

Original Paper

Experimental study on vertical propagation of hydraulic fracturing in multilayer permeability heterogeneous reservoirs: Based on true triaxial experiment and acoustic emission monitoring



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ABSTRACT

To investigate the influence mechanisms of formation permeability on hydraulic fracture vertical propagation behavior in the southern Songliao Basin of China, this study constructed a physical experimental model simulating multilayer permeability heterogeneous reservoirs. Through true triaxial hydraulic fracturing experiments combined with quantitative fracture area measurement, 3D fracture reconstruction, and real-time AE monitoring, systematic analysis was performed on key geological and engineering factors affecting fracture vertical extension. The results indicate that three typical distribution patterns exist in heterogeneous permeability formations: ascending pattern, sandwiched pattern, and leaping pattern. Interlayer permeability contrast significantly controls fracture propagation, with hydraulic fractures preferentially extending into high-permeability layers while low-permeability layers experience substantial suppression due to fluid competition. As the permeability ratio between adjacent layers and target layers increases, the fracture height-to-length ratio exhibits an upward trend. To quantitatively characterize cross-layer fracture propagation behavior, a critical threshold K_{ϕ} was innovatively defined. When $K_{\phi} \leq 0.5$, fractures are permeability gradient dominated; when $K_{\phi} > 0.5$, the regime transitions to middle layer weighting dominance. Increasing injection rate reduces fracturing fluid leak-off at weak interfaces, concentrating hydraulic energy at fracture tips to enhance penetration capacity into low-permeability layers. Low-viscosity fracturing fluids optimize fracture area distribution while maintaining cross-layer propagation capability. Vertical stress contrast positively correlates with fracture extension capacity in high-permeability layers but negatively correlates in low-permeability layers due to hydraulic isolation effects. These findings provide deeper insights into fracture geometry and propagation mechanisms in multilayer heterogeneous permeability formations, offering theoretical foundations for optimizing hydraulic fracturing design parameters.

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1. Introduction

As the global energy structure transitions toward low-carbon development, the exploitation of unconventional oil and gas resources such as shale oil and gas and tight oil and gas has become a core strategy for ensuring energy security (Wei et al., 2023; Zou

et al., 2018). Currently, major tight oil and gas blocks both domestically and internationally have established mature engineering systems with significant technological breakthroughs. However, in the southern Songliao Basin, China, reservoirs exhibit unique geomechanical characteristics. These formations feature vertically stacked lithological sequences demonstrating substantial interlayer variations in permeability and in-situ stress, resulting in severely confined vertical fracture propagation during hydraulic fracturing operations, thus constraining stimulation effectiveness (Cai et al., 2022; Liu et al., 2023; Meng et al., 2024; Wang et al., 2024a). Furthermore, the dynamic coupling between permeability gradient distribution, the in-situ stress field, and

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fluid dynamics creates highly complex fracture propagation pathways. This results in numerous fracturing operations failing to effectively communicate with target formations, directly constraining individual well productivity enhancement (Fan et al., 2020; Guo et al., 2025; Shi et al., 2020; Zhang et al., 2023a). Therefore, investigating fracture propagation mechanisms in multilayer permeability systems holds significant theoretical and engineering value for guiding fracturing process optimization in such reservoirs.

Extensive physical experiments and theoretical studies on the true triaxial hydraulic fracturing mechanism for heterogeneous multilayer fracture propagation have been conducted both domestically and internationally (Guo et al., 2021; Heng et al., 2019; Huang et al., 2023; Xian et al., 2026; Xu et al., 2022). In unconventional reservoirs, factors influencing the vertical propagation of hydraulic fracturing cracks in heterogeneous reservoirs can be categorised into geological and engineering aspects. Geological factors primarily encompass differences in in-situ stress between strata, rock mechanical properties, stratum thickness, and interface characteristics. Engineering factors mainly include the injection rate and fracturing fluid viscosity (Wang et al., 2015; Yu et al., 2024; Zhao et al., 2022). To this end, Huang et al. (2024) investigated the influence of coal seam strength heterogeneity on hydraulic fracturing crack propagation across boundaries through physical experiments and numerical simulations. The results indicate that when cracks propagate from low-strength coal seams to high-strength zones, pump pressure increases significantly, fracture width enlarges, and both coal displacement and stiffness degradation rate accelerate; conversely, when fractures enter low-strength zones, pore pressure drops abruptly, triggering instantaneous crack propagation. Altammar et al. (2019) constructed multilayer specimens using a composite material of gypsum, talc, and anhydrite to investigate the influence of rock mechanical properties on hydraulic crack propagation. They concluded that cracks propagating from soft layers into hard layers deflect or bend to bypass high-modulus zones. Cong et al. (2024) conducted true triaxial hydraulic fracturing tests on horizontal wells using artificial specimens composed cement mortar-coated natural coal and mudstone interbeds. They analyzed the effects of in-situ stress, injection parameters, and interfacial cementation strength on fracture morphology. Their findings revealed that the vertical stress ratio, injection rate, and fracturing fluid viscosity promote fracture penetration through interbeds, while low stress ratios promote fracture deflection. Jiang et al. (2019) investigated the propagation behavior of hydraulic fractures crossing coal-rock interfaces under varying interfacial friction coefficients. They proposed a theoretical model that accounts for interfacial friction, stress state, and the angle between the hydraulic fracture and the interface. Zhang et al. (2022) investigated the influence of interlayer dip angle, vertical stress differential, interface strength, and interlayer brittleness on fracture propagation behavior in interbedded shale formations. They classified hydraulic fracture propagation patterns into four types: Type I-arresting pattern; Type II-deflection pattern; Type III-penetration pattern; Type IV-multi-composite pattern. However, some researchers have employed natural rock specimens to study fracture propagation behavior in composite formations. Tan et al. (2019) prepared three-layer and five-layer complex composite specimens of coal-rock and sandstone to investigate the effects of fracturing fluid viscosity and injection rate on fracture morphology. He et al. (2022) conducted hydraulic fracturing experiments on sandstone-mudstone-shale composite formations, analyzing the effects of lithological interfaces and fracturing fluid viscosity on fracture morphology. Zou et al. (2022) employed true triaxial fracturing experiments on thinly

interbedded tight sandstones from the Shanxi Formation in the Ordos Basin to reveal the mechanisms of non-uniform initiation and vertical propagation of multicluster fractures.

Numerical simulations also play a crucial role in studying hydraulic fracture propagation in complex formations (Hatami and Walsh, 2022; Pakzad et al., 2017; Peirce and Detournay, 2022; Zhang et al., 2024; Zou et al., 2025). Wang et al. (2024b) developed theoretical models and solution methodologies to investigate hydraulic fracture propagation mechanisms at heterogeneous interfaces. Their findings revealed that interfaces with abrupt elastic property changes induce multiscale tip behavior, and fracture propagation patterns are governed jointly by conventional toughness-viscosity competition parameters and material discontinuity effect parameters. Zheng et al. (2022) employed a three-dimensional block discrete element method to develop a hydraulic fracturing model for multilayered shale reservoirs with permeable bedding planes. They analyzed fracture penetration capability across layers based on dilation mechanisms under different fracturing fluid viscosity and injection rates. Their findings were corroborated by analogue material experiments conducted by Zhang et al. (2022). Although research on hydraulic fracture propagation in heterogeneous composite formations has progressed, existing studies exhibit limitations: First, physical simulation experiments have primarily focused on engineering parameters' influence on fracture morphology in heterogeneous reservoirs, while systematic investigations of propagation mechanisms in multilayer permeability systems remain scarce; Second, existing studies predominantly employ single-factor analysis to examine control mechanisms of geological/engineering parameters on fracture morphology, yet the competitive mechanisms of interlayer permeability within multilayer systems remain quantitatively unexplored; Third, traditional methods primarily rely on fracture surface morphology observations in rock specimens, making it difficult to accurately capture real-time dynamic evolution of 3D fracture networks.

In summary, this study addresses the critical issue of restricted vertical propagation of fractures in shallow, multilayer heterogeneous reservoirs. Based on defined permeability, mechanical properties, and stress conditions, a multilayer heterogeneous reservoir test model was constructed (Fig. 1). We conducted true triaxial hydraulic fracturing experiments combined with CT scanning and acoustic emission (AE) inversion for comprehensive fracture characterization. The study investigated the effects of permeability distribution, injection rate, fracturing fluid viscosity, and vertical stress gradient on vertical fracture propagation. The research unequivocally identified a permeability competition threshold dominated mechanism governing interlayer fracture penetration and further revealed distinct asymmetric propagation patterns under coupled flow-stress interactions. The findings of this study provide theoretical support for the development of heterogeneous reservoirs, effectively underpin the optimization and innovation of hydraulic fracturing technologies for shallow reservoirs in the Songliao Basin.

2. Experimental design and methods

2.1. Specimen preparation

Due to the difficulty in obtaining natural rock specimens from complex, heterogeneous reservoirs, this study employs compacted artificial rock specimens to construct multilayer heterogeneous rock specimens exhibiting permeability gradient distributions. This approach enables precise control over the spatial heterogeneity of permeability parameters across rock layers, providing a repeatable, standardized specimen foundation for conducting

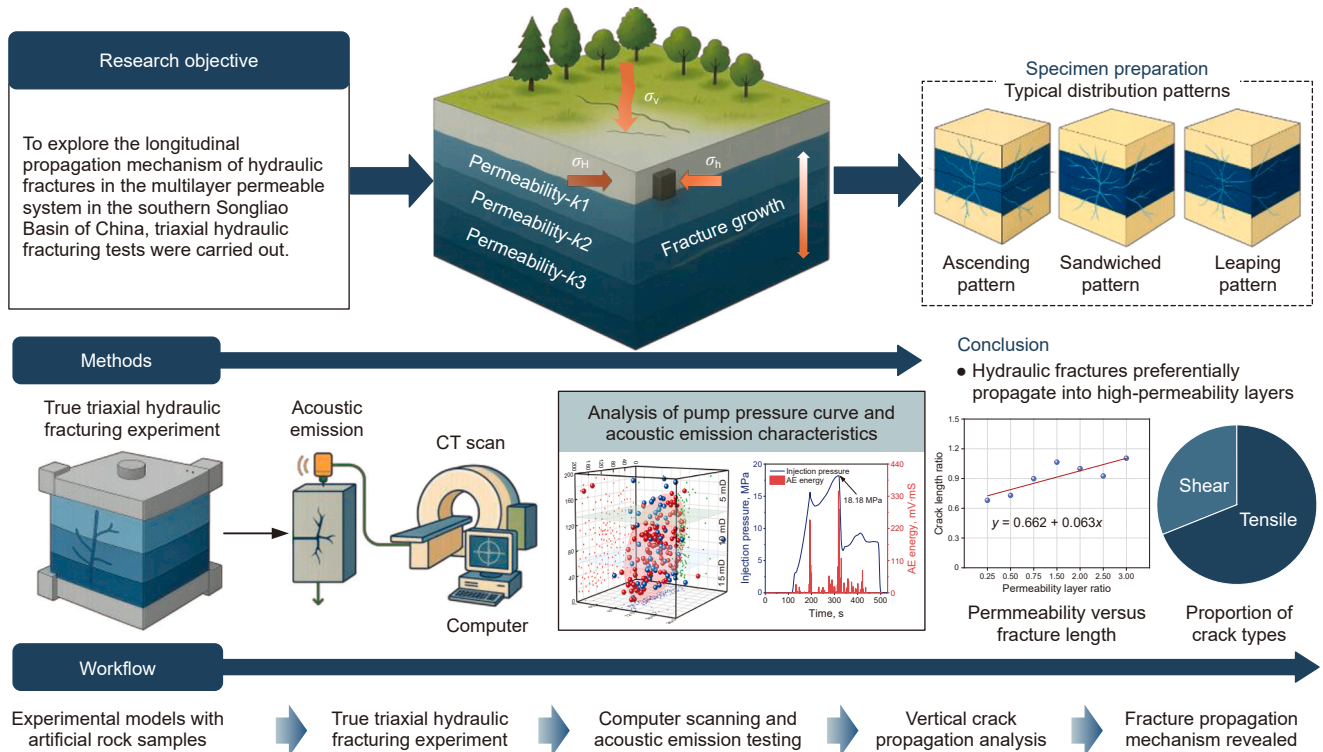


Fig. 1. Construction of a multilayer permeability heterogeneous reservoir physical model.

physical simulation experiments of hydraulic fracturing (Cong et al., 2022; Xue et al., 2022; Zhang et al., 2019).

