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ORIGINAL PAPER

Numerical simulation of hydraulic fracture propagation in tight oil reservoirs by volumetric fracturing

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Abstract Volumetric fracturing is a primary stimulation technology for economical and effective exploitation of tight oil reservoirs. The main mechanism is to connect natural fractures to generate a fracture network system which can enhance the stimulated reservoir volume. By using the combined finite and discrete element method, a model was built to describe hydraulic fracture propagation in tight oil reservoirs. Considering the effect of horizontal stress difference, number and spacing of perforation clusters, injection rate, and the density of natural fractures on fracture propagation, we used this model to simulate the fracture propagation in a tight formation of a certain oilfield. Simulation results show that when the horizontal stress difference is lower than 5 MPa, it is beneficial to form a complex fracture network system. If the horizontal stress difference is higher than 6 MPa, it is easy to form a planar fracture system; with high horizontal stress difference, increasing the number of perforation clusters is beneficial to open and connect more natural fractures, and to improve the complexity of fracture network and the stimulated reservoir volume (SRV). As the injection rate increases, the effect of volumetric fracturing may be improved; the density of natural fractures may only have a great influence on the effect of volume stimulation in a low horizontal stress difference.

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1 Introduction

Due to ultralow matrix permeability, multistage fracturing of horizontal wells is recognized as the main stimulation technology for an economical and effective approach to recover oil and gas from tight reservoirs (Zhao et al. 2012; Li et al. 2013). The main mechanism (King 2010) is to open natural fractures and expand them until shear sliding occurs in the process of hydraulic fracturing. The multi-stage, multi-perforation clusters per fracturing treatment in a horizontal wellbore and the natural fractures may create a fracture network system that may enhance the stimulated reservoir volume (SRV) and improve both the initial production and the ultimate recovery factor (Mayerhofer et al. 2008; Cipolla et al. 2009). There are many factors which influence the fracture propagation, like the horizontal stress difference, density of natural fractures, injection rate, number of perforation clusters, and the spacing of clusters (Yost et al. 1988; Palmer et al. 2007; Cipolla et al. 2011; Olson and Wu 2012).

Many researchers have studied the complex propagation of hydraulic fractures induced by volumetric fracturing with different numerical simulation approaches. Dahi-Taleghani and Olson (2009), Dahi-Taleghani (2010) and Keshavarzi et al. (2012) used a two-dimensional finite element method to simulate the complex fracture propagation. In this model, a uniform and constant net pressure is loaded on the surface of the hydraulic fractures. Olson (2008) and Olson and Dahi-Taleghani (2009) presented a pseudo-three-dimensional complex fracture network model based on the displacement discontinuity method, which considered the injection of non-Newtonian fluids, Carter filtration, random non-planar propagation and fracture height extension in three layers. Zhao and Young (2009) used a two-dimensional particle discrete element method, where the model consists of cohesive particles and pore space between these particles. The pore pressure will increase with the injection of the fracturing fluid, and it will remove the cohesion between particles. The simulated natural fractures are non-cohesive or weakly cohesive. Nagel et al. (2011) and Zangeneh et al. (2012) used a discrete element method to simulate the complex fracture network system. In this model, the rock mass is divided by multiple joints. The fractures only propagate along the joint network. No new hydraulic fractures occur and grow except the initial natural fractures. In recent years, the simulation technology of a complex fracture network has been developed, which combines with a micro-seismic imaging system to represent the complexity of hydraulic fractures. There are two primary models. One is the wire mesh model (Xu and Ghassemi 2009; Xu et al. 2010; Meyer and Bazan 2011), which can effectively simulate the complexity of fractures and the spacing between perpendicular fractures; another one is the unconventional fracture model (Weng et al. 2011), which describes complex geological conditions and evaluates the propagation of complex fractures more strictly. However, the extended finite element and boundary element method may not apply various hydraulic pressures on the fracture surface, and also does not consider the impact of seepage and leak off of fracturing fluids; the discrete element method restricts the path of hydraulic fractures.

In this study, we use a mixed finite element and discrete element method to build a model for predicting propagation of fractures induced by volumetric fracturing in a tight oil reservoir. By using this model, we mainly examine the impact of horizontal stress difference, number and spacing of perforation clusters, injection rate, and density of natural fractures on fracture patterns. This research may have a significant effect on future hydraulic fracturing design of tight oil reservoirs.

