Experimental Evaluation on the Conductivity of Branch Fracture with Low Sand Laying Concentration and Its Influencing Factors in Shale Oil Reservoirs

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The productivity of shale oil reservoirs is mainly determined by the hydraulic fractured reservoir volume. The branch fractures with low sand laying concentration are the main channels connecting the shale matrix and the major fractures. Maintaining the branch fracture conductivity is significant to the production of shale oil. In this study, a series of shale branch fracture conductivity and soaking experiments were conducted using a core flooding device and a small reactor, and the influences of different factors on the fracture conductivity were evaluated. The results show that when the sand laying concentration in fractures is less than 3 kg/m², the branch fractures present a significant stress sensitivity. Particularly when the sand laying concentration is less than 1 kg/m², and the closure pressure is greater than 15 MPa, there will be a risk of proppant embedded and fracture closed. The antiswelling agent has an inhibitory effect on the shale swelling. When the concentration of the antiswelling agent in the gel-breaking fluid is 2%, the swelling factor of shale powder is only 1.84%. Comparatively, the 0.5% of the antiswelling agent has a poor effect which can cause the shale rock to crack when the effective stress decreases. It can cause the fracture conductivity to decline by 70-90% when the gel-breaking fluid flows back associated with the shale oil. The probability of core breaking and proppant embedding will increase. The frequent shut-in and rapid open-flow for production can accelerate the damage of fracture conductivity. It is necessary to optimize the fracing fluid and the open flow scheme to prevent the rapid decline of production in shale oil reservoirs.

1. Introduction

Shale oil is an important unconventional oil and gas resource, which occurs in the nanoscale pore and fracture system of shale oil reservoirs in the form of adsorbed and free state [1–3]. There are abundant reserves of shale oil in China, and the technically recoverable resource ranks third in the world [4–6]. At present, China is still in the early stage of shale oil exploration and development, which is 30–40 years later than the United States [5, 6]. Compared with the shale oil reservoirs of marine deposits in the United States [6], (1) the organic-rich shale in China is mainly deposited in continental lakes, with a large content of clay minerals, poor brittleness, and the wall of the well that is easy to collapse, causing difficulties in the construction of horizontal wells and staged fracturing [4–7]; (2) shale oil resources in China are mainly distributed in Mesozoic-Cenozoic basins. The basins were formed late, the degree of thermal evolution was low, the oil quality of shale oil was relatively thick, and the fluidity was poor, which also caused difficulties in development [5–8]. Therefore, the technology of fracturing shale oil reservoirs in the United States is not completely suitable for China, and the technology suitable for Chinese geological characteristics needs to be tackled and developed [5–9].
The development of shale oil reservoirs in the United States made a major breakthrough around 2005 and began to enter a period of rapid growth around 2009. As of March 2015, the production of shale oil in the United States had reached 0.6673 million tons per day, accounting for 59.12% of the total daily production of 1.1288 million tons of crude oil that month in the United States. Since then, affected by the decline in international oil prices, the production of shale oil in the United States had gradually declined, but it rebounded rapidly in 2016. Despite slight fluctuations, it continued to rise. In the next ten years, the production of shale oil will continue to grow. After 2026, the daily production of shale oil will remain at the level of 1.35 to 1.5 million tons, accounting for about 60% of the total production of crude oil. Shale oil production in the United States is expected to start to decline after 2031, and it will drop to 1.15 million tons per day by 2050 [9, 10]. At present, the exploration and development of shale oil in China have made important progress and are gradually moving towards commercial development [9, 11]. In recent years, China Geological Survey, CNPC, SINOPEC, and Yanchang Oilfield have increased their exploration and development efforts of shale oil, which have made important discoveries and breakthroughs in multiple series of strata in different basins. Industrial oil flow of shale oil has been obtained in many places, including the Cangdong Sag of the Dagang Oilfield in the Bohai Bay Basin and the Jimsar Sag of the Junggar Basin, and construction of shale oil fields has been started [9–12]. Among them, in 2007, the shale oil and gas field began to be paid attention to in Shengli Oilfield of SINOPEC. And in 2011, the first special exploration well for shale oil, well Boyeeping1, was deployed [11]. As of the end of 2018, Shengli Oilfield has conducted tests of the section of 68 wells where mud and shale have been developed in the Jiayang Depression. The initial production of 40 wells reached the standard for industrial oil and gas flow [13]. In 2019, three new risk wells of shale oil were deployed, drilled, fractured, and developed in Shengli Oilfield. Judging from the effect of on-site implementation, the production capacity of pilot test wells is high at the initial stage of fracturing, but due to the impact of shut-in and multiple sudden changes in open flow pressure, the production decline rate increases linearly, which restricts the stable production of a single well [14, 15]. The matrix seepage capacity of the calcareous shale oil reservoir is poor, and the production capacity after fracturing is mainly determined by the reservoir volume reformed through hydraulic fracturing. The branch fractures are the main channels connecting the shale matrix and the main fractures. However, due to the limitation of the fracturing technology, the sand laying concentration is relatively low. How to maintain the long-term effectiveness of branch fractures is very important [16, 17].

Many experiments have been conducted to reveal the pressure sensitivity of fracture conductivity at low sanding concentration and found that the fracture conductivity was mainly controlled by the fracture surface roughness at low sanding concentration, while at high sanding concentration, it was controlled by the proppant placement; under single-layer sanding concentration, fracture conductivity decreased significantly and linearly with embedding depth; the variable flow pressure has little effect on the fracture conductivity at low sanding concentration [18–21]. Besides, shale contains a lot of clay minerals and has low compressive strength. It is easy to soften and swell after being soaked in water [22]. In the process of fracturing, opening flow, and production, it is necessary to pay attention to the influence of pressure fluctuation on the conductivity of branch fractures and to accurately grasp the stress sensitivity of branch fractures [23, 24]. After shale is soaked in water-based fracturing fluid, the damage caused by the leak off of gel-breaking fluid and the risk of shale hydration swelling especially need to be focused on to prevent excessive open flow pressure from causing shale particles on the wall of branch fractures to fall off and causing proppant to embed in the fractures, which will cause the fracture conductivity to decrease [25–29]. And the antiswelling effect of fracturing fluid on the stability of branch fractures needs to be clarified [30]. Revealing the stress sensitivity of branch fractures and their influencing factors has important guiding significance for fracturing, opening flow, and optimizing production speed.

