Numerical and Experimental Simulation of Hydraulic Fracture Propagation Mechanism in Conglomerate Formation Based on Hybrid Finite-Discrete Element Method

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Abstract: Hydraulic fracturing was the main technology to achieve the economic development of conglomerate reservoirs, knowing that the hydraulic fracture propagation mode was of great significance for improving the development of conglomerate reservoirs. This paper proposed a new method to understand the hydraulic fracture behavior based on a hybrid finite-discrete element method. The simulation indicated that a complex fracture network was created near the wellbore in the studied conglomerate reservoir, and hydraulic fracture propagation around the gravel layer was the main failure mode when the hydraulic fracture reached the gravel layer. From the simulations, it was shown that under small differences in horizontal stress and tensile strength, the hydraulic fracture propagated more easily around the gravel layer, while it could cross the gravel under large differences in horizontal stress and tensile strength. Greater tensile strength differences can reduce the complexity of the fracture network. In addition, higher pumping rates and viscosities of fracturing fluid contribute to the complex fracture network and also can produce more gravel crosses when the hydraulic fracture is met. The main reason was that a higher pumping rate and higher viscosity of fracturing fluid can obtain a higher net pressure, which can ensure the hydraulic fracture crosses the gravel layer.

Keywords: hydraulic fracture; failure mode; gravel; horizontal stress; tensile strength

1. Introduction

Conglomerate reservoirs, as an important component of the oil and gas supply, have an important role in guaranteeing economic development [1,2]. Due to their low permeability and porosity, hydraulic fracturing has been the predominant technology for economic development [3,4]. Because of the serious heterogeneity caused by the gravel layer, the hydraulic fracture propagation mechanism is quite different from that in shale formation and sandstone formation.

To understand the fracture propagation mechanism, some scholars have conducted experiments and numerical simulations to understand the multi-fracture propagation law, the interaction mechanism between natural fractures and hydraulic fractures, and the interaction mechanism between hydraulic fracture and bedding planes [5–8]. Based on experimental simulations, Liu [9,10] and Luege [11] investigated the interaction mechanism between natural fractures and hydraulic fractures. They found that the horizontal stress difference and approach angle are the controlling factors affecting fracture propagation, increasing the pumping rate and viscosity of the fracturing fluid can effectively promote hydraulic fractures across natural fractures, and that a low pumping rate and viscosity of the fracturing fluid can increase the stimulated volume. Ren [12], Zhang [13], Zheng [14,15] and Zou [16,17] proposed a new numerical simulation method to understand the influence of horizontal stress differences, approach angle, pumping rate and viscosity of fracturing fluid on fracture propagation. From the simulations, it was indicated that large stress differences and approach angles were adverse to the fracture network. When the stress...
difference was larger than 14 MPa, and the approach angle was over 60°, the natural fractures could not contribute to the formation of a complex fracture network. In addition, a low pumping rate and viscosity of the fracturing fluid favored creation of a complex fracture network, and a high pumping rate and viscosity of the fracturing fluid made it easier for a hydraulic fracture to cross a natural fracture. In shale formation, the bedding plane is another factor affecting fracture propagation in the vertical direction [18–20]. Simulations indicated that large stress differences could prevent a hydraulic fracture from propagating in the vertical direction, and it would be arrested by the bedding plane, while a low pumping rate and viscosity of the fracturing fluid could promote the hydraulic fracture arrested by the bedding plane, which was good for the creation of a complex fracture network. Meanwhile, a high pumping rate and viscosity of the fracturing fluid could enable a hydraulic fracture to cross the bedding plane.

From the current studies cited above, it can be concluded that the formation was a homogeneous reservoir or the difference in rock mechanical strength was very low, which could effectively describe the change in shale or tight sandstone when the numerical simulations were conducted to investigate fracture propagation. However, because the numerical models are hardly able to describe the fracture propagation due to the existence of gravel layers, it is necessary to propose a new method to describe hydraulic fracture propagation in a conglomerate reservoir. Based on the experiments and simulations, the effect of gravel on fracture propagation was discussed, a numerical model for conglomerate formation based on a hybrid finite-discrete element method was proposed, and the fracture propagation mode was analyzed.

