

Article

Fracture Propagation in Shale and Its Impacts on Shale Gas Production Under Thermal–Fluid–Mechanical Coupling Environments

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Featured Application

The findings offer theoretical guidance for thermal stimulation and hydraulic fracturing design in shale gas reservoirs, facilitating the optimization of gas production strategies.

Abstract

Shale gas reservoirs can develop extensive fracture networks via hydraulic fracturing. Nevertheless, gas stored in matrix pores remains hard to produce efficiently. Thermal stimulation helps trigger secondary fracture growth inside the matrix and forms multiscale gas–water flow channels to improve reservoir productivity. In this study, a thermo–hydro–mechanical (THM) model is established using COMSOL Multiphysics. The model accounts for fluid seepage, heat transfer, mechanical deformation, and fracture evolution, and assesses shale gas productivity under combined hydraulic fracturing and thermal injection. The effects of initial permeability, injection pressure, and in situ stress on fracture propagation are investigated. Three heating strategies are considered: preheating, heating during fracturing, and continuous heating throughout production. Simulations reveal that thermal injection improves displacement, permeability, and porosity around injection locations. Continuous heating achieves the most obvious fracture expansion. After 6000 days, the daily gas production of the three schemes reaches 50.6839, 73.2167, and 81.403 million m³/d, corresponding to production increases of 44.5% and 60.6%.

Keywords: shale gas; heating injection; thermal–fluid–mechanical coupling; fracture propagation; production optimization



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1. Introduction

Shale gas reservoirs have complex lithological compositions, high thermal maturity, and deep burial depths, with pore spaces mainly dominated by nanoscale structures [1,2]. Creating interconnected fracture networks via fracturing is a prerequisite for efficient shale gas exploitation [3,4]. Conventional hydraulic fracturing builds artificial flow channels to boost reservoir permeability [5–7]. Stress perturbation during fracturing alters rock effective stress and induces deformation and microcracks, which reorganize fracture networks and modify shale pore and permeability characteristics [8,9]. However, shale is a self-contained

source-reservoir system where gas is primarily stored in nanopores [10]. Conventional hydraulic fractures are wide-aperture macrocracks and cannot connect tiny hydrocarbon-bearing pores, leading to trapped shale gas in the matrix [11,12]. In addition, water intrusion swells shale clay and organic matter, forming severe water lock barriers that block cross-scale gas migration [13–15].

Reservoir thermal stimulation is a promising technique to improve unconventional hydrocarbon recovery, which has been applied in coalbed methane and shale oil field development [16–18]. As shown in Figure 1a, thermal injection can act as secondary reformation after hydraulic fracturing to further raise gas production [19,20]. The coupled hydraulic–thermal method outperforms single water fracturing: heat vaporizes pore water to eliminate water-lock damage; differential mineral thermal expansion and pore water phase transformation generate thermally induced fractures to increase matrix porosity and permeability [21]. The coupling of injection pressure, reservoir temperature, pore pressure, and in situ stress destroys initial rock stress equilibrium, redistributes pore fluids, and alters rock mechanical behaviors [22,23]. It promotes continuous evolution of cross-scale pore-fracture networks and facilitates shale gas desorption, diffusion, and multiphase flow. Thus, the hydraulic stress field, thermal field, and seepage field together form a complex multiphysics coupling system during composite stimulation [24–26]. At a larger spatial and temporal scale, prolonged fluid injection may also induce pore-pressure diffusion and stress redistribution beyond the near-well region, potentially promoting fault reactivation and injection-induced seismicity [27].

Current laboratory tests and numerical simulations separately investigate shale hydraulic fracturing and pure thermal cracking [28–32]. Heider developed phase-field numerical frameworks to simulate hydraulic fracture propagation, capturing complex fracture initiation and branching behaviors [28]. Nevertheless, quantitative control laws of inherent reservoir properties on coupled fracture propagation remain unclear. Initial formation pressure and matrix permeability control pore pressure distribution, fluid migration, and damage evolution. Most existing thermo–hydro–mechanical models oversimplify initial boundary conditions, lacking quantitative comparisons of fracture extension across heterogeneous shale from various basins, which prevents customized fracturing parameter design [33,34].

Furthermore, the long-term evolution of porosity-permeability and multi-thousand-day gas production under hydrothermal coupling lack quantitative assessment. Permeability is the core index to evaluate stimulation performance. Existing studies only analyze pore changes under independent hydraulic or thermal loading, without long-term comparison of production rate and recovery factor among different thermal schemes [35]. This fails to objectively evaluate the long-term economic benefits of coupled stimulation technology. Most current thermal injection research adopts either pre-fracturing heating or post-fracturing heating alone [36–38]. Few studies systematically compare the stimulation performance of three thermal schedules: preheating, post-heating, and continuous synchronous heating during fracturing. The mechanisms through which heating timing regulates fracture development and matrix damage also remain poorly understood.

Preheating raises the temperature of intact shale first to generate dense thermally induced microcracks inside the matrix. Subsequent hydraulic fracturing can propagate along these pre-existing thermal microcracks to form complex fracture networks and expand stimulated reservoir volume. Esemeh E [21] further confirmed that thermally generated fractures form the primary migration pathways for pyrolysis hydrocarbons. Lu et al. [5] conducted coupling experiments combining preheating and supercritical CO₂ fracturing. The results showed that preheating greatly reduces shale breakdown pressure and increases fracture branching. These works are limited to qualitative laboratory observations.

No thermo-damage numerical models have been established to quantify how preheating temperature and duration affect subsequent hydraulic fracture propagation, nor have they compared preheating with synchronous and post-fracturing heating under unified working conditions.

