Imbibition and Oil Recovery Mechanism of Fracturing Fluids in Tight Sandstone Reservoirs

Hui Gao,* Yalan Wang, Yonggang Xie, Jun Ni, Teng Li, Chen Wang, and Junjie Xue

ABSTRACT: The fracturing fluid residing in a reservoir undergoes spontaneous imbibition. Here, to explore the mechanism of fracturing fluid imbibition and oil displacement, experiments on the spontaneous imbibition of fracturing fluid under different influencing factors were conducted on a core sample from the Ordos Basin of the Chang 8 formation. Combined with nuclear magnetic resonance technology, we quantitatively evaluated the degree of oil production of different pores during the fracturing fluid displacement process. Experimental results show that fracturing fluid salinity, fracturing fluid interfacial tension, and crude oil viscosity are negatively correlated with oil recovery. The phenomenon of microscale imbibition oil displacement occurs in pores of various scales in the core. The imbibition scale was between 0.10 and 1608.23 ms. The degree of crude oil production in the pores at each scale increased with increasing imbibition time. Moreover, the crude oil viscosity, fracturing fluid salinity, and fracturing fluid interfacial tension are negatively correlated with the degree of oil production at various pore scales. Decreasing crude oil viscosity significantly improves the degree of small-pore (0.1−16.68 ms) crude oil production; the low interfacial tension possesses a higher degree of oil production in the large pores (>16.68 ms), and the increment in the degree of oil production under different salinities of the small pores (0.1−16.68 ms) is greater than that of the large pores (>16.68 ms).

1. INTRODUCTION

China has numerous tight sandstone reservoirs, with estimated geological and technically recoverable resources of approximately 178.20 × 10^8 t and 17.65 × 10^8 t, respectively.1 The narrow pore throat diameter of tight oil reservoirs results in low natural productivity. Therefore, the main method of developing these reservoirs involves the combination of vertical wells and volume fracturing technology. The microfractures produced by the geological structure and pool forming process and the artificial fractures newly formed during the fracturing process provide good seepage channels for the migration of crude oil into the reservoir. The low flow back rate of the fracturing fluid causes it to remain in the reservoir, resulting in certain formation damage. However, the fracturing fluid retained in the reservoir undergoes spontaneous imbibition; this can be advantageously utilized to improve oil recovery and decrease formation damage.2

Spontaneous imbibition is defined as the imbibed process of water into rocks at different reservoir conditions.3 Imbibition is an important development method for tight sandstone reservoirs.4−7 Tight oil production from reservoirs highly depends on the spontaneous imbibition of tight rocks.8−9 Spontaneous imbibition and forced imbibition are two different imbibition categories, depending on whether the injected water is imbibed by capillary pressure alone or by other forces. Spontaneous imbibition dominates the entire oil displacement process.5,10−11 The capillary pressure between water and in situ crude oil is the primary mechanism for

