

Invited review

Mechanisms and diagnostic methods of fracture-driven inter-well interference in shale gas reservoirs

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Abstract:

Fracture-driven inter-well interference has become a major constraint on dense shale-gas development. To address this issue, this review synthesizes the communication pathways, diagnostic responses, formation mechanisms, controlling factors, research methods, and mitigation measures of inter-well interference. Evidence from field monitoring, physical experiments and numerical simulation is organized using a source-pathway-response-control framework. Fracture-driven inter-well interference has been shown to arise from coupled hydraulic and geomechanical processes rather than fracture length alone. Hydraulic fractures may connect directly with offset wells or activate natural fractures and faults that transmit pressure and fluid over longer distances. Parent-well depletion and transient stress shadows can rotate local stresses and redirect new fractures, while multi-cluster competition concentrates fluid in dominant fractures. Geological susceptibility is governed mainly by weak plane architecture, stress state, heterogeneity, depletion history, and well spacing. In turn, event intensity and duration are controlled by treatment scale, cluster design, pumping schedule, fracturing sequence, and offset-well operation. Reliable diagnosis requires complementary evidence: Pressure and production data detect abnormal responses; tracers and downhole pressure verify hydraulic fracture communication; microseismic and distributed fiber-optic measurements constrain fracture growth; and transient or numerical models quantify severity. The review therefore proposes a connectivity-based diagnosis that distinguishes geometric, hydraulic and production connectivity. Future work should integrate multi-well experiments, field-calibrated multiphysics models, interpretable data-driven prediction, and closed-loop operational control. The proposed framework supports risk-based well spacing, stimulation design, and platform-scale management of shale-gas reservoirs.

1. Introduction

Fracture-driven inter-well interference (FDII), also called frac hit or pressure channeling, is an abnormal response in an offset well that occurs during or after the stimulation of

a neighboring treatment well and may involve changes in pressure, fluid, production, or mechanical characteristics. With reduced well spacing, pad development and infill drilling, FDII increasingly constrains stimulation efficiency, well in-

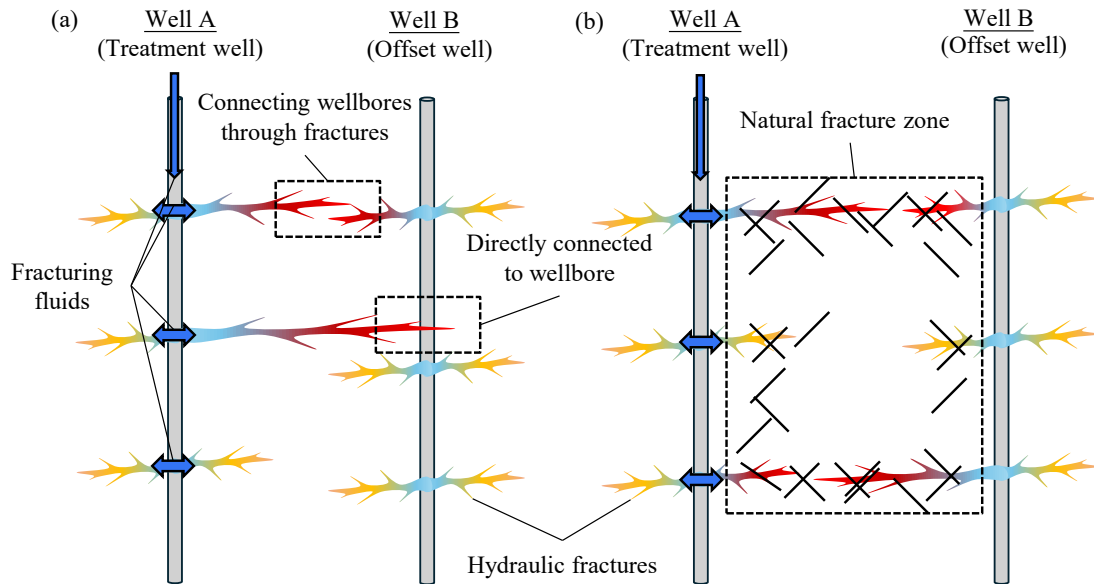


Fig. 1. Principal FDII pathways: (a) Hydraulic fracture-dominated frac-hit and (b) natural fracture-dominated frac-hit. Adapted from Xu et al. (2023).

tegrity and platform-scale recovery in shale gas reservoirs (King, 2010; Gupta et al., 2020; Taghavinejad et al., 2022).

Typical responses include offset-well pressure surges, tracer or flowback-water breakthrough, production decline, casing deformation, and wellbore-integrity failure. Large-scale fracturing in heterogeneous shale may connect induced fractures with natural fractures, faults or depleted regions. Local fracture interaction can in turn develop into inter-well hydraulic or mechanical communication (Dahi Taleghani and Olson, 2011; Kolawole and Ispas, 2020; Taghavinejad et al., 2022).

Field observations, laboratory experiments and numerical models have shown that FDII is not controlled by fracture length alone but its occurrence depends on the coupled evolution of fracture propagation, weak-plane activation, stress redistribution, pathway conductivity, and the operating state of the offset well (Mayerhofer et al., 2010; Gupta et al., 2021; Al-Shami et al., 2023). However, these factors are often reviewed separately, leaving the multiscale transition from fracture interaction to a measurable and potentially damaging frac-hit response that is insufficiently synthesized. Early interference studies established the field-scale significance of frac hits and their dependence on completion and reservoir conditions (Gupta et al., 2021; Taghavinejad et al., 2022).

Accordingly, this review addresses four core questions that define the scientific and engineering logic of this review:

- 1) How do hydraulic fractures, natural fractures and faults interact to create long-distance inter-well pathways?
- 2) How do parent-well depletion, stress shadow and multi-cluster competition redirect or concentrate fracture growth?
- 3) Which geological and engineering variables determine the occurrence range and severity of interference?
- 4) How should observations on pressure, tracers, microseisms, distributed acoustic/temperature sensing

(DAS/DTS), production, and wellbore data be integrated to identify and quantify frac hits?

The literature is organized using a source-pathway-response-control framework. Therefore, this review first classifies fracture communication pathways and field responses, then analyzes pathway-forming mechanisms and separates geological susceptibility from controllable engineering factors. Finally, it compares numerical, experimental, field, and data-driven methods before linking diagnosis with mitigation and real-time regulation. The objective is a mechanism-based foundation for risk assessment, stimulation optimization, and platform-scale shale-gas development.

2. Classification and identification methods of inter-well fracture interference

Inter-well fracture interference exhibits diverse pathways, responses and accordingly has various consequences. This section classifies the dominant communication pathway and the observable offset-well response, while Section 3 explains the causal geomechanical processes. The categories are interpretive end members rather than mutually exclusive event types, since a hydraulic fracture may activate a natural fracture or fault before a response is detected in the offset well.

2.1 Classification by communication pathway and response effect

The dominant pathways are summarized below and illustrated in Figs. 1 and 2.

- 1) Hydraulic-fracture-dominated frac hit. Direct or indirect communication develops between created hydraulic fractures and an offset wellbore or fracture system. Small well spacing, large treatment volume, long fracture half-length, and strong propagation asymmetry increase this risk (Marongiu-Porcu et al., 2016; Xu et al., 2023).

Table 1. Response-based classification of frac-hit effects in offset wells.