Fig. 2 illustrates the fabrication process for multilayer heterogeneous rock specimens prepared using a $200 \times 200 \times 200$ mm cubic steel mold. The artificial rock specimens prepared using a layer-by-layer progressive compaction process achieved precise control of single-layer permeability through accurate regulation of quartz sand ratios and epoxy resin infiltration pressure while constructing gradational interlayer transition zones with layer thicknesses of approximately 2 mm. Since the experiment focused on the influence of permeability heterogeneity on fracture

propagation natural fractures were not explicitly introduced in the artificial rock specimens. The specific procedure is as follows: (1) Seven rock materials with different permeability values were selected for this study. Based on the target permeability requirements, quartz sand of various particle sizes was screened using standard sieves (coarse sand: 0.07–0.075 mm; medium sand 0.045–0.05 mm; fine sand <0.015 mm) through standard sieving. Epoxy resin binder and hardener were mixed at a predetermined ratio (5%–30% binder by mass of quartz sand) to ensure uniform encapsulation of sand particles and control pore structure. (2) Subsequently, the mixture is layered into a $200 \times 200 \times 200$ mm



Fig. 2. Fabrication process of multilayer heterogeneous rock specimens.

cubic steel mold. The three rock specimen layers measure 65, 70, and 65 mm thick respectively. After each layer is filled, a pronged compaction rake is used to gently agitate the mixture, eliminating internal voids and ensuring tight interlayer bonding. (3) After filling, the rock specimen is pressed in a hydraulic press and held at pressure for 30 min. The synergy of pressure and time regulates particle compaction and cement strength. (4) The pressed rock specimen is transferred to a constant-temperature curing chamber and cured at 50 °C for 36 h to enhance cement stability. (5) The specimen is placed in room temperature curing for 15 days before use.

To satisfy experimental requirements, this study prepared large-scale artificial rock specimens while simultaneously drilling layered core columns with a diameter of $\phi 25$ mm (covering 9 permeability zones). As shown in Table 1, key rock mechanical parameters including permeability, tensile strength, and elastic modulus were measured for the rock specimens. The average relative error between measured and target permeability values was $\leq 1\%$, meeting API core testing specifications. Furthermore, parameters such as tensile strength, elastic modulus, and Poisson's ratio for the prepared specimens fall within the typical mechanical characteristics range of sandstones in the study area (Du et al., 2025; Li et al., 2025; Vieira Lima et al., 2025; Zhang et al., 2023b), validating the geological similarity of the artificial rock specimens. This provides a reliable physical simulation foundation for studying reservoir fracturing mechanisms.

On the surface of the middle layer of the rock specimen, drill a 15 mm diameter, 160 mm deep hole along the reservoir strike to simulate a horizontal well. Simultaneously, use a 10 mm diameter, 150 mm long steel pipe as the wellbore model. At a position 20 mm below the bottom of the fracturing section, drill a 5 mm diameter flow-through hole. The specimen structure is shown in Fig. 2(c). After drilling, the specimen was left undisturbed for 12 h. The wellbore was then consolidated using marble adhesive and high-strength epoxy resin. Following 24 h of curing, the specimen underwent a hydraulic fracturing test to assess sealing performance. A pressure of 2 MPa was applied for 5 min. Finally, the treated specimen was placed in a cool room for 48 h to ensure complete bonding between the resin adhesive and the wellbore wall.

In this study, fracturing fluids with viscosities of 30, 100, 200, and 300 mPa·s were prepared. The 30 mPa·s fracturing fluid was formulated by mixing glycerol and water at a mass ratio of 1:6. For the 100 mPa·s viscosity, the fracturing fluid comprised 0.15% hydroxypropyl guar gum (HPG), 0.03% citric acid, and 0.5% surfactant, utilizing a weakly crosslinked network to suppress fluid loss. For the 200 mPa·s viscosity, the HPG concentration was increased to 0.25% based on the previous formulation, with 0.05% borax crosslinker introduced. The 300 mPa·s viscosity formulation consisted of 0.3% HPG, 0.08% citric acid, and 1% surfactant. Through the addition of 0.5% red tracer, fracture surface visualization was enhanced. Measured viscosities were 30.2 ± 1.5 , 98.7 ± 4.2 ,

203.6 ± 8.7 , and 298.4 ± 12.1 mPa·s respectively, with deviations $< 5\%$. This confirmed the formulation's reliability and controllability for studying fracture propagation in permeability gradient reservoirs.

2.2. Hydraulic fracturing experimental system

This study employed a self-developed true triaxial hydraulic fracturing physical simulation system (Fig. 3), integrated with CT scanning and AE synchronous monitoring technology to achieve multidimensional characterization of fracture dynamic propagation and rock fracture response during reservoir fracturing. The experimental apparatus consists of a true triaxial loading system, a fracturing fluid injection unit, and a multi-parameter synchronous monitoring system. The true triaxial loading system features three independently servo-controlled hydraulic cylinders capable of applying a maximum confining pressure of 70 MPa. It simulates in-situ reservoir stress conditions within a built-in fluid-solid coupling chamber. The fracturing fluid injection unit utilizes a high-precision plunger pump with a flow rate range of 0.01–50 mL/min and pressure resolution of 0.1 MPa.

The multi-parameter monitoring system achieves multiscale acquisition of fracture evolution through an AE array and CT scanning module. The AE monitoring system consists of an 8-channel wide-frequency AE sensor array with a frequency range of 20–400 kHz. AE sensors were mounted on the rock specimen surface, with sensor distribution shown as “Distribution of AE sensors” in Fig. 3(b). The emission frequency was set at 40 kHz, acquisition cycle at 0.4 μ s, and P-wave wavelength at 70 mm. This AE system enables real-time capture of spatiotemporal evolution characteristics of fracture initiation and branching events, accurately localizing fracture propagation positions and directions. The CT scanning system employs micro-focus X-ray CT technology with a resolution of 10 μ m and scanning interval of 0.1 mm. Post-experiment, 3D reconstruction of the rock specimen was performed to quantitatively analyze fracture geometry. Combined with permeability gradient distribution, the influences of geological and engineering factors on fracture propagation were analyzed.

2.3. Experimental procedures and plans

This study focuses on hydraulic fracture propagation behavior in multilayered heterogeneous permeability reservoirs. Through designed true triaxial hydraulic fracturing physical simulation experiments, it investigates the regulatory mechanisms of inter-layer permeability distribution, injection rate, fracturing fluid viscosity, and vertical stress difference on fracture propagation. The experimental procedure encompasses three stages: stress loading, fracturing fluid injection, and fracture characterization. First, rock specimens were placed in the true triaxial loading

Table 1
Physical and mechanical properties of simulated materials.

Test number	Permeability, mD	Porosity, %	Elastic modulus, GPa	Poisson's ratio	Uniaxial compressive strength, MPa	Tensile strength, MPa
#1-2.5mD	2.3	11.47	23.75	0.21	78.2	7.83
#2-5mD	5.4	13.21	20.52	0.22	71.9	5.97
#3-7.5mD	7.4	14.76	19.18	0.22	65.3	5.12
#4-10mD	10.4	16.08	18.26	0.22	59.7	4.62
#5-15mD	14.7	17.35	17.49	0.22	54.8	4.31
#6-20mD	20.8	18.52	16.72	0.23	50.3	3.94
#7-22.5mD	23.1	19.38	16.05	0.23	47.5	3.72
#8-30mD	29.6	20.64	15.42	0.23	43.1	3.48
#9-40mD	40.7	21.87	14.93	0.23	39.6	3.15

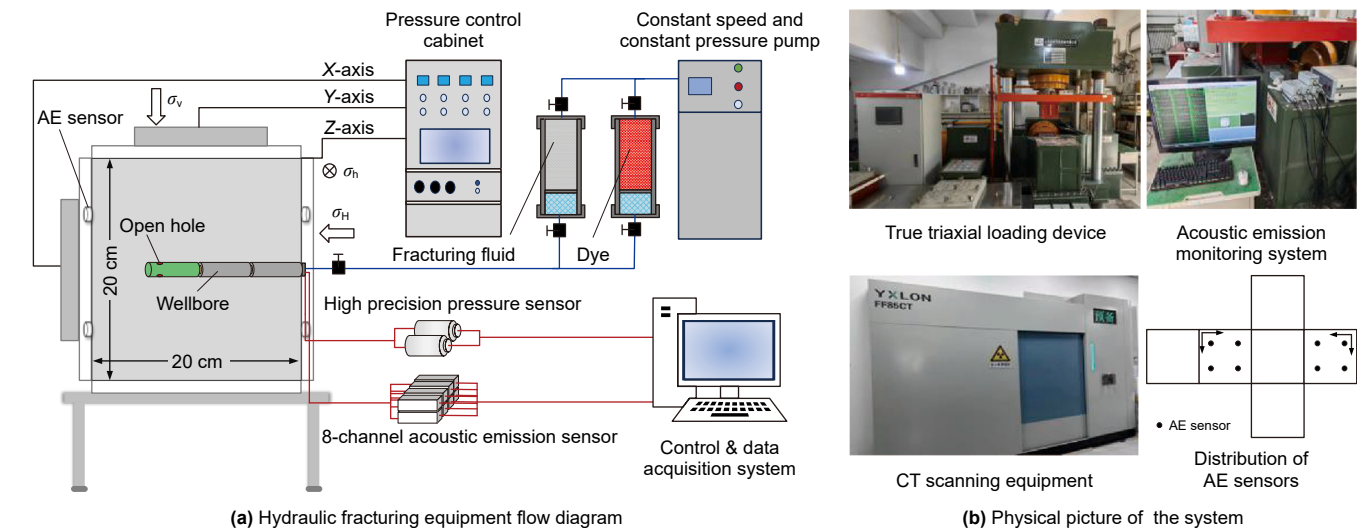


Fig. 3. Flowchart of true triaxial hydraulic fracturing.

system. Predefined triaxial stresses were applied through a servo-control module and maintained steadily for 30 min to eliminate stress relaxation effects. Subsequently, fracturing fluid was injected into the specimen using a high-precision plunger pump, while pressure-time curves and AE signals were synchronously collected to track fracture initiation and propagation in real-time. After fracturing completion, pressure was released and specimens were retrieved. Digital rock analysis systems were utilized for CT scanning, reconstructing three-dimensional fracture networks to quantify parameters including fracture length, branching angles, and interlayer penetration depth.

This study employed artificially prepared tri-layered heterogeneous specimens to simulate actual reservoir permeability heterogeneity. A total of 13 experimental sets were conducted, with detailed experimental schemes presented in Table 2. The triaxial stress parameters and operational parameters adopted in this experiment were determined by the scaling criteria (De Pater et al., 1994) and calibrated with in-situ stress data and operational data from shallow reservoirs in the southern Songliao Basin. The experimental scheme focused on four key parameter categories: permeability distribution, injection rate, fracturing fluid viscosity, and vertical stress difference. Using reference specimen #R1 as the baseline, four test groups were systematically compared. Group S (#S1–#S3) investigated the impact of multilayered permeability on fracture propagation by

configuring three permeability distributions: 15:20:40, 25:10:30, and 7.5:30:22.5 mD. Group F (#F1–#F3) quantified flow rate modulation effects in heterogeneous reservoirs at 5/10/15 mL/min injection rates. Group V (#V1–#V3) analyzed fracture propagation and fluid loss behavior using viscosity gradients of 100/200/300 mPa·s. Group T (#T1–#T3) revealed vertical stress difference controls on interlayer penetration by adjusting vertical principal stresses. This scheme establishes a multi-scale, multi-parameter collaborative experimental framework, providing systematic theoretical underpinnings for fracturing optimization in multilayered heterogeneous reservoirs.

3. Experimental results and analysis

3.1. Effect of interlayer permeability heterogeneity on fracture propagation

In multilayered permeability systems, the interlayer permeability heterogeneity exerts significant control over fracture propagation patterns. Utilizing CT scanning and AE monitoring techniques, we systematically investigated fracture propagation behaviors under different permeability distribution patterns. For experiments #R1, #S1, #S2, and #S3, three distinct types of permeability distribution patterns were designed as follows.

Table 2
Scheme for hydraulic fracturing simulation experiments.

Group	Test number	Triaxial stress, MPa			Flow rate, mL/min	Viscosity, mPa·s	Permeability distribution (K_{up} : K_{middle} : K_{down}), mD
		σ_v	σ_H	σ_h			
Reference specimen S	#R1	26	22	18	20	30	5:10:15
	#S1	26	22	18	20	30	15:20:40
	#S2	26	22	18	20	30	25:10:30
	#S3	26	22	18	20	30	7.5:30:22.5
F	#F1	26	22	18	5	30	5:10:15
	#F2	26	22	18	10	30	5:10:15
	#F3	26	22	18	15	30	5:10:15
V	#V1	26	22	18	20	100	5:10:15
	#V2	26	22	18	20	200	5:10:15
	#V3	26	22	18	20	300	5:10:15
T	#T1	24	22	18	20	30	5:10:15
	#T2	28	22	18	20	30	5:10:15
	#T3	30	22	18	20	30	5:10:15

- (1) Ascending pattern (AP): Low-medium-high permeability layers (e.g., 5:10:15, 15:20:40 mD), simulating positive rhythm reservoirs.
- (2) Sandwiched pattern (SP): Medium-low-high permeability layers (e.g., 25:10:30 mD), simulating reservoirs containing low-permeability interlayers.
- (3) Leaping pattern (LP): Low-high-medium permeability layers (e.g., 7.5:30:22.5 mD), characterizing discontinuous abrupt-permeability systems.

