 0.4, T_h decreases sharply with the increase in *WI* and in the range of *WI* from 0.4 to 1.0, T_h decreases slowly with the increase in *WI*. This shows that in the weak water-wet range with *WI* of 0–0.4, the imbibition time increases significantly with the weakening of water-wetness; while in the medium–strong water-wet range with *WI* of 0.4–1.0, the imbibition time decreases slowly with the increase in *WI.*

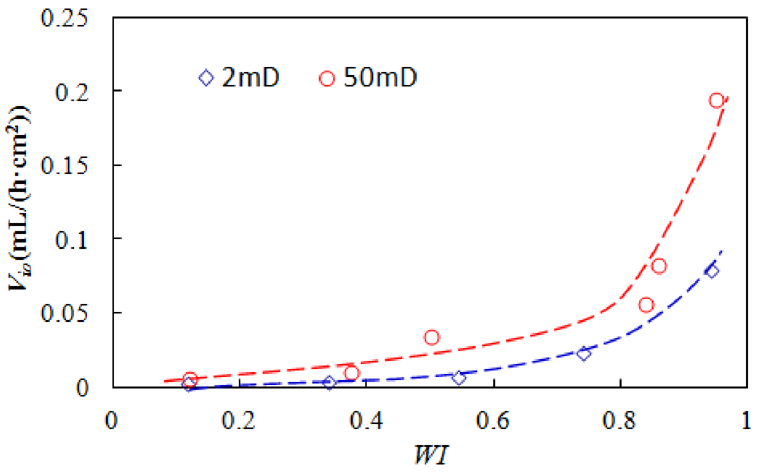
According to the analysis of the above experimental results, it can be inferred that the weaker water wettability of the oil layer indicates longer oil imbibition time. Under the same weak water-wet conditions, the medium–high permeability oil layer can complete the imbibition in a short time after contacting the imbibition liquid. However, the ultra-low permeability (tight) oil layer requires a long time to complete the imbibition and discharge of the matrix crude oil. Therefore, in the exploitation of low permeability tight oil layers, the coordination between the oil production rate and the imbibition rate should receive special attention.

3.3. Relationship between Oil Imbibition Rate and Core Wettability

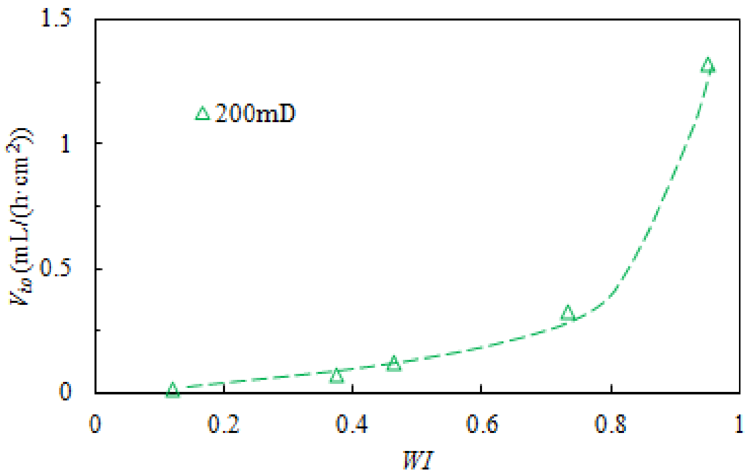
In the production of low permeability tight oil reservoirs, the rate of imbibition is one of the main criteria to determine the matching injection–production rate. As a parameter closely related to the production of low permeability tight oil reservoirs, the average oil imbibition rate V_{io} is determined in the process of imbibition experiments according to Formula (2), and the relationship between V_{io} and wettability index *WI* is obtained (Figure 6).

Figure 6 shows that whether it is an ultra-low permeability core or a medium–high permeability core, a positive correlation exists between the oil imbibition rate and the wettability index. Linear correlation coefficients of 2, 50, and 200 mD are 0.84, 0.80, and 0.86, respectively. The rate of oil imbibition of the ultra-low permeability (k = 2 mD) core with strong water wetness (*WI* = 0.95) is 44 times higher than that of the core with weak water wetness (*WI* = 0.12). On this basis, the imbibition rate of the ultra-low permeability tight and strongly hydrophilic oil layer is exponentially higher than that of the weakly hydrophilic oil layer.

As shown in Figure 6, the oil imbibition rate V_{io} has two distinct intervals with the increasing law of the wettability index *WI*, and the boundary wettability index is approximately 0.4. For the convenience of explanation, *WI* < 0.4 is called the weak water–humidity interval, and *WI* > 0.4 is the strong water–humidity interval. In the weak water-wet region, V_{io} increased slowly with *WI* increasing; in the strong water-wet region, V_{io} increased quickly with *WI* increasing. This finding indicates that only when the wettability is in the strong water-wet region, the rate of oil imbibition and drainage can be greatly improved by enhancing the water-wetness of the core.