2 Numerical simulation and analysis

2.1 Fracture propagation model

The rock deformation is based on a linear elastic fracture mechanism. The governing equation consists of a stress equilibrium equation and a fracturing fluid flow equation (continuity equation). In this model, the coupling of fluid flow in fractures and rock deformation of the matrix block is based on the continuum discrete element method. The domain is discretized into many matrix blocks, which are linked by virtual springs. The breakage of a spring represents the failure of the rock. There is a fracture element between two blocks to calculate the flow of fracturing fluids and the distribution of the hydraulic pressure. As an external load, the hydraulic pressure will be applied on the surface of fractures. We use the finite element method to solve the deformation of continuous blocks, and use the discrete element method to solve the breakage of springs. The spring breakage is based on the maximum tensile stress criterion and the Mohr–Coulomb criterion. Figure 1 indicates the calculation model. Due to the ultralow matrix permeability of tight oil reservoirs, the seepage and leak off of fracturing fluids can be ignored. This model mainly considers some key parameters, including rock mechanical properties, in situ stress, reservoir pressure, natural fracture characteristics, injection rate, and the fracturing fluid viscosity.

The key point of the successful volumetric fracturing is to connect the natural fractures in the reservoir. Many studies show that the horizontal stress difference is the major geological factor contributing to form a complex fracture network system. Laboratory fracturing experiments (Blanton 1982; Warpinski and Teufel 1987; Gu and Weng 2010) indicate that a horizontal stress difference of lower than 4 MPa is beneficial to open the natural fractures and form complex fractures; and a horizontal stress difference of higher than 8 MPa is unsuitable for opening the natural fractures, it is easier to form a planar fracture. 4–8 MPa is the transition zone from complex fractures to planar fractures.

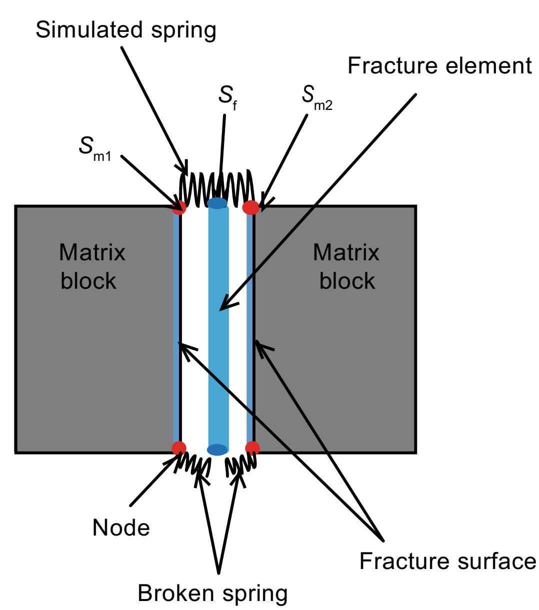

Fig. 1 Sketch of calculation model

By using the real reservoir data and fracturing parameters, we simulated the volumetric fracturing in a tight oil formation of a certain oilfield, and examined the impact of the horizontal stress difference, linear density of natural fractures, number and spacing of perforation clusters on fracture patterns. Figure 2 shows the model of a horizontal well with single-stage fracturing and 4 perforation clusters. The horizontal well trajectory is perpendicular to the maximum horizontal stress. The creation of the natural fractures is from random sampling. The angle of natural factures is real reservoir data, which varies from 0 to 30° oriented to the maximum horizontal stress.

2.2 Calculation of the stimulated reservoir volume (SRV)

The conception of the SRV is presented by Mayerhofer et al. (2008). According to the production data from the Barnett shale gas, the bigger the volume of the fracture network, the better the effect on production after fracturing. The primary calculation method for the SRV is to divide the micro-seismic monitor data into several blocks, which are presented as bands, and to add up the volume of all blocks, shown as Fig. 3. For ease of calculation, the calculation of the SRV can be simplified as the calculation of the stimulated reservoir area (SRA), which is a permeability enhanced area. In that case, the solution can be the calculation of any closed region. The main calculation method includes the ellipse method, boundary analytical method, and the probability method. In this study, we use the ellipse method to calculate the stimulated reservoir area, shown as Fig. 4. We only accumulate the effective closed region area of the fracture network, which is connected the fracture network, as the part of the stimulated reservoir area. The single plane fractures cannot be