The permeability ratio range was set from 1:0.25 to 1:3 to quantify the control mechanisms of permeability heterogeneity on fracture morphology. All other parameters remained constant: vertical stress difference $\Delta\sigma_v = 8$ MPa, fracturing fluid viscosity $\mu = 30$ mPa·s, and injection rate $Q = 20$ mL/min.

The following displays the fracture pressure curves, AE characteristics, and 3D fracture reconstructions for specimens #R1, #S1, #S2, and #S3. Based on experimental data analysis, rock specimens with different permeabilities exhibit similar fracture evolution patterns during fracturing, specifically manifested in four continuous stages: Initial pressure storage period (Stage I): Pressure maintained baseline characteristics, as fracturing fluid gradually filled the wellbore annulus, the pump pressure curve began to show a gradual upward slope. No significant AE signals were observed in this stage; Fracture initiation period (Stage II): The pump pressure curve exhibited a steep surge. Upon reaching the critical fracture pressure, primary fractures began to nucleate. During this stage, with concurrent development of micro-fracture networks, the acoustic emission monitoring system captured low-frequency, low-amplitude AE signals; Fracture propagation period (Stage III): After primary fracture formation, the process entered a seepage-dominated phase. The pump pressure curve displayed high-level oscillations or stabilized characteristics. As fracture spaces became fully saturated, secondary fracture extensions could be induced. AE event frequency peaked during this stage; Pressure unloading period (Stage IV): Flowback operations commenced after injection cessation, causing the pump pressure to plummet precipitously. Fracture flow channels became fully connected, and virtually no AE activity was observable during this stage.

Fig. 4 presents experimental observations for specimen #R1 (5:10:15 mD), demonstrating significant coupling between hydraulic fracture propagation dynamics and pump pressure

fluctuations. As shown in Fig. 4(a), an approximate 3 s delay exists between AE signals and the pump pressure curve. During the initial propagation phase at $t = 117$ –204 s, pump pressure increased steadily at 0.22 MPa/s to its peak of 16.31 MPa, accompanied by densely released AE events with >60% concentrated in the 10 mD layer, reflecting localized fracturing behavior as the fracture tip encountered high-strength rock units. When pressure abruptly dropped to 10.48 MPa at $t > 204$ s with a subsequent secondary plunge, AE events in the 15 mD layer increased to 1.7 times those in the 5 mD layer, indicating a strongly permeability-gradient-controlled interlayer breakthrough mechanism, during fracture propagation from the 10 to 15 mD layer, fracturing fluid preferentially migrated toward the 15 mD medium, generating localized interlayer responses. Upon entering a stable period at $t > 257$ s, the pump pressure curve maintained oscillations within ± 0.1 MPa amplitude, corresponding to steady-state vertical propagation of the main hydraulic fracture (HF), where fracture geometry was essentially finalized with a total height of 168.58 mm and vertical fracture proportions of 19.9%, 41.5%, and 38.6% in the 5, 10, and 15 mD layers, respectively. The staged pump pressure evolution demonstrates that the steady pressure rise corresponds to 10 mD layer dominated fracture initiation, inter-layer pressure plunges reflect fluid-imbibition-induced drag reduction in the 15 mD layer, and stable oscillations arise from equilibrium between steady fracture propagation in the 15 mD layer and tip resistance in the 5 mD layer, enabling slightly asymmetric fracture extension.

Fig. 5 presents experimental observations for specimen #S1 (15:20:40 mD). The pump pressure curve reached its peak of 21.37 MPa at $t = 225$ s. At this moment, AE events were uniformly distributed across all three layers, indicating balanced fracture initiation from the 20 mD layer. When entering the fracture propagation phase at $t = 225$ –388 s, two gradient transitions occurred in pump pressure, simultaneously triggering a significant increase in AE energy density within the 40 mD layer. This demonstrates that high-permeability media, dominated by fluid-driven advantages, preferentially breached the effective stress threshold to form fractures. After secondary pump pressure gradually rose to 15.84 MPa, an abrupt pressure drop began, accompanied by complete fracture penetration through the entire 40 mD layer. At this stage, 46% of AE events concentrated in the 40 mD layer, reflecting frictional fracture extension along preferential flow channels. As shown in Fig. 5(b) and (c), the main fracture

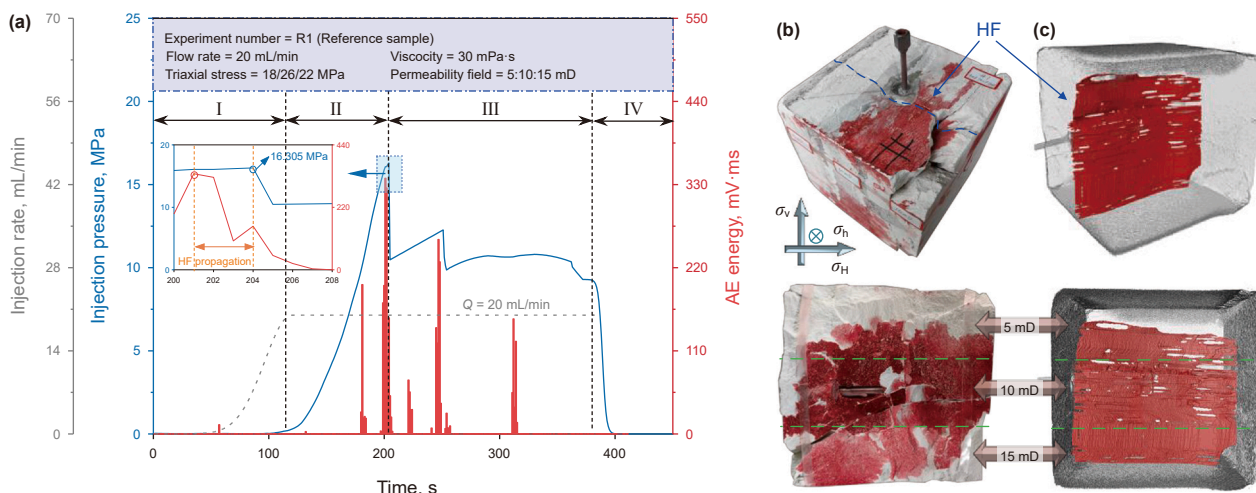


Fig. 4. Specimen #R1: (a) Pump pressure curve and AE data; (b) Physical hydraulic fracture morphology documentation of rock specimen; (c) CT-based 3D fracture reconstruction.

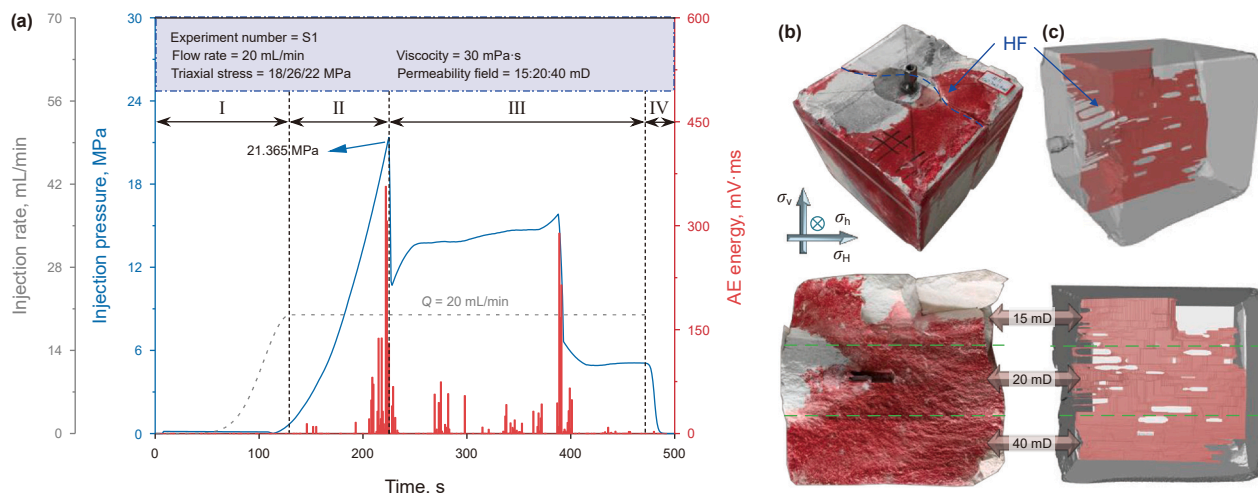


Fig. 5. Specimen #S1: (a) Pump pressure curve and AE data; (b) Physical hydraulic fracture morphology documentation of rock specimen; (c) CT-based 3D fracture reconstruction.

propagated primarily along the high-permeability 40 mD layer, exhibiting permeability gradient dominated asymmetric characteristics. The HF nearly penetrated all three layers, with vertical extension proportions of 28.9%, 36.8%, and 34.3% in the 15, 20, and 40 mD permeability layers respectively. The fracture extension ratios in medium/high-permeability layers significantly exceeded those in low-permeability layers, showing similar high-permeability-dominated fracture development characteristics as observed in specimen #R1.

Fig. 6 presents experimental observations for specimen #S2 (25:10:30 mD). This specimen exhibits a permeability configuration where a 10 mD low-permeability middle layer intercepts bilateral high-permeability layers of 25/30 mD. As shown in the pump pressure curve of Fig. 6(a), during the initiation phase at $t = 128\text{--}222$ s, pressure increased steadily at 0.21 MPa/s to its peak of 20.42 MPa. When $t > 222$ s, the pressure curve transitioned to an oscillating pattern. Ultimately, the accumulated AE event counts in the 25 and 30 mD layers approached a balanced ratio of 1:1.1, with highly convergent AE intensity frequency distributions, indicating minimal fluid loss rate differences between the bilateral high-permeability layers. As shown in Fig. 6(b) and (c), the HF propagated bidirectionally from the 10 mD layer to form a vertical main

fracture with a total height of 165.99 mm. The vertical fracture proportions in the 25, 10, and 30 mD layers were 24.4%, 42.2%, and 33.4% respectively. The fracture length difference between bilateral high-permeability layers reduced to 9%. This fracture distribution characteristic reveals the weak driving effect of the minor permeability gradient (25 $\rightarrow$ 30 mD), where the 30 mD layer leveraged its 1.2-times permeability advantage to generate limited driving force for fracture extension. This resulted in nearly balanced fracture propagation rates on both sides, ultimately forming a weakly symmetric extension structure constrained by the permeability gradient with the 10 mD layer as the central axis.

Fig. 7 presents experimental observations for specimen #S3 (7.5:30:22.5 mD). As shown in the pump pressure curve of Fig. 7(a), the pump pressure curve exhibits significant correlation with the permeability-layered structure. During the fracture initiation phase, pressure rose to its peak of 19.94 MPa, where fractures preferentially developed in the 30 mD layer. The distribution ratio of AE events between the 7.5 and 22.5 mD layers was 1:1.2, indicating relatively synchronized initial fracturing on the low-permeability side. When $t = 193\text{--}265$ s, the pump pressure curve displayed high-frequency oscillations. Pressure peaks corresponded to fluid release effects during rapid extension in the

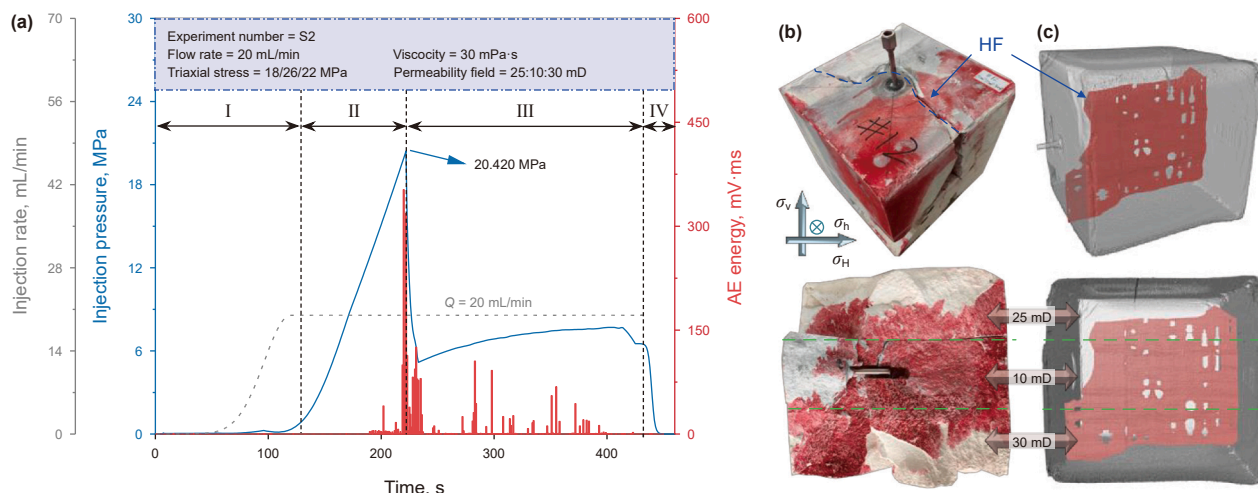


Fig. 6. Specimen #S2: (a) Pump pressure curve and AE data; (b) Physical hydraulic fracture morphology documentation of rock specimen; (c) CT-based 3D fracture reconstruction.

