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Multiscale and Multiphysics Mechanisms of Proppant Fracture Conductivity Evolution in Hydraulic Fracturing

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Abstract: Hydraulic fracturing is a core stimulation technology for unconventional oil and gas development, in which proppants play a decisive role in sustaining fracture conductivity. As fracturing operations extend toward deep reservoirs, high-temperature and high-pressure (HTHP) environments, and complex fracture networks, the mechanical response, transport behavior, and coupled interactions among proppants, fracturing fluids, and rock formations exhibit pronounced multiscale and multiphysics characteristics. These coupled processes constitute a fundamental constraint on the long-term stability of fracture conductivity. This review focuses on the formation and evolution of proppant-supported fracture conductivity and systematically examines the material characteristics and applicable conditions of different proppant types. From a multiscale perspective, four core mechanisms governing proppant behavior during hydraulic fracturing are synthesized: physical support and embedment–crushing processes under fracture closure; compaction-induced conductivity degradation within proppant packs; thermofluid-dynamic controls on proppant settling and migration inside fractures; and cooperative transport mechanisms between proppants and fracturing fluids that sustain long-term conductivity. The effects of cyclic loading, HTHP environments, and fluid rheology on the coupled behavior of the proppant–fluid–rock system are further analyzed. Current limitations are identified in predicting mechanical behavior under extreme conditions, constructing multiscale coupled models, and bridging laboratory-scale observations with field-scale performance. Recent progress in multiscale multiphysics modeling and proppant design is summarized, and future research directions at the intersection of engineering thermophysics and energy engineering are outlined. The review provides a theoretical basis for proppant selection, conductivity evaluation, and efficient development of unconventional reservoirs.

Keywords: Hydraulic fracturing; Proppants; Fracture conductivity evolution; Multiscale multiphysics coupling; Thermofluid transport; Fracture mechanics; Engineering thermophysics

1 Introduction

Oil and natural gas remain primary global energy resources, and continuous advances in exploration and development technologies have supported sustained production growth. Over the past five years, unconventional oil and gas development has emerged as a major driver of the global petroleum industry. According to the *World Energy Statistical Yearbook 2025*, global unconventional oil and gas production reached 2.46 billion tonnes of oil equivalent in 2024, accounting for 29.6% of total oil and gas output, with an average annual growth rate of 5.8% during 2019–2024, markedly higher than the 1.2% growth rate of conventional resources. Shale reservoirs, as a representative class of unconventional formations, exhibit pronounced anisotropy in mechanical and flow properties. Their development performance is strongly influenced by brittleness index, organic matter content, and transport mechanisms such as slip flow and Knudsen diffusion, which impose specific requirements on proppant selection and fracturing design [1]. As a result, the performance and governing mechanisms of proppants that sustain fracture conductivity have become a focal topic in both academic research and industrial practice.

In hydraulic fracturing operations, high-pressure fluids are injected to create fractures, while proppants are transported into the fractures to prevent closure. With the expansion of fracturing toward deeper reservoirs, high-temperature and high-pressure (HTHP) conditions, and increasingly complex fracture networks, conventional proppants face challenges including mechanical degradation and long-term conductivity loss. Proppant technologies have evolved from single-material systems to multifunctional composites, progressing from quartz sand to ceramic and resin-coated proppants, and more recently to a variety of emerging proppant concepts and associated techniques. Although substantial progress has been achieved in understanding microscale mechanisms and in developing multiphysics coupled simulations [2], the long-term performance evolution of proppants under extreme conditions and the associated multiscale multiphysics coupling mechanisms remain insufficiently understood. The core scientific issues can be summarized as follows:

• mechanisms of conductivity degradation induced by cyclic closure stress;

• particle crushing and embedment processes and their impact on pore-network evolution;

• coupled effects among fluid rheology, proppant settling, and transport behavior;

• scale gaps and parameter transfer challenges among laboratory experiments, numerical simulations, and field applications;

• influence pathways of THM/THMC (thermal–hydraulic–mechanical–chemical) multiphysics coupling under HTHP conditions.

These issues fundamentally involve thermofluid - particle transport and multiphysics coupling processes within the framework of engineering thermophysics, and they directly constrain the long-term stability of hydraulic fracturing performance. This review systematically synthesizes current research on proppant action mechanisms, provides a comprehensive analysis of the characteristics and applicable conditions of different proppant types, and focuses on multiscale perspectives of physical support, fracture conductivity maintenance, anti-settling and migration control, and cooperative interactions between proppants and fracturing fluids. By deepening the understanding of multiscale multiphysics coupling behavior in proppant systems, the scientific basis of fracturing design can be strengthened, supporting efficient oil and gas development and offering reference insights for interdisciplinary research at the interface of engineering thermophysics and energy engineering.

2 Types and Characteristics of Proppants

Proppants serve as the structural "skeleton" of hydraulic fractures, and their technological evolution has closely followed the demands of oil and gas development. The progression has advanced from low-cost natural materials represented by quartz sand, to high-strength ceramic proppants developed for deep and high-stress reservoirs, and further to resin-coated technologies introduced to improve stability and functional performance. In recent years, new challenges associated with supporting complex fracture networks and evaluating fracturing effectiveness in unconventional reservoirs have stimulated the development of functionalized and intelligent proppants, including low-density, self-suspending, and tracer-based systems. To clearly present this technological spectrum and its application logic, a three-dimensional framework based on "material properties–core functions–application scenarios" is adopted to illustrate the transition from natural baseline proppants toward engineered high-performance, multifunctional, and intelligent systems, reflecting continuous improvements in strength, functionality, and adaptability to complex operating conditions. The resulting classification scheme is summarized in Figure 1, and each category is examined in detail below.

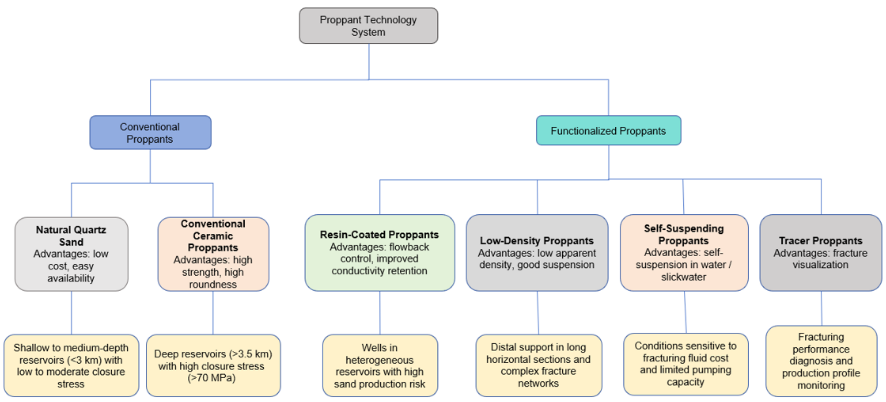

Figure 1. Proppant development framework

2.1 Natural Quartz Sand

Natural quartz sand is the earliest proppant used in hydraulic fracturing and remains widely applied due to its abundant availability and relatively low cost. It consists primarily of SiO_2, typically exceeding 95%, and exhibits good chemical stability and corrosion resistance.