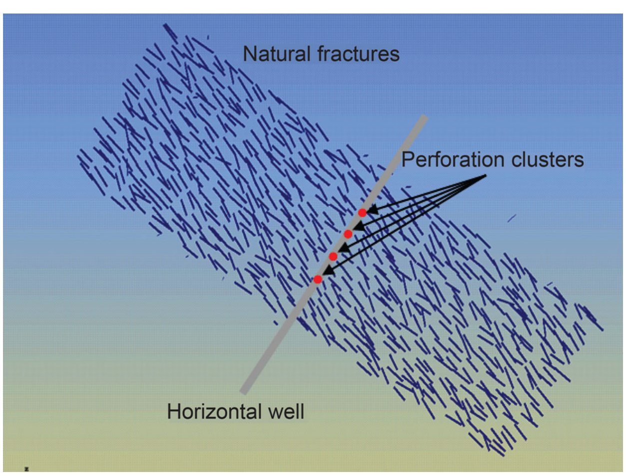

Fig. 2 Single-stage fractured horizontal well with 4 perforation clusters

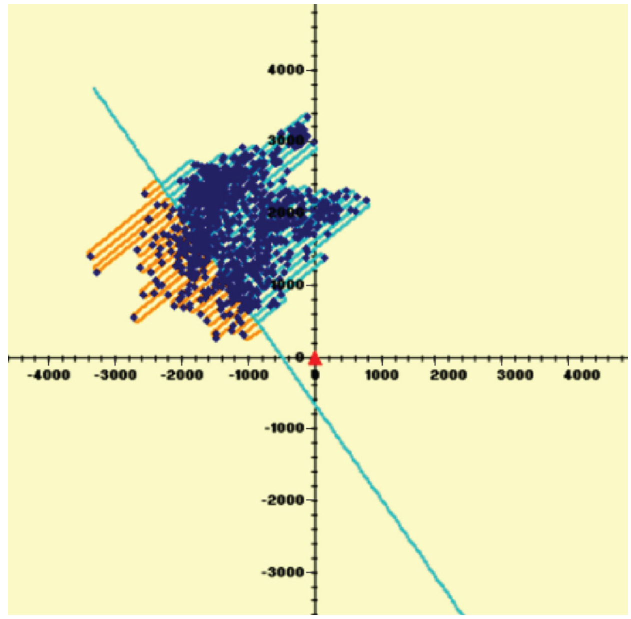

Fig. 3 Estimating SRA from micro-seismic mapping data

included, as shown in Fig. 5. First we calculate the stimulated reservoir area, and assume the fracture height equaling the reservoir thickness. Then we calculate the SRV with Eq. (1).

$$SRV = SRA \times H_{\mathrm{f}} = \sum_{i=1}^{n} A_i H_{\mathrm{p}}, \tag{1}$$

where H_{f} is the fracture height; SRA is the stimulated reservoir area; H_{p} is the reservoir thickness.

2.3 Impact of the horizontal stress difference

In this simulation, the linear density of the natural fractures is 0.12 m/m^2, the number of the perforation clusters is 4, the perforation cluster spacing is 20 m, and the injection rate is 15 m^3/min. Figure 6 shows the fracture network geometry at horizontal stress differences of 3, 6, and 9 MPa, respectively. Figure 6a shows under a horizontal stress difference of 3 MPa, once the hydraulic fracture meets a natural fracture, hydraulic fractures could easily deflect and connect with more natural fractures. The stimulated reservoir area (SRA) is about 12,450 m^2, and the average fracture length is 411 m. Under a horizontal stress difference of 6 MPa, the fracture network is narrower. The SRA is about 6470 m^2, and the average fracture length is 458 m, shown as Fig. 6b. Under a horizontal stress difference of 9 MPa, when the hydraulic fracture encounters a natural fracture, instead of deflecting, the hydraulic fracture will more easily pass through the natural fracture, which will cause the number of connected natural