Response type	Typical field signals	Possible interpretation	Engineering implications
Negative interference	Pressure surge followed by production decline, water increase, tracer breakthrough or casing/integrity risk	Strong hydraulic communication, damaging fluid invasion or stress disturbance in an already depleted drainage region	Mitigation is required; offset-well management and treatment parameters should be adjusted
Apparent positive interference	Short-term pressure or production improvement in an offset well	Temporary re-pressurization or connection to remaining reserves	Should be evaluated cautiously because the long-term benefit may disappear or turn negative
Negligible or undetectable response	No clear pressure, tracer, production or integrity response	Weak or absent effective connectivity, excessive spacing or poor pathway conductivity	May indicate an acceptable interference level, but monitoring uncertainty should be considered

- 2) Natural-fracture-dominated frac hit. Injected fluid activates pre-existing natural fractures or weak planes, which transmit pressure or fluid toward adjacent wells. This pathway is favored by high fracture density, suitable orientation, strong connectivity, and weak cementation (Xu et al., 2023).
- 3) Fault-slip-induced frac hit. High-pressure fluid enters a fault or damage zone, reduces effective normal stress, and promotes shear slip or permeability enhancement. The response may include long-distance pressure communication, casing deformation, and wellbore-integrity damage (Xu et al., 2022; Wang et al., 2025).

Frac-hit events can also be classified according to the response observed in the offset well. The same pathway may generate different outcomes depending on depletion state, fracture conductivity, operating status, and wellbore condition; therefore, the response type should be interpreted together with the identified communication pathway. Table 1 summarizes the principal response categories and their engineering implications (He et al., 2023a; Zhao et al., 2024).

2.2 Identification and evaluation methods

Accurate identification and severity evaluation are prerequisites for effective mitigation. Field diagnosis should determine whether an offset-well response has occurred, identify the most likely communication pathway, and evaluate whether the response is transient, sustained or damaging. Production and pressure monitoring, tracer testing, microseismic/DAS interpretation, pressure/production-transient analysis, and data-driven indicators should therefore be applied as complementary stages of one diagnostic workflow. Table 2 summarizes the diagnostic role, applicable methods, and typical outputs at each stage of inter-well fracture-interference evolution.

A practical diagnostic sequence consists of four stages. First, real-time pressure, rate, fluid and wellbore monitoring captures abnormal responses. Second, tracer, sealed-well or downhole pressure, microseismic and DAS/DTS observations constrain the inter-well pathway and connectivity. Third, pressure/production-transient analysis and quantitative indices evaluate transmissibility, persistence and production impact.

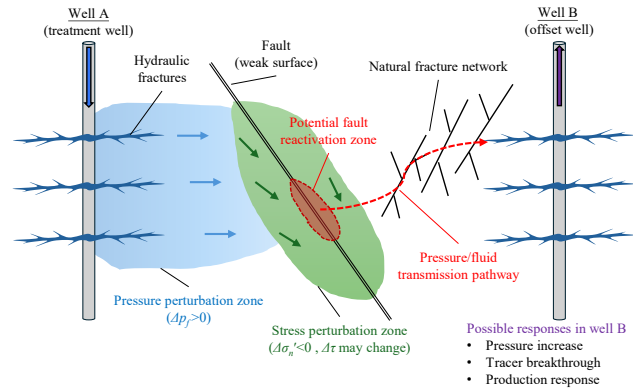


Fig. 2. Fault-mediated FDII pathway. Synthesized from Biot (1941), Morris et al. (1996), and He and Li (2024).

Finally, numerical or data-driven models translate the diagnosis into risk prediction and operating control. The reliability of interpretation increases when geometric, hydraulic and production evidence are mutually consistent.

2.2.1 Production performance analysis

Production and pressure monitoring provide the earliest and most accessible evidence of inter-well interference. Changes in tubing or casing pressure, gas or water rate, fluid composition, flowback behavior, and ion concentration can identify event timing and intensity (He et al., 2024; Li et al., 2024). These data support real-time warning and post-hit recovery assessment. However, additional evidence is usually required to determine the fracture pathway (Abbaszadeh and Cinco-Ley, 1995; Seth et al., 2021; Cai and Dahi Taleghani, 2022).

2.2.2 Tracer monitoring

Tracer monitoring provides direct evidence for fluid exchange between wells. First-arrival time, recovered concentration, and stage-specific recovery profiles identify connected stages and compare pathway strength (Ao et al., 2024). Tracers are limited by cost, test duration, adsorption, dilution, and their inability to reconstruct complete fracture geometry independently (He et al., 2024).

Table 2. Roles of identification methods in the evolution stages of inter-well fracture interference.

Evolution stage	Main diagnostic question	Applicable methods	Typical output and role
Monitoring/abnormal-response capture	Has the offset well responded during or shortly after stimulation?	Wellhead tubing/casing pressure, downhole pressure-temperature gauges, production-rate and water-production monitoring	Detects pressure, production, or water anomalies for early warning
Verification/connectivity confirmation	Has an effective inter-well flow path been established?	Tracer monitoring, sealed-well/downhole pressure, chemical-ion tracking, microseismic event migration, DAS/DTS response	Confirms hydraulic connectivity and constrains the interaction pathway
Evaluation/severity quantification	How strong is the interference and what is its impact on production?	Pressure/production transient analysis, frac-hit pressure integral index, multi-well material-balance analysis	Quantifies interference intensity, affected volume, and production impact
Prediction/risk control	Where and when may interference occur under future designs?	Numerical simulation, geo-engineering risk maps, machine-learning models, real-time diagnostic workflows	Predicts interference risk and guides stimulation and mitigation design

2.2.3 Microseismic and fiber-optic evidence

Microseismic and fiber-optic observations establish spatial and temporal constraints on possible fracture interaction. Event migration toward an offset well, concentration of events in the inter-well corridor, and DAS/DTS strain or temperature responses synchronized with pumping can indicate fracture approach, weak-plane activation or fracture arrival (Liu et al., 2021; Ning et al., 2022). However, these signals primarily constitute geometric and mechanical evidence: Microseismicity may reflect shear deformation rather than a conductive fracture, tensile opening may be aseismic, and fiber-optic responses require interpretation against well geometry and operating conditions. Therefore, these should be combined with pressure, tracer or production responses before effective hydraulic communication is confirmed (Warpinski et al., 2005; Jiang et al., 2022; You et al., 2025).

2.2.4 Pressure/production transient analysis

Pressure and production-transient methods quantify the hydraulic effect of the established pathway. By jointly matching the pressure decline, pressure interference, production history and material balance of treatment and offset wells, analytical or numerical models can estimate inter-well transmissibility, connected drainage volume, and the persistence of communication. For example, multi-well production matching has been used to quantify inter-well communication in single-phase shale gas reservoirs (Chu et al., 2020; Escobar et al., 2021; Qin et al., 2023). Semi-analytical pressure-transient and multi-basin interference-test methods further extended this quantification across different well-pad settings (Awada et al., 2016; Almasoodi et al., 2023).

2.2.5 Comprehensive index evaluation

Quantitative indices provide a rapid means of comparing frac-hit severity among stages, wells and platforms. The Frac Hit Pressure Integral Index and related pressure- or production-response indicators combine response amplitude, duration and recovery behavior to classify interference risk and support

operational decision-making (Zeng et al., 2025). However, such indices should be calibrated against field connectivity and production consequences, so that the same threshold is not applied indiscriminately across different blocks.