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controlling oil production from fractured tight reservoirs.\textsuperscript{12} Pores consist of different mineral components, such as quartz, carbonate, and feldspar, which have different affinities for oil and water. This is the reason that crude oil can be produced through spontaneous imbibition.\textsuperscript{13} Our previous work showed that oil recovery from spontaneous imbibition is different in different pores depending on the petrophysical properties of the tight cores.\textsuperscript{14} The microscopic pore structure of reservoirs is an important factor affecting imbibition. The pore throat radius of tight oil reservoirs is on the nanometer scale and the thickness of the adsorption layer is on the micron scale.\textsuperscript{15–17} Pores above the submicron scale play a leading role in the process of oil displacement in tight reservoirs owing to the thickness of the adsorption layer, and nano-submicron pores contribute less to imbibition recovery.\textsuperscript{18} In cores with different pore structure combinations, the ratio of medium to large pore throats determines the extent of oil production in different pores.\textsuperscript{19} Adding surfactants to the fracturing fluid can effectively reduce the interfacial tension and improve the oil recovery after fracturing reformation.\textsuperscript{20–30} Based on the mass method experiment, it was found that the degree of salinity is negatively correlated with spontaneous imbibition recovery;\textsuperscript{31,32} fractures can effectively expand the imbibition area of the dense matrix in contact with water, thereby increasing the recovery and imbibition rate.\textsuperscript{33} Guo and Ren noted that there is a certain optimal interfacial tension that reduces the amount of bypassed oil in the formation, resulting in the highest imbibition recovery, rather than a lower interfacial tension corresponding to the higher oil recovery.\textsuperscript{34,35} Jing et al. studied the influence of matrix permeability, temperature, pressure, pore size, and fracture density on the degree of dynamic imbibition production; a normalized model of the dimensionless imbibition recovery degree is obtained using dimensionless experimental parameters.\textsuperscript{36} However, previous studies mainly considered the impact of a fracturing fluid on rock surface tension after fracturing, without considering the effect of spontaneous imbibition of the fracturing fluid on improving the oil displacement efficiency during the shut-in process, after fracturing fluid injection. Few studies have been conducted on the degree of oil production for retained fracturing fluids at different pore scales. Moreover, tight sandstone reservoirs are characterized by strong heterogeneity, resulting in different imbibition and oil displacement effects. This research primarily examined the critical factor and characteristics of oil displacement by using core samples from the Ordos Basin of the Chang 8 formation, through an experiment on the spontaneous imbibition of the fracturing fluid at reservoir temperature and pressure conditions. The difference in oil recovery at different pore scales was quantitatively characterized via NMR technology to evaluate the degree of oil production in different pores during the process of fracturing fluid imbibition and displacement; that is, by comparing the effects of crude oil viscosity, fracturing fluid interfacial tension, and fracturing fluid salinity on the fracturing fluid spontaneous imbibition, the mechanism of fracturing fluid imbibition and oil displacement is understood, furthering the efficient development of tight oil reservoirs.

2. EXPERIMENTAL SECTION

2.1. Materials. The fracturing fluid used in this experiment was provided by the PetroChina Oil and Gas Technology Institute of Changqing Oilfield Company, which is a clean fracturing fluid in the field of construction. The simulated crude oil used in the experiment was a mixture of kerosene and crude oil, with a volume ratio of 1:3 and a viscosity and a density of 3.67 mPa·s and 820 kg/cm\(^3\), respectively, at room temperature and at atmospheric pressure. Mn\textsuperscript{2+} was added to the simulated formation water to remove hydrogen signals. Three tight sandstone core samples were selected from the Chang 8 formation in the Ordos Basin. The basic information and properties of the three samples are shown in Table 1. The porosity of the experimental rock samples was distributed within 3.05–9.94%, with an average value of 12.61%. The gas permeability varied from 0.03 to 0.16 mD, with an average value of 0.09 mD.

| sample no. | porosity/% | permeability/mD | diameter/cm | length/cm |
|-----------|------------|----------------|-------------|-----------|
| 1         | 9.94       | 0.16           | 2.50        | 4.52      |
| 2         | 6.90       | 0.08           | 2.50        | 4.76      |
| 3         | 3.05       | 0.03           | 2.50        | 4.21      |

2.2. Experimental Setup. The experimental device, comprising a high-temperature and high-pressure displacement flow instrument (LDY-150), automatic interface tension meter (JYW-200C), a syringe pump (ISCO-500D), and core holders, was manufactured by the Jiangsu Huaxing Petroleum Instrument Co., Ltd, with a pressure resistance of 50.0 MPa. The Geospec2/53 NMR equipment for core observation was imported from Britain, with a 2 MHz permanent magnet, 50 mm probe, 1–30 MHz radio frequency distribution, 0.27 ms echo time, 50 s measurement waiting time, 64 scanning times, and a signal-to-noise ratio of 30, achieved via a CPMG sequence with an average of 1024 echoes. The magnetic field intensity, resonance frequency (RF), and RF frequency control accuracy are 0.5 T, 10 MHz, and 0.01 MHz, respectively.

