The Law and Mechanism of the Sample Size Effect of Imbibition Oil Recovery of Tight Sedimentary Tuff

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ABSTRACT: Imbibition is an important mechanism to improve the recovery factor (RF) of a tight oil reservoir. Accurately evaluating the oil production capacity of tight oil reservoirs by imbibition is of great significance for the formulation of oilfield production plans and productivity prediction. However, there is currently no unified regulation on the selection of rock sample size in tight oil reservoir imbibition evaluation experiments, resulting in great differences in reservoir imbibition oil production capacity obtained from rock samples of different sizes, which brings great challenges to the efficient development of tight oil reservoirs. To clarify the law and mechanism of the rock sample size effect of tight core imbibition oil recovery, this paper takes the newly discovered tight sedimentary tuff (TST) oil reservoir as an example. First, several representative real cores were collected. Then, their wettability and pore structure characteristics were analyzed. Finally, physical simulation experiments of imbibition under different rock sample sizes were conducted. The results show that the TST has very favorable imbibition conditions, which are manifested in the following: (i) the wettability is weakly hydrophilic to hydrophilic; (ii) the mineral composition is tuffaceous minerals, calcite, and quartz, without clay minerals; (iii) micro-nanoscale pores are developed; and (iv) the pore throats are evenly distributed. In the imbibition experiments of rock samples of different sizes, the oil production characteristics of the core surface, the variation form of imbibition rate, pore production characteristics, and the influence mode of imbibition pressure on imbibition do not have the sample size effect. However, the RF of the spontaneous imbibition has an obvious sample size effect, and there is a good exponential function relationship between the imbibition RF and the specific surface area (SSA) of cores. The fundamental reason why the rock sample size effect of the TST imbibition oil recovery is relatively stable and has strong regularity is that its pore structure and wettability are relatively homogeneous and stable. The change of rock sample size does not have a great impact on the distribution of the core pore structure and wettability, resulting in no significant change in its imbibition power, resistance, and distance. Therefore, the main factor determining the imbibition RF of rock samples with different sizes is their SSA. The research results of this work can provide an important theoretical basis for understanding the law and mechanism of TST imbibition oil recovery and unifying the imbibition experimental results of small-sized rock samples.

1. INTRODUCTION

With the continuous decrease in the production of conventional oil and gas resources, unconventional oil and gas resources such as tight oil have become important replacement resources. In 2019, the production of tight oil in the United States was close to $4 \times 10^8$ t, and its proportion in the total crude oil production reached 65.1%. The development of tight oil in China started late. In 2018, the production of tight oil was about $10^5 \times 10^4$ t. At present, China is vigorously developing the exploration and development theory and technology of tight oil, and tight oil production is expected to further increase. The biggest feature of tight oil reservoirs is that their pore size is very small, and fluid seepage is very difficult. Traditional water flooding is difficult to establish an effective displacement pressure gradient between water injection wells and oil production wells due to the ultrahigh seepage resistance. For some tight oil reservoirs with developed natural fractures, due to the great difference in seepage capacity between fractures and the matrix, water flooding will quickly form burst flooding in the fracture channel, thereby resulting in extremely low sweep efficiency. Due to the special performance of tight oil reservoirs during water flooding, water huff and puff oil production technology is regarded as one of the key means to...
exploit tight oil reservoirs.\textsuperscript{17−22} Its construction process is divided into three stages. First, a certain volume of water is injected into the reservoir through a production well, then the well is soaked for a period of time, and finally, oil is produced through the production well. The feasibility of water huff and puff for tight oil reservoirs lies in the following: first, the water huff and puff technology does not require the ultrahigh injection pressure required for water flooding, and there will be no burst flooding between production wells and water injection wells; second, water huff and puff technology can effectively produce oil by using mechanisms such as energy enhancement, imbibition, and oil−water gravity differentiation.\textsuperscript{23−25} Compared with energy enhancement and oil−water gravity differentiation, imbibition is a more complicated problem, and it is also a hotspot in the current research on the efficient development of tight oil reservoirs.\textsuperscript{26−29}

Imbibition refers to the process where the wetting phase enters the pore throat under capillary force to displace the non-wetting phase, and the capillary force is the main driving force of the imbibition process.\textsuperscript{30−35} In the development of tight oil reservoirs, when the wetting phase of the reservoir is water and the non-wetting phase is oil, the injected water will displace the crude oil to larger pores and fractures under the action of capillary force, and then the oil is produced under the action of pressure difference. Therefore, the factors that determine the effect of imbibition oil recovery in tight oil reservoirs mainly include the wetting phase, non-wetting phase, and rock pore structure. Scholars have conducted a lot of research on these. (i) Wetting phase: Yu et al. studied the imbibition mechanisms of Winsor I-type surfactant solution in oil-wet porous media.\textsuperscript{34} Zhao et al. studied the types and formation mechanisms of residual oil after two-surfactant imbibition.\textsuperscript{35} Zhang et al. studied the increased viscosity effect for fracturing fluid imbibition in shale.\textsuperscript{36} (ii) Non-wetting phase: Meng et al. studied the effect of fluid viscosity on SI.\textsuperscript{37} Kibria et al. studied the influence of wettability on the SI.\textsuperscript{38} Rezaveisi et al. conducted the experimental investigation of matrix wettability effects on water imbibition in fractured artificial porous media.\textsuperscript{39} (iii) Rock pore structure: Yang et al. studied the effects of the TOC content on SI.\textsuperscript{40} Liu et al. studied the impacts of mineral composition and the pore structure on SI in tight sandstone.\textsuperscript{41} (iv) Comprehensive influencing factors: Roosta et al. studied the temperature effect on wettability and oil recovery efficiency during SI.\textsuperscript{42} Wang et al. studied the characteristics of oil distributions in forced and SI of the tight oil reservoir.\textsuperscript{43} Amadu and Pegg obtained the analytical solution to SI under a vertical temperature gradient based on the theory of SI dynamics.\textsuperscript{43} Zhou et al. studied the effect of the KCL concentration, confining pressure, and imbibition direction on the SI in igneous rocks.\textsuperscript{44}