2. Experiment

In the experiment, a cube conglomerate rock with size of 300 mm × 300 mm × 300 mm was created, and a wellbore with diameter of 12 mm and length of 158 mm was located in the center of the rock sample. The load on Sample 1 comprised a maximum horizontal principal stress and minimum horizontal principal stress of 14 MPa and 8 MPa, respectively, while the vertical stress was 20 MPa; the load on Sample 2 comprised a maximum horizontal principal stress and the minimum horizontal principal stress of 14 MPa and 12 MPa, respectively, while the vertical stress was 20 MPa. The viscosity of the hydraulic fracturing fluid was 1.0 mPa·s, and the injection rate was 50 mL/min.

Before the experiment, the Young’s modulus and Poisson’s rate were measured to guarantee the rock mechanical properties of the samples were the same. From the measurements, the Young’s modulus and Poisson’s rate for Sample 1 were 34.2 GPa and 0.281, respectively, and for Sample 2, 34.7 GPa and 0.274, respectively, indicating that the rock mechanical properties of the samples were the same. Figure 1 shows the fracture distribution in the conglomerate rock. The experimental results indicated that the created fracture network was much more complex in Sample 2 compared with Sample 1, and the hydraulic fracture more easily deviated from the gravel when it came across the gravel layer; only when the size of the gravel was small enough could the hydraulic fracture cross the gravel layer. The effect of gravel size, stress field and injection rate on fracture propagation should be further studied by numerical simulation.

Figure 2 shows the injection pressure change with time. As indicated in Figure 2, the injection pressure experienced a sharply increase when more branch fractures were created. As indicated in Figure 2, the breakdown pressure and extension pressure of Sample 1 were 15.36 MPa and 12.41 MPa, while they increased to 17.29 MPa and 14.36 MPa, increasing by 12.57% and 15.71%, respectively. In addition, the change in injection pressure also indicated that a great fluctuation had taken place compared with Sample 1. From the comparison, it can be found that with the increase in branch fractures, the breakdown pressure and extension pressure had an obvious increase, and the injection pressure also experienced a great fluctuation. Thus, a complex fracture network created near the wellbore can increase the breakdown pressure and extension pressure in hydraulic fracturing. To deep dig the
fracture propagation mechanism in conglomerate formation, a numerical model based on the hybrid finite-discrete element method was created.

![Image of hydraulic fractures](image1.png)

(a) Sample 1

![Image of hydraulic fractures](image2.png)

(b) Sample 2

**Figure 1.** Hydraulic fracture distribution of Sample 1 and Sample 2 under different stress fields. (a) Stress difference was 4 MPa; (b) Stress difference was 4 MPa.

**Figure 2.** Injection pressure change in Sample 1 and Sample 2.

![Injection pressure change graph](image3.png)

**Figure 2.** Injection pressure change in Sample 1 and Sample 2.
3. Numerical Simulation

3.1. Governing Equation

To quantitatively characterize the hydraulic fracture propagation characteristics in a conglomerate reservoir, a hybrid finite-discrete element method was introduced to simulate the hydraulic fracture propagation. The distribution of gravel was generated by the Monte Carlo method.

In the simulation, the relationship between stress and strain can be described as follows:

\[ \sigma_{ij} + b_i - \rho u_{i,t} - \alpha u_{i,t} = 0 \]  \hspace{1cm} (1)

\[ \sigma_{ij} = D_{ijst} \varepsilon_{st} \]  \hspace{1cm} (2)

\[ \varepsilon_{ij} = \frac{1}{2} (u_{ij} + u_{ji}) \]  \hspace{1cm} (3)

where \( \sigma_{ij} \) is the Cauchy tensor; \( b_i \) is the body force; \( \rho \) is the density of rock; \( \alpha \) is the damping coefficient; \( u_i \) is the displacement; \( \varepsilon_{ij} \) is the strain; \( D_{ijst} \) is the Hooke tensor.