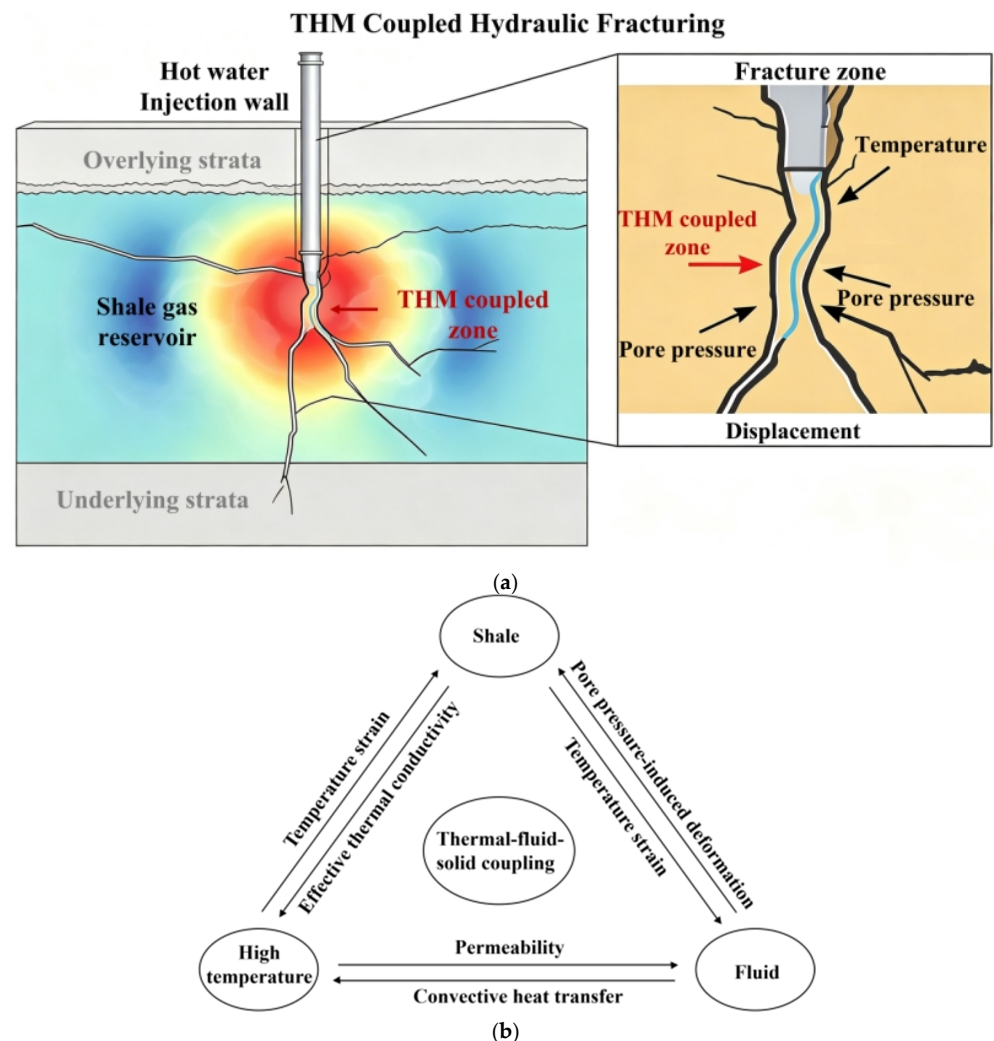


Figure 1. Schematic diagram of THM-coupled hydraulic fracturing in a shale-gas reservoir. (a) Conceptual sketch of thermal injection and THM-coupled response around the wellbore; (b) schematic of multi-physics coupling relationships among shale, fluid, and high-temperature conditions.

Synchronous heating continuously supplies heat to artificial fractures throughout hydraulic fracturing. The co-action of fracturing-induced stress and real-time thermal stress drives bidirectional fracture extension, which theoretically delivers the best permeability enhancement. Yet quantitative research on this method is quite limited. ExxonMobil's Electrofrac process realizes synchronous heating by placing conductive heating elements inside hydraulic fractures after fracture initiation. The reservoir temperature can reach up to 673 K, where high temperatures convert kerogen into mobile oil and gas. Pilot field tests have proven that synchronous heating effectively promotes matrix fracture development [17,21]. Thoram and Ehlig-Economides proposed a scheme of injecting high-temperature saturated steam while fracturing [30]. Convective heat transfer expands the heated reservoir zone and intensifies matrix thermal cracking during fracturing. Cui et al. [39] built a microwave-induced thermo-mechanical damage coupled model to simulate microwave radiation synchronous with fracturing. They quantified matrix damage increments caused by thermal stress disparities among different shale minerals. Nevertheless, existing models for

synchronous heating only simulate this single scheme. No unified comparison benchmark has been set to quantitatively identify its advantages in oil and gas production compared with preheating and post-heating.

Post-heating, namely thermal treatment after full formation of hydraulic fractures, is the most widely adopted thermal stimulation schedule in global field operations, supported by abundant laboratory and numerical results. Horsrud et al. [37] conducted thermo-mechanical tests on North Sea shale and verified that post-fracturing heating simultaneously modifies shale mechanical strength and permeability. Tiwari et al. [16] applied 3D CT scanning to characterize pore evolution in Green River oil shale after post-fracturing heating. They found that high temperatures create massive new pores in the matrix surrounding existing fractures. Masri [17] performed high-temperature mechanical tests on Tournemire shale and quantified how post-fracturing heating alters rock deformation and failure characteristics. Wang et al. [31] established a numerical model exclusively for post-fracturing fracture heating, and demonstrated that heating hydraulic fractures markedly improves shale gas recovery. Hoda [38] completed numerical inversion using field monitoring data from ExxonMobil's long-term low-temperature post-heating pilot in Colorado, and validated the stable production enhancement effect of post-fracturing thermal injection.

Overall, most existing studies only investigate one heating schedule in isolation without control-variable comparisons of preheating, synchronous heating, and post-heating within a unified modeling framework. In addition, current models contain unnecessary fluid coupling terms and fail to eliminate irrelevant flow interference. Refined simulation frameworks focusing purely on thermo-hydro-mechanical-damage coupling with identical hydraulic fracturing preconditions are still lacking. As a result, the internal mechanisms governing cross-scale fracture evolution in shale under different heating timings cannot be fully clarified, restricting large-scale field application of combined hydraulic-thermal stimulation.

In this paper, a thermal-fluid-mechanical coupled numerical model was first proposed using COMSOL Multiphysics software version 6.4 for shale gas extraction with heat injection. Accounting for fracture growth and local thermal equilibrium, the multiphysics coupling processes of temperature, pore pressure, and rock deformation were modeled. Secondly, numerical simulations of shale fracturing were conducted under conventional hydraulic pressure with parameters set accordingly. The evolution process and stress contour plots of damage, stress, displacement, and temperature were obtained. The influences of different initial water pressure and initial permeability conditions on fracture propagation were studied. Furthermore, under the coupling effect of water pressure and thermal recovery, the influences of different high temperatures on fracture propagation were studied. The effects of preheating treatment, post-heating pretreatment, simultaneous preheating and real-time heating (sequential heating treatments), as well as the duration of temperature exposure, on fracture propagation were analyzed. The displacement of the injection hole and the change in water flow velocity were also discussed. It was found that the effect on fracture propagation of post-heating, preheating, and sequential heating treatments successively increased. In the sequential heating treatment condition, the largest range of fracture propagation occurred when the temperature of the heating pretreatment was continuously maintained at around 540K. Finally, the simulation studies of shale gas production rate were carried out under these three different heat treatment methods. The influence laws of porosity, permeability, and gas production rate were analyzed and compared. It was found that both porosity and permeability increased due to the formation of interconnected fracture networks during conventional hydraulic fracturing. The gas production rate stabilized at 50.6839 million m³/d after 6000 days, with pressure differential-driven

seepage mechanisms causing subsequent production decline. Preheating to 673 K significantly enhanced thermal expansion effects, promoting fracture propagation. Pore volume and permeability further increased beyond conventional hydraulic fracturing, achieving a 44.5% higher gas production rate (73.2167 million m³/d) compared to the conventional method. Continuous heating (maintained at 473 K) resulted in a significant increase in the growth rates of porosity and permeability. After 6000 days, gas production reached 81.403 million m³/d, achieving a production increase rate of 60.6%. In summary, thermal stimulation can significantly enhance shale gas production efficiency, with staged heating yielding the highest extraction efficiency.

