Influencing Factors and Application of Spontaneous Imbibition of Fracturing Fluids in Tight Sandstone Gas Reservoir

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ABSTRACT: This work is based on high-precision fluid spontaneous imbibition experiments to quantitatively study the imbibition rate, imbibition capacity, and imbibition curve characteristics of fracturing fluids in tight sandstone reservoirs. The objective of the work is to explore the influence of tight sandstone physical characteristics, fracturing fluid composition, salinity, viscosity, surface tension on fracturing fluid imbibition, and further analyze its main controlling factors. To evaluate imbibition characteristics more deeply, the pore throat structure and micromorphology of tight sandstone before and after imbibition were described by mercury intrusion test and scanning electron microscope test, respectively. Furthermore, the mineral composition and dilatation characteristics of the tight sandstone samples were identified by XRD and a linear dilatometer, respectively. The results show that the drilled tight sandstone samples from the Shaximiao Formation reservoir have strong heterogeneity, high clay mineral content, more developed micro/nanopores, less developed fractures, and strong hydration expansion. Since the average pore throat radius of tight sandstone samples is between 0.1 and 0.2 μm, the imbibition driving force is strong. The imbibition rate is fast, and the imbibition basically reaches a steady state within 24 h, which makes the imbibition capacity basically greater than 50%. Based on the analysis of the main control factors of imbibition, the surface tension of the fluid properties has the greatest impact on the imbibition recovery factor. The result not only helps to understand the absorption mechanism of fracturing fluid in tight sandstone reservoirs and then evaluates the degree of interaction between fluid and tight sandstone but it is also crucial for the prediction of flowback rate.

1. INTRODUCTION

In recent years, tight sandstone oil and gas, as one of the important types of unconventional oil and gas resources, is in a stage of rapid development in exploration and development. It has large-scale output in Sichuan, Ordos, Bohai Bay, Songliao, and other basins and has become a “key area” and “bright spot” for China’s oil and gas reserves and production. As unconventional oil and gas exploration and development represented by shale oil and gas has developed rapidly, volume fracturing technology has become an essential technology for the construction of this type of oil and gas resource capacity. That is, hydraulic fracturing “breaks” the reservoir and forms a complex fracture network. The tight sandstone gas in the Middle Jurassic Shaximiao Formation in the Qilin block in the central Sichuan Basin has the characteristics of shallow burial depth and short well construction period. However, the natural fractures in the reservoir are not developed, and it is difficult to form a complex fracture network after hydraulic fracturing. The existing volume fracturing technology has obvious incompatibility in the reservoir stimulation of tight sandstone gas in this area.

In recent years, researchers’ understanding of imbibition has continued and moved to new heights. Mahadevan proposed that when the production pressure drop is greater than the
capillary force, the fracturing fluid is flowed back to the surface through artificial fractures; when the production pressure drop is less than the capillary force, the fracturing fluid retention in the reservoir will adversely affect the productivity, that is, “water lock”, which is an important reason for the decline of gas well productivity. The research results of Shanley et al. show that when the water saturation is close to 40%–50%, the productivity of gas wells will be seriously damaged. Bahrami used numerical modeling to study the relationship between fracturing fluid imbibition and productivity during fracturing of West Australian low-permeability tight gas reservoirs. The results show that the spontaneous imbibition of fracturing fluid can lead to the formation of “water lock” and clay expansion, which is an important factor affecting the productivity of tight gas reservoirs, especially for water-sensitive tight reservoirs. At present, the experimental research on the imbibition law of oil and gas reservoirs can be divided into two categories: static imbibition and dynamic imbibition according to the purpose of the experiment. According to the difference in the macroscopic flow direction of the wetting phase and the nonwetting phase caused by different experimental boundary conditions, it can also be divided into codirectional imbibition and reverse imbibition. Experimental and theoretical simulation studies demonstrate the effects of different imbibition modes. The complex fracture network provides flow channels for codirectional imbibition, which forms a favorable expulsion effect of imbibition and promotes higher recovery factor and displacement efficiency than reverse imbibition. However, reverse spontaneous imbibition usually occurs in fractured and unconventional reservoirs, which causes water lock damage.

