

Original Paper

Numerical study on hydraulic fracture propagation in anisotropic shale considering bedding plane characteristics

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ABSTRACT

China possesses abundant shale gas resources. As the core method for enhancing shale gas production, hydraulic fracturing technology has seen increasing application alongside the rapid development of the industry. However, the inherent strong anisotropy of shale results in significant differences in mechanical properties between parallel and perpendicular bedding directions, leading to highly complex crack propagation patterns. This study employs the discrete element method (DEM) to construct numerical models of hydraulic fracturing in shale under varying bedding inclinations. It systematically investigates the hydraulic fracture propagation behavior in bedding shale and quantitatively analyses the effects of *in-situ* stress conditions and injection rates on crack propagation characteristics and failure modes. The results indicate that the stress distribution calculated by the isotropic DEM model aligns well with the analytical solution, validating the model's reliability. Hydraulic fractures initiate in regions with negative tangential stresses around the wellbore and primarily propagate along bedding planes. The state of *in-situ* stress significantly influences crack morphology. As the lateral pressure coefficient K_0 decreases, the maximum crack propagation length decreased from 114.48 to 92.95 mm, yet interlayer propagation intensifies. The propagation direction increasingly aligns with the direction of maximum principal stress, thereby promoting the development of secondary cracks and increasing the complexity of the fracture network. Increasing the injection rate can significantly enhance maximum crack propagation length from 105.41 to 126.19 mm, reduce fracture tortuosity and roughness, and induce fracture branching to form complex fracture networks. Analysis of micro-failure modes reveals that hydraulic fracturing in shale is dominated by tensile failure. Notably, a decrease in K_0 or an increase in injection rate drives a transition in the failure mechanism from a “bedding-dominated” to a “matrix-dominated” regime, characterized by a marked increase in the proportion of matrix tensile failures. These findings provide theoretical support for optimizing fracturing parameters and enhancing reservoir stimulation efficiency in shale gas reservoirs within the Sichuan region.

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1. Introduction

China's cumulative proven geological reserves of shale gas exceed $2.8 \times 10^{12} \text{ m}^3$, with annual production consistently surpassing $2.0 \times 10^{10} \text{ m}^3$. Cumulative gas output has exceeded $1.0 \times 10^{11} \text{ m}^3$, establishing shale gas as a vital successor resource to conventional natural gas in safeguarding national energy security

(Zou et al., 2017; Wang et al., 2024). Guided by the dual carbon goals, shale gas as a clean and low-carbon fossil fuel, holds irreplaceable strategic value in optimizing China's coal-dominated energy consumption structure, reducing carbon emission intensity and enhancing energy self-sufficiency through its efficient development.

Hydraulic fracturing technology is the core key technology for overcoming the low porosity and low permeability characteristics of shale, thereby enabling increased shale gas reserves and production. Its application scale continues to expand alongside the rapid development of the shale gas industry. However, as a typical layered sedimentary rock, shale exhibits pronounced inherent anisotropy (Johnston and Christensen, 1995; Niandou

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et al., 1997; Li et al., 2012a). This characteristic leads to substantial disparities in mechanical parameters—such as elastic modulus, Poisson's ratio, and tensile strength—between directions parallel and perpendicular to bedding planes, with differences often varying by a factor of 2–5. Consequently, the initiation, propagation pathways, and failure modes of hydraulic fractures become highly complex. For instance, fractures are prone to deflecting along bedding planes to form horizontal fractures or may experience restricted vertical propagation due to the barrier effect of bedding planes, thereby severely

compromising stimulation effectiveness and gas well productivity. Therefore, elucidating the mechanisms governing the propagation of hydraulic fractures in anisotropic shale formations and precisely identifying the key factors influencing fracture evolution holds significant strategic importance and practical engineering value. This knowledge is essential for optimizing fracturing operation parameters, enhancing the stimulated reservoir volume (SRV), advancing the efficient development of domestic shale gas resources, and supporting the achievement of the dual carbon goals.

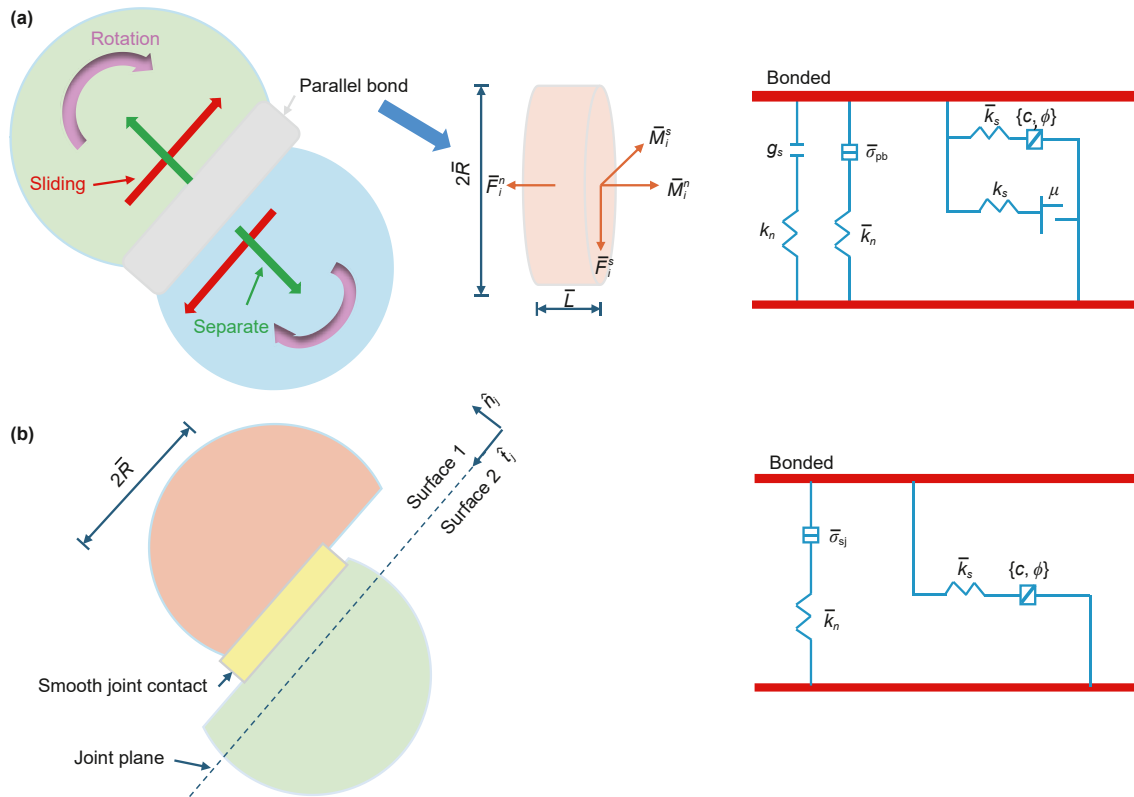


Fig. 1. Contact model schematic diagram. (a) Parallel bond model, (b) smooth joint model.

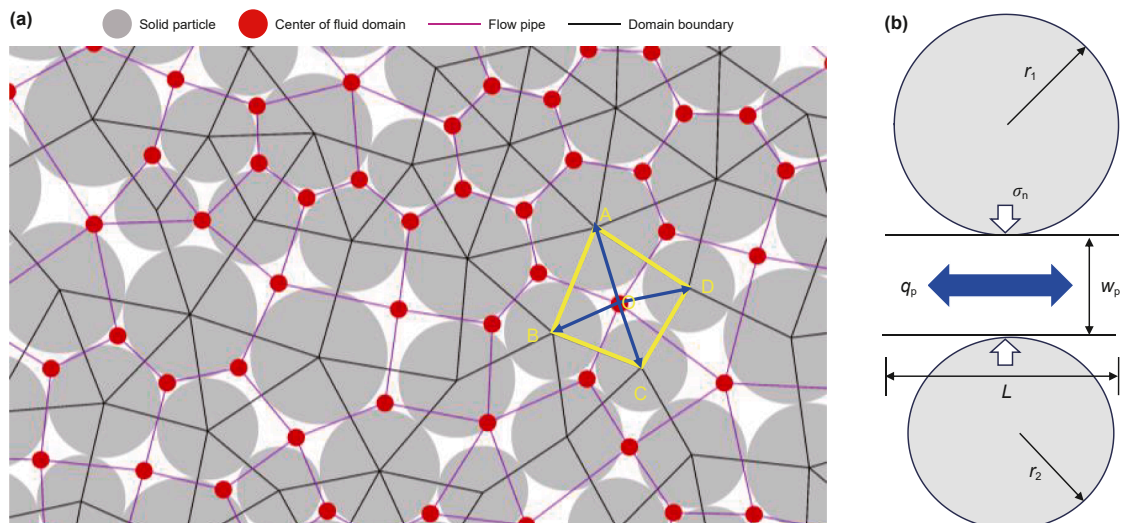


Fig. 2. Schematic diagram of (a) fluid domain and flow pipe, (b) flow pipe between two adjacent particles.

Table 1
Microscopic parameters of calibrated shale uniaxial compression models.

Parallel bond model		Smooth joint model	
Parameters	Value	Parameters	Value
Minimum particle radius, mm	0.35	Normal stiffness, GPa	2850
Particle density, kg/m ³	2500	Shear stiffness, GPa	12,200
Young's modulus, GPa	20	Tensile strength, MPa	28
Normal-to-shear stiffness ratio	4.5	Cohesion, MPa	52
Parallel tensile strength, MPa	78	Bedding thickness, mm	0.44
Parallel cohesion, MPa	78	Loading rate, m/s	0.05

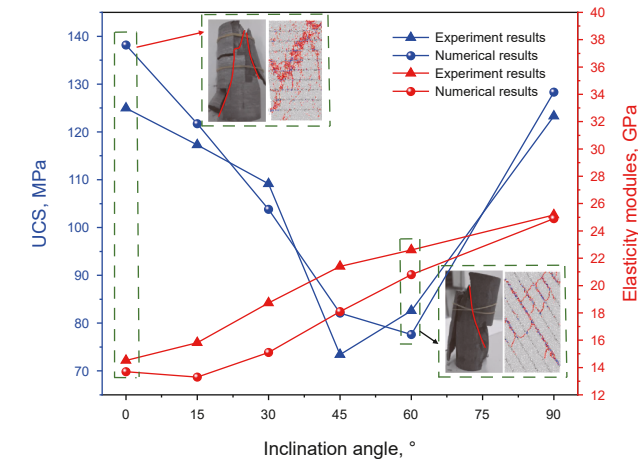


Fig. 3. Comparison of experiment results from UCS and E with numerical results.

