Numerical Simulation of Spontaneous Imbibition under Different Boundary Conditions in Tight Reservoirs

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ABSTRACT: Based on the spontaneous imbibition phenomenon and seepage mechanism of the tight core, a spontaneous imbibition model of the tight reservoir was established. The imbibition experiment was used to verify the reliability of the model and reverse the parameters. The relative error between the experimental and model recovery is within 5%. The model is used to calculate the oil recovery and oil saturation distribution characteristics of spontaneous imbibition in tight reservoirs under different boundary conditions. The model results show that the imbibition area and imbibition recovery are different under different boundary conditions [one-end-open, two-end-open, two-end-close (TEC), and all-face-open (AFO)]. If the imbibition area increases, imbibition recovery increases. If the side is closed, the spontaneous imbibition occurring at two end faces does not interfere with each other in the initial stage. When the imbibition process under TEC conditions is advanced to the middle and late stage, the superimposed effect occurs between the two imbibition leading edges. Under the AFO condition, the imbibition process has a superimposed effect at the corner between the end face and the side face. The superimposed effect of the end face is more obvious than that of the side face. The superimposed effect not only improves the oil washing efficiency but also inhibits the imbibition area.

1. INTRODUCTION

Tight oil reservoirs that can be developed by imbibition are widely distributed. The pore throat size of tight reservoirs is greatly different, which leads to the capillary pressure difference between the pore throats. The capillary pressure of a small pore throat is greater than that of a large pore throat, which leads to the wet phase fluid being absorbed by the small pore throat and the nonwet phase fluid being discharged by the large pore throat. The process of the wetting phase displacing the nonwetting phase in porous media is called spontaneous imbibition. In the process of tight reservoir development, reservoir rocks may not be completely immersed in injected fluids. The contact position and region between the rock surface and water are very complex. It is significant for the development strategy of tight oil reservoirs to study the influence of boundary conditions on spontaneous imbibition.

The existing common spontaneous imbibition research methods are experimental methods, which are used to qualitatively study the influence of various factors on imbibition. In contrast, the quantitative study of spontaneous imbibition based on numerical simulation technology is less. Østebø Andersen et al. explored the role of spontaneous imbibition in oil recovery and fluid displacement and the influence of boundary conditions on cocurrent and countercurrent imbibition. Behbahani studied the reverse imbibition characteristics of strong water wetting cores through numerical simulation, which showed that the square root of the fluid viscosity product can scale the imbibition recovery degree curve under different fluid viscosities. Andersen and Qiao studied the effect of viscous coupling and capillary back pressure. Pooladi-Darvish discussed the numerical simulation of imbibition under different boundary conditions, but he ignored the capillary back pressure when dealing with the numerical model. Ma and Zhang studied the imbibition curves of different oil–water viscosity ratios under four boundary conditions. It is considered that the imbibition under all-face-open (AFO) boundary conditions belongs to radial seepage at the side faces and linear seepage at the end faces. The effects of different boundary conditions on spontaneous imbibition were studied by experimental methods. The experimental methods are limited by the sensitivity of experimental instruments and the timeliness of observation, so it is difficult to ensure that the accuracy of each experiment is consistent. The oil-phase fluid attached to the
core surface cannot be completely measured in experiments, which results in large errors. Because the spontaneous imbibition experiment is more sensitive to core heterogeneity than the conventional displacement experiment, the imbibition results measured by different cores often vary greatly when the basic physical property parameters cannot be completely consistent. Using the spontaneous imbibition model to study the spontaneous imbibition process of tight sandstone can overcome the abovementioned two defects, it is appropriate to quantitatively analyze the influence of imbibition boundary conditions on the spontaneous imbibition process and the data measurement is also accurate.

Based on the spontaneous imbibition theory in tight reservoirs, we established the spontaneous imbibition model in tight reservoirs by the mathematical expression of imbibition. The imbibition experiment was used to verify the reliability of the model and reverse the parameters.

2. MATHEMATICAL MODEL AND VALIDATION

2.1. Description of Spontaneous Imbibition. The spontaneous imbibition process mainly refers to the spontaneous flow of oil and water in porous media under the influence of capillary pressure. The capillary pressure of fluids can be expressed as

\[ P_c = \frac{2\sigma_{\text{ow}} \cos \theta_{\text{ws}}}{r_t} \]  

(1)

where \( \sigma_{\text{ow}} \) is the interfacial tension between oil and water phases; \( \theta_{\text{ws}} \) is the angle of wetting of the rock surface; and \( r_t \) is the pore throat radius. Equation 1 shows that when the pore size in porous media is smaller, the capillary pressure is larger.