With the aim of revealing the basic mechanism of imbibition, a large number of experimental and theoretical studies have been carried out. The unanimous conclusion from these investigations is that imbibition rate and imbibition capacity are controlled by petrophysical properties, pore throat properties, fluid properties, temperature, and pressure. In addition, a large number of studies have shown that the ultimate recovery of imbibition is mainly controlled by the interaction between rock minerals and fluids, as well as various physical and chemical processes, such as the mineral content of the matrix and formation fluids. By exploring the effects of different salinity and mineral content on the imbibition capacity, desaturation, and permeability of tight sandstone, it is concluded that high salinity can inhibit the expansion of clay minerals and reduce the liquid absorption capacity. In addition, clay minerals tend to swell, leading to changes in pore structure. Although imbibition research has gradually matured at the experimental level, the reasons for the difference in ultimate recovery under different rock properties and fluid conditions have not yet been reasonably explained. And most of the imbibition mechanisms are aimed at conventional gas reservoirs and shale gas reservoirs, but the exploration of imbibition characteristics of tight sandstones is still lacking, especially for the complex tight sandstone gas reservoirs in the Sichuan Basin. Due to the wide distribution of pores in tight sandstone, micro- and nano-scale structures, strong heterogeneity, and significant difference from conventional rocks, it makes exploration and development more difficult.

The work aimed to evaluate the imbibition characteristic for tight sandstone reservoir under different influence conditions, such as petrophysical features, fracturing fluid composition, salinity, viscosity, and surface tension. The pore throat structure of tight sandstones was identified using scanning electron microscope (SEM) and mercury intrusion test. The rock and clay mineral contents of the tight sandstone samples were determined by XRD. Furthermore, the linear expansion ratio was evaluated by a linear dilatometer. Using the above measurement results, the pore distribution and fractal characteristics before and after imbibition are discussed, and imbibition curve characteristics under different conditions are illustrated. Finally, the main controlling factors affecting imbibition are analyzed to understand the imbibition mechanism of fracturing fluids and the interaction of fluids with tight sandstones.

2. SPONTANEOUS IMBITION EXPERIMENT

2.1. Experimental Equipment and Materials.

(1) Experimental equipment: 1:10000 Mettler high-precision balance, DSA100 contact angle measuring instrument, beaker, hook, 0.1 mm fishing line.

(2) Experimental fluid: deionized water, 1% and 10% KCl brine, 1% and 2.5% fluorine-containing cationic surfactant, and 0.04% and 0.1% slickwater are selected as experimental fluids, and their basic characteristic parameters are listed in Table 1.

| Fluid          | Density (g/cm³) | Viscosity (mPa·s⁻¹) | Surface Tension (mN/m) |
|----------------|----------------|---------------------|------------------------|
| distilled water| 1.00           | 1.0                 | 72.0                   |
| 1% KCl         | 1.01           | 0.98                | 72.3                   |
| 10% KCl        | 1.06           | 0.87                | 74.1                   |
| 1% surfactant  | 0.99           | 0.98                | 40.0                   |
| 2.5% surfactant| 0.96           | 0.89                | 21.1                   |
| 0.1% slickwater| 1.05           | 5.0                 | 28.0                   |
| 0.04% slickwater| 1.02          | 2.0                 | 32.0                   |

2.2. Experimental Procedures.

(1) First, natural core drilled from tight sandstone formation is mechanically cut to a target size of approximately 5 cm in length and 2.5 cm in diameter.

(2) The core is cleaned and dried to a constant weight state, and its basic physical properties such as porosity and permeability are recognized through the testing process.

(3) The core is attached to an electronic balance with an accuracy of 0.0001 g is used to accurately weigh the sample imbibition over time and transmit the data to a computer.

(4) An electronic balance with an accuracy of 0.0001 g is used to accurately weigh the sample imbibition over time and transmit the data to a computer.

(5) The spontaneous imbibition curve of each sandstone core is recorded.

2.3. Analysis of Experimental Results. The high-precision mass method was used to measure the spontaneous
imbibition curves of all of the real cores treated by high-temperature drying in distilled water solution. A high-precision electronic balance was used to record the change of core weight during spontaneous imbibition in real time. The schematic diagram of the whole self-imbibition experimental device is shown in Figure 1.