2.3. Experimental Procedures. The experimental procedure is briefly described as follows: first, three natural cores with a diameter of approximately 25 mm were washed with benzene and dried. Their permeability was measured using a gas measurement apparatus. Then, the core samples are placed inside in a high-pressure vessel. The simulated formation water was injected into the cores at 0.05 mL/min until there was no \( T_2 \) change between NMR scans, indicating that the cores were fully saturated with the simulated formation water. The oven temperature was set at the formation temperature of 65 °C. A confining pressure of 12 MPa was applied. It should be noted that the uncertainty for measuring the confining pressure and injecting pressure is ±0.1 MPa. Three pore volumes (PVs) of the simulated crude oil with a viscosity of 3.67 mPa·s were introduced into the samples to establish the initial oil saturation at 0.05 mL/min. The injection pressure was 10 MPa both in water saturation and oil saturation. The LFNMR scan was applied to obtain the \( T_2 \) spectrum of the oil-saturated samples. As shown in Figure 1, the core samples were held in a nonmagnetic core holder. We did not need to disconnect when
scanning. The oven temperature and the confining pressure for core imbibition same as water saturation were 65 °C and 12 MPa, respectively. Note that confining pressure is provided by using a syringe pump to apply fluorocarbon oil possessing no hydrogen signals. Confining pressure is controlled slightly higher than the injecting pressure in the core samples to ensure that fluids can be imbibed from one side of the core sample. Spontaneous imbibition experiments were conducted at different times intervals, that is, 0, 24, 48, 72, 96, and 120 h. The core samples were then scanned to obtain the T2 spectrum for different imbibition scenarios. Finally, upon completing experiment group 1, the core samples were cleaned with benzene and dried. The above experimental steps were repeated for the second and third spontaneous imbibition experiment groups, with a crude oil viscosity of 5.27 and 7.13 mPa·s, respectively.

The above first set of experimental steps was repeated to obtain the initial oil-water distribution. The addition of 0, 0.1, and 0.5% surfactant TOF-1 to the fracturing fluid was conducted to change the interfacial tension and investigate its influence on the effect of oil displacement. The above first set of experimental steps was repeated, thereby establishing the initial oil-water distribution. The cores were placed in fracturing fluids with different salinities to conduct spontaneous imbibition experiments to investigate the influence of fracturing fluid salinity on oil displacement. The experimental parameters of core samples are shown in Table 2.

### Table 2. Experimental Parameters of Core Samples

| Group | Crude Oil Viscosity (mPa·s) | Fracture Fluid Salinity (mg/L) | Interfacial Tension (mN/m) | Core Sample |
|-------|-----------------------------|-----------------------------|---------------------------|-------------|
| 1     | 3.67                        | 25,000                      | 20.32                     | 1           |
| 2     | 5.27                        | 25,000                      | 20.32                     | 2           |
| 3     | 7.13                        | 25,000                      | 20.32                     | 3           |
| 1     | 3.67                        | 25,000                      | 20.32                     | 1           |
| 2     | 3.67                        | 25,000                      | 2.43                      | 2           |
| 3     | 3.67                        | 25,000                      | 0.84                      | 3           |
| 1     | 3.67                        | 25,000                      | 20.32                     | 1           |
| 2     | 3.67                        | 35,000                      | 20.32                     | 2           |
| 3     | 3.67                        | 45,000                      | 20.32                     | 3           |

3. RESULTS AND DISCUSSION

Since the 1980s, NMR technology has been widely used to observe the fluid distribution and pore volume changes under different environmental conditions. This technique can quantitatively characterize the change in the core pore volume parameters by measuring the transverse relaxation T2 distribution of the sample; the two have a good corresponding relationship. The NMR T2 value reflects the size of the specific surface of the rock pore throat, which is proportional to the pore throat radius, indicating that a larger T2 value corresponds to a larger core pore throat.