The physical properties of quartz sand proppants are characterized by distinct particle-size distributions, with commonly used specifications including 20/40, 30/50, 40/70, and 70/140 mesh. As illustrated in Figure 2, particle size directly governs fracture permeability. In addition, the relatively high surface roughness of quartz sand leads to more complex interactions with fracturing fluids, which in certain conditions can affect transport efficiency and final placement patterns.

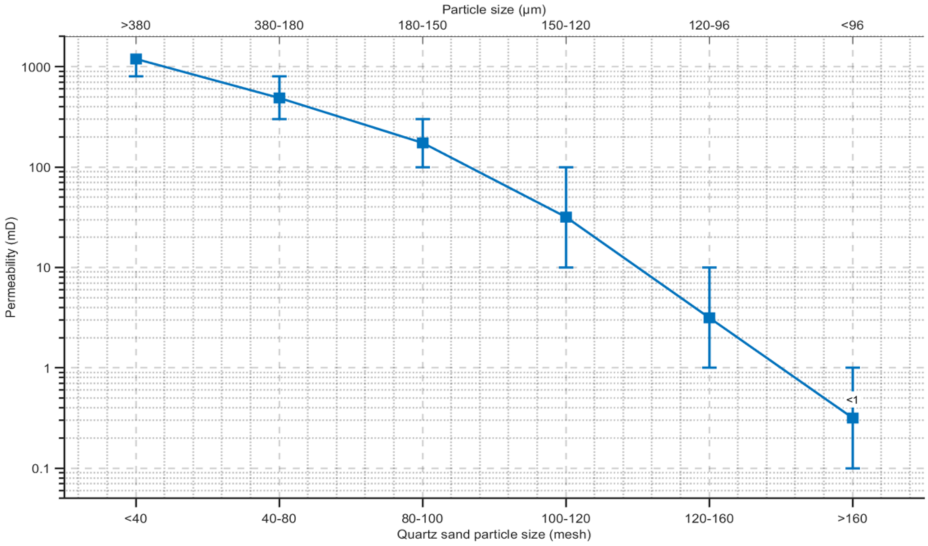

Figure 2. Effect of quartz sand particle size on permeability

2.2 Artificial Ceramic Proppants

Artificial ceramic proppants were developed to overcome the limitations of quartz sand under high-stress conditions and mainly include ceramic and sintered bauxite-based proppants. China is among the world's major producers of ceramic proppants, with products primarily consumed domestically. In 2023, the market size of ceramic proppants in China exceeded 45 billion RMB, and the average annual growth rate in recent years reached approximately 10%, underscoring their central role in deep, high-pressure reservoir development. These proppants are manufactured through high-temperature sintering, using high-purity bauxite, silica, and additives, and exhibit high strength, high roundness, and uniform particle-size distributions.

The defining characteristic of ceramic proppants is their superior mechanical performance. Compressive strengths can reach 103–138 MPa [3], substantially exceeding those of natural quartz sand, making them suitable for deep reservoirs with vertical stresses up to 110 MPa. Recent studies indicate that high-quality ceramic proppants achieve roundness and sphericity values above 0.9, with bulk densities ranging 1.38–1.65 g/cm^3 [3]. These attributes enable relatively high porosity and fracture conductivity to be maintained under elevated stress. The smooth surface of ceramic proppants also reduces friction with fracturing fluids, facilitating long-distance transport and more uniform placement. However, production costs—typically three to five times higher than those of quartz sand—limit widespread application in low- to medium-stress reservoirs. Consequently, ceramic proppants are primarily applied in deep tight oil and gas reservoirs and high-temperature, high-pressure environments, particularly in intervals with vertical stresses exceeding 70 MPa, where they demonstrate clear technical and economic advantages.

2.3 Resin-Coated Proppants

Resin-coated proppants are composite systems formed by applying specialized resin layers to the surfaces of conventional proppants and have been increasingly adopted in petroleum engineering over the past five years. Their key advantage lies in combining the mechanical strength of the base proppant with the functional properties of the coating, thereby improving stability under high-stress and corrosive conditions. Recent studies classify resin-coated proppants into three main categories: thermosetting resin-coated, thermoplastic resin-coated, and thermoreactive resin-coated proppants.

Thermosetting resin-coated proppants typically employ phenolic or epoxy resins and exhibit excellent thermal stability and compressive strength, performing effectively in deep reservoirs with formation temperatures exceeding 120°C. Thermoplastic resin-coated proppants utilize materials such as polystyrene or polyethylene, which can recover their shape after deformation, enhancing elastic adaptability and supporting sustained fracture conductivity under cyclic production conditions, particularly in formations with variable in-situ stress. Thermoreactive resin-coated proppants represent a more recent innovation; their coatings undergo crosslinking reactions under specific conditions (e.g., changes in temperature or pH), forming robust three-dimensional networks that markedly improve packing stability. This behavior effectively suppresses proppant flowback and fine-particle embedment, thereby supporting long-term conductivity in multistage fracturing operations and structurally complex reservoirs.

2.4 Other Emerging Proppants

With continued advances in unconventional resource development, performance requirements for proppants have become increasingly stringent, leading to the emergence of several novel proppant concepts. Ultralow-density proppants are a representative example, typically exhibiting densities below 1.5 g/cm^3 and offering favorable suspension and transport characteristics. Through hollow or porous structural designs, these proppants substantially reduce density while maintaining sufficient mechanical strength, thereby improving distribution uniformity in horizontal sections. They are mainly applied in ultralow-permeability reservoirs and long horizontal wells.

Table 1. Comprehensive performance and application data of hydraulic fracturing proppants

Dimension	Natural Quartz Sand	Artificial Ceramic Proppants	Resin-Coated Proppants	Low-Density Proppants	Self-Suspending Proppants	Tracer Proppants
Typical price (RMB/t)	800–1200 (raw ≈350)	1350–2500+	1550–3000+	2500–5000+	2000–4000+	3000–8000+
Material system	SiO_2(> 95%)	High-alumina bauxite, silica	Substrate + resin coating	Hollow/porous materials	Substrate + hydrophilic layer	Substrate + tracer agents
Manufacturing features	Widely available; crushing–washing–screening	Concentrated resources; pelletizing–sintering	Substrate-dependent; coating-curing	High technical threshold; hollow/foamed forming	Medium–high threshold; surface modification	Highest threshold; tracer integration
Key physical properties	41–69 MPa; roundness 0.6–0.7; ρ = 1.4–1.8 g/cm^3	103–138 MPa; roundness >0.9; ρ = 1.38–1.65 g/cm^3	Strength substrate-dependent; flowback control; conductivity retention +29–36% (60 MPa)	Moderate strength; ρ <1.5 g/cm^3; excellent suspension	Strength ≈ substrate; self-suspension in water/slickwater; crush ratio 2.07% (35 MPa)	Strength substrate-dependent; detectable; crush ratio decreased by >35% (69 MPa)
Main applications	Shallow–medium depth; low–moderate stress; large-scale fracturing	Deep/ultra-deep reservoirs; high stress, high-temperature and high-pressure (HTHP)	Medium–high stress; heterogeneous fractures; flowback-prone wells	Long horizontals (>2 km); ultra-low permeability; complex fracture networks	Slickwater/water fracturing; cost-sensitive fluids; limited pumping capacity	Fracture diagnostics; production profiling; fracturing evaluation
Core advantages	Lowest cost; abundant resources; easy transport	Highest strength; best long-term conductivity	Balanced performance; good long-term stability	Best transport and placement; penetrates complex networks	Simplified fluid system; reduced fluid cost	Enables fracture visualization; diagnostic information
Main limitations	Low strength; fines generation at high stress	High cost; high density	High cost; temperature sensitivity	High unit-volume cost; limited absolute strength	Higher cost than sand; conductivity durability concerns	Very high cost; requires detection systems