In this study, aiming at the branch fractures with low sand laying concentration in shale oil reservoirs, a core flooding device and a small reactor were used to carry out fracture conductivity tests. The effects of proppant type, sand laying concentration, the roughness of fracture surfaces, soaking of gel-breaking fluid, and changes of effective stress on fracture conductivity were evaluated. The stress sensitivity of fracture conductivity and the influence of gel-breaking fluid soaking on fracture stability were comprehensively analyzed. Finally, suggestions for the optimization of fracturing fluid and open flow schemes for production were proposed.

2. Experimental Equipment and Methods

2.1. Experimental Equipment. The core flooding equipment used in experiments is shown in Figure 1(a). It is mainly composed of a core holder, high-pressure constant flow pumps, intermediate containers, a back pressure regulator, a measuring cylinder, an air bath, pressure transducers, a data collector, and a computer. The core holder can be filled with 5-50 cm long standard-size cores. The maximum working pressure of the constant flow pumps is 40 MPa, which has a flow rate of 0.01-10 ml/min.

The mainly used high-temperature and high-pressure (HTHP) reactor is shown in Figure 1(b). The effective volume of the common reactor is 196 ml, and the max working pressure is 30 MPa. A pressure gauge is installed on the cap of the reactor, which has a measuring range of 0-40 MPa and an accuracy of 0.1%. In order to observe the effect of CO₂ partial pressure and pH on the scaling process, another kind of HTHP reactor with the same effective volume was used, which has transparent glasses on the two ends of the reactor for observation. The visualization reactor can resist a pressure of 20 MPa and a temperature of 120°C. Besides, the thermostank, conical bottles, electronic balance, volumetric flask, measure cylinder, beaker, glue head dropper,
2.2. Experimental Materials

2.2.1. Preparation of Experimental Materials

(1) Shale core: taken from well Niu 55-X1 in Shengli Oilfield of China, there are a total of 20 cores with the same lithology and uniform texture, 2.5 cm in diameter and 3-8 cm in length, of which 16 are intact and 4 are broken. In addition, some shale debris was ground into powder.

(2) Proppant: 40/70 mesh ceramsite and 40/70 mesh quartz sand.

(3) Antiswelling agent: the code is AS-1, and the main components are KCl and other additives, such as cationic surfactant and organosilane. The original concentration is 40 wt%.

(4) Test fluid: light crude oil (the viscosity of crude oil is 5.1 mPa·s at 80°C) and distilled water (used to prepare aqueous solution of antiswelling agent).

2.2.2. Preparation of Branch Fracture with Low Sand Laying Concentration. In order to conduct the test of branch fracture conductivity, intact standard shale cores were split into two parts along the axis by means of wire cutting or locally increasing pressure to fracture to fill the proppant. The purpose was to simulate the flat surface of fractures and the rough surface of fractures, respectively. The specific steps of filling proppant and processing branch fractures are as follows: (1) calculate the wall area of the fractures of the half-moon-shaped core and weigh the proppant according to the sand laying concentration; (2) a layer of double-sided tape is pasted on the fracture wall of half-moon core, and a layer of proppant is prelaid. The remaining proppants were placed on the fracture surface and aligned two half-moon cores. When proppants are laid, a ruler is used to flatten proppants to ensure that proppants are relatively evenly distributed. Place a metal filter with the same diameter as the core at each end of the core to prevent the migration of proppant, and wrap a layer of aluminized paper with a shaping effect around the side and both ends of the core. The metal filter is 270 mesh, which can prevent proppants from falling out and migration; (3) place the core in a thermoplastic tube (heat resistance of 200°C), and use a hot air blower to shrink the thermoplastic tube to the outside of the core to prevent the proppant from falling off due to the separation of fractures. The diameter of the thermoplastic tube after shrinkage can match the core diameter and will not affect the fractures, as shown in Figure 2.

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2.3. Experimental Procedures

2.3.1. Test of Single-Phase Conductivity of Branch Fractures.

The core flooding device and light oil were used to test the conductivity of branch fractures (not polluted by water). The main experimental steps are as follows: (1) put the shale core used to simulate the branch fractures into the core holder and connect the pipeline equipment. Put them into the incubator at the designed temperature for heat preservation; (2) use a constant-flux pump to preadd a certain confining pressure to the core holder, set the back pressure, and inject light oil into the core until the oil is discharged at the back end of the core; (3) inject light oil into the core at a certain flow rate (0-10 ml/min), record the pressure at the front and back ends of the core, and calculate the conductivity of the branch fractures (Figure 3).

Assuming that the permeability of the shale matrix is negligible compared with the permeability of branch fractures, the flow through the fractures satisfies the Darcy formula:

\[ Q = \frac{K A \Delta P}{\mu \Delta L} = \frac{K W_f \Delta P}{\mu \Delta L}. \]  

(1)

Then, the calculation formula for the conductivity of the core fracture can be further obtained as follows:

\[ \frac{K W_f}{\mu \Delta L} = \frac{Q}{\Delta P}. \]  

(2)

In the formula, \( Q \) is the flow rate of test fluid, ml/s; \( A \) is the cross-sectional area of the fracture, cm\(^2\); \( \Delta P \) is the displacement pressure difference, 0.1 MPa; \( \mu \) is the viscosity of test fluid, mPa·s; \( \Delta L \) is the length of the core, cm; \( K \) is the permeability of the fracture, \( \mu m^2 \); \( W_f \) is the width of the fracture, cm; \( D \) is the diameter of the core, cm; \( K W_f \) is the conductivity of the fracture, \( \mu m^2 \cdot cm \). Assuming that \( W_f \) remains constant during the diversion process, \( K \) can be used as the apparent permeability.