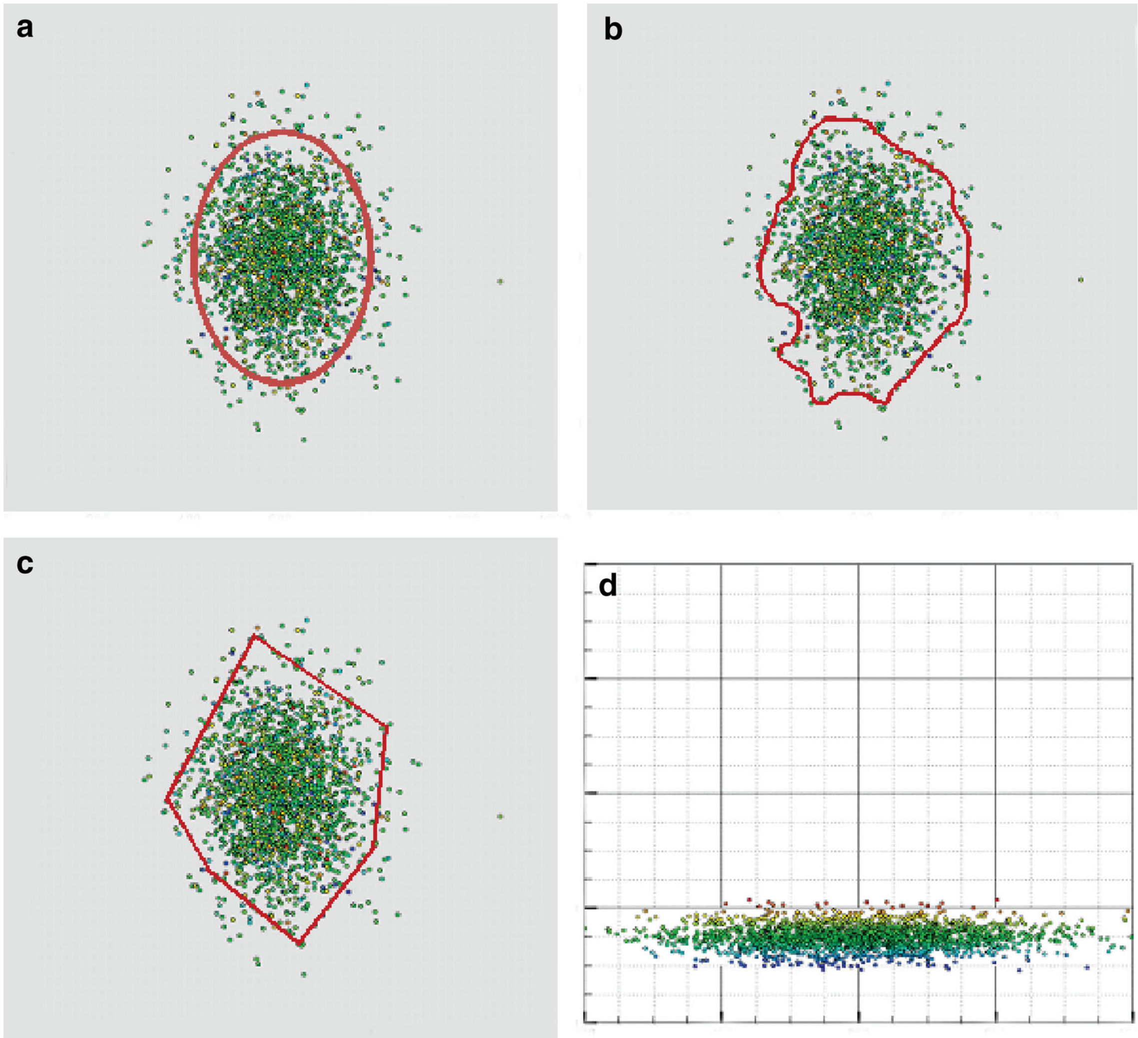

Fig. 4 Methods for calculating the SRA. **a** Ellipse method; **b** Probability method; **c** Boundary analytical method; **d** Profile map

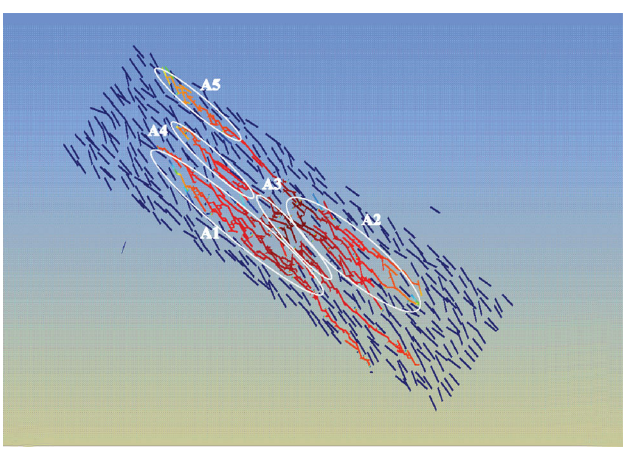

Fig. 5 Calculation of the stimulated reservoir area by the ellipse method

fractures to reduce. The SRA is about 3100 m^2, and the average fracture length is 493 m, shown as in Fig. 6c.

With a lower horizontal stress difference, the natural fractures could easily be opened by hydraulic fractures, and then form branch fractures. Finally, the hydraulic fractures connect with the natural fractures to form a complex fracture network system. With an increase in the horizontal stress difference, the SRV is reduced and the average fracture length is increased. When the horizontal stress difference is higher than 6 MPa, the fracture geometry changes from a complex fracture network to planar fractures, which causes a reduction in the SRV and an increase in the fracture length. The horizontal stress difference of the target formation is 3–5 MPa. It is beneficial to form a complex fracture network by volumetric fracturing.