By summarizing the previous studies on tight oil imbibition oil recovery, it can be found that, at present, the main method that scholars use to study the imbibition oil recovery of tight oil reservoirs is still the imbibition experiments of small-sized cores in the laboratory. However, there are currently no API standards or China petroleum industry standards for core size selection in the process of imbibition experiments, which may lead to great differences in imbibition experimental results obtained by rock samples of different sizes. The fundamental reason why the change of rock sample size may have a great impact on the imbibition oil recovery characteristics of tight cores is that, for specific types of rocks, when the rock sample size changes, the pore structure and wettability distribution in the core may change significantly, resulting in obvious differences in imbibition oil recovery effects, especially for tight cores with strong heterogeneity. Therefore, for core-scale imbibition experiments, the reasonable selection of rock sample size is very important. At present, there are relatively few studies on the sample size effect of tight core imbibition, but some scholars have also conducted research in this area and gained some understanding. For example, Zhu et al. believed that the imbibition rate of short rock samples was faster than that of long rock samples.\textsuperscript{45} Wang et al. selected cores with lengths of 0.05, 0.10, 0.20, 0.50, 1.00, and 2.00 m for SI, and the numerical simulation results showed that the smaller the rock sample size, the higher the core RF.\textsuperscript{46} Mingshuang et al. selected cores with the same diameter and length of 2 and 4 cm for the SI experiment and found that the RF of SI of tight cores is negatively correlated with their length.\textsuperscript{47} Wang et al. believed that, under the premise of the same other conditions, the shorter the core length, the better the dynamic imbibition effect.\textsuperscript{48} Wang et al. found that, in the volumetric fracturing of tight oil reservoirs, when the length of the matrix block increases, the RF of the reservoir first decreases sharply and then decreases slowly. The authors believed that the fundamental reason for this phenomenon is that the smaller matrix blocks have a higher SSA.\textsuperscript{49} It can be seen that scholars have made active explorations on the sample size effect of tight oil imbibition and have achieved beneficial results, but there are still the following problems: (i) the existing studies only focus on the rock sample size effect of imbibition RF but do not discuss in detail the rock sample size effect law of oil production characteristics of the core surface, imbibition rate, pore production characteristics, and the influence of pressure on imbibition; (ii) the existing research only obtains the qualitative understanding between core imbibition RF and the rock sample size but does not realize the quantitative characterization of the two; (iii) the mechanism of the sample size effect of tight oil imbibition is not explained. The existence of the above problems makes the results of the imbibition experiments of rock samples of specific sizes in the laboratory have huge blindness and uncertainty in characterizing the results of imbibition experiments of other sizes of rock samples and evaluating the ability of reservoir imbibition oil recovery. Therefore, it is of great significance to clarify the law of the rock sample size effect of tight core imbibition.

The innovations of this work mainly include the following aspects: (i) A newly discovered and new type of tight oil reservoir was selected as the research object, namely, the TST oil reservoir. (ii) In the study of the sample size effect of imbibition, in addition to imbibition RF, the law of the sample size effect of core surface oil production characteristics, imbibition rate, imbibition pore production characteristics, and the influence of imbibition pressure on imbibition was also studied. (iii) The mathematical model between the imbibition RF and the rock sample size was obtained, the quantitative description of the relationship between the imbibition RF and the rock sample size was realized, and the prediction effect of the model was in good agreement with the experimental results. (iv) The pore structure and wettability of TST were analyzed in detail, and the law and mechanism of the sample size effect of TST imbibition were explained.

The rest of this paper is organized as follows: Section 2 introduces the geographical location, reservoir characteristics, and development status of the TST oil reservoir. Section 3...
introduces the materials, equipment, and procedures of the experiment, including the core pore structure test, glass etching imbibition experiment, and imbibition experiments of cores with different sizes. Section 4 shows the analysis and discussion of the experimental results. First, the test results of the core pore structure are analyzed, and the imbibition experimental results of glass etching and cores of different rock samples sizes are analyzed, including the imbibition rate, imbibition RF, pore production characteristics, and the influence of pressure on imbibition. Next, the law of the sample size effect of TST imbibition is summarized. Finally, the mechanism of the sample size effect of TST imbibition is analyzed. Section 5 summarizes these findings. The proposed methods and sequence of steps are shown in Figure 1.

The objective of this work is to determine the law and mechanism of the rock sample size effect of TST imbibition. The research results reveal the pore structure characteristics and imbibition characteristics of TST and provide a solid basis for unifying the imbibition experimental results of small-sized cores of the TST and the prediction of the imbibition oil recovery effect of a single well at the oilfield scale.

2. RESERVOIR BACKGROUND

Malang Tiaohu sag in Santanghu basin, located in the northeast of Xinjiang, is the main battlefield of tight oil exploration and development of the Tuha oilfield. In 2013, tight oil was found for the first time in the second member of the Permian Tiaohu formation in the sag, and good well testing and production test results were obtained. Further exploration and development practice found that this tight oil reservoir is quite different from the tight oil reservoirs that have been discovered at home and abroad in reservoir lithology, crude oil physical properties, and the source—reservoir configuration relationship. The details are as follows: (i) the oil reservoir lithology is neither sandstone nor shale and carbonate but sedimentary tuff. (ii) The lithology is pure, no argillaceous, with well-developed pores and high oil saturation. (iii) Crude oil belongs to medium-heavy oil, not light oil, with a density of 0.89–0.91 g/cm³. (iv) The hydrocarbon source rock is not in close contact with the oil reservoir but separated from the oil reservoir. The crude oil generated by the hydrocarbon source rock of the second member of the Lucaogou formation migrates up to 100–500 m along the fault, passes through the volcanic lava of the first member of Tiaohu formation, and accumulates in the sedimentary tuff of the second member of Tiaohu formation. The reservoir was finally named as a TST oil reservoir, which belongs to a new and special type of tight oil reservoir and has important exploration and development value. The geographical location of the TST oil reservoir is shown in Figure 2a. In Figure 2a, the geographical location is on the left and the stratigraphic distribution in the vertical direction is on the right. The cross section of the TST oil reservoir and the migration path of crude oil during reservoir formation are shown in Figure 2b.

By the end of 2018, the pilot area for effective development of tight oil in block Ma 56 has been built, with an annual production capacity of 25.6 × 10⁴ t, making the oil reservoir the first tuff tight oil reservoir successfully explored and developed in China or possibly globally. Although the TST oil reservoir is very special and shows good development prospects, it also faces the common problems of other tight oil reservoirs, such as low RF of natural energy depletion, difficulty in energy supplement, and low recovery degree. After nearly 8 years of development practice, the oilfield found that the development effect of conventional water flooding and gas flooding is not ideal. Currently, after the end of natural energy depletion exploitation, the oilfield mainly adopts water huff and puff technology to further enhance the RF of the reservoir. The oilfield production data have shown that the water huff and puff technology can improve the RF of the TST oil reservoir to a certain extent.

Imbibition is an important mechanism of water huff and puff oil recovery. Accurate evaluation of reservoir imbibition oil recovery capacity is of great significance to understand and improve the oil recovery potential of water huff and puff in tight oil reservoirs. However, the evaluation experiment of reservoir imbibition capacity is often closely related to the size of the selected rock sample. Therefore, it is very necessary to clarify the law and mechanism of the rock sample size effect of

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**Figure 1.** Flowchart of this work.
TST imbibition so as to provide a solid theoretical basis for evaluating reservoir imbibition and water huff and puff oil production capacity.

3. EXPERIMENTAL SECTION

3.1. Materials. The experimental contents of this study include core pore structure analysis and imbibition experiments of different rock sample sizes. Therefore, the experimental materials include cores, oil, and water. In the imbibition experiments, artificial cores and real cores are currently the most used. The artificial cores are characterized by convenient manufacture, low cost, and high repeatability.69,70 The characteristic of the real cores is that they directly represent the real pore structure characteristics of the reservoir, which is more in line with the actual reservoir situation, but its shortcomings are difficulty in obtaining and higher cost. The cores used in this paper are the real cores of the reservoir. In addition, to observe the imbibition phenomenon of the TST more intuitively, this study enlarged the local pore structure of the TST and made a corresponding glass etching model to clearly and intuitively observe the core imbibition process. The details are as follows.