3.1. Influence of Crude Oil Viscosity on Spontaneous Imbibition. Figure 2 shows the T2 relaxation distribution of core sample 1 at different times and crude oil viscosities.
the simulated crude oil was saturated, the NMR curve had an obvious bimodal distribution, with a high right peak and low left peak. This indicates that there are two different types of pores in the core sample, that is, small pores (0.01−16.68 ms) and large pores (16.68−1608.23 ms). According to the NMR T2 spectrum, it is found that T2 signals in both pores decrease with spontaneous imbibition, suggesting that oil is driven from the core sample. Figure 2a shows the beginning of spontaneous imbibition (0−24 h); the T2 signal in the large pores is more significantly reduced than that in the small pores when the simulated crude oil viscosity is high, at 7.13 mPa·s. This indicates that in situ oil in the large pores is more readily displaced during the initial imbibition stage. The reason is that the capillary pressure is smaller in the larger pores, and the fracturing fluid is readily imbibed into the larger pore and enhances the oil recovery from such pores. After spontaneous imbibition for 120 h, the T2 signal changed slightly in both pores, suggesting that imbibition ended. Compared to Figures 2b,c, the T2 signals in the small pores were more significantly reduced with the decrease in crude oil viscosity, indicating that in situ oil in the small pores is more readily driven out. Figure 3 presents the oil recovery of core sample 1 at different spontaneous imbibition times and different crude oil viscosities. It appears that the imbibition rate increases faster from 0 to 24 h for the three crude oil viscosities. Imbibition slows as the oil is displaced and stops at 120 h. The final oil recovery is 41.52% for a crude oil viscosity of 3.67 mPa·s and 34.97% for a viscosity of 5.27 mPa·s. The lowest oil recovery of approximately 30.37% occurs for a viscosity of 7.13 mPa·s. In summary, the crude oil viscosity is negatively correlated with oil recovery.

By comparing the results, the degree of oil production (R) at different pore scales is calculated as follows

\[ R = \frac{V_0 - V_1}{V_0} \times 100\% \]  

where \( R \) is the degree of oil production, \( V_0 \) is the overburden area of the T2 curve at a certain pore after simulated crude oil saturates, and \( V_1 \) is the overburden area of the T2 curve at a certain pore at different spontaneous imbibition times.

Figure 4 illustrates the degree of oil production in core sample 1 at different pore scales. The degree of oil production is different between small pores and large pores at different spontaneous imbibition times and crude oil viscosities. For core sample 1, the degree of oil production in the large pores is higher than that in the small pores after 120 h of imbibition. Figure 4a shows that the degree of oil production in the small pores increases significantly with the decrease in crude oil viscosity during the initial imbibition stage. The degree of oil production in the small pores consistently increased during the later imbibition stage. Figure 4b shows that the degree of oil production shows an upward trend with increasing imbibition and the increment in the degree of oil production gradually increases with decreasing crude oil viscosity. The degree of oil production in the large pores decreased when the crude oil viscosity was 7.13 mPa·s, indicating that some oil in the small pores entered the large pores after 72 h of spontaneous imbibition. When the crude oil viscosity was 7.13 mPa·s, the maximum degree of oil production in the small pores was 24.1%, the minimum was 8.38%, and the average was 16.94%. The highest degree of oil production in the large pores was 47.61%, the lowest was 36.46%, and the average was 43.81%. When the crude oil viscosity was 5.27 mPa·s, the maximum degree of oil production in the small pores was 29.21%, the minimum was 18.6%, and the average was 23.6%. The maximum degree of oil production in the macropores was 50.12%, the minimum was 43.27%, and the average was 46.39%. When the crude oil viscosity was 3.67 mPa·s, the maximum degree of oil production in the small pores was 30.37%.
36.91%, the minimum was 21.86%, and the average was 30.96%. The maximum degree of oil production in the macropores was 53.63%, the minimum was 45.54%, and the average was 49.83%. Table 3 shows that the degree of oil production in the small pores is much lower than that in the large pores under high crude oil viscosity. The oil displacement in the core mainly originates from large pores. As the crude oil viscosity decreases, the degree of oil production in both the small and large pores improved; however, the increment in the degree of oil production in the small pores was greater than that in the large pores, demonstrating that the decrease in crude oil viscosity has clearly contributed to the degree of oil production in the small pores; this is attributed to the lower crude oil viscosity, which results in a lower adhesion to the core and is thus more conducive to displacing the crude oil in the small pores. Therefore, reducing the crude oil viscosity can effectively improve the oil recovery of tight reservoir cores dominated by small pores.