(**a**)



(**b**)

Figure 6. Relationship between oil imbibition rate and wettability index: (**a**) k = 2 mD and k = 50 mD and (**b**) k = 200 mD.

Comparing the ultra-low permeability core with medium–high permeability cores in Figure 6, we can find that the relationship between oil imbibition rate and wettability index is very different in magnitude. Taking the strong water-wet condition of WI = 0.95 as an example, the oil imbibition rate of the ultra-low permeability core is only 5.9% of the medium–high permeability core.

3.4. Relationship between the Imbibition Oil Limit Recovery and Core Wettability

Figure 7 shows the correlation between the imbibition oil limit recovery E_{iol} of cores with permeabilities of 2, 50, and 200 mD and wettability index WI. Figure 7 shows that the relationship between E_{iol} and wettability index WI of ultra-low permeability and medium–high permeability cores has the same qualitative characteristics. In the oil-wet range with a wettability index of −1.0–0, whether it is an ultra-low permeability core or a medium–high permeability core, the imbibition oil recovery is 0. When the rock is water-wet, E_{iol} of cores with permeability from 2 to 200 mD increase fast firstly and then slowly with the increase in WI. These results show that for weak water-wet rock (WI < 0.5), its potential of enhanced oil recovery by imbibition is greater than that of strong water-wet rock.

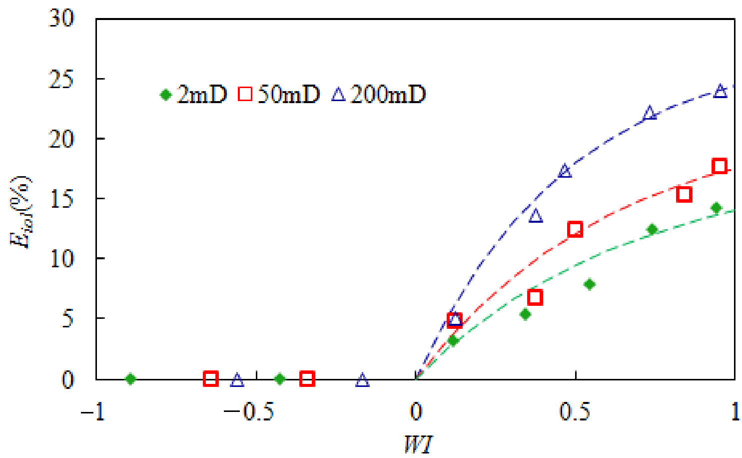


Figure 7. Relationship between imbibition oil limit recovery and wettability index.

The results of this paper are not limited to the comparison of the imbibition effects of two cores with different wettability indices [8,16]; instead, the correlation law between imbibition recovery and core wettability is obtained. According to the experimental results shown in Figure 7, the correlation model between E_{iol} and *WI* under the experimental conditions is established as Formula (3):

$$E_{iol} = a\,[1 - \exp(bWI)] \tag{3}$$

The coefficients *a* and *b* in the formula are determined with the experimental results by using the nonlinear least-square method. As shown in Table 4, under the experimental conditions of this study, corresponding to the permeability of 2, 50, and 200 mD cores, *a* in Formula (3) is 18.0, 22.0, and 27.9, *b* is −1.50, −1.60, and −2.08, and goodness-of-fit is 0.856, 0.980, and 0.834.

Table 4. Function fitting parameters.

Permeability of Core (mD)	Coefficients		Goodness of Fit
	a	*b*	
2	18.0	−1.50	0.856
50	22.0	−1.60	0.980
200	27.9	−2.08	0.834

E_{iol} increases greatly with *WI* increasing in the entire water-wet interval. However, even for a strongly water-wet core with a wettability index of 0.95, its imbibition oil limit recovery is very limited; especially, the E_{iol} of the extra-low permeability core is only 14%. This finding shows that for low permeability tight oil layers, enhancing hydrophilicity is effective in improving the imbibition oil recovery, but the potential to improve oil recovery by only relying on the imbibition effect is limited.

Analysis and comparison of the experimental results in Figure 7 show that under weak water-wet conditions, the imbibition oil limit recovery of the ultra-low permeability core is only approximately 40% of that of the medium–high permeability core. However, this condition does not indicate that the oil imbibition effect is less important in the production of ultra-low permeability tight oil layers than in medium–high permeability oil layers.