As shown in Figures 1 and 2, the saturated oil core was completely submerged in water, and the surface of the core can come into contact with water by means of fixing a device. Under the combined action of capillary pressure and gravity, the water first enters the surface throat of the core and gradually empties into the small-size throat inside the core. During this process, the oil-phase fluid of equal volume in the core is discharged, and after a long period of spontaneous imbibition, the mobile oil in the core will be completely replaced.

As shown in Figures 1 and 2, experimental studies on imbibition are mostly focused on the case of complete water submerged of tight cores. Imbibition can take place on each end face of the core in this completely open boundary condition. In the spontaneous imbibition experiments of tight cores, radial and linear seepage can occur at the side and end of the spontaneous imbibition process. The oil and water flow at the left and right end of the rock matrix grid usually percolates linearly. The flow of oil and water on the side of the rock matrix grid is usually radial.

In the same group of experiments, the pore structure and wettability of the cores used for spontaneous imbibition are different, which makes the comparison of spontaneous imbibition experiments disturbed by the properties of the rocks. The establishment of the spontaneous imbibition model can deal with this problem.

2.2. Establishment of the Spontaneous Imbibition Model. To study the law of spontaneous imbibition process in a tight oil reservoir, the spontaneous imbibition model was established. According to the characteristics of tight cores, the model limitations are as follows:

(1) The spontaneous imbibition process of the core is regarded as the isothermal seepage process.
(2) The oil and water phases are insoluble during spontaneous imbibition.
(3) The compressibility of the fluid and rock matrix is ignored.
(4) The spontaneous imbibition process was carried out under the condition of water wetting.
(5) For the convenience of calculation, the capillary pressure curve and relative permeability curve are simplified as the function of water saturation.

According to the basic theory of two-phase seepage, seepage equations can be used to describe the imbibition process.

(1) Equation of continuity

\[ \phi \frac{\partial s_w}{\partial t} + \frac{\partial w}{\partial x} + \frac{\partial v_w}{\partial y} = 0 \]

(2) Equation of motion

\[ V_w = -\frac{K_{\text{ow}}}{\mu} \frac{\partial p}{\partial t} \]

(3) Auxiliary equation

Figure 1. Schematic diagram of spontaneous imbibition.

Figure 2. Physical diagram of spontaneous imbibition.
\[ p_c(S_w) = p_o - p_w \]
\[ s_o + s_w = 1 \]

(4) Initial conditions

\[ p(x, y, t = 0) = p^0(x, y) \]
\[ S(x, y, t = 0) = S^0_w(x, y) \]

Different boundary types [AFO, one-end-open (OEO), two-end-open (TEO), and two-end-close (TEC)] are mainly caused by the difference of boundary condition equations.

Boundary conditions of AFO

\[ P_o(x, y, t)|_{x=0, y \leq S_H} = P_{bc}^E(t) \]
\[ P_o(x, y, t)|_{x=L, y \leq S_H} = 0 \]
\[ P_o(x, y, t)|_{x=0, y > S_H} = P_{bc}^S(t) \]
\[ P_o(x, y, t)|_{x=L, y > S_H} = 0 \]
\[ P_o(x, y, t)|_{0 \leq x \leq L, y = 0} = P_{bc}^S(t) \]
\[ P_o(x, y, t)|_{0 \leq x \leq L, y = H} = P_{bc}^S(t) \]

where \( P_{bc}^S(t) \) is the side capillary pressure back pressure and \( P_{bc}^E(t) \) is the end capillary pressure back pressure.

