Experimental study on deformation and permeability enhancement of oil sand reservoir by hydraulic fracturing technique under true triaxial stress

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Abstract
Hydraulic fracturing technology is often applied to form a permeable zone for geothermal resources near the borehole in tight reservoirs to improve the permeability and extraction efficiency. Steam or hot water is often injected to dissolve the heavy oil to increase its fluidity during the extraction. As the numerical simulation or two-dimensional physical experiments have great limitations to simulate hydraulic fracturing of oil sand reservoirs, this study conducted a large-scale three-dimensional physical simulation experimental study of hydraulic fracturing with high temperature of oil sand reservoir under true triaxial stress state and monitored the water pressure change at various points inside the box during the hydraulic fracturing by laying pressure sensors. The experimental results showed that the hydraulic breakdown pressure of oil sands increases with the increase in $\sigma_2$, which is related to the increase in $\sigma_1$ limiting the fracture growth and the decrease in effective stress during fluid injection. To better describe the breakdown pressure variation, we developed a new oil sand breakdown pressure prediction model considering the true triaxial stress condition, which showed a good prediction effect. Due to the formation of fluid hysteresis zone during the fracture expansion, the fluid pressure recorded by the internal pressure sensor lagged behind the injection pressure. Hydraulic fracturing produced shear fractures inside the oil sands under low $\sigma_2$ conditions and tensile fractures under high $\sigma_2$ conditions, and the permeability was significantly increased after hydraulic fracturing, in which the shear fractures formed under low $\sigma_2$ showed a better permeability enhancement effect than the tensile fractures formed under high $\sigma_2$. The research and analysis in this study can provide reasonable suggestions and feasibility analysis for the design and construction of heavy oil extraction.

KEYWORDS
hydraulic fracturing, oil sands, permeability, true triaxial stress
1 | INTRODUCTION

As one of the excellent fuels for modern industrial systems, oil has huge reserves worldwide.1-3 In 2018, China's proven oil reserves reached 3.5 billion tons, including a 100 million ton oil field were added and 959 million tons of new proven geological reserves, a year-on-year increase of 9.4%.4 Among China's petroleum resources, conventional crude oil accounts for only about 30%, and the rest are heavy oil (15%), super heavy oil (25%), and asphalt.5 China is rich in heavy oil resources, but due to its large molecular weight and high viscosity, the development cost is relatively high and the development technology is complicated. In order to effectively exploit heavy oil resources, many scholars have conducted numerous studies on the mechanical properties and reservoir geological conditions of oil sands, which originated from the large-scale in situ thermal recovery studies of oil sands conducted in Canada in the 1980s.6,7 Chute et al.8 measured the electrical conductivity and relative permittivity of oil sand samples in Athabasca and evaluated the feasibility of large-scale electromagnetic heating on-site. Scott and Seto9 performed laboratory measurements of thermal conductivity and thermal diffusion coefficients of oil sand samples to predict the actual conditions of in situ thermal stimulation. Takahashi et al.10 developed a 3D geological model of the Athabasca oil sand area in Canada based on logging and seismic data, which provides a basis for the later deployment design and production prediction of heavy oil recovery. Qiao et al.11 studied the physical and mechanical properties and microscopic composition of the oil sands of Fengcheng, Xinjiang, and found that the oil sands in Fengcheng are mainly composed of asphalt, quartz, and dickite and generally contain intercalated layers. The oil sands exhibited the volume shear shrinkage or shear expansion in shear tests. Wu et al.12 studied the in situ stress field distribution and established a three-dimensional stress field model for the reservoir, in view of the non-homogeneous characteristics of the shallow heavy oil reservoir in Fengcheng, which can better reflect the lithological interface and stress characteristics of the reservoir and can effectively guide the hydraulic fracturing of the reservoir.