2.3.2. Test of Gel-Breaking Fluid Intrusion and Soaking.

In order to grasp the influence of gel-breaking fluid on the permeability of shale matrix and wall stability of branch fractures, the following three experiments were conducted:

1. The high-temperature and high-pressure shale dilatometer was used to measure the swelling factor of shale: (a) grind the shale core into powder (pass through a 100 mesh sieve), and dry it at 105°C for more than 4 hours for later use; (b) use a balance to weigh 5 g of the sample and put it into the press mold for compaction, then put it into the main measuring cup for heat preservation; (c) move the slider for detecting displacement downwards until it touches the sample, and inject 15-20 ml of gel-breaking fluid into the main measuring cup to contact the core powder; (d) open the test software, record the swelling amount of the shale powder sample, and calculate the swelling factor

2. (2) The core flooding device was used to conduct the experiment of gel-breaking fluid intrusion: (a) splice the hollow metal core with the intact shale core and put them into the core holder; (b) add confining pressure to the core and vacuum. And inject gel-breaking fluid into the hollow metal core (to simulate the space of fractures) (Figure 4); (c) under the action of pressure difference, the gel-breaking fluid is filtered to the end face of the shale core; (d) use the pressure depletion method to measure the changes of core permeability before and after filtration loss with gas (helium) and to evaluate the damage of the core permeability caused by the gel-breaking fluid

3. The small high-temperature and high-pressure reactor was used to conduct the observation experiment of shale soaking: put a single piece of damaged shale core into the high-temperature and high-pressure reactor. Inject the gel-breaking fluid to 4/5 volume of the reactor, and then inject nitrogen to the designed pressure after capping. Then, put the reactor in the incubator for heat preservation, and take it out after a certain period of time to observe the breakage of shale.

2.3.3. Test of Fracture Stress Sensitivity When Gel-Breaking Fluid Flows Back during Production.

The core flooding device was used to simulate the mixed flowback process of gel-breaking fluid and shale oil in the branch fractures. The law of oil-water two-phase flow in branch fractures, the influence
on fracture conductivity, and the loss of fracture conductivity due to the changes of effective stress were analyzed. The experimental procedure is similar to the procedure in Section 2.3.1 to measure the conductivity of branch fractures with oil. The main difference is that a water injection pipeline was added at the injection end to achieve a mixed injection of oil and water. During the experiment, the changes of effective stress under complex working conditions could be simulated by controlling the back pressure and confining pressure.

2.4. Experimental Schemes. In order to achieve the purpose of the research, the experimental schemes are designed, as shown in Tables 1 and 2. Among them, Table 1 is the experimental scheme of branch fracture conductivity in shale oil reservoirs, including the single-phase conductivity test of branch fractures (Cases 1-1 to 1-5) and the stress sensitivity test of gel-breaking fluid flowback and production (Cases 2-1 to 2-5). The influences of proppant type (ceramic and quartz sand), sand laying concentration (1-5 kg/m$^2$), the roughness of fracture wall (flat and rough), the water content of flowback fluid (fw = 0-100%), and effective closure stress (controlled by the back pressure valve, at 5-25 MPa) are mainly investigated. The experiment temperature is 80°C, the injection rate is 0.1 or 0.5 ml/min (depending on the situation: 0.1 ml/min is used for single-phase flow, and 0.5 ml/min is used for the multiphase flow, which can ensure the rates of water and oil injected accurately using constant-flux pumps), and the test fluid is light oil and 0.5% antiswaelling agent solution. Table 2 is the experimental scheme for the damage of gel-breaking fluid to matrix permeability, in which the test of swelling factor (Cases 3-1 to 3-3) mainly studies the effect of concentration of antiswaelling agent (0-2 wt%) on shale swelling (atmospheric pressure, 80°C), the test of gel-breaking fluid intrusion and filtration (Case 4-1-4) mainly studies the influence of gel-breaking fluid soaking on physical properties of shale under high temperature and high pressure (0.5-16 MPa, 80°C, filtration time is 4 hours), and the test of soaking observation (Cases 5-1 to 5-4) studies the influence of gel-breaking fluid soaking on physical properties of shale under normal temperature and low pressure (soaking for 24 hours under normal temperature and atmospheric pressure, soaking 24 hours under 145°C and saturation pressure).

3. Experimental Results and Analysis

3.1. The Original Conductivity of Branch Fracture and Its Influencing Factors

3.1.1. Influence of Proppant Type. During the fracturing process of the shale reservoir, 40/70 mesh ceramsite and 40/70 mesh quartz sand were mainly used as proppants for branch fractures. The experiment tested the conductivity of flat fractures with the sand laying concentration of 3 kg/m$^2$ under the condition that the effective closure pressure gradually increased (Cases 1-1 and 1-2). The results are shown in Figures 5 and 6 and Table 3. According to the analysis, (1) when ceramsite was selected as the proppant, as the back pressure of the core holder was gradually reduced, the effective closure pressure acting on the fractures gradually increased from 5 MPa to 25 MPa, the conductivity of fractures obtained by calculation correspondingly dropped from 828.60 md-mm to 133.00 md-mm, and the apparent permeability also dropped from 478.96 md to 76.88 md, down to 16% of the original; (2) when quartz sand was used as the proppant, similar laws can be obtained. The effective closure pressure increased from 5 MPa to 25 MPa, and the conductivity of fractures dropped from 687.14 md-mm to 102.81 md-mm, and the apparent permeability dropped from 319.60 md to 47.82 md, a total down to 15%; (3) in general, the permeability of branch fractures with low sand laying concentration in shale shows significant stress sensitivity. Comparing the two proppants of quartz sand and ceramsite, under the same effective closure pressure and the same sand laying concentration, the initial width of fractures filled with quartz sand is larger than that of the ceramsite. However, the fracture conductivity filled with ceramsite is significantly higher than that of filled with quartz sand, and the former is 1.2-1.6 times that of the latter. Judging from the normalized curve, the conductivity of the fractures filled with quartz sand decreases faster with the increase of the closure pressure, and the ceramsite has a stronger antiextension ability.

3.1.2. Influence of Sand Laying Concentration. The commonly used low-priced quartz sand was selected as the proppant to conduct the test of conductivity of shale fractures under the sand laying concentration of 1, 3, and 5 kg/m$^2$ (Cases 1-2, 1-3, and 1-4). The results are shown in Figures 7 and 8 and Table 4 (the results of 3 kg/m$^2$ sand laying concentration are in Section 3.1.1). According to the analysis, (1) when the sand laying concentration is 1 kg/m$^2$, as the effective closure pressure increases (5 MPa→25 MPa), the fracture conductivity has dropped drastically from the initial 451 md-mm to 3.25 md-mm, a decrease of 138 times. It means that the lower the sand laying concentration of fractures is, the stronger the stress sensitivity may be. Under the action of higher closure pressure, there is the possibility of proppant embedding and fracture closure. For example, when the closure pressure is greater than 15 MPa, the fracture conductivity is rapidly reduced; (2) when the sand laying concentration increases to 5 kg/m$^2$, with the increase of the closure pressure, the fracture conductivity decreases. But the decline is significantly reduced, from the initial 3860 md-mm to 639 md-mm, a decrease of 6.04 times; (3) comparing the conductivity of fractures under three sand laying concentrations of 1, 3, and 5 kg/m$^2$, the conductivity of sand laying concentration of 5 kg/m$^2$ is significantly higher than that of sand laying concentration of 1 and 3 kg/m$^2$. However, there is higher stress sensitivity under low sand laying concentration, such as 1 kg/m$^2$. Two critical sand laying concentrations are suspected. One is that when the sand laying concentration is less than a certain critical value (3 kg/m$^2$), the conductivity is significantly reduced. The second is that when the sand laying concentration is further reduced to a certain critical value (1 kg/m$^2$), the proppant embedding will cause the stress sensitivity to become more prominent.
**Table 1: Experimental scheme of branch fracture conductivity in shale oil reservoirs.**