2. THM Coupling Mathematical Model in Fracture Propagation

The process of thermal injection for shale gas extraction is a process of THM multi-physics coupling. Additional uneven expansion and contraction induced by the additional heat affect the aperture and permeability of fractures. These changes in permeability alter flow paths and temperature, while flow paths modify temperature, creating complex feedback loops. THM coupling describes the complex multiphysics problem involving the interaction of fluid flow, mechanical deformation, and heat transfer. Correspondingly, coupling equations are derived by jointly coupling the physics fields of fluid dynamics, solid mechanics, and heat conduction equations.

2.1. Basic Assumptions and Simplifications

The THM mathematical model characterizes multifield interactions among shale deformation, gas-fluid flow, and heat transfer under thermal stimulation, with separate governing equations adopted for the fracture domain and shale-matrix porous domain. The following assumptions are made for the THM coupled model in shale gas extraction:

- (1) The shale gas is assumed to be a Newtonian fluid, and the Navier–Stokes equations can be applied.
- (2) The shale matrix is assumed to be a continuous medium, with elastic, plastic, or thermal expansion effects.
- (3) The effects of thermal convection, conduction, and radiation (radiation may be neglected depending on the circumstances) are considered.
- (4) A single-phase gas flow simplification is adopted in this model. Under simulated conditions, shale possesses low initial water saturation, and water vapor generated by pore-water evaporation occupies only a limited mass fraction. Thus, vapor exerts a minor influence on pore-pressure propagation and rock-damage evolution. Full gas-water two-phase flow involving evaporation-condensation phase change is not implemented in the present model and will be considered in future work.

2.2. Governing Equations for Fluid Flow and Heat Transfer

In this model, fluid-flow and heat-transfer behaviors are treated in two distinct computational domains: the fracture domain and the shale-matrix porous domain.

For regions consisting of fractures, the following set of conservation equations is adopted. Fluid motion is solved by the Navier–Stokes volume-of-fluid (NS-VOF) method. At the domain interface, pressure, fluid velocity, and temperature are coupled to realize physical information exchange between the two domains.

- (1) Mass conservation equation (continuity equation):

$$\frac{\partial \rho_f}{\partial t} + \nabla \cdot (\rho_f u) = 0 \quad (1)$$

where ρ_f is the density of shale gas, and u is the velocity vector.

- (2) Momentum conservation equation (Navier–Stokes equation):

$$\rho_f \left(\frac{\partial \mathbf{u}}{\partial t} + \mathbf{u} \cdot \nabla \mathbf{u} \right) = -\nabla p + \mu \nabla^2 \mathbf{u} + \mathbf{f}_b \quad (2)$$

where p is the fluid pressure, $\mathbf{f}_b$ is the volumetric force, τ is the viscous stress tensor ($\tau = \mu(\nabla \mathbf{u} + \nabla \mathbf{u})^T$), and μ is the viscosity of the fluid.

- (3) Energy conservation equation (heat conduction equation):

$$\rho_f c_{pf} \left(\frac{\partial T_f}{\partial t} + \mathbf{u} \cdot \nabla T_f \right) = k_f \nabla^2 T_f + \Phi + Q_f \quad (3)$$

where T_f is the temperature of the fluid, c_{pf} is the specific heat capacity, k_f represents the thermal conductivity of the fluid, Φ is the viscous dissipation term ($\Phi = \tau : \nabla \mathbf{u}$), and Q_f is the internal heat source within the fluid.

For the low-permeability shale-matrix porous domain, fluid flow follows Darcy's law. The mass transport, seepage flow, and heat transfer are described by the following set of porous-media governing equations [11]:

- (4) Mass conservation equation for porous shale matrix:

$$\rho_f S_p \frac{\partial p}{\partial t} + \nabla \cdot (\rho_f \mathbf{u}_D) = Q_m \quad (4)$$

where ρ_f is the density of the fluid, p is the fluid pressure, $\mathbf{u}_D$ is the Darcy velocity, Q_m is the mass source term, and S_p is the fluid storage coefficient; this can be expressed as $S_p = \phi \chi_f$, where ϕ is the shale porosity and χ_f is the compressibility of the fluid.

- (5) Darcy's law for fluid flow:

$$\mathbf{u}_D = -\frac{k}{\mu} \nabla p \quad (5)$$

where k is the intrinsic permeability of the shale matrix, and μ is the dynamic viscosity of the fluid.

- (6) Energy conservation equation (heat conduction equation):

$$(\rho c_p)_{\text{eff}} \frac{\partial T}{\partial t} + \rho_f c_{p,f} \mathbf{u}_D \cdot \nabla T = \nabla \cdot (k_{\text{eff}} \nabla T) + Q \quad (6)$$

where $(\rho c_p)_{\text{eff}}$ is the effective volumetric heat capacity of the porous medium, T is the temperature, $c_{p,f}$ is the specific heat capacity of the fluid at constant pressure, k_{eff} is the effective thermal conductivity of the porous matrix, and Q is the volumetric heat source term.

2.3. Governing Equations for Mechanical Field

The governing equations for the mechanical field in shale gas extraction are as follows:

- (1) Solid mechanics equation (conservation of momentum)

$$\rho_s \frac{\partial^2 \mathbf{d}}{\partial t^2} = \nabla \cdot \boldsymbol{\sigma} + \mathbf{f}_s \quad (7)$$

where ρ_s is the solid density, $\mathbf{d}$ is the solid displacement, $\mathbf{f}_s$ is the solid volumetric force, and $\boldsymbol{\sigma}$ is the Cauchy stress tensor ($\boldsymbol{\sigma} = \mathbf{C} : \boldsymbol{\varepsilon}$, where $\mathbf{C}$ is the elastic tensor and $\boldsymbol{\varepsilon}$ is the strain tensor).

(2) Heat conduction equation in shale matrix

$$\rho_s c_s \frac{\partial T_s}{\partial t} = k_s \nabla^2 T_s + Q_s \quad (8)$$

where T_s is the solid temperature, c_s is the specific heat capacity of the solid, k_s is the thermal conductivity of the solid, and Q_s is the internal heat source within the solid.