Boundary conditions of OEO

\[ P_o(x, y, t)|_{x=0, y \leq S_H} = P_{bc}^E(t) \]
\[ P_o(x, y, t)|_{x=L, y \leq S_H} = 0 \]
\[ q_o(x, y, t)|_{x=0, y \leq S_H} = 0 \]
\[ q_o(x, y, t)|_{x=L, y \leq S_H} = 0 \]
\[ q_o(x, y, t)|_{0 \leq x \leq L, y = 0} = 0 \]
\[ q_o(x, y, t)|_{0 \leq x \leq L, y = H} = 0 \]

Boundary conditions of TEO

\[ P_o(x, y, t)|_{x=0, y \leq S_H} = P_{bc}^E(t) \]
\[ P_o(x, y, t)|_{x=L, y \leq S_H} = 0 \]
\[ q_o(x, y, t)|_{x=0, y \leq S_H} = 0 \]
\[ q_o(x, y, t)|_{x=L, y \leq S_H} = 0 \]
\[ q_o(x, y, t)|_{0 \leq x \leq L, y = 0} = 0 \]
\[ q_o(x, y, t)|_{0 \leq x \leq L, y = H} = 0 \]

Boundary conditions of TEC

\[ q_o(x, y, t)|_{x=0, y \leq S_H} = 0 \]
\[ q_o(x, y, t)|_{x=L, y \leq S_H} = 0 \]
\[ q_o(x, y, t)|_{x=0, y > S_H} = 0 \]
\[ q_o(x, y, t)|_{x=L, y > S_H} = 0 \]
\[ P_o(x, y, t)|_{0 \leq x \leq L, y = 0} = 0 \]
\[ P_o(x, y, t)|_{0 \leq x \leq L, y = H} = 0 \]

The relationship between the oil-water relative permeability curve and fluid saturation in the spontaneous imbibition process is defined as

\[ k_{rw} = k_n^w \left( \frac{S_{rw} - S_{wc}}{1 - S_{wc} - S_{rw}} \right)^n \]  \hspace{1cm} (2)

\[ k_{ro} = k_n^o \left( \frac{1 - S_{ro} - S_{rw}}{1 - S_{wc} - S_{rw}} \right)^m \] \hspace{1cm} (3)

where \( k_{rw} \) is the water-phase relative permeability; \( k_{ro} \) is the oil-phase relative permeability; \( K_n^w \) is the water-phase permeability corresponding to residual oil saturation; \( K_n^o \) is the oil-phase permeability corresponding to immobile water saturation; \( S_{rw} \) is the water saturation; \( S_{ro} \) is the immobile water saturation; \( S_{ro} \) is the residual oil saturation; \( n \) is the water-phase relative permeability curve index; and \( m \) is the oil-phase relative permeability curve index. In the rock matrix grid, the immobile water saturation is equal to the initial water saturation for easy calculation.

\( K_n^w, K_n^o, S_{wc}, \text{ and } S_{ro} \) are obtained by experiment. The “m” and “n” are obtained by fitting in the model. The fitting process of “m” and “n” is as follows:

Compared to the simulated imbibition recovery under different “m” and “n” conditions with the experimental recovery, we can obtain the appropriate “m” and “n” value when the simulated recovery is the closest to the experimental recovery. The complete relative permeability equation was established by substituting the fitting water-phase permeability index and oil-phase permeability index.

Capillary pressure is related to several factors, such as the reservoir pore structure, fluid physical properties, and fluid–solid interface properties. Capillary pressure is the main driving force of spontaneous imbibition, which is of great significance to spontaneous imbibition. The equation for calculating capillary pressure can be described as

\[ P_c = \sigma (\phi / k)^{1/2} J(S_w) \] \hspace{1cm} (4)

where \( \phi \) is the porosity of the core and \( k \) is the core permeability. \( J(S_w) \) is the average capillary pressure function of the reservoir. Based on the data of capillary pressure and water saturation of several cores, the \( J(S_w) \) was fitted. Pooladi-Darvish and coworkers found that the \( J(S_w) \) function can be replaced by \(-\ln S \). Equation 4 can be transformed into eq 5

\[ P_c = -\sigma (\phi / k)^{1/2} \ln(S) \] \hspace{1cm} (5)

where \( S \) is the normalized saturation (see the nomenclature). Equation 5 can synthesize the interfacial tension, wettability,
rock matrix permeability, porosity, and capillary pressure curve of the reservoir fluid.

According to the function relationship between relative permeability and capillary pressure and water saturation in eqs 2, 3, and 5, the relative permeability curve and capillary pressure curve are constructed, and then, the spontaneous imbibition model of the tight oil reservoir is established.

As shown in Figure 3, the block center grid model can be used to simulate the spontaneous imbibing phenomenon of oil and water fluids in the porous media, which is convenient to set the different boundary conditions and observe the distribution of fluids in the rock matrix grid.

