Research Article

Seepage Characteristics of a Low Permeability Sandstone Reservoir in Mobei Oilfield, Junggar Basin

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The microscopic pore structure characteristics and the oil-water two-phase seepage law in the low permeability sandstone reservoir in Mobei oilfield in Junggar Basin were analyzed through laboratory experiments. The results of mercury pressure, constant velocity mercury pressure, thin slice of casting, and CT scan analyses showed that the reservoir had strong microheterogeneity with the presence of local large channels. The large channel had a small volume but considerably contributed to the permeability, which played a crucial role in the reservoir seepage. The relative permeability curve showed that with the increase of water saturation, the relative permeability of the oil phase decreased rapidly; the water phase relative permeability of glutenite, gravel-bearing sandstone, and coarse sandstone increased slightly; and the water cut increased rapidly. The relative permeability of the water phase of medium and fine sandstone increased, the water cut increased rapidly, and the residual oil saturation was high. In the process of core displacement, on-line CT scanning monitoring showed that before the breakthrough of the water drive front, the oil saturation decreased greatly along the way. After the breakthrough of the water drive front, the water cut increased rapidly and directly entered the ultrahigh water cut stage. Owing to the serious heterogeneity of the micropore structure, the fingering phenomenon was obvious in the process of displacement.

1. Introduction

The Mobei oilfield is located on the Mobei uplift in the hinterland of Junggar Basin. The reservoir of Sangonghe Formation in Mobei 2 is located on the faulted anticline structural belt dipping southwestward, which is controlled by the East fault of the Mobei 2 well, and the reservoir sand body type is a front sand body of braided river delta [1]. The reservoir lithology mainly comprises medium and fine sandstone, followed by coarse sandstone and glutenite. The proportion of fine sandstone in J1s21 is high, accounting for 50%. The lithology of J1s22 is coarse, dominated by medium sandstone, followed by glutenite and coarse sandstone. The average porosity of the J1s21 reservoir is 13.6%, and its permeability is mainly distributed between 1 and 40 × 10⁻³ μm², with an average of 8.05 × 10⁻³ μm²; the reservoir thus belongs to the low porosity and ultralow permeability type. The average porosity of the J1s22 reservoir is 13.3%, and its permeability is between 1 and 512 × 10⁻³ μm². It is scattered, indicating that the reservoir heterogeneity is very strong with an average permeability of 13.4 × 10⁻³ μm²; generally, it is a low porosity and low permeability reservoir. The reservoir type belongs to the gas cap reservoir with a low permeability under the action of edge and bottom water; this is vertically subdivided into two reservoirs: J1s21 and J1s22, which are developed separately.

Development of the J1s21 reservoir started in 2001 and has been developed every year from 2007 to 2011. At present, it is currently at the end of its development. As of December 2020, there are 22 wells in the block, with a daily liquid production of 208 t, daily oil production of 60 t, water cut of 71.1%, recovery rate of 15.4%, and oil recovery rate of 0.17. The development effect is poor.

Development of the J1s22 reservoir started in 2000. As of December 2020, there is one well in the block, with a daily liquid production of 3.0 t and oil production of 0.1 t. Development effect is poor at 97.7%, and the recovery rate is 10.9%. The development effect is extremely poor.
2. Pore Structure of the Reservoir

The conventional mercury injection experiment shows that the pore throat of the Sangonghe Formation reservoir in Mobei 2 mostly presents double peaks (Figure 1), which differs from the normal distribution of the pore throat of a common sandstone reservoir. The microheterogeneity of the pore throat of this reservoir is strong. Through the comparative analysis of constant velocity mercury injection experiment results from the Sangonghe Formation reservoir in Mobei 2 oilfield and a low permeability sandstone reservoir (Figure 2), we found that the distribution of a large throat in the Mobei oilfield reservoir is considerably heterogeneous, especially for rock samples with large permeability (generally more than 10 mD), and the large throat is extremely developed. The permeability is mainly controlled by the large throat, and a smaller throat has little contribution to the seepage capacity.