The temperature field calculated from Equation (8) is coupled with the mechanical field in Equation (7) through thermal deformation. Fluid–rock heat exchange changes the local shale temperature, and the resulting thermal expansion or contraction modifies the stress field. In particular, when the injection-fluid temperature is lower than the initial formation temperature, the local temperature decrease induces thermal contraction and associated stress redistribution. The resulting stress state is subsequently used in the tensile and shear failure criteria described in Section 2.4, thereby allowing the cooling effect to influence damage initiation and fracture propagation through thermo-mechanical coupling.

2.4. Tensile–Shear Coupled Damage Evolution Model for Shale

Under external loading, shale generates tensile splitting fractures and shear slip fractures simultaneously. These two types of irreversible damage accumulate continuously and jointly reduce the bearing stiffness of the rock mass. To quantitatively describe the whole evolution process of coupled tensile–shear fractures, the Mohr–Coulomb strength criterion is adopted to distinguish the tensile and shear plastic loading stages, and the tensile damage variable D_t and shear damage variable D_c are defined, respectively. The superposition of the two damage variables yields the overall damage field D . The damage field is coupled into the elastic constitutive relation to realize stiffness reduction, which fully characterizes the progressive failure behavior of the rock mass.

2.4.1. Tensile and Shear Yield Discrimination Functions

Based on the Mohr–Coulomb criterion combined with a tensile cut-off criterion, the tensile failure function F_1 and shear failure function F_2 are introduced to determine whether an element enters a tensile-dominated or shear-dominated damage state, as given in Equations (9) and (10).

$$F_1 = \sigma_1 - f_{t0} \quad (9)$$

$$F_2 = -\sigma_3 + \frac{1 + \sin \varphi}{1 - \sin \varphi} \sigma_1 - f_c \quad (10)$$

where σ_1 and σ_3 are the maximum and minimum principal stresses, respectively. In the present study, tensile stress is taken as positive and compressive stress as negative, and the principal stresses are ordered as $\sigma_1 \geq \sigma_2 \geq \sigma_3$. f_{t0} is the uniaxial tensile strength of shale, f_c is the uniaxial compressive strength of shale, and φ represents the internal friction angle of shale.

To eliminate physically meaningless false damage, time-derivative constraints of yield functions $\partial F_1 / \partial t > 0$ and $\partial F_2 / \partial t > 0$ are introduced. To suppress spurious damage during unloading, the loading conditions $\partial F_1 / \partial t > 0$ and $\partial F_2 / \partial t > 0$ are introduced. Damage evolution is activated only when the corresponding failure criterion is satisfied, and the associated failure function continues to increase.

The Mohr–Coulomb criterion is used to identify shear-dominated failure, whereas the tensile cut-off criterion is used to describe tensile failure. The two failure functions F_1 and F_2 are evaluated simultaneously at each material point. When only $F_1 \geq 0$ is satisfied, tensile damage is activated; when only $F_2 \geq 0$ is satisfied, shear damage is activated. If both failure criteria and their corresponding loading conditions are satisfied, the tensile and shear damage variables evolve according to their respective evolution laws, and their

combined contribution is subsequently represented by the total damage variable D defined in Equation (10). Therefore, the transition between tensile- and shear-dominated failure is governed by the current principal-stress state and the activation of the two failure functions, without introducing an additional empirical mixed-mode transition function.

2.4.2. Tensile Damage Variable D_t

Tensile damage evolves only when both the tensile failure criterion $F_1 \geq 0$ and the loading condition $\partial F_1 / \partial t > 0$ are satisfied. Otherwise, no additional tensile damage is generated. The evolution law of the tensile damage variable D_t is given by Equation (11):

$$D_t = \min \left\{ 0.99, \max \left[0, 1 - \left(\frac{\varepsilon_{t0}}{\varepsilon_1} \right)^2 \right] \right\} \quad (F_1 \geq 0 \text{ and } \frac{\partial F_1}{\partial t} > 0) \quad (11)$$

where $\varepsilon_{t0} = \frac{f_{t0}}{E_0}$ denotes the elastic ultimate tensile strain of shale; ε_1 is the maximum principal tensile strain of the element; E_0 is the initial elastic modulus of shale.

The function $\max(0, \cdot)$ limits the lower limit of damage to 0 to prevent physically meaningless negative damage values. The function $\min(0.99, \cdot)$ restricts the maximum damage value to 0.99. This avoids zero element stiffness and ensures stable numerical solutions of multifield coupling. D_t ranges from 0 to 0.99, and a larger value means more developed tensile fractures.

2.4.3. Shear Damage Variable D_c

Shear damage evolves only when both the shear failure criterion $F_2 \geq 0$ and the loading condition $\partial F_2 / \partial t > 0$ are satisfied. Otherwise, no additional shear damage is generated. The evolution law of the shear damage variable D_c is given by Equation (12):

$$D_c = \min \left\{ 0.99, \max \left[0, 1 - \left(\frac{\varepsilon_{c0}}{\varepsilon_3} \right)^2 \right] \right\} \quad (F_2 \geq 0 \text{ and } \partial F_2 / \partial t > 0) \quad (12)$$

where $\varepsilon_{c0} = \frac{f_c}{E_0}$ is the ultimate elastic compressive strain of shale; ε_3 stands for the minimum principal compressive strain of the element.

The shear damage variable D_c ranges from 0 to 0.99, where $D_c = 0$ represents the undamaged state, and a larger value of D_c indicates a higher degree of shear damage.

The evolution of D_t and D_c is governed by both the corresponding failure criterion and loading condition. Tensile damage evolves when $F_1 \geq 0$ and $\partial F_1 / \partial t > 0$ are simultaneously satisfied, whereas shear damage evolves when $F_2 \geq 0$ and $\partial F_2 / \partial t > 0$ are simultaneously satisfied. When the corresponding loading condition is not satisfied, no additional damage is generated.

2.4.4. Total Damage Field D

Rock failure is usually accompanied by the development of tensile fractures and shear-slip fractures, and the associated tensile and shear damage may jointly contribute to the deterioration of the mechanical properties of the rock mass. To account for the combined effects of the two damage modes, a coupled damage variable D is defined by superimposing the tensile damage variable D_t and the shear damage variable D_c , as given in Equation (13):

$$D = \min(0.99, D_t + D_c) \quad (13)$$

The total damage D varies from 0 to 0.99. $D = 0$ corresponds to intact rock without fractures; $0 < D < 0.99$ represents the initiation and local propagation of fractures; and $D = 0.99$ represents a highly damaged state in which the element approaches the loss of its load-bearing capacity.

The present model does not introduce an additional mode-I/mode-II mixed-mode criterion. Tensile and shear failure are assessed separately using F_1 and F_2 , while their combined effect is included through D . Therefore, the coupling used here describes the joint contribution of D_t and D_c to rock degradation, rather than an explicit interaction between K_I and K_{II} .