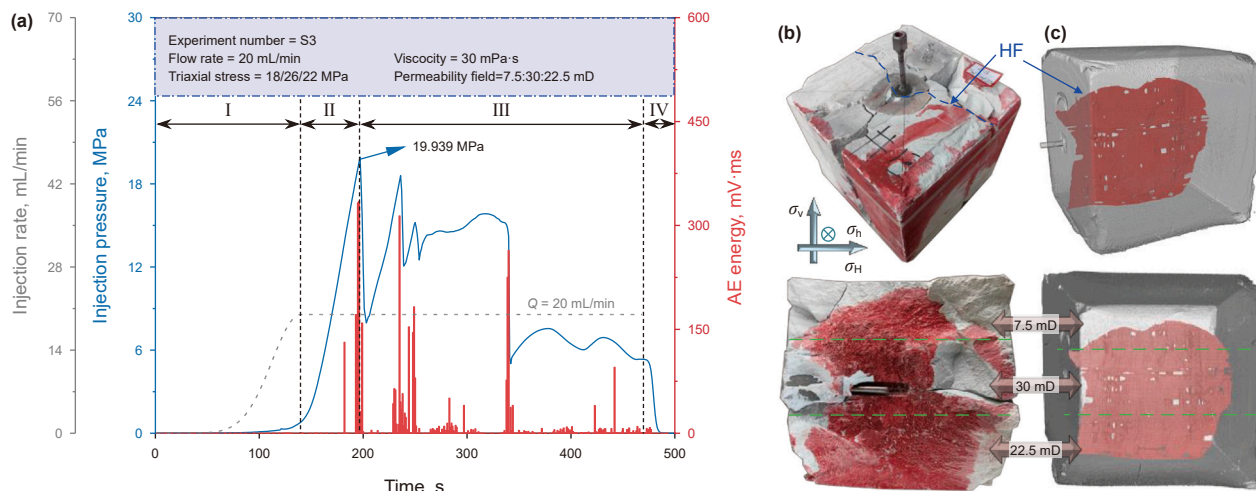


Fig. 7. Specimen #S1: (a) Pump pressure curve and AE data; (b) Physical hydraulic fracture morphology documentation of rock specimen; (c) CT-based 3D fracture reconstruction.

high-permeability 30 mD layer, while pressure troughs originated from sudden increases in extension resistance triggered by the 7.5 mD layer. The 22.5 mD layer provided wave-damping effects through fracturing fluid loss rates. As fracture propagation gradually stabilized, the 22.5 mD layer began to dominantly drive extension. As revealed in Fig. 7(b) and (c), CT 3D reconstruction confirms that fracture morphology is affected by the permeability gradient. The total fracture height reached 163.6 mm, with vertical fracture height proportions of 18.1% and 39.7% in the 7.5 and 22.5 mD layers respectively.

Fig. 8 reveals fracture characteristics driven by permeability gradients through a composite representation of layered fracture contact area (FCA) and AE event ratio (AER) in rock specimens. The bar chart represents FCA within individual permeability layers for each specimen, the curve shows AER within individual permeability layers, the error bars indicate the uncertainty discrepancy between fracture area data measured via CT scanning and physical specimen dissection.

Experimental observation of four specimen groups reveals that permeability differences significantly affect fracture extension. When the permeability ratio exceeds 1.5, obvious dominant channels form in high-permeability layers; for instance, the energy density peak in the 40 mD layer of specimen #S1 is notably higher than in the 15 mD layer. This phenomenon originates from

the dual optimization effect of high-permeability media, reducing critical stress required for rock rupture while enhancing fracturing fluid drive efficiency, thereby dominating vertical fracture extension (Wang et al., 2024a). Under moderate permeability differences, fracture propagation exhibits stepwise characteristics. Data from specimen #R1 demonstrate the 10 mD layer serves as an energy transfer hub, evidenced by its 48.5% FCA proportion and 44.7% AER. At this point, the 10 mD medium-permeability layer exploits its local permeability advantage over the overlying 5 mD low-permeability layer to create an interfacial pressure gradient, concentrating fracturing fluid into directional extension kinetic energy. In specimen #S2, FCA difference between the bilateral 25 and 30 mD high-permeability layers is only 8.3%, indicating weak permeability contrast fails to establish dominant pressure gradients, leading to uniform bilateral fracturing fluid energy distribution. Notably, specimen #S3 highlights the integration capability of the high-permeability core layer, the 30 mD layer accounts for 41.0% FCA and 45.6% AE energy, forming a hydraulic convergence core by adsorbing fracturing fluid. Simultaneously, the 22.5 mD layer exhibits 12.6% higher FCA than the 7.5 mD layer, verifying permeability control over fracture morphology.

In summary, for laminated reservoirs with heterogeneous permeability, the differentiation phenomenon in hydraulic fracture area fundamentally reflects competitive fracturing fluid allocation between layers. Taking specimen #S1 as an example, its 40 mD layer achieved an FCA of 12,041.94 mm²; based on average fracture width estimation, fracture volume in this layer accounted for 40.0% of the total volume, exceeding the 38.3% AER in the same layer. This discrepancy demonstrates that high-permeability layers optimize fluid transport pathways, achieving larger-scale fracture volume expansion at lower rupture energy consumption. This low-consumption high-efficiency characteristic stems from synergistic effects of fracture energy reduction and flow resistance attenuation. The fracture energy reduction effect manifests as reduced effective stress intensity in high-permeability media due to enhanced pore connectivity, enabling greater fracture surface growth per unit volume of AE energy release. The flow resistance attenuation effect is evidenced by significantly lower flow resistance in high-permeability layers compared to low-permeability layers, promoting preferential fracturing fluid injection into high-permeability channels. This phenomenon creates local fluid pressure buildup zones during injection, effectively accelerating fracture extension rates in high-permeability layers (Lyu et al., 2019).

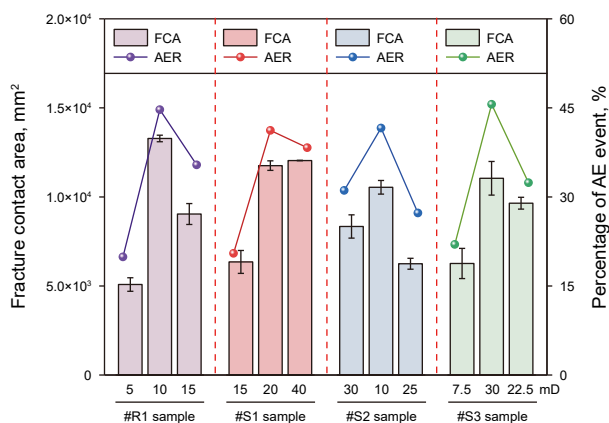


Fig. 8. Evolution curves of fracture contact area and AE events across different interlayer permeability distributions.

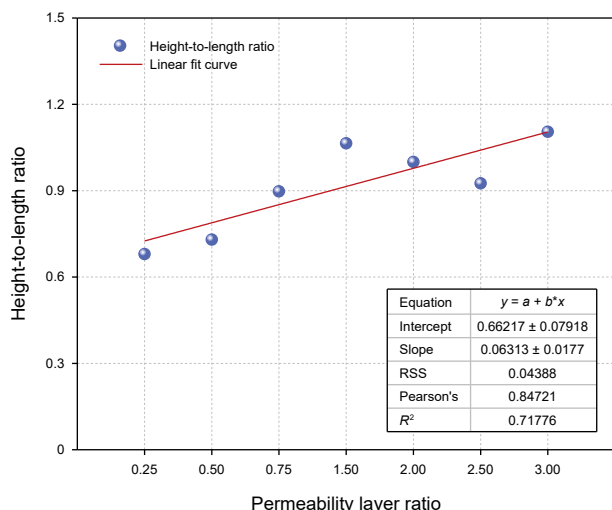


Fig. 9. Permeability gradient versus fracture length relationship curve.

Fig. 9 presents a fitting curve of permeability layer ratio (adjacent layer/target layer) versus fracture height-to-length ratio, demonstrating the control mechanism of permeability heterogeneity on fracture morphology. The horizontal axis represents adjacent layer permeability divided by central target layer permeability; the vertical axis shows adjacent layer vertical fracture length divided by central target layer horizontal fracture length.

Analysis of Fig. 9 indicates that as the permeability ratio increases, the fracture height-to-length ratio exhibits an overall upward trend, reaffirming high-permeability layers' control over fracture propagation direction. When adjacent layer permeability exceeds that of the central target layer ($x > 1$), fracturing fluid preferentially enters the high-permeability adjacent layer, driving rapid vertical fracture extension. In specimen #S1, adjacent layer ratios of 0.75 and 2 resulted in a significantly higher fracture length ratio in the 40 mD layer compared to the 15 mD layer. When adjacent layer permeability is lower than the central target layer ($x < 1$), as in specimen #S3, adjacent layer ratios of 0.25 and 0.75 confined fracturing fluid to the 30 mD layer, where horizontal fracture propagation dominated and vertical extension was constrained. This phenomenon demonstrates that a higher central layer permeability relative to adjacent layers promotes horizontal fracture extension, with the fracture length ratio increasing by approximately 6.3% on average per unit increase in permeability ratio. The intercept of the linear equation $y = 0.662 + 0.063x$ holds critical geological significance: when the permeability ratio equals 1 (homogeneous conditions), the fracture height-to-length ratio remains 0.73, indicating horizontal bedding planes still govern approximately 73% of horizontal propagation. The curve shows permeability differences explain about 72% of fracture differentiation behavior, with the remaining 28% attributed to dispersion. This dispersion reflects interference from non-permeability factors, potentially arising from interfacial roughness between the central layer and adjacent layers or pre-existing fractures.

3.2. Effect of injection rates on fracture propagation

This study selected four specimens, experimental groups #F1, #F2, #F3 and control group #R1, to investigate fracture propagation differences in multilayer permeability reservoirs under different injection rates. Each specimen was injected at rates of 5, 10, 15 and 20 mL/min respectively. The permeability distribution

of specimens was 5:10:15 mD with triaxial in-situ stresses of 26, 22 and 18 MPa. Fig. 10 displays 3D reconstruction results of fractures and pump pressure curves under different injection rates.

Analysis of Fig. 10(a) reveals that at an injection rate of 5 mL/min, fracture propagation in specimen #F1 was primarily controlled by the siphoning effect of high-permeability layers. Fractures preferentially extended along the underlying 15 mD high-permeability layer, with localized fractures developing in the medium 10 mD layer. The upper 5 mD low-permeability layer exhibited only faint fracture traces due to natural barrier effects. Both 3D CT reconstruction and physical specimen imaging confirm that the vertical main fracture did not reach the 15 mD layer but initiated at the 10 mD/15 mD interface, achieving an interlayer fracture area of 23,938.29 mm². The fracture morphology displayed a single dominant branch with sparse dye tracer distribution, where low-permeability boundaries clearly restricted vertical growth, conforming to the path of least resistance mechanism. When injection rate increased to 10 mL/min (Fig. 10(b)), under identical permeability and geostress conditions, breakthrough propagation occurred in the 5 mD low-permeability layer, enhancing full-layer connectivity. The pressure curve indicates a peak pump pressure decrease to 19.02 MPa, 10.6% lower than specimen #F1, demonstrating that heightened fluid kinetic energy partially offset low-permeability barrier resistance. At 15 mL/min (Fig. 10(c)), fracture propagation transitioned to fluid-dominated behavior. In specimen #F3, fracture lengths in low-permeability layers approached those in high-permeability layers, with significantly increased fracture width fluctuation ranges. Peak pump pressure further dropped to 18.18 MPa, indicating progressive dominance of fluid inertial forces in the fracturing process. AE energy release exhibited high-frequency sustained strong oscillations. The extension velocity ratio between high and low-permeability layers decreased markedly, signifying weakening influence of permeability contrasts on propagation dynamics.

Analysis of pump pressure curves in Fig. 10 under different injection rates demonstrates that breakdown pressure progressively decreases with increasing injection rates, in agreement with prior studies (Huang et al., 2022; Jiang et al., 2023). This reduction primarily occurs through two mechanisms. First, high-velocity fluid rapidly entering the reservoir creates significant pressurization zones within the rock mass, directly weakening tensile strength and facilitating fracture initiation. Second, accelerated pore pressure diffusion at higher injection rates elevates pore pressure in permeable layers adjacent to fractures. This increase in pore pressure reduces effective stress in the rock matrix, indirectly compromising structural stability. The combined effect of these two mechanisms lowers the breakdown pressure of the rock.