3.1.1. Experimental Cores. All experimental cores are representative real cores of the TST oil reservoir of the Tiaohu formation in the Santanghu basin, and the coring depth is 2644.18–2712.34 m. The basic parameters of the experimental cores are shown in Table 1. During the experiment, the cores with a diameter of 2.5 cm are called small-sized cores, and the cores with a diameter of 10 cm are called large-sized cores. A total of 12 small-sized cores and 2 large-sized cores were selected in the experiment. The diameters of the small-sized cores ranged from 2.472 to 2.56 cm.
The TST cores are weakly hydrophilic to hydrophilic. This is also an important prerequisite for using water huff and puff technology in the production of the TST oil reservoirs in the Tuha oilfield.  

### 3.1.2. Preparation of the Glass Etching Model

The glass etching model used in the experiment was made according to the cast thin section, scanning electron microscopy (SEM), and high-pressure mercury intrusion test results of the real cores. However, because the matrix pores of the tight core belong to the micro-nanoscale and the pore radius is very small, it is etched according to the same proportion as the core, then it is very difficult to make and observe, and the cost of making samples is also very expensive. Up to now, there are no reports in the literature on the actual one-to-one reduction of the pore structure of the tight core using the glass etching model, and it is difficult to achieve from the prior art. Therefore, when making the glass etching model, this study enlarges the pore structure of the actual TST core. Meanwhile, to give full play to the role of glass etching and clarify the differences of pores of different sizes in the process of imbibition oil recovery, when making the glass etching model, a part of the actual core was enlarged by 1500 and 2000, respectively, which were combined and named as the high permeability area and low permeability area. The average pore throat radius in the low permeability area is 0.098 mm and that in the high permeability area is 0.13 mm. The substrate and cover of the glass etching model are float glass, which has the advantages of good flatness, no water ripple, good transparency, and not easy to damage during etching. The fabrication process of the micro model includes pretreatment, laser etching, cleaning, sintering, and testing. After the glass etching model was made, the hydrophilicity of the glass etching model was tested by a contact angle instrument, and the results showed that the core was weakly hydrophilic (the contact angle is 50–55°), which is similar to the wettability of the actual cores.

It should be noted that, although the glass etching model used in this study is not equal to the real pore structure of the TST, there is a slight difference in wettability distribution from the real cores. However, it is an equal magnification of the pore structure of the real TST, and the wettability is less different from the real cores. Therefore, it can still reflect the imbibition characteristics of the TST to a certain extent. Compared with CT imaging and NMR imaging that describe the imbibition characteristics of tight oil cores, the glass etching model achieves real visualization. Under the existing technical level, such research is still of great exploratory significance for understanding the imbibition characteristics of the TST. As for the impact of reducing the average pore radius of the rock from the current 100 μm level to 0.07 μm (the actual average pore radius of the TST is 0.07 μm), it still needs further research, especially in the real visual experimental research.

### 3.1.3. Experimental Oil

The formation crude oil of the TST oil reservoir is medium-quality, high-viscosity, high-wax, and medium-pour-point. The average pore radius of the TST cores is only 0.063 μm. Therefore, when the formation crude oil is used for the imbibition experiment, the process of core saturation with oil is very difficult, the imbibition experiment takes a long time, the NMR test and measurement errors are large, and the imbibition phenomenon on the core surface is not easy to observe. Therefore, this study replaces the formation oil with kerosene. Compared with the wettability of the rock itself, the influence of kerosene on the wettability of the rock is negligible. The viscosity of kerosene is 1.05 mPa s, and the density is 0.795 kg/m³ at a room temperature of 25 °C.

### 3.1.4. Experimental Water

The experimental water was configured according to the type of formation water, which was a NaHCO₃ type and its salinity was 9000 mg/L. However, to observe the change of the oil signal in different pores of the core at different imbibition times, NMR technology was widely used in this experiment. Due to the NMR technology mainly monitoring the hydrogen signal in the fluid, to observe the change of the oil signal, the hydrogen signal in the water must be shielded. In this study, a high concentration of MnCl₂·4H₂O was added to the water to shield the hydrogen signal in the NMR test.

### Table 1. Basic Parameters of Experimental Cores

| core no. | diameter (cm) | length (cm) | permeability (×10⁻⁵ μm²) | porosity (%) | experimental content |
|----------|---------------|-------------|--------------------------|--------------|---------------------|
| T1       | 2.529         | 2.529       | 0.062                    | 19.22        | cast thin section test |
| T2       | 2.510         | 2.000       | 0.050                    | 15.26        | SEM test |
| T3       | 2.472         | 1.938       | 0.026                    | 14.09        | high-pressure mercury intrusion test |
| T4       | 2.474         | 1.998       | 0.037                    | 16.38        | high-pressure mercury intrusion test |
| T5       | 2.511         | 1.842       | 0.054                    | 19.31        | NMR test |
| T6       | 2.509         | 1.806       | 0.125                    | 16.99        | NMR test |
| T7       | 2.480         | 4.752       | 0.04                     | 18.17        | SI |
| T8       | 2.491         | 4.478       | 0.051                    | 15.91        | FI |
| T9       | 10.02         | 8.22        | 0.072                    | 20.23        | SEM test |
| T10      | 2.500         | 3.000       | 0.054                    | 16.21        | SI |
| T11      | 2.480         | 4.500       | 0.072                    | 16.49        | SI |
| T12      | 2.500         | 5.502       | 0.046                    | 18.21        | SI |
| T13      | 2.510         | 7.012       | 0.049                    | 19.04        | SI |
| T14      | 10.040        | 7.600       | 0.054                    | 18.01        | SI |

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the water. The concentration of MnCl$_2$·4H$_2$O used in the experiment was 72 g/L, so the final salinity of the experimental water was 81 g/L. In the imbibition experiment, it is a common method of adding MnCl$_2$·4H$_2$O to water to shield the signal of hydrogen ions in water. For the TST, the addition of MnCl$_2$·4H$_2$O to water has little effect on the pore structure and wettability of the core. Meanwhile, in the visual experiment of the glass etching model, to observe the oil–water two-phase distribution, an appropriate amount of Sudan red was added to the oil and an appropriate amount of methylene blue was added to the water to make the oil red and water blue.

### 3.2. Equipment

The experiment in this study includes four parts: the pore structure analysis experiment, glass etching model imbibition experiment, multiple small-sized rock sample imbibition experiments (NMR monitoring, SI, and FI), and large-sized rock sample imbibition experiments (NMR monitoring). In all experiments in this study, the external dimensions of the cores were measured using a Vernier caliper. The porosity was measured using a 113 helium porosity meter (American Core Lab Corporation, Houston, Texas, USA), and the permeability was measured by a 112 air permeability meter (American Core Lab Corporation, Houston, Texas, USA). The NMR instrument adopted a MacroMR12-150H-I large aperture NMR analyzer produced by Suzhou Niumai Company. The other experimental equipment used in each experiment is shown below.