### Table 3. Degree of Oil Production in Core Sample 1 at Different Pore Scales

| Group | Pore Scale | 24 h | 48 h | 72 h | 96 h | 120 h |
|-------|------------|------|------|------|------|-------|
| 1     | Small pores | 8.38 | 14.34 | 18.38 | 19.48 | 24.1  |
|       | Large pores | 36.46 | 44.23 | 43.22 | 47.57 | 47.61 |
| 2     | Small pores | 18.6 | 20.84 | 23.96 | 25.48 | 29.21 |
|       | Large pores | 43.27 | 44.63 | 45.96 | 47.99 | 50.12 |
| 3     | Small pores | 21.86 | 29.09 | 32.17 | 34.77 | 36.91 |
|       | Large pores | 45.54 | 47.84 | 50.14 | 52.02 | 53.63 |

3.2. Influence of Interfacial Tension on Spontaneous Imbibition. Figure 5 presents the oil recovery at various spontaneous imbibition stages and under three types of interfacial tensions for core sample 2. After the simulated oil was saturated, the T<sub>2</sub> spectrum of core sample 2 showed a bimodal distribution with a high right peak and a low left peak, indicating that large pores develop better than small pores. The small pores of core sample 2 are mainly distributed from 0.01 to 16.68 ms and the large pores from 16.68 to 372.76 ms. The bimodal peaks of core sample 2 decreased after 24 h of spontaneous imbibition and exhibited a different downward trend between small and large pores with the decrease in interfacial tension. The T<sub>2</sub> signal in the large pores reduced significantly with the lower interfacial tension. At 48 h of spontaneous imbibition, the right peak decreased significantly, the left peak decreased slightly, and the amplitude was lower than the right peak. The capillary force weakened due to the decrease in interfacial tension and the fluidity of the fracturing fluid greatly improved, which is conducive to oil displacement. There was a consistent decrease in the peak amplitude from 72 to 96 h. After 120 h of imbibition, both the left and right peaks stopped decreasing, that is, the imbibition had reached a balance. With spontaneous imbibition of 120 h, the oil recovery efficiencies of sample 2 were 22.21, 30.07, and 41.6%, respectively. Figure 6 shows that the interfacial tension is negatively correlated with oil recovery efficiency, that is, the oil recovery efficiency increases as interfacial tension decreases.

Figure 7 illustrates the degree of oil production in the small and large pores at various spontaneous imbibition stages for core sample 2. After 120 h of spontaneous imbibition, the degree of oil production in both the small and large pores showed an upward trend. When the interfacial tension was 20.03 mN/m, the degree of oil production in the small pores was higher than that in the large pores, indicating that crude oil was mainly replaced through the small pores, from 0 to 120 h of spontaneous imbibition. The degree of oil production in the large pores improved significantly with the decrease in interfacial tension. When the interfacial tension was 2.83 and 0.84 mN/m, respectively, the large pores exhibited higher oil production for all imbibition stages compared to the small pores. As shown in Figure 7a, the degree of oil production increases in the small pores as imbibition progresses. The degree of oil production in the small pores gradually increases with the increase in interfacial tension. Figure 7b shows that the low interfacial tension corresponds to a higher degree of oil production in the large pores and the increment in the degree of oil production in the large pores was 20.03 mN/m, the degree of oil production in the small pores was higher than that in the large pores, indicating that crude oil was mainly replaced through the small pores, from 0 to 120 h of spontaneous imbibition.
of oil production is greater than that in small pores. When the interfacial tension was 20.83 mN/m, the maximum degree of oil production in the small pores was 26.99%, the minimum was 12.03%, and the average was 18.57%. The maximum degree of oil production in the large pores was 16.96%, the minimum was 8.44%, and the average was 13.72%. When the interfacial tension was 2.43 mN/m, the maximum degree of oil production in the small pores was 26.81%, the minimum was 10.08%, and the average was 19.61%. The maximum production degree in the large pores was 36.49%, the minimum was 19.25%, and the average was 29.71%. When the interfacial tension was 0.84 mN/m, the maximum degree of oil production in the small pores was 33.38%, the minimum was 13.26%, and the average was 25.71%. The maximum degree of oil production in the large pores was 52.24%, the minimum was 32.07%, and the average was 44.44%. Table 4 shows that the degree of oil production at various scales is negatively correlated with the interfacial tension of the fracturing fluids. The reduction in interfacial tension contributes to a significant increase in the degree of oil production in the large pores. Adding surfactants to the fracturing fluid can lower the oil-water interfacial tension, leading to a drop in the capillary forces during the imbibition process. Therefore, the capillary force at the front edge of the oil-water phase was not sufficient to overcome the viscous force, preventing the crude oil in some of the small pores from being driven out completely. However, the reduction in IFT leads to a decrease in capillary pressure and reduces the resistance to oil flowing in large pores at the same time, which means that the fracturing fluid is readily imbibed into the larger pore and the oil in the large pores is more readily displaced. Moreover, before the experiment of interfacial tension on spontaneous imbibition, we have tested the wettability of the core before and after the experiment. The result indicated that it was hydrophilic and adding the surfactant creates no change in wettability.