At present, numerous scholars have undertaken extensive research into the fracture propagation mechanisms associated with hydraulic fracturing. In laboratory testing, [Wang et al. \(2025\)](#) employed a combined approach of acoustic emission localization and characteristic parameter extraction to systematically investigate the entire process of fracture initiation, propagation and breakthrough during shale hydraulic fracturing. They demonstrated that the fracture evolution characteristics observed in the experiments exhibited good consistency with micro-seismic monitoring results from field hydraulic fracturing operations, thereby validating the reliability of the physical simulation. [Ma et al. \(2017\)](#) focused on investigating the regulatory effect of multiple bedding planes on the vertical propagation of hydraulic fractures. They discovered that when stress differentials exceed critical thresholds, hydraulic fractures can traverse multiple bedding planes to achieve vertical connectivity, thereby providing experimental evidence for volumetric modification of deep reservoirs. [Stanchits et al. \(2015\)](#) employed high-precision acoustic emission monitoring technology to conduct hydraulic fracturing tests on heterogeneous shale containing natural weak planes. They systematically analyzed the influence of natural weak plane development on fracture propagation pathways and fracture network morphology. [Diaz et al. \(2020\)](#) focused on cyclic hydraulic fracturing technology. Through a series of experiments, they discovered that varying cycle durations significantly influence the intensity of acoustic emission activity, hydraulic energy utilization efficiency, fracture propagation area, and propagation rate. This provides experimental support for optimizing cyclic fracturing operation parameters. [Kumari et al. \(2018\)](#) conducted single-well

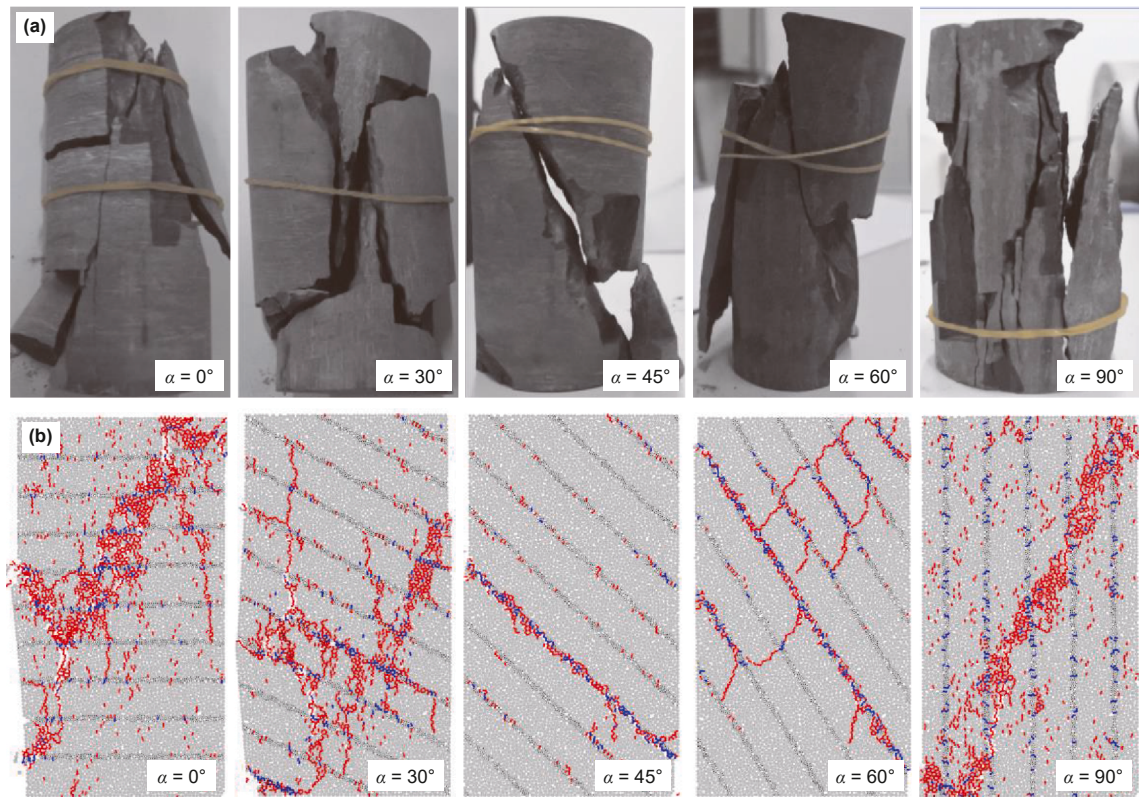


Fig. 4. Failure modes of specimens with different bedding inclinations. (a) Experiment results, (b) numerical results (red and blue lines represent tensile cracks and shear cracks, respectively).

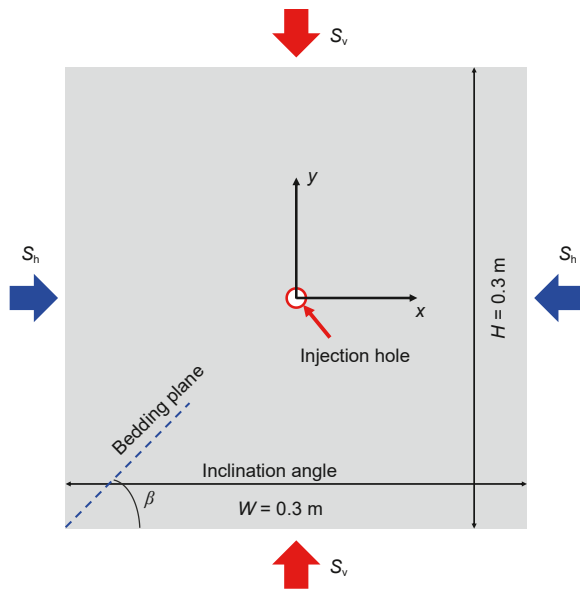


Fig. 5. Hydraulic fracturing DEM model.

fracturing tests under thermally coupled conditions, revealing that elevated temperatures promote the generation of numerous microfractures near the fractured wellbore while simultaneously reducing both the tensile strength and breakdown pressure of the reservoir. This provides theoretical reference for fracturing design in deep, high-temperature shale gas reservoirs.

In the field of numerical computation research, the numerical methods employed to simulate hydraulic fracturing in rock

formations have become increasingly diverse. Among these, continuous medium numerical methods have gained the widest application in simulating hydraulic fracturing within anisotropic strata due to their simplicity of modelling and high computational efficiency. Deng et al. (2024) developed a fully coupled solver for the discrete crack-propagation finite element method (XFEM) based on the He-Hutchinson theory, successfully elucidating the initiation mechanism and propagation patterns of fractures within layered shale formations. Liao et al. (2022) employed the XFEM to establish a multiphase fluid–solid coupled numerical model for horizontal well fracturing. This model systematically simulated fracture propagation processes under sequential and alternating fracturing strategies, analyzing the comparative effects of different fracturing approaches on fracture network morphology and reservoir enhancement outcomes. Saber et al. (2023) utilized XFEM coupled with a cohesive zone model (CZM) to elucidate how material anisotropy, bedding dip angle, and fracture spacing govern fracture morphology in isotropic shale. Zhang et al. (2023a) employed finite element modelling to conduct thermo-hydraulic-mechanical (THM) coupled simulations, revealing the regulatory mechanism of natural fractures on fracture propagation pathways and thermal recovery performance. Their findings confirmed that the synergistic interaction between thermal and hydrostatic pressures significantly promotes rock fracturing, enhancing reservoir modification efficacy. Zou et al. (2020) established a predictive model for fracture initiation and deflection based on modified maximum circumferential tensile stress criteria, quantifying the influence of anisotropy parameters in unconventional reservoirs on fracture initiation pressure, initiation direction, and deflection patterns. In addition to the finite element method, the boundary element method (BEM) is also widely employed in hydraulic fracturing simulation studies: Chen et al. (2022)

Table 2
Fluid parameters in hydraulic fracturing model.

Bulk modulus, GPa	Viscosity, Pa·s	Stress-sensitive factor, MPa ^{−1}	Residual aperture, m	Injection rate, m ³ /s	Dimensionless coefficient
2.0	1e−3	0.08	1.9e−7	0.001	0.2

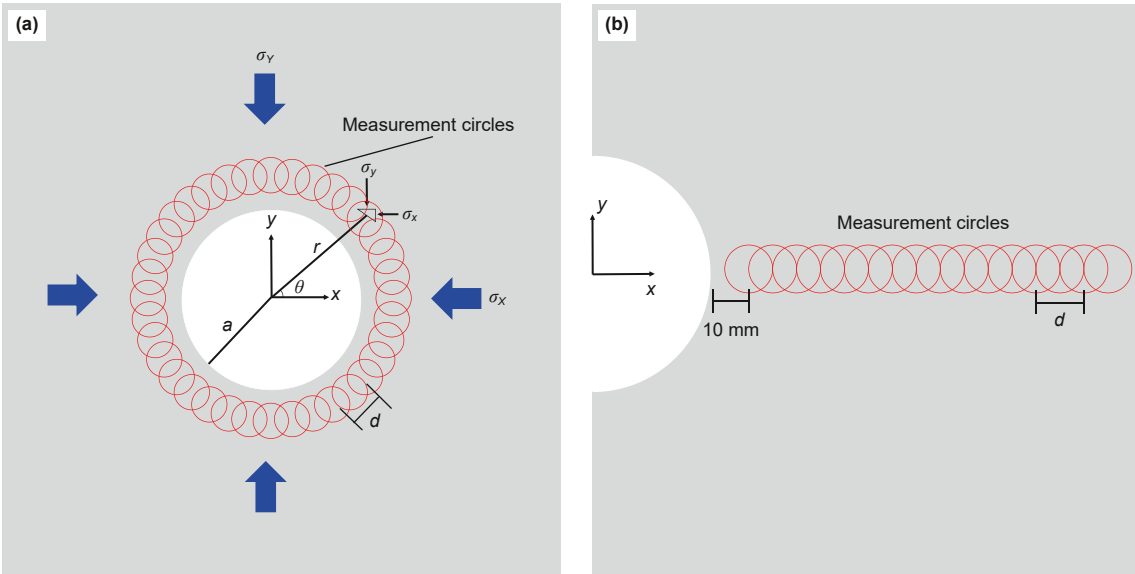


Fig. 6. Position of measurement circles. (a) Around the injection hole, (b) along the x-axis direction. Measurement circle diameter $d = 16$ mm. Angle between adjacent measurement circles in the polar system is 10° . Distance between adjacent measurement circles is equal to $d/2$.