<table>
<thead>
<tr>
<th>No.</th>
<th>Proppant type (40/70 mesh)</th>
<th>Sand laying concentration (kg/m²)</th>
<th>Fracture surface</th>
<th>Test fluid</th>
<th>Injection rate (ml/min)</th>
<th>Confining pressure (MPa)</th>
<th>Back pressure (MPa)</th>
<th>Closure pressure (MPa)</th>
<th>T (°C)</th>
<th>Core No.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1-1</td>
<td>Ceramsite</td>
<td>3</td>
<td>Smooth</td>
<td>Light oil</td>
<td>0.1</td>
<td>25</td>
<td>20➔0</td>
<td>5➔25</td>
<td>80</td>
<td>4</td>
</tr>
<tr>
<td>1-2</td>
<td>Quartz sand</td>
<td>3</td>
<td>Smooth</td>
<td>Light oil</td>
<td>0.1</td>
<td>25</td>
<td>20➔0</td>
<td>5➔25</td>
<td>80</td>
<td>4</td>
</tr>
<tr>
<td>1-3</td>
<td>Quartz sand</td>
<td>1</td>
<td>Smooth</td>
<td>Light oil</td>
<td>0.1</td>
<td>25</td>
<td>20➔0</td>
<td>5➔25</td>
<td>80</td>
<td>10-1</td>
</tr>
<tr>
<td>1-4</td>
<td>Quartz sand</td>
<td>5</td>
<td>Smooth</td>
<td>Light oil</td>
<td>0.1</td>
<td>25</td>
<td>20➔0</td>
<td>5➔25</td>
<td>80</td>
<td>10-1</td>
</tr>
<tr>
<td>1-5</td>
<td>Quartz sand</td>
<td>3</td>
<td>Rough</td>
<td>Light oil</td>
<td>0.1</td>
<td>25</td>
<td>20➔0</td>
<td>5➔25</td>
<td>80</td>
<td>14-1</td>
</tr>
<tr>
<td>2-1</td>
<td>Quartz sand</td>
<td>3</td>
<td>Smooth</td>
<td>fw = 100➔0%</td>
<td>0.5</td>
<td>25</td>
<td>20</td>
<td>5</td>
<td>80</td>
<td>4</td>
</tr>
<tr>
<td>2-2</td>
<td>Quartz sand</td>
<td>1/3/5</td>
<td>Smooth</td>
<td>fw = 50%</td>
<td>0.5</td>
<td>25</td>
<td>Stepped down</td>
<td>5➔25</td>
<td>80</td>
<td>9/4/9</td>
</tr>
<tr>
<td>2-3</td>
<td>Quartz sand</td>
<td>3</td>
<td>Smooth</td>
<td>fw = 0%</td>
<td>0.1</td>
<td>25</td>
<td>Drastic fluctuation</td>
<td>5 &lt; - &gt; 25</td>
<td>80</td>
<td>4</td>
</tr>
<tr>
<td>2-4</td>
<td>Quartz sand</td>
<td>1</td>
<td>Rough</td>
<td>fw = 0%</td>
<td>0.1</td>
<td>25</td>
<td></td>
<td>5 &lt; - &gt; 25</td>
<td>80</td>
<td>13</td>
</tr>
<tr>
<td>2-5</td>
<td>Quartz sand</td>
<td>1</td>
<td>Rough</td>
<td>fw = 50%</td>
<td>0.1</td>
<td>25</td>
<td></td>
<td>5 &lt; - &gt; 25</td>
<td>80</td>
<td>13-1</td>
</tr>
</tbody>
</table>
TABLE 2: Experimental scheme for the damage of gel-breaking fluid to matrix permeability.

<table>
<thead>
<tr>
<th>No.</th>
<th>Test item</th>
<th>Content of antiswelling agent (%)</th>
<th>Rock properties</th>
<th>P (MPa)</th>
<th>T (°C)</th>
<th>Time (h)</th>
<th>Core No.</th>
</tr>
</thead>
<tbody>
<tr>
<td>3-1</td>
<td>Swelling factor</td>
<td>0</td>
<td>100 mesh powder</td>
<td>3.5</td>
<td>60</td>
<td>5</td>
<td>N55</td>
</tr>
<tr>
<td>3-2</td>
<td>Swelling factor</td>
<td>0.5</td>
<td>100 mesh powder</td>
<td>3.5</td>
<td>60</td>
<td>5</td>
<td>N55</td>
</tr>
<tr>
<td>3-3</td>
<td>Swelling factor</td>
<td>2</td>
<td>100 mesh powder</td>
<td>3.5</td>
<td>60</td>
<td>5</td>
<td>N55</td>
</tr>
<tr>
<td>4-1</td>
<td>Gel-breaking fluid loss</td>
<td>0.5</td>
<td>Horizontal bedding</td>
<td>5</td>
<td>60</td>
<td>5</td>
<td>16B</td>
</tr>
<tr>
<td>4-2</td>
<td>Gel-breaking fluid loss</td>
<td>0.5</td>
<td>Horizontal bedding</td>
<td>10</td>
<td>60</td>
<td>5</td>
<td>12</td>
</tr>
<tr>
<td>4-3</td>
<td>Gel-breaking fluid loss</td>
<td>0.5</td>
<td>Horizontal bedding</td>
<td>15</td>
<td>60</td>
<td>5</td>
<td>17</td>
</tr>
<tr>
<td>4-4</td>
<td>Gel-breaking fluid loss</td>
<td>0.5</td>
<td>Inclined bedding</td>
<td>10</td>
<td>60</td>
<td>5</td>
<td>3</td>
</tr>
<tr>
<td>5-1</td>
<td>Soaking observation</td>
<td>0/0.5</td>
<td>Cracked core</td>
<td>0.1</td>
<td>20</td>
<td>72</td>
<td>4</td>
</tr>
<tr>
<td>5-2</td>
<td>Soaking observation</td>
<td>0/0.5</td>
<td>Cracked core</td>
<td>0.1</td>
<td>20</td>
<td>72</td>
<td>8</td>
</tr>
<tr>
<td>5-3</td>
<td>Soaking observation</td>
<td>0/0.5</td>
<td>Cracked core</td>
<td>&gt;0.1</td>
<td>145</td>
<td>24</td>
<td>10</td>
</tr>
<tr>
<td>5-4</td>
<td>Soaking observation</td>
<td>0/0.5</td>
<td>Cracked core</td>
<td>&gt;0.1</td>
<td>145</td>
<td>24</td>
<td>11</td>
</tr>
</tbody>
</table>