The current extraction techniques for heavy oil mainly include steam soaking, steam drive, steam assisted gravity drainage (SAGD) for double horizontal wells, and vertical horizontal steam drive (VHSD) for vertical and horizontal wells.13 The principle of all these technologies is based on the heat injection into the underground during extraction, such as injecting steam, hot water, or some hydrocarbons to dissolve the heavy oil and increase its fluidity. Meanwhile, the continuous injection of water with high-pressure or high-rate will activate the primary fractures and form a large number of secondary fracture networks in the reservoir, establish the connection channel between injection and production wells to improve the reservoir porosity and permeability around the wellbore, shorten the preheating cycle, and thus improve the development rate of steam chamber and the production and extraction efficiency of heavy oil.14 Xu15 used finite element techniques to model the hydraulic fracturing process in loose oil sand formations in three dimensions, and based on the continuum mechanics, the strain softening model was used to simulate the fluid flow process and the deformation and failure process of the sand matrix. Al-Bahlani and Babadagli16 discussed the development of SAGD technology and illustrated the superiority and limitations of laboratory physical experiments and numerical simulations, as well as the challenges faced by heavy oil production in the future. They believed that indoor experimental and numerical simulation studies are still important research aspects for the future. Lin et al.17 developed a mathematical model of circulating steam heat transfer in SAGD horizontal section and found that significant pressure and temperature drops occur in the long oil pipe during steam cycle preheating, the lower the steam injection flow rate, the lower the dryness, and the more favorable the heat transfer between the annulus and the oil layer. Zhang et al.18 proposed a SAGD fast preheating technology, which used the dilatancy principle of rock mechanics to shorten the preheat time and improve the heavy oil production by artificial hydraulic dilatancy between the steam injection and production wells. Field practice showed that steam injection wells treated with hydraulic dilatancy are ready for production after 2-3 months of steam cycle preheating, and the production efficiency can be significantly improved.

At present, numerical simulations and two-dimensional physical simulation experiments are mostly used to study the fracture evolution and seepage enhancement mechanism of hydraulically fractured oil sand reservoirs. Numerical simulation techniques often simplify the boundary conditions and material properties, and different forms of structural discretization can produce large differences in the results and accuracy obtained, and the randomness is relatively large. Physical simulation experiments usually simulated a small scale, three-dimensional physical simulation experiments involved less, and did not consider the impact of the actual situ stress state in the reservoir on the dilatancy and hydraulic transformation, and the intermediate principal stress \( \sigma_2 \) has an important impact on the dilatancy, deformation, and seepage laws of oil sand reservoirs. Therefore, this study carried out a three-dimensional physical simulation experiment considering the true triaxial stress state of actual formation, which involved the large-scale high-temperature
hydraulic fracturing the oil sand reservoir under different intermediate principal stress conditions, and conducted the permeability measurements before and after hydraulic fracturing, so as to investigate the fracture characteristics and dilatancy behavior of the oil sands, and to evaluate the effect of hydraulic fracturing on permeability enhancement in order to optimize the field construction parameters and provide scientific reference for efficient extraction of heavy oil.

2 | MATERIALS AND EXPERIMENTAL PROCEDURES

2.1 | Specimen preparation

The oil sands for this experiment were taken from Xinjiang oil field, and the lump oil sand samples were first crushed by crusher, and then, the oil sand particles used to suppress the reservoir were screened according to the test requirements. Certain additives, such as phosphorus containing organic matter, were added to the oil sand particles as the plasticizer to better simulate the physical and mechanical properties of the reservoir. Studying the fine physical properties of oil sands can observe the microscopic pore structure, fracture development and connectivity, and composition of oil sands more intuitively, which can provide a basis for the analysis of dilatancy mechanism and on-site targeted dilatancy and transformation measures of the extraction of heavy oil. Firstly, the oil sands were analyzed by particle size analysis, as shown in Figure 1, the oil sand particle size was mainly concentrated in the range of 100–350 μm, with an average particle size of 225 μm, which belonged to the fine-medium particle size. The results of field emission scanning electron microscopy (SEM) showed that asphalt cements existed between the oil sand particles. The location and shape of the asphalt can be observed by the "bee-like structure" in the SEM micrograph of oil sands,19 and we identified the grit by the small raised particles on the surface. The oil sand was highly loose, and there were few contact points or surfaces between the oil sand particles, resulting in a relatively loose microstructure, and breccia-like oil sand particles had sharp edges and corners, some of the particles were wrapped by asphalt, as shown in Figure 2. The energy spectrum analysis test showed that the oil sands contain the highest amount of silicon and carbon, reaching 29% and 21%, respectively (Figure 3). Once the crushed oil sand particles were prepared for the simulated reservoir, the oil sand particles were compressed and molded to simulate the formation using a rock compression molding system at a compression pressure of 10 MPa. The compressed oil sands are shown in Figure 4.