Fig. 11 displays layer specific fracture coverage area and acoustic emission ratio under different injection rates. Overall fracture area progressively increases with rising injection rates, primarily because greater injected volumes rapidly form high pressure zones within specimens, providing enhanced driving forces for fracture propagation thus enlarging fracture surfaces. At 5 mL/min, the medium-permeability layer developed 2255.01 mm² FCA and 34.6% AER, with 65.4% AER consumed for interlayer fracture extension. Both low and high-permeability layers exhibited near zero FCA values, confirming inability to overcome permeability hierarchy barriers at low rates. When injection rate reached 10 mL/min, fluid kinetic energy and permeability gradient commenced dynamic competition. In specimen #F2, high-permeability layer FCA surpassed the medium layer at 5089.21 mm², while low-permeability layer achieved breakthrough FCA rising from 0 to 800.24 mm². This verifies high kinetic energy driving fracturing fluid to breach low-permeability flow resistance barriers, though permeability distribution still dominated fracture differentiation.

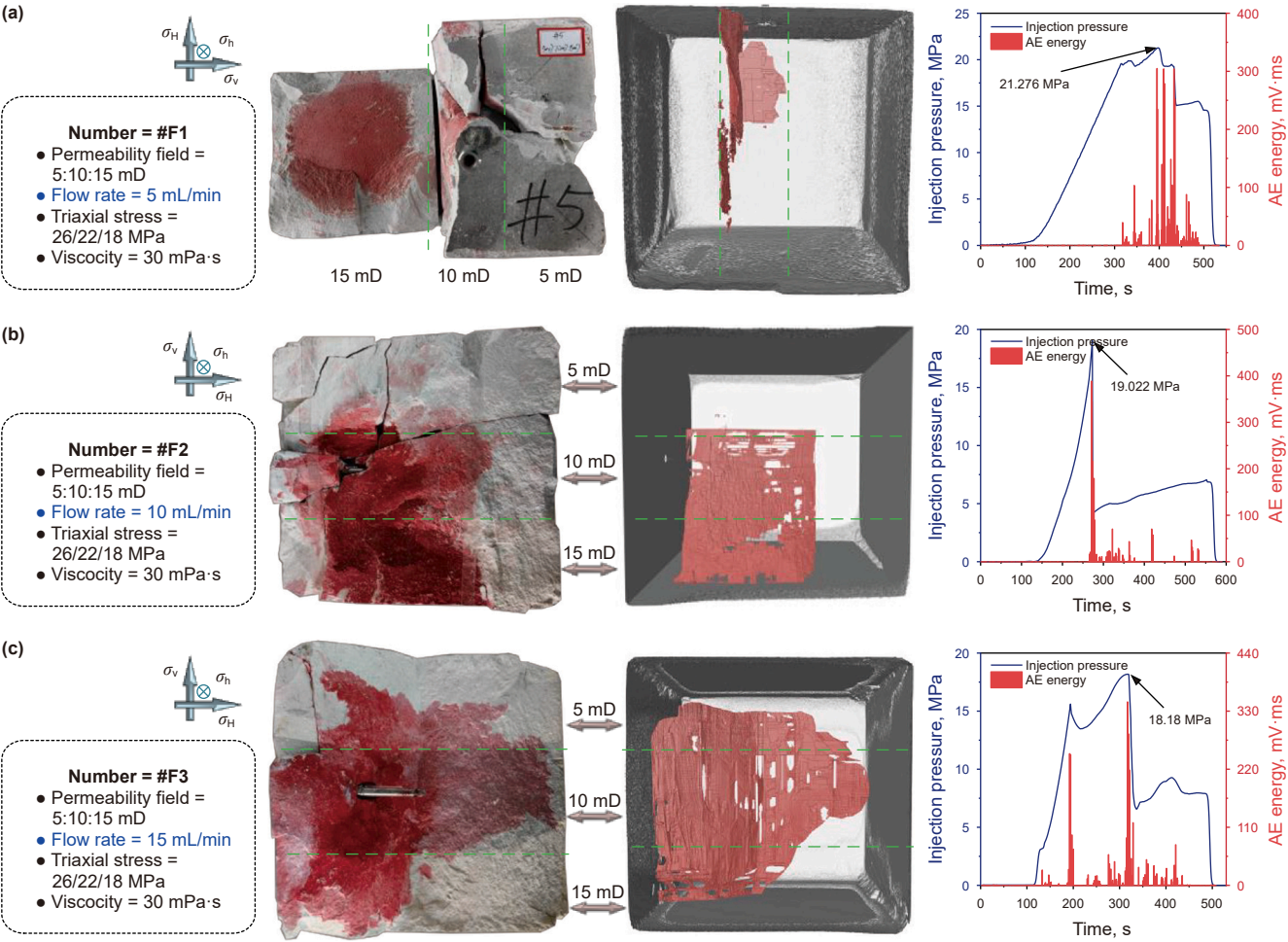


Fig. 10. Fracture morphology and pump pressure curves of specimens under different injection rates.

At 15 mL/min injection rate, fractures demonstrated system scale extension characteristics. Low-permeability layer FCA surged to 4317.13 mm², representing 439.5% growth versus #F2 specimen. FCA difference between high and low-permeability layers narrowed to 479.69 mm². Meanwhile the medium-permeability layer regained dominance with 58.4% FCA proportion, demonstrating gradual weakening control of permeability gradient as injection volume escalates.

As shown in Fig. 12, fracture length distribution characteristics under different injection rates along four directions (10 mD Z-axis (+, 0), 15 mD Y-axis (−, 0), 10 mD Z-axis (−, 0), 5 mD Y-axis (+, 0)) are presented. As injection volume increases from 5 to 20 mL/min, fracture length in low-permeability layers grows substantially. For instance, in the 5mD layer direction, fracture length surged from

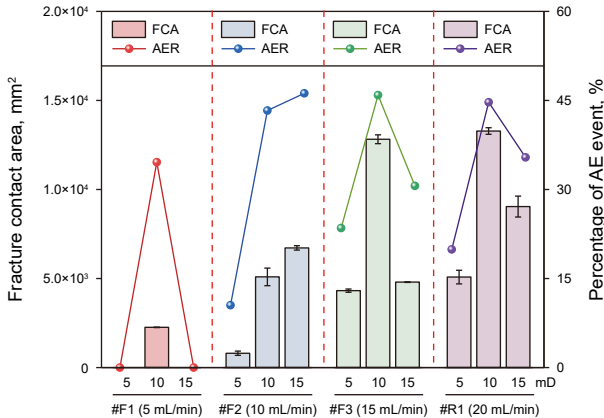


Fig. 11. Evolution curves of fracture contact area and AE events across different injection rates.

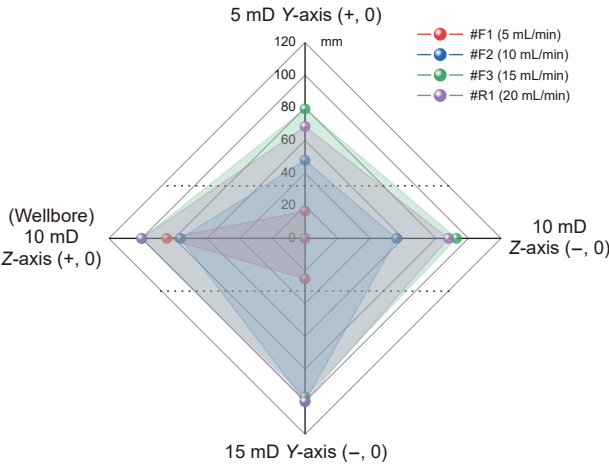


Fig. 12. Fracture length distribution at different injection rates.

approximately 16.67 to 68.58 mm in specimen #R1. This reflects high injection volumes imparting greater kinetic impact to fracturing fluid, driving fractures to overcome local stress concentrations and achieve vertical extension. Concurrently, the major-minor axis ratio of fractures characterized by directional length differences progressively decreases with rising injection rates. At 5 mL/min, permeability gradients induced uneven fracture extension with axial differences exceeding 51%. By contrast, fracture length disparities across orientations diminished to under 20% at 15/20 mL/min injection rates. This demonstrates that elevated injection rates significantly weaken constraints of formation permeability heterogeneity on fracture geometry. High fluid kinetic energy compensates for natural propagation limitations in low-permeability reservoirs fundamentally, transitioning fractures from localized tearing patterns to full-domain extension patterns in heterogeneous formations.

3.3. Effect of fracturing fluid viscosity on fracture propagation

This study selected four specimens, experimental groups #V1, #V2, #V3 and control group #R1, to investigate fracture propagation differences in multilayer permeability reservoirs under different fracturing fluid viscosities. Each fracturing fluid exhibited viscosities of 30, 100, 200 and 300 mPa·s respectively. The permeability distribution of specimens was 5:10:15 mD with triaxial in-situ stresses of 26, 22 and 18 MPa. Fig. 13 displays 3D

reconstruction results of fractures and pump pressure curves under different fracturing fluid viscosities.

As shown in Fig. 13(a), under 100 mPa·s viscosity conditions, fracture propagation exhibited typical permeability-controlled characteristics. The main fracture surface extended along the 15 mD high-permeability layer, forming a dominant channel with uniform width and clear boundaries, while limited but observable fracture propagation occurred in the 5 mD low-permeability layer. CT reconstruction demonstrated significant fracture deflection at high-permeability interfaces, indicating fluid capture by permeable layers. The pressure curve revealed a peak pressure of 18.14 MPa at $t = 307$ s. When viscosity increased to 200 mPa·s (Fig. 13(b)), fractures penetrated the entire medium and high-permeability layers, reaching the specimen surface. Multiple feathering branches developed in the high-permeability layer. Pressure peaked at 17.96 MPa at $t = 224$ s, corresponding to concentrated energy release during medium-permeability rock penetration. At 300 mPa·s viscosity (Fig. 13(c)), fracture area in the low-permeability layer increased with fracturing fluid viscosity. High-permeability layer fractures also extended to the specimen surface. Quantitative CT analysis indicated lower fracture wall roughness in high-permeability zones than in low-permeability regions, demonstrating inefficient etching capacity on low-permeability walls. The pressure curve recorded a peak of 19.41 MPa at $t = 174$ s, with two periodic pressure build-up events occurring between $t = 176$ and 284 s. Peak fracture

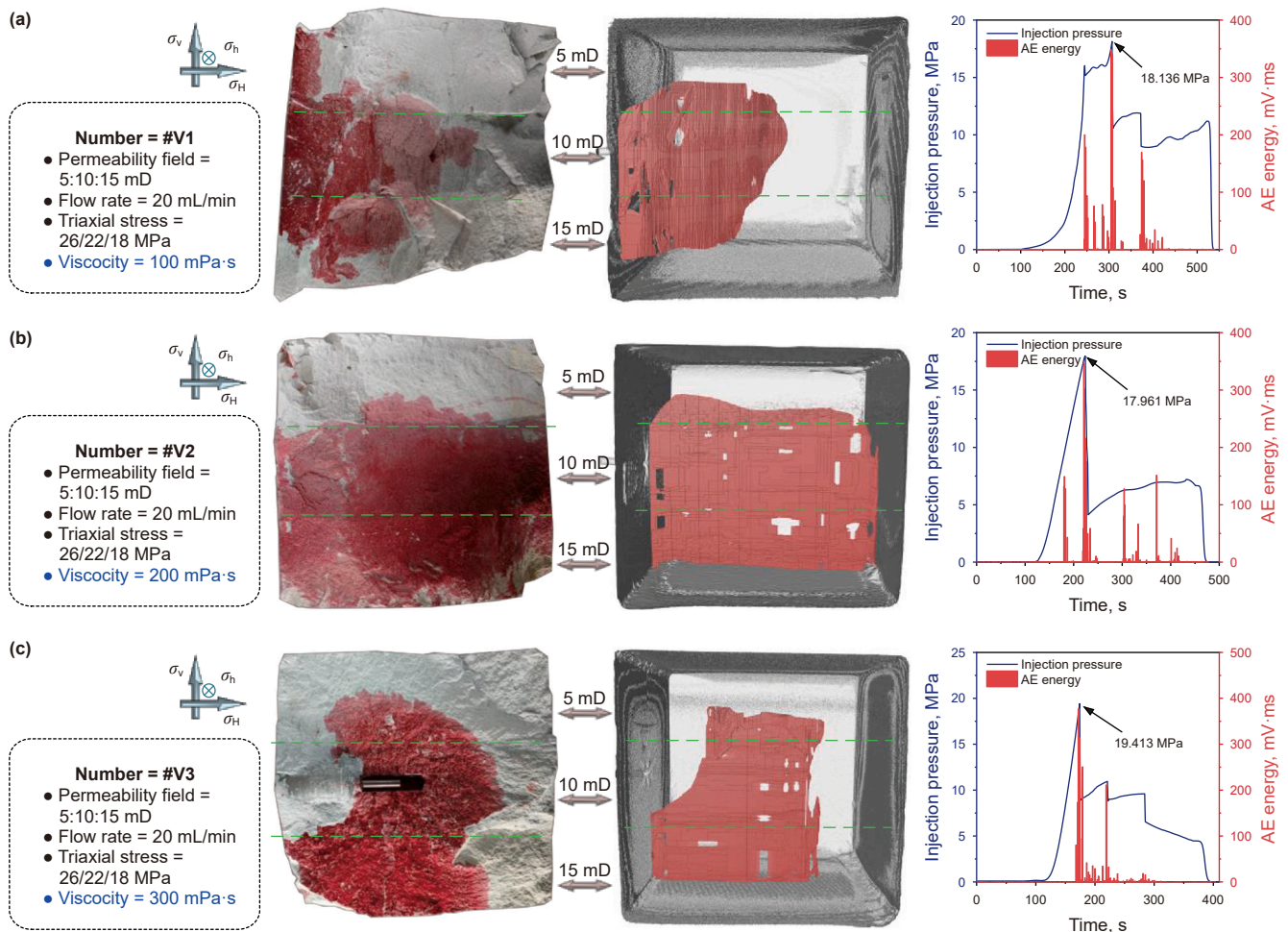


Fig. 13. Fracture morphology and pump pressure curves of specimens under different fracturing fluid viscosities.

pressure increased with rising viscosity. Higher viscosity fracturing fluids reduced fluid leakoff during fracture formation, thereby channeling more energy into fracture extension. However, while reducing leakoff, increased in-fracture fluid friction simultaneously created greater resistance, necessitating higher pressures to overcome resistance and achieve rock fracture initiation.