#### (i) Pore structure analysis experiment

The test thin section was made by Beijing Riyueshi Mining Co., Ltd. and observed and identified by a polarizing microscope. SEM adopted the COXEM-EM-30 Plus ultrahigh-resolution SEM. The high-pressure mercury intrusion adopted a Poremaster PM-33-13 mercury intrusion instrument.

#### (ii) Glass etching model imbibition experiment

To simulate the oil–water two-phase imbibition in the core, one end of the etching model was completely open and the other end was closed. The digital microscope used was DinoLite, and the software used to process the imaging results was Dino capture 2.0. During the experiment, a backlight and reflector were used to improve the image and video quality of the digital microscope. The experimental equipment is shown in Figure 4. (a) Small-sized rock sample imbibition experiments: The SI experiments of small-sized cores were completed in an imbibition bottle, and the measurement accuracy of the imbibition bottle was 0.001 mL. The FI experiment was completed in an autoclave, and the pressure pump used was an ISCO-260D high-precision displacement pump, which was produced by the Teledyne ISCO Company in the United States. The experimental equipment is shown in Figure 5a,b. (b) Large-sized rock sample imbibition experiments: The imbibition experiments of the large-sized cores were completed in a beaker, as shown in Figure 5c.

### 3.3. Procedure

The corresponding experimental procedures of the four main experiments are as follows.

#### 3.3.1. Pore Structure Analysis Experiment

All of the pore structure analysis experiments strictly complied with the testing standards of the China petroleum industry. The core porosity and permeability test referred to SY/T 5336-2006. The test thin section and SEM test referred to SY/T 6103-2004. The high-pressure mercury intrusion test referred to SY/T 5346-2005. The NMR test referred to SY/T 6490-2014.

#### 3.3.2. Glass Etching Model Imbibition Experiment

(a) A vacuum pump was used to vacuum the already made glass etching model for 12 h. (b) When the core was completely vacuumed, the glass etching model was saturated with the experimental oil dyed with Sudan red at a pressure difference of 0.1 MPa, and when the glass etching model was fully saturated with oil, a scanning microscope was used to record its original saturated oil state. (c) The glass etching model saturated with the experimental oil was put into a beaker containing water dyed with methylene blue. When the oil and water came into contact, the imbibition officially began. Thereafter, a scanning microscope was used to observe the distribution characteristics of the oil and water in the glass etching model at regular intervals. (d) The imbibition experiment of the no. 1 core was conducted in a beaker, which belonged to SI, so the imbibition process at different times could be observed. The imbibition experiment of the no. 2 core was conducted in an autoclave, which belonged to FI, so it could only observe the oil–water distribution before and after the imbibition. In the glass etching model imbibition experiment of this study, the pore size of the glass etching model was relatively large, and the glass etching model had a certain ultimate bearing strength. Therefore, 0.2 MPa confining pressure was applied to the glass etching model to study the influence of pressure on imbibition.

#### 3.3.3. Small-Sized Rock Sample Imbibition Experiments under NMR Monitoring

The imbibition experiments of small-sized cores include SI and FI. The spontaneous imbibition was conducted in an imbibition bottle, and the experimental steps were mainly divided into four steps: (i) first, selecting the core, cleaning the core, drying it and then saturating the core with oil in three ways: vacuum saturation, autoclave high-pressure saturation, and displacement saturation. When the saturation process was finished, the core was put into the oil barrel for aging for 30 days. (ii) When the core aging was completed, the core surface was wiped, and then the NMR T2 spectrum curve of the core was tested in the original saturated oil state. (iii) The prepared experimental water was poured into the imbibition bottle in advance, and then, the core saturated with experimental water was put into the imbibition bottle. When
the core was completely submerged in water, it was considered that the imbibition began, and with increasing imbibition time, the imbibition phenomenon and oil production were continuously recorded. (iv) The NMR T₂ curve of the core was tested at regular intervals. The core preparation process of FI was the same as that of SI, but the difference is that FI was conducted in an autoclave. Because the autoclave is opaque and difficult to measure, the FI experiment of small-sized cores could only be measured by NMR technology. Meanwhile, the FI experiment always needed to maintain high pressure, so the NMR T₂ spectrum curve of the core could only be tested at the beginning and after the imbibition.

3.3.4. Large-Sized Rock Sample Imbibition Experiments under NMR Monitoring. The process of the SI experiment of large-sized rock samples was the same as that of small-sized rock samples. The difference is that the imbibition experiments of the small-sized cores were in an imbibition bottle, while the large-sized cores were in the beaker.

4. RESULTS AND DISCUSSION

4.1. Pore Structure Characteristics. 4.1.1. Cast Thin Section Test. The test results of the cast thin section can reflect not only the mineral composition of the rock but also the pore characteristics. The cast thin section test results of core T1 are shown in Figure 6.
Figure 6 shows that the lithology of tight oil in Tiaohu formation is sedimentary tuff, and the basic mineral composition of the rock includes tuftaceous minerals, calcite, and quartz and does not contain clay minerals. The rock mineral composition measured by the cast thin section is the same as that measured by the X-ray diffractometer. The pores of the TST are mainly composed of structural fractures, bubble-like structures, and matrix micropores. Core T1 developed a structural fracture, which was filled with calcite. A large number of bubble-like structures can also be seen in the tuff, which is filled with calcite single crystals. In the matrix, there is not only massive calcareous cementation but also floating quartz particles that are subangular to subcircular and mostly silty sand. A lot of unfilled micropores are also developed in the matrix.

4.1.2. SEM Test. The SEM experiment is the most direct and effective method of observing the micropore size of the core. In the SEM experiment, a certain part of the end face of the core was selected for different magnifications, the experimental core
is T2, and the experimental observation results are shown in Figure 7.75

Figure 7a shows that, when observed at a lower magnification, the pores of the TST are mainly composed of tight matrix pores, bubble-like structures, and very few microcracks. As the magnification increases, the fractures and pores in the core can be seen more clearly. However, when the magnification is 5000 times, as shown in Figure 7d, the fractures in the core can be seen (filled with calcite), but the matrix pores are still relatively tight. In Figure 7e,f, the observation multiple of the matrix and fracture was continuously enlarged, the micromorphology of the fracture and scale of the matrix pore can be seen at this scale, and it can be seen that the scale of the matrix pores is at the micro-nano level.

4.1.3. High-Pressure Mercury Intrusion Test. The high-pressure mercury intrusion experiment is an effective method of studying the pore throat structure of the tight core. The capillary pressure curve and pore distribution characteristics of T3 and T4 are shown in Figures 8 and 9, respectively.

Figure 10. NMR $T_2$ spectrum curve: (a) T5 and (b) T6.