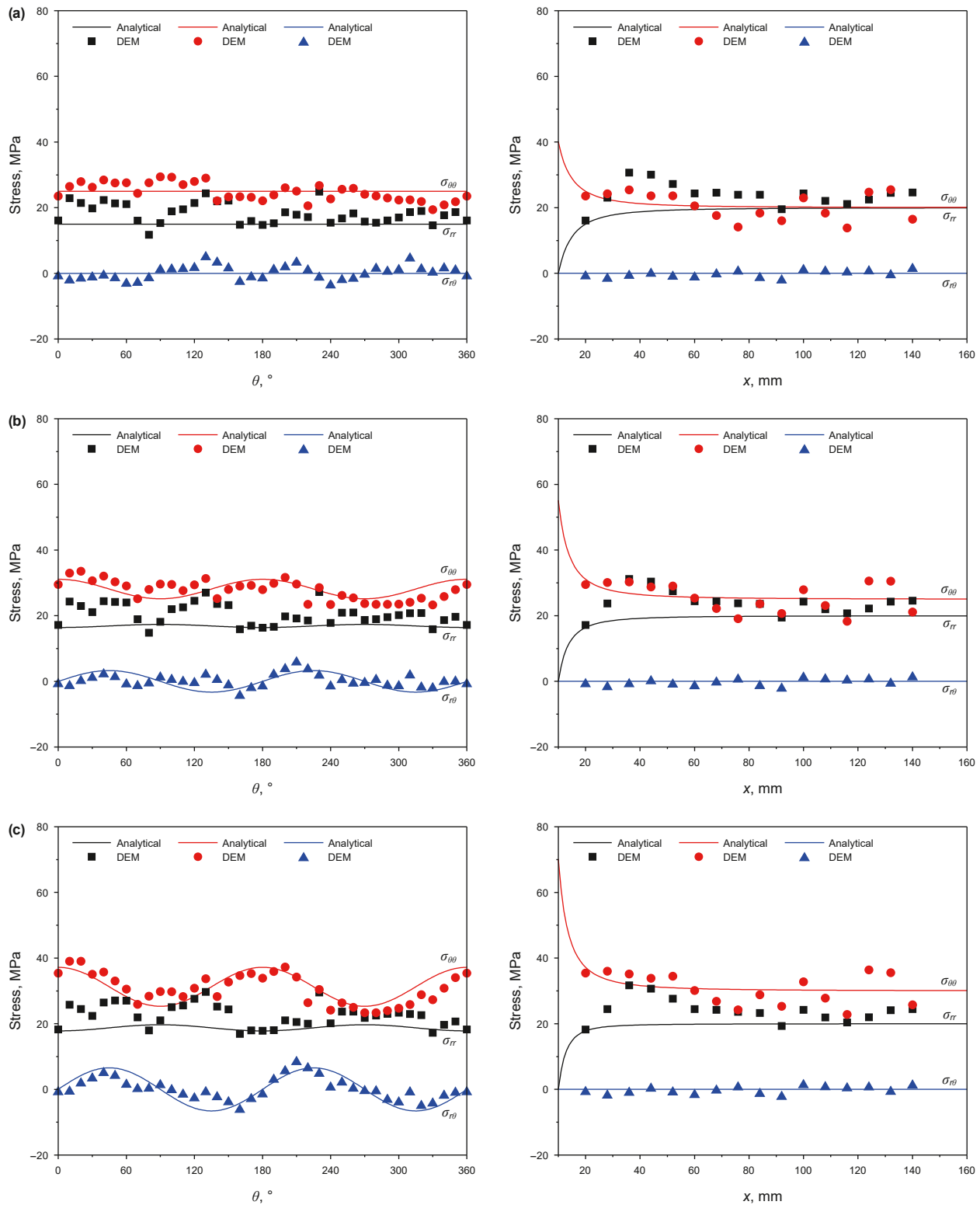


Fig. 7. Stress distributions around the borehole (left column) and along the x -axis (right column) under different stress conditions calculated using isotropic DEM models and analytical solutions. (a) $\sigma_x = 20$ MPa, $\sigma_y = 20$ MPa, (b) $\sigma_x = 20$ MPa, $\sigma_y = 25$ MPa, (c) $\sigma_x = 20$ MPa, $\sigma_y = 30$ MPa.

established a fully coupled plane strain model based on the boundary element method, theoretically analyzing the crack initiation criteria and fracture breakdown pressure calculation mechanism. Jiang et al. (2022) combined the boundary element method with seepage mechanics theory to propose a production

decline evaluation model for fractured vertical wells, verifying the regulatory effect of directional fractures on gas well productivity within anisotropic formations. Cheng et al. (2022) developed a fully coupled numerical model for hydraulic fracturing based on the dual boundary element method (DBEM), focusing on

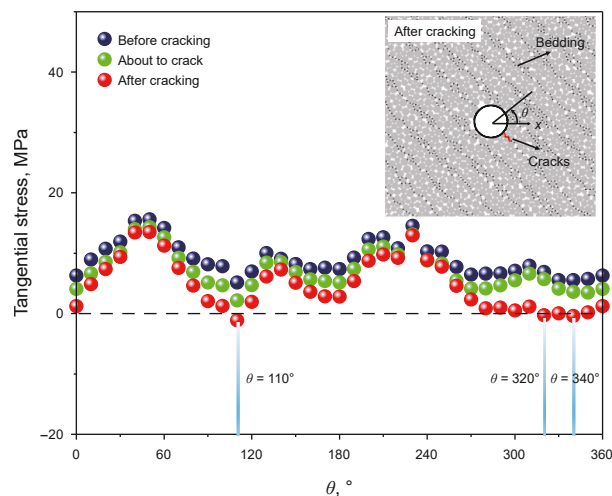


Fig. 8. Tangential stress variation during wellbore cracking process.

elucidating the influence of natural fracture distribution characteristics around the wellbore on the evolution of artificial fracture networks. However, traditional boundary element methods (BEM) and most finite element methods (FEM) fundamentally assume rock media homogeneity, making it difficult to accurately characterize the heterogeneous features of shale, such as its layered structure and natural fractures. Although certain modified finite element models (Yang et al., 2004; Li et al., 2019) can preliminarily address heterogeneity issues by introducing equivalent parameters or partitioned modelling approaches, significant challenges persist in simulating crack dynamic propagation and large deformations. These include complex mesh generation, considerable difficulty in mesh reconstruction, and low computational efficiency.

To date, some scholars have attempted to employ the discrete element method to simulate the hydraulic fracturing process in anisotropic shale formations (Al-Busaidi et al., 2005; Shimizu et al., 2011; Yoon et al., 2014; Huang et al., 2019), achieving preliminary results. However, existing research lacks sufficient

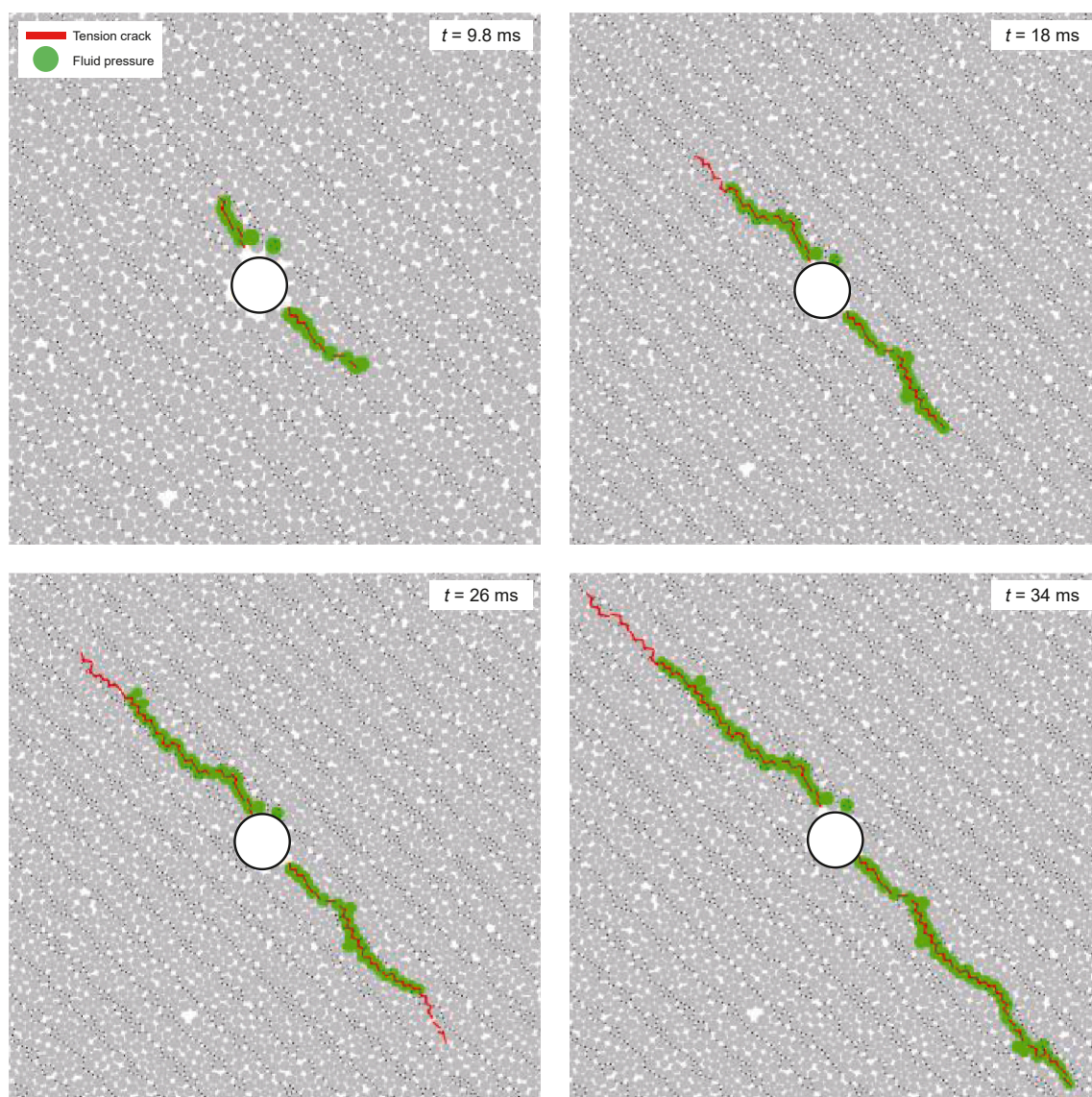


Fig. 9. Crack propagation at different time.