### Table 4. Degree of Oil Production in Core Sample 2 at Different Pore Scales

| group | pore scales | 24 h | 48 h | 72 h | 96 h | 120 h |
|-------|------------|------|------|------|------|-------|
| 1     | small pores | 12.03| 14.73| 16.88| 22.20| 26.99 |
| 1     | large pores | 8.44 | 12.16| 14.95| 16.10| 16.96 |
| 2     | small pores | 10.08| 15.34| 18.97| 26.79| 26.87 |
| 2     | large pores | 19.25| 26.14| 30.96| 35.71| 36.49 |
| 3     | small pores | 13.26| 20.78| 28.79| 32.36| 33.38 |
| 3     | large pores | 32.07| 40.68| 46.92| 50.31| 52.24 |

3.3. Influence of Salinity on Spontaneous Imbibition.

After the simulated crude oil saturates, the T2 spectrum of core sample 3 is bimodal and the left peak is higher than the right (Figure 8), indicating that the core is dominated by small pores. We divided the pores in core sample 3 into small and large pores, with the curve distribution ranging from 0.01 to 16.68 and 16.68 to 179.46 ms, respectively. At 24 h of spontaneous imbibition, the left peak decreased significantly and the right peak decreased slightly lower than the left. With the increase in salinity, the downward trend of the left peak became more obvious. The decrease in amplitude of the bimodal peak was consistent between imbibition at 72 and 96 h. After imbibition for 120 h, both the left and right peaks stopped decreasing, indicating a spontaneous termination to imbibition. As shown in Figure 9, oil recovery under different salinities increases faster during the initial stages of spontaneous imbibition (0−24 h), and the rate of increase in oil recovery slowed as imbibition progressed. The ultimate oil recovery was 13.58% at a salinity of 45,000 mg/L and at 35,000 mg/L the oil recovery was 15.45%. The highest oil recovery, approximately 17.31%, occurred at 25,000 mg/L. Figure 9 shows that the fracturing fluid salinity is negatively
correlated with oil recovery; that is, the oil recovery efficiency decreases as the fracturing fluid salinity increases.

Figure 10 shows that the oil production of small pores is higher than that of large pores during the spontaneous imbibition process, indicating that oil displacement mainly occurs in small pores. With the decrease in fracturing fluid salinity, the degree of oil production in both the small and large pores increases; however, the improvement to the degree of oil production in the large pores is smaller. The major factor affecting the degree of oil production in the small pores is the difference in ion concentration, which causes the salt ions in the core to diffuse to the surrounding environment; thus, the low-salinity fracturing fluid enters the core through the large pores, resulting in a certain imbibition displacement pressure difference and helping to drive the crude oil out of the small pores. When the fracturing fluid salinity was 25,000 mg/L, the maximum degree of oil production in the small pores was 20.3%, and the minimum was 6.47%; the average was 14.67%. The highest, lowest, and average degrees of oil production in the large pores were 16.65, 9.56, and 11.96%, respectively. When the fracturing fluid salinity was 35,000 mg/L, the maximum degree of oil production in the small pores was 18.17%, the minimum was 5.66%, and the average was 11.99%. The maximum, minimum, and average degrees of oil production in the large pores were 14.2, 9.3, and 9.04%, respectively. When the fracturing fluid salinity was 45,000 mg/L, the maximum degree of oil production in the small pores was 16.08%, the minimum was 5.54%, and the average was 10.29%. The maximum degree of oil production in the large pores was 10.5%, the minimum was 5.1%, and the average was 7.2%. Table 5 demonstrates that the degree of oil production at various scales is negatively correlated with the fracturing fluid salinity and the decrease in fracturing fluid salinity significantly contributes to the degree of oil production in the small pores. Therefore, the salinity of the injected fracturing fluid should not exceed that of the formation water; otherwise, the low pressure inside the core impedes the crude oil from being driven out of the smaller pores.