Fig. 14 displays layer specific FCA and AER under different fracturing fluid viscosities. The viscosity-controlled fracture propagation mechanism exhibits nonlinear coupling characteristics. At 100 mPa·s viscosity, total fracture area decreased to 14,509.99 mm² compared to specimen #R1, with low, medium, and high-permeability layers showing reductions of 69.7%, 37.1%, and 48.9% respectively. This indicates viscosity-induced flow resistance suppressed fracture growth across all layers at 100 mPa·s, particularly reducing fluid retention efficiency in low-permeability layers through viscosity-permeability coupling, thereby weakening propagation capability. When viscosity reached 200 mPa·s, total FCA recovered to 22899.62 mm², with the low-permeability layer marginally recovering to 1657.30 mm², demonstrating viscous forces initiated fracturing in low-permeability zones. The proportion of AE events in this layer gradually increased. At 300 mPa·s viscosity, total FCA declined again to 18632.41 mm², but low-permeability layer FCA increased by 104.6% relative to #V2 specimen, while medium and high-permeability layer FCA decreased. This reflects an energy redistribution mechanism under ultra-high viscosity, reduced fluid leakoff created localized high-pressure zones in low-permeability layers, significantly elevating AE activity, whereas excessive viscous resistance decayed energy release efficiency in medium and high-permeability layers.

In summary, specimen #R1 achieved peak FCA and optimized inter-layer uniformity through viscosity-permeability synergy. Although the 200 mPa·s specimen exhibited maximum FCA in the high-permeability layer, it showed marked inter-layer differentiation. Conversely, the 300 mPa·s specimen achieved targeted propagation in the low-permeability layer at the cost of total FCA. This phenomenon confirms viscosity regulation can reshape fracture architecture across layers through viscous force redistribution.

Fig. 15 presents fracture length data across four permeability directions under different fracturing fluid viscosities. The physical mechanism of viscosity-controlled directional fracture propagation exhibits stage evolution. As viscosity increased, the fracture length disparity between high- and low-permeability strata

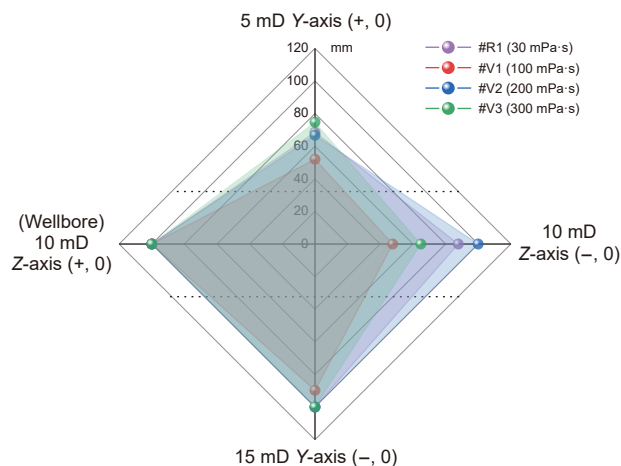


Fig. 15. Fracture length distribution at different fracturing fluid viscosities.

progressively decreased. For instance, specimen #V3 showed counter-trend growth in the 5 mD low-permeability direction, reducing the high/low-permeability fracture length difference to 25.34 mm, while the 10 mD Z-axis (–, 0) direction declined to 64.88 mm. Here, ultra-high viscosity induced energy accumulation in low-permeability zones by suppressing fluid leakoff, driving fractures to breach permeability barriers. However, excessive viscous resistance simultaneously constrained energy release in medium-permeability directions. Moreover, high-viscosity fracturing fluids significantly inhibited leakoff, promoting fracture propagation dominated by rigid dilation mechanisms in both high- and low-permeability layers, thereby tending to form simplified fracture geometries. This aligns with findings from Zhao et al. (2024). Therefore, in hydraulic fracturing of multilayered heterogeneous reservoirs, fracturing fluid viscosity effectively influences fracture propagation by regulating fluid energy distribution pathways. Specifically, fracture lengths in high-permeability layers consistently exceeded those in low-permeability layers across all viscosities. As viscosity rose, the fracture length disparity between high- and low-permeability layers progressively converged, while in-fracture pressure gradients gradually intensified.

Fig. 16 investigates the regulatory mechanism of viscosity-permeability interactions on fracture aperture by measuring partial fracture propagation paths and apertures. As viscosity increased from 30 to 300 mPa·s, fracture aperture exhibited stepwise growth. In specimen #R1, the average aperture in the 10 mD layer measured merely 0.056 mm, whereas the main fracture aperture in specimen #V3's 15 mD layer reached 0.309 mm, representing a 5.5-fold increase. The core mechanism lies in elevated viscosity significantly enhancing the viscous propping effect of the fluid, where high-viscosity fracturing fluid generates stronger fracture wall support forces while simultaneously suppressing fluid leakoff into the formation, promoting aperture expansion. However, discrepancies persisted across permeability layers. For instance, at 300 mPa·s viscosity, fracture aperture in the 10 mD layer stagnated at 0.051 mm due to energy competition constraints. Although fluid leakoff suppression intensified, inherently weak flow capacity limited fracture dilation efficiency. Conversely, the 15 mD layer achieved a main fracture aperture of 0.309 mm under identical high viscosity owing to its natural high-permeability characteristics. This demonstrates that optimal viscosity maximizes the advantages of the rigid dilation mechanism in high-permeability media.

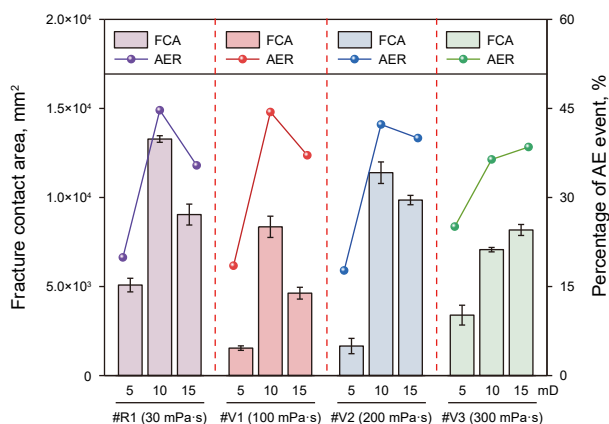


Fig. 14. Evolution curves of fracture contact area and AE events across different fracturing fluid viscosities.

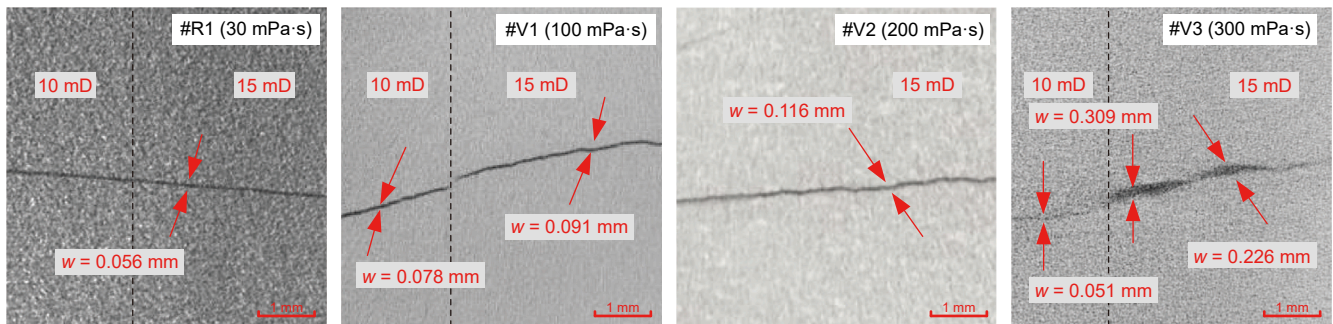


Fig. 16. Fracture aperture under different fracturing fluid viscosities.

3.4. Effect of vertical stress difference on fracture propagation

This study selected four specimens, experimental groups #T1, #T2, #T3 and control group #R1, to investigate fracture propagation differences in multilayer permeability reservoirs under different vertical stress differences. Each vertical stress difference measured 6, 8, 10 and 12 MPa respectively. The permeability distribution of specimens was 5:10:15 mD with an injection rate of 20 mL/min, and fracturing fluid viscosity of 30 mPa·s. Fig. 17 displays 3D reconstruction results of fractures and pump pressure curves under different vertical stress differences.

As shown in Fig. 17(a), under a vertical stress difference of 6 MPa, fracture propagation in the specimen exhibited permeability-dominated stratified responses. Specimen #T1 incurred partial damage during post-experiment CT scan handling, but no fracturing fluid seepage was observed on the fracture surface, confirming no impact on experimental results. The CT reconstruction marked this handling-induced fracture surface in blue. Physical specimen imagery revealed that fractures predominantly propagated within the 15 mD layer, forming a continuous main fracture network, while the 5 mD layer displayed only intermittently distributed micro-fractures. The pressure curve

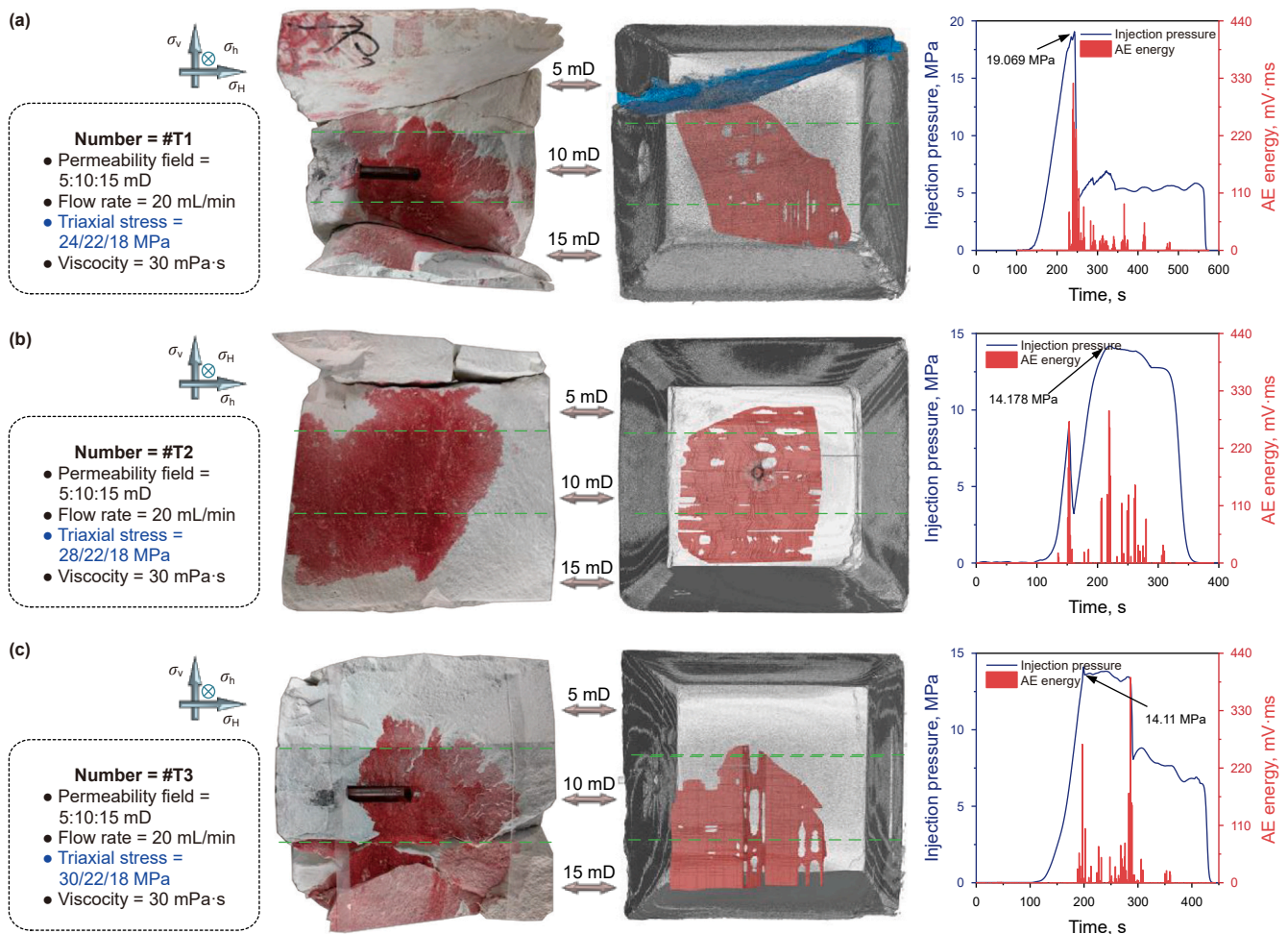


Fig. 17. Fracture morphology and pump pressure curves of specimens under different vertical stress differences.

peaked at 19.07 MPa at $t = 243$ s, subsequently exhibiting an oscillatory mode with ± 0.2 MPa amplitude during $t = 248$ –563 s.