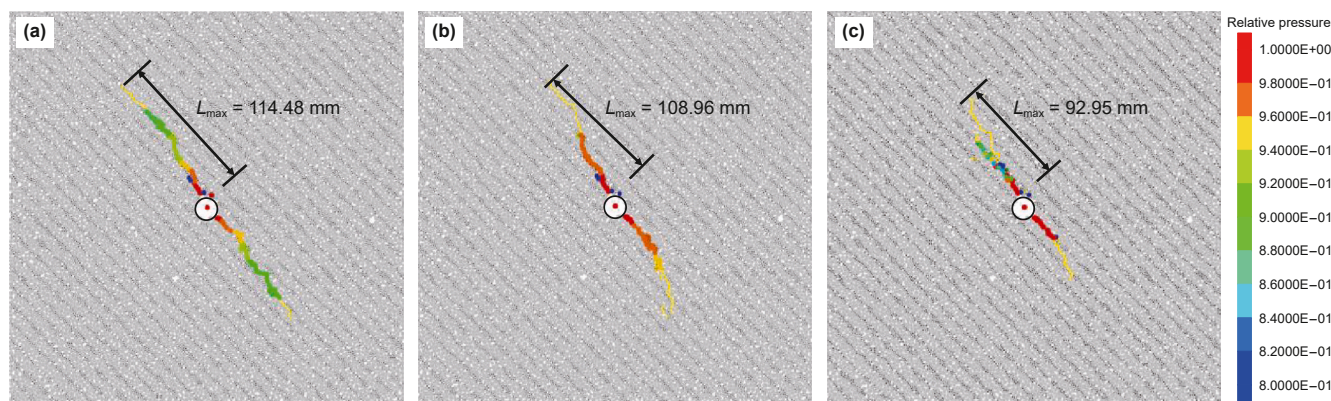


Fig. 10. Hydraulic fracture propagation at 45° bedding inclination under different stress conditions. (a) $K_0 = 1$, (b) $K_0 = 0.8$, (c) $K_0 = 2/3$.

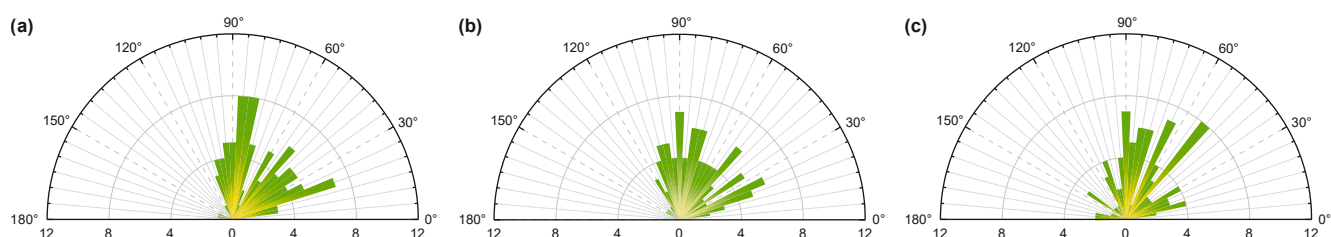


Fig. 11. Wind rose diagram of fracture angles under varying stress conditions for 45° bedding inclination. (a) $K_0 = 1$, (b) $K_0 = 0.8$, (c) $K_0 = 2/3$.

quantitative analysis of fracture propagation mechanisms under coupled injection rates and *in-situ* stress conditions. The quantitative influence of bedding inclination on fracture initiation, propagation pathways, and failure modes under varying injection rates and *in-situ* stress differentials remains unclear. To this end, this study investigates anisotropic shales from the Longmaxi Formation in Sichuan Province. We improve domain volume fluid–solid coupling algorithm and construct a numerical model for hydraulic fracturing in shales which accounting for varying bedding inclinations. The paper systematically examines fracture propagation behavior within anisotropic shales during hydraulic fracturing operations, with particular emphasis on quantifying the influence mechanisms of *in-situ* stress differentials and injection rates on the initiation, expansion, and failure patterns of hydraulic fractures. The research findings are expected to provide theoretical underpinnings and technical guidance for optimizing hydraulic fracturing parameters and enhancing reservoir modification efficiency in shale gas reservoirs within the Sichuan region.

2. Methodology

2.1. Contact model and fluid–solid coupling algorithm

In simulating hydraulic fracturing using discrete elements, the fluid–solid coupling between the fluid and bedding shale, as well as the expansion of fluid-driven fractures, is primarily modeled through a pipe domain within bonded particles. Particle motions follow Newton's second law, with interactions between

neighboring particles described by force–displacement relations. When bonds between particles break, the forces previously supported by these bonds are released, changing the stresses around the wellbore and potentially triggering new fractures. Consequently, this method can simulate crack initiation, propagation, and particle interactions.

Firstly, a solid particle assembly of the shale matrix is created. In this study, the shale matrix is characterized by the parallel bond (PB) model. For the solid particles within the shale matrix, the PB model can transmit both forces and moments, effectively representing the mechanical properties of the rock material. To simulate the mechanical behavior of weak interfaces within the rock, [Pierce et al. \(2007\)](#) introduced a smooth joint model (SJM). The smooth joint replaces the defined layer line with a parallel bond contact at a specified distance, allowing particles near the smooth contact surface to interpenetrate and slide along it. Consequently, the smooth joint (SJ) model is used to represent the bedding planes in shale, with a schematic diagram of the contact model shown in [Fig. 1](#).

[Fig. 2\(a\)](#) shows the basic structure of a conventional pipe-network flow model used for a cohesive granular aggregate to simulate fluid–solid coupling during hydraulic fracturing. In [Fig. 2\(b\)](#), the flow pipe between adjacent particles is modeled as a pair of parallel plates with a perforated gap, and the fluid flow within the pipe is considered as parallel plate seepage. It is assumed that the initial fluid pressure in each domain is uniform. In the 2D model, the pipe dimensions in the out-of-plane direction are set to 1 unit. When two adjacent fluid domains exchange fluid,

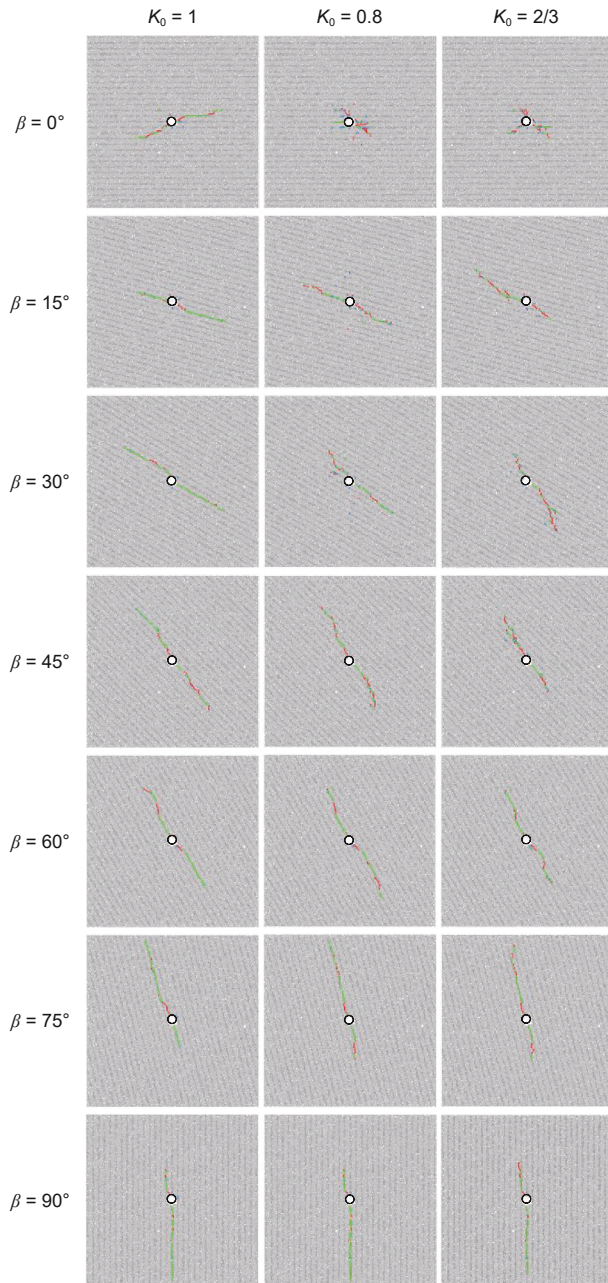


Fig. 12. Hydraulic fracture propagation behavior at different bedding inclinations under vary stress conditions (red = PB tensile crack, black = PB shear crack, green = SJ tensile crack, blue = SJ shear crack).

the volumetric flow rate (q_p , m^3/s) through the pipe can be calculated using the previously derived Poiseuille equation (Zimmerman and Bodvarsson, 1996).

$$q_p = \frac{w_p^3}{12u} \frac{(P_2 - P_1)}{L} \quad (1)$$

In the equation: u is the dynamic viscosity of the fluid; w_p is the flow pipe aperture, m ; P_1 and P_2 are the fluid pressures in fluid domain 1 and fluid domain 2, respectively; L is the length of the flow pipe.

To consider the model's initial permeability, we assume the residual aperture (w_0) for each pipe based on the model's geometry and the contact normal forces between adjacent particles, and update the apertures (w_p) of the flow pipes at each time step. Simultaneously, to account for the closure of flow paths under confining pressure, we employ a physics-based relationship between the flow pipe aperture (w_p) and the normal contact stress (σ_n). Based on the model geometry and contact forces, the flow pipe aperture (w_p) is updated at each time step using the following formula (Duan et al., 2021).

$$\begin{cases} w_p = w_0 \exp\left(-\frac{\gamma\sigma_n}{3}\right) & (\text{in compression}) \\ w_p = w_0 + \lambda\Delta w_d & (\text{in tension or ruptured}) \end{cases} \quad (2)$$

In the equation: w_0 is the initial aperture when the contact normal force is zero, determining the magnitude of the initial permeability; γ is the contact stress sensitivity factor; λ is the dimensionless coefficient; Δw_d is the mechanical gap between adjacent particles, m .