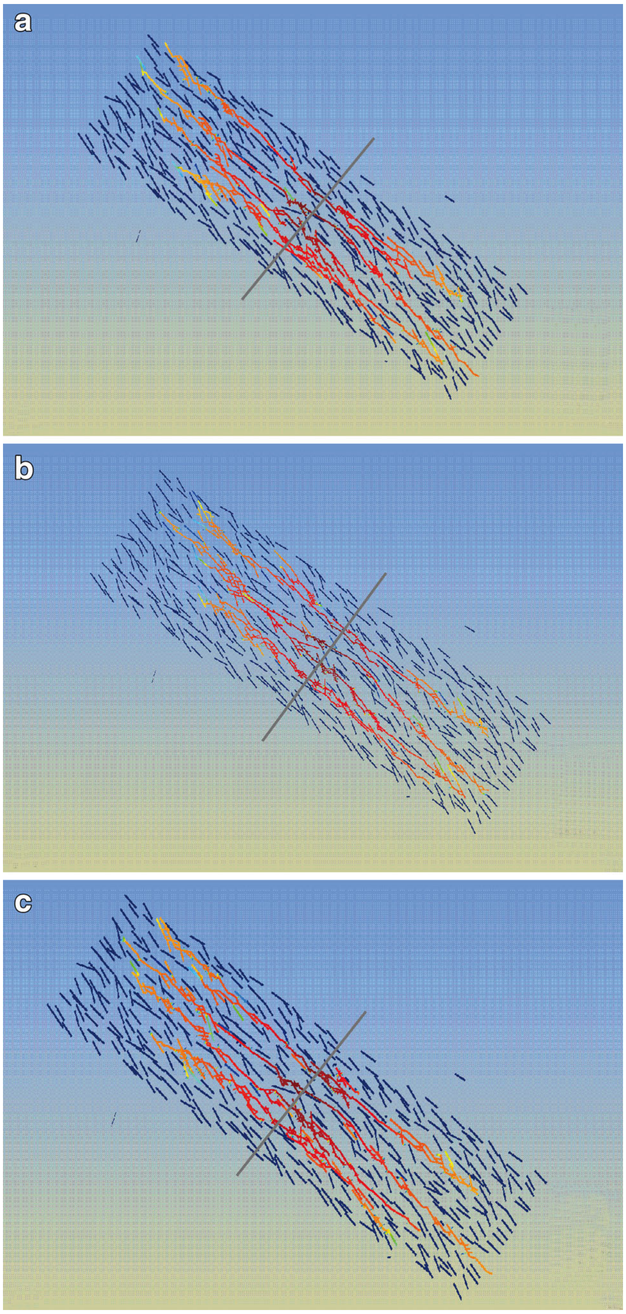

Fig. 6 Fracture geometry under various horizontal stress differences. **a** 3 MPa; **b** 6 MPa; **c** 9 MPa