According to the mercury pressure analysis data of reservoir rock samples, effective porosity, permeability, median radius, mean capillary radius, maximum pore throat radius, unsaturated pore volume, etc., 10 parameters are preferred, and the reservoir is divided into 5 categories by the K-means cluster analysis method (Figures 3 and 4) [2, 3].

The permeability of a type-I reservoir is more than $100 \times 10^{-3}$ $\mu$m$^2$. The lithology is mainly gravel-bearing coarse sandstone and coarse sandstone; the content of interstitial material is low, less than 4%. The cement mainly comprises siliceous and secondary quartz, while the miscellaneous base is mainly kaolinite and argillaceous components. The main pore types are primary intergranular and residual intergranular pores, with coarseness, skewness, and some macropores.

The permeability of a type-II reservoir is $60-100 \times 10^{-3}$ $\mu$m$^2$. The main lithology is coarse and medium sandstone; the content of interstitial material is low (2-6%), and the cement mainly comprises siliceous material and calcite, while the miscellaneous base is mainly kaolinite and argillaceous components. The main pore types are primary intergranular and residual intergranular pores, with coarseness, skewness, and a small number of macropores.

![Figure 1: Results of the conventional mercury injection experiment in Sangonghe reservoir of Mobei 2.](image1)

![Figure 2: Throat distribution characteristics of low permeability sandstone: (a) Sangonghe reservoir of Mobei 2; (b) a low permeability sandstone reservoir.](image2)
The permeability of a type-III reservoir is $20-60 \times 10^{-3} \mu m^2$. The main lithology is medium sandstone, wherein the interstitial material is between 3 and 6%, and the cement mainly comprises siliceous materials, calcite, and iron calcite, while the miscellaneous base is mainly kaolinite and argillaceous components. The main pore types are primary intergranular and intergranular solution pores.

The permeability of a type-IV reservoir is $10-20 \times 10^{-3} \mu m^2$. The lithology mainly comprises fine and medium sandstone. The content of interstitial material is between 3 and 7%, and the cement is mainly siliceous material and calcite, followed by kaolinite and argillaceous components. The main pore types are primary intergranular and intergranular solution pores.

The permeability of a type-V reservoir is $0.1-10 \times 10^{-3} \mu m^2$. The lithology is mainly fine sandstone; the content of interstitial material is between 4 and 8%, and the cement is mainly siliceous, while the miscellaneous base is mainly kaolinite and argillaceous components. The remaining intergranular and primary intergranular pores have small pore throats.

3. Two-Phase Seepage of Oil and Water

Characteristics of the relative permeability curve of medium sandstone in the main lithology of the $J_1s^2$ reservoir (Figure 5): with the increase in water saturation, relative permeability of the oil and water phases decreases rapidly and increases slightly, respectively, and the water cut increases rapidly. The production performance of $J_1s^2$ is as follows (Figure 6): after the water breakthrough, the liquid and oil quantities decrease, and the water cut rises sharply. The water cut of the $J_1s^2$ production mode increases rapidly while the liquid volume decreases greatly.

The main lithology of the $J_1s^2$ reservoir is represented by the relative permeability curve of fine sandstone (Figure 7): with the increase of water saturation, the relative permeability of the oil phase decreases rapidly, the relative permeability of the water phase increases slightly, and the water cut increases rapidly. The production performance of $J_1s^2$ is as follows (Figure 8): after water breakthrough, the liquid volume decreases slightly, the oil volume decreases, and the water cut increases moderately. The water cut of the $J_1s^2$ production mode increased while the liquid volume decreased slightly.
4. Analysis of the Oil-Water Movement at the Core Scale

The three-dimensional distribution information of CT values and porosity of the core in the Mobei block was obtained through CT scanning technology, and the core-scale heterogeneity characteristics of the Mobei block were recognized. On this basis, the core displacement experiment based on CT scanning was conducted. The oil saturation distribution in the process of core water flooding in the Mobei block was monitored on-line in real time through CT scanning technology. The water displacement characteristics were evaluated, and the relationship between the oil saturation and heterogeneity characteristics on the core scale is analyzed.