2.2 | Experimental apparatus

The multi-field coupled coal-rock dynamic disaster prevention and control technology simulation system developed independently by Chongqing University, as shown in Figure 5, was used for this hydraulic fracturing experiments of the oil sands. The effective model size of the test system reaches 1000 mm × 400 mm × 400 mm, and the servo controlling loading system can provide a maximum loading pressure of 5000 kN in one direction; and there are four independent hydraulic loading systems in two directions, which can realize four-stage loading for presurization, and the maximum loading pressure of a single group of hydraulic loading system can reach 3000 kN. Each group of hydraulic loading system can be controlled individually, which can more realistically simulate the true triaxial stress state of underground reservoir. At the same time, it can provide a maximum fluid pressure of 10 MPa and a maximum temperature of 250°C. The system can conduct the tests of coal and gas outburst, fluid permeability measurement, hydraulic fracturing, and dynamic loading under the coupled conditions of true triaxial stress-permeability-temperature. The 64-channel data acquisition system can monitor the pressure, temperature, and other parameter changes at different positions of oil sands, meeting the requirements of this experiment.

2.3 | Experimental procedure and scheme

Before the physical simulation experiment, oil sands were compressed and the laying of pressure sensors was completed. The arrangement of pressure sensors in the oil sand specimen box is shown in three-dimensional and sectional views in Figure 6 to monitor the water pressure
changes at various points during the hydraulic fracturing process. After the oil sands were compressed and closing the lid, the multifunctional experimental box was transferred from the forming system to the true triaxial loading system using the aerial crane and the counterforce frame was installed for the true triaxial stress loading. The specific loading scheme for the stresses is shown in Figure 7. The initial true triaxial stress points were set to $\sigma_z = \sigma_1 = 10 \text{ MPa}$, $\sigma_y = \sigma_2 = 6 \text{ MPa}$, and $\sigma_x = \sigma_3 = 6 \text{ MPa}$. $\sigma_1$ and $\sigma_3$ were then kept constant, and $\sigma_2$ was increased to 7 MPa, 8 MPa, 9 MPa, and 10 MPa to investigate the effect of intermediate principal stress on the breakdown pressure and fracture propagation pattern of the oil sands. Under maintaining each stress condition, high-temperature water with a temperature of 80°C was injected from the fluid inlet at a loading rate of 0.2 MPa/s, then entered the hollow of the central pipe column, and was injected along the central channel in the nozzle direction through the perforating joint and continued to be loaded until the pressure decreased, and the measured pressure was the breakdown pressure of the oil sand reservoir. The hydraulic injection pressure path is shown in Figure 7B, and the nozzle propulsion speed of 50 mm/min corresponds to a loading rate of 0.2 MPa/s. The hydraulic fracturing device mainly consists of a forward and backward device, measuring components, and an injecting drilling system, and the well-connected hydraulic fracturing device is shown in Figure 8.

Seepage tests with nitrogen gas injection were conducted before and after the hydraulic fracturing experiments to investigate the permeability enhancement effect of the oil sand dilatancy zone after hydraulic fracturing. To avoid the effect of high-temperature water on the permeability testing, we first introduced 0.5 MPa nitrogen into the chamber to drive out the water remaining in the chamber after high-temperature hydraulic fracturing experiment, and the pressurization gas at the inlet was injected with a very slow rate to avoid any possible damage to the sample with the pressure difference. The process lasted for 6 h. To ensure that the temperature of the oil sands in the chamber returned to room temperature, we then started the permeability tests after 12 h. High-pressure gas was injected into the oil sand box steadily by the driving of the booster pump and the regulating action of the pressure reducing valve and then was passed at the outlet through the gas-liquid separator and dryer. The flow data were recorded by the gas flow meter, and then, the permeability
could be calculated. Darcy’s law is often used to describe the relationship between permeability rate and pressure drop gradient of the fluid with gas-liquid two-phase, and we make the following assumptions: Nitrogen is a stable linear seepage in oil sands, without considering the slip-page effect; nitrogen in the oil sands is laminar flow, and there is no chemical reaction with oil; the absolute permeability is a variable determined by the nature properties of the oil sands, independent of pressure and flow, without considering the compressibility of porous media and fluid; the seepage process is isothermal. Darcy’s equation for oil and gas two-phase seepage can be expressed as follows:

$$\bar{v}_c = -k k_{rc} / \mu_c (\nabla p_c - \gamma_c \nabla D) \quad (1)$$

where $k$ is the absolute permeability of the oil sands, m$^2$; $k_{rc}$ is the relative permeability of the oil or gas phase; $v_c$ is the seepage rate of the oil or gas phase, m$^3$/s; $\mu$ is the dynamic viscosity of the oil or gas phase, Pa·s; $p_c$ is the gas pressure, Pa; $D$ is the length of the gas flow through the oil sand specimen box, m; $\gamma_c$ can be calculated from the average density of the fluid within the seepage path, $\gamma_c = \rho_cg$.

3 | TEST RESULTS AND ANALYSIS

3.1 | Fracture characteristics of oil sands under different intermediate principal stresses

Figure 9 shows the breakdown pressure $p$ of the oil sands as a function of the intermediate principal stress $\sigma_2$. The fluid injection pressure can be monitored by a pressure sensor at the inlet pipe. It can be seen from that as the
intermediate principal stress increases, the breakdown pressure of oil sands also increases. This is because the increase in intermediate principal stress limits the lateral expansion and deformation of oil sands during the water injection and pressurization, which improves the ability of the oil sands to resist deformation and fracture, and the breakdown pressure of the oil sands increases significantly. Secondly, the phenomenon of increased breakdown pressure is also related to the effective stress effect. In the fluid injection, as the fluid pressure continues to increase, the effective stresses in all three directions of the oil sands are reduced, which is equivalent to the stress unloading effect, and the increase in $\sigma_2$ can weaken this unloading effect in the $\sigma_2$ direction, which finally limits the process of hydraulic fractures from expansion to failure, thus enhancing the bearing capacity of the oil sands and increasing the breakdown pressure.

The hydraulic breakdown pressure of rocks is influenced by several factors, including the initial in situ stress state. Mechanistic analysis of breakdown pressure is important for evaluating the stress state of rock. The conventional breakdown pressure prediction models did not take into account the actual true triaxial stress state of the rock and their applicability to weakly consolidated rocks such as oil sands was debatable. Therefore, we assumed that a borehole of radius $a$ is drilled in the rock, which is mainly affected by in situ stress ($\sigma_1$, $\sigma_2$, and $\sigma_3$), fluid pressure $p$, and initial pore pressure $p_0$. After introducing the polar coordinate system and utilizing the principle of stress superposition, the principal stress components ($\sigma_{rr}$ and $\sigma_{\theta \theta}$) around the borehole can be obtained as follows:

$$\begin{align*}
\sigma_{rr} &= \frac{1}{3} \left( \sigma_1 + \sigma_2 + \sigma_3 \right) \left( 1 - \frac{a^2}{r^2} \right) + \frac{1}{3} \left( \sigma_1 - \frac{\sigma_2 + \sigma_3}{2} \right) \left( 1 - \frac{4a^2}{r^2} + \frac{3a^4}{r^4} \right) \cos 2\theta + \frac{p}{r^2} \frac{a^2}{2} \\
\sigma_{\theta \theta} &= \frac{1}{3} \left( \sigma_1 + \sigma_2 + \sigma_3 \right) \left( 1 + \frac{a^2}{r^2} \right) - \frac{1}{3} \left( \sigma_1 - \frac{\sigma_2 + \sigma_3}{2} \right) \left( 1 + \frac{3a^4}{r^4} \right) \cos 2\theta - \frac{p}{r^2} \frac{a^2}{2} 
\end{align*}$$

(2)

 intermediate principal stress increases, the breakdown pressure of oil sands also increases. This is because the increase in intermediate principal stress limits the lateral expansion and deformation of oil sands during the water injection and pressurization, which improves the ability of the oil sands to resist deformation and fracture, and the breakdown pressure of the oil sands increases significantly. Secondly, the phenomenon of increased breakdown pressure is also related to the effective stress effect. In the fluid injection, as the fluid pressure continues to increase, the effective stresses in all three directions of the oil sands are reduced, which is equivalent to the stress unloading effect, and the increase in $\sigma_2$ can weaken this unloading effect in the $\sigma_2$ direction, which finally limits the process of hydraulic fractures from expansion to failure, thus enhancing the bearing capacity of the oil sands and increasing the breakdown pressure.