Due to the plastic characteristics of the reservoir, it was obviously inappropriate to consider the model of rock brittleness only. Therefore, the finite element method was used to solve the block deformation in the model, and then the matrix method was used to calculate the nonlinear problem in the stress space. Firstly, the plastic criterion was used to judge whether a certain element enters the plastic deformation stage. If the criterion was met, the stress of the element was corrected, and the Drucker–Prager criterion was used to describe the failure of rock.

\[
\begin{cases}
\Delta \varepsilon_i = B_i \Delta u_e \\
\Delta \sigma_i = D \Delta \varepsilon_i \\
\sigma^n_i = \sigma^{n-1}_i + \Delta \sigma_i \\
F^n_e = \sum_{i=1}^{N} B^T \sigma^n_i w_i J_i
\end{cases}
\]  \hspace{1cm} (4)

where \( B_i \) is the matrix of strain; \( \sigma^{n}_i \) is the stress of the current step; \( \sigma^{n-1}_i \) is the stress of the previous step; \( F^n_e \) is the load of element node; \( w_i \) is the weight function; \( J_i \) is the Jacobi matrix.

During the simulation, the fluid flow within the fracture is described as follows:

\[ q = -\frac{w^3}{12\mu} \frac{\partial p}{\partial s} \]  \hspace{1cm} (5)

Additionally, the local continuity equation in the fracture is described as

\[ \frac{\partial w}{\partial t} + \frac{\partial q}{\partial s} + q_l = 0 \]  \hspace{1cm} (6)

The global mass conservation equation can be stated as

\[ Q_0 = \int_{\Omega} \frac{\Delta w}{\Delta t} ds + \int_{\Omega} q_l ds \]  \hspace{1cm} (7)

where \( p \) is the fluid pressure; \( w \) is the fracture width; \( t \) is time; \( q \) is the volume flow; \( q_l \) is the filtration loss of the fracturing fluid.

Due to the injection of fracturing fluid, the pressure at the perforation had a great increase, and the elements had a tensile failure or shear failure, namely the maximum principal stress reached the tensile strength of the rock, and a tensile failure occurred, or the Mohr–Coulomb criterion was met, and the shear failure occurred. The failure criterion is demonstrated as follows:

\[ -\sigma_l > \sigma_T \]  \hspace{1cm} (8)
\[ |\tau| > \tau_0 + \tan \phi \sigma''_n \]  

(9)

where \( \sigma_i \) is the maximum principal stress; \( \sigma_T \) is the tensile strength of the rock; \( \tau_0 \) is the cohesion strength of the rock.

In this simulation, the Monte Carlo method was used to describe the distribution of gravels, and the diameter of the gravels was described by exponential distribution.

\[
f(x) = \begin{cases} \frac{1}{2a} & x - a \leq x \leq x + a \\ 0 & \text{otherwise} \end{cases}
\]

(10)

\[
n(l, L) = \alpha L^D w L^{-\alpha}
\]

(11)

According to the fluid mass balance, at a certain period, part of the injected fluid fills the fracture, and the rest is lost to the rock matrix, as shown in the following equation:

\[
\frac{\partial d}{\partial t} + \nabla \cdot q (q_t + q_b) = q_{inj} \delta(x, y)
\]

(12)

Then, the control equation of rock matrix involves coupling fluid flow and rock deformation, as follows:

\[
\sigma_{ij} - \sigma''_{ij} = \frac{E}{1+v} \left( \epsilon_{ij} + \frac{2v}{1+2v} \epsilon_{kk} \delta_{ij} \right) - \alpha \left( p_w - p_w^0 \right) \delta_{ij}
\]

(13)