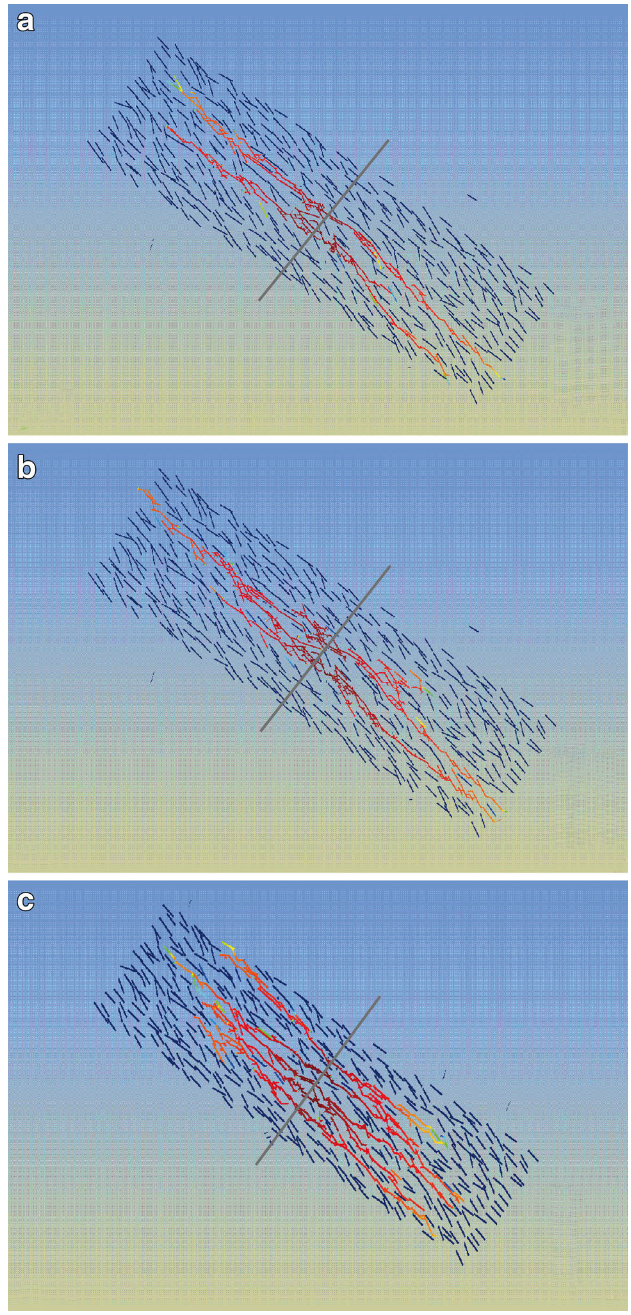

Fig. 7 Fracture geometry under various perforations. **a** 2 clusters, 6 m^3/min injection rate; **b** 2 clusters, 8 m^3/min injection rate; **c** 5 clusters, 15 m cluster spacing, 15 m^3/min injection rate

2.4 Impact of the number and spacing of perforation clusters

The number and spacing of perforation clusters has a direct influence on the fracture propagation geometry of horizontal well fracturing (Cheng 2009). For a tight oil reservoir, 2 perforation clusters, 20 m cluster spacing and 6–8 m^3/min injection rate cannot meet the requirement of stimulated reservoir volume (SRV). The SRA is only 1243 m^2 (Fig. 7a). The directions of the hydraulic fractures are the same as those of the natural fractures. The number of branch fractures is too low to form a complex fracture network system. Once the number of the perforation clusters is increased to 5 and the cluster spacing is reduced to 15 m (Fig. 7c), more natural fractures are induced to open and connect with each other to form a fracture network, shown as Fig. 7c. The SRA increases from 12,450 m^2 in 4

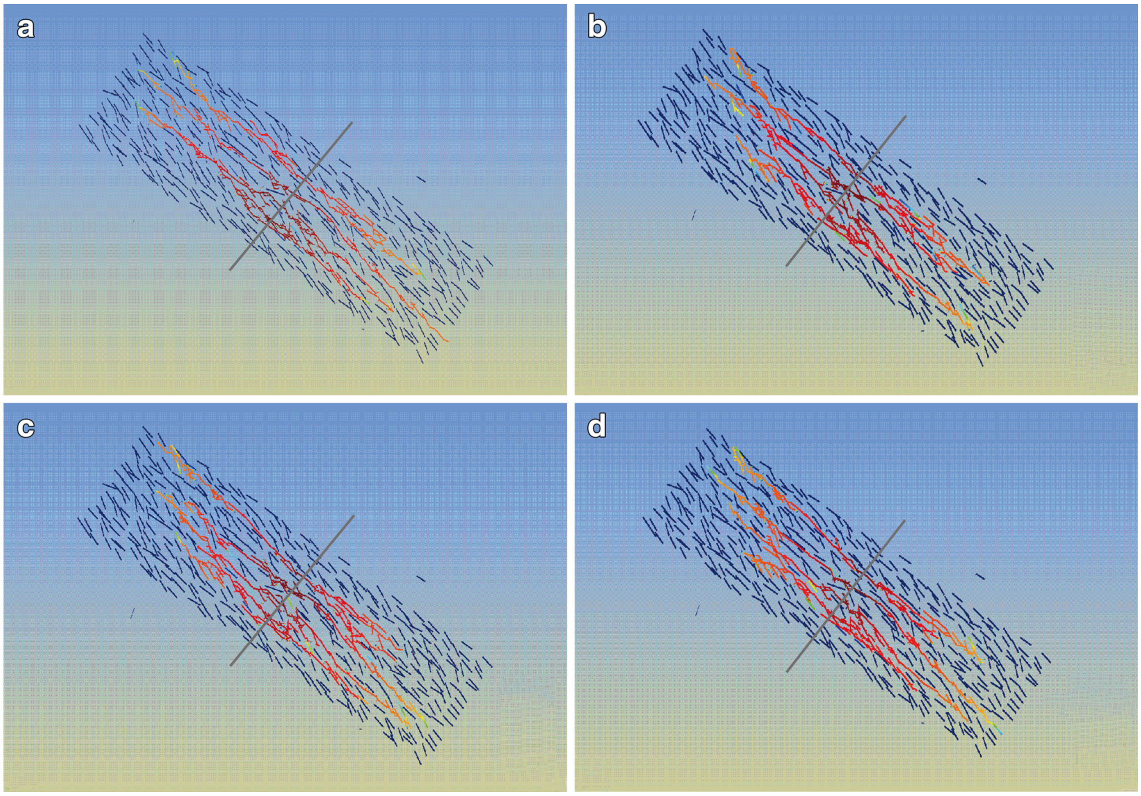

Fig. 8 Fracture geometry at various injection rates. **a** 10 m^3/min; **b** 12 m^3/min; **c** 14 m^3/min; **d** 15 m^3/min

clusters (20 m cluster spacing) to 15,040 m^2, and the average fracture length reduces from 411 to 379 m.