Figure 11. Imbibition characteristics of model no. 1 at different imbibition times: (a) saturated oil status, (b) imbibition 5 h, (c) imbibition 30 h, and (d) imbibition 288 h. Reprinted with permission from ref 76. Copyright 2022 Journal of Petroleum Science and Engineering.
permeability is 0.1 distributed pore size is 0.063 with an average of 51.698%. Therefore, for TST, the most is 0.1 cores, the pore radius that contributes most to the permeability and 30.135%, with an average of 29.077%. However, in the two proportions in the pore volume of the two cores are 28.018 although the pores of sedimentary tu

...development of micro-nanopores. The wettability of the TST is concentrated pore distribution, good homogeneity, and widely porosities and permeabilities, their NMR T6 saturated water are shown in Figure 10.

Figure 12. Comparison of model 2 before and after imbibition: (a) saturated oil status and (b) after 288 h of imbibition. Reprinted with permission from ref 76. Copyright 2022 Journal of Petroleum Science and Engineering.

Figure 8a,b shows that the middle section of the mercury intrusion curve of the TST cores not only has a large span but also is relatively gentle, indicating that the pore distribution of the TST is very uniform. The sorting coefficients of the two cores are 1.174 and 1.155, with an average of 1.165, which further indicates that the pore structure of the TST has a good sorting ability. The displacement pressures (threshold pressure) of the two cores are both 4.124 MPa, the average values of the pore radius are 0.066 and 0.074 μm, with an average of 0.07 μm, and median radii are 0.065 and 0.079 μm, with an average of 0.072 μm. Figure 9a,b shows that the most distributed pore size in the TST cores is 0.063 μm, and its proportions in the pore volume of the two cores are 28.018 and 30.135%, with an average of 29.077%. However, in the two cores, the pore radius that contributes most to the permeability is 0.1 μm, and the contribution rates are 48.502 and 54.893%, with an average of 51.698%. Therefore, for TST, the most distributed pore size is 0.063 μm, and the most contribution to permeability is 0.1 μm.

4.1.4. NMR Test. The NMR T2 spectrum curves of T5 and T6 saturated water are shown in Figure 10.

Figure 10 shows that, for the two cores with different porosities and permeabilities, their NMR T2 spectrum curves show a single peak, indicating that the pore radius distribution in the core is relatively concentrated and the core has good homogeneity. The transverse relaxation time of NMR T2 spectrum curves of the two cores is mainly concentrated in 0.1−10 ms, and the overall difference of the NMR signal is small and relatively stable, which further indicates that, although the pores of sedimentary tuff are tight, the homogeneity and sorting of pores are good.

In summary, TST is a kind of rock with a relatively simple mineral composition (excluding clay minerals), relatively concentrated pore distribution, good homogeneity, and widely developed micro-nanopores. The wettability of the TST is weakly wet to wet, which is conducive to imbibition. The study of the pore structure of the TST provides an important foundation and basis for studying its imbibition law.

4.2. Glass Etching Model Imbibition Experiment. In the SI experiment of the glass etching model, the oil−water distribution of the core at different times is shown in Figure 11.

From Figure 11, the change law of the imbibition rate, imbibition range, and imbibition path of the SI of the TST at the glass etching model scale can be obtained, and the details are as follows.

4.2.1. Imbibition Rate. Compared with the real pore size of the actual core, the pore size of the glass etching model is larger, so its imbibition process is relatively slow and requires a relatively long time. At the beginning of 5 h of imbibition, it belongs to the start-up stage of glass etching model imbibition, and the imbibition phenomenon has occurred locally in the core at this time. After 30 h of imbibition, the imbibition phenomenon of the core is already very obvious, which can be considered as the middle stage of the imbibition of the glass etching model. After 288 h of imbibition, the imbibition phenomenon in the glass etching model is more obvious, but at this time, the imbibition of the glass etching model has entered the final stage, and the imbibition oil recovery in the glass etching model has stopped. It can be seen from the changes of oil production and average imbibition depth that, in the glass etching model imbibition, the imbibition rate is fast in the early stage (0−33 h), slow in the late stage (33−288 h), and finally tends to balance (after 288 h). In addition, on the whole, the imbibition effect of the low permeability area is better than that of the high permeability area, and its imbibition rate is relatively faster.

4.2.2. Imbibition Range. With increasing imbibition time (from the beginning to the end of imbibition), the imbibition range in the glass etching model gradually expands, and from the change law of the imbibition rate, it is known that the imbibition range expands fast in the early stage and slow in the middle and late stage. Meanwhile, there is an obvious imbibition boundary and front edges at different imbibition times, and after the end of imbibition, the imbibition phenomenon of the core is already very obvious, which can be considered as the middle stage of the glass etching model. After 288 h of imbibition, the imbibition phenomenon in the glass etching model is more obvious, but at this time, the imbibition of the glass etching model has entered the final stage, and the imbibition oil recovery in the glass etching model has stopped. It can be seen from the changes of oil production and average imbibition depth that, in the glass etching model imbibition, the imbibition rate is fast in the early stage (0−33 h), slow in the late stage (33−288 h), and finally tends to balance (after 288 h). In addition, on the whole, the imbibition effect of the low permeability area is better than that of the high permeability area, and its imbibition rate is relatively faster.
out” here has two meanings: one is that it is difficult for water to enter deeper pores only by capillary force; the other is that, even if a small amount of water enters the deep part of the glass etching model, the displaced oil has to go through a long and high resistance path to reach the surface of the glass etching model to achieve effective imbibition. The combination of the above two effects makes it very difficult for the oil in the deep part of the glass etching model to be produced only by the imbibition effect. Therefore, only the oil close to the core surface can be produced by imbibition, and the imbibition of the TST belongs to surface imbibition.

4.2.3. Imbibition Path. The micro oil−water imbibition path shows that, when water enters the matrix from the fracture, the oil−water imbibition has a clear dominant seepage channel instead of uniform advancement. This can also be obtained from the capillary force calculation model. The imbibition force and resistance of pores with different radii are not identical, which leads to the uneven distribution of imbibition front edges. Therefore, the commonly known “imbibition depth” of the reservoir is a concept of average value. Figure 11d shows that, after 288 h of imbibition, the average imbibition depth of multiple statistical points can be calculated roughly, and the average imbibition depth is about 24.368 mm.

4.2.4. Effect of Pressure. To study the effect of pressure on imbibition oil recovery, the glass etching model was placed in an autoclave and a confining pressure of 0.2 MPa was applied. The comparison of the glass etching model before and after imbibition is shown in Figure 12.

Figure 12 shows that increasing the imbibition pressure can significantly increase imbibition depth and imbibition oil production. For the no. 2 glass etching model, when the imbibition pressure increases to 0.2 MPa, the average imbibition depth is 39.131 mm, which is deeper than that of the no. 1 glass etching model and the imbibition oil production is also more. Similar to SI, in FI, the imbibition effect in the low permeability area is better than that in the high permeability area.