Figure 3 was the flowchart of the fluid–solid coupling approach. In order to avoid errors caused by mesh size, the mesh size was firstly optimized. According to the experimental results of Zhang et al., a hydraulic fracturing model with the same size and the same stress field as Zhang et al.’s experimental model was established in the study to simulate the changes in fracture pressure and fracture extension pressure in the process of hydraulic fracturing. According to the experimental results, when the stress field is 12 MPa–10 MPa–8 MPa and the injection rate is 30 mL/min, the breakdown pressure of the reservoir rock is 31.97 MPa, and the fracture extension pressure is 9.7 MPa. In the process of simulation, mesh sizes were set as 5 mm, 2 mm, 1 mm, 0.5 mm and 0.1 mm, respectively. Through simulation, it was found that with the reduction in mesh size, the breakdown pressure of the reservoir was closer to the experimental value. When the mesh size was 1mm, the breakdown pressure of reservoir rock was 31.84 MPa, and the error from the experimental value was only 0.13 MPa. The fracture extension pressure was 9.64 MPa, and the error was 0.06 MPa. When the mesh size was 0.5 mm and 0.1 mm, the errors between experimental and simulated values were further reduced. When the mesh size was 0.5 mm, the errors of breakdown pressure and extension pressure of the reservoir rock were 0.09 MPa and 0.05 MPa, respectively. When the mesh size was 0.1 mm, the errors of breakdown pressure and extension pressure of the reservoir rock were 0.07 MPa and 0.04 MPa, respectively. As can be seen from Figure 4, when the mesh size was 1 mm, the calculated results tended to be stable, and the error with the experimental value met the accuracy requirement. Combined with computational efficiency, the grid size was selected as 1 mm in the study.

3.2. Simulation Results and Discussion

In the simulation, a 2D simulation model with a size of 400 m × 200 m was established, and the injection point was located in the center of the model, the maximum horizontal principal stress and minimum horizontal principal stress were 80 MPa and 70 MPa, respectively. The basic parameters of the model are shown in Table 1. In addition, the stress field was calculated with the logging data, and the mechanical properties of rock matrix and gravel were decided on the basis of logging data and mechanical experiments. In the simulation, we defined the percentage of gravels that were crossed as the ratio between the number of gravels that were crossed and the total.
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3.2.1. Horizontal Stress Difference

To understand the effect of horizontal stress differences on fracture propagation, horizontal stress differences of 6 MPa, 10 MPa, 14 MPa and 18 MPa (the stress difference coefficients were 0.075, 0.125, 0.175, and 0.225) were simulated and analyzed, and the simulation results were as shown in Figures 5 and 6. As can be seen from the simulation, the stimulated area decreased with the increase in stress difference. Moreover, the hydraulic
fracture more easily propagated around the gravel when it reached the gravel under the low stress difference. When the stress difference was 6 MPa, three dominant fractures were created above the injection point, and two dominant fractures were created below the injection point. In addition, the five fractures were all propagated around the gravel when they reached the gravel. When the stress difference increased to 10 MPa, two dominant fractures were created above the injection point, and two dominant fractures were created below the injection point. In addition, the complexity of the fractures decreased obviously compared with that when the stress difference was 6 MPa. Under these circumstances, the hydraulic fracture still propagated around the gravels; only some fractures crossed the gravels near the injection point. When the stress difference increased to 14 MPa, the complexity of fractures continued to decrease compared with that when the stress difference was 10 MPa. In the stimulated area, the percentage of gravels that were crossed increased to 8.4% from 2.7% when the stress difference was 10 MPa, increasing by 211.11%. When the stress difference increased to 18 MPa, the stimulated area had an obvious decrease, and the percentage of gravels that were crossed increased to 10.2%.

Figure 5. Numerical simulation of hydraulic fracture under different stress differences. (The Red represent gravel, the black point represent the injection point).

Figure 6. Net pressure distribution in hydraulic fracture under different stress differences.

From the analysis above, it can be seen that propagation around the gravel was the main failure mode of the conglomerate formation; the horizontal stress difference and tensile strength were the two main factors affecting the failure mode. From the simulations, the stimulated areas were 3640 m², 2090 m², 1820 m², and 1140 m². Under high stress differences, the stimulated volume by hydraulic fracturing was obviously decreased with
the increase in stress difference. When the stress difference was less than 14 MPa, a complex fracture network was created when the horizontal stress differences were 6 MPa and 10 MPa, and the percentage of gravels that were crossed was only 1.4% and 2.3%, respectively. When the horizontal stress difference increased to 14 MPa and 18 MPa, the area of the complex fracture network experienced an obvious decrease, and the percentage of gravels that were crossed increased to 8.4% and 10.2%, respectively.