Increasing the number of perforation clusters and reducing the cluster spacing are beneficial to improve the complexity of the fracture network under the condition of low horizontal stress difference (Manchanda et al. 2012). However, propagation of multiple fractures at a low horizontal stress difference will lead to interaction among fractures (Bunger et al. 2011), which causes compressed middle fractures. Due to the small fracture width, as the hydraulic fracture propagates, the volume of liquid that is injected into the fractures will be reduced. Therefore, it is hard to inject the proppant into the fractures thus leading to sand plugging (Olsen et al. 2009). On the other hand, if the horizontal stress difference is high, the fracture propagation becomes difficult if the horizontal well has a close fracture spacing. As a result, the number of fractures will be reduced. Therefore, a reduction in the effective stimulated area which is caused by short perforation cluster spacing should be avoided.

2.5 Impact of the injection rate

Injection rate is one of the most important engineering factors in tight oil reservoir stimulation (King et al. 2008). The simulation results show that a high injection rate is beneficial to improve the complexity of the fracture network. Figure 8 indicates the geometry of the fracture network after volumetric fracturing at different injection rates. The horizontal stress difference is 3 MPa, the number of the perforation clusters is 4 and the cluster spacing is 20 m. The simulation results show that the higher the injection rate, the bigger the SRA. When the injection rate increases from 10 to 15 m^3/min, the SRA increases from 8080 to 14,910 m^2 correspondingly.

2.6 Impact of the linear density of natural fractures

If the linear density of natural fractures increases from 0.12 m/m^2 (Fig. 6) to 0.14 m/m^2, more stimulated natural fractures are developed. With 4 perforation clusters, 20 m cluster spacing and 15 m^3/min injection rate, the SRA will increase by a large margin. When the horizontal stress difference is 3 MPa, the SRA increases from 12,450 to 15,870 m^2, an increases of about 27.5 % (Fig. 9a). When the horizontal stress difference is 6 MPa, the SRA increases from 6470 to 6900 m^2, only 6.6 % larger (Fig. 9b). This result shows the linear density of the natural fractures only has a large impact on the volumetric fracturing in a low horizontal stress difference (Wu and Pollard 2002). Under a higher horizontal stress difference, the hydraulic fractures may hardly open and connect with the natural

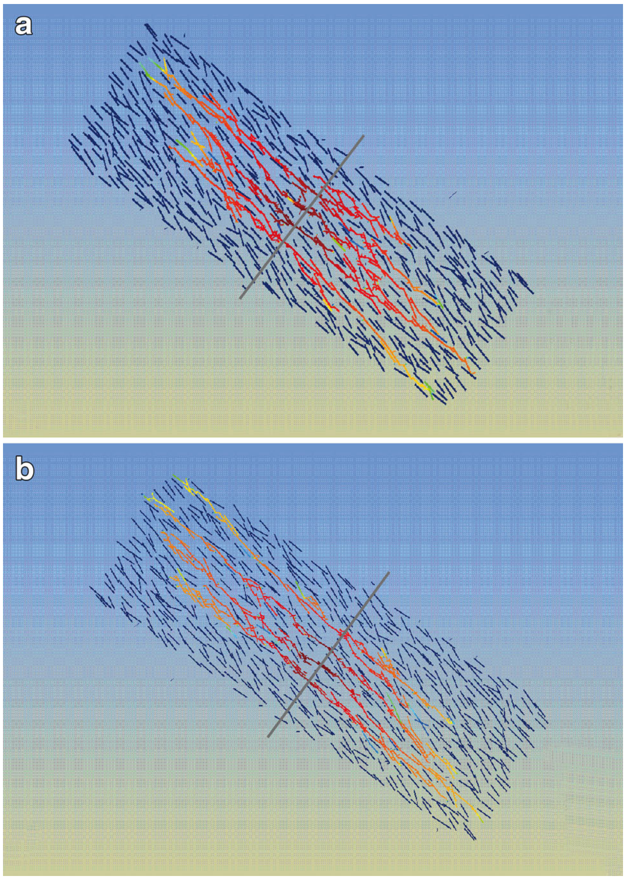

Fig. 9 Fracture geometry under higher linear density of natural fractures. **a** Horizontal stress difference of 3 MPa; **b** Horizontal stress difference of 6 MPa

fractures even if the linear density is high and volumetric stimulation will be difficult.

3 Field application

By using the physical properties and fracturing parameters (Table 1) of a tight oil reservoir in a certain oilfield, we simulated the fracture geometry after volumetric fracturing. Then the SRA was calculated and the simulated result was compared with the real micro-seismic monitoring result to verify the accuracy of our model.