At each time step, the change in fluid volume within a fluid domain (ΔV_f) can be calculated by summing the source flow and connected pipe flow for that time step:

$$\Delta V_f = \left(q_{\text{inj}} + \sum_{i=1}^n q_p^{(i)} \right) \Delta t_f \quad (3)$$

where q_{inj} is the injection rate, m^3/s ; for all other non-injection fluid domains, q_{inj} is set to zero; $q_p^{(i)}$ is the volumetric flow rate through the pipe, m^3/s ; Δt_f is the time step for flow calculation, s ; n is the number of pipes surrounding the flow domain.

The change in fluid pressure within the fluid domain at each time step is calculated according to the following equation:

$$\Delta p = \frac{K_f}{V_d} (\Delta V_f - \Delta V_d) \quad (4)$$

In the equation: K_f is the fluid bulk modulus; V_d is the apparent volume of the fluid domain; ΔV_f is the change in fluid volume within the domain; ΔV_d is the change in domain volume due to mechanical deformation.

Considering the stability of flow calculations, the fluid pressure update in Eq. (5) for each time step should be less than the fluid pressure difference between adjacent domains calculated in Eq. (1). Kong et al. (2021) proposed an appropriate flow time step (Δt_f) to ensure stable fluid flow calculations, expressed as

$$\Delta t_f < \alpha_t \frac{V_d}{K_f \sum_{i=1}^N \frac{w_{pi}^3}{12\mu L_i}} = \Delta t_{fc} \quad (5)$$

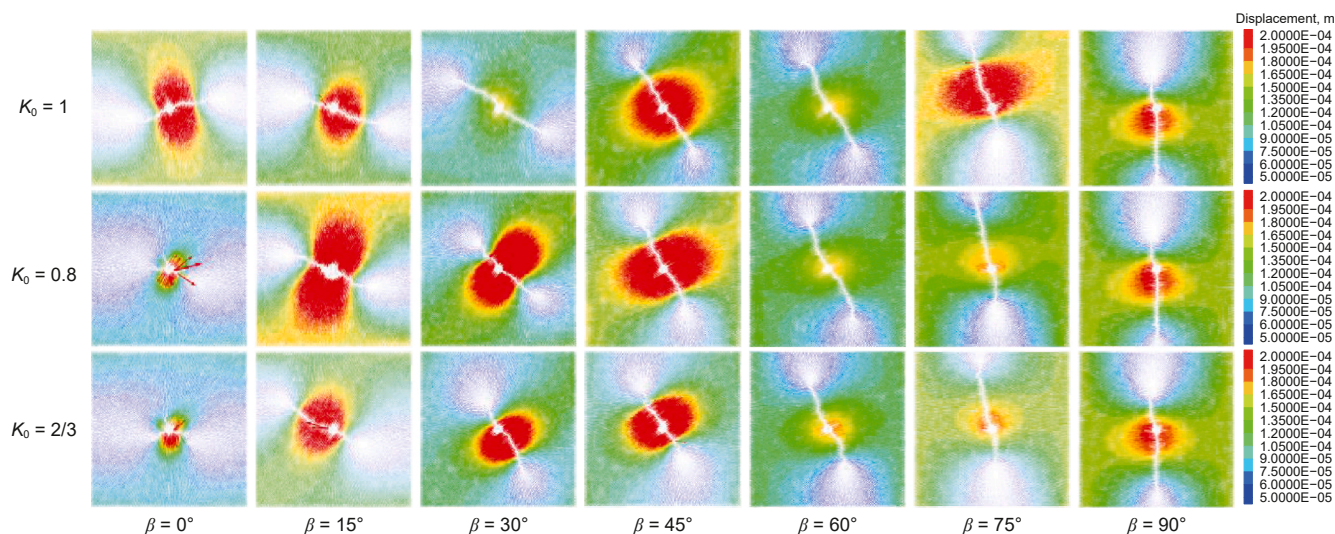


Fig. 13. Displacement field of hydraulic fracturing numerical models under different bedding inclinations and stress conditions.

where α_t is the safety factor for the flow time step, with a value range of (0,1); N is the number of flow pipes within a domain; w_{pi} and L_i represent the aperture and length of the i -th flow pipe within the domain, respectively; Δt_{fc} is the critical flow time step.

2.2. Improved domain volume algorithm

To ensure precision during the pressure update process for the fluid, we have precisely calculated the volume of the fluid domain at each time step, along with the change in domain volume. We implement a simplified volume calculation algorithm using the fish language because the fluid domain may have various geometric shapes (such as triangles, quadrilaterals, pentagons). For geometric volume calculation, we take a quadrilateral fluid domain as an example (see Fig. 2). In this algorithm, all fluid domains must first be traversed to determine the position of the center of mass for each domain. Subsequently, at each time step, all particles composing the domain are traversed in a specific sequence. The coordinates of each center point traversed by the particles are recorded and sequentially named as A, B, C, and D. The domain volume can be divided into four triangles. For example, the volume of each triangle (ΔOAB) can be calculated using the cross product of OA and OB. By sequentially scanning all vertices in the domain and summing the volumes of the four triangles, we obtain the geometric volume of the domain.

3. Model parameters and validation

3.1. Calibration and selection of numerical model parameters

Based on the uniaxial compression test results of the Longmaxi Formation shale (Xie et al., 2021), a uniaxial compression model incorporating bedding planes was developed using discrete element method. The specimen dimensions were 50 mm × 100 mm, with a bedding plane spacing of 10 mm. An axial displacement control loading method was applied, with the upper and lower surfaces loaded toward the center at a constant rate of 0.05 m/s. The uniaxial compression model utilized a minimum particle radius of 0.35 mm, and the maximum-to-minimum

particle size ratio was set to 1.66, satisfying the particle radius ratio requirement (Ding et al., 2014). As a result, 6325 particles and 15,399 contacts were generated. Particles were randomly distributed within the numerical model, with density of 2500 kg/m³. Numerical simulations of uniaxial compression tests were performed on shale with six different bedding inclinations (0°, 15°, 30°, 45°, 60°, 90°). Through trial and error, the relevant micro-parameters of the model were ultimately obtained, as shown in Table 1.

Fig. 3 compares the results of simulated uniaxial compression tests on shale with six different bedding inclinations to those from actual experiments. The uniaxial compressive strengths at bedding inclinations of 0°, 15°, 30°, 45°, 60°, and 90° were 138.19, 121.7, 103.8, 82.1, 77.6 and 128.3 MPa, respectively. The corresponding elastic modulus were 13.7, 13.3, 15.1, 18.1, 20.8 and 24.9 GPa. The uniaxial compression simulation results indicate that the unconfined compressive strength (UCS) and E values are in good agreement with the experimental data, with an average error of less than 10%. This demonstrates that the method effectively reproduces the mechanical properties of bedding shale.

Furthermore, the failure patterns obtained from the numerical simulations were compared with those observed in laboratory tests. As shown in Fig. 4, the simulated rock failure patterns generally align with the experimental results. For specimens with a low bedding inclination (0°), under axial loading, primary cracks develop nearly parallel to the loading direction, predominantly exhibiting tensile failure. The likelihood of crack propagation along the bedding planes is low. For specimens with moderate bedding inclinations (30°, 45°), shear failure along the bedding planes is more prevalent, as the shear strength of the bedding planes is generally lower than that of the matrix. For shale specimens with a 60° bedding inclination, failure was characterized by tensile failure of the matrix, which penetrated the bedding planes, combined with shear failure along the bedding planes. During axial loading, specimens at 90° exhibit no lateral restraint, causing the weak bedding planes to fail first and ultimately producing multiple tensile cleavage planes that penetrate the specimen.

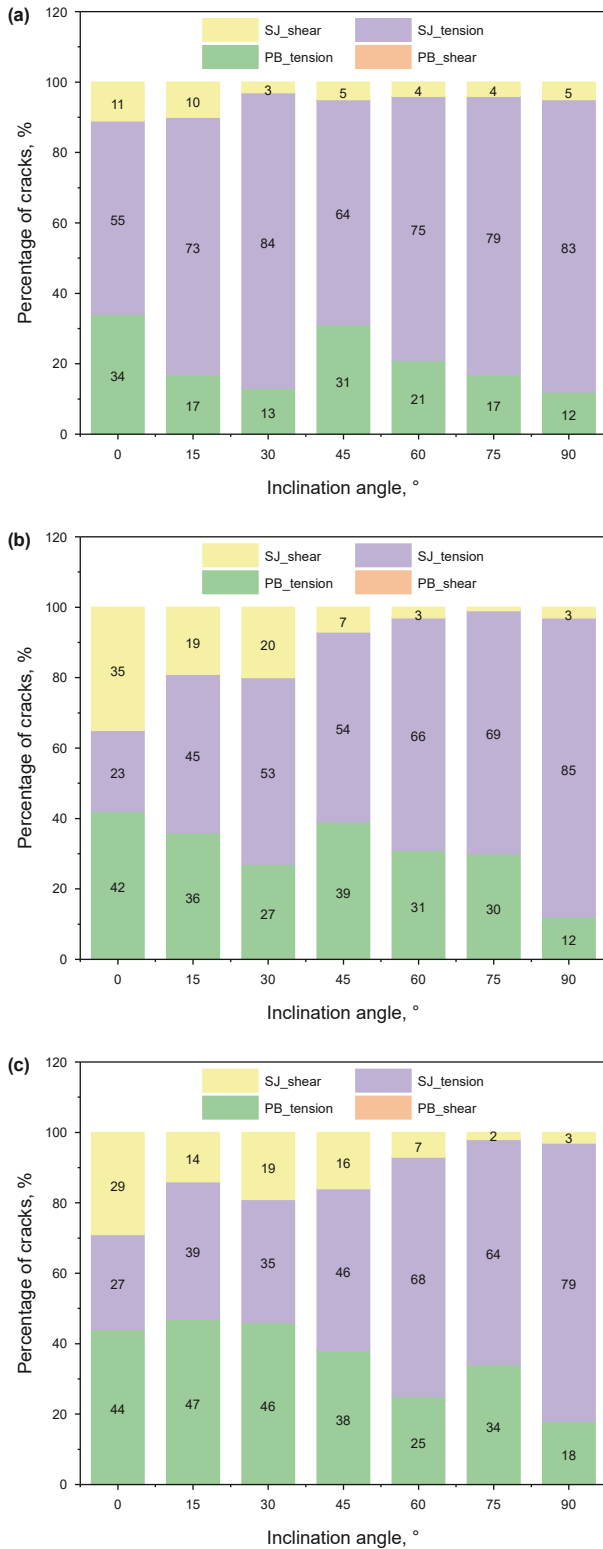


Fig. 14. The proportion of PB tensile-shear cracks and SJ tensile-shear cracks under different bedding inclination angles and stress conditions. (a) $K_0 = 1$, (b) $K_0 = 0.8$, (c) $K_0 = 2/3$.