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\sigma_{rr} &= \frac{1}{3} \left( \sigma_1 + \sigma_2 + \sigma_3 \right) \left( 1 - \frac{a^2}{r^2} \right) + \frac{1}{3} \left( \sigma_1 - \frac{\sigma_2 + \sigma_3}{2} \right) \left( 1 - \frac{4a^2}{r^2} + \frac{3a^4}{r^4} \right) \cos 2\theta + \frac{p}{r^2} \frac{a^2}{2} \\
\sigma_{\theta \theta} &= \frac{1}{3} \left( \sigma_1 + \sigma_2 + \sigma_3 \right) \left( 1 + \frac{a^2}{r^2} \right) - \frac{1}{3} \left( \sigma_1 - \frac{\sigma_2 + \sigma_3}{2} \right) \left( 1 + \frac{3a^4}{r^4} \right) \cos 2\theta - \frac{p}{r^2} \frac{a^2}{2} 
\end{align*}$$

(2)
1. Stress state $\sigma_{\theta\theta}^1$: $\sigma_{\theta\theta}^1$ is mostly dominated by the true triaxial stresses ($\sigma_1$, $\sigma_2$, and $\sigma_3$), and its equation can be expressed as follows:

$$\sigma_{\theta\theta}^1 = \frac{1}{3} (\sigma_1 + \sigma_2 + \sigma_3) \left( 1 + \frac{a^2}{r^2} \right) - \frac{1}{3} \left( \frac{\sigma_2 + \sigma_3}{2} \right) \left( 1 + \frac{3a^4}{r^4} \right) \cos 2\theta$$

Thus, the hydraulic breakdown pressure criterion for oil sands can be expressed as follows:

$$\sigma_{\theta\theta}^t = \sigma_{\theta\theta} - p_0 = \sigma_{\theta\theta}^1 + \sigma_{\theta\theta}^2 + \sigma_{\theta\theta}^3 - p_0 = -\sigma_t \quad (7)$$

Bringing Equation (6) into Equation (7) yields:

2. Stress state $\sigma_{\theta\theta}^2$: $\sigma_{\theta\theta}^2$ is mainly dominated by the total fluid pressure $p$. The fluid pressure includes the initial fluid pressure $p_0$ and the hydraulic loading pressure $p_h$. The equation can be expressed as follows:

$$\sigma_{\theta\theta}^2 = -p \frac{a^2}{r^2} = -(p_h + p_0) \frac{a^2}{r^2} \quad (4)$$

Considering the damage around the borehole wall, that is, $r = a$, so the above formula can be simplified as follows:

$$p = \frac{(1 - \nu) \left[ \frac{2}{3} (\nu_1 + \nu_2 + \nu_3) - 3 \left( \nu_1 - \frac{\nu_2 + \nu_3}{2} \right) \cos 2\theta - \frac{\nu_0 (1 - 2\nu)}{1 - \nu + 2\nu} \right] p_h + \sigma_t}{1 - \nu + 2\nu \nu} \quad (9)$$

Equation (9) is the breakdown pressure prediction model of oil sands considering true triaxial stress state, and the above equation can be simplified under the condition of neglecting the initial pore pressure.

$$p = \frac{(1 - \nu) \left[ \frac{2}{3} (\nu_1 + \nu_2 + \nu_3) - 3 \left( \nu_1 - \frac{\nu_2 + \nu_3}{2} \right) \cos 2\theta + \sigma_t \right]}{1 - \nu + 2\nu \nu} \quad (10)$$

In order to verify the applicability of the proposed breakdown pressure prediction model, the Poisson’s ratio $\nu$ of the oil sands was measured to be 0.42, and the effective stress coefficient of permeability $\nu$ and azimuth angle $\theta$ was set to be 0.15 and 15° taking the trial-and-error method, respectively. The breakdown pressure of the oil sands under different intermediate principal stresses can be calculated by bringing the stress state shown in Figure 7A into Equation (10), and the calculated breakdown pressure is compared with the breakdown pressure obtained from the experiment (Figure 9), as shown.