Table 1. Basic input parameters of the model.

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<tr>
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<td>Minimum horizontal principal stress</td>
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<tr>
<td>Properties of gravel</td>
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<td>GPa</td>
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<td>Viscosity of fracturing fluid</td>
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3.2.2. Tensile Strength

To further understand the effect of tensile strength differences on fracture propagation, the tensile strengths of gravel of 7.4 MPa, 8.4 MPa, 9.4 MPa and 10.4 MPa were analyzed. As indicated in Figures 7 and 8, with the increase in the tensile strength of gravel, the complexity of the fractures obviously decreased. As indicated in Figure 4, when the tensile strength was 7.4 MPa, which meant that the tensile strength difference between gravel and matrix was 1.11 MPa, a complex fracture network was created near the injection point, and five predominant fractures were created in the far-field zone. When the tensile strength of the gravel was 8.4 MPa and the tensile strength difference between gravel and matrix increased to 2.11 MPa, the simulation indicated that a complex fracture network was created near the injection point, while only four predominant fractures were created in the far-field zone. Compared with the scenario when tensile strength was 7.4 MPa, the percentage of gravels that were crossed increased from 1.3% to 2.7%. When the tensile strength of the gravel increased to 9.4 MPa, more gravels were crossed near the injection point, accounting for 8.9% of the total gravels in the stimulated area. Meanwhile, only two predominant fractures were created in this model. When the tensile strength increased to 10.4 MPa, the complex degree of the fracture network had an obvious decrease, and the percentage of gravels that were crossed increased to 13.7%. The simulation results indicated that with the increased difference in tensile strength between gravel and matrix, the hydraulic fracture more easily propagated around the gravel, and the complex degree of the fracture network had an obvious decrease.

3.2.3. Pumping Rate

To understand the influence of pumping rate on hydraulic fracture propagation, the effects of pumping rates of 2.0 m³/min, 4.0 m³/min, 6.0 m³/min and 8.0 m³/min on
fracture propagation were simulated. The simulation results (as shown in Figures 9 and 10) indicated that when the pumping rate was 2.0 m$^3$/min, only three fractures were created near the wellbore, and one main fracture propagated in the far-field zone. When the pumping rate was increased to 4.0 m$^3$/min, the number of hydraulic fractures experienced a slight increase, with four hydraulic fractures created near the wellbore and one main fracture propagated in the far-field zone. When the pumping rate was increased to 6.0 m$^3$/min, the number of hydraulic fractures experienced a dramatic increase, with five hydraulic fractures created near the wellbore and three main fractures propagated in the far-field zone. When the pumping rate was increased to 8.0 m$^3$/min, six hydraulic fractures were created near the wellbore, and four main fractures propagated in the far-field zone. Increasing the pumping rate also could promote hydraulic fractures across the gravel. From the simulations, only 4.3% of gravels were crossed when the hydraulic fracture met the gravels under a pumping rate of 2.0 m$^3$/min, and it increased to 5.7% when the pumping rate was increased to 4.0 m$^3$/min. When the pumping rate was continuously increased to 6.0 m$^3$/min, the ratio of gravels that were crossed by hydraulic fractures increased to 8.7%, and it dramatically increased to 11.4% when the pumping rate was increased to 8.0 m$^3$/min. The simulations indicated that a high pumping rate was another factor affecting complex fracture network generation. When the pumping rate was higher than 4.0 m$^3$/min, a complex fracture network was generated near the wellbore, and the ratio of gravels that were crossed by hydraulic fractures also experienced a dramatic increase.

![Numerical simulation of hydraulic fracture under different tensile strengths.](image)

**Figure 7.** Numerical simulation of hydraulic fracture under different tensile strengths. (The Red represent gravel, the black point represent the injection point).