Figure 5: Test curves of fracture conductivity using different types of proppant: (a) ceramsite; (b) quartz sand.

Figure 6: Comparison of fracture conductivity using different types of proppant: (a) correlation between conductivity and closure pressure; (b) normalized fracture conductivity.
3.1.3 Influence of Fracture Surface Roughness. The cores with rough fracture walls were used to conduct the conductivity test under the sand laying concentration of 3 kg/m² of 40/70 mesh quartz sand (Case 1-5). The results are shown in Figures 9–11 and Table 5. According to the analysis, (1) different from flat fractures, the surface of fractures is undulating with more shale bedding sections, which will affect the filling of proppant in the fractures. Generally, the width of

<table>
<thead>
<tr>
<th>No.</th>
<th>Confining pressure (MPa)</th>
<th>Back pressure (MPa)</th>
<th>Closure pressure (MPa)</th>
<th>Fracture conductivity (md·mm)</th>
<th>Apparent permeability (md)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Ceramsite Ratio Quartz sand Ratio Ceramsite Quartz sand</td>
<td>1</td>
<td>25</td>
<td>20</td>
<td>5</td>
</tr>
<tr>
<td>1</td>
<td>25</td>
<td>15</td>
<td>10</td>
<td>15</td>
<td>3</td>
</tr>
<tr>
<td>2</td>
<td>25</td>
<td>10</td>
<td>15</td>
<td>20</td>
<td>4</td>
</tr>
</tbody>
</table>

Note: the initial seam width is 1.73 mm when filled with ceramsite and 2.15 mm when filled with quartz sand.

Figure 7: Test curves of fracture conductivity under different sand laying concentrations: (a) 1 kg/m²; (b) 5 kg/m².

Figure 8: Comparison of fracture conductivity under different quartz sand laying concentrations: (a) correlation between conductivity and closure pressure; (b) normalized fracture conductivity.
the initially filled fractures is larger (the width of natural fractures is 4.12 mm, and the width of flat fractures is 2.15 mm under the same sand laying concentration). The initial conductivity is higher, but it also has stronger stress sensitivity; (2) as the effective closure pressure increases from 5 MPa to 25 MPa, the conductivity of fractures decreases from 1060.77 md·mm to 100.37 mm, a decrease of 10.56 times. Under the same conditions, the conductivity of flat fractures decreases by 6.68 times. It shows that there is a greater impact on the conductivity of fracturing fractures when the effective stress increases. Particularly under high closure pressure, the conductivity of fractures decreases faster; (3) according to the experimental data, the formula of the hydraulic conductivity of the fracture and the smooth fracture is obtained as shown in Figure 11(a).

### Table 4: Test results of fracture conductivity under different sanding laying concentrations.

<table>
<thead>
<tr>
<th>No.</th>
<th>Confining pressure (MPa)</th>
<th>Back pressure (MPa)</th>
<th>Closure pressure (MPa)</th>
<th>Fracture conductivity (md·mm)</th>
<th>Apparent permeability (md)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1 kg/m² Ratio 5 kg/m² Ratio 1 kg/m² 5 kg/m²</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>25</td>
<td>20</td>
<td>5</td>
<td>451.04 1</td>
<td>3805.08 1</td>
</tr>
<tr>
<td>2</td>
<td>25</td>
<td>15</td>
<td>10</td>
<td>173.09 0.38</td>
<td>1991.08 0.52</td>
</tr>
<tr>
<td>3</td>
<td>25</td>
<td>10</td>
<td>15</td>
<td>72.17 0.16</td>
<td>1188.65 0.31</td>
</tr>
<tr>
<td>4</td>
<td>25</td>
<td>5</td>
<td>20</td>
<td>7.73 0.02</td>
<td>749.61 0.20</td>
</tr>
<tr>
<td>5</td>
<td>25</td>
<td>0</td>
<td>25</td>
<td>3.25 0.01</td>
<td>639.04 0.17</td>
</tr>
</tbody>
</table>

Note: when the sanding laying concentration is 1, 3, and 5 kg/m², the corresponding initial slit width is 1.02, 2.15, and 3.17 mm.

3.2. The Influence of Gel-Breaking Fluid on the Stability of the Fracture Surface

3.2.1. Inhibitory Effect of the Antiswelling Agent on Shale Hydration and Swelling. The shale powder from well Niu 55-X1 was used to measure the swelling hydration factor (Cases 3-1, 3-2, and 3-3), and the results are shown in Figure 12. The figure shows that after the antiswelling agent solution contacts the shale, the shale powder swells rapidly and tends to be stable after about 30-40 minutes. Through measurement, when the antiswelling agent concentration is 0 wt% (distilled water), 0.5 wt%, and 2 wt%, the swelling factor of shale powder is 4.27%, 4.02%, and 1.84%, respectively. Among them, the 2 wt% antiswelling agent has the best antiswelling effect, followed by 0.5 wt%, and the distilled water is the worst.