In the simplified block center grid model, the outer blue grid is the water grid and the inner yellow grid is the rock matrix grid. The number of cell grids is determined by considering the requirements of calculation speed and precision. All grids have the same size. Different boundary types (AFO, OEO, TEO, and TEC) are mainly caused by the difference of boundary condition equations.

After the spontaneous imbibition model of the tight oil reservoir was established, the spontaneous imbibition experiment of the tight oil reservoir was set to verify the model. The results of the spontaneous imbibition experiment were compared with those of the spontaneous imbibition model, and the reliability and accuracy of the model were analyzed using the comparative results.

2.3. Verification Experiment Design. In spontaneous imbibition experiments, the saturated oil core was submerged in formation water, which made all surfaces of the cores come into contact with formation water. The experiments were carried out under the conditions of room temperature and atmospheric pressure. We used six cores for spontaneous imbibition experiments. After the imbibition process began, the water on the surface of the core began to invade the small-sized throat in the core, and the oil phase in the macrospores of the core would be displaced and attached to the core surface. By shaking the flask, the oil phase attached to the core surface was completely floating on the surface of the formation water.

During the spontaneous imbibition experiment, the core was cut into cylindrical shape and the physical parameters of the core were measured. After completing the saturated oil process, we calculated the initial oil saturation of the core:

\[
S_{oi} = \frac{w_{oi} - w_f}{\rho_o \cdot \phi \cdot V_i} \times 100\% \tag{6}
\]

where \(S_{oi}\) is the initial oil saturation; \(w_{oi}\) is the dry core mass; \(w_f\) is the core mass after being saturated with oil; \(\rho_o\) is the density of the oil phase; \(V_i\) is the core apparent volume.

In the spontaneous imbibition experiment, the time of complete core immersion was used as the imbibition initial time, and each specific time point of spontaneous imbibition was recorded. At each specific time point, we shake the imbibition flask and calculate the oil-produced volume at each specific time point. Equation 7 was used to calculate imbibition recovery at each specific time:

\[
\eta = \frac{V_{op}}{\phi \times V_i \times S_{oi}} \tag{7}
\]

where \(\eta\) is the imbibition recovery and \(V_{op}\) is the volume of oil imbibition.

When the increase in imbibition recovery measured at two adjacent times is less than 5%, the spontaneous imbibition process is regarded as coming to an end and the spontaneous imbibition experiment is stopped (140 h). The imbibition recovery corresponding to a specific time was calculated to establish the relationship curve between the imbibition time and imbibition recovery.

2.4. Verification Experiment Procedure. According to the experimental data of spontaneous imbibition and the simulation results of the spontaneous imbibition model, the reliability and accuracy of the model were verified by comparing the imbibition recovery.

When the model parameters were set, the permeability of the water source grid in different directions was 1000 mD, and the porosity was set as 1. The matrix grid was set up according to the core data in Table 1 which is based on the JL-1 rock sample.

| Experimental parameters | Parameter value |
|-------------------------|----------------|
| the length of the core   | 5 cm           |
| core diameter            | 2.5 cm         |
| core permeability        | 0.194 mD       |
| core porosity            | 0.1221         |
| initial oil saturation   | 0.9559         |
| water phase viscosity    | 1.0 mPa·s      |
| oil phase viscosity      | 8.87 mPa·s     |
| residual oil saturation  | 0.094          |
| water-phase relative     | 1              |
| permeability, \(K_w^*\)  |
| oil-water interfacial    | 22.48 mN/m     |
| tension                  |
| rock compressibility     | 6.4 × 10^{-4} MPa^{-1} |
| water compressibility    | 3.5 × 10^{-4} MPa^{-1} |
| oil compressibility      | 7 × 10^{-4} MPa^{-1} |

For example, the permeability of the rock matrix grid is set to 0.094 according to the core gas measurement permeability. In particular, the core sample was saturated with oil at a pressure of 25 MPa, and the core sample was not saturated with water before being saturated with oil, which led to the initial oil saturation reaching 0.9559.

The JL-1 simulation curve was obtained by the model development. In the model, the parameters which are obtained by fitting are the water-phase relative permeability curve index and oil-phase relative permeability curve index. From the relative permeability curve, we can simulate the imbibition process.
recovery by the model development. Comparing the simulated recovery under different index conditions with the experimental recovery, we can obtain the appropriate index when the simulated recovery is the closest to the experimental recovery. In Figure 4, combined with core parameters, the water-phase permeability index $n$ is 3 and the oil-phase permeability index $m$ is 1.5 through curve fitting.