Tracer proppants integrate intelligent response and tracking technologies to enable precise monitoring of hydraulic fractures. Functional materials such as fluorescent carbon quantum dots and magnetic nanoparticles have been incorporated into proppants to provide both visual and physical markers of fracture locations. Cheng [4] developed environmentally responsive tracer proppants by coating quartz sand with polymer layers containing trace substances, whose release could be precisely regulated by salinity and temperature. Under low-salinity or high-temperature conditions, rapid tracer release occurs, and analysis of flowback concentration curves enables inference of proppant positions within fractures.

Self-suspending proppants improve pumping performance through surface modification and hydrodynamic optimization. Zhou [5] developed a self-suspending proppant by optimizing formulations with polyacrylamide thickeners and L binders, achieving stable suspension in water, thermal and salinity resistance, and complete gel breaking. The resulting fracture conductivity was comparable to that of conventional quartz sand. Field applications demonstrated continuous sand transport with slickwater, leading to marked production increases and providing effective technical support for slickwater fracturing.

In summary, the technological spectrum of proppants spans from conventional quartz sand and ceramic materials to functionalized resin-coated, low-density, self-suspending systems, and further to intelligent tracer proppants. This spectrum addresses requirements ranging from basic mechanical support to the resolution of complex engineering challenges. To facilitate engineering selection, the key technical and economic parameters of six representative proppant types are compared in Table 1. Proppant selection is inherently a multi-objective optimization process that requires balancing reservoir geological conditions, operational requirements, and project economics. Traditional proppants establish the foundational selection framework, while functionalized and intelligent proppants provide targeted solutions for specific challenges.

3 Mechanisms Governing Proppant Function in Hydraulic Fracturing

Figure 3 presents a unified "input–process–output" framework describing the evolution of proppant-supported fracture conductivity. The inputs (left) include closure stress, temperature, fluid rheology, proppant properties, and fracture geometry as primary controlling factors. The outputs (right) comprise key engineering metrics, including fracture conductivity C_f, permeability, and fracture-width evolution. The central process layer consolidates four core mechanisms: physical support (embedment/crushing/rearrangement), conductivity maintenance (compaction), transport control (settling–migration/flowback scour), and multifield synergy (chemical effects). In the schematic, blue solid lines indicate direct pathways dominated by individual factors such as stress or fluid properties; orange solid lines highlight key interaction pathways associated with multifield coupling (e.g., temperature–chemistry and stress–parameter coupling); and red solid lines depict inter-process coupling and feedback, such as embedment $\rightarrow$ compaction and settling $\rightarrow$ fracture-width evolution. By establishing a structured linkage between multiscale physical fields and engineering performance indicators, this framework provides a systematic analytical basis for predicting long-term proppant behavior and optimizing fracturing design.

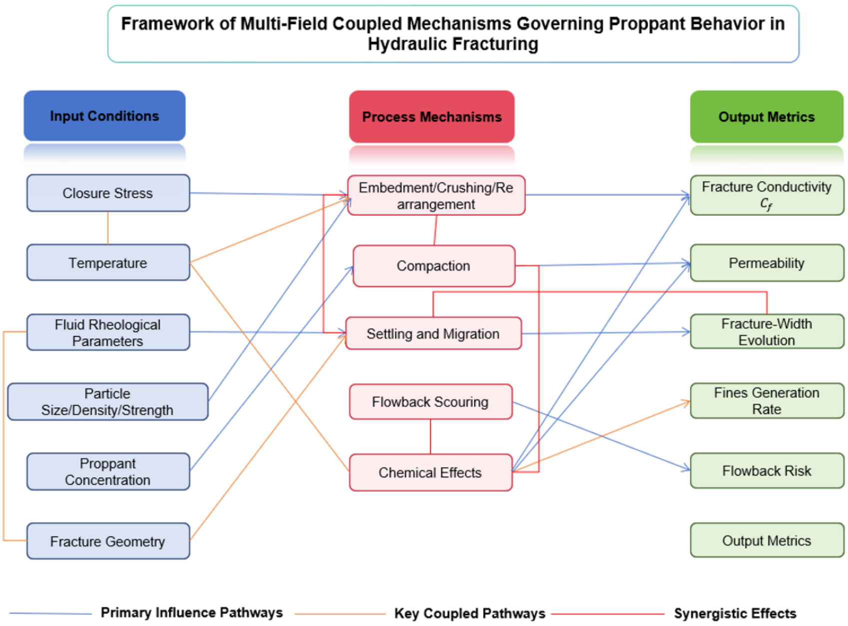

Figure 3. Multifield coupling framework for proppant mechanisms in hydraulic fracturing

3.1 Physical Support Mechanisms

Physical support by proppants constitutes the basis for maintaining effective flow pathways in fractured reservoirs. The governing processes involve coupled particulate mechanics and rock mechanics. After pumping stops, as the fracturing fluid flows back and in-situ stress is restored, fracture-closure loading is transferred to the proppant grains, forming complex grain–grain contact networks and grain–rock contact interfaces. Under cyclic loading, proppant embedment and crushing can be described using a contact-stress model based on rock fatigue damage [6]:

$$\sigma_p = (\sigma_c - p_f) \,/\, (\varepsilon n_s A_e) + p_f \tag{1}$$

where, σ_p is the average contact stress of proppant grains; σ_c is the closure stress; p_f is the fracture-fluid pressure; ε is the embedment ratio; n_s is the areal density of proppant; and A_e is the average embedment area per grain. This relation indicates that, during cyclic loading, fatigue-induced degradation of rock hardness increases the embedment area, thereby driving an evolving redistribution of contact stress [6]. This interpretation provides a theoretical basis for understanding accelerated embedment, increased crushing, and the associated decline in fracture conductivity under dynamic stress conditions.