Data-driven methods extend frac-hit identification from post-job interpretation to rapid screening and real-time classification. Random forest, support-vector and deep-learning models can integrate geological, completion, pressure, and production variables to identify high-risk wells and classify interference severity (Almasoodi et al., 2023; He et al., 2024; Zeng et al., 2025). Recent work has demonstrated the automated classification of fracture-driven interactions from time-aligned surface-pressure responses in shut-in offset wells (Ashraf et al., 2020). Their field application, however, requires representative labeled data, cross-block validation, and geomechanical constraints to maintain interpretability and transferability.

Diagnostic methods serve complementary functions. Pressure and production monitoring capture the event; microseismic and distributed acoustic or temperature sensing constrain fracture growth and interaction location; tracers and downhole pressure verify hydraulic communication; transient analysis and quantitative indices evaluate severity and production impact; while numerical or data-driven models support prediction and control.

3. Mechanisms of inter-well fracture interference formation

The formation of inter-well fracture interference can be understood as three linked processes: Abnormal fracture propagation or weak-plane activation, establishment of an effective inter-well pathway, and amplification of the offset-well response. The principal mechanisms are hydraulic-fracture interaction with natural fractures and faults, depletion- or fracturing-induced stress-field disturbance, and heterogeneous competitive growth of multi-cluster fractures. These mechanisms often act together and determine whether fracture growth remains within the target region or evolves into long-

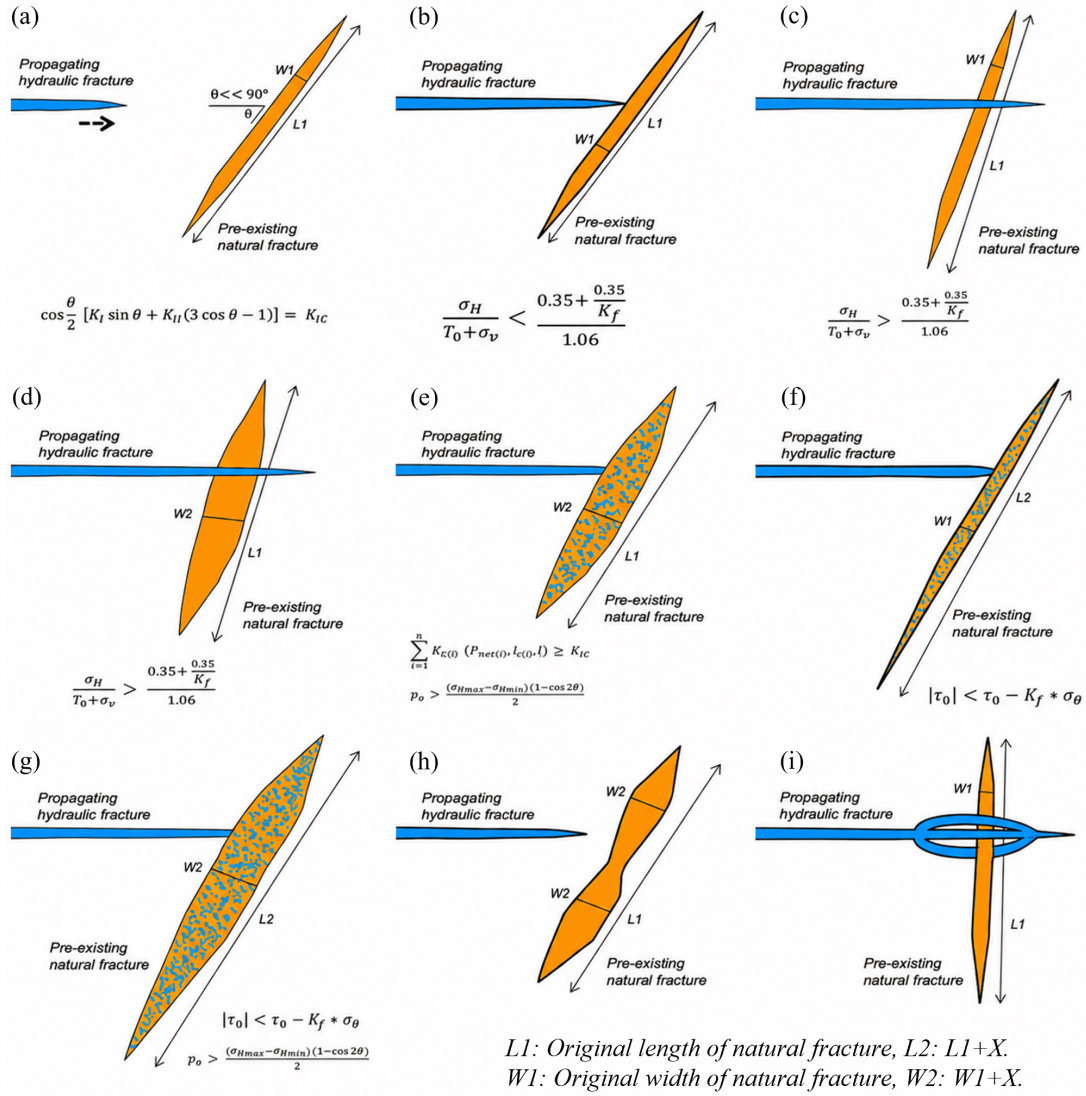


Fig. 3. Typical interaction mechanisms between hydraulic fractures and natural fractures: (a) HF–NF before intersection, (b) fracture arrest, (c) crossing without dilation, (d) crossing with dilation, (e) dilation reactivation, (f) shear reactivation, (g) shear-dilation reactivation, (h) pre-intersection debonding and (i) three-dimensional fracture bypass. Reproduced from Kolawole and Ispas (2020).

distance communication.

In the following mechanism analysis, mechanism is used to describe the physical process through which abnormal fracture growth evolves into inter-well connectivity. This is intentionally distinguished from the controlling-factor discussion in Section 4, where the same geological or engineering variables are treated as risk indicators and design constraints rather than as complete causal processes.

3.1 Interaction between hydraulic fractures and natural fractures/faults

Hydraulic-fracture interaction with natural fractures and faults is a primary mechanism of inter-well communication in shale reservoirs. Natural fractures, bedding planes and faults alter local stress, strength and conductivity; they may arrest a hydraulic fracture, be crossed by it, or be activated to redirect

fluid along a weak plane. When activated weak planes are favorably oriented and sufficiently connected, they can guide pressure and fluid over distances much greater than the direct extension of a single planar hydraulic fracture.

The interaction outcome is governed by approach angle, horizontal stress contrast, effective normal stress, interface friction and cohesion, cementation strength, and net pressure. Strong, closed interfaces and high stress contrast generally favor crossing, whereas weak or favorably oriented interfaces under low effective normal stress promote opening, shear activation or diversion (Renshaw and Pollard, 1995; Janiszewski et al., 2019; Kolawole and Ispas, 2020).

A hydraulic fracture may cross, arrest, dilate, shear-reactivate, debond from or bypass a natural fracture (Fig. 3). Crossing tends to preserve propagation along the far-field principal-stress direction, whereas arrest, dilation, debonding, and shear activation can redirect fluid into connected weak

planes. FDII becomes likely only when this redirected pathway reaches an adjacent fracture system or well and retains sufficient conductivity for pressure or fluid transmission (Kolawole and Ispas, 2020; Wang and Yao, 2022; Qin et al., 2024).