4.3. Small-Sized Rock Sample Imbibition Experiments. The imbibition experiment of the glass etching model can directly reflect the imbibition rate, imbibition range, and imbibition path, but the glass etching model is only two-dimensional imbibition on a plane after all. The core-scale imbibition belongs to three-dimensional imbibition. Considering the length of the study, we selected a representative rock sample T7 to describe in detail its oil production characteristics and pore production characteristics during the SI process.

4.3.1. Imbibition Rate and RF. The imbibition phenomenon of T7 is shown in Figure 13, and the imbibition oil production, oil production rate, and RF at different imbibition times are shown in Figure 14.

Figures 13 and 14 both show that, at the beginning of imbibition, oil is continuously produced from the core surface, and the imbibition oil recovery rate is very fast. However, as the imbibition time increases, the imbibition oil recovery rate decreases rapidly and tends to balance gradually. After 36 h, the imbibition oil production does not increase. The cumulative imbibition oil production is 1.4 mL, and the imbibition RF is 33.75%. The NMR $T_2$ spectrum curve at different imbibition times is shown in Figure 15a. It can be seen that the envelope area of the core NMR $T_2$ spectrum curve is the largest at the initial stage of imbibition, while with the increasing imbibition time, it gradually decreases, and the decreasing rate is fast at the initial stage and slow at the later stage. The change law of the envelope area of the NMR $T_2$ curve has good consistency with the change law of oil production recorded by the actual imbibition bottle, which fully indicates that the imbibition rate of the TST is fast in the early stage and slow in the middle and late stage.

4.3.2. Pore Production Characteristics. Different transverse relaxation times of the abscissa of the NMR $T_2$ spectrum curve correspond to different core pore radii. According to the long-term classification standard of the oilfield and the shape of the NMR $T_2$ spectrum curve, in this study, the pore radius intervals corresponding to the lateral relaxation times of 0.01−1, 1−10, and 10−100 ms are defined as small pores, medium pores, and large pores, respectively. According to the principle of NMR and the mercury intrusion and NMR data of multiple TST cores, the relationship between NMR transverse relaxation time $T_2$ and pore radius $r$ of the TST is shown in eq 1.

$$r = 0.0342 \times (T_2)^{0.778}$$ (1)

where $r$ represents the pore radius of the TST and $T_2$ represents the NMR transverse relaxation time of the rock. According to eq 1, the pore radii corresponding to the small, medium, and large pores of the core in this experiment are 0.00998−0.03542, 0.03542−0.20813, and 0.20813−1.22285 μm, respectively. The variation law of oil-bearing signals in the three types of pore intervals is shown in Figure 15b. It can be seen from Figure 15b that, within the 166 h imbibition time, 0.3 mL of oil is produced from small pores, 0.96 mL from medium pores, and 0.14 mL from large pores. Therefore, the oil productions of small pores, medium pores, and large pores account for 21.31, 68.46, and 10.23% of the total oil production, respectively. This shows that the imbibition oil production of the TST mainly comes from medium pores, and the contribution of large pores and small pores to the total oil production is relatively small. The main reasons for this phenomenon include two aspects: the first and most important reason is that the volume of the medium pores of the core is the largest compared with that of small and large pores. The second reason is the phenomenon of oil displacement between pores by imbibition. The phenomenon of oil displacement between pores by imbibition refers to that in the process of
imbibition; due to the difference in internal capillary dynamics and seepage resistance of pores of different sizes, the oil will displace mutually in pores. Generally speaking, the phenomena of oil displacement between pores by imbibition mainly include oil in small pores entering middle pores, oil in small pores entering large pores, oil in small pores first entering middle pores and then entering large pores, and oil in medium pores entering large pores, as shown in Figure 16. After the above series of displacements, there is a lot of oil accumulated in the medium pores and large pores of the core. However, the capillary force in the large pores is very small, and the fluid seepage is very difficult, so it only places close to the surface of the core, and the oil can flow out. Therefore, the oil in the large pores contributes little to the cumulative oil production during the imbibition process. For the oil in very small pores, although its imbibition power is strong, its flow resistance is also very large, so its final contribution to imbibition is relatively small. In medium-sized pores, the capillary force of oil is relatively strong, and its imbibition resistance is relatively lower than that of small pores. Therefore, in medium-sized pores, the effective imbibition displacement of oil is formed under the action of capillary force, making the medium-sized pores become the main force of imbibition oil production.
4.3.3. Effect of Pressure. To further study the influence of imbibition pressure on the imbibition RF, the FI experiment of small-sized cores was conducted, and it was completed in an autoclave. Since the pressure of RF must always be maintained at 25 MPa during the experiment, the oil recovery characteristics of FI can only be obtained by comparing the oil-bearing characteristics before and after the experiment, and the imbibition characteristics during the experiment cannot be obtained. Considering that the volume of oil produced by core imbibition in an autoclave is small and the collection error is large, the RF of the core FI can only be obtained by calculating the core NMR RF, the experimental core is T8 (the pore structure characteristics are similar to those of rock sample T7), and the test result is shown in Figure 17.

Figure 17 shows that, after an imbibition time of 220 h, the envelope area of the core NMR T2 spectrum curve has decreased significantly, which means that the FI can effectively mobilize the oil in the tight core. After calculating the change of the envelope area of the NMR T2 spectrum curve before and after imbibition, the RF of FI of the small-sized core T8 is 53.35%. Compared with SI, the RF has increased by 19.6%.

Similarly, the pore radius intervals corresponding to the RF NMR relaxation times of 0.01−1, 1−10, and 10−100 ms are determined as small pores, medium pores, and large pores, respectively. The oil productions of small pores, medium pores, and large pores are 0.474, 1.304, and 0.073 mL, and their proportions in the total oil production are 25.61, 70.45, and 3.94%, respectively. The change of the NMR T2 spectrum curve in Figure 14 and the calculated pore development characteristics both show that RF is beneficial to enhance the RF of small and medium pores.

4.4. Large-Sized Rock Sample Imbibition Experiments. To further study the sample size effect law of SI of the TST, a large-sized rock sample imbibition experiment was conducted. As mentioned above, the pore size and porosity of the TST are very small, so the NMR imaging of a small-sized core is generally not ideal. However, a large-sized rock sample can overcome this problem well. Because the pore volume of the large-sized rock sample is relatively large, the core is saturated with more oil; thus, the NMR signal is stronger.

Two large-sized cores conducted the imbibition experiments. Considering the length of the study, only the SI oil production characteristics and pore production characteristics of rock sample T9 are discussed in detail below.

4.4.1. Imbibition Rate and RF. To accurately describe the change of oil saturation in the core, the large-sized rock sample was divided into three sagittal planes for observation (each plane has a certain thickness). The NMR imaging results of the three sagittal planes at different imbibition times are shown in Figure 18. The change laws of the imbibition oil recovery rate and imbibition RF are shown in Figure 19.

Figure 18 shows that the NMR signal of sagittal plane 2 is stronger than those of sagittal plane 1 and sagittal plane 3. This is mainly because the area (volume) of sagittal plane 2 itself is the largest, and the amount of the saturated oil in its observation range is high, which makes its NMR signal strong. Two large-sized cores conducted the imbibition experiments. Considering the length of the study, only the SI oil production characteristics and pore production characteristics of rock sample T9 are discussed in detail below.