3. MERCURY INTRUSION TESTS

3.1. Analysis of Pore Throat Characteristics. The pore size distribution of tight sandstone samples 1, 2, and 3 is shown in Figures 2–4, respectively, which was determined by the method of mercury intrusion. The average pore throat radii R of the sandstone samples 1, 2, and 3 before imbibition were determined as 0.1256, 0.1147, and 0.3733 μm, respectively. After spontaneous imbibition over the entire outer surface and drying treatment, the average pore throat sizes of cores 1, 2, and 3 were measured as 0.1132, 0.1094 and 0.1069 μm, respectively. The average pore throat radius after imbibition was decreased to different degrees compared with that before imbibition. The contribution of different pore throat radii to permeability in tight sandstones 1, 2, and 3 is expressed as a percentage, as shown in Figure 5. The distribution range of pore throat radius that contributes to core permeability is mainly 10–100 μm. The curves all show a peak, and the pore throat radius corresponding to the maximum contribution peak is between 50 and 100 μm.

3.2. Fractal Dimension Analysis. In the 1980s, the French scientist Mandelbrot found fractal geometry to explain the irregular, unstable, and highly complex structures in nature and achieved remarkable results. It has been widely used in the field of geology. As an effective method to characterize the pore structure of rocks, fractal dimension has become one of the indispensable reservoir characteristic physical parameters. According to the geological significance of fractal dimension, the smaller its value is, the better the connectivity and homogeneity of the pores it represents. The smaller the fractal dimension value, the higher the permeability reflected in the macroscopic view, which means that the connectivity of the reservoir pores is good. For reservoirs with fractal characteristics, the fractal dimension is in the range of 2–3. When the fractal dimension value is close to 2.0, it indicates that the pore structure of the reservoir is simple and the homogeneity is excellent; if the fractal dimension value is close to 3.0, the above characteristics are opposite.

Based on the experimental data of mercury intrusion, combined with previous research on fractal theory, the fractal characteristics of the pore structure of tight sandstone reservoirs in the Shaximiao formation in central Sichuan Basin were explored. The fractal dimension model based on the mercury intrusion experimental data is as follows

\[
\lg(1 - S_{Hg}) = (D - 3)\lg P_i - (D - 3)\lg P_s
\]

where, the capillary pressure (MPa) is marked as \(P_c\), the mercury injection pressure (MPa) is noted as \(P_s\), the intrusive mercury saturation is expressed as \(S_{Hg}\), and the fractal dimension is represented by \(D\).

The mercury intrusion data of samples 1, 2, and 3 were used to generate a scatter plot of \(\lg(1 - S_{Hg})\) versus \(\lg P_s\), and then, a linear regression was performed on the scatter plot to calculate the slope \(k\) of the regression line, as shown in Figures 6–8, respectively. Finally, the fractal dimension \(D\) can be obtained by the formula \(D = 3 - k\). Table 2 shows the fitting results of the pore fractal characteristics of the three tight sandstone samples before and after imbibition. The results show that the scatter fitting is not a straight line but has obvious turning points. After analysis, the pores of the tight sandstone of the Shaximiao formation in the Sichuan Basin are identified as three-stage multifractal features. It is divided into three pore intervals of 0.1–1.0, 1.0–10.0, and 10.0–100.0 μm. According to the
classification standard of the pore size in hydraulic fracturing, the above three pore intervals correspond to small pores, mesopores, and macropores, respectively. It can be seen from Table 2 that the fractal dimension of small pores in tight sandstone reservoirs is $2.5783 - 2.8158$, with an average of 2.7351; the fractal dimension of medium pores is $2.5182 - 2.7103$, with an average of 2.6419; the fractal dimension of large pores is $2.7706 - 2.9753$, with an average of 2.9023. It can be seen from the above data that the fractal dimensions of the three kinds of pores are, from small to large, mesopores, small pores, and large pores. That is, the reservoir has better mesoporous pore structure and stronger homogeneity, and the pore structure of small pores and macropores is more complex. After

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**Figure 3.** Pore throat distribution and capillary pressure curve of sandstone 2.