At the microscale, physical support involves three coupled processes: grain rearrangement, grain embedment, and grain crushing. During early closure, grains transition from suspension to settling and compaction, and their spatial configuration rearranges to form an initial load-bearing skeleton. As effective stress increases, grains begin to embed into the rock surface; embedment depth is governed by the Young's modulus and Poisson's ratio of the rock and proppant, together with local stress conditions. When closure pressure rises beyond the intrinsic strength of the proppant, crushing becomes dominant, generating fines that block pore pathways and cause a rapid permeability decline. These coupled microscale processes jointly determine the mechanical stability and seepage characteristics of the proppant-filled region and ultimately control long-term conductivity evolution [6]. Xu et al. [7] formulated this coupling as an elastic-mechanics problem and established stress–strain governing equations for the proppant–rock system:

$$\rho_{\mathrm{si}} \frac{\partial^2 u_i}{\partial t^2} = \nabla \cdot \sigma_i + F_{\mathrm{v}i} \tag{2}$$

$$\sigma_i = C_i \cdot \varepsilon_i \tag{3}$$

$$\varepsilon_i = \frac{1}{2} \left[(\nabla u_i)^{\mathrm{T}} + \nabla u_i \right] \tag{4}$$

where, ρ_{si} is the solid density; $F_{\mathrm{v}i}$ is the body-force vector; ∇ denotes the gradient/divergence operator; u_i, σ_i, and ε_i represent the displacement, stress, and strain tensors, respectively; C_i is the stiffness matrix; and T indicates transpose. This system characterizes the coupled deformation of proppant and rock under closure stress; proppant concentration directly influences the equivalent mechanical parameters of the system.

At the mesoscale, support is expressed through the overall mechanical behavior of a proppant pack, governed by the arrangement of grains within the fracture and the stress response of the associated pore structure. Chen and Liu [8] reported that, during fracturing treatment, proppants are placed in layered form. The fracture porosity considering proppant embedment is expressed as:

$$\varphi_f = \frac{\mathrm{LHW}_{f0} \frac{4\pi R^3 N}{3}}{\mathrm{LHW}_{f0}} \tag{5}$$

where, φ_f is the fracture porosity accounting for embedment(dimensionless); L is the fracture length (m); H is the fracture height (m); W_{f0} is the initial fracture width immediately after hydraulic fracturing (m); R is the proppant radius (assumed spherical, m); and N is the total number of placed proppant particles within the fracture (dimensionless). This formulation is derived from geometric placement and embedment-depth considerations, and the predictions show close agreement with laboratory conductivity measurements. The embedment depth increases with closure stress and proppant particle size but decreases with increasing formation Young's modulus [8]. Under the same closure stress, increasing the number of placement layers or using larger particle sizes can raise fracture conductivity [8]. These observations indicate that the pore structure and conductivity of a proppant pack are stress-dependent and strongly influenced by placement parameters. Mesoscale physical support is therefore dynamic, and optimization of particle size and placement strategy is central to maintaining high-conductivity pathways.

At the macroscale, support refers to the contribution of non-uniform proppant deposition patterns to maintaining fracture aperture and overall conductivity under closure stress. Using a hybrid model, Xu et al. [7] simulated proppant distributions in multi-cluster fractures and found that proppants tend to concentrate near the wellbore and toward the lower portions of fractures, forming high-concentration supported zones. In contrast, the upper portions and far-field regions commonly exhibit proppant concentrations below 3%, indicating pronounced vertical and lateral heterogeneity. The analysis further demonstrated distinct closure behaviors across concentration zones: low-concentration regions close rapidly under high stress, whereas high-concentration regions retain higher permeability and effective fracture width, thereby dominating long-term conductivity. These findings indicate that macroscale support depends not only on injected mass but also on spatial distribution and concentration gradients, providing a mechanistic basis for optimizing fracturing design and proppant-transport strategies.

A mechanistic understanding of physical support provides a basis for optimizing proppant selection, concentration design, and placement strategies. It is also important to note that shale matrices are not homogeneous; pervasive microfractures can strongly influence flow behavior. It has been reported that such microfractures can yield permeability estimates from the early hyperbolic segment of pressure-decline curves that are 1–2 orders of magnitude higher than those derived from full-curve analyses, suggesting complex flow interactions between the fracture system and the matrix after proppant embedment [9]. In addition to strength, the match between particle size and fracture geometry is critical. Numerical studies indicate that, in reservoirs containing natural fracture corridors, increasing proppant particle size can markedly increase the risk of bridging at narrow intersections, thereby reducing the conductivity of complex hydraulic-fracture networks [10]. This further highlights particle-size selection as a key element for achieving effective physical support and sustaining long-term fracture conductivity.

3.2 Conductivity Maintenance Mechanisms

Proppant-supported fracture conductivity is a primary indicator for evaluating fracturing performance. Its long-term persistence involves coupled physicochemical processes. Under the API (American Petroleum Institute) Recommended Practice 19D, which standardizes the measurement of proppant long-term conductivity, fracture conductivity C_f can be described using an extended Darcy-law expression [11]:

$$C_f = KW_f = \frac{99.998\mu QL}{W_f \Delta PW} \cdot W_f = \frac{99.998\mu QL}{\Delta PW} \tag{6}$$

where, Q is the test flow rate (ml/min); W_f is the proppant-pack thickness (cm); L is the distance between pressure taps (cm); K is the permeability of the proppant pack (μm^2); ΔP is the pressure drop (kPa); μ is the fluid viscosity (mPa·s); W is the proppant-pack width in the conductivity cell (cm); and C_f is fracture conductivity (μm^2·cm). Conductivity maintenance is primarily governed by three factors: packing configuration, compaction effects, and long-term stability.

Packing configuration determines the basic characteristics of the pore network. Pore structure and connectivity vary markedly across packing modes. Sun [12] reported that, under closure stress, proppants tend to form dense packing arrangements (e.g., hexagonal close packing or cubic close packing). Although such packings exhibit lower initial porosity, they are structurally more stable under stress. Multi-layer placement can increase supported fracture width, a critical parameter for maintaining conductivity. In field operations, natural size segregation leads to larger grains dominating near-wellbore primary fractures, whereas far-field regions tend to contain smaller grains or remain partially unsupported, yielding a non-uniform pore structure along the fracture length. Optimizing size grading and injection schedules can improve conductivity distribution along the fracture, thereby increasing the effectiveness of the fracture network.

Compaction effects represent a major driver of long-term conductivity decline and involve proppant deformation, crushing, and fines generation. These processes lead to irreversible blockage of flow pathways and sustained conductivity loss. Theoretical analyses by Sun [12] indicate that embedment depth increases with closure stress and that larger grains are more prone to embedment and crushing. This behavior is closely linked to the evolving compressibility of shale fractures. Studies indicate that embedment and compaction modify fracture width and porosity, thereby increasing fracture compressibility and causing permeability and conductivity to decline with effective stress, while supported fractures still retain markedly higher conductivity than unsupported fractures [13].

Long-term stability of fracture conductivity is influenced by the combined effects of formation-fluid chemistry, temperature variations, and stress cycling. Stress cycling is widely recognized as a dominant cause of irreversible conductivity degradation. On one hand, closure stress and areal proppant concentration strongly control crushing: lower concentrations and higher cycle numbers correspond to higher crushing rates; higher roundness and sphericity promote more uniform stress distributions and improved resistance to crushing [13]. On the other hand, cyclic loading can progressively reduce the hardness of fracture faces through rock fatigue damage, leading to increasing embedment depth and stepwise permanent conductivity loss, with the largest damage typically occurring during the first loading event [13]. In this context, fracture-network designs that promote complexity and shear slip can redistribute local stresses and reduce stress sensitivity, thereby improving the persistence of fracture conductivity [12].