4.1. Experimental Device and Conditions

4.1.1. Experimental Device. This experiment was conducted on the core on-line displacement CT scanning system. The scanning system adopts an 8-layer spiral CT scanner from General Electric (GE), with a scanning voltage of 120 kV, current of 130 mA, minimum scanning thickness of 1.25 mm, and resolution scale of 200 μm. One group uses QUIZIX 5200 double pumps as the injection system, while the other uses ISCO 100DX double pumps as the confining pressure control system. The nonmetal core holder is used to ensure that the X-ray passes through smoothly and reduces the X-ray hardening. The core on-line displacement CT scanning system can conduct on-line CT scanning of the core displacement process in real time, and the automatic data acquisition system collects the flow and pressure data of the inlet and outlet in the displacement process.

4.1.2. Experimental Samples and Conditions. According to Table 1, the selected cores include fine, medium, and gravel-bearing medium sandstone, and the air permeability of the cores ranges three orders of magnitude (1-100 × 10^{-3} μm²), which can accurately represent the characteristics of various reservoir types in the block. At 40°C, the viscosities of water and oil are 0.984 and 0.662 mPa·s, respectively.

4.2. Experimental Steps. (1) After drilling and grinding the selected rock samples, we measured the basic physical parameters, prepared the experimental water and oil to measure their viscosity and temperature, set up the experimental process, and completed the preexperimental preparation. (2) The rock samples were loaded into the holder with a constant confining pressure of 20 MPa. Simultaneously, through the outer heating device, experiment temperature of the entire process was maintained constantly at 40°C. The rock samples were then dry-scanned under the set CT scanning conditions to obtain the dry model. (3) The confining pressure was kept constant, the simulated formation water from both ends of the rock sample under pressure was vacuumed and saturated, and the single-phase flow experiment was conducted to test the permeability of the water phase at this time after reaching complete saturation. Subsequently, the rock sample was scanned at this time under the same CT scanning conditions as above to obtain.
the wet model. (4) Highly viscous white oil was injected to create bound water by the gradient pressurization method and repelled until no water came out of the outlet; this was then transferred to the kerosene injection to repel the previous white oil. (5) Water flooding experiment was started at the set flow rate, and the water flooding was scanned online in real time under the same scanning conditions as before. The injection pressure changes during the water flooding were monitored, and the liquid production at the outlet was recorded. (6) Steps 2-5 were repeated to complete the water flooding experiment of other rock samples, and the experimental data were processed and analyzed.

4.3. Experimental Data Processing. Dry core scanning is conducted with CT scanning and imaging technology, and the CT value of the dry rock fault surface, $CT_{\text{dry}}$, is equal to the sum of the CT values of the rock skeleton and the air in the pore space (see formula (1)). The saturated cores are scanned after achieving saturated formation water, and the CT value of the saturated formation water core is equal to the sum of CT values of the rock skeleton and the saturated formation water in the pore (see formula (2)) [4–7]:

$$CT_{\text{dry}} = (1 - \Phi)CT_{\text{grain}} + \Phi CT_{\text{air}}, \quad (1)$$

$$CT_{\text{waterwet}} = (1 - \Phi)CT_{\text{grain}} + \Phi CT_{\text{water}}, \quad (2)$$

where $CT_{\text{dry}}$ is the CT value of the dry rock fault surface, $CT_{\text{waterwet}}$ is the CT value of the fault surface after the rock is 100% saturated with water, $CT_{\text{grain}}$ is the CT value of the rock skeleton, $CT_{\text{air}}$ is the CT value of air; $\Phi$ is porosity of the rock (%), and $CT_{\text{water}}$ is the CT value of the formation water.