**Figure 4.** Pore throat distribution and capillary pressure curve of sandstone 3.

**Figure 5.** Diagram of permeability contribution with pore throat radii of sandstones 1, 2, and 3.

**Figure 6.** Pore fractal characteristics of sandstone 1.
imbibition, the fractal dimensions of all of the three cores increased, indicating that imbibition makes the pore structure more complex and more heterogeneous. The spontaneous imbibition process is usually regarded as a complex physical and chemical process, which involves the expansion and migration of clay minerals and the ion exchange of soluble salts in the pores. However, the pores of this tight sandstone have multistage distribution characteristics, and the smaller the pore throat radius, the greater the driving force of imbibition. Therefore, in the imbibition process, the fluid first goes to the small pores and then gradually enters the mesopores and macropores. The migration of fluid in the pores exists in the imbibition section from small pores to macropores and the diffusion section from macropores to the matrix. During the diffusion process, the fluid migrates from the macropores to the matrix, which reduces the water saturation inside the macropores, which is beneficial to oil and gas production.

4. LINEAR EXPANSION RATE

The OF1150—80−1 dynamic linear dilatometer was employed to evaluate the linear expansion rate of tight sandstone. The tight sandstone was crushed into 100 mesh powder, and then 10 g was taken and pressed for 2 h at 20 MPa to form small cylindrical rock samples, with a height of about 1 cm. The prepared samples were placed in a working cylinder, and different working liquids were passed into the core cylinder to measure the linear expansion rate of the artificial core in the axial direction.

The curve of linear expansion rate and time was drawn to compare the expansion rate of the same sandstone sample under different working liquids, which is shown in Figure 9. Potassium

![Figure 7](https://example.com/figure7.png)

**Figure 7.** Pore fractal characteristics of sandstone 2.

![Figure 8](https://example.com/figure8.png)

**Figure 8.** Pore fractal characteristics of sandstone 3.

![Figure 9](https://example.com/figure9.png)

**Figure 9.** Linear expansion rate of the tight sandstone sample treated with different fluids.

| Fractal Dimension of Tight Sandstone in Shaximiao Formation, Sichuan Basin | Fractal Dimension of Different Pore Intervals |
|---|---|---|---|
| Number | 0.1−1 μm | 1−10 μm | 10−100 μm |
| D | R² | D | R² | D | R² |
| 1-before imbibition | 2.8158 | 0.9613 | 2.6973 | 0.9860 | 2.9753 | 0.9668 |
| 1-after imbibition | 2.8544 | 0.9535 | 2.7416 | 0.9953 | 2.9610 | 0.9077 |
| 2-before imbibition | 2.5783 | 0.9776 | 2.5182 | 0.9937 | 2.9610 | 0.9493 |
| 2-after imbibition | 2.8492 | 0.9821 | 2.5029 | 0.9875 | 2.9671 | 0.9234 |
| 3-before imbibition | 2.8112 | 0.8142 | 2.7103 | 0.9902 | 2.7706 | 0.9756 |
| 3-after imbibition | 2.8780 | 0.9649 | 2.8515 | 0.9742 | 2.9518 | 0.9844 |
chloride with different mass fractions acts as a swelling inhibitor. The linear expansion rate of the tight sandstone of the Shaximiao formation with deionized water was determined to be 6.88%. Similarly, the linear expansion ratios of 0.25% surfactant, 0.5% KCl, 5% KCl, and 10% KCl to the tight sandstone of the Shaximiao Formation were evaluated as 6.47%, 4.87%, 3.23%, and 1.11%, respectively. Compared with deionized water as working fluid, using 10% KCl as the fluid reduces the linear expansion rate of tight sandstone by 83.87%, indicating that 10% KCl has a significant inhibitory effect on the hydration and expansion of clay minerals contained in tight sandstone.

The linear expansion effect of low-viscosity slickwater and its components on tight sandstone over time is shown in Figure 10. The low-viscosity slickwater is formulated with the on-site fracturing fluid formulation of tight sandstone reservoirs, consisting of 0.1% drag reducing agent, 0.25% surfactant, and 99.65% distilled water. The experimental results show that the linear expansion ratio of slickwater to tight sandstone is 4.70%, which is less than 6.88% of deionized water, 6.47% of surfactant, and 5.08% of drag reducing agent. It is worth noting that the linear expansion curve of slickwater still grows slowly in the stable segment. The reason why the slickwater linear expansion ratio test result is lower than the data of its composition can be attributed to the slow hydration expansion of clay minerals due to the influence of complex composition.