3.3 Anti-Settling and Migration-Control Mechanisms

Proppant settling and migration during fracturing directly determine final placement in complex fracture networks and control post-treatment conductivity. Based on Stokes' law for force balance on a single particle in a Newtonian fluid, with corrections for sand ratio and wall effects, Li [14] proposed a theoretical model for proppant settling velocity in fractures:

$$v_p' = v_p \cdot f_c \cdot f_w \tag{7}$$

where, v_p' is the corrected settling velocity; v_p is the free settling velocity of a single particle; f_c is the concentration correction factor; and f_w is the wall-effect correction factor. Under laminar conditions, v_p follows:

$$v_p = \frac{g\left(\rho_s - \rho\right) d_p^2}{18\mu} \tag{8}$$

Li [14] identified carrier-fluid viscosity as the key parameter controlling settling. Under the reported experimental conditions (injection rate 0.16 m^3/h), 20/40 mesh ceramic proppants settled rapidly in water (viscosity $\sim$1 mPa·s), forming steep dunes with limited transport distance. In contrast, in a guar-based fluid (viscosity 30 mPa·s), settling was slower, transport distance increased by approximately 15–20%, dune shapes became gentler, and proppants could enter more distal secondary fractures [14].

Anti-settling behavior can be improved through fluid-property control, coordinated optimization of operational and material parameters, and cooperation with fracture-structure effects. Specifically:

• **Fluid-property control**: Increasing carrier-fluid viscosity is a direct means to delay settling. Physical simulations indicate that, relative to water, guar fluids with viscosities around 30 mPa·s can increase transport distance and promote entry into more distal secondary fractures [14]. Numerical results further indicate that viscoelasticity can influence suspension behavior [14]. Optimization of fluid formulation is therefore foundational for improving proppant transport.

• **Coordination of operational and material parameters**: Within a given fluid system, higher pumping rates can increase horizontal transport capacity [14]. Reducing proppant density and particle size also increases transport distance and promotes entry of smaller grains into microfractures [15]. Overall, injection rate, particle size, and fluid viscosity constitute key engineering controls governing distribution and transport in complex networks.

• **Engineering implementation strategy**: A "staged" pumping schedule is commonly adopted, using low-density and small-size proppants in early stages to access complex fracture networks, followed by conventional proppants to fill primary fractures, thereby optimizing the overall supported profile.

For complex fracture networks, deliberate use of structural characteristics can be effective. Flow partitioning occurs at fracture junctions: near the wellbore, entry of proppants into secondary fractures relies primarily on fluid carrying; in far-field regions, gravity-driven settling becomes more influential [14]. Jet-entry location can modify near-wellbore flow structures and hence the initial settling location [15]. Recent studies further indicate that fracture-wall roughness and its spatial distribution can alter transport pathways and final placement patterns. For example, roughness in central regions may split proppant-laden flow, forming a double-triangular deposit with a central void, which can influence long-term conductivity [16].

Migration-control mechanisms aim to preserve the long-term integrity of proppant packs and prevent destructive displacement due to production-fluid scouring. A critical equilibrium velocity exists for a settled dune: when flow velocity remains below this threshold, the dune is stable; once exceeded, settled proppants can re-suspend and migrate [14]. This provides a hydrodynamic basis for controlling flowback rates to reduce proppant flowback. Computational Fluid Dynamics studies further show that complex fracture flow fields can impose substantial scouring potential on placed dunes [15], indicating that even moderate average velocities may coexist with local unstable flow structures capable of causing localized destabilization and migration. Optimizing anti-settling and migration control is therefore essential for achieving uniform placement and sustaining long-term conductivity, particularly in long horizontal wells and structurally complex reservoirs. Nevertheless, transport and placement in rough, complex fracture networks remain constrained by conventional smooth-fracture assumptions, highlighting the need for coupled transport models that quantify roughness effects [17–19].

3.4 Cooperative Mechanisms Between Proppants and Fracturing Fluids

The synergistic interaction between proppants and fracturing fluids constitutes a critical factor for the success of hydraulic fracturing operations. Their interaction spans the entire process, from wellbore transport and in-fracture placement to the long-term maintenance of fracture conductivity. Laboratory experiments and field applications conducted over the past five years indicate that this synergy is primarily manifested across three dimensions: compatibility of proppant transport, fracture-environment responsiveness, and long-term conductivity safeguarding. These dimensions are coupled through multiphysical processes, jointly optimizing fracture-stimulation effectiveness [19, 20].

Compatibility of proppant transport is fundamentally governed by the precise matching between the rheological properties of fracturing fluids and the physical characteristics of proppants, which directly determines suspension stability and transport distance. Studies have shown that medium-viscosity fracturing fluids are more suitable for suspending small- to medium-sized proppants and achieving uniform placement, whereas high-viscosity systems are better matched with large-sized proppants for short-distance but efficient filling [19].

When fracturing fluids (e.g., slickwater) exhibit power-law fluid behavior, vortex structures generated at fracture branches can promote proppant redirection and migration. The intensity of this effect depends on the coupled regulation of the fluid consistency index and sand ratio [20]. Overall, the matching relationship of "medium viscosity with small particle size and high viscosity with large particle size" can significantly enhance proppant placement efficiency within complex fracture networks [19].

Fracture-environment responsiveness refers to the dynamic adaptation of both fracturing fluids and proppants to fracture geometry, temperature, and other in-situ conditions. During transport, the fracturing fluid is required to maintain elastic resistance against settling during fracture extension, exhibit shear-thinning behavior to reduce drag at turning points, and retain sufficient viscosity during placement to prevent fracture collapse [19].

Adaptive fracturing-fluid systems are capable of automatically adjusting viscosity in response to fracture temperature, enabling drag reduction at low temperatures and enhanced proppant-carrying capacity at high temperatures, thereby significantly extending proppant transport distances into secondary fractures [19]. Meanwhile, proppant particle size must be compatible with fracture width: small-sized proppants can pass through narrow fracture throats, whereas medium-sized proppants can form more stable sand-dune structures in wider fractures [20].

Long-term conductivity safeguarding focuses on maintaining the sustained conductivity of proppant-supported fractures through cooperative effects between fracturing fluids and proppants. The use of low-fluid-loss fracturing fluids combined with graded proppant mixtures of different particle sizes can reduce pore plugging and lower the risk of flow-channel blockage.

The addition of flexible fibers to fracturing fluids can form three-dimensional network structures that enhance suspension stability, while stabilizing agents can suppress proppant dissolution and crushing under high formation temperatures [19]. Optimized cooperative systems have been shown to significantly improve the retention of long-term fracture conductivity [20]. In addition, favorable flowback characteristics of fracturing fluids are essential, as they minimize damage to proppant wettability caused by residual fluids and prevent flow-channel blockage induced by water-lock effects.