From Equation (2) to Equation (1), we obtain the formula for calculating the porosity by applying the saturation difference method

$$\Phi = \frac{CT_{\text{waterwet}} - CT_{\text{air}}}{CT_{\text{water}} - CT_{\text{air}}} \times 100\%. \quad (3)$$

The pores of the rock saturated formation water are connected to each other, and the saturated formation water pores represent the connected pore distribution characteristics of the reservoir. Thus, the pore fluid distribution characteristics of the reservoir can be obtained by scanning the same core section before and after the presence of saturated formation water.

In the process of water flooding, the stress sensitivity caused by the change of the pore fluid pressure in the core is ignored. The pore structure of the core remains unchanged, but only the oil saturation in the pores changes. Simultaneously, the CT value of the rock fault plane at a certain time during displacement is [8–12]

$$CT_{x,t} = (1 - \Phi)CT_{\text{grain}} + \Phi(S_wCT_{\text{water}} + S_oCT_{\text{oil}}). \quad (4)$$
According to $S_o + S_w = 1$ and formulas (3) and (4), the water and oil saturation of the core at the displacement time can be calculated:

\[
S_o = \frac{C_{T_{\text{water wet}}} - C_{T_{\text{xt}}}}{C_{T_{\text{water wet}}} - C_{T_{\text{dry}}}} \cdot \frac{C_{T_{\text{water}}} - C_{T_{\text{air}}}}{C_{T_{\text{water}}} - C_{T_{\text{oil}}}},
\]

\[
S_w = 1 - \frac{C_{T_{\text{water wet}}} - C_{T_{\text{xt}}}}{C_{T_{\text{water wet}}} - C_{T_{\text{dry}}}} \cdot \frac{C_{T_{\text{water}}} - C_{T_{\text{air}}}}{C_{T_{\text{water}}} - C_{T_{\text{oil}}}},
\]

where $C_{T_{\text{xt}}}$ is the core CT value at a certain time of displacement and $S_w$ is water saturation (%).

4.4. Analysis of Experimental Results

4.4.1. Experimental Results of MB2005-56. According to the section combination diagram of the dry-scanning CT value distribution of the MB2005-56 rock sample (Figure 9), the CT value distribution on each section is relatively uniform in general, and the rock sample is relatively homogeneous; some red spots in the section may represent some mineral particles with high CT values.

The X-section, Y-section, and three-section diagrams of porosity distribution of rock sample MB2005-56 (Figure 10) show that the porosity distribution of the whole rock sample is relatively uniform, and there are no contiguous large pore and small pore areas.

The X-section group of oil saturation at a typical time during water flooding (Figure 11) shows that before the breakthrough of the displacement front, the invasion of the water phase during displacement is very uniform. This is consistent with the advance of the oil saturation front shown in Figure 12, which also indirectly indicates that the whole rock sample is relatively homogeneous. Owing to the similar viscosities of oil and water in the process of displacement, the oil phase is retained in many areas of the rock sample for a long time from the breakthrough of the displacement front to the end of water flooding, and the remaining oil is formed. However, its distribution is relatively uniform, which also reflects that the whole rock sample is relatively homogeneous, and its formation is mainly attributed to the similar viscosities of oil and water.

CT scanning technology is used for the real-time on-line monitoring of saturation to obtain the oil saturation distribution along MB2005-56 at every moment of the water flooding process. Figure 12 shows that before 0.2371 PV, the oil saturation distribution curve basically maintains the trend of uniform advance to the outlet. Before and after 0.2371 PV, the oil saturation front advanced to the outlet, which was consistent with the water breakthrough observed at the outlet for about 12 min. After 0.2371 PV, the oil saturation distribution curve shows a uniform and gentle decline, and a rapid rise in water cut is observed at the outlet, directly entering the stage of ultrahigh water cut. The above analysis of the entire displacement process is consistent with the change law of the oil displacement efficiency curve in Figure 13. In general, the entire displacement process is similar to the displacement of a piston.

4.4.2. Experimental Results of MB2274-16. The section combination diagram of the dry-scanning CT value distribution of the MB2274-16 rock sample (Figure 14) shows that the
**Figure 10:** Porosity distribution in X-section, Y-section, and three-sections of MB2005-56.