Figure 10 shows a micro-seismic monitoring diagram, which is the fracture geometry of a horizontal well after 8-stage fracturing. Table 2 shows the results of micro-

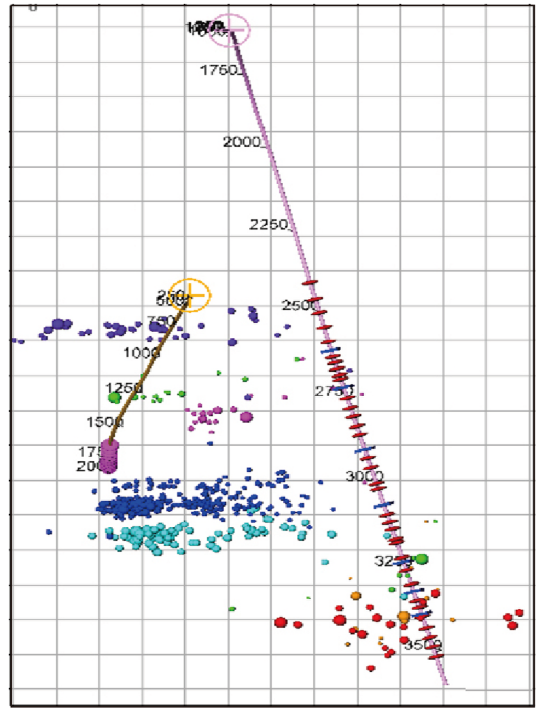

Fig. 10 Micro-seismic monitoring diagram

seismic monitoring, including the band length, band width, and the fracture height. According to these results, the SRV is 12×10^6 m^3. Figure 11 indicates the simulated fracture geometry, the SRV is 10.9×10^6 m^3. The error between the real fracturing and simulation results is only 8.2 %. This result verifies the accuracy of the model proposed in this paper.

4 Conclusions

(1) By using a mixed finite element and discrete element method, a model has been built to predict the propagation of fractures induced by fracturing in a tight oil reservoir. The influence of horizontal stress difference, number and spacing of perforation clusters, injection rate, and the linear density of natural fractures on fracture propagation has been studied with this model.

(2) When the horizontal stress difference is lower than 5 MPa, it is beneficial to form a complex fracture network system; when the horizontal stress

Table 1 Reservoir physical properties and fracturing parameters

Target formation	Permeability, 10^{-3} μm^2	Porosity, %	Horizontal stress difference, MPa	Perforation clusters	Cluster spacing, m	Injection rate, m^3/min
Tight oil	0.27	7.5	3	5	30	15

Table 2 Comparison of simulation and micro-seismic monitoring results

Formation	Calculation method	Stage number	Band length, m	Fracture height, m	Band width, m	SRV, m^3	Error, %
Tight oil	Micro-seismic monitoring result	8	330	82.5	165	12×10^6	8.2
			198	25	171		
			283	22.9	72.3		
			340	26.3	129		
			373	34.7	177		
			171	41	96.5		
			304	30.3	127		
			217	98	42.4		
	Simulation result	8	300	30	152	10.9×10^6	

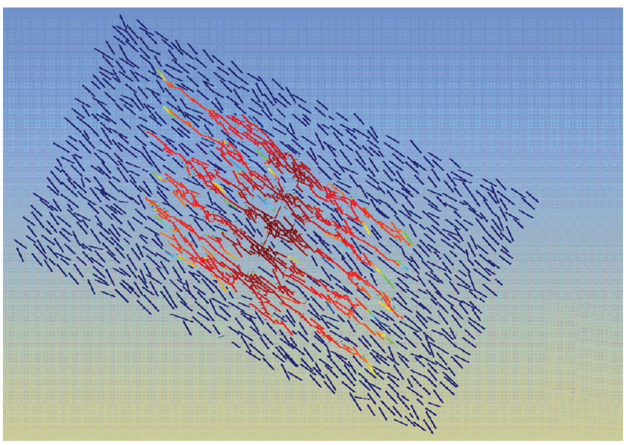

Fig. 11 Simulated fracture geometry

difference is higher than 6 MPa, it is easy to form a planar fracture system. The density of natural fractures only has a great influence on the effect of volumetric stimulation when there is a low horizontal stress difference.

(3) When there are low horizontal stress differences, increasing perforation clusters or reducing cluster spacing has a little impact on increasing the stimulated reservoir volume (SRV). The interaction among fractures is serious. Fractures at some regions will deflect and coalesce. With high horizontal stress differences, increasing the number of perforation clusters is beneficial to open and connect more natural fractures, and to improve the complexity of the fracture network and the SRV. As the injection rate increases, the effect of volumetric fracturing may be improved.

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