The final imbibition recovery measured by the spontaneous imbibition experiment is 36.97%, and the final imbibition recovery calculated using the spontaneous imbibition model is 38.65%. The relative error between the two is 4.54%, which can prove the reliability and accuracy of the model. It shows that the influence of different boundaries on spontaneous imbibition can be studied with the model.

As shown in Figures 5 and 6, the relative permeability curve and capillary pressure curve required by this model were plotted. Comparing the simulated recovery under different index conditions with the experimental recovery, we can obtain the appropriate index when the simulated recovery is the closest to the experimental recovery.

3. RESULTS AND DISCUSSION

3.1. Description of Different Boundary Conditions. As shown in Figure 7, according to the location and number of closed boundaries, the boundary conditions were divided into four types: AFO, OEO, TEO, and TEC.

The models for the four boundary conditions are all composed of the rock matrix grid, water grid, and closed boundary grid, and the water saturation at the water grid is set as 1. Spontaneous imbibition occurs at the open boundary and interior of the rock matrix grid. The closed boundary of the model is the dead grid. The closed boundary has no effect on the internal physical parameters of the rock matrix grid and the water grid. There is material exchange between the rock matrix grid and the water grid at the open boundary.

3.2. Curve Characteristics of Different Boundary Conditions. The basic physical property parameters in Table 1 were input into the spontaneous imbibition model. When the increase in imbibition recovery measured at two adjacent times is less than 5%, the spontaneous imbibition process is stopped. As shown in Figure 8, imbibition recovery curves were calculated and drawn, which makes a comparative
analysis of imbibition recovery curves under the influence of the four boundary conditions.

The area of a single end face of the tight core simulated by the spontaneous imbibition model was calculated to be 4.91 cm², and the side area of the model was 39.27 cm². The ratio of the side area to the single end face area is 8. "S" represents the area of a single end face, so the side area is "8S". Table 2 shows the calculation results of the surface areas involved in imbibition under various conditions.

Table 2. Imbibition Area and Imbibition Recovery under Different Boundary Conditions

| boundary condition | imbibition area | imbibition recovery/% |
|--------------------|-----------------|-----------------------|
| AFO                | 10S             | 36.81                 |
| TEC                | 8S              | 35.32                 |
| TEO                | 2S              | 13.51                 |
| OEO                | S               | 6.76                  |

As shown in Figure 8 and Table 2, spontaneous imbibition models under all boundary conditions reached a stable state finally. Spontaneous imbibition recovery increased with the increase in imbibition area.

The two curves of AFO and TEC are very close. AFO has the highest imbibition recovery, and TEC has the second highest imbibition recovery. Both of these boundary conditions take the side as an open boundary. Compared with OEO and TEO with no open-side boundary, the imbibition recovery of AFO and TEC boundary conditions is obviously higher than that of the latter two boundary conditions, which indicates that the side boundary is the main imbibition region.

In terms of imbibition area, TEO is twice that of OEO. Because the imbibition of the two end faces is equal under TEO conditions, the increase in end face area leads to a proportional increase in imbibition recovery.

In terms of imbibition area, the imbibition area of AFO is 25% larger than that of TEC. In terms of imbibition recovery, AFO is only 4.22% larger than TEC. When the side boundary is open, the effect of the end face on the imbibition recovery is not obvious.

3.3. Saturation Distribution Characteristics of Different Boundary Conditions. The oil saturation distribution maps of the matrix grid at different times were drawn, and the influence of different boundary conditions on imbibition was analyzed.

As shown in Figure 9 and Table 3, the results under OEO conditions show that the imbibition leading edge which locates on the opening end face pushes forward. With the imbibition leading edge pushing forward, the imbibition distance gradually lengthens and the speed of the imbibition leading edge gradually decreases.

The imbibition leading edge at the end face forms a rectangle with a constant width and decreasing length at the position of the rock matrix grid without imbibition. When the imbibition resistance is close to the capillary pressure, the imbibition leading edge cannot extend further, which indicates that the spontaneous imbibition process is coming to an end.

Compared with OEO conditions, the imbibition model under TEO conditions opens two end faces. As shown in Figure 10, with the imbibition leading edges pushing forward, the imbibition leading edges at the end faces form a rectangle with constant width and decreasing length at the position of the rock matrix grid without imbibition. In particular, the rectangle has the longitudinal midline of the rock matrix grid as the axis of symmetry.