3. Stress state $\sigma_{\theta\theta}^3$: $\sigma_{\theta\theta}^3$ presents the additional circumferential stress caused by the fluid during permeating from the borehole to the formation under the action of fluid pressure difference. Based on the thermoelasticity theory of porous media, the equation of $\sigma_{\theta\theta}^3$ can be described as follows:

$$\sigma_{\theta\theta}^3 = \frac{\nu}{2} \frac{1 - 2\nu}{1 - \nu} \left( 1 + \frac{a^2}{r^2} \right) (p - p_0) \quad (5)$$

where $\nu$ denotes the effective stress coefficient of permeability, taking values from 0 to 1; $\nu$ denotes the Poisson’s ratio of the oil sands.

When the minimum circumferential stress of the oil sands reaches the tensile strength, macroscopic fractures are generated within the oil sands and damage occurs with a rapid drop in fluid pressure. The total circumferential stress can be expressed as the superposition of the three circumferential stress components mentioned above:

$$\sigma_{\theta\theta} = \sigma_{\theta\theta}^1 + \sigma_{\theta\theta}^2 + \sigma_{\theta\theta}^3 = \frac{1}{3} (\sigma_1 + \sigma_2 + \sigma_3) \left( 1 + \frac{a^2}{r^2} \right) - \frac{1}{3} \left( \frac{\sigma_2 + \sigma_3}{2} \right) \left( 1 + \frac{3a^4}{r^4} \right) \cos 2\theta \quad (6)$$
in Figure 10, which shows that the breakdown pressure derived from the prediction criterion is very close to the breakdown pressure obtained from the experiment, and can show a linear increase with the increase in the intermediate principal stress, and the linear fitting degree $R^2$ is up to 0.9999. However, the breakdown pressure predicted by the proposed breakdown pressure criterion is slightly higher than the experimental one, which may be related to the physical and mechanical properties of the oil sands, with low uniaxial compressive strength and high-volume dilatation rate, but it can be negligible, the fit of predicted and actual values reached 0.9924, and the two are still in good agreement.