Figure 17. Variation of the NMR T2 spectrum curve before and after SI.
stage. Meanwhile, the NMR signals at the boundaries of the three sagittal planes are all significantly reduced, which further indicates that the imbibition of the TST belongs to surface imbibition. Figure 19 shows that the change law of the imbibition oil recovery rate and imbibition RF of the large-sized rock sample are the same as those of the small-sized core, which is that, with increasing imbibition time, the imbibition oil recovery rate and imbibition RF increase rapidly at first,
then decrease rapidly after reaching the peak value, and finally tend to be stable. After 36 h of imbibition, the large-sized rock sample no longer produces oil, and the imbibition RF is 10.78%, which is significantly lower than that of the small-sized core. The difference in imbibition RF between small-sized and large-sized rock samples indicates that the imbibition RF of the TST has an obvious sample size effect.

4.4.2. Pore Production Characteristics. The variation law of the NMR $T_2$ spectrum curve of the large-sized rock sample at different imbibition times is shown in Figure 20a. Compared with the small-sized core, the sample size of the large-sized rock sample is larger, and the probability of microfractures existing is larger. It can be seen from Figure 19 that the main part of the NMR $T_2$ spectrum curve of the large-sized rock sample is a single peak, but a slight turning occurs at a relaxation time of 23.817 ms, and this is caused by the existence of microfractures in the core. However, since the main pores of the TST are still dominated by matrix pores, the existence of microfractures has little effect on the overall pore structure of the core. Therefore, the pores of the large-sized rock sample are also divided into three types, and a core NMR relaxation time of 0.01–1 ms is also defined as small pores, 1–10 ms is defined as medium pores, and 10–100 ms is defined as large pores. The oil content in the three types of pores and their variation with increasing imbibition time are shown in Figure 20b.

Figure 20a shows that, as the imbibition time increases, the NMR $T_2$ spectrum curve of the large-sized rock sample gradually decreases, but the magnitude of the decrease is not as large as that of SI of small-sized cores, and the difference in the imbibition RF also illustrates this point. The reasons for this phenomenon mainly include the following: the first is that the SSA of the core decreases with the increase in the core size, and the second is that the pore structure of the TST is relatively homogeneous; its imbibition belongs to surface imbibition; therefore, its imbibition depth is relatively stable.

The comprehensive effect of the above two aspects makes the proportion of oil produced by imbibition in the total oil content of the core decrease with the increasing core size. Figure 20b shows that, among the three types of pores, the oil production by imbibition mainly comes from medium pores. The contributions of small pores (0.01–1 ms), medium pores (1–10 ms), and large pores (10–100 ms) to the total oil production are 0.77, 85.98, and 13.25%, respectively. The contribution of the three types of pores to the total oil production in a large-sized rock sample SI experiment is similar to that of a small-sized core, and the reason is also the same as that of a small-sized core.

4.5. Law of the Sample Size Effect of Imbibition. Through the imbibition experiments of the TST in the glass etching model size, small-sized cores, and large-sized cores, we can summarize the imbibition sample size effect law of the TST in oil production characteristics of the core surface, imbibition rate, imbibition RF, pore production characteristics, and the effect of imbibition pressure on imbibition. The details are as follows.

4.5.1. Oil Production Characteristics of the Core Surface. Through the SI experiments of multiple small-sized cores and large-sized cores of different sizes, it can be found that, in the early stage of imbibition of the TST, the surface of the core always produces intensive oil in a large area, the distribution of oil production points is very uniform, and the size of oil bubbles is relatively uniform. Therefore, there is no sample size effect on the oil production characteristics of the core surface of the TST imbibition. The main reason for emphasizing this is that, for different types of tight cores, the oil production characteristics of imbibition on the core surface are not the same. For example, for the tight volcanic rocks in the Santanghu basin, the oil extracted from the core by imbibition is mainly local large particle oil droplets, the oil extraction points are scattered, and the size of oil bubbles is also different.

4.5.2. Imbibition Rate. Through multiple imbibition experiments of the TST cores with different sizes, it can be found that the imbibition rate of the TST presents obvious parabolic characteristics. The imbibition rate increases rapidly to the peak in the early stage, then decreases rapidly, and finally tends to be stable. Generally, after 36 h, the cores no longer produce oil by imbibition. Therefore, the variation form of the imbibition rate (parabolic characteristics) and the final stable imbibition time of the TST do not have a sample size effect.

4.5.3. Imbibition RF. The results of SI experiments of the TST cores with different sizes show that the change of rock sample size has great impact on imbibition RF, and the larger the rock sample size, the lower the imbibition RF. According to the pore structure characteristics (pores are relatively homogeneous) and imbibition characteristics (surface imbibition and the imbibition depth are stable) of the TST, it can be determined that the fundamental reason why the imbibition RF of the TST decreases with increasing rock sample size is that the SSA is different for rock samples of different sizes. For cores of different sizes, their SSA and imbibition RF are shown in Table 2.

| sample no. | type | SSA (m$^{-2}$) | RF (%) |
|------------|------|----------------|--------|
| T7         | small| 2.034          | 33.75  |
| T9         | large| 0.643          | 10.78  |
| T10        | small| 2.27           | 35.82  |
| T11        | small| 2.06           | 29.83  |
| T12        | small| 1.96           | 32.40  |

After exponential fitting of the imbibition RF and SSA of cores in Table 2, it is found that the fitting coefficient is 0.9801. This shows that, for cores of different sizes, the specific surface area is indeed the decisive factor in determining core imbibition RF. Based on this, this paper proposes for the first time an empirical model of the sample size effect of the SI RF of the TST, as shown in eq 2.

$$R_{SI} = k \times e^{bS}$$  \hspace{1cm} (2)

In eq 2, $R_{SI}$ refers to the RF of SI, %; $k$ and $b$ refer to the cross-sized coefficient of SI, and their values are 6.7028 and 0.7624, respectively; $S$ refers to the SSA, m$^{-2}$. To further determine the accuracy of eq 2, the imbibition experiments of a small-sized core and a large-sized core were conducted. The comparison between the experimental results and the prediction results of eq 2 is shown in Table 3.

Table 3 shows that eq 2 has good adaptability in characterizing the RF of the SI of cores with different sizes, and the average error is only 4.68%, indicating that the accuracy of eq 2 is very high. The more experimental data, the higher the accuracy of eq 2.
The reason why the cross-size SI model of the TST presented in eq 2 has a relatively simple expression form is that TST has a relatively homogeneous pore structure and relatively stable wettability distribution characteristics. The values of $k$ and $b$ are empirical constants calculated from the experimental results, which are closely related to the rock wettability, pore throat radius, interfacial tension between oil and water, etc. When changing the specific experimental conditions, such as changing the experimental oil from kerosene to other types of oil, the values of $k$ and $b$ must be recalculated through experiments. In the process of imbibition oil recovery in an actual TST oil reservoir, a horizontal well with staged fracturing is used, and the SSA of the reservoir imbibition is equal to the ratio of the fracture area to the reservoir volume (the volume within the actual drainage radius). The values of $k$ and $b$ can be obtained through laboratory experiments, but the experimental conditions such as pressure, temperature, and oil–water viscosity must completely simulate the actual reservoir conditions. Then, eq 2 can be used to obtain the imbibition RF of a horizontal well with staged fracturing. Therefore, the biggest contribution of this model is to obtain the qualitative and quantitative relationship between the imbibition RF and its SSA of the TST, and it will provide a solid theoretical basis and reference for oilfields to understand and optimize imbibition oil production.