As shown in Table 4, with imbibition leading edges pushing forward, the imbibition distance gradually lengthens and the speed of the imbibition leading edges gradually decreases. When the imbibition resistance is close to the capillary pressure, the imbibition leading edges cannot extend further, which indicates that the spontaneous imbibition process is coming to an end.

As shown in Table 2, in terms of imbibition area, the TEO condition is twice as large as the OEO condition. In terms of imbibition recovery, the TEO condition is also twice as large as the OEO condition, which indicates that the imbibition recovery is consistent with the imbibition area. As shown in Tables 3 and 4, when the two opening end faces are far away
from each other, the imbibition leading edges push forward independently.

Under TEC conditions, the model was imbibed through the side only. As shown in Figure 11, at the initial stage of spontaneous imbibition, the imbibition leading edges form a rectangle with a constant length and decreasing width at the position of the rock matrix grid without imbibition. In particular, the rectangle has the horizontal midline of the rock matrix grid as the axis of symmetry.

As shown in Table 5, with imbibition leading edges pushing forward, the imbibition distance gradually lengthens and the speed of the imbibition leading edges gradually decreases. The rectangle gradually becomes smaller and finally disappeared, which indicates that all the rock matrix grids were swept by imbibition.

Compared with TEO conditions, the imbibition boundaries under TEC conditions are less distant from each other. When imbibition enters the middle and late stage, the superimposed effect occurs, which makes the two imbibition leading edges disappear.

As shown in Figure 11, the oil saturation distribution of TEC presents a symmetrical state of upper and lower, which indicates that the capillary pressure plays a dominant role, while the influence of gravity is not obvious.

The bond number can be used to quantitatively describe the influence of gravity and capillary pressure on the imbibition process, which is defined as:

$$N_B^{-1} = C \left( \frac{\sigma \phi}{k} \right) \Delta \rho g h$$

Where $N_B^{-1}$ is the bond number; $C$ is the model coefficient of the cylindrical core simulated by the model (the value is 0.4 in the model); $\Delta \rho$ is the density difference between oil and water; $g$ is the acceleration of gravity; and $h$ is the height.

When the bond number is greater than 5, it can be regarded that the capillary pressure plays a dominant role and the influence of gravity is not obvious. When the bond number is less than 1, gravity gradually becomes the main force of the spontaneous imbibition process. With the bond number decreasing, gravity gradually becomes stronger.

Based on the parameter set in Table 1, the bond number of the model is 2708, which is far larger than that of the gravity-influenced critical value (the value is 5). Therefore, the influence of gravity on the oil saturation distribution under TEC conditions can be ignored.

Compared with the other boundary conditions, both end faces and side faces are open under the AFO condition. As shown in Figure 12, the superimposed effect occurs at the corner of the end face and the side face, which displays the fact that the imbibition leading edge at the corner is gradually blurred in the distribution of oil saturation. The superimposed effect at the corner gradually expands to the side face and end face. Because the size of the end face is smaller than that of the side face, the superimposed effect of the end face is more

Table 4. Imbibition Distance under TEO Conditions

| period of time (h) | imbibition distance (cm) | imbibition speed (cm/h) |
|-------------------|--------------------------|-------------------------|
| 0−5              | 0.38                     | 0.076                   |
| 5−24             | 0.74                     | 0.01895                 |
| 24−48            | 1.07                     | 0.01458                 |
| 48−96            | 1.29                     | 0.00458                 |

Table 5. Imbibition Distance under TEC Conditions

| period of time (h) | imbibition distance (cm) | imbibition speed (cm/h) |
|-------------------|--------------------------|-------------------------|
| 0−5              | 0.36                     | 0.072                   |
| 5−24             | 0.62                     | 0.01368                 |
| 24−48            | 0.81                     | 0.00792                 |
obvious than that of the side face. When imbibition enters the middle and late stage, the end face is seriously affected by the superimposed effect.

As shown in Figure 12, at the initial stage of spontaneous imbibition, the unswept region gradually forms into an elliptical region under AFO conditions. The elliptical region has the horizontal midline of the rock matrix grid as the long axis and the longitudinal midline of the rock matrix grid as the short axis. When imbibition enters the middle and late stage, the superimposed effect occurs, which makes the four imbibition leading edges disappear.