**Figure 9** Variation of breakdown pressure with intermediate principal stress of oil sands

**Figure 10** Comparison between measured breakdown pressure and predicted value of the proposed model

**Figure 11** Evolution of fluid pressure sensor monitoring data for three profiles at $\sigma_2 = 6$ MPa

### 3.2 Fracture evolution characteristics of oil sands under different intermediate principal stresses

Pressure sensors were arranged in the oil sand specimen box to record the hydraulic pressure in real time in order
to explore the internal fluid pressure changes and fracture evolution during the fluid injection, and the specific placement is shown in Figure 6. The pressure sensors in the three profiles (A, B, and C) during the fluid injection process were collected in real time, and the data were automatically saved by the computer. Considering that the end face of this specimen is square, the sensor data of four typical points in each profile are selected for analysis according to its geometric symmetry. Figure 11A–C shows the fluid pressure data at the inlet pipe and recorded by the sensors at the monitoring points of the three profiles (A, B, and C) when $\sigma_2 = 6$ MPa, respectively. As can be seen from the figures, the sensor monitoring data at each profile also change significantly. Since profile A is closest to the center of fluid injection, the measured fluid pressure also changes first. The fracture development includes three stages: fracture initiation, stable expansion, and unstable expansion. The crack of rock corresponds to the emergence of fractures. The continuous injection of fluid continues to stimulate the oil sand particles and the asphalt cements, causing the cementation strength between particles and asphalt cements to decrease, resulting in the initiation of fractures and expanding from the tip, and the fluid gradually flows into the fracture leading to the increase in fluid pressure inside the oil sands. Only A1 and A6 in profile A recorded the fluid pressure.
data after fracture expansion, and their fluid pressure changes lagged the change in injection pressure. Many factors cause the fluid pressure distribution inside the fracture, is not completely uniform, for example, the flow of high-viscosity fluid (water) into the main fracture will lag behind the development of the fracture tip, forming a blank zone without fluid action at the fracture tip, that is, forming a fluid hysteresis zone,\(^\text{26,27}\) as shown in Figure 13. Therefore, the continuous injection of high-pressure fluid or increasing fluid pressure is required to stimulate fracture expansion, at which stage the fracture begins to expand steadily, generating macroscopic shear or tensile fractures until reaching the breakdown pressure of the oil sands, followed by unstable expansion of fractures through the oil sands. Figure 11 also marks the fracture stable extension and unstable expansion stages in the variation of fluid pressure. The fluid pressure data of B1, B6, and B3 were recorded in profile B. The fluid pressure data of C1, C6, and C3 were also recorded in profile C, the fluid pressure of C3 was greater than that of A3 and B3, and the fluid pressure of C1 was lower than that of A1 and B1, which indicated that shear fracture, rather than tensile fracture, was formed as the main fracture inside the oil sands. This is due to the fluid injection along the direction of minimum principal stress, which deflects the fracture extension direction under the action of the principal stress difference\(^{\sigma_1 = 10 \text{ MPa}, \sigma_2 = 6 \text{ MPa}}\) and eventually forms a shear fracture, and the schematic diagram of the fracture extension is shown in Figure 12. There is always no fluid pressure response in the No. 8 sensor, indicating that no fractures are formed here.

Figure 14A–C shows the fluid pressure data recorded by the pressure sensor at the inlet pipe and the pressure sensors at the three profiles (A, B, and C) in real time when \(\sigma_2 = 10 \text{ MPa}\), respectively, and some sensors also recorded the change of internal fluid pressure as the fractures expanded during the hydraulic fracturing. Figure 14 also marks the fracture stable extension and unstable expansion stages in the variation of fluid pressure. Only No. 1 and No. 6 sensors show fluid pressure data, and No. 3 and No. 8 have no fluid pressure response, indicating that there are no fractures formed at these two locations. The fluid pressure at NO. 1 is always greater than that at NO. 6, the fluid pressure at A1 is greater than that at B1 and C1, and the fluid pressure at A6 is greater than that at B6 and C6, indicating that the fracture direction is not significantly deflected during the fracture extension, and the tensile fracture, rather than the shear fracture, appeared as the main fracture during the high-pressure fluid fracturing. This is due to the increase in \(\sigma_2\) to reduce the principal stress difference, when \(\sigma_1 = \sigma_2 = 10 \text{ MPa}\), and there is no principal stress difference to deflect the fracture direction, thus forming tensile fractures. The schematic diagram of tensile fracture expansion is shown in Figure 15. When reaching the fracture instability expansion stage after the breakdown pressure, the fluid injection pressure drops rapidly (Figure 14), which means that the rapid formation of the macroscopic tensile fracture makes a large amount of fluid injected into the fractures rapidly, resulting in the secondary increase in internal fluid pressure (Figure 14).