3.2. Establishment and validation of hydraulic fracturing models

As shown in Fig. 5, a hydraulic fracturing model with dimensions of $0.3 \text{ m} \times 0.3 \text{ m}$ was established, where β is defined as the angle between the bedding plane and the positive x -axis direction. To simulate the state of shale under *in-situ* stress at a depth of 1000 m, the empirical formula by Li et al. (2012b) was employed to set the vertical stress to 20 MPa, the horizontal stress to 20 MPa, and the initial pore pressure to 10 MPa. Furthermore, the formation is assumed to be fully saturated. The model's effectiveness was validated by comparing the stresses near the injection hole with theoretical solutions. The injection hole radius is 10 mm. *In-situ* stress remained constant throughout the fracturing process. The confining pressure principle dynamically calculates and controls the velocity of the boundary wall based on the difference between the measured stress and target stress ($\Delta\sigma$) and stiffness.

The hydraulic fracturing model parameters are based on the calibrated microparameters listed in Table 1. To enhance simulation efficiency, the minimum particle size for the fracturing model is set to 1.2 mm. Fluid parameters, such as bulk modulus and fluid viscosity, are derived from water. The permeability distribution of shale ranges from nano-darcy (nD) to micro-darcy (μD) (Sander et al., 2017). The residual aperture w_0 can be estimated based on Eq. (6) (Duan et al., 2021; Li et al., 2024):

$$w_0 = \sqrt[3]{\frac{12k_0 V_m}{N\bar{R}}} \exp\left(-\frac{\gamma\sigma_n}{3}\right) \quad (6)$$

Here, k_0 is the permeability of the model, V_m is the area of the model, N is the number of particles, and $\bar{R}$ is the average particle radius. In the model, $N = 9897$, $\bar{R} = 0.0016 \text{ m}$, and $V_m = 0.09 \text{ m}^2$. The reservoir's equivalent permeability is considered to be $0.1 \mu\text{D}$, and the initial aperture w_0 can be calculated using Eq. (6), yielding $1.9 \times 10^{-7} \text{ m}$. The effect of confining pressure on macroscopic permeability can be determined from Duan et al. (2021), where its value is set to 0.08 MPa^{-1} . Additionally, the microscopic parameters of the injected fluid in the model are shown in Table 2.

In the DEM model, two sets of measurement circles (diameter = 16 mm) are installed to measure stress conditions, as shown in Fig. 6. The first set consists of 36 measurement circles uniformly distributed around the wellbore wall at $r = 20 \text{ mm}$. The second set comprises 16 measurement circles along the x -axis, ranging from $x = 20 \text{ mm}$ to $x = 140 \text{ mm}$. The stresses measured from these circles can be transformed into polar coordinates using the equation (Duan and Kwok, 2016).

To validate the numerical model, we measured the stress distribution of the isotropic model near the injection hole under three far-field stress conditions: (a) $\sigma_x = 20 \text{ MPa}$, $\sigma_y = 20 \text{ MPa}$; (b) $\sigma_x = 20 \text{ MPa}$, $\sigma_y = 25 \text{ MPa}$; and compared (c) $\sigma_x = 20 \text{ MPa}$, $\sigma_y = 30 \text{ MPa}$ with the analytical solution (Duan and Kwok, 2016).

Fig. 7 compares the stress distribution around the wellbore and along the positive x -axis direction, as calculated from the analytical solution, with the stress distribution measured from the DEM model. Compressive stress is represented by positive values. From Fig. 7(a–c), the radial stress (σ_{rr}) remains nearly constant. It can be observed that the radial stress near the hole exhibits significant deviation from the analytical solution, likely due to the inherent heterogeneity of the discrete element model itself, leading to high

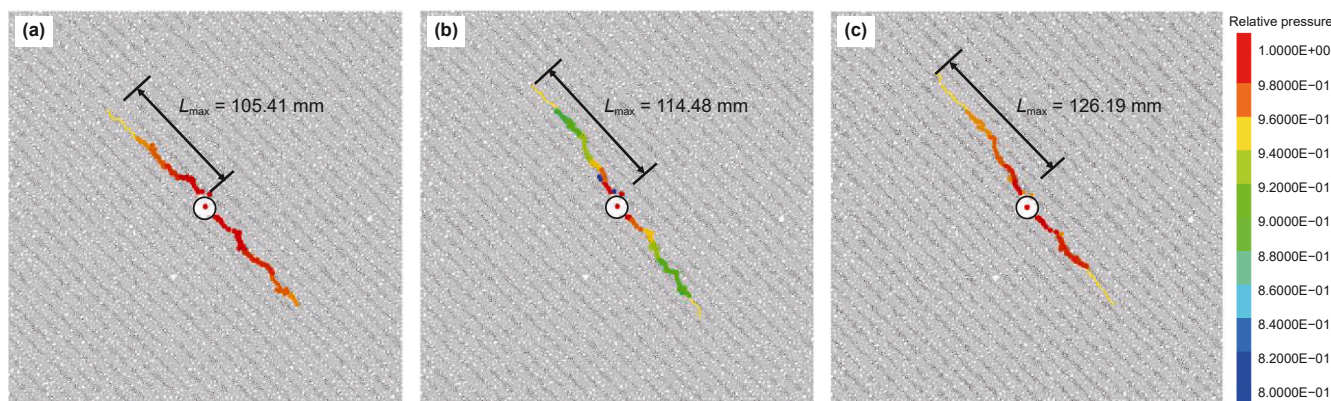


Fig. 15. Hydraulic fracture propagation at a 45° bedding inclination under different injection rates. (a) $1.0 \times 10^{-3} \text{ m}^3/\text{s}$, (b) $5.0 \times 10^{-3} \text{ m}^3/\text{s}$, (c) $1.0 \times 10^{-2} \text{ m}^3/\text{s}$.

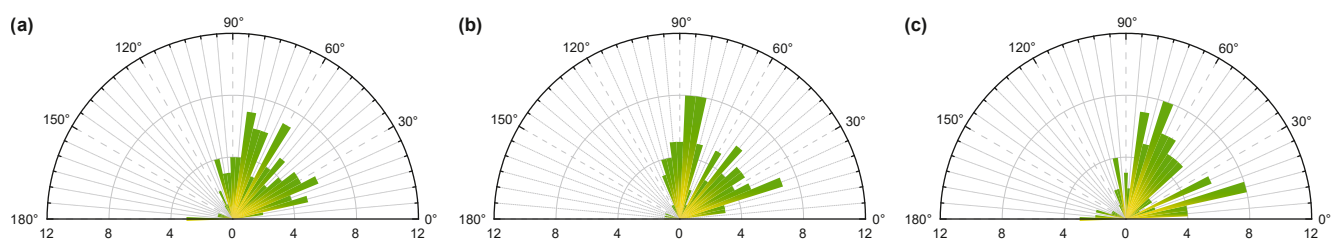


Fig. 16. Wind rose diagram of fracture dip angles at a 45° bedding inclination angle under different injection rates. (a) $1.0 \times 10^{-3} \text{ m}^3/\text{s}$, (b) $5.0 \times 10^{-3} \text{ m}^3/\text{s}$, (c) $1.0 \times 10^{-2} \text{ m}^3/\text{s}$.

stress concentration at certain points (Duan and Kwok, 2016; Zhang et al., 2024). Furthermore, the substantial deviation between radial stress near $x = 40 \text{ mm}$ and the analytical solution is attributed to increased model heterogeneity caused by a limited number of particles. Subsequent simulations with a larger number of particles demonstrate a gradual reduction in this discrepancy. Fig. 7(a) shows that shear stress remains zero due to the symmetric geometry and loading conditions. Along the x -axis, $\sigma_{\theta\theta}$ continuously decreases while σ_{rr} continuously increases until both principal stresses approach the applied far-field stress. Fig. 7(b) and (c) reveal that the anisotropy of the far-field stress significantly influences the stress distribution. Both the tangential stress ($\sigma_{\theta\theta}$) and shear stress ($\sigma_{r\theta}$) exhibit periodic fluctuations, which intensify as σ_Y increases. At 90° and 270°, $\sigma_{\theta\theta}$ reaches its minimum value, aligning with the direction of the maximum stress (σ_Y). The magnitude and oscillation characteristics of the three stress components show excellent agreement between the analytical and numerical results.

4. Patterns of hydraulic fracture propagation in anisotropic bedding shale

4.1. Hydraulic fracture propagation characteristics

Prior to fluid injection, the wellbore wall undergoes compression due to confining pressure. As fluid pressure increases, the stress state within the wellbore wall progressively shifts towards tensile stress. As illustrated in Fig. 8, under the same model, as the fluid pressure in the injection well gradually increases, the overall tangential stress around the wellbore decreases. When the tangential stress becomes negative, as at 110°, 320°, and 340°, it indicates that the stress state in these regions has transitioned to tensile stress. Three tensile cracks form when the tensile stress exceeds the tensile strength. The cracks initially manifest on the borehole wall, aligning with the direction of the bedding planes.

The evolution of the crack at each time step is shown in Fig. 9, where tensile microcracks are represented by red lines and fluid pressure is represented by green dots. It can be observed that crack propagation and fluid infiltration occur simultaneously, with fluid permeating along the crack path and driving the propagation process. The resulting crack morphology exhibits an asymmetric double-winged crack, roughly parallel to the bedding plane direction.

4.2. Factors affecting crack propagation

4.2.1. Effect of in-situ stress

Although extensive research has been conducted on the effects of *in-situ* stress and injection rate on hydraulic fracturing of bedding shale (Zhang et al., 2023b, 2024; Chang et al., 2022; Duan et al., 2018), most studies have been carried out on an isotropic basis. For bedding shale exhibiting significant anisotropy, vertical stress and injection rate not only independently influence fracture initiation and propagation but also interact with bedding inclination to jointly determine fracture orientation and branching. Therefore, this section explores the effects of vertical stress and injection rate on hydraulic fracture propagation behavior, providing a more targeted engineering foundation for optimizing fracturing designs.

A hydraulic fracturing model with a 45° bedding inclination was selected to investigate the influence of varying stress conditions on hydraulic fracture propagation. The injection rate was set to $5.0 \times 10^{-3} \text{ m}^3/\text{s}$, and the relative pressure was defined as the ratio of net pore pressure to maximum pressure. The lateral pressure coefficient K_0 was defined as the ratio of horizontal stress to vertical stress. Fig. 10 reveals that hydraulic fractures generally exhibit significant tortuosity and asymmetric propagation due to local heterogeneity. As K_0 gradually decreases, the relative fluid pressure becomes less effectively distributed—shifting from initial coverage at the fracture tip to concentration near the wellbore end.