5. RESULTS AND DISCUSSION

5.1. Dimensionless Analysis. The imbibition capacity and imbibition rate cannot be combined in one graph at the same time, which is not conducive to the effective identification of fluid imbibition characteristics. Imbibition capacity and imbibition rate are characteristic parameters of the rock itself, independent of the size and shape of the sample. Therefore, it is necessary to develop a new method for imbibition data processing, which normalizes the influence of sample size and shape and better reflects the properties of the rock itself. The water absorption capacity of tight sandstone is affected by the sample size, porosity, and mineral composition. The dimension analysis method was used in this work to analyze the influence of these factors on the fracturing fluid absorption capacity. The relationship between the amount of imbibed water per unit pore volume and the imbibition time was used to analyze the imbibition capacity. Spontaneous imbibition is a process in which the wetting phase liquid spontaneously displaces the nonwetting phase gas, so the maximum liquid absorption capacity is equivalent to the imbibition recovery rate of the gas, which represents the maximum water absorption per unit pore volume. To eliminate the influence of the experimental sample length and experimental method on the test results, the relationship between the amount of imbibed liquid per unit sample volume and the square root of time per unit length was introduced. This method can stably obtain the imbibition characteristic parameters of the reservoir rock itself and better meet the needs of theoretical research and field analysis. The basic imbibition parameters of core are listed in Table 3.

5.2. Analysis of Influence Factors. 5.2.1. Imbibition Characteristics. The core samples used in the experiments are of different lengths, so it is necessary to rely on the mathematical model to normalize the experimental results. The suction rate and maximum suction capacity of fracturing fluid are two important parameters concerned in fracturing fluid flowback.

![Figure 10. Linear expansion rate of the tight sandstone sample treated with different fracturing fluid components.](image)

Table 3. Basic Imbibition Parameters of Core

| core number | length (cm) | radius (cm) | permeability (mD) | porosity (%) | pore volume (mL) | imbibition volume (mL) | imbibition recovery (%) | fluid |
|-------------|-------------|-------------|------------------|--------------|-----------------|-----------------------|------------------------|-------|
| 1           | 3.8         | 2.5         | 0.0743           | 7.63         | 1.4232          | 0.6815                | 47.89                  | DW    |
| 2           | 3.8         | 2.5         | 0.108            | 10.05        | 1.8746          | 1.0302                | 54.96                  | DW    |
| 3           | 3.8         | 2.5         | 0.0112           | 3.72         | 0.6939          | 0.3125                | 45.04                  | DW    |
| 4           | 5.0         | 2.5         | 0.0615           | 9.90         | 2.4298          | 1.2795                | 52.66                  | DW    |
| 5           | 2.3         | 2.5         | 0.1438           | 9.52         | 1.0748          | 0.8448                | 78.60                  | DW    |
| 6           | 5.0         | 2.5         | 0.0428           | 10.03        | 2.4617          | 1.8105                | 73.55                  | DW    |
| 7           | 5.0         | 2.5         | 0.0424           | 9.93         | 2.4372          | 1.5153                | 62.17                  | SW1   |
| 8           | 5.0         | 2.5         | 0.0421           | 9.97         | 2.4470          | 1.4024                | 57.31                  | K1    |
| 9           | 5.0         | 2.5         | 0.0417           | 9.92         | 2.4347          | 1.2785                | 52.51                  | S1    |
| 10          | 5.0         | 2.5         | 0.0432           | 10.05        | 2.4666          | 1.6693                | 67.68                  | SW2   |
| 11          | 5.0         | 2.5         | 0.0420           | 9.92         | 2.4347          | 1.6685                | 68.53                  | K2    |
| 12          | 5.0         | 2.5         | 0.0418           | 9.90         | 2.4298          | 1.4564                | 59.94                  | S2    |

*Notation: DW, distilled water; SW1, 0.1% slickwater; SW2, 0.04% slickwater; K1, 10% KCl; K2, 1% KCl; S1, 0.25% surfactant; S2, 0.1% surfactant.
analysis, which can be characterized by imbibition rate and suction capacity.