Overall, proppant–fluid cooperation results from coupled multiphysics processes, and optimization targets a full-chain coordination of "property compatibility–environment responsiveness–long-term persistence". Future work should strengthen mechanistic analysis at the microscale and integrate numerical simulation with laboratory experimentation to develop more precise cooperative-control models for efficient fracturing in tight reservoirs and other complex formations. Of particular importance are wettability behavior, interfacial interactions, and the associated imbibition dynamics in microfractures, which underlie long-term conductivity safeguarding. Given that fracture roughness and micro-geometry strongly influence fluid transport, accurate descriptions of rough-surface wettability, contact-angle evolution, and their effects on imbibition dynamics are central to constructing cross-scale cooperative-control models linking microscale interfacial processes to macroscale conductivity performance [21–23].

3.5 Summary of Performance Differences Across Proppant Types Within Core Mechanisms

Proppants are key materials for sustaining long-term fracture conductivity, and performance differences among proppant types directly affect stimulation outcomes. Based on a comparative analysis of quartz sand, ceramic proppants, resin-coated proppants, and low-density proppants, marked differences are observed across the core mechanisms of physical support, conductivity maintenance, anti-settling and migration control, and proppant–fluid cooperation. These differences provide a mechanistic basis for field selection and process optimization.

Physical support. Ceramic proppants, due to high compressive strength, perform best under high closure stress and provide stable mechanical support in deep reservoirs. Resin-coated proppants, through coating encapsulation and inter-particle bonding, improve pack integrity and reduce rearrangement and embedment. Quartz sand exhibits lower strength and is prone to crushing under moderate closure stress, generating fines that block pore space. Low-density proppants generally provide the lowest mechanical strength and are primarily suited to shallow reservoirs with low closure stress. Regarding skeleton stability, clustered structures formed by resin-coated proppants are the most stable, followed by dense packing of ceramic proppants; quartz sand is more sensitive to particle-shape effects, whereas low-density proppants tend to form looser structures that are more readily reconfigured.

Long-term conductivity maintenance. Ceramic proppants typically show the lowest crushing under cyclic loading, generate fewer fines, and impose less pore blockage. Resin-coated proppants can buffer stress through coatings and suppress core crushing; organic fines from coating damage tend to exert less severe conductivity impairment. Quartz sand exhibits higher crushing, and the resulting hard, angular fines can promote pore cutting and blockage. Low-density proppants may show limited crushing under low stress but can undergo plastic deformation. In terms of chemical stability, ceramic proppants are generally inert and corrosion-resistant; resin-coated performance depends on coating chemistry; quartz sand can dissolve under acidic conditions; and low-density proppants with organic components may be susceptible to degradation.

Anti-settling and migration control. Settling and migration depend strongly on density and surface properties. Low-density proppants settle most slowly and display favorable suspension in slickwater, supporting long-distance placement in complex networks. Quartz sand exhibits intermediate settling and can be transported effectively through rheology control. Resin-coated proppants may show more complex settling behavior due to surface modification. Ceramic proppants settle fastest and commonly require higher-viscosity fluids or higher pumping rates. Regarding placement uniformity, low-density proppants and quartz sand more readily reach far-field regions but often at lower concentrations; ceramic proppants tend to accumulate near the wellbore; resin-coated proppants can achieve improved distribution through wettability adjustment. In terms of flowback resistance, bonded structures of resin-coated proppants provide the strongest resistance, followed by dense packing of ceramic proppants; quartz sand in low-concentration zones is more prone to remobilization, while low-density proppants are generally the most susceptible to flowback.

Based on the comparative assessment across the four core mechanisms, the following overall characterizations can be drawn. Ceramic proppants perform effectively in deep, high-stress reservoirs due to high strength and sustained conductivity, though their density imposes transport challenges that require appropriate carrier-fluid capacity and pumping rates. Resin-coated proppants provide the most balanced overall performance by improving physical support and conductivity persistence while offering certain advantages in proppant–fluid cooperation, making them suitable for high closure stress, complex fracture networks, and heterogeneous reservoirs. Quartz sand remains widely applicable due to low cost and favorable transport characteristics in shallow to medium-depth reservoirs with low to moderate closure stress, particularly for large-scale volume fracturing where operational cost is critical. Low-density proppants offer distinct advantages for placement in complex networks and distal support, especially in long horizontal wells and naturally fractured formations, though limited strength restricts application in high-stress reservoirs.

In summary, quartz sand, ceramic proppants, resin-coated proppants, and low-density proppants exhibit systematic differences across physical support, conductivity maintenance, anti-settling and migration control, and proppant–fluid cooperation. To provide a clear and direct comparison and to support engineering selection, the analysis is consolidated in Table 2.

Table 2. Comparison of performance differences across core mechanisms for proppants

Action Mechanism	Evaluation Aspect	Quartz Sand	Ceramic Proppant	Resin-Coated Proppant	Low-Density Proppant
Physical support	Compressive strength	Low; prone to crushing under high closure stress	High; optimal performance under high stress	Medium–high, depending on substrate reinforcement	Low; plastic deformation dominates under low closure stress
	Structural (skeleton) stability	Strongly affected by particle shape and roundness; prone to rearrangement	Dense packing; high stability under stress	Cluster bonding; strong integrity and resistance to embedment	Loose structure; easily adjustable but weak long-term stability
Conductivity retention	Crushing and fines generation	High crushing rate; hard angular fines easily block pore channels	Lowest crushing rate under cyclic loading; minimal fines	Coating suppresses grain breakage; organic fines have limited impact	Low crushing at low stress; plastic deformation dominant
	Chemical stability	Susceptible to acid dissolution; rapid long-term conductivity decline	Highest chemical inertness; strong resistance to fluid corrosion	Stability depends on coating; requires chemical compatibility with reservoir	Potential degradation of organic components; long-term stability uncertain

Continued on next page

Action Mechanism	Evaluation Aspect	Quartz Sand	Ceramic Proppant	Resin-Coated Proppant	Low-Density Proppant
Settling & migration control	Settling behavior	Moderate settling; adjustable via fluid rheology	Fastest settling; requires high-viscosity fluids or high pump rates	Complex behavior after surface modification; coating–fluid dependent	Slowest settling; excellent suspension in slickwater
	Placement efficiency	Can reach far-fracture regions, but with low proppant concentration	Accumulates near wellbore; difficult long-distance transport	Tunable wettability; good adaptability to complex fracture networks	Best far-field placement; uniform distribution along fracture length
	Flowback resistance	Re-migration likely in low-concentration zones; moderate production stability	Dense packing provides resistance, but flowback impact remains significant	Bonded structure highly stable; best flowback resistance	Loose structure prone to flowback; requires sand control measures
Synergy with fracturing fluids	Transport & operational requirements	Low fluid-performance requirements; simple operation and high cost efficiency	Extremely demanding: high viscosity, high rate, high pump pressure	Surface modification improves wettability; good fluid–proppant synergy	Minimal requirements; compatible with water or slickwater, reducing cost and complexity
Overall applicability	Typical reservoir scenarios	Shallow to medium-depth reservoirs with low–moderate closure stress; large-scale volume fracturing for cost reduction	Deep and ultra-deep reservoirs with high closure stress or high temperature and pressure	High closure stress, heterogeneous or complex fracture networks; high sand-production risk wells	Long horizontal wells; naturally fractured and ultra-low-permeability reservoirs
Mechanism sensitivity	Sensitivity to closure stress	High	Low	Medium (reduced by coating reinforcement)	High (deformation replaces crushing)
	Fatigue sensitivity	High	Low	Medium–low (stress buffering by coating)	Medium (plastic strain accumulation)
	Temperature sensitivity	Low	Low	High (glass transition of resin coating)	Medium–high (material dependent)
	Sensitivity to fluid rheology	Low	High	Medium	Very low
Dominant failure modes	-	Crushing-dominated → fines plugging	Embedment-dominated (in soft formations)/ compaction failure	Flowback-dominated (if uncured) or residue plugging (if coating degrades)	Flowback/re-migration dominated/long-term creep failure

4 Core Scientific Issues and Theoretical Frontiers in Proppant Mechanism Research

4.1 Theoretical Limitations and Knowledge Gaps in Existing Studies

Despite substantial progress in understanding proppant action mechanisms, significant theoretical limitations and knowledge gaps remain. These limitations can be broadly summarized into four major aspects.