Most existing studies resolve local interaction modes under simplified conditions, and the remaining challenge is to quantify when these local events develop into reservoir-scale hydraulic communication. In the southern Sichuan Basin, numerous studies have demonstrated that the fracturing-induced interference of shale gas horizontal wells is closely correlated with the excessive propagation of large-scale natural fractures in a single direction (King, 2010). When the dominant weak-plane orientation intersects the direction between wells, hydraulic fractures can be captured and redirected, forming one or more channelized pathways that connect neighboring stimulated regions (Qin et al., 2024).

Faults represent larger and potentially more hazardous discontinuities. Their cores and damage zones may contain weak fillings and connected fractures, making them susceptible to pressure penetration, shear activation, and permeability enhancement (McClure and Horne, 2014; Igonin et al., 2019). Once a hydraulic fracture intersects an activated fault zone, the fault can transmit pressure and fluid over a large distance and may also produce casing deformation, casing-connection failure, or other wellbore-integrity problems (Dusseault et al., 2001; Xu et al., 2022; Wang et al., 2025). Fault location, orientation, sealing state, and mechanical stability are therefore essential inputs for frac-hit risk evaluation (Yehya et al., 2022).

From a geomechanical perspective, fault activation can be described using the effective-stress principle, the Coulomb shear-failure criterion, slip-tendency analysis, and the Coulomb failure stress change (Biot, 1941; Morris et al., 1996; Zoback, 2007). For a fault plane with cohesion c_f and friction coefficient μ_f , the effective normal stress is expressed as:

These equations provide a first-order basis for fault-stability evaluation, while their thresholds require a consistent stress convention. Interpretation should also account for three-dimensional stress heterogeneity, fault roughness, filling properties, hydraulic connectivity, and time-dependent pressure diffusion:

$$\sigma'_n = \sigma_n - \alpha p_f \quad (1)$$

where σ_n denotes the total normal stress on the fault, p_f denotes the fluid pressure, α denotes the Biot coefficient, and σ'_n is effective normal stress. Slip is promoted when shear stress τ satisfies the Coulomb criterion:

$$\tau \geq c_f + \mu_f \sigma'_n \quad (2)$$

Equivalently, slip tendency T_s represents the ratio of acting shear stress τ to available shear resistance. Here, c_f represents fault cohesion and μ_f denotes the fault-friction coefficient:

$$T_s = \frac{\tau}{c_f + \mu_f \sigma'_n} \quad (3)$$

Fault reactivation is likely when T_s approaches or exceeds 1. For injection-induced perturbations, ΔC_{FS} denotes the Coulomb failure-stress change, $\Delta\tau$ denotes the shear-stress

change, and $\Delta\sigma'_n$ is the effective-normal-stress change:

$$\Delta C_{FS} = \Delta\tau - \mu_f \Delta\sigma'_n \quad (4)$$

Pore-pressure diffusion into a fault reduces effective normal stress, and poroelastic or fracture-induced stress perturbations can further increase the resolved shear stress (Kettlety et al., 2020). When the slip tendency or Coulomb failure stress reaches a critical level, fault slip and shear dilation may sharply increase pathway conductivity. If the activated fault or damage zone intersects the offset-well fracture system or wellbore region, it can generate abrupt, long-distance, high-intensity inter-well interference (Kettlety and Verdon, 2021; He and Li, 2024).

Thermal and chemical processes may further activate weak planes. Cold or carbon-dioxide-based fluids generate local thermal stress and alter fracture growth. Fluid-rock reactions may weaken fillings, modify mineral structure, and change fracture aperture (Zang et al., 2026; Zhou et al., 2026).

Thermo-hydro-mechanical-chemical coupling is especially relevant in deep reservoirs and reactive-fluid systems. In these settings, fault activation cannot be described by pore pressure alone. Modeling and experiments have indicated that thermal stress and chemical alteration may intensify slip and fracture development, although field effects require site-specific calibration (Shi et al., 2023; Zhou et al., 2026).

3.2 In-situ stress field disturbance and fracture diversion

Production depletion and multi-well fracturing continuously reconstruct the inter-well stress field. Parent-well depletion creates a pressure and total-stress deficit around the existing stimulated region, whereas active hydraulic fractures generate transient stress shadows. Both effects change horizontal stress magnitude and orientation, causing newly initiated fractures to grow asymmetrically, deflect toward low-stress corridors, or interact with neighboring fracture systems.

A quantitative description of stress-field disturbance requires stress-path coefficients, effective-stress changes, and local principal-stress rotation. These relationships link pore-pressure evolution to changes in horizontal total stress and explain how depletion or injection modifies fracture orientation (Segall and Fitzgerald, 1998; Zangeneh et al., 2015; Zoback, 2007). In depletion or injection zones, the stress-path coefficients may be defined as:

$$K_h = \frac{\Delta\sigma_h}{\Delta p_p} \quad (5)$$

$$K_H = \frac{\Delta\sigma_H}{\Delta p_p} \quad (6)$$

where Δp_p denotes the pore-pressure change, and σ_h and $\Delta\sigma_H$ are the corresponding changes in the minimum and maximum horizontal total stresses; and K_h and K_H represent the corresponding horizontal stress-path coefficients. The effective-stress changes are:

$$\Delta\sigma'_h = \Delta\sigma_h - \alpha\Delta p_p \quad (7)$$

$$\Delta\sigma'_H = \Delta\sigma_H - \alpha\Delta p_p \quad (8)$$

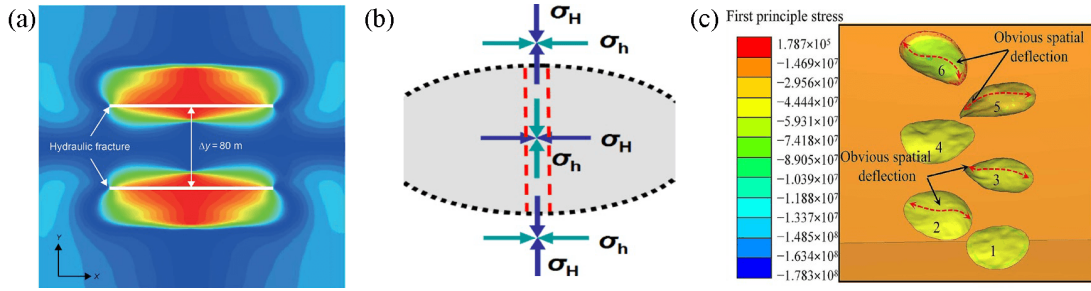


Fig. 4. Stress reorientation and fracture diversion induced by depletion and stress-shadow effects: (a) Depletion-induced stress reorientation near parent-well fractures, (b) reversed-stress region during production-induced depletion and (c) fracture diversion caused by stress-shadow redistribution. Reproduced from Zhang et al. (2022), Wang and Weijermars (2023), and Ju et al. (2025).

where $\Delta\sigma'_h$ and $\Delta\sigma'_H$ represent the increments of the minimum horizontal effective stress and the maximum horizontal effective stress, respectively.

During parent-well depletion, pore pressure decreases and poroelastic contraction reduces the horizontal total stress around the depleted stimulated region. Although the effective stress may increase, the reduction in minimum horizontal total stress and the associated change in horizontal stress contrast can create a low-stress corridor that attracts or redirects fractures initiated from a nearby infill well. The degree of attraction is controlled by the Biot coefficient, a reservoir constraint, stress-path coefficients, and the geometry of the depleted region; it is therefore a coupled pressure-stress effect rather than a simple response to the pore-pressure gradient.