2.4.5. Damage-Coupled Constitutive Relationship

The coupled total damage field is introduced into the elastic constitutive model of porous media. The equivalent elastic modulus of the element is reduced according to damage to quantify the stiffness degradation effect caused by fracture propagation, as shown in Equation (11) [5]:

$$E_d = (1 - D)E_0 \quad (14)$$

where E_d is the equivalent elastic modulus of the element after damage evolution.

2.4.6. Numerical Representation and Identification of Fracture Propagation

In this work, fracture evolution is simulated within the framework of continuum damage mechanics. Tensile damage D_t and shear damage D_c are solved separately to obtain the total damage variable D . No phase-field method, cohesive-zone model, or embedded-discontinuity approach is adopted. Fracture initiation and propagation are represented by the degradation of element elastic stiffness via the total damage variable D , rather than inserting explicit discrete fracture geometry.

The tensile and shear failure modes are first identified using the corresponding failure criteria F_1 and F_2 . When the corresponding failure criterion and loading condition are satisfied, the tensile damage variable D_t or shear damage variable D_c evolves according to Equations (11) and (12). The two damage components are subsequently combined into the total damage variable D according to Equation (13).

The total damage variable D is introduced into the elastic constitutive relation through the damage-dependent equivalent elastic modulus $E_d = (1 - D)E_0$. As damage accumulates, the local elastic stiffness progressively decreases. The resulting redistribution of the stress field may cause neighboring elements to satisfy the corresponding failure and loading conditions, leading to further damage accumulation and spatial extension of the damaged zone. Through this iterative damage–stiffness–stress redistribution process, the initiation, propagation, and interaction of damaged zones can be continuously represented within the finite-element domain.

Fracture propagation is therefore characterized by the spatial distribution and temporal evolution of the total damage variable D . Regions with relatively low values of D correspond to intact or slightly damaged shale, whereas connected regions with high values of D represent strongly damaged zones and are interpreted as developed fracture paths. This continuum representation enables complex fracture development to be simulated without explicitly tracking discrete crack surfaces, remeshing the computational domain, or introducing additional discontinuity elements. In this model, matrix pores and damage-induced fractures are decoupled; fracture volume is not incorporated into the matrix-porosity calculation.

2.5. Thermal–Fluid–Structural Coupling Boundary Conditions

At the fluid–solid interface (Γ_{fs}), the coupling boundary conditions are as follows:

- (1) Kinematic conditions (no-slip boundary)

$$\mathbf{u} = \frac{\partial \mathbf{d}}{\partial t} \quad (15)$$

where $\mathbf{u}$ is the fluid velocity and $\mathbf{d}$ is equal to the solid interface velocity.

(2) Dynamic conditions (force equilibrium)

$$\sigma_s \cdot \mathbf{n} = \sigma_f \cdot \mathbf{n} \quad (16)$$

where $\mathbf{n}$ is the interfacial normal vector, σ_s is the solid stress, and σ_f is the fluid stress ($-p\mathbf{I} + \boldsymbol{\tau}$).

(3) Thermal coupling conditions (continuity of temperature and heat flux)

$$T_f = T_s \quad (17)$$

Equation (17) represents the continuity of temperature,

$$k_f \frac{\partial T_f}{\partial \mathbf{n}} = k_s \frac{\partial T_s}{\partial \mathbf{n}} \quad (18)$$

Equation (18) expresses the continuity of heat flux.

(4) Thermal–solid coupling (thermal stress)

Solid materials undergo thermal strain in response to changes in temperature.

$$\varepsilon_{th} = \alpha(T_s - T_0)\mathbf{I} \quad (19)$$

where α is the thermal expansion coefficient, T_0 is the reference temperature, and $\mathbf{I}$ is the unit tensor, respectively.

The formula for total strain can be expressed as:

$$\varepsilon = \varepsilon_{mech} + \varepsilon_{th} \quad (20)$$

When the injection-fluid temperature is lower than the initial formation temperature, fluid–rock heat exchange causes a local decrease in shale temperature. According to Equations (19) and (20), this temperature decrease induces thermal contraction, which modifies the local stress field and generates cooling-induced thermal stress. The resulting stress redistribution is subsequently reflected in the principal stresses used in the tensile and shear failure criteria, thereby influencing damage initiation and fracture propagation.

2.6. Gas Production Calculation

Based on the flow-field results within fractures obtained from numerical simulation, gas production is calculated by boundary integration. The instantaneous gas flow rate is determined by integrating the fluid velocity at the fracture outlet boundary, as expressed in Equation (21):

$$Q = 24 \times 3600 \times \frac{H}{\rho_{ga}} \int v_f ds \quad (21)$$

where Q is the cumulative gas production, H is the model thickness, ρ_{ga} is the gas density under standard conditions, and v_f is the fluid velocity obtained from numerical solutions of fracture internal flow.

The cumulative gas production throughout the simulation period can be further acquired by integrating the instantaneous production rate over time:

$$V_g = \int_0^t Q dt \quad (22)$$

where V_g is the cumulative gas production, and t denotes the production time.

3. Numerical Simulation of Shale Gas Production Under Coupled Hydraulic–Thermal Stimulation

3.1. Thermo–Hydro–Mechanical Analysis

Numerical simulations in this work were performed using COMSOL Multiphysics. As a finite-element-based multiphysics platform, it is widely used to address strongly coupled THM problems in shale reservoirs. With robust solvers for complex boundary conditions, the software enables direct coupling of heat transfer, fluid flow, and solid deformation, allowing realistic representation of shale responses under reservoir conditions.

A THM coupling model in shale gas production was constructed using three core modules. The Porous Media Flow Module was used to characterize fluid flow in shale pores and natural fractures, including anisotropic permeability and nonlinear flow effects. The Solid Mechanics Module was adopted to capture stress, strain, and rock failure criteria. The Heat Transfer Module described heat conduction, convection, and radiation within the shale medium.

A particular emphasis of this study is placed on fracture initiation and propagation behavior under coupled thermal–hydraulic loading. By integrating the above modules, the evolution of multiple physical fields and dynamic fracture development were obtained. Key outputs include temperature distributions, stress–strain fields, pore pressure variations, and fracture propagation paths. These results provide reliable data support and a scientific basis for optimizing shale gas development schemes.

Based on the test conditions and procedures, a square with a side length of 100 m was established as the shale body. A circle with a radius of 5 m was then excavated at the center of this square using a Boolean subtraction operation. This circle serves as the pressure injection well, as shown in Figure 2.