The variation curve of the imbibition amount per unit pore volume with the imbibition time is shown in Figure 11a, and the corresponding imbibition characteristic curve of the imbibition amount under the corresponding unit sample volume with the time square root of the unit length is shown in Figure 11b. The samples selected for the imbibition experiments have the same lithology, and the experimental results show that the imbibition curves have the same trend. In the early stage of imbibition, the accumulated water absorption increased rapidly with time, but the corresponding water absorption rate decreased rapidly with time. In the late stage of imbibition, the imbibition amount tends to be stable, indicating that the imbibition process gradually reaches an equilibrium state. To study the effect of clay minerals on the imbibition capacity, the same sample was redried and imbibed again, and the changes of imbibition curves were compared, as shown in Figure 12. Since the imbibition reproducibility of the three tight sandstone samples is poor, it shows that the internal pore structure changes obviously after spontaneous imbibition. The water absorption volume of the secondary imbibition increases significantly because the clay minerals swelling with water absorption create microcracks and increase the pore volume of the rock and thus improves the imbibition capacity of the tight sandstone. By comparing the mercury intrusion curves before and after imbibition, after imbibition treatment, the internal water saturation changed, and the pore throats were filled due to the expansion and migration of clay minerals. The average pore throat radius of the rock samples decreased, and the pore volume was reduced. However, after repeated drying and imbibition of the sample, it regained sufficient imbibition capacity as the water saturation of the sample decreased. With the accumulation of imbibition, capillary pressure and osmotic pressure drive the continuous generation of microfractures, and the expanded microfractures increase the volume and connectivity of pore fractures, resulting in a significant increase in imbibition capacity and imbibition rate. Figure 13 is the SEM images of tight sandstone samples before and after imbibition. Scanning electron microscope images show that the sample pores are relatively developed. Moreover, the pore types are classified as intergranular pores and intragranular dissolved pores. Its cementation types are mainly shown as cushion type and enlarged type, and the cementation material is represented by chlorite. After imbibition, the intergranular filling becomes more obvious, and the hydration and expansion of clay minerals occupy the pore throat channels, which induces the formation of intragranular dissolution pores and expansion of microcracks.

5.2.2. Salinity. With the aim of exploring the effect of different salinity on the imbibition of tight sandstone, three core samples numbered 6, 8, and 11 were used for imbibition experiments at different salinities, and the relevant imbibition curves are shown in Figure 14. The experimental results show that the spontaneous imbibition weight of the tight sandstone sample in deionized water is the largest, and the imbibition capacity is the strongest, reaching 1.8105 g. As the salinity increases to 10000 mg/L, the imbibition capacity decreases to 1.6685 g. The minimum imbibition capacity of 1.4024 g appears when the imbibition fluid salinity is set to a maximum of 100 000 mg/L. The main reason for the decrease of imbibition capacity caused by the increase of salinity is that the osmotic pressure caused by the difference in the salt concentration drives water molecules to enter the high-concentration fluid from the low-concentration pore area through the semipermeable membrane formed by clay.

![Figure 11](image1.png)
(a) Imbibition volume/pore volume vs time^{0.5}

![Figure 12](image2.png)
(b) Imbibition volume/sample volume vs time^{0.5}/length

Figure 11. Imbibition characteristic curve.

Figure 12. Repetition immersion tests.
minerals. The three tight sandstones with similar physical properties can reach the imbibition stable state within 24 h under different salinities. In conclusion, although salinity reduces imbibition capacity, it has no significant effect on spontaneous imbibition rate and imbibition stabilization time.