As production continues, the depletion zone expands around the parent well and its legacy fractures. The accompanying poroelastic contraction alters both horizontal principal stresses and can rotate the local principal-stress direction. When a child-well fracture approaches this region, it preferentially propagates toward the reduced-total-stress corridor and may connect with existing hydraulic fractures, activated natural fractures, or the parent-well drainage region. This depletion-induced fracture attraction is a principal mechanism of parent-child well frac hits.

Fracture deflection can be expressed through local principal-stress rotation. In the horizontal plane, θ represents the rotation angle, σ_H represents the initial maximum horizontal stress, and $\Delta\sigma_x$, $\Delta\sigma_y$, and $\Delta\tau_{xy}$ are the perturbation stresses:

$$\tan 2\theta = \frac{2\Delta\tau_{xy}}{\sigma_H - \sigma_h + \Delta\sigma_x - \Delta\sigma_y} \quad (9)$$

The same shear perturbation produces greater deflection when depletion reduces the horizontal stress contrast. Predictions should therefore combine depletion, stress-path coefficients, well spacing, vertical offset, and the distribution of shear-stress perturbation (Safari et al., 2017; Taghaviinejad et al., 2022; Zhang et al., 2022).

Depletion-induced attraction strengthens as the pressure and total-stress deficits grow and the child fracture approaches the parent stimulated region. Vertical separation, original stress anisotropy, legacy-fracture geometry, and barriers may alter the trajectory or prevent direct connection. These factors bind the mechanism but do not eliminate the tendency toward a

depleted low-stress corridor (Safari et al., 2017; Wang et al., 2022; Guo et al., 2024).

The second pathway is provided by dynamic stress interference. During simultaneous, sequential or zipper fracturing, each propagating fracture increases the minimum horizontal stress in adjacent regions and rotates the local stress field. Appropriate sequencing can distribute fractures between wells, whereas an excessive overlap of stress shadows can suppress inner clusters, promote asymmetric outer or dominant fractures, and redirect fracture growth toward neighboring wells or weak-plane corridors. Thus, the timing and spatial relationship of multi-well operations directly affect the frac-hit risk.

Depletion and stress shadows produce a common geomechanical consequence. They modify local stress anisotropy and principal-stress direction, which diverts fractures from the far-field trajectory (Fig. 4). The diversion magnitude depends on the depletion history, stress-path response, and superposed fracture-induced stresses. However, hydraulic and field-response evidence is still required to confirm FDII.

3.3 Competitive propagation and heterogeneous extension of multi-cluster fractures

Staged multi-cluster fracturing is designed to initiate several fractures within one stage, but the fractures rarely receive identical fluid and energy. Near-wellbore friction, reservoir heterogeneity, natural fractures, perforation differences, and stress shadowing produce competitive growth among clusters. This competition is a key internal mechanism by which one or a few fractures become excessively long and increase the probability of reaching an adjacent well.

Once a cluster initiates earlier or enters a lower-stress or weak-plane region, it will accept more fluid, grow faster and create a stress shadow that suppresses neighboring clusters. The resulting positive feedback concentrates injection into dominant fractures, while under-stimulated clusters remain short or close prematurely. The dominant fractures then control the effective stimulated width and the inter-well extension risk of the stage.

When a dominant fracture is aligned with an inter-well natural-fracture corridor, fault zone or depletion-induced low-stress region, its preferential growth can exceed the planned fracture half-length and establish communication with an offset well. Multi-cluster imbalance therefore does not inde-

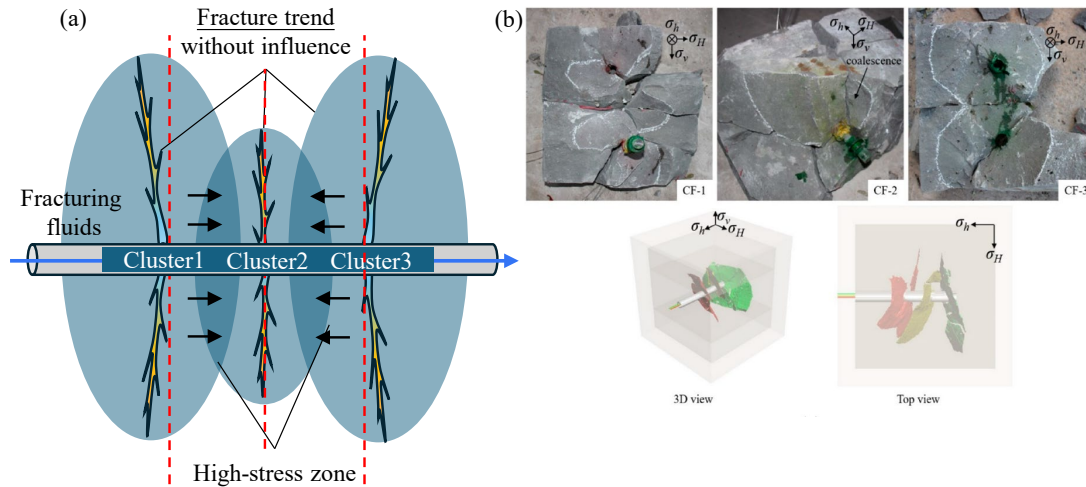


Fig. 5. Competitive propagation of multi-cluster fractures: (a) Mechanism of competitive propagation and (b) experimental photograph of fracture competitive propagation under triaxial stress. Adapted from Bi et al. (2021).

pendently create every frac hit but amplifies the geological and stress conditions that favor long-distance connection.

Numerical and experimental studies consistently show unequal fracture initiation, fluid partitioning and competitive growth among clusters (Roussel and Sharma, 2011; Bunker et al., 2012; Manchanda and Sharma, 2014). Sector-scale and multi-horizontal-well simulations further confirm that stress shadowing and operational sequence can amplify fracture asymmetry (Liu et al., 2023).

Accordingly, frac-hit control should improve cluster-level uniformity and prevent the excessive growth of a single fracture. Appropriate cluster spacing, limited-entry perforation, balanced perforation friction, controlled pumping rate and fluid volume, and temporary plugging/diversion can redistribute fluid among clusters and reduce the probability of a dominant fracture evolving into an inter-well pathway (Chang et al., 2025).

The true-triaxial results indicate asynchronous growth and fluid concentration in dominant clusters (Fig. 5). A dominant fracture can extend beyond its design region and intersect a weak-plane corridor, fault, or depleted low-stress zone. Cluster uniformity therefore exerts a direct engineering control on inter-well extension risk.

In summary, inter-well fracture interference develops through the combined action of three mechanism groups:

- 1) Hydraulic fractures activate or intersect natural fractures and faults to create preferential pathways;
- 2) parent-well depletion and multi-well stress shadows redirect fracture growth toward inter-well low-stress or weak-plane corridors;
- 3) multi-cluster competition concentrates fluid and energy into dominant fractures.

The coupling of these mechanisms determines whether a local fracture interaction develops into effective and sustained inter-well communication.

4. Analysis of main controlling factors for inter-well fracture interference

Inter-well fracture interference is controlled by the coupling of intrinsic reservoir conditions, development history and fracturing design. Identifying the dominant controls is necessary for defining risk thresholds, selecting well spacing and formulating differentiated mitigation strategies. This section separates geological susceptibility from engineering variables that can be adjusted during development and stimulation.