4.1.1 Limitations in predicting proppant mechanical behavior under extreme conditions

Under extreme geological conditions, the prediction of proppant mechanical behavior remains highly uncertain. Most existing models are developed under idealized assumptions and fail to accurately capture the long-term mechanical response of proppants subjected to complex stress fields at high temperature and high pressure. In recent years, the increasing deployment of hydraulic fracturing in ultra-deep wells (>6000 m) has revealed severe challenges associated with rapid fracture conductivity degradation under high closure stress, typically exceeding 50 MPa.

Field applications in ultra-deep carbonate reservoirs of the Tahe Oilfield illustrate that fractures generated by acid fracturing tend to close rapidly, leading to accelerated conductivity loss and insufficient fluid supply, ultimately resulting in rapid production decline [24]. These discrepancies primarily arise from an incomplete understanding of proppant embedment, crushing, and rearrangement behaviors under complex stress conditions in heterogeneous formations, a challenge that is particularly pronounced in unconventional reservoirs such as shale gas and tight oil. This evidence indicates that, under ultra-deep and extreme operating conditions, the actual rate of fracture conductivity decay is often significantly higher than predictions based on conventional conditions or simplified theoretical models.

Accurate characterization of fracture conductivity degradation in ultra-deep wells is therefore essential for reliable production forecasting and optimized fracturing design. A key source of prediction bias lies in the insufficient understanding of the dynamic evolution of natural fracture systems. Natural fractures are characterized by multistage formation histories and selective reactivation, with long-term opening–closure behavior governed by the coupling of paleo- and present-day stress fields. These fractures constitute a dynamic geological background that critically influences long-term proppant mechanical response. Current models remain inadequate in describing proppant behavior within such environments, particularly when hydraulic fractures interact with multistage natural fracture networks [25–27].

4.1.2 Challenges in constructing multiscale coupled models

The development of multiscale coupled models remains a major challenge. Existing studies often treat macroscopic fracture conductivity and microscopic proppant behavior independently, lacking a robust cross-scale theoretical framework. Current numerical simulation techniques struggle to accurately represent the coupled interactions among fluids, proppants, and rock matrices.

On the one hand, conventional experimental methods are unable to adequately characterize complex geometries such as narrow branch fractures, while most simulations rely heavily on laboratory-derived parameters and fail to incorporate dynamic processes such as proppant crushing and fracture surface roughness evolution. As a result, predictive accuracy remains insufficient to support refined fracturing design optimization. On the other hand, the coupled chemical–mechanical effects induced by long-term interactions between proppants and formation fluids have not been systematically addressed. Comprehensive models that simultaneously account for mineral dissolution, secondary precipitation, and associated geochemical processes are still lacking.

Furthermore, geological heterogeneity introduces additional uncertainty into multiscale modeling. Variations in pore structure, pore type, and connectivity among different lithofacies in shale formations (e.g., laminated shale versus massive mudstone) significantly influence fluid storage and transport behavior, further complicating the development of pore-scale to fracture-scale coupled models [28–30].

4.1.3 Scale discrepancies between experimental and field data

Scale discrepancies between laboratory experiments and field observations represent another critical issue. Proppant performance parameters obtained under laboratory conditions are often difficult to directly apply to field-scale predictions, leading to substantial uncertainty in hydraulic fracturing performance evaluation. Laboratory experiments are typically conducted under simplified and controlled conditions that cannot fully replicate the complex geological environments, fluid flow regimes, and multiphysical couplings encountered in the field. This inherent “scale gap” between theory and practice limits the engineering applicability of existing models and proppant selection methodologies.

4.1.4 Key coupling pathways under high-temperature and high-pressure conditions

Temperature and pressure are the two most influential environmental variables controlling hydraulic fracturing performance, particularly in reservoirs characterized by high stress and elevated temperature. Under HTHP conditions, interactions among proppants, fracturing fluids, and rocks exhibit strong multiphysical coupling effects, which can be summarized through several critical pathways.

For resin-coated proppants, increasing temperature may induce polymer coating softening, creep, or even thermal degradation, thereby compromising bonding strength and long-term structural stability. Studies indicate that under coupled high-temperature and high-closure-stress conditions, coating debonding may occur, generating residues that clog pore channels and severely degrade long-term fracture conductivity. The temperature sensitivity of resin-based materials is substantially greater than that of inorganic proppants such as ceramics [31]. Moreover, resin softening may promote inter-particle adhesion, further reducing effective porosity and permeability of the proppant pack.

Temperature is a key parameter governing the rheological performance of fracturing fluids. Regardless of whether the system is water-based, oil-based, or waterless, temperature variations can significantly influence viscosity, viscoelasticity, shear stability, and proppant-carrying capacity.

Taking CO_2 dry fracturing systems as an example, increasing temperature markedly reduces the solubility and thickening efficiency of thickeners in supercritical CO_2, resulting in decreased system viscosity and weakened flow-control capability, which in turn adversely affects proppant transport and placement efficiency [32]. This indicates that temperature adaptability is a core factor that must be explicitly considered in the design and field application of fracturing-fluid systems.

Thermal variations further modify rock stress states and mechanical properties. Thermal diffusion between drilling fluids and formations can induce redistribution of pore pressure and in situ stress in near-wellbore regions, influencing shale strength and wellbore stability [33]. Elevated temperature intensifies rock hydration swelling and chemical softening, reducing cohesion and facilitating deeper proppant embedment. Embedment depth increases with temperature and couples with the stress field to form a TMC degradation mechanism.

In tight reservoirs such as shale, temperature gradients may act as independent driving forces, inducing thermo-osmotic effects that, together with chemical potential and pressure gradients, govern fluid and ion transport. This coupled transport mechanism significantly alters pore pressure and water saturation distributions in the near-fracture matrix, thereby influencing permeability and long-term conductivity stability through effective stress modulation [34]. Elevated temperatures may also accelerate mineral dissolution and secondary precipitation, forming positive feedback with mechanical processes and exacerbating fracture conductivity degradation.