Fig. 17(b) demonstrates that under a 10 MPa vertical stress difference, misalignment of maximum and minimum horizontal principal stress directions by experimental personnel caused divergent fracture orientations while maintaining vertical fracture planes. Physical specimens and 3D CT reconstructions showed continuous main channels in medium/high-permeability layers with straighter paths and sharper boundaries than #T1, while fractures also initiated in the 5 mD layer. The pressure peak decreased to 14.18 MPa compared to #T1. AE data revealed a dual-stage energy release: the first peak corresponded to rupture events dominated by the 10 mD layer, while the second reflected tensile-shear composite failure in high/low-permeability layers. This indicates that increased vertical stress difference promoted propagation dominated by tension through enhancing normal stress on fracture planes.

In Fig. 17(c), with vertical stress difference elevated to 12 MPa, fracture propagation displayed permeability-stress coupled rupture characteristics. Physical specimens showed fractures concentrated primarily in the 15 mD layer, with minimal development in the 5 mD low-permeability layer, revealing vertical stress gradient inhibition. 3D CT reconstructions further confirmed directional extension in high-permeability layers, indicating that the 12 MPa stress difference suppressed interlayer fluid migration via enhanced stress shadow effects. The pressure curve linearly surged to 14.11 MPa during $t = 111$ –199 s, corresponding to macroscopic brittle failure, then abruptly dropped to 8.2 MPa at $t = 284$ s, validating rapid formation of a single dominant flow channel. Synchronized AE curves exhibited bimodal temporal responses, the first peak linked to tensile events during high-permeability layer pre-cracking, while the second coincided exactly with the pressure peak, manifesting concentrated tensile-shear composite failure.

Fig. 18 displays layer specific FCA and AER under different vertical stress differences. At the 6 MPa low stress difference in specimen #T1, permeability distribution dominated fracture propagation. The 10 mD layer exhibited absolute predominance with 6935.12 mm² FCA, accounting for 61.1% of the total, while AE events exceeded 57%. FCA in the 15 and 5 mD layers measured 34.4% and 4.5% respectively, indicating fluid primarily followed optimal permeability pathways. When vertical stress difference increased to the 8–10 MPa range, fracture propagation entered a dual-layer competitive synergy phase. For instance, specimen #T2 showed expanded FCA in the 15 mD layer, with acoustic emission

AE events concurrently migrating toward this high-permeability layer, revealing that elevated vertical stress difference effectively activated rupture mechanisms in the 15 mD layer. At the 12 MPa high stress difference, the high-permeability layer achieved 8298.47 mm² FCA, constituting 51.3% and surpassing the 10 mD layer for the first time. The 5 mD layer FCA decreased to 831.41 mm², representing only 5.1%. Consequently, as vertical stress difference escalated, FCA progressively increased in high-permeability layers but diminished in low-permeability layers due to hydraulic isolation barriers. The total FCA remained in dynamic equilibrium throughout. This phenomenon fundamentally stems from stress driven directional fluid energy transfer toward high-permeability channels, ultimately establishing a cross-strata redistribution mechanism, which is synchronously corroborated by AE event patterns.

Fig. 19 displays distribution characteristics of fracture lengths in four directions under different vertical stress differences. Under low vertical stress differences, permeability contrast dominated fracture extension, with fractures in the 15 mD high-permeability layer exceeding those in the 5 mD low-permeability layer by 20.2 mm. During the intermediate phase (8–10 MPa), stress differences reduced the fracture length gap by overcoming low-permeability resistance through kinetic energy compensation mechanisms while enhancing propagation in high-permeability layers. At high vertical stress differences, stress deflection barrier effects triggered interlayer energy redistribution in high-permeability layer and simultaneously suppressed low-permeability layer extension, causing the gap to rebound to 44.69 mm. This phenomenon aligns with patterns in Fig. 18, revealing a nonlinear regulatory mechanism of vertical stress differences on fracture morphology.

4. Discussion

4.1. Fracture type analysis using RA-AF values from AE

The macroscopic failure of rock essentially results from the complex evolution of internal microcracks, encompassing their initiation, coalescence, and interconnection. These processes not only control rock fracturing behavior across different loading stages but also determine the ultimate scale and mode of failure (Dong et al., 2020; Wang et al., 2024c). AE technology serves as an effective nondestructive method for monitoring rock failure characteristics, categorizing rock fractures into two fundamental mechanisms: tension and shear. Microcracks of different rupture types generate distinct AE signals during formation. To address

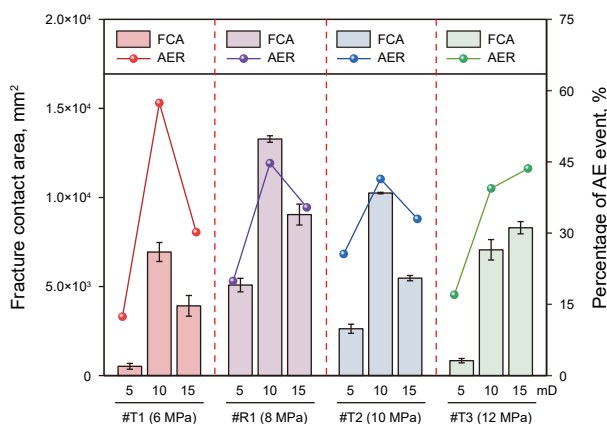


Fig. 18. Evolution curves of fracture contact area and AE events across different vertical stress differences.

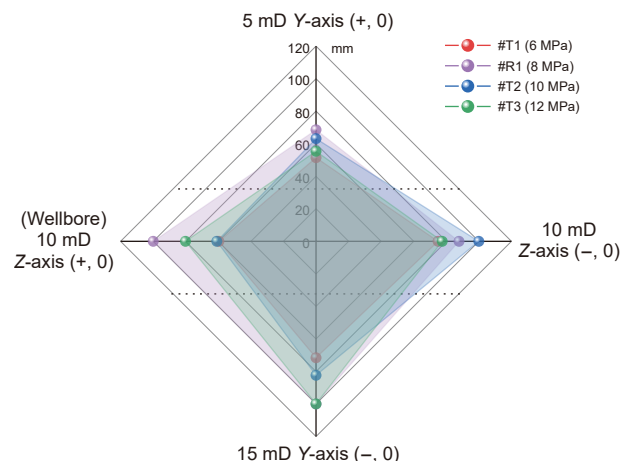


Fig. 19. Fracture length distribution at different vertical stress differences.

this, Aggelis and his co-workers (Aggelis et al., 2011, 2013; Aggelis, 2011) introduced two key parameters, AF (average frequency of acoustic emission counts) and RA (rise time to amplitude ratio), to analyze and evaluate rock crack failure mechanisms. Specifically, tensile microfailure events typically exhibit higher AF and lower RA values, while shear ruptures tend to display lower AF and higher RA values, as shown in Fig. 20. Research commonly employs a discrimination line for quantitative differentiation, where the region above this line represents tensile failure proportion and the area below indicates shear failure proportion. Although criteria for determining this discrimination line vary, this study adopts the standard proposed by Wang et al. (2024d) using RA divided by AF equal to 1 as the threshold distinguishing tensile ruptures from shear ruptures. This study employed a multi-channel AE monitoring system to capture elastic micro-fracture signals induced during hydraulic fracturing in real time. The built-in software of the acoustic emission equipment calculated the time difference of arrival based on pre-calibrated sensor spatial coordinates to achieve 3D event localization and automatically filtered invalid signals with low signal-to-noise ratios ensuring positioning accuracy within ± 2 mm.

Fig. 21 illustrates reconstructed AE characteristics of fracture morphology under different factors. In the three-layer reservoir with permeability contrasts, hydraulic fracturing is co-dominated by tensile and shear fractures, yet shear fractures consistently exhibit lower proportions. As shown in Fig. 21(a), differences in fracture types across permeability distribution patterns remain minimal, with tensile fractures persistently predominant at 68%–78%. This indicates limited direct influence of permeability on fracture types, fundamentally attributable to the relative stability of rock failure criteria which permeability contrasts cannot directly alter. Permeability primarily affects fracture formation by controlling fracturing fluid migration pathways and energy accumulation rates. Efficient energy accumulation in high-permeability layers favors tensile ruptures, but this occurs at the expense of reduced fluid diffusion in low-permeability layers and diminished shear rupture energy, indirectly affecting spatial distribution of fracture types. Fig. 21(b) demonstrates that increased injection rates significantly elevate tensile fracture proportions while reducing shear fracture

proportions, aligning with Yao et al. (2025). This phenomenon arises as high-speed injection concentrates hydraulic energy at fracture tips, reduces interlayer filtration losses, and enhances fracture penetration capability and net pressure. These mechanisms create preferential channels for rapid pore pressure buildup in high-permeability layers, thereby prioritizing tensile ruptures. Conversely, restricted fluid filtration in low-permeability layers suppresses weak-plane shear fractures due to insufficient local pressure gradients. Fig. 21(c) reveals that elevated fracturing fluid viscosity increases tensile fracture proportions and reduces shear fracture proportions. Specifically, viscous resistance from high-viscosity fluids impedes relative slip along fracture walls, weakening shear kinetic energy conversion efficiency. Simultaneously, such fluids inhibit fluid loss into microfractures, concentrating energy on propagating a single dominant fracture (Butt et al., 2023; Chen et al., 2015). Fig. 21(d) indicates that increasing vertical stress differences further intensify tensile fracture dominance. Enhanced vertical principal stress differences directly elevate normal stress along the minimum principal stress direction, raising critical shear stress in the Coulomb criterion particularly at interlayer interfaces thus requiring greater fluid energy for shear fracturing. Concurrently, increased vertical stress differences facilitate tensile ruptures where although the minimum horizontal principal stress direction must still overcome rock tensile strength, progressively amplified vertical stress differences promote sustained pressure accumulation in relatively low-stress orientations, creating favorable propagation paths for tensile fractures. Furthermore, within high-permeability layers, increased vertical stress differences compress pore spaces, accelerating pore pressure buildup and objectively enhancing conditions for tensile ruptures.

Experimental data analysis confirms that elevated injection rates, fracturing fluid viscosity, and vertical stress differences all drive a transition toward tensile fracture-dominated propagation. These factors enhance energy concentration at fracture tips, suppress fluid loss, or raise shear fracturing thresholds, collectively increasing tensile fracture proportions while reducing shear fracture proportions. In comparison, permeability exerts weaker influence on fracture type differentiation.

4.2. Permeability's dominant control mechanism on fracture propagation thresholds

In multilayered heterogeneous reservoirs, permeability ratios not only control fracture propagation direction through interlayer fluid allocation disparities but also dominate critical phase transitions in fracture morphology via energy competition mechanisms. This study deciphers a tripartite coupling mechanism encompassing high-permeability layers' fluid-siphoning effect, middle layers' regulatory function, and low-permeability layers' barrier effect through comparative experiments testing four representative permeability distribution patterns. To quantify cross-layer fracture propagation behaviors, the following core parameters are defined:

Permeability gradient, a geological parameter reflecting the difference span between high-permeability layers and low-permeability layers, where its expression is:

$$\Delta K_{\text{gradient}} = \frac{K_{\text{max}} - K_{\text{min}}}{K_{\text{mid}}} \quad (1)$$

where $\Delta K_{\text{gradient}}$ represents the permeability span between reservoir layers; K_{max} , K_{mid} , and K_{min} denote the permeability values of high-permeability, medium-permeability, and low-permeability layers respectively, mD.