3.2.2. Permeability Damage of Gel-Breaking Fluid to Shale Matrix. No. 3, No. 16B, No. 12, and No. 17 cores were selected to conduct the evaluation experiment of the damage to the permeability of shale matrix caused by the loss of the gel-breaking fluid (Cases 4-1 ~ 4-4). The results are shown in Table 6 and Figure 13. It can be seen from the figure and the table that (1) after the experiment, No. 16B core is broken into two pieces, fractures appeared on the end faces of No. 12 and No. 17 cores, and no obvious change is found in the appearance of No. 3 core; (2) according to the measurement of permeability, the initial permeability of No. 3 core is relatively high, and the gel-breaking fluid is easy to invade and damage the permeability, which decreases by about 12.37%. However, the other three cores showed varying degrees of hydration and breaking, and the measured core permeability increases, at 11-50%; (3) due to the hydration and expansion of clay minerals, the intrusion of gel-breaking fluid into shale will cause certain permeability damage. But under the condition of stress release, shale is easy to break along with the bedding, form microfractures, or even break into blocks or sheets.

3.2.3. Phenomenon Observation of Shale Core Soaking and Broken in Gel-Breaking Fluids. No. 4, No. 8, No. 10, and No. 11 cores were selected to conduct the observation experiment of shale core soaking and broken in gel-breaking fluids under the condition of normal pressure and temperature (0.101 MPa and 20°C) and the condition of saturated pressure and 145°C, respectively (Cases 5-1 ~ 5-4). The gel-breaking fluids include distilled water and a 0.5%...
antiswelling agent. The results are shown in Figure 14. It can be obtained by observation and analysis that (1) under normal pressure and normal temperature, the fragmentation of No. 4 and No. 8 broken cores are more serious and they dissociate into rock fragments of different sizes after being soaked in distilled water for 24 hours. After being soaked in a 0.5% antiswelling agent, the cores also dissociate, but the degree of dissociation is less than that in distilled water; (2) under saturated vapor pressure and 145°C, the relatively intact cores of No. 10 and No. 11 are broken into three small pieces after being soaked in distilled water for 24 hours. While when soaked in 0.5% antiswelling agent, only 1-2

Table 5: Test results of rough fracture conductivity.

<table>
<thead>
<tr>
<th>No.</th>
<th>Confining pressure (MPa)</th>
<th>Back pressure (MPa)</th>
<th>Closure pressure (MPa)</th>
<th>Fracture conductivity (md·mm)</th>
<th>Ratio</th>
<th>Apparent permeability (md)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>25</td>
<td>20</td>
<td>5</td>
<td>1060.77</td>
<td>1</td>
<td>257.47</td>
</tr>
<tr>
<td>2</td>
<td>25</td>
<td>15</td>
<td>10</td>
<td>659.60</td>
<td>0.62</td>
<td>160.10</td>
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<tr>
<td>3</td>
<td>25</td>
<td>10</td>
<td>15</td>
<td>304.58</td>
<td>0.29</td>
<td>73.93</td>
</tr>
<tr>
<td>4</td>
<td>25</td>
<td>5</td>
<td>20</td>
<td>202.51</td>
<td>0.19</td>
<td>49.15</td>
</tr>
<tr>
<td>5</td>
<td>25</td>
<td>0</td>
<td>25</td>
<td>100.37</td>
<td>0.09</td>
<td>24.36</td>
</tr>
</tbody>
</table>

Note: the initial seam width is 4.12 mm.

Figure 11: Comparison of conductivity of rough fracture and smooth fracture: (a) correlation between conductivity and closure pressure; (b) normalized fracture conductivity.

Figure 12: Swelling factor of shale powder with time at different concentrations of antiswelling agent.
pieces of cores fall off; (3) in summary, cores that are broken by other reasons (such as shale falling or cracking caused by changes in ground stress caused by opening and closing wells) are more susceptible to the intrusion of the gel-breaking fluid, which will accelerate the fragmentation. When the core remains intact, the antiswelling agent has a better effect on preventing clay swelling and preventing core cracking. When the core is taken out of the cup, the water in

<table>
<thead>
<tr>
<th>Core No.</th>
<th>Size cm × cm</th>
<th>Bedding direction</th>
<th>Confining pressure (MPa)</th>
<th>Original permeability (md)</th>
<th>Filter loss pressure (MPa)</th>
<th>Damaged permeability (md)</th>
<th>Damage rate (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>16B</td>
<td>2.6 × 2.5</td>
<td>Horizontal</td>
<td>8</td>
<td>0.0199</td>
<td>5</td>
<td>0.0221</td>
<td>-11.11</td>
</tr>
<tr>
<td>12</td>
<td>2.34 × 2.5</td>
<td>Horizontal</td>
<td>8</td>
<td>0.023</td>
<td>10</td>
<td>0.0677</td>
<td>-29.36</td>
</tr>
<tr>
<td>17</td>
<td>1.46 × 2.5</td>
<td>Horizontal</td>
<td>8</td>
<td>0.0712</td>
<td>15</td>
<td>0.1071</td>
<td>-50.57</td>
</tr>
<tr>
<td>3</td>
<td>1.22 × 2.5</td>
<td>Inclined</td>
<td>8</td>
<td>0.1310</td>
<td>10</td>
<td>0.1146</td>
<td>12.37</td>
</tr>
</tbody>
</table>

Table 6: Test results of gel-breaking fluid damage to shale matrix permeability.

![Image 1](http://pubs.geoscienceworld.org/gsa/lithosphere/article-pdf/doi/10.2113/2021/4500227/5370313/4500227.pdf)

**Figure 13:** The state of shale core after the gel-breaking fluid filter loss.

**Figure 14:** Phenomenon of hydration and swelling of shale core in the water.
the cup is carefully poured out, and a soft mat is laid on the table. Then, the core in the cup is poured onto the soft mat, and the experimenter does not touch the core during the whole process, so as to ensure the accuracy of the experiment.

3.3. Analysis of Oil-Water Two-Phase Seepage and Stress Sensitivity in Fractures

3.3.1. Oil-Water Two-Phase Seepage Law and Relative Permeability Curves in Fractures. Under confining pressure of 25 MPa, back pressure of 20 MPa, and sand laying concentration of 3 kg/m², light oil and 0.5% antiswelling agent aqueous solution were used to inject into the fractures at the same time with the total injection rate of 0.5 ml/min. By modifying the water and oil injection rates separately to reduce the water content from 100% to 0% gradually, the conductivity of fracture and relative permeability of oil and water phases were measured (Case 2-1). The results are shown in Figures 15 and 16 and Table 7. It can be seen from the figure and table that (1) during the process of opening wells to produce and flowback of fracturing fluid, under the premise that the conductivity of shale fractures remains basically stable, the displacement pressure difference within the fractures will change. On the whole, it increases first and then decreases, which is caused by the mutual interference of oil and water two-phase flow; (2) the obtained oil-water relative permeability curve in the fractures is basically X-shaped, the saturation of irreducible water and irreducible oil is close to 0, and the isotonic point is at Sw = 60%, which indicates that the fracture wall is relatively hydrophilic.