**Figure 11:** X-section diagram of the oil saturation at a typical time in the water flooding process of MB2005-56.
CT value distribution of each section in the first half of the MB2274-16 rock sample is relatively uniform. Some red spots in the section may represent some mineral particles with high CT values. In the second half of the MB2274-16 rock sample, contiguous high CT value distribution bands are observed, which indicates the occurrence of high-density minerals. The above phenomena also appear in all types of sections of CT value distribution with dry-scanned rock samples. Based on the above two aspects and from the perspective of the dry-scan CT value distribution, the first half of the rock sample MB2274-16 is relatively homogeneous, and high-density mineral bands appearing in the second half of the rock sample result in strong heterogeneity.

The porosity distribution in X-section, Y-section, and three-section diagrams of the MB2274-16 rock sample (Figure 15) shows that the porosity distribution in the first half of the whole sample is relatively uniform. Comparing the porosity distribution in the second half of the rock sample with the dry-scan CT value distribution, we found that the large pore area developed around the high-density mineral belt below the X-section, the small pore area formed in the corresponding high-density mineral belt in the Y-
section, and nonhomogeneous areas will affect the subsequent water flooding process. In general, the homogeneous areas in the second half of the rock sample are very poor.

The X-section and Y-section groups of oil saturation at a typical time during the water flooding process (Figure 16) show that before 0.0638 PV, the water phase invasion during displacement is very uniform. This is consistent with the advance of the oil saturation front in Figure 17, which also indirectly indicates that the first half of the entire rock sample is relatively homogeneous. After 0.0638 PV, the water phase invasion mainly uses the oil near the macropore area developed around the high-density mineral belt in the second half of the rock sample, which also corresponds to the analysis in Figure 16. As the oil-water viscosity is similar in the displacement process, the oil phase is retained for a long time from the front breakthrough to the end of water flooding in the first and second halves of the sample, and residual oil forms, mainly due to the identical viscosities of oil and water.

CT scanning technology is used for the real-time on-line monitoring of saturation to obtain the oil saturation distribution at each time of the MB2274-16 water flooding process, as shown in Figure 17. Before 0.0638 PV, the oil saturation distribution curve maintains the trend of uniform advance towards the outlet. Subsequently, the oil saturation distribution curve advances to near the outlet in a short time. This is considered to be related to the development of large pore areas around the high-density mineral belt. After 0.2553 PV, the displacement front completely breaks through. For a long time after this, the oil saturation distribution curve shows a uniform and gentle decline. Simultaneously, the water cut at the outlet increases rapidly and directly enters the ultrahigh water cut stage. The above analysis of the entire displacement process is consistent with the change law of the displacement efficiency curve shown in Figure 18. The whole process of water flooding is summarized as follows: Before the displacement front reaches the high-density mineral belt, the displacement process is similar to a piston displacement. After the displacement front reaches the high-density mineral belt, the massive pore area is similar to the high conductivity fracture, and the displacement process is obvious [13].

Based on the above results, the first half of the MB2274-16 sample is relatively homogeneous, which is the main reason for the uniform advance of the displacement front before 0.0638 PV. Subsequently, the rapid breakthrough of the water drive was mainly ascribed to the existence of a high porosity area similar to a “high conductivity fracture” in the second half of the rock sample. Finally, the water cut rose rapidly, forming a large amount of remaining oil, mainly due to the identical viscosities of oil and water [14].

4.4.3. Experimental Results of MB2274-47. According to the section combination diagram of the dry-scan CT value distribution of the MB2274-47 rock sample (Figure 19), a low CT value area is observed in blue on each section of the first half of the MB2274-47 rock sample, which may represent low-density clay minerals. A large portion of the second half of the sample shows contiguous high CT value areas in red on each slice, which may represent high-density barite.