5.2.3. Viscosity. Considering that the viscosity parameter in the fluid properties will affect the imbibition, three tight sandstone samples marked 6, 7, and 10 are immersed in slickwater with different viscosities to conduct a comprehensive imbibition exploration, and the results are depicted in Figure 15. Distilled water was chosen as the initial fluid, the variable of 1 mPa/s\(^{-1}\) is set to a low-viscosity solution, and its imbibition capacity reaches a maximum value of 1.8105 g. The slickwater prepared with 0.04% drag reducing agent can achieve a viscosity of 2 mPa/s\(^{-1}\). Under this condition, an imbibition capacity of 1.6693 g is achieved. The lowest imbibition capacity of 1.5253 g occurs under the fluid displacement of 5 mPa/s\(^{-1}\) prepared with 0.1% drag reducer. At a viscosity of 5 mPa/s\(^{-1}\), the time required for imbibition stabilization is significantly longer than that at lower viscosity. It can be concluded that the increase in fluid viscosity leads to a slower imbibition rate and a longer time to reach a steady state of self-imbibition. This phenomenon is explained by the adverse effect of viscosity-controlled fluidity on imbibition displacement.

5.2.4. Surface Tension. The preparation of fluids with different surface tensions is accomplished by adding different concentrations of surfactants in deionized water. The three similar lithological tight sandstone samples, denoted as 6, 9, and 12, were flooded with solutions of different surface tensions to complete imbibition measurement. The relationship between the imbibition mass and the imbibition time under different surface tension is depicted in Figure 16. In deionized water, the surface tension was measured to be 72 mN/m. Under this driving action, the imbibition capacity of the tight sandstone sample is measured to be 1.8105 g. The 0.1% surfactant was added to deionized water to form a 40 mN/m experimental fluid, and the imbibition capacity of the tight sandstone sample under its displacement is determined as 1.4564 g. The 0.25% surfactant solution was prepared as a fluid with a low surface tension of 21 mN/m, and the imbibition capacity after
establishing imbibition equilibrium is 1.2785 g. It is concluded that the decrease of surface tension leads to the decrease of imbibition capacity. The results show that although the reduction of surface tension improving the fluidity of the fluid, the effect that weakens the capillary force, which is identified as the driving force of imbibition, is more significant, making it less conducive to the displacement of tight sandstone gas by imbibition.

5.2.5. Fracturing Fluid Composition. The absorption of fracturing fluid in tight sandstone reservoirs is mainly driven by capillary force and clay osmotic pressure. The composition and properties of the fracturing fluid are the main factors that affect the driving force of absorption, which in turn affects the absorption capacity of the fracturing fluid. Four parallel samples of the tight sandstone rock in Table 2 were selected and immersed in distilled water, slickwater, 10% KCl solution, and 0.25% surfactant to determine the effect of different fracturing fluid composition on imbibition capacity, respectively, as shown in Figure 17. The results show that when the cationic surfactant is used as the imbibition liquid, the wetting angle of the sandstone surface can be significantly improved, and the capillary force and surface hydrophilicity can be reduced, as shown in Figure 18; when 10% KCl solution is used as the imbibition liquid, clay hydration can be effectively suppressed and the stability of the sandstone sample is improved.

5.3. Analysis of Main Control Factors. In addition to being affected by the size and shape of the core, the imbibition
rate reflects a comprehensive characteristic, which is mainly related to the sandstone microstructure, mineral composition, liquid properties, and the interaction between sandstone and liquid. In this analysis, permeability, porosity, liquid viscosity, surface tension, and fluid salinity were focused on to explore the main controlling factors affecting spontaneous imbibition characteristics.

The main factors and levels affecting spontaneous imbibition are listed in Table 4, and corresponding imbibition recovery of different parameter levels are presented in Table 5. The results show that the controlling factors affecting imbibition are arranged as follows: surface tension > porosity = permeability > salinity > viscosity. Among the above factors, the fluid properties are human-controlled factors and the surface tension is the main control factor affecting the self-absorption effect. In the process of tight gas recovery, the surface tension can be adjusted by adding surfactants. This method is an effective measure to improve the spontaneous imbibition recovery rate of tight gas reservoirs and shorten the shut-in time of a single well. Likewise, the salinity of the fracturing fluid can be reduced to increase the efficiency of spontaneous imbibition, thereby reducing the shut-in time.