3.3.2. Changes in Fracture Conductivity during Normal Depressurization Production. 0.5% antiswelling agent aqueous solution and light oil were used to measure the conductivity of shale fractures under different sand laying concentrations at a volume ratio of 1 : 1 and a total flow rate of 0.5 ml/min (Case 2-2). The experimental results are shown in Figures 17 and 18 and Table 8. According to the analysis, (1) when the sand laying concentration is 1 kg/m², as the closure pressure increases, the fracture conductivity decreases from 11.14 md-mm to 0.74 md-mm, a decrease of 93%; when the sand laying concentration is 3 kg/m², the fracture conductivity drops from 135.11 md-mm to 20.90 md-mm, a decrease of 85%; when the sand laying concentration is 5 kg/m², the fracture conductivity drops from 330.12 md-mm to 138.47 md-mm, a decrease of 58%. By comparison, it shows that the higher the sand laying concentration, the smaller the decrease of fracture conductivity will be as the closure pressure increases; (2) however, compared with the conductivity measured with oil in Section 3.1.2, under the condition of two-phase flow, the rock mechanical strength of shale fractures decreases affected by soaking of the water phase, which results in a corresponding decrease in conductivity. The conductivity can only reach 2.47%-27.70% of the conductivity measured with oil. And the smaller the sand laying concentration, the greater the decrease in conductivity caused by water soaking, which will cause the fractures to close prematurely. In addition, it was found that the ratio of the conductivity measured with two phases to the conductivity measured with oil under low closure pressure is lower than that under high closure pressure. This phenomenon may indicate that the shale on the fracture wall under low closure pressure is more likely to break, decrease in strength, and close the fractures due to the influence of the water phase. This phenomenon is consistent with the understanding obtained from the test of
3.3.3. Damage to Fracture Conductivity Caused by Intermittent Open Flow for Production. In order to investigate the damage to fracture conductivity caused by intermittent open flow for production, three sets of comparative experiments were designed. In Case 2-3, light oil was used to test under the condition of sand laying concentration of 3 kg/m² and fracturing fractures. In Case 2-4, light oil was used to test under the condition of sand laying concentration of 1 kg/m² and fracturing fractures. In Case 2-5, 1:1 light oil and 0.5% antiswelling agent were used to test under the condition of sand laying concentration of 1 kg/m² and fracturing fractures. Initially, the well was opened to open flow, the back pressure was atmospheric pressure, the effective closure pressure was 25 MPa, the back pressure after shut-in was 20 MPa, and the effective closure pressure was 5 MPa. The well was opened and closed repeatedly for three times to obtain four conductivity under high closure pressure each time the well was opened and three conductivity under low closure pressure each time the well was shut in. The results are shown in Figures 19 and 20 and Table 9.

Through analysis, it can be concluded that (1) opening and shutting the well to open flow has an important influence on the fracture conductivity. The change of closure pressure...
makes the fracture conductivity increase and decrease inter-mittently, that is, the fracture conductivity decreases when the well is opened and increases when the well is shut in.

(2) Under the condition of medium sand laying concentration and open flow with oil phase in Case 2-3, fracture conductivity is $1.07 \times 10^{-22} - 2.05 \times 10^{-20} \text{ md} \cdot \text{mm}$ at well opening and $6.91 - 8.30 \times 10^{-1} \text{ md} \cdot \text{mm}$ at well shut-in. With the increase of the number of opening and shutting the well, the conductivity when opening and shutting is reduced by 17% (average value of the second opening and the third opening) and 17%; it should be noted that when changing from the third well shut-in to the third well opening, the well opening depressurization rate is slower, which is 0.33 MPa/min, resulting in a smaller decrease in conductivity and making the conductivity of the third well opening higher than the previous two. (3) Under the condition of low sand laying concentration and open flow with oil phase in Case 2-4, fracture conductivity is $3.48 - 4.70 \text{ md} \cdot \text{mm}$ at well opening and $2.26 - 2.73 \times 10^{-1} \text{ md} \cdot \text{mm}$ at well shut-in. Compared with Case 2-3, the conductivity is reduced by 3 times and 27-63 times, respectively. The opening and shut-in of the well cause a decrease in conductivity of 26% and 17%, respectively. (4) Case 2-5 is similar to Case 2-4, but it was under the condition of open flow with two phases. Treatment conductivity is $2.47 - 3.74 \text{ md} \cdot \text{mm}$

<table>
<thead>
<tr>
<th>No.</th>
<th>Confining pressure (MPa)</th>
<th>Back pressure (MPa)</th>
<th>Closure pressure (MPa)</th>
<th>Conductivity (md·mm)</th>
<th>Apparent permeability (md)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1 kg/m² Ratio</td>
<td>3 kg/m² Ratio</td>
</tr>
<tr>
<td>1</td>
<td>25</td>
<td>20</td>
<td>5</td>
<td>11.14 1</td>
<td>135.11 1</td>
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<tr>
<td>2</td>
<td>25</td>
<td>10</td>
<td>15</td>
<td>3.97 0.36</td>
<td>63.88 0.47</td>
</tr>
<tr>
<td>3</td>
<td>25</td>
<td>0</td>
<td>25</td>
<td>0.74 0.07</td>
<td>20.90 0.15</td>
</tr>
</tbody>
</table>

Note: the initial seam width of sand paving concentration 1, 3, and 5 kg/m² is 1.3, 2.1, and 3.46 mm, respectively.

Figure 18: Effect of effective closure pressure increase on fracture conductivity: (a) correlation between conductivity and closure pressure; (b) normalized fracture conductivity; (c) ratio of water-oil conductivity and oil conductivity.
3.46 md·mm at well opening and 68.66-129.68 md·mm at well shut-in. Compared with Case2-4, the fracture conductivity decreased by about 1.5 and 3 times, respectively. The opening and shut-in of the well cause a decrease in conductivity of 28% and 47%, respectively. (5) In summary, opening and shutting the well frequently has damage to the fracture conductivity.

**Figure 19:** Test curves of fracture conductivity when back pressure fluctuates drastically: (a) $fw = 0\%$, 3 kg/m$^2$ (Case 2-3); (b) $fw = 0\%$, 1 kg/m$^2$ (Case 2-4); (c) $fw = 50\%$, 1 kg/m$^2$ (Case 2-5).