4. CONCLUSIONS

(1) The restrictive factors of spontaneous imbibition included crude oil viscosity, interfacial tension, and salinity. The experimental results showed that the fracturing fluid salinity, fracturing fluid interfacial tension, and crude oil viscosity were all negatively correlated with oil recovery efficiency.

(2) The phenomenon of microscale imbibition oil displacement occurred in the pores of various scales in the core. The imbibition scale was between 0.10 and 1608.23 ms. The degree of crude oil production in the pores at each scale increased with increasing imbibition time.

(3) The crude oil viscosity was negatively correlated with the degree of oil production of various pore scales and decreasing the crude oil viscosity significantly improved the degree of oil production in the small pores. The fracturing fluid interfacial tension was negatively correlated with the degree of oil production at various pore scales. The low interfacial tension possessed a higher degree of oil production in the large pores and

Figure 8. T2 relaxation distribution of core sample 3. (a) T2 signals at various spontaneous imbibition stages at 45,000 mg/L. (b) T2 signals at various spontaneous imbibition stages at 35,000 mg/L. (c) T2 signals at various spontaneous imbibition stages at 25,000 mg/L.

Figure 9. Oil recovery of core sample 3 at different spontaneous imbibition times.
the increment in the degree of oil production was greater than that of the small pores. The salinity of the fracturing fluid was negatively correlated to the degree of oil production at various pore scales. Therefore, the salinity of the formation water should not be exceeded when choosing the salinity of the injected fracturing fluid.

**AUTHOR INFORMATION**

**Corresponding Author**

Hui Gao — School of Petroleum Engineering, Xi’an Shiyou University, Xi’an 710065, China; Ministry of Education, Engineering Research Center of Development and Management for Low to Ultra-Low Permeability Oil & Gas Reservoirs in West China, Xi’an 710065, China; Xi’an Key Laboratory of Tight Oil (Shale Oil) Development, Xi’an 710065, China; orcid.org/0000-0003-2561-5514; Phone: +86 13572244837; Email: ghtopsun1@163.com

**Authors**

Yalan Wang — School of Petroleum Engineering, Xi’an Shiyou University, Xi’an 710065, China; Ministry of Education, Engineering Research Center of Development and Management for Low to Ultra-Low Permeability Oil & Gas Reservoirs in West China, Xi’an 710065, China; Xi’an Key Laboratory of Tight Oil (Shale Oil) Development, Xi’an 710065, China

Yonggang Xie — Oil and Gas Technology Institute of Changing Oilfield Company, PetroChina, Xi’an 710018, China; National Engineering Laboratory for Exploration and Development of Low-permeability Oil & Gas Fields, Xi’an 710018, China

**Jun Ni** — Research Institute of Shaanxi Yanchang Petroleum (Group) Co., Ltd., Shannxi Xi’an 710075, China

**Teng Li** — School of Petroleum Engineering, Xi’an Shiyou University, Xi’an 710065, China; Ministry of Education, Engineering Research Center of Development and Management for Low to Ultra-Low Permeability Oil & Gas Reservoirs in West China, Xi’an 710065, China; Xi’an Key Laboratory of Tight Oil (Shale Oil) Development, Xi’an 710065, China

**Chen Wang** — School of Petroleum Engineering, Xi’an Shiyou University, Xi’an 710065, China; Ministry of Education, Engineering Research Center of Development and Management for Low to Ultra-Low Permeability Oil & Gas Reservoirs in West China, Xi’an 710065, China; Xi’an Key Laboratory of Tight Oil (Shale Oil) Development, Xi’an 710065, China

**Junjie Xue** — School of Petroleum Engineering, Xi’an Shiyou University, Xi’an 710065, China; Ministry of Education, Engineering Research Center of Development and Management for Low to Ultra-Low Permeability Oil & Gas Reservoirs in West China, Xi’an 710065, China; Xi’an Key Laboratory of Tight Oil (Shale Oil) Development, Xi’an 710065, China

Complete contact information is available at:
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**Notes**

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