Collectively, these pathways demonstrate that under HTHP conditions, proppant system behavior is not a simple superposition of individual physical processes but rather a dynamically coupled THMC response. Future studies must prioritize the development of temperature-explicit multiphysical coupling models and systematically incorporate temperature cycling and thermal shock effects in experimental designs to accurately predict long-term fracture conductivity evolution under extreme conditions.

4.2 Key Directions for Future Mechanism Research

In light of the identified theoretical limitations and knowledge gaps, future research on proppant mechanisms should focus on several priority directions. First, the development of intelligent multiphysical experimental and characterization techniques will serve as a major breakthrough. Advanced imaging tools such as high-resolution X-ray micro-computed tomography (μ-CT) and magnetic resonance imaging, combined with artificial intelligence–based image analysis, enable dynamic monitoring of proppant behavior under complex conditions.

Second, multiscale multiphysical numerical simulation methodologies represent a critical research frontier. By integrating molecular dynamics, discrete element methods, finite element analysis, and computational Computational Fluid Dynamics, unified simulation frameworks spanning micrometer to reservoir scales can be established. In this context, refined modeling of microscopic pore structures is particularly important. A series of pore-scale characterization and flow prediction models based on fractal theory [35–37] have demonstrated improved accuracy in describing multiphase flow behavior in tight reservoirs, providing valuable theoretical tools for micro–macro coupled modeling.

In addition, environmentally friendly proppant design theories are emerging as a new research focus. Wu et al. [37] successfully developed a controllable self-generated proppant with a high sphericity yield (78%) using an optimized polyvinyl alcohol/methylcellulose/styrene–divinylbenzene spheres composite dispersion system under solvent-free conditions. The synergistic enhancement of single-particle strength (32 N) and acid resistance (acid solubility of 2.47%) offers important experimental evidence for the precise design and mechanistic understanding of green proppants. With the accelerating low-carbon transition of the global energy sector, theoretical studies on biodegradable, mineral-modified, or recyclable proppants are becoming increasingly important.

Finally, optimization of field-scale validation and feedback mechanisms will facilitate deeper integration between theory and practice. Establishing closed-loop feedback systems that link real-time fracturing monitoring with theoretical models enables continuous refinement and calibration of proppant mechanism models. In recent years, sustained investment in digital hydraulic fracturing technologies has positioned intelligent proppant monitoring and optimization as a major strategic focus within the oil and gas industry. The industrial deployment of these technologies is expected to provide abundant field-scale data to support future mechanistic research on proppant behavior.

5 Conclusions

This study systematically reviews the current state of research and emerging trends in the mechanisms governing proppant behavior in hydraulic fracturing. The integrated analysis demonstrates that proppants, as a core component of hydraulic fracturing technology, play a decisive role in the efficient development of unconventional oil and gas resources. From a materials perspective, proppants have evolved from conventional natural quartz sand to high-strength ceramic proppants, resin-coated proppants, and various novel functionalized proppants. While material performance has continuously improved, corresponding theoretical understanding has lagged behind technological advancements.

From a mechanistic standpoint, physical support, fracture conductivity maintenance, settlement prevention and migration control, and synergistic interaction with fracturing fluids collectively constitute the theoretical framework describing proppant functionality. However, the coupling relationships among these mechanisms and their dynamic evolution under complex geological conditions have not yet been fully elucidated. Existing studies still face substantial challenges, including inaccurate prediction of proppant mechanical behavior under extreme conditions, difficulties in constructing robust multiscale coupled models, and pronounced scale discrepancies between laboratory experiments and field observations.

To address these limitations, future research should prioritize the development of intelligent multiphysical coupled experimental and characterization techniques, multiscale and multiphysical numerical simulation methodologies, environmentally friendly proppant design theories, and optimized field-scale validation and feedback mechanisms. Advancing these directions is essential for improving predictive accuracy and enhancing the scientific basis of proppant selection and fracturing design.

Research on proppant mechanisms is currently at a critical stage characterized by both theoretical breakthroughs and technological innovation. Through interdisciplinary collaboration and methodological integration across multiple scales and physical domains, substantial progress is expected in predicting proppant behavior under complex geological conditions, designing and optimizing intelligent proppants, and promoting the application of environmentally sustainable proppant systems. These advances will provide a solid theoretical foundation and technical support for the efficient, economical, and environmentally responsible development of unconventional oil and gas resources.

Author Contributions

Conceptualization, F.Y.W. and Q.Z.; methodology, M.L.Z.; software, F.Y.W.; validation, F.Y.W. and Q.Z.; formal analysis, M.L.Z.; investigation, Q.Z.; resources, Q.Z.; data curation, F.Y.W.; writing—original draft preparation, F.Y.W.; writing—review and editing, Q.Z. and M.L.Z.; visualization, F.Y.W.; supervision, Q.Z.; project administration, Q.Z.; funding acquisition, Q.Z. All authors have read and agreed to the published version of the manuscript.

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Data Availability

The data used to support the research findings are available from the corresponding author upon request.

Conflicts of Interest

The authors declare no conflicts of interest.

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Nomenclature

Symbol	Description	Unit	Applicability/Notes
σ_p	Average contact stress of a proppant particle	MPa	Under fracture closure conditions; used in proppant embedment models
σ_c	Fracture closure stress	MPa	In-situ stress environment
p_f	Fluid pressure within the fracture	MPa	Fracturing fluid pressure
ε	Proppant embedment ratio	-	Ratio of embedment depth to particle diameter
n_s	Proppant surface density	particles·m^{-2}	Number of proppant particles per unit area
A_e	Average embedment contact area of a single proppant	m^2	Proppant–rock contact area
ρ_{si}	Solid density	kg·m^{-3}	Proppant or rock matrix
$F_{\mathrm{v}i}$	Body force vector	N·m^{-3}	Includes gravity and fluid drag forces
μ_i	Displacement tensor	m	Solid deformation
σ_i	Stress tensor	Pa	Internal stress within solid media
ε_i	Strain tensor	-	Solid deformation
C_i	Stiffness matrix	Pa	Elastic material parameters
φ_f	Fracture porosity	-	After proppant placement
L	Fracture length	m	Propped fracture length
H	Fracture height	m	Propped fracture height
R	Proppant radius	m	Assumed spherical geometry
N	Total number of placed proppant particles	-	Total amount within the fracture
W_{f0}	Initial fracture width	m	Immediately after hydraulic fracturing
C_f	Proppant fracture conductivity	μm^2·cm	Measured following API standards
K	Permeability of the proppant pack	μm^2	Darcy flow regime
W_f	Proppant pack thickness	cm	Conductivity cell testing
Q	Test flow rate	mL/min	Laboratory condition
ΔP	Pressure differential	kPa	Laboratory condition
μ	Fluid viscosity	mPa -s	Newtonian fluid assumption
v_p	Free settling velocity of a single particle	m·s^{-1}	Laminar flow (Stokes regime)
v_p'	Corrected actual settling velocity	m·s^{-1}	Includes concentration and wall effects
f_c	Proppant concentration correction factor	-	High-concentration suspension
f_w	Fracture wall effect correction factor	-	Narrow fracture conditions
ρ_s	Proppant density	kg·m^{-3}	True particle density
ρ	Fluid density	kg·m^{-3}	Fracturing fluid