Using artificial cores of uniform size (φ2.5 × 6 cm), water flooding experiments were carried out under the same conditions. The ratio of imbibition oil recovery to water displacement efficiency of the core with the same permeability and wettability index is defined as the imbibition and displacement ratio R_{id}. Figure 8 shows the experimental law that R_{id} of medium–high permeability (200 mD) and ultra-low permeability (2 mD) cores monotonically increases with *WI* increasing. Comparing and analyzing the experimental results in Figure 8, under the experimental conditions of this study, the imbibition and displacement ratios of the two cores are very close. This finding shows that, based on the water-flooding efficiency, the contribution rate of oil imbibition in ultra-low permeability cores to crude oil production in the cores is not lower than that in medium–high permeability cores. In addition, considering that the water-flooding resistance in the ultra-low permeability tight oil layer is extremely large, the pressure difference to drive the matrix crude oil is difficult to establish, and the imbibition effect is more important in its production than in the medium–high permeability oil layer.

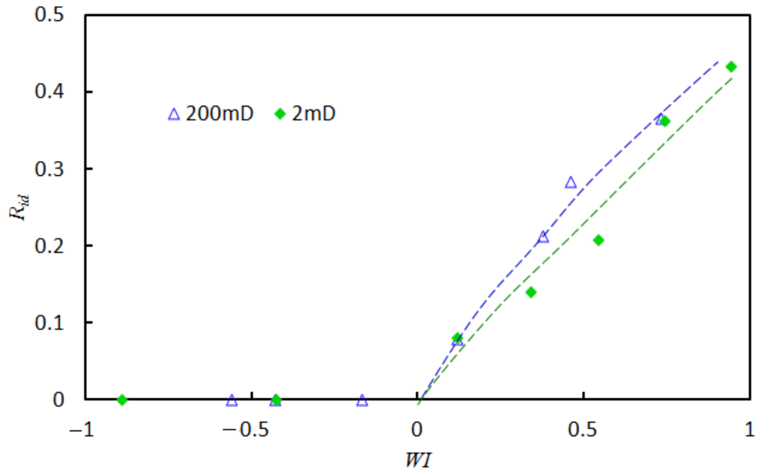


Figure 8. Relationship between imbibition–displacement ratio and wettability index.

4. Conclusions

The results obtained in this paper can provide experimental parameters for analyzing the characteristics of imbibition in actual reservoirs, and for optimizing the production plan with the goal of giving full play to the effect of imbibition. Moreover, some conclusions can be made:

(1) The critical time T_h for high-speed oil imbibition and the critical time T_t for termination of oil imbibition of ultra-low permeability and high permeability cores decrease with the increase in wettability index *WI*. The weaker water wettability of the oil layer indicates a longer imbibition period. In addition, ultra-low permeability (tight) oil layers require longer time to effectively discharge the matrix crude oil than the medium–high permeability oil layers.

(2) A positive correlation is found between the oil imbibition rate V_{io} and the wettability index *WI*. In the weak water-wet region, the oil imbibition rate increases slowly with *WI* increasing; in the strong water-wet region, the oil imbibition rate increases fast with *WI* increasing.

(3) In the water-wet range of the wetting index from 0 to 1.0, a nonlinear positive correlation is found between the imbibition oil limit recovery E_{iol} of ultra-low permeability and medium–high permeability cores and *WI*. Compared with the strongly water-wet oil layer, the weakly water-wet oil layer with a wettability index of 0–0.5 has a greater contribution to oil recovery by using the enhanced imbibition method. According to the experimental results, a power exponent model between E_{iol} and *WI* was established.

(4) The imbibition–displacement ratio, which characterizes the contribution rate of imbibition recovery to crude oil recovery, increases monotonically with *WI* increasing. The imbibition–displacement ratio of the ultra-low permeability core is similar to that of the medium–high permeability core. Comprehensively considering that the water-flooding resistance in the ultra-low permeability tight oil layer is extremely large, the imbibition effect is more important in its production than in the medium–high permeability oil layer.

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Nomenclature

E_{io}	imbibition oil recovery, %
E_{iol}	imbibition oil limit recovery, %
Q_{oe}	amount of crude oil discharged from the imbibition end face, mL
Q_{oo}	original amount of oil in core, mL
R_{id}	ratio of imbibition to displacement, dimensionless parameter
T_h	critical time of high-rate imbibition, min
T_t	critical time of terminal imbibition, min
V_{io}	oil imbibition rate, mL/(cm^2·h)
WI	wetting index, dimensionless parameter
a	coefficient, dimensionless parameter
b	coefficient, dimensionless parameter
q_{io}	volume of imbibition oil discharged per area, mL/cm^2
q_{iol}	limit volume of imbibition oil discharged per area, mL/cm^2
t	imbibition time, min

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