![Net pressure distribution in hydraulic fracture under different tensile strengths.](image)

**Figure 8.** Net pressure distribution in hydraulic fracture under different tensile strengths.

3.2.4. Viscosity of Fracturing Fluid

The viscosity of the fracturing fluid is another factor affecting hydraulic fracture propagation in a conglomerate formation. To understand the influence of hydraulic fracturing fluid on fracture propagation, the effects of fracturing fluids with viscosities of 1.0 mPa·s,
5.0 mPa·s, 20.0 mPa·s, and 50.0 mPa·s on hydraulic fracture propagation were simulated. The simulations (as shown in Figures 11 and 12) indicated that a complex fracture network with five fractures was created near the wellbore when the fracturing fluid viscosity was 1.0 mPa·s, and two main fractures were propagated in the far-field zone. When the viscosity of the fracturing fluid was increased to 5.0 mPa·s, the simulation results were the same as those when the fracturing fluid was 1.0 mPa·s. When the viscosity of the fracturing fluid was increased to 20.0 mPa·s, great changes took place in that only three predominant fractures were created near the wellbore, and two main fractures were created in the far-field zone. When the viscosity of the fracturing fluid was increased to 50.0 mPa·s, only two hydraulic fractures were created near the wellbore, and they could propagate in the far-field zone. Increasing the viscosity of the fracturing fluid also had a great effect on the failure mode of conglomerate formation. When the viscosity of the fracturing fluid was 1.0 mPa·s, only 2.3% of gravels were crossed by hydraulic fractures. When the viscosity of the fracturing fluid was 5.0 mPa·s showed a tendency toward that same percentage when the viscosity of the fracturing fluid was 1.0 mPa·s. When the viscosity of the fracturing fluid was increased to 20.0 mPa·s, the percentage of gravels crossed by hydraulic fractures increased to 7.9%, then continuously increased to 10.6% when the viscosity of the fracturing fluid was increased to 50.0 mPa·s. The simulations above indicated that high viscosities of fracturing fluid can promote hydraulic fracture propagation into the far-field zone and force hydraulic fractures across the gravel. The main reason was that high-viscosity fracturing fluids can reduce the leak-off of fracturing fluid to the matrix, thus the net pressure in the fracture can be guaranteed. High net pressure can ensure that a hydraulic fracture crosses the gravel.

![Figure 9](image1.png)

*Figure 9.* Numerical simulation of hydraulic fracture under different pumping rates. (The Red represent gravel, the black point represent the injection point).

![Figure 10](image2.png)

*Figure 10.* Net pressure distribution in hydraulic fracture under different pumping rates.
was similar, the hydraulic fractures could extend in several different directions; thus, more gravels were crossed during the hydraulic fracturing, but decreased greatly. When the cohesion strength of gravel increased to 62.12 MPa, only one fracture was created. From the simulations, it can be concluded that many more propagation trajectories were created when the cohesion strength differences between gravel and matrix were low. The main reason was that because the energy consumption was similar, the hydraulic fractures could extend in several different directions; thus, more main fractures and induced fractures could be created. However, hydraulic fractures could only propagate around the gravel under high cohesion strength differences between the gravel and matrix, because the energy consumption was relatively low.

3.2.5. Cohesion Strength

To understand the influence of differences in cohesion strength on fracture propagation, the cohesion strengths of gravel at 43.12 MPa, 50.12 MPa, 56.12 MPa and 62.12 MPa were analyzed. From the simulations (Figures 13 and 14), a complex fracture network was created when the cohesion strength of gravel was 43.12 MPa, and four predominant fractures were formed below the injection point. When the cohesion strength of gravel increased to 50.12 MPa, three main fractures were created. When the cohesion strength of gravel increased to 50.12 MPa, three main fractures were created. When the cohesion strength of gravel climbed to 56.12 MPa, only two main fractures were created, and the stimulated area decreased greatly. When the cohesion strength increased to 62.12 MPa, only one fracture was created in the simulation. It was also noticed that with the increase in cohesion strength, the percentage of gravel that was crossed showed a sharp decrease. When the cohesion strength was 43.12 MPa, 64.14% gravels were crossed during the hydraulic fracturing, but decreased to 2.3% when the cohesion strength increased to 56.12 MPa and decreased to 1.4% when the cohesion strength was 62.12 MPa. From the simulations, it can be concluded that many more propagation trajectories were created when the cohesion strength differences between gravel and matrix were low. The main reason was that because the energy consumption was similar, the hydraulic fractures could extend in several different directions; thus, more main fractures and induced fractures could be created. However, hydraulic fractures could only propagate around the gravel under high cohesion strength differences between the gravel and matrix, because the energy consumption was relatively low.