As shown in Tables 5 and 6, AFO is consistent with the side-face imbibition speed of TEC, which indicates that imbibition occurring on the side face is unaffected by the end face. As shown in Tables 4 and 6, the imbibition speed of AFO at the end face is obviously lower than that of TEO, which indicates that the imbibition at the end face is greatly affected by the superimposed effect.

As shown in Figure 13, under AFO conditions, the imbibition leading edge at all faces disappear under the influence of the superimposed effect at the late stage of spontaneous imbibition. At the end face, the S1 region and S3 region are more affected by the superimposed effect than the S2 region. All of the abovementioned areas are equidistant from the end face boundary but the oil saturation at the S2 region is higher, which indicates that the oil washing efficiency is high with the strengthening of the superimposed effect.

In terms of oil washing efficiency, the superimposed effect of spontaneous imbibition has a positive effect on enhanced oil recovery.

As shown in Figure 14, in terms of imbibition distance at the end face, the imbibition distance of TEO and OEO is larger than that of AFO. Because the imbibition front changes rapidly in the early stage, Figure 14 only shows the imbibition front position in the first 48 h and does not reach the end of the imbibition process (140 h). In terms of imbibition speed at the end face, the imbibition speed of TEO and OEO is also larger than that of AFO, which indicates that the imbibition at the end face of AFO is affected by the superimposed effect. The superimposed effect makes the imbibition leading edge reach a smaller distance and inhibits the swept region at the end face.

### Table 6. Imbibition Distance under AFO Conditions

| period of time (h) | end-face imbibition distance (cm) | side-face imbibition distance (cm) | end-face imbibition speed (cm/h) | side-face imbibition speed (cm/h) |
|-------------------|----------------------------------|----------------------------------|---------------------------------|---------------------------------|
| 0–5              | 0.25                             | 0.36                             | 0.05                            | 0.072                           |
| 5–24             | 0.47                             | 0.62                             | 0.01158                         | 0.01368                         |
| 24–48            | 0.69                             | 0.81                             | 0.00458                         | 0.00792                         |

### Figure 14. End face imbibition position under different boundary conditions.
In terms of swept region, the superimposed effect of spontaneous imbibition has a negative effect on enhanced oil recovery.

4. CONCLUSIONS

(1) The side region is the main region of spontaneous imbibition. Imbibition recovery increases with increasing imbibition area.
(2) When the side boundary is closed, the imbibition process of the two end faces is independent due to the distance between them. The recovery of TEO is twice that of OEO. Due to the short distance between the sides of the TEC, when imbibition entered the middle and late stage, the imbibition front was seriously affected by the superimposed effect.
(3) Since the effect of capillary pressure under TEC conditions is greater than that of gravity, the distribution of saturation is symmetrical in the longitudinal direction.
(4) Under AFO conditions, the superimposed effect occurs at the corner of the end face and the side face. The superimposed effect of the end face is more obvious than that of the side face.
(5) The imbibition area of AFO is 25% larger than that of TEC, but the imbibition recovery of AFO is only 4.22% larger than that of TEC. The superimposed effect not only improves the oil washing efficiency in the superimposed area but also inhibits the imbibition area.
(6) The differences in the internal properties of spontaneous imbibition models can have a great influence on the advance of the imbibition front, which will be an important direction of future research.

■ APPENDIX

The process of fitting the relative permeability curve.

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Notes
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■ NOMENCLATURE

$P_c$ capillary pressure
$\sigma_{ow}$ interfacial tension between oil and water
$\theta_w$ wetting angle
$r_w$ pore throat radius
$S$ normalized water saturation dimensionless
$S_{iw}$ immobile water saturation
$S_o$ residual oil saturation
$k_{aw}$ water-phase relative permeability
$k_o$ oil-phase relative permeability
$k_w^*$ water-phase permeability corresponding to residual oil saturation
$k_w^*$ oil-phase permeability corresponding to immobile water saturation
$\phi$ porosity of the core
$S_i$ initial oil saturation
$w_i$ dry core mass
$w_o$ core mass after being saturated with oil
$V_t$ core apparent volume
$\eta$ imbibition oil recovery
$N_b$ bond number
$\Delta \rho$ density difference between oil and water
$g$ acceleration of gravity
$m$ oil-phase relative permeability curve index
$n$ water-phase relative permeability curve index

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