The physical mechanisms by which inter-well fracture interference forms have been discussed in Section 3. This section focuses on the controlling factors, namely variables that change the probability, intensity and influence range of those mechanisms. The same factor may influence more than one mechanism; for example, natural-fracture orientation controls hydraulic-fracture capture, while well spacing determines whether the resulting pathway can reach an offset well.

4.1 Geological factors

Geological factors define the intrinsic susceptibility of a reservoir to fracture diversion and long-distance communication. The effects of such factors cannot be eliminated by operational adjustment, but they can be characterized and incorporated into well placement, stage design and risk zoning.

Natural fractures and faults are the most direct geological controls because they provide mechanically weak and potentially conductive structures. Their density, orientation, persistence, aperture, filling, cementation and connectivity determine whether a hydraulic fracture is crossed, arrested or redirected and whether an activated pathway can extend between wells. Field observations from international shale developments and southern Sichuan have shown that fracture corridors and fault-related weak zones are closely associated with severe frac-hit events (Kettlety and Verdon, 2021; Shen et al., 2024; Qin et al., 2024).

The *in-situ* stress field controls the preferred hydraulic-fracture orientation and the tendency for deflection or branch-

Table 3. Geological factors influencing shale gas inter-well fracture interference.

Specific factor	Influence on interference risk	Quantitative research evidence	Reference
Horizontal stress difference	Controls fracture planarity, turning and branching. Low contrast favors weak-plane interaction and complexity; high contrast favors planar but potentially long fractures	The risk depends on both stress contrast and the alignment of the preferred fracture direction with offset wells or weak-plane corridors	He et al. (2020); Wang et al. (2024)
Natural fracture network	Fracturing fluid tends to propagate along natural fractures, forming long-distance high-conductivity channels	Field cases in southern Sichuan show that natural fractures and fault-related weak zones are major pathways for inter-well fracture interference	Duan et al. (2024); Tang et al. (2023); Yang et al. (2025)
Faults/fracture zones	High-pressure fluid can induce fault slip, forming large-scale and long-distance interference channels	Fault slip may result in shear dilation, casing deformation, and long-distance pressure communication	Wang et al. (2025); Ling et al. (2024); Song et al. (2024)
Rock mechanical properties	Elastic properties, tensile strength, fracture toughness, bedding and heterogeneity control initiation, height growth, branching, and conductivity	Mechanical properties influence frac-hit risk through their coupling with stress and weak-plane architecture rather than through brittleness alone	He et al. (2020)

ing. A small horizontal stress contrast facilitates interaction with weak planes, fracture turning and network complexity, thereby increasing pathway uncertainty; meanwhile, a large stress contrast favors more planar propagation, but may still generate long fractures if treatment energy is high and the fracture is aligned with the offset well. Local stress heterogeneity caused by faults, folds, lithologic contrasts, and production depletion is therefore more informative for frac-hit prediction than stress contrast alone (King, 2010; Zhang et al., 2022).

The rock's mechanical properties and reservoir heterogeneity further determine fracture initiation pressure, toughness, width, height containment, and conductivity. Young's modulus, Poisson's ratio, tensile strength, fracture toughness, brittleness, bedding and elastic-property contrast influence whether fractures remain planar, branch, cross interfaces or become captured by weak layers. Their effect is generally expressed through interaction with the stress field and natural-fracture system rather than as a single independent brittleness index (Cipolla et al., 2010).

Therefore, before fracturing design, geological susceptibility should be evaluated using natural-fracture and fault architecture, present-day stress magnitude and orientation, depletion-induced stress change, lithologic and elastic contrasts, and weak-plane mechanical properties. These parameters can identify zones prone to direct fracture extension, weak-plane capture, fault activation, or depletion-induced attraction.

4.2 Engineering factors

These are controllable variables affecting the risk of inter-well fracture interference. However, through optimized design and refined construction, the occurrence probability and severity of interference can be controlled and mitigated to a certain extent.

The primary geometric constraint is well spacing. Communication between fractures becomes more likely when spacing approaches the effective reach of hydraulic and connected

natural fractures. Observations at the southern Sichuan show higher interference at small spacing. Production and simulation studies have also indicated reduced estimated ultimate recovery for parent and infill wells (Chen et al., 2021; Shen et al., 2024; Yang et al., 2025). Therefore, a universal threshold is inappropriate; design spacing must reflect fracture orientation, fault distance, depletion range, vertical offset, and treatment intensity (Yong et al., 2021; Ibrahim, 2022; Fu et al., 2023).

The fracturing parameters determine the propagation scale and cluster balance. Excessive fluid volume per cluster, high injection intensity, or poorly balanced perforation friction can promote dominant-fracture growth, whereas suitable pumping schedules, limited-entry design, and temporary plugging/diversion improve cluster uniformity and restrict uncontrolled extension (Al-Muntasheri et al., 2009; Guo et al., 2023). The fracturing sequence also matters: Simultaneous or zipper operations create strong inter-well stress interaction, while the timing of child-well stimulation relative to parent-well depletion controls the strength of fracture attraction. Offset-well shut-in, pressure management, preloading, or selective refracturing can be considered where field evidence supports their effectiveness (Manchanda and Sharma, 2014; Ibrahim et al., 2018; Chang et al., 2025).

Engineering optimization should therefore match well spacing and vertical placement to the predicted fracture and weak-plane reach, constrain fluid volume and pumping rate according to the target stimulated volume, improve cluster-level fluid distribution, and coordinate fracturing and production schedules among neighboring wells. The objective is not to eliminate all interaction but to prevent uncontrolled pathways that cause damaging fluid invasion, production loss, or wellbore-integrity failure.

The geological and engineering factors influencing inter-well fracture interference are summarized and compared in Tables 3 and 4, respectively.

Overall, geological factors determine where inter-well communication is most likely to occur, while engineering

Table 4. Engineering factors influencing shale gas inter-well fracture interference.

Specific factor	Influence on interference risk	Quantitative research evidence	Reference
Well spacing	Smaller well spacing corresponds to higher interference probability and severity	When well spacing decreases, Estimated Ultimate Recovery loss and adjacent-well response intensity generally increase; field and simulation studies suggest that spacing below about 300-350 m should be carefully evaluated	He et al. (2020); Wei et al. (2018); Yang et al. (2025)
Operation parameters	Fluid volume per cluster, pumping rate, perforation friction and cluster spacing control fracture reach and cluster balance	High treatment intensity and poor cluster uniformity promote dominant-fracture growth; limited-entry and diversion can reduce this risk	Duan et al. (2024); Chang et al. (2025)
Development sequence/fracturing mode	Fracturing sequence and parent-well production history reconstruct the inter-well stress field and alter fracture attraction and stress shadowing	Stronger parent-well depletion and inappropriate multi-well sequencing can increase asymmetric growth and adverse production impact	Yang et al. (2025); Guo et al. (2024)

factors control whether the available pathways are activated and how severe the resulting response becomes. Effective frac-hit control therefore requires geology-engineering integration: Risk zoning based on natural fractures, faults, stress, and depletion, followed by differentiated well spacing, cluster design, pumping, and offset-well management.

5. Research methods and applicability analysis of inter-well fracture interference

The increasing complexity of shale-gas development has forced the development of research methods for FDII. Early studies mainly focused on whether hydraulic fractures from neighboring wells could geometrically overlap, whereas current studies increasingly aim to identify how fracture propagation, natural-fracture or fault activation, stress redistribution, pressure communication, and production response jointly evolve into effective inter-well interference. Therefore, numerical simulation, physical experiments, field monitoring, and data-driven methods should not be regarded as independent techniques but as complementary tools for understanding different stages of the same FDII process.