According to the X-section, Y-section, and three-section diagrams of porosity distribution of the MB2274-47 rock sample (Figure 20), the porosity of the first half of the entire rock sample is larger than that of the second half. Notably, there are obvious dual-porosity medium structure characteristics in this rock sample. A small low-density clay mineral area in a small part of the first half corresponds to a contiguous high porosity area, which can be regarded as the “high conductivity fracture.” In the latter part, the contiguous high-density barite mineral area corresponds to a large area of low porosity, which can be regarded as the “dense matrix.”

The X-section diagram of the oil saturation (Figure 21) at a typical time during the water flooding process shows...
**Figure 15:** Porosity distribution in X-section, Y-section, and three-section diagrams of MB2274-16.

**Figure 16:** X-section diagram of the oil saturation at a typical time in the water flooding process of MB2274-16.
that before 0.0344 PV, the invasion of the water phase in the displacement process is very uniform; this is consistent with the advance of the oil saturation front shown in Figure 22. During the displacement from 0.0344 to 0.0688 PV, obvious fingering can be observed. Owing to the similar viscosities of oil and water in the process of displacement, the oil phase is retained in many areas in a small part of the first half and a large part of the second half of the rock sample for a long time from the front breakthrough to the end of water flooding. Subsequently, the remaining oil is formed, which is mainly due to the similar viscosities of oil and water [15].

The oil saturation distribution during the water flooding of MB2274-47 was obtained through real-time on-line saturation monitoring technology based on CT scanning (Figure 23). It can be seen that before 0.0344 PV, the oil saturation distribution curve maintains the trend of uniform advance to the outlet. During the displacement process from 0.0344 to 0.0688 PV, the oil saturation distribution curve speeds up obviously towards the outlet; this is likely attributed to the influence of the displacement front passing through the “high conductivity fracture.” After 0.0688 PV, the oil saturation distribution curve shows a gentle and obvious decline in most of the latter half of the sample when the displacement front advances to this area. This corresponds to the seepage matrix of the dual-porosity medium. A long time after the complete breakthrough of the displacement front, the distribution curve of oil saturation shows a small range of uniform and gentle decline. Simultaneously, the output of the outlet shows that the water cut rises rapidly
and directly enters the ultrahigh water cut stage. The above analysis of the whole displacement process is consistent with the change law of the displacement efficiency curve shown in Figure 23. The entire process of water flooding is summarized as follows: Before the displacement front reaches the low-density clay mineral belt, the displacement
Figure 21: X-section diagram of the oil saturation at a typical time in the water flooding process of MB2274-47.
The process is similar to a piston displacement. Once the displacement front reaches the low-density clay mineral belt, the displacement process shows obvious fingering. After the displacement front reaches the high-density dense barite area, the supplementary seepage mechanism of dual-porosity media is obvious [16].

Therefore, the heterogeneity of the MB2274-47 rock sample is considerably strong according to the above experimental results, which is also the main reason for many phenomena occurring in the process of water flooding.

5. Conclusions

1. The microheterogeneity of the reservoir is strong, and there are local large pores. The volume of large pores is small, but it contributes considerably to the permeability and plays a leading role in the reservoir seepage.

2. Characteristics of the relative permeability curve of medium sandstone: with the increase in water saturation, relative permeability of the oil and water phases decreases rapidly and increases slightly, respectively, and the water cut increases rapidly. The relative permeability curve of fine sandstone: with the increase of water saturation, the relative permeability of the oil phase decreases rapidly, the relative permeability of the water phase increases slightly, and the water cut increases rapidly.

3. In the process of water flooding, the oil saturation along the way decreases greatly before the breakthrough of the water flooding front. After the breakthrough of the water drive front, the water cut rises rapidly and directly enters the stage of ultrahigh water cut. Owing to the serious heterogeneity of the micropore structure, the fingering phenomenon is obvious in the process of displacement.

Figure 22: Oil saturation distribution during the water flooding process of MB2274-47.

Figure 23: Curve of displacement efficiency vs. PV injection during the water flooding of MB2274-47.
Data Availability

Data will be available on request.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

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