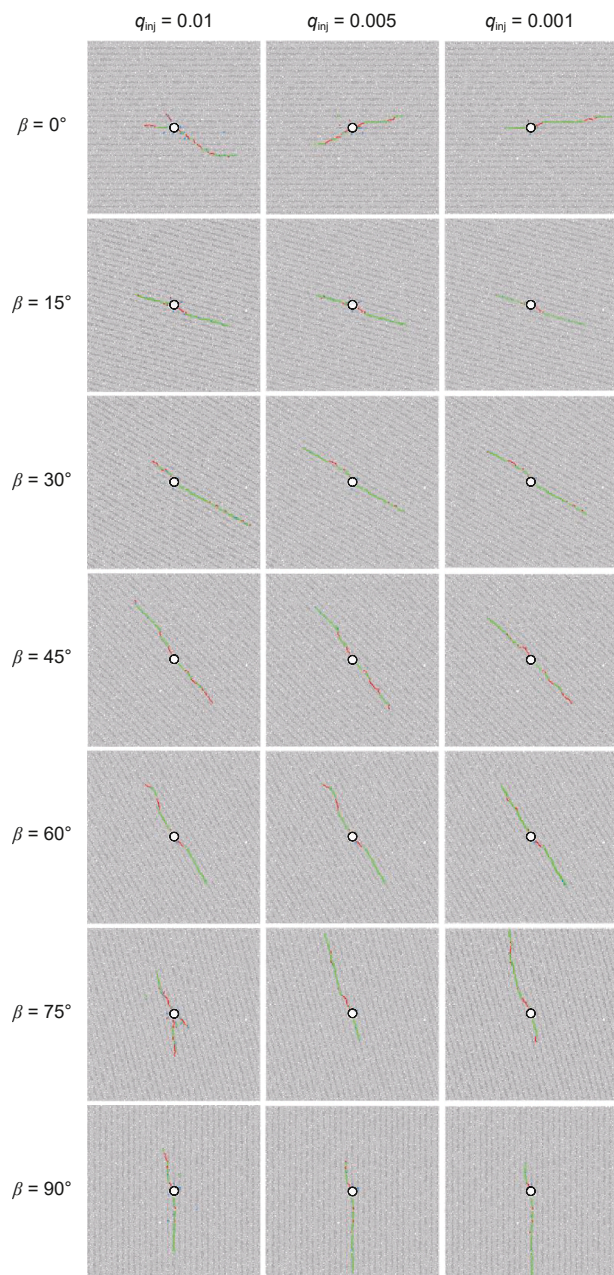


Fig. 17. Hydraulic fracture propagation behavior under different bedding inclinations and injection rates (red = PB tension crack, black = PB shear crack, green = SJ tension crack, blue = SJ shear crack).

The crack propagation path indicates that as K_0 decreases, cracks in the upper wing first propagate along the rock matrix and then along the bedding plane. However, due to increased vertical stress, the cracks gradually shift toward the direction of maximum principal stress (the vertical direction), resulting in an additional layer-crossing propagation event. Furthermore, the model with $K_0 = 2/3$ exhibits an additional secondary crack. As K_0 decreases, the crack length L progressively diminishes from 114.48 to 92.95 mm. This reduction occurs because lower K_0 values induce more interbedding failures and even secondary cracks, resulting in shorter overall crack lengths.

Fig. 11 demonstrates that varying *in-situ* stress conditions significantly influence the propagation direction of hydraulic fractures at 45° bedding inclination. When $K_0 = 1$, fracture

inclinations predominantly fall within the 75° – 85° range, with eight fractures in each interval. As K_0 decreases to 0.8, fractures primarily cluster between 85° and 90° , with seven fractures in this range. When K_0 decreases to $2/3$, the crack inclinations predominantly range from 45° to 50° , with eight cracks in this interval. The crack inclination distribution does not approach 90° , likely due to the influence of secondary cracks forming around 45° . This suggests that smaller *in-situ* stress differentials can reduce the occurrence of secondary cracks.

To comprehensively investigate the effects of varying *in-situ* stresses on the initiation and propagation of hydraulic fractures in shale with different bedding inclinations, a series of numerical studies was conducted under normal fault stress conditions ($\sigma_V > \sigma_H$). The primary focus was on crack propagation patterns around the wellbore, displacement field distributions, and hydraulic fracture failure modes. The micro-parameters and hydraulic parameters in the model were identical to those in Section 4.1. The horizontal stress (σ_H) was consistently maintained at 20 MPa, while the vertical stress (σ_V) was set to 20, 25, and 30 MPa, respectively.

Fig. 12 illustrates crack propagation in shale with varying bedding inclinations under three distinct *in-situ* stress conditions during hydraulic fracturing. The crack propagation patterns predominantly exhibit single hydraulic fractures extending along bedding planes, primarily because bedding strength is significantly lower than rock matrix strength. During crack initiation, the initiation location and propagation path are controlled considerably by the bedding plane inclination and *in-situ* stress. At low inclination ($\beta = 0^\circ$), *in-situ* stress significantly influences the initiation location at the wellbore. At other inclinations, variations in vertical stress have little effect on crack initiation location but do affect the propagation path.

Under *in-situ* stress condition ($K_0 = 1$), hydraulic fracturing primarily induces tensile failures along bedding planes, accompanied by minor tensile failures along the matrix. From $K_0 = 1$ to $K_0 = 2/3$, the crack propagation direction gradually shifts toward the maximum principal stress direction. This manifests as the crack tip transitioning from propagating along bedding planes to progressively traversing the rock matrix, with an increase in the frequency of interbedding failure. Analysis of the effects of *in-situ* stress on models with varying bedding inclinations reveals that as the bedding inclination increases, the influence of vertical stress variations on crack propagation path diminishes. At 0° bedding inclination, extensive tensile matrix failure occurs around the wellbore. The primary crack propagation direction shifts from two to three, accompanied by numerous interbedded cracks. This happens because the dominance of interbedded cracks weakens, leading cracks to manifest predominantly as secondary cracks.

High stress differentials ($K_0 = 2/3$) compel hydraulic fractures to traverse bedding planes directly. This phenomenon closely aligns with the physical observations documented by **Ma et al. (2017)** in their laboratory triaxial fracturing experiments. They observed that LMX-1 rock specimens subjected to high vertical stress differentials (vertical stress 30 MPa, minimum horizontal stress 10 MPa, stress differential up to 20 MPa) exhibited a pronounced tendency for hydraulic fractures to traverse bedding planes directly upon encountering them. This finding further corroborates the reliability of the simulation results.

Fig. 13 displays the displacement field from a hydraulic fracturing model under varying *in-situ* stress conditions and different bedding plane inclinations. It is evident that both bedding plane inclination and *in-situ* stress influence the morphology of the displacement field, as well as the distribution of high-displacement zones near the wellbore and low-displacement zones near the fracture tip. The red displacement zones

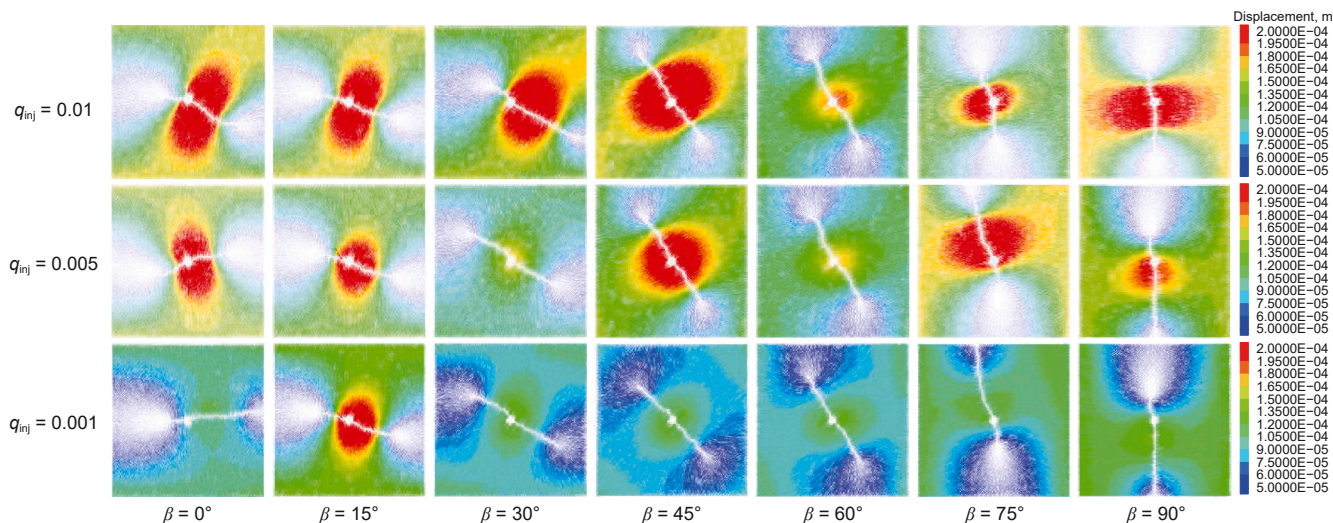


Fig. 18. Displacement field of hydraulic fracturing numerical models under different injection rates and bedding inclination angles.

surrounding the wellbore indicate the maximum displacement in this vicinity, driven by higher fluid pressure. The morphology and extent of low-displacement zones reflect the degree of interaction between *in-situ* stress and hydraulic fracturing. The outward displacement direction in the low-displacement zones indicates that the effect of hydraulic fracturing outweighs the influence of *in-situ* stress. On the other hand, the displacement zones on both sides of the main fractures exhibit not only large magnitudes but also extensive coverage. For instance, in the model with a bedding inclination of 15°–90°, two asymmetrically distributed main fractures align in a straight line, directly splitting particles along the bedding plane. Compared to the $K_0 = 0.8$ and $K_0 = 2/3$, it can be concluded that interbedded fractures exhibit a more substantial hydraulic fracturing effect.