5.1 Numerical simulation

Numerical simulation quantitatively evaluates fracture propagation, stress disturbance, and reservoir-scale inter-well communication (Lecampion et al., 2018). In early analytical studies, Khristianovich-Geertsma-de Klerk, Perkins-Kern-Nordgren, and pseudo-three-dimensional models were used to estimate single-fracture dimensions. However, they could not represent multi-cluster stress interaction, natural-fracture diversion, or depletion-induced stress reconstruction (Thompson, 2018; Zhao et al., 2024).

Displacement-discontinuity and multi-fracture models were subsequently introduced to quantify stress shadows and competitive growth (Peirce and Detournay, 2008; Bunger et al., 2012; Dontsov and Peirce, 2017). This simplified geology, however, limited complex-network representation. Discrete fracture network, embedded discrete fracture, and complex-

fracture models later represented crossing, arrest, branching, and weak-plane activation (Dahi Taleghani and Olson, 2011; Kresse et al., 2013; Weng, 2015). These methods support the evaluation of natural-fracture-mediated communication (Kresse et al., 2013; Qin et al., 2023).

More recently, parent-child well development has promoted the use of coupled hydraulic-mechanical and poromechanical models, which can evaluate how long-term production changes pore pressure, horizontal stress magnitude and local stress orientation, thereby redirecting child-well fractures toward depleted regions and modifying inter-well interference during well-pad production (Safari et al., 2017; Wang et al., 2022; Guo et al., 2024). Fault-related frac hits have further required effective-stress, slip-tendency and Coulomb-failure analyses to evaluate fault reactivation and long-distance pressure transmission (He and Li, 2024; Wang et al., 2025). Recent multi-well and well-pad simulations have extended these analyses to development-scale optimization and depletion-dependent interference prediction (Wei et al., 2021; Du et al., 2025).

At present, numerical simulation is mainly used for mechanism testing, sensitivity analysis and design optimization. It can evaluate the effects of well spacing, vertical offset, cluster spacing, fracturing sequence, treatment intensity, depletion history, and fault distance on FDII risk. However, the simulation results depend strongly on stress-state characterization, natural-fracture properties, fracture conductivity, fault parameters, and production-history calibration. Thus, numerical models should be constrained by physical experiments and field monitoring rather than used as standalone predictors of frac-hit severity.

5.2 Physical experiments

Physical experiments isolate fracture-interaction mechanisms under controlled stress and injection conditions. Conventional observations established that the approach angle, stress contrast, weak-plane strength, pumping conditions, and neighboring-fracture interaction control crossing, diversion, branching, as well as dominant-fracture growth (Warpinski and Teufel, 1987; Dahi Taleghani and Olson, 2011; Sarmadi-

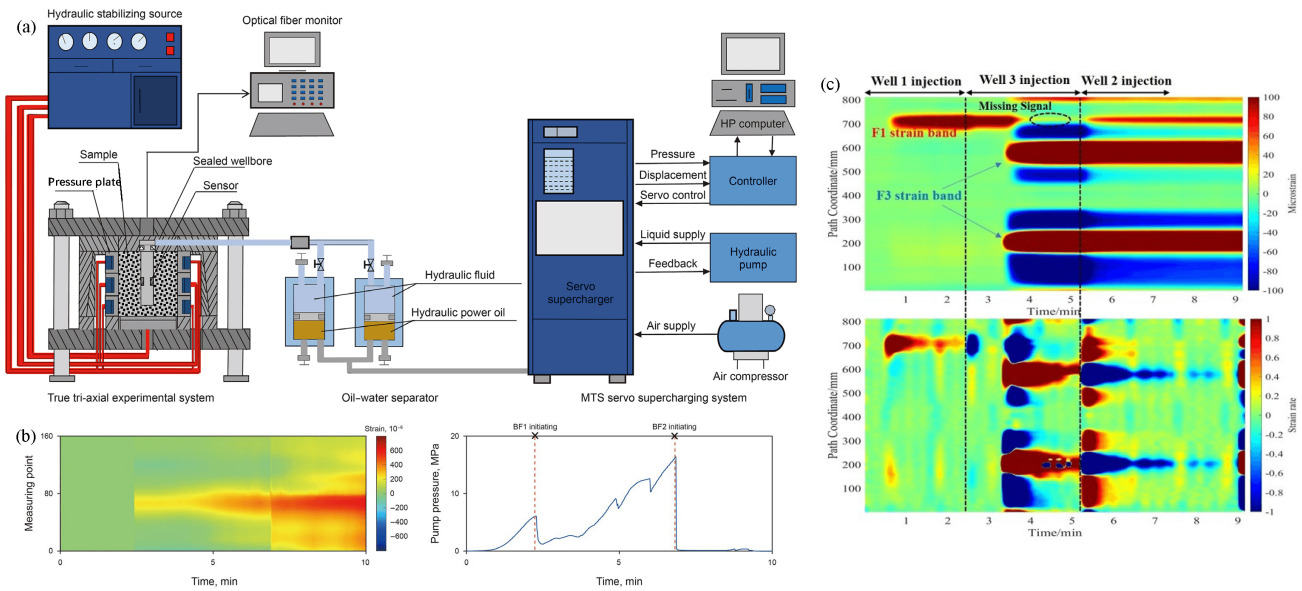


Fig. 6. Evolution of experimental and monitoring techniques for hydraulic-fracture propagation and inter-well interaction: (a) True-triaxial fracturing system with fiber-optic monitoring, (b) fiber-optic strain response during fracture propagation and (c) fiber-optic diagnosis of multiwell fracture interaction. Reproduced from Guo et al. (2025).

valeh and Rasouli, 2015). New visual true-triaxial experiments in layered media further clarified the dynamic competition and redirection of multiple fractures (Huang et al., 2026). As shown in Fig. 6, recent experimental systems integrate true-triaxial loading with distributed fiber-optic monitoring to resolve fracture propagation and multi-well interaction in both space and time.

At present, physical experiments combine controlled mechanics with time-resolved monitoring. Figure 6 illustrates how true-triaxial systems and distributed fiber-optic sensing capture fracture initiation, bedding activation, fiber intersection, stress-shadow development, and sequential multi-well interaction (Wang et al., 2024; Guo et al., 2025). These measurements link final geometry to propagation history, although the laboratory scale and boundaries remain limiting factors.

Despite the above advances, physical experiments remain restricted by scale effects; laboratory samples cannot fully reproduce field-scale fracture length, reservoir heterogeneity, long-term depletion, proppant transport, or multi-well stress interference. Therefore, physical experiments are most suitable for mechanism verification and numerical-model calibration, rather than the direct prediction of frac-hit distance or severity.

5.3 Field monitoring

Field monitoring is essential because it determines whether mechanisms inferred from simulations and experiments actually occur at the reservoir scale. Early frac-hit diagnosis mainly relied on offset-well pressure surges, water breakthrough, tracer response, production decline, or casing-integrity problems. These signals are operationally useful but non-unique, because a pressure or production response may result from hydraulic communication, poroelastic stress transfer or drainage interference.