**Figure 20:** The variation of fracture conductivity with the switching time when back pressure fluctuates drastically: (a) correlation between fracture conductivity and switching time; (b) correlation between normalized fracture conductivity and closure pressure.
conductivity under high closure pressure and low closure pressure. The compaction effect of the former is more prominent, and the latter is easy to cause proppant migration or shale shedding to block the fracture seepage channel, which will affect the stability of the conductivity. In the case of low sand laying concentration and oil-water two-phase flow, opening and shutting the well has the greatest damage to the fracture conductivity.

4. Discussion

In terms of the conductivity of branch fractures with low sand laying concentration, there are many studies that have good consistency with our studies [31–36]. Except for the stress sensitivity of shale fracture conductivity, for the effect of fracturing fluid and scheme of production on fracture conductivity, Feng et al. carried out a study on the damage factors of fracturing fluid to reservoirs. In order to avoid damage to the reservoir caused by the salinity of fracturing fluid and pH value, it was recommended that the KCl content in the fracturing fluid is greater than 2%, and the pH value of the gel-breaking fluid and filtrate of fracturing fluid should be controlled below 11 [33]. Huang and Pu developed a high-efficiency compound gel breaker for cross-linked guar gum fracturing fluid in response to the serious damage to shale reservoirs caused by guar gum fracturing fluid, which can accelerate the gel breaking through the redox system, effectively reduce the content of residues and residual gel, and reduce the damage to the permeability of matrix and the conductivity of fractures [34]. Regarding the open flow system after fracturing shale oil reservoirs, Liu et al. conducted experiments and analysis on core samples at different depths in the Qingshankou Formation of well A in Songliao Basin to explore and optimize the system of shut-in and to control the flowback after fracturing in shale reservoirs. That is, in the initial stage of fracturing fluid flowback, it is necessary to select a smaller nozzle to control the open flow as much as possible, to control the steady drop of wellhead pressure, and to adjust the nozzle size in time to ensure a stable nozzle coefficient curve [35]. Shang established an optimization process of open flow scheme by studying the shut-in and open flow scheme after fracturing in shale reservoirs. The critical sand-carrying velocity of the wellbore is used to determine the initial flowback rate, and the closed state of hydraulic fractures is used to determine the time of opening the well [36]. In summary, by controlling the loss of fracturing fluid and reducing the interfacial tension of the prepad fluid, the capillary self-absorption of the fracturing fluid can be inhibited, and the fracturing fluid is promoted to flow back quickly to reduce the infiltration of shale fractures and their surfaces. In addition, a reasonable production pressure difference can be used to protect shale oil reservoirs effectively and maintain the fracture conductivity as well as high production.

In addition, it should be pointed out that the value of fracture conductivity measured in this study with low sanding concentration is smaller than that of other similar measurements, and there are two reasons for this phenomenon: First, the experimental conditions are different. For example, in this study, the antiswelling agent and real light oil are used to determine the fracture conductivity under different water contents (rather than the standard 8% salt solution). The antiswelling agent can lead to the hydration change of the fracture wall and the decrease of the strength, while the viscosity of crude oil is relatively high and the relative permeability value is less than 1, resulting in a small fracture conductivity. Second, subject to the level of the experimental device used, there are areas to be improved in terms of pressure monitoring position (the two ends of the crack are not directly connected), monitoring accuracy (the range of the pressure gauge is large, and the accuracy is low, especially for very small displacement pressure difference, the monitoring error is large), and the stability of crack sanding (the partially filled proppant will be squeezed out of the crack, resulting in the reduction of the crack width). In the future experiment of fracture conductivity with low sand concentration, the experimental device should be improved.

5. Conclusion

(1) The branch fractures with low sand laying concentration have a significant stress sensitivity. Under a certain closure pressure, the problem of fracture closure may occur, causing the proppant to be embedded in the fracture wall. The wall of natural fractures is very tortuous, which is not conducive to the proppant migration and stable support and can result in stronger stress sensitivity. When the sand laying concentration in fractures is less than 3 kg/m², the initial
fracture width is less than 2-3 mm, and the fracture conductivity measured with light oil will decrease quickly with closure pressure increase. Particularly under the condition of sand concentration less than 1 kg/m³, when the closure pressure is larger than 15 MPa, there will be a risk of proppant embedded and fracture closure.

(2) The antiswelling agent in the gel-breaking fluid has an inhibitory effect on the swelling of shale clay. The antiswelling agent with a concentration of 2% has a better effect, and the swelling factor of shale powder is only 1.84%. Comparatively, the antiswelling agent with a concentration of 0.5% has a poor effect. Under high closure pressure, the intrusion of a low-concentration antiswelling agent into the matrix of shale will cause the hydration and swelling of shale, leading to the core permeability decrease. However, when the effective stress of the shale core is reduced, the expansion and splitting between the shale beddings will play an important role. Namely, the shale core damaged by the gel-breaking fluid may also generate microfractures or even break along the bedding.

(3) Considering the oil-water two-phase flow in the fractures during the flowback process of the gel-breaking fluid, the conductivity of branch fractures is lower than that of the value measured with light oil. The probability of core breaking, particles falling off, and proppant embedding on the wall of fractures increases. Besides, increasing the closure pressure, reducing the sand laying concentration, and the pore pressure fluctuation all can reduce the fracture conductivity. Particularly, the frequent and severe shut-in and open flow can damage the fracture conductivity significantly.

(4) It is necessary to design and optimize a reasonable fracturing fluid and open flow for production scheme to avoid a rapid decline in shale oil production. By controlling the loss of fracturing fluid and reducing the interfacial tension of the prepad fluid, the capillary imbition of fracturing fluid can be inhibited, and the fracturing fluid can be promoted to flow back quickly to reduce the soaking of shale fracture surfaces. In addition, a reasonable production pressure difference can be used to protect shale oil reservoirs effectively and maintain the fracture conductivity as well as the high production.

Data Availability
The authors would like to provide the data if the readers have a reasonable request.

Conflicts of Interest
The authors declare that they have no conflicts of interest.

Acknowledgments
This research is supported by the Major National R&D Project: Key technologies of seismic and wellbore fine exploration (2016ZX05006-002) and the Natural Science Foundation of Shandong Province (ZR2020ME090).

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