6. CONCLUSIONS

A systematic imbibition evaluation experiment was carried out to investigate imbibition characteristics of tight sandstone samples and to explore the main controlling factors affecting imbibition. The essential conclusions are summarized as follows:

1. Since the tight sandstone samples from the Shaximiao Formation reservoir have strong heterogeneity, high clay mineral content, more developed micro/nanopores, less developed fractures, and strong hydration expansion, the imbibition capacity of different samples under the same fluid condition is quite different, indicating that imbibition is affected by the pore throat structure and rock physical properties.

2. Since the average pore throat radius of tight sandstone samples is between 0.1 and 0.2 μm, the imbibition driving force is strong. The imbibition rate is fast, and the imbibition basically reaches a steady state within 24 h, which makes the imbibition capacity basically greater than 50%. After repeated imbibition of the same rock sample, the imbibition capacity increases significantly, which is attributed to the increase of pore volume and the change of imbibition pore structure due to the hydration and expansion of clay minerals.

3. Based on the analysis of the main control factors of imbibition, the surface tension of the fluid properties has the greatest impact on the imbibition recovery factor. In the process of tight gas recovery, the surface tension can be adjusted by adding surfactants, which is an effective measure to improve the spontaneous imbibition recovery rate of tight gas reservoirs and shorten the shut-in time of a single well.

Table 4. Main Factors and Levels Affecting Spontaneous Imbibition

| parameter level | viscosity (mPa/s) | salinity (mg/L) | surface tension (mN/m) | permeability (mD) | porosity (%) |
|-----------------|------------------|----------------|------------------------|------------------|-------------|
| k1              | 1 1 0 72         | 0.01 3.7       |                        |                  |             |
| k2              | 2 10 000 40      | 0.07 7.6       |                        |                  |             |
| k3              | 5 100 000 21     | 0.11 10.1      |                        |                  |             |

Table 5. Analysis of Key Factors Affecting the Spontaneous Imbibition

| parameter level | imbibition recovery of different parameter levels (%) |
|-----------------|------------------------------------------------------|
| k1              | 73.35 73.35 45.04 45.04 |
| k2              | 67.68 68.53 47.89 47.89 |
| k3              | 62.17 57.31 62.64 62.64 |
| differential R  | 11.38 16.24 17.60 17.60 |
| optimal level   | 1 0 21 10.1 |
| factor order    | 5 4 1 2 2 |

different parameter levels are presented in Table 5. The results show that the controlling factors affecting imbibition are arranged as follows: surface tension > porosity = permeability > salinity > viscosity. Among the above factors, the fluid properties are human-controlled factors and the surface tension is the main control factor affecting the self-absorption effect. In the process of tight gas recovery, the surface tension can be adjusted by adding surfactants. This method is an effective measure to improve the spontaneous imbibition recovery rate of tight gas reservoirs and shorten the shut-in time of a single well. Likewise, the salinity of the fracturing fluid can be reduced to increase the efficiency of spontaneous imbibition, thereby reducing the shut-in time.

6. CONCLUSIONS

A systematic imbibition evaluation experiment was carried out to investigate imbibition characteristics of tight sandstone samples and to explore the main controlling factors affecting imbibition. The essential conclusions are summarized as follows:

1. Since the tight sandstone samples from the Shaximiao Formation reservoir have strong heterogeneity, high clay mineral content, more developed micro/nanopores, less developed fractures, and strong hydration expansion, the imbibition capacity of different samples under the same fluid condition is quite different, indicating that imbibition is affected by the pore throat structure and rock physical properties.

2. Since the average pore throat radius of tight sandstone samples is between 0.1 and 0.2 μm, the imbibition driving force is strong. The imbibition rate is fast, and the imbibition basically reaches a steady state within 24 h, which makes the imbibition capacity basically greater than 50%. After repeated imbibition of the same rock sample, the imbibition capacity increases significantly, which is attributed to the increase of pore volume and the change of imbibition pore structure due to the hydration and expansion of clay minerals.

3. Based on the analysis of the main control factors of imbibition, the surface tension of the fluid properties has the greatest impact on the imbibition recovery factor. In the process of tight gas recovery, the surface tension can be adjusted by adding surfactants, which is an effective measure to improve the spontaneous imbibition recovery rate of tight gas reservoirs and shorten the shut-in time of a single well.

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Notes

The authors declare no competing financial interest.

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