Microseismic monitoring provides spatial evidence of fracture propagation and weak-plane activation (Pearson, 2001; Fisher et al., 2005; Warpinski et al., 2005; Ketter et al., 2008). It is useful for identifying fracture extension toward offset wells, natural-fracture corridors, or fault zones. However, microseismic events mainly record shear-related deformation and do not necessarily indicate conductive hydraulic pathways (Schultz et al., 2020). Pressure monitoring and pressure-transient analysis can capture the timing, magnitude and persistence of offset-well responses, whereas tracer monitoring provides direct evidence for fluid exchange between wells (Escobar et al., 2021; Ao et al., 2024; Wei et al., 2025). DAS/DTS and distributed strain sensing further improve the temporal and spatial resolution of fracture-arrival and inter-well communication diagnosis (Pakhotina et al., 2020; Jiang et al., 2022; You et al., 2025). Coupled stress-fracture-fault modeling provides an additional bridge between observed seismicity and the underlying activation mechanism (Hui et al., 2022; Zhou et al., 2025). Current field diagnosis therefore emphasizes multi-source evidence. Pressure and production data identify abnormal responses; microseismic and fiber-optic data constrain fracture geometry; tracer data verify hydraulic communication; and pressure/production-transient analysis evaluates long-term impact. This integrated workflow is necessary to distinguish geometric connectivity, hydraulic connectivity and production connectivity (Raghavan and Chen, 2013; Seth et al., 2021; Cai and Dahi Taleghani, 2022). Field case studies combining pressure-hit analysis, microseismic information, and open-hole diagnostics demonstrate the value of cross-validating multiple evidence types (Dean et al., 2006; Awada et al., 2016; Raterman et al., 2018).

Table 5. Comparison of research methods for shale gas inter-well fracture interference.

Method	Main role in FDII research	Key advantage	Main limitations
Numerical simulation	Mechanism testing and design optimization	Quantifies fracture propagation, stress redistribution and inter-well communication	Strong dependence on model assumptions and calibration
Physical experiment	Mechanism verification	Directly observes fracture diversion, branching and weak-plane activation	Scale and boundary effects
Field monitoring	Reservoir-scale diagnosis	Captures pressure response, fracture geometry, tracer breakthrough, and production impact	Single data source is often non-unique
Data-driven method	Risk screening and real-time classification	Integrates large geological, completion and production datasets	Limited interpretability and transferability

5.4 Data-driven and machine learning methods

Data-driven methods have emerged because FDII is controlled by many coupled geological and engineering variables, including well spacing, natural-fracture intensity, fault distance, depletion time, pumping rate, fluid volume, cluster design, and offset-well pressure. Machine-learning models can integrate these variables to classify frac-hit risk and identify high-risk wells or stages (Beckwith, 2011; Ashraf et al., 2020; Zeng et al., 2025). Data-analytics workflows have also been applied to quantify parent-well production impacts following frac hits (He et al., 2023b).

The advantage of data-driven methods is rapid screening and real-time classification using large geological, completion, pressure, and production datasets. However, their reliability depends on labelled data quality, feature selection, and training-set representativeness. Models trained in one block may not transfer directly to another block with different stress regimes, natural-fracture systems or completion practices. Therefore, machine learning should be used as a geomechanics-constrained decision-support tool rather than a replacement for mechanism-based analysis.

5.5 Applicability and integration

Overall, each research method contributes to a different stage of FDII analysis. Numerical simulation supports mechanism testing and design evaluation; physical experiments verify local fracture-interaction processes; field monitoring confirms reservoir-scale communication; and data-driven methods support rapid risk prediction and classification. No single method can independently describe the full evolution from fracture propagation to offset-well production response, but their integration provides the methodological basis for the connectivity-based diagnostic framework discussed in the following section. A systematic comparison and summary of these research methods are presented in Table 5.

6. Integrated analysis: Mechanisms, connectivity and diagnosis

Inter-well fracture interference develops through the progressive linkage of abnormal fracture propagation, conductive pathway formation, and offset-well response. Hydraulic-fracture extension, natural-fracture or fault activation, depletion-induced stress redistribution, and multi-cluster competition provide the mechanical conditions for interference, but these processes do not necessarily indicate effective inter-well communication (King, 2010; Kresse et al., 2013; Zhao et al., 2024).

Accordingly, geometric, hydraulic and production connectivity should be distinguished. Geometric connectivity indicates that hydraulic fractures, activated weak planes, or microseismic events extend into the inter-well region, whereas hydraulic connectivity requires actual pressure or fluid transmission between wells. Production connectivity further refers to sustained changes in gas production, water production, pressure decline, or wellbore integrity. Therefore, fracture length, microseismic-event distribution, or stimulated reservoir volume alone cannot determine frac-hit severity (Pearson, 2001; Warpinski et al., 2005; Mayerhofer et al., 2010). Physical inter-well models further show that apparent geometric overlap and effective production interference are not equivalent because matrix permeability and pathway conductivity mediate the response (Cinco-Ley et al., 1978).

Reliable diagnosis requires the integration of multiple types of evidence. Microseismic monitoring and fracture-geometry inversion provide spatial evidence of possible fracture propagation; pressure monitoring, tracer testing and DAS/DTS responses verify hydraulic communication; and production-transient analysis or well-integrity responses quantify its engineering consequences. Because each method characterizes a different stage or aspect of the interference process, a single monitoring signal is generally insufficient to confirm an effective frac-hit event (Escobar et al., 2021; Ao et al., 2024; You et al., 2025).

Frac-hit risk should therefore be evaluated by determining

whether geological and stress conditions promote abnormal fracture growth, whether a conductive inter-well pathway can form, and whether the resulting communication causes unacceptable production or integrity impacts. This integrated framework provides a basis for optimizing well spacing, cluster spacing, pumping parameters, fracturing sequence, and offset-well management under specific geological and depletion conditions (Qin et al., 2024; Chang et al., 2025; Yang et al., 2025).

7. Conclusions and prospects

This review synthesizes FDII in shale gas reservoirs using a source-pathway-response-control logic. The main findings are as follows:

- 1) Inter-well fracture interference is a coupled evolution process rather than simple excessive growth of a single fracture. It begins with abnormal hydraulic-fracture propagation, weak-plane activation, fault slip, or stress perturbation; then, it develops through an effective hydraulic or mechanical pathway; and it is finally expressed as pressure, tracer, production, or wellbore-integrity response in offset wells.
- 2) The dominant mechanisms include hydraulic fracture-natural fracture/fault interaction, effective-stress reduction and fault reactivation, stress-shadow-induced fracture diversion, and multi-cluster competitive propagation. These mechanisms may coexist, so field cases should not be interpreted using a single-factor explanation.
- 3) Geological and engineering variables should be treated as risk controls rather than repeated as mechanisms. Natural-fracture density, fault distance, stress contrast, depletion degree, well spacing, cluster spacing, fluid volume, and pumping schedule jointly determine interference probability and severity.
- 4) A staged diagnostic workflow is required for inter-well fracture interference. Production and pressure monitoring capture abnormal responses, while tracer, microseismic and DAS/DTS data verify effective connectivity. Pressure-transient analysis and quantitative indices evaluate severity, and numerical or data-driven models support risk prediction and real-time control.

Future research should pursue three directions. First, field-calibrated geomechanical models should link effective stress, fault slip tendency, stress-path coefficients, and fracture deflection. Second, staged diagnosis should integrate pressure, tracer, microseismic, distributed sensing, and production data. Third, geomechanical constraints should guide interpretable prediction and closed-loop control. Real-time systems could then update frac-hit risk during pumping and support injection adjustment, offset-well shut-in, and controlled cooperative stimulation.

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Conflicts of interest

The authors declare no competing interest.

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