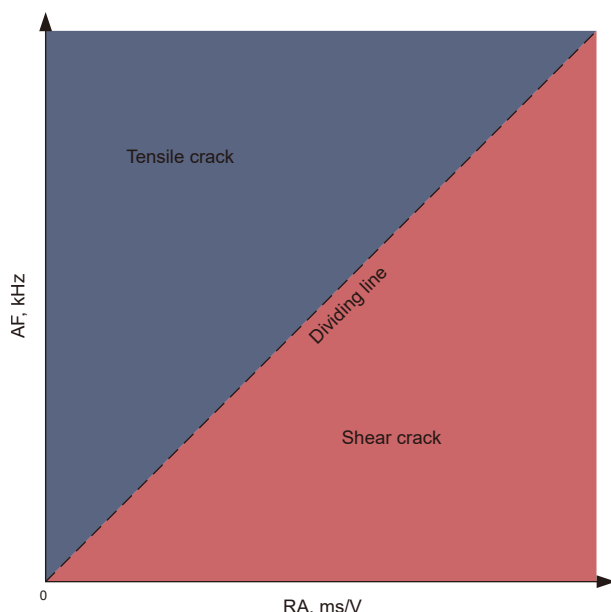


Fig. 20. Schematic diagram of fracture type classification.

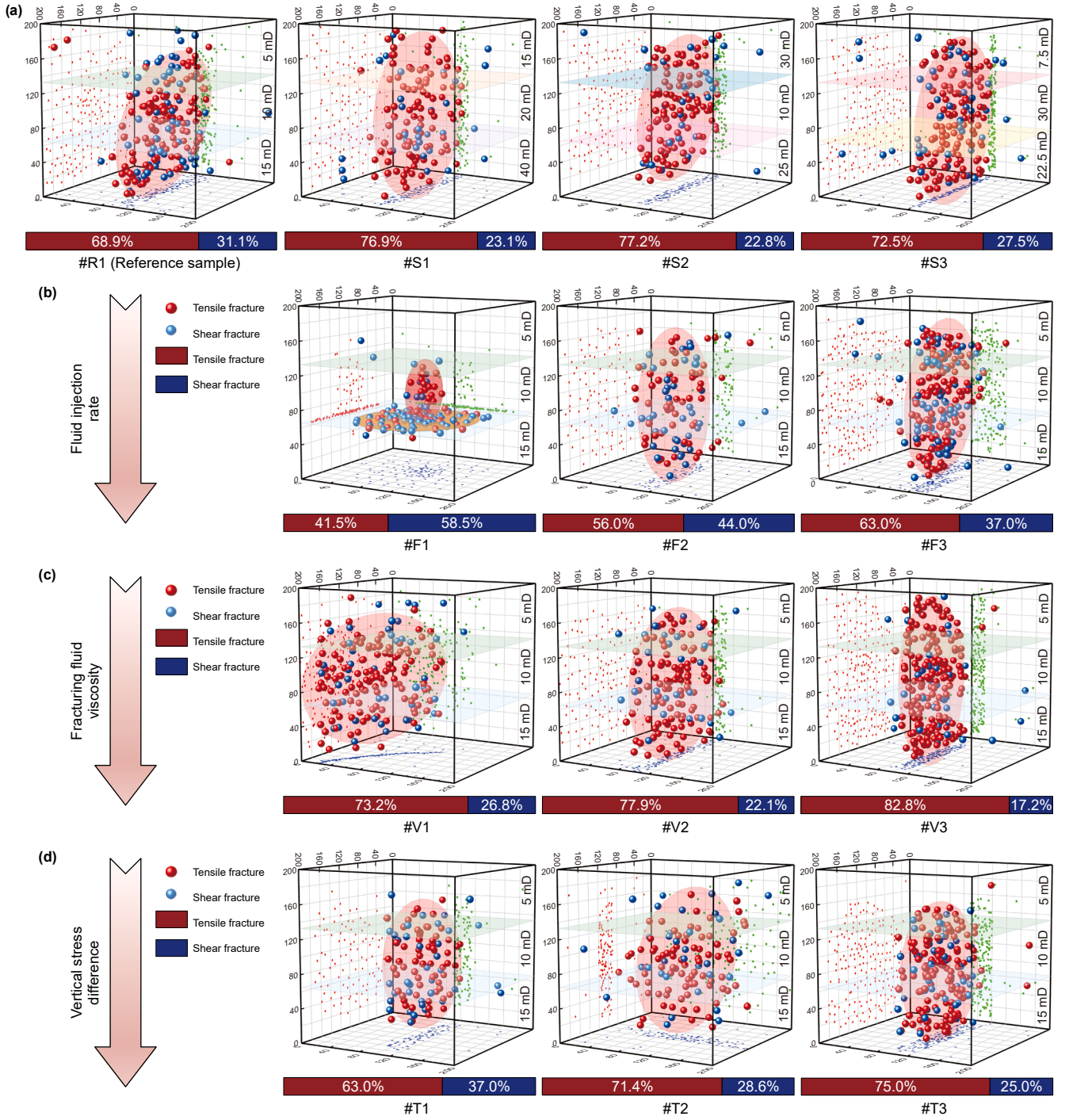


Fig. 21. Reconstructed diagram of AE characteristics for fracture morphologies under different factors.

The middle layer relative weighting, characterizing the pivotal regulation capability of middle layers on fluid energy, where its expression is:

$$\lambda_{\text{mid}} = \frac{K_{\text{mid}}}{K_{\text{max}} + K_{\text{min}}} \quad (2)$$

where λ_{mid} denotes the regulation capability of the target middle layer in energy allocation.

The competitive equilibrium between these two mechanisms is determined by the critical threshold K_{ϕ} , where its expression is:

$$K_{\phi} = \frac{\lambda_{\text{mid}}}{\Delta K_{\text{gradient}}} \quad (3)$$

Based on experimental specimen data, calculated critical threshold values are presented in Table 3. When permeability weighting factor $K_{\phi} > 0.5$ (as in specimen #S3), the middle layer weighting dominates fracture propagation, forming a pivotal-regulation fracture pattern characterized by middle-layer-controlled vertical equilibrium penetration with AE energy proportion exceeding 45%; conversely, when $K_{\phi} \leq 0.5$ (as in specimen

Table 3
Relationship between critical threshold and fracture morphology.

Test number	Permeability distribution (K_{up} : K_{middle} : K_{down}), mD	λ_{mid}	$\Delta K_{gradient}$	K_{ϕ}	Threshold judgment
#R1	5:10:15	0.5	1	0.5	$K_{\phi} \leq 0.5 \rightarrow$ Permeability gradient dominateds
#S1	15:20:40	0.36	1.25	0.29	$K_{\phi} \leq 0.5 \rightarrow$ Permeability gradient dominateds
#S2	25:10:30	0.18	0.8	0.23	$K_{\phi} \leq 0.5 \rightarrow$ Permeability gradient dominateds
#S3	7.5:30:22.5	0.6	1	0.6	$K_{\phi} > 0.5 \rightarrow$ mid layer weighting dominates

#S2), permeability gradient governs fluid allocation, where high-permeability layer fluid-siphoning and low-permeability layer barrier effects jointly induce fracture deflection.

Based on the foregoing analysis, when permeability weighting factor $K_{\phi} \leq 0.5$ (permeability gradient dominated regime), priority should be given to increasing treatment pumping rate to enhance fluid kinetic energy for overcoming interlayer resistance, simultaneously employing low-viscosity fracturing fluids to reduce flow resistance, combined with stratified fluid injection techniques to balance interlayer pressure differentials, thereby mitigating high/low-permeability layer interference on fracture propagation. When $K_{\phi} > 0.5$ (middle layer weighting dominated regime), the middle layer directional perforation scheme should be optimized, concurrently implementing real-time injection profile adjustment to lock energy within the pivotal layer, maximizing middle layer dominance and promoting vertically balanced fracture extension. The critical threshold proposed in this study was established under specific experimental conditions for target reservoirs in the southern Songliao Basin, and its universal applicability requires consideration of geological engineering contexts. For instance, when absolute in-situ stress levels increase, the energy barrier to be overcome for fracture penetration through layers will significantly rise, potentially elevating the actual critical threshold. The brittle ductile properties of rocks indicate that quartz rich formations readily generate branch fractures reducing penetration difficulty, while the creep behavior of plastic layers enhances stress shielding effects, causing the critical threshold to exhibit dynamic evolution characteristics.

In this study, although artificial rock specimens effectively supported experimental parameter optimization through controlled permeability gradient design, the fundamental distinction between artificial and natural reservoir rocks must be acknowledged. Artificial rock specimens achieve high homogeneity in mechanical properties via uniform cementation materials, constituting an essential difference from natural reservoir rocks. These heterogeneous cementation characteristics closely associated with sedimentary structures cause fracture propagation paths in natural reservoirs to be more susceptible to mineral interface control, resulting in stronger randomness and discontinuity, whereas the uniform cementation system of artificial rock specimens may weaken mineral composition control on fracture behavior. Moreover, natural reservoirs develop significantly distinct features such as microfracture networks and intercrystalline porosity. These pore structures not only govern dynamic fluid loss behavior and flow path selection during fracturing, but may also induce heterogeneous stress concentration effects during rock failure, ultimately affecting the complexity of fracture 3D morphology.

These fundamental differences may cause deviations in experimentally observed fracture geometries compared to natural reservoirs. However, the core mechanism revealed in this study that permeability gradients dominate fracture propagation direction reflects fundamental mechanical principles of fluid rock interactions. These mechanisms are intrinsically independent of material mesostructural differences, possessing universality for understanding dynamic fracture propagation. For this purpose,

subsequent research will systematically quantify geological structural plane control on fracture penetration through layers across different permeability distributions based on in-situ observation data from natural reservoirs. Concurrently, to overcome limitations of current critical threshold models, focus will address the deficiency in coupling multiple parameters including vertical in-situ stress differentials, fracturing fluid viscosity, and injection rates. Building upon this, efforts will concentrate on establishing coupled governing equations integrating permeability competition mechanisms and stress forcing mechanisms, ultimately establishing a dynamic prediction system for fracture penetration behavior applicable to strongly heterogeneous reservoirs, thereby providing theoretical support for complex reservoir fracturing design.

5. Conclusions

To investigate the vertical propagation mechanisms of hydraulic fractures in multilayer permeability systems of the southern Songliao Basin in China, true triaxial hydraulic fracturing experiments were conducted using artificial rock specimens, examining the effects of interlayer permeability heterogeneity, injection rate, fracturing fluid viscosity, and vertical in-situ stress contrast on hydraulic fracture vertical propagation. By integrating CT scanning and AE monitoring, real-time dynamic analysis of the fracture propagation process was achieved, revealing complete mechanisms from fracture initiation to stable propagation. The following conclusions were drawn:

- (1) In multilayer heterogeneous permeability reservoirs, interlayer permeability contrast exerts significant control on fracture propagation. Hydraulic fractures preferentially extend into high-permeability layers, while low-permeability layers experience substantial suppression due to fluid competition. As the permeability ratio between adjacent layers and the target layer increases, the fracture height-to-length ratio exhibits an upward trend, following the relationship $y = 0.662 + 0.063x$, indicating that a per-unit increase in the permeability ratio elevates the fracture height-to-length ratio by approximately 6.3% on average.
- (2) For ascending, sandwiched, and leaping permeability distribution patterns, the critical threshold where interlayer energy competition governs fracture morphology is determined as 0.5; when $K_{\phi} \leq 0.5$, fractures are permeability gradient dominated, while when $K_{\phi} > 0.5$, the regime transitions to middle layer weighting dominance.
- (3) Increasing injection rate progressively weakens constraints from interlayer permeability heterogeneity on fracture propagation; significantly enhanced fluid kinetic energy gradually enlarges FCA in low-permeability layers, reducing the maximum extension disparity between high-low permeability layers to less than 20% and shifting fracture morphology from localized tearing to domain-wide propagation.

- (4) Elevating fracturing fluid viscosity facilitates hydraulic fracture extension into low-permeability layers, thereby achieving greater fracture height at the expense of total FCA; consequently, to balance fracture cross-layer capacity and FCA coverage, low-viscosity fracturing fluids should be employed to enhance fracture network complexity and fluid propagation capability.
- (5) Under identical interlayer permeability distributions, increasing vertical stress contrast drives cross-layer redistribution of fracturing fluid energy. Specifically, fracture propagation capacity in high-permeability layers positively correlates with vertical stress contrast, whereas effective stimulated area in low-permeability layers decreases due to hydraulic isolation effects.
- (6) Tensile fracture events dominate fracture failure across different interlayer permeability systems, with mean proportion exceeding 60%. Permeability exhibits no significant regulatory effect on fracture type distribution. The proportion of tensile fractures rises notably with increasing injection rate, fracturing fluid viscosity, and vertical stress contrast, while shear fractures exhibit negative correlation; nevertheless, tensile rupture remains the primary failure mode.

CRedit authorship contribution statement

Lin-Hao Zou: Writing – review & editing, Writing – original draft, Methodology, Investigation, Data curation, Conceptualization. **Wei Li:** Validation, Supervision, Resources, Methodology, Funding acquisition. **Yi-Nao Su:** Resources, Project administration, Conceptualization. **Huan Zhao:** Visualization, Validation, Software, Formal analysis. **Jing-Ming Gai:** Validation, Software, Investigation.

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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