Figure 11. Numerical simulation of hydraulic fracture under different viscosities of fracturing fluid. (The Red represent gravel, the black point represent the injection point).

Figure 12. Net pressure distribution in hydraulic fracture under different viscosities of fracturing fluid.
(The Red represent gravel, the black point represent the injection point).

area decreased greatly. When the cohesion strength increased to 62.12 MPa, only one fracture was created in the simulation. It was also noticed that with the increase in cohesion strength, the percentage of gravel that was crossed showed a sharp decrease. When the cohesion strength was 43.12 MPa, 64.14% gravels were crossed during the hydraulic fracturing and cohesion strength on fracture propagation, and the conclusions were drawn as follows:

(1) A complex hydraulic fracture network formed near the injection point was the main characteristic when the hydraulic fracturing was performed in the conglomerate formation, and some predominant fractures were created in the far-field zone.

(2) A formation with low cohesion strength between gravel and matrix, stress differences and high tensile strength was beneficial for complex fracture network formation. Moreover, a high pumping rate and high viscosity of the fracturing fluid can improve the complexity of the hydraulic fracture network.

(3) Many more hydraulic fracture trajectories develop in homogeneous formations than in heterogeneous formations. The main reason is that because the energy consumption is similar in homogeneous formations, hydraulic fractures can extend in several different directions, thus creating more main fractures and induced fractures. However, hydraulic fractures can only propagate around the gravel under large differences in cohesion strength between the gravel and matrix, because the energy consumption is relatively low.

(4) Propagating around the gravel was the main failure mode when a hydraulic fracture came across the gravel. With the increase in net pressure in the hydraulic fracture, more

Figure 13. Numerical simulation of hydraulic fracture under different cohesion strengths of gravel. (The Red represent gravel, the black point represent the injection point).

Figure 14. Net pressure distribution in hydraulic fracture under different cohesion strengths of gravel.

4. Conclusions

To understand the propagation mechanism of hydraulic fractures in a conglomerate formation, experimental and numerical simulations were conducted to discover the effect of horizontal stress differences, tensile strength, pumping rate, viscosity of hydraulic fracturing and cohesion strength on fracture propagation, and the conclusions were drawn as follows:

(1) A complex hydraulic fracture network formed near the injection point was the main characteristic when the hydraulic fracturing was performed in the conglomerate formation, and some predominant fractures were created in the far-field zone.

(2) A formation with low cohesion strength between gravel and matrix, stress differences and high tensile strength was beneficial for complex fracture network formation. Moreover, a high pumping rate and high viscosity of the fracturing fluid can improve the complexity of the hydraulic fracture network.

(3) Many more hydraulic fracture trajectories develop in homogeneous formations than in heterogeneous formations. The main reason is that because the energy consumption is similar in homogeneous formations, hydraulic fractures can extend in several different directions, thus creating more main fractures and induced fractures. However, hydraulic fractures can only propagate around the gravel under large differences in cohesion strength between the gravel and matrix, because the energy consumption is relatively low.

(4) Propagating around the gravel was the main failure mode when a hydraulic fracture came across the gravel. With the increase in net pressure in the hydraulic fracture, more
gravel were crossed by the hydraulic fracture. In addition, larger differences in tensile strength between the gravel and rock matrix enabled hydraulic fractures to propagate much more easily around the gravel.

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**References**


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