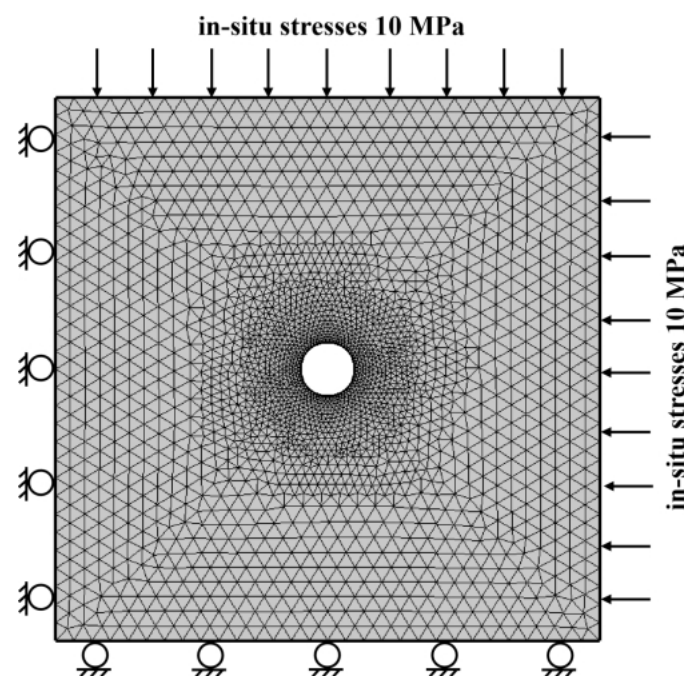


Figure 2. Construction of shale reservoir model under hydrothermal recovery conditions.

The 100 m × 100 m computational domain is adopted to investigate near-well multiphysics responses during shale gas injection. No multi-case domain-size sensitivity analysis is performed in this study. For all simulated scenarios, pressure disturbance and damage zones do not reach the outer boundaries, so boundary effects exert negligible influence on near-well results. This model focuses on mechanism exploration rather than direct full-scale

field reservoir prediction. The parameter settings for the shale model are as follows, with the key global-model parameters summarized in Table 1.

Table 1. Global model parameters.

Parameters	Units	Value
Uniaxial compressive strength	MPa	60
Angle of internal friction	°	25
Initial porosity	/	0.03
Residual porosity	/	1×10^{-3}
Poisson's ratio	/	0.25
Initial permeability	m ²	1×10^{-20}
Injection pressure	MPa	32
Initial thermal conductivity of solids	W/(m·K)	3
Specific heat capacity of solids	J/(kg·K)	900
Initial heat transfer coefficient	W/(m ² × K)	50
Thermal expansion coefficient of solids	1/K	6×10^6
Initial temperature	K	293.15
Injection temperature	K	373.15

This physical configuration follows typical modeling frameworks for shale hydrothermal stimulation. Certain geological complexities are simplified herein to focus on near-well multiphysics coupling mechanisms. All numerical simulations are performed on a workstation with an Intel Xeon Gold 6248R CPU (24 physical cores, 3.0 GHz). For a typical simulation covering a production period of 6000 days, the wall-clock computation time is approximately 42–50 h. The three representative thermal-stimulation cases consume about 140 h in total. All COMSOL thermo–hydro–mechanical coupled simulations adopt CPU-based computation without GPU acceleration.

3.2. Theoretical Analysis

3.2.1. Analysis of the Shale Fracturing Process

The fracturing process of shale under the combined effects of temperature and pore water pressure can be divided into four typical stages [12,33]:

Stage 1: Initial damage stage. Shale first undergoes elastic deformation due to temperature changes and pore water pressure. This stage is characterized primarily by the closure or slight expansion of microfractures, while the overall integrity of shale is maintained. Temperature gradients induce thermal stresses inside shale, while pore water pressure reduces the effective stress.

Stage 2: Stable Fracture Propagation Stage. With continuous temperature loading and pore pressure buildup, micro-fractures inside shale start to expand steadily. Fractures grow at a low rate in this phase, yet accumulated damage remarkably elevates shale permeability. The joint action of thermal stress and pore water pressure further accelerates the extension of shale fractures.

Stage 3: Fracture Interconnection Stage. When fractures expand sufficiently, primary fractures form and interconnect. This stage exhibits a sudden surge in permeability and the formation of macroscopic fracture surfaces. The mechanical performance of shale degrades drastically, which may trigger abrupt shale failure.

Stage 4: Residual Through-Fracturing Stage. After macroscopic fracture planes are formed, shale still possesses certain residual bearing capacity. This stage is mainly governed by frictional sliding along fracture surfaces, and the coupling effect of seepage and stress becomes the controlling factor for shale deformation.

3.2.2. Numerical Model Calculation Process

The computational study is conducted in two stages: steady-state and transient simulations. First, the steady-state simulation is used to model the displacement and stress state of the shale matrix prior to fracturing. Next, the transient simulation uses the solution from the previous step to model transient fracture propagation under THM coupling. The results of this process are shown in Figure 3 as the stress and displacement magnitude plots.

The effects of temperature and pore water pressure in thermal-enhanced shale gas extraction are coupled through multiphysics simulation, which significantly enhances gas desorption efficiency and flow capacity. However, further research into the underlying mechanisms and optimization of the thermal injection process parameters are required for its industrial application.

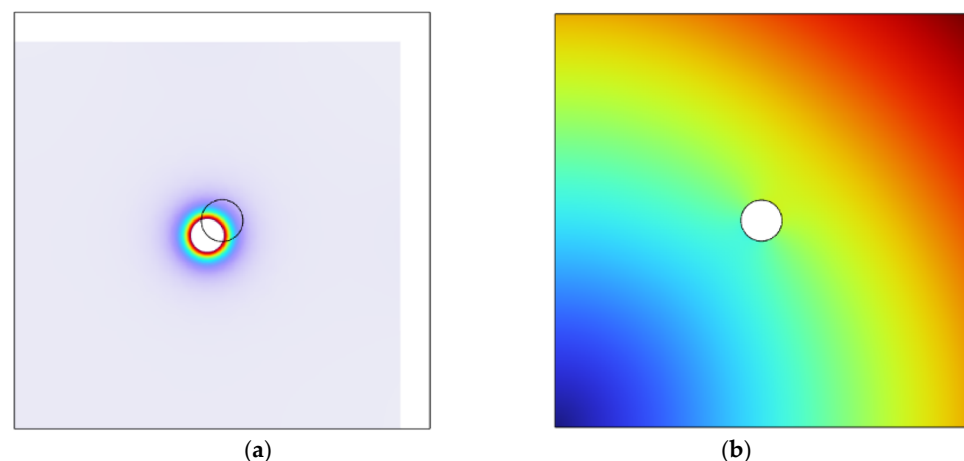


Figure 3. Steady-state contour diagrams of stress and displacement under THM coupling. (a) Contour of stress magnitude; (b) contour of displacement field. This schematic diagram only illustrates distribution patterns, without quantitative color-bar scales.