3.3 | Permeability evolution before and after hydraulic fracturing

In order to evaluate the effect of permeability enhancement after hydraulic fracturing, the permeability tests of nitrogen injection were conducted before and after the hydraulic fracturing tests. 2 MPa nitrogen was injected from the inlet and was injected into the oil sand box steadily by the driving of the booster pump and the regulation of the pressure reducing valve, and the outlet was connected to the atmosphere, filtered by the gas-liquid separator and the dryer, and then, the gas flow meter was connected to record the flow data after the gas flow was stabilized, and the permeability was calculated by Darcy’s law (Equation 1). The permeability of oil sands before and after hydraulic fracturing under different intermediate principal stresses is shown in Figure 16. As shown in the figure, the permeability of oil sands before and after hydraulic fracturing decreases significantly with the increase in intermediate principal stresses, which is due to the increase in intermediate principal stress causes the pores and fractures of the oil sand reservoir to be compressed, the contact area between particles increases, and the seepage channel gradually closes with the increase in stress, resulting in a decrease in the initial permeability and the post-fracturing permeability.\(^{\text{28}}\) The oil sands produced obvious tensile fractures or shear fractures after...
hydraulic fracturing, and the seepage channels increased, leading to a significant increase in the permeability of oil sands, indicating that the hydraulic fracturing produced a permeability enhancement effect on the oil sands. The increases in permeability at $\sigma_2 = 6, 7, 8, 9,$ and $10$ MPa are reaching $739.93\%$, $710.56\%$, $725.46\%$, $646.46\%$, and $578.03\%$, respectively, which implies that the increase in intermediate principal stress decreases the increasing effect of permeability. From Section 3.2, hydraulic fracturing produces shear fractures inside the oil sands under the low intermediate principal stress condition, and as the intermediate principal stress increases, it will cause hydraulic fracturing to produce a transform from shear fractures to tensile fractures inside the oil sands due to the decrease in the principal stress difference ($\sigma_1 - \sigma_2$), so the influence of shear fractures on the increase in permeability is greater than that of tensile fractures. The fracture caused by tensile failure is along the direction of nitrogen injection, and the permeability increase is limited. And when the stress difference action causes shear fracture to develop, the angle between the fracture and the nitrogen injection direction is increased with a complex seam network generation within the oil sands and the permeability increase is more obvious. Therefore, in the hydraulic fracturing construction design of field reservoir, the high-pressure water injection direction is suggested to set to be along the intermediate principal stress direction, which is able to produce the largest principal stress difference ($\sigma_1 - \sigma_2$), and the hydraulic fracture expansion direction will be deflected under the action of the principal stress difference, producing macroscopic shear fractures and the best permeability enhancement effect.

4 | CONCLUSION

In order to study the fracture expansion behavior and permeability enhancement effect of oil sand reservoir under hydraulic fracturing with high temperature, this study conducted an experimental study of large-scale high-temperature hydraulic fracturing of oil sand reservoir under different intermediate principal stress conditions, the pressure sensors were arranged in three profiles inside the oil sands to reflect the internal fluid pressure changes, the permeability tests were conducted before and after hydraulic fracturing, and the main conclusions of this study are as follows:

1. As the $\sigma_2$ increases, the hydraulic breakdown pressure in the oil sands also increases. This is due to the increase in $\sigma_2$ limits the lateral expansion of the oil sands during the water injection and pressurization, and the effective stress decreases during the fluid injection, which is equivalent to the stress unloading effect, and the increase in the $\sigma_2$ weakens this unloading effect in the $\sigma_2$ direction, which finally limits the expansion of the hydraulic fractures and leads to the increase in the breakdown pressure. A new breakdown pressure prediction model of oil sands considering true triaxial stress condition is established, which shows a good prediction effect with the experiment results.

2. The fractures generated by hydraulic fracturing cause high-pressure fluid to flow into them, resulting in significant changes in fluid pressure inside the oil sands. Since the flow of high-viscosity fluid (water) into the main fracture lagged the expansion of the fracture tip, forming a fluid hysteresis zone, so the fluid pressure distribution inside the fracture is not completely uniform, resulting in the fluid pressure change lagging behind the injection pressure change. Under the low intermediate principal stress conditions, the direction of fracture expansion is deflected due to the principal stress difference ($\sigma_1 - \sigma_2$), and eventually shear fractures are formed, while on the contrary, tensile fractures are formed under high intermediate principal stress conditions.
3. The oil sands are hydraulically fractured to form obvious tensile fractures or shear fractures, resulting in the significant permeability enhancement. The effect of shear fractures on permeability enhancement is greater than that of tensile fractures. Therefore, in the hydraulic fracturing construction design in the field reservoir, it is better to set the high-pressure water injection along the intermediate principal stress direction, which will produce the maximum principal stress difference \( (\sigma_1-\sigma_3) \), and the hydraulic fracture extension direction will be deflected under the action of the principal stress difference, producing macroscopic shear fractures and the best permeability enhancement effect.

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ETHICAL APPROVAL

It is not relevant to my work.

DATA AVAILABILITY STATEMENT

The experimental data supporting the conclusions are available from the corresponding author on request.

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