4.5.4. Pore Production Characteristics. According to the visual imbibition experiment of the cast thin section and the NMR imaging experiment of large-sized core imbibition, the imbibition oil production of the TST belongs to typical surface imbibition. The imbibition oil production mainly comes from the oil at a certain depth from the core surface. Therefore, there is no sample size effect in the imbibition oil recovery mode (surface imbibition) of the TST. Meanwhile, although the pore types of the TST include the structural fracture, bubble structure, and matrix micropore, the main pore type of the rock is the matrix micropore. Due to the good sorting and concentrated distribution of pores of the TST, medium pores are the main force of the TST imbibition, and the contribution of large pores and small pores to the cumulative oil production of core imbibition is relatively small. Therefore, there is no sample size effect in the pore production interval (mainly medium pores, supplemented by small pores and large pores) of the TST imbibition.

4.5.5. Effect of Pressure. In the glass etching model and small-sized core imbibition experiments, the imbibition RF of the core increases with the increasing imbibition pressure. Therefore, in the imbibition process of the TST, the phenomenon that the imbibition RF changes with the change of imbibition pressure does not have a sample size effect. Regardless of the size of the core, the imbibition RF of the core will increase with the increasing imbibition pressure.

4.6. Mechanism of the Sample Size Effect of Imbibition. Except for the imbibition RF, other imbibition oil production characteristics of the TST do not change significantly with the change of the rock sample size. The fundamental reason is that TST has a relatively homogeneous pore structure. For the TST samples of different sizes, the pore throat size and the matching relationship between the pore throats inside the core are relatively stable, the force of the crude oil is relatively uniform under the action of capillary force, and the migration path is relatively stable. Therefore, during the imbibition process of cores of different sizes, the oil production characteristics of the core surface, imbibition rate, imbibition pore production characteristics, and the influence of imbibition pressure on imbibition will not change significantly. The uniform pore structure of the TST also makes the rock samples of different sizes have a relatively stable imbibition depth. Therefore, when the SSA of the core decreases rapidly with increasing rock sample size, the core RF decreases rapidly.

4.7. Limitations of Our Study. Although we have demonstrated important research on the law and mechanism of the sample size effect of TST imbibition, there are still the following two limitations in this work: (i) Limited by the existing production level of the cast thin section, the cast thin section samples in this work are made by magnifying the pore structure of TST by a certain multiple. Therefore, there are still some differences between the observation results of microscopic imbibition in this paper and the actual microscopic imbibition characteristics of TST. (ii) In this paper, the relationship between the imbibition RF and the SSA of the rock sample of TST is obtained. However, for an actual horizontal fracturing well, the distribution of artificial fractures and natural fractures in the reservoir is extremely complex, and the seepage boundary of the reservoir is also very difficult to determine. Therefore, the SSA of a real horizontal-fractured well is not easy to be measured accurately, which is also the difficulty in the application of the imbibition recovery model obtained in this paper.

5. SUMMARY AND CONCLUSIONS

This paper takes a newly discovered and new type of TST oil reservoir as an example and conducts experimental research on its wettability, pore structure, and imbibition characteristics of different rock sample sizes, and the following conclusions are obtained:

1. TST is composed of tuffaceous minerals, calcite, and quartz. The pore types include structural fractures, bubble-like structures, and matrix micropores, in which matrix micropores are the main pore type. The pore sizes that occupy the largest pore volume and contribute the most to permeability are 0.063 and 0.1 μm, respectively. The pore structure of the rock has good sortability, and the average sorting coefficient is only 1.145.

2. The imbibition of TST has obvious imbibition front and boundary, which belongs to surface imbibition, but there are dominant imbibition channels locally. With increasing imbibition time, the imbibition rate is fast in the early stage, then drops rapidly after reaching the peak, and eventually tends to zero. The imbibition RF also increases rapidly in the early stage, slowly increases in the middle and late stages, and gradually stabilizes. Generally, after 36 h, the range and depth of imbibition no longer change.

3. Increasing imbibition pressure can effectively improve the imbibition range and imbibition RF of the TST. In

### Table 3. Comparison between the Experimental Results and the Prediction Results in eq 2

| Sample no. | Type | $S$ (m$^{-1}$) | Measured RF (%) | Predicted RF (%) | Relative Error (%) |
|------------|------|---------------|-----------------|-----------------|--------------------|
| T13        | Small| 1.88          | 28.38           | 28.10           | 0.98               |
| T14        | Large| 0.66          | 12.10           | 11.09           | 8.38               |
| Average    |      |               | 25.45           | 25.14           | 1.22               |
the glass etching model, the pressure increases by 0.1 MPa, and the imbibition depth increases by 20.483 mm. In the small-sized cores, the imbibition RF with an imbibition pressure of 25 MPa is 19.6% higher than that of SI.

(4) In imbibition oil production of the TST, the oil production of medium pores is the largest and those of small pores and large pores are relatively small. The reason is that, on the one hand, the pore volume of the medium pores is the largest, and on the other hand, it is also due to the oil displacement mechanism between pores by imbibition.

(5) In imbibition oil production of the TST, the oil production characteristics of the core surface, the variation form of imbibition rate, pore production characteristics, and the influence mode of imbibition pressure on imbibition do not have the sample size effect. However, the RF of the SI has an obvious sample size effect. In this work, the RF of the SI model established for the first time has good applicability.

(6) The fundamental reason for the stable sample size effect of TST imbibition is that its pore structure and wettability are very evenly distributed.

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Notes

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■ NOMENCLATURE

| Abbreviation | Definition                                      |
|--------------|-------------------------------------------------|
| RF           | recovery factor                                  |
| TST          | tight sedimentary tuff                          |
| SI           | spontaneous imbibition                          |
| FI           | forced imbibition                               |
| SSA          | specific surface area                            |
| NMR          | nuclear magnetic resonance                      |
| SEM          | scanning electron microscopy                    |
| CT           | computed tomography                              |
| SY/T         | recommended Chinese petroleum industry standards|
| T2 (ms)      | NMR transverse relaxation time                  |
| T1−T14       | core number                                      |
| eq           | equation                                         |
| h            | hour                                             |
| R (μm)       | pore radius                                      |
| RSI (%)      | RF of spontaneous imbibition                    |
| k            | cross-size coefficient of spontaneous imbibition |
| b            | cross-size coefficient of spontaneous imbibition |
| S (m⁻¹)      | specific surface area of the core               |

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