(1) Temperature effect

Temperature changes primarily affect shale fracturing through three mechanisms: ① inducing thermal stress, which causes rock to expand or contract; ② altering rock mechanical properties, such as reducing the elastic modulus; and ③ changing the properties of pore fluids, for example, by altering their viscosity. Shale gas is mainly adsorbed onto surfaces of organic matter, and the rate of this process declines exponentially as the temperature rises. The reservoir temperature is increased by injection of heat, which also significantly reduces gas adsorption capacity. Increasing recoverable gas volumes is achieved by promoting the desorption of adsorbed methane into a free state.

(2) Pore pressure effect

The primary effects of pore water pressure are to reduce the effective stress in rock, promote the opening and propagation of fractures, and induce hydraulic fracturing. The process of heat injection-induced pressure increase proceeds as follows: First, heating causes pore water to expand and partially vaporize, thereby elevating pore pressure. The effective stress within the rock is reduced by this increased pore pressure, which ultimately promotes the expansion of natural fractures by tensile force. At the same time, the hydraulic fracturing and heat injection process increases the pressure inside the rock, causing the fracture network to expand.

(3) Coupling effects

The interaction between temperature and pore water pressure leads to temperature gradients, which drive fluid flow. Pressure affects heat transfer efficiency, and the coupling

determines rock stress and state. Additionally, increased heating is known to cause pore water expansion and gas expulsion, with the result that a pore pressure drop is directly induced. Thermal convection is driven by temperature gradients and alters pressure. The way in which fluid saturation and velocity are controlled by pore pressure affects the efficiency of both convective and reservoir heat transfer.

4. Study on Fracture Propagation in Shale Gas Reservoirs Under Hydraulic–Thermal Stimulation

4.1. Fracture Propagation Under Conventional Water Pressure

Numerical simulations of shale fracturing were performed under conventional hydraulic fracturing conditions with the parameter settings listed in Table 2. In this case, water at 293 K is injected into the formation with an initial geothermal temperature of 373 K. The resulting fluid–rock heat exchange and cooling-induced thermal stress are accounted for through the thermo-mechanical coupling. The distributions of shale damage, stress, displacement, and thermal stress during fracture propagation are presented in Figure 4.

Table 2. Conventional hydraulic fracturing parameters.

Parameters	Unit	Values
Temperature (T_0)	K	293
Water pressure (P)	MPa	32
in situ stress (P_0)	Mpa	10
Geothermal temperature (T)	K	373
Initial permeability	m^2	1×10^{-20}

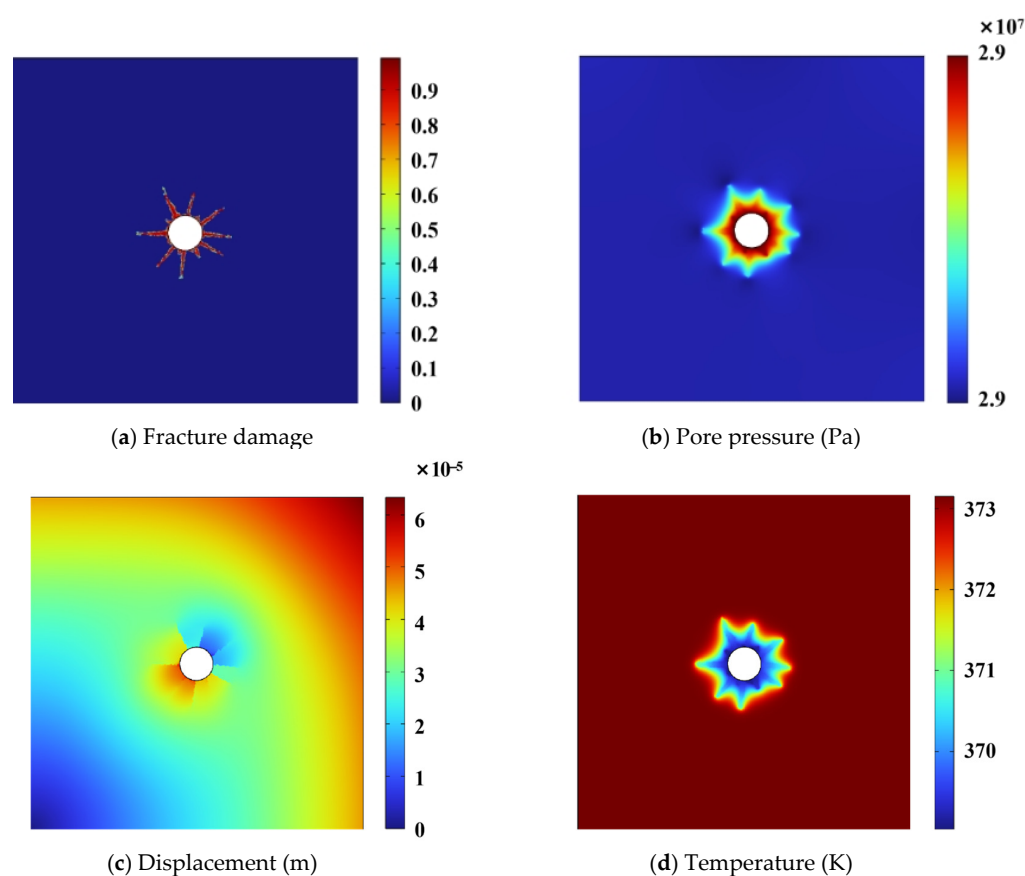


Figure 4. Contour distributions of fracture damage, pore pressure, displacement, and temperature under conventional hydraulic fracturing.

Figure 4 presents the contour distributions of four key physical fields at a representative stage of the conventional hydraulic fracturing simulation under the standard conditions (32 MPa water pressure and 293 K injection temperature). Figure 4a shows that damage initiates around the injection well and propagates outward along several preferential directions, forming a branched fracture pattern. As shown in Figure 4b, the pore pressure is highest in the vicinity of the injection well and decreases progressively toward the far-field region, indicating pressure diffusion from the injection zone into the shale matrix. The displacement field in Figure 4c exhibits a pronounced spatially nonuniform distribution around the wellbore, reflecting deformation and stress redistribution induced by fluid injection and fracture development.

Meanwhile, Figure 4d shows a distinct low-temperature region surrounding the injection well because the injected water temperature (293 K) is lower than the initial formation temperature (373 K). Fluid–rock heat exchange therefore produces local cooling and thermal contraction near the injection region. Through the thermo-mechanical coupling described above, this temperature variation modifies the local stress state and consequently influences the tensile and shear damage evolution. The spatial correspondence among the damage, pore-pressure, displacement, and temperature fields demonstrates that fracture propagation under conventional hydraulic fracturing is governed by the coupled effects of fluid-pressure diffusion, mechanical deformation, and cooling-induced thermo-mechanical stress redistribution.