To further investigate the micro-fracture mechanisms under varying *in-situ* stress conditions during hydraulic fracturing of bedding shale, the percentage distribution of PB tensile cracks, PB shear cracks, SJ tensile cracks, and SJ shear cracks in Fig. 12 was analyzed. The results are shown in Fig. 14. The study revealed that both bedding inclination and *in-situ* stress significantly influence microfracture evolution. Specifically, in Fig. 14(a–c), the model primarily exhibits tensile failure with minimal shear failure, and no matrix shear failure is observed. Shear cracks on bedding planes account for a maximum of 35%, clearly demonstrating that during hydraulic fracturing of bedding shale, hydraulic fractures primarily propagate along bedding planes, generating a large number of tensile cracks. Simultaneously, across specimens from 15° to 75°, the percentage of tensile fractures on bedding planes (SJ_tension) gradually decreases as K_0 decreases, while the percentage of tensile fractures in the matrix (PB_tension) gradually increases. This indicates that under vertical stress influence, the model exhibits more matrix tensile failure traversing bedding planes. In contrast, the 90° specimen exhibits no significant variation in the ratio of SJ to PB tensile cracks under different stress conditions. Furthermore, for specimens with low inclinations (0° to 45°), the proportion of shear failure along bedding planes increases as K_0 decreases. This may result from heightened shear crack activity induced by elevated stress levels.

4.2.2. Effect of injection rate

Fig. 15 shows the hydraulic fracture propagation patterns at a 45° bedding inclination under different injection rates. It can be observed that when the injection rate increases from 1.0×10^{-3} to

1.0×10^{-2} m³/s, the initiation location of hydraulic fractures remains largely unchanged. However, the expansion path primarily affects the upper wing of the fractures more significantly. As the injection rate increases, the maximum crack propagation length increases from 105.41 to 126.19 mm. This may be attributed to high injection rates reducing crack tortuosity and surface roughness, as the fluid permeation time is shorter (Zhang et al., 2024). Fig. 16 shows that as the injection rate increases, the range of crack inclination angles shifts from the initial vicinity of 45° to the vicinity of 90° or 0°. This demonstrates that increased local fluid pressure alters the direction of crack propagation.

To comprehensively investigate the influence of injection rates on the initiation and propagation of hydraulic fractures in other bedding shales, three injection parameters were employed in the numerical simulation: 1.0×10^{-3} , 5.0×10^{-3} , and 1.0×10^{-2} m³/s. The confining pressure in both the horizontal and vertical directions of the model was set to 20 MPa. All other micro-parameters and hydraulic parameters of the model remained consistent with those in Section 4.1.

The simulation results for fracture distribution and model displacement field are shown in Figs. 17 and 18, respectively. Fig. 17 indicates that injection rate and bedding inclination exert certain influences on the initiation and propagation of hydraulic fractures. When the injection rate is 1.0×10^{-3} m³/s, all layered models develop only two main fractures. When the injection rate increases to 1.0×10^{-2} m³/s, only the 0° and 75° models develop three main fractures. This occurs because as the injection rate increases, the fracturing fluid injected through the wellbore cannot dissipate quickly enough, leading to elevated pressure at the injection well. Consequently, fracture initiation points may occur at more locations. Fig. 18 visually demonstrates that as the injection rate increases, the red displacement range of particles near the wellbore gradually expands, while the blue displacement range near the fracture tip diminishes. This indicates insufficient fluid flow within the fracture, causing greater particle disturbance near the injection hole. Therefore, increasing the injection rate yields superior hydraulic fracturing results.

High injection rates promote the formation of complex, multi-branched fractures and flatten their morphology. This aligns perfectly with recent *in-situ* shale fracturing results monitored via acoustic emission and CT scanning by Zhang et al. (2024) and Chang et al. (2022), confirming that high injection rates induce the generation of intricate branched fracture networks.

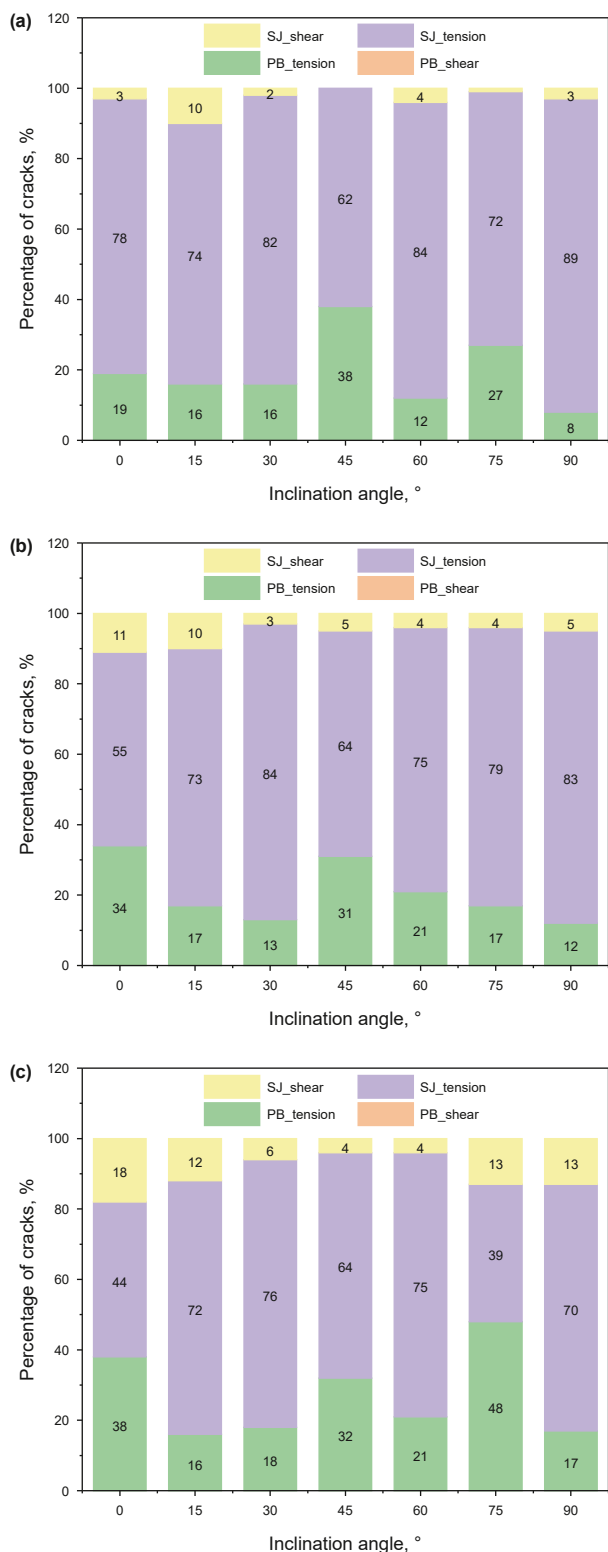


Fig. 19. The proportion of PB tension-shear cracks and SJ tension-shear cracks under different injection rates and bedding inclinations. (a) $1.0 \times 10^{-3} \text{ m}^3/\text{s}$, (b) $5.0 \times 10^{-3} \text{ m}^3/\text{s}$, (c) $1.0 \times 10^{-2} \text{ m}^3/\text{s}$.

To understand the micro-fracture mechanisms of cracks in bedding shale during hydraulic fracturing under different injection rates, statistical analysis was conducted on the percentage distribution of PB tensile cracks, PB shear cracks, SJ tensile cracks, and SJ shear cracks depicted in Fig. 17. The results are shown in Fig. 19. Taking 0° bedding plane inclination as an example, as the injection rate increases, the proportion of tensile fractures on the bedding plane decreases from an initial 78% to 44%. Meanwhile, the proportions of shear fractures on the bedding plane and tensile fractures in the matrix increase from 3% to 18% and from 19% to 38%, respectively. This indicates that the injection rate alters fracture failure patterns. At low injection rates, failure is dominated by model SJ tensile failure; at high injection rates, failure is primarily a mixture of models PB and SJ tensile failure. Therefore, appropriately increasing the injection rate is an effective way to enhance hydraulic fracturing effectiveness.

5. Conclusions

- (1) Fracture initiation is governed by the evolution of tangential stress at the borehole wall. As fluid pressure accumulates, the tangential stress on the wellbore wall becomes negative (tensile stress), leading to the initiation of tensile fractures in regions such as 110° and 320° . The initial fracture orientation highly correlates with the direction of the bedding plane. The subsequent propagation involves simultaneous fluid infiltration and crack extension, resulting in the formation of asymmetric, bedding-parallel double-wing fractures.
- (2) The *in-situ* stress regime plays a critical role in determining fracture geometry and cross-layer behavior. A reduction in the lateral pressure coefficient (K_0) from 1 to $2/3$ was found to suppress fracture growth, decreasing the maximum crack propagation length from 114.48 to 92.95 mm (about 18.8% reduction). Under low K_0 conditions, the dominance of vertical stress reorients the fracture path from bedding-parallel to vertical propagation (along the maximum principal stress). This reorientation promotes cross-layer propagation and the development of secondary cracks, thereby enhancing the complexity of the fracture network.
- (3) Elevating the injection rate from 1.0×10^{-3} to $1.0 \times 10^{-2} \text{ m}^3/\text{s}$ significantly promotes fracture extension. Higher rates resulted in an increase in maximum crack propagation length from 105.41 to 126.19 mm (19.7%), while simultaneously mitigating fracture tortuosity and surface roughness. Furthermore, high-rate injection expanded the high-displacement zone around the borehole and facilitated fracture branching (e.g., the development of three main fractures in 0° and 75° bedding models), confirming that higher flow rates are conducive to forming more complex fracture networks.
- (4) Hydraulic fracturing in anisotropic shale is predominantly characterized by tensile failure, with shear failure playing a subsidiary role (bedding-plane shear cracks generally constitute less than 35% of the total). The failure mechanism is highly sensitive to operating conditions: a decrease in K_0 or an increase in injection rate drives a transition from a “bedding-dominated” to a “matrix-dominated” regime. For instance, at a 0° bedding inclination, increasing the injection

rate reduced the proportion of bedding-plane tensile cracks (SJ_tension) from 78% to 44%, while increasing matrix tensile cracks (PB_tension) from 19% to 38%. This shift indicates that high stress differentials and high flow rates effectively overcome bedding confinement and induce matrix failure.

CRediT authorship contribution statement

Cheng Hu: Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Data curation. **Jun-Peng Zou:** Writing – review & editing, Supervision, Resources, Project administration, Funding acquisition. **Yu-Yong Jiao:** Writing – review & editing, Supervision. **Hong-Fei Duan:** Writing – review & editing, Resources, Conceptualization. **Quan Zhang:** Writing – review & editing, Supervision, Investigation, Data curation. **Xue-Feng Yan:** Writing – review & editing, Supervision, Formal analysis.

Data availability statement

Data will be made available on request.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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