4.2. Effect of Different Initial Conditions on Fracture Propagation

4.2.1. Effect of Different Water Pressures on Fracture Propagation

Numerical simulations were conducted to analyze fracture propagation at pressures of 30 Mpa, 32 Mpa and 34 Mpa under constant parameters and standard water pressure conditions, with all pressures applied for identical durations. The damage, pore pressure, and displacement contour plots are displayed in Figure 5. The fracture damage contours in Figure 5a–c indicate that increasing injection pressure markedly promotes fracture propagation. The progressive accumulation of local damage significantly enhances the connectivity of branch fractures. Elevated injection pressure exacerbates stress concentration at fracture tips, which rapidly drives the in situ stress to surpass the tensile strength of rock masses. Under high fluid pressure, the shale matrix becomes more susceptible to damage, accompanied by pore collapse and extensive microdefect generation, which further facilitates the initiation and progressive expansion of hydraulic fractures. In addition, the pore pressure distributions in Figure 5d–f exhibit typical radial variation characteristics. Pore pressure remains relatively stable in regions far from the fracture network. In the vicinity of the injection wellbore, the radial coverage of the high-pressure fluid zone expands continuously as injection pressure increases. In contrast, a sharp decline in pore pressure is observed near fracture tips. When high-pressure fluid migrates toward fracture extremities, the viscous resistance within narrow fracture apertures induces redistribution of the surrounding stress field. Pore fluid pressure counteracts the normal stress acting on fracture surfaces, thereby reducing the effective stress at fracture tips and lowering the net pressure threshold for sustained fracture growth. Moreover, the displacement contours in Figure 5g–i verify that the overall deformation degree of shale rock increases distinctly with the rise in injection pressure, with the maximum displacement occurring at the far-field boundary of the numerical model. Near the injection wellbore, water pressure-induced deformation partially offsets the displacement caused by the original in situ stress, resulting in noticeable differences in wellbore-proximal displacement. Higher injection pressure ultimately extends the influencing range of rock deformation across the entire computational domain.

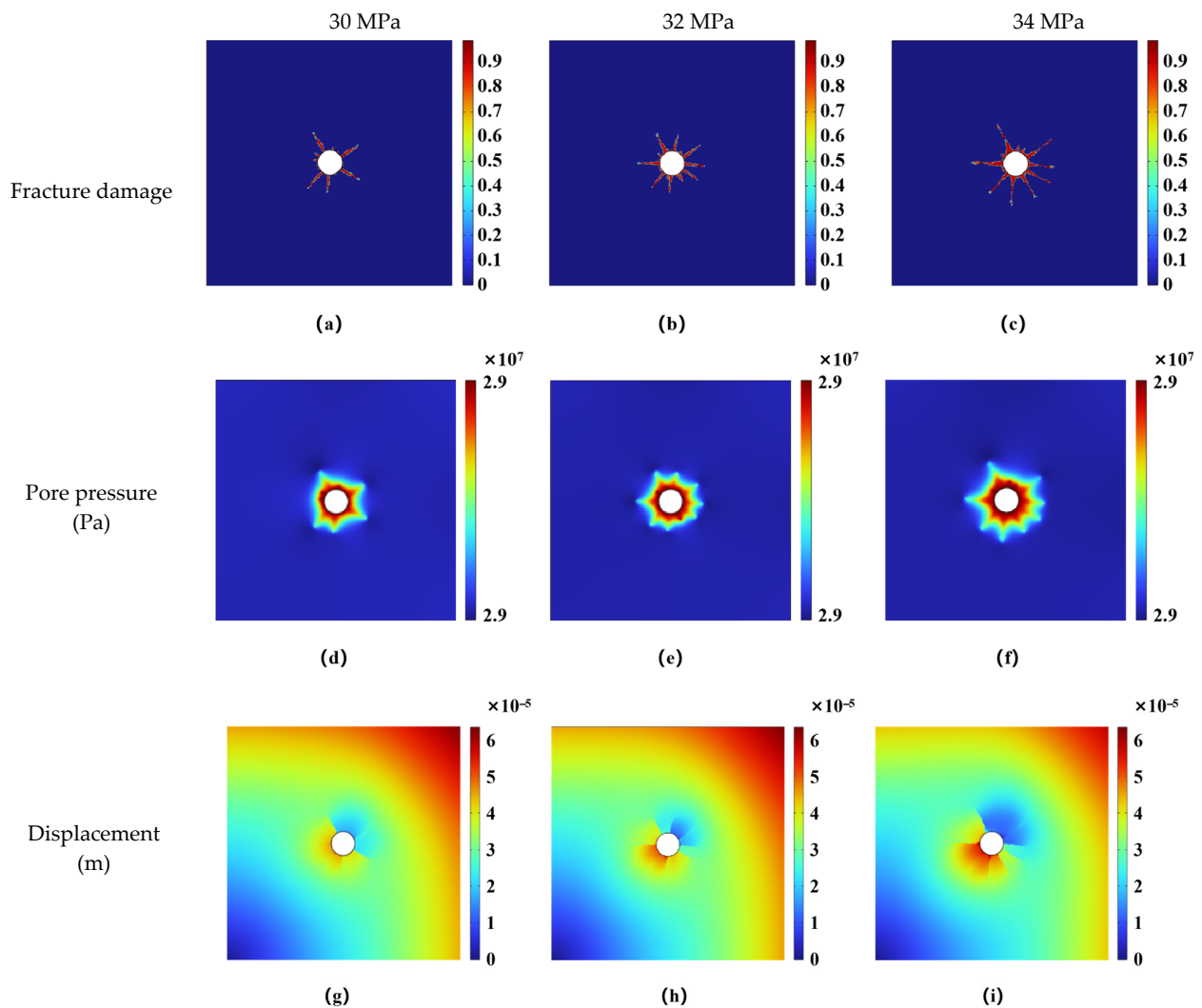


Figure 5. Contour distributions of fracture damage, pore pressure, and displacement under injection water pressures of 30 MPa, 32 MPa, and 34 MPa.

4.2.2. Effect of Different Initial Permeability on Fracture Propagation

Fracture propagation was modelled using numerical simulations. The hydraulic pressure was kept at 32 MPa and the other conventional hydraulic pressure parameters were kept constant. The computer tests were done with initial permeability values of $1 \times 10^{-21} \text{ m}^2$, $1 \times 10^{-20} \text{ m}^2$ and $1 \times 10^{-19} \text{ m}^2$. These were all exposed to the same hydraulic pressure for the same amount of time. The resulting damage, pressure, and displacement contour plots are shown in Figure 6. The damage fracture contour plot shows that fractures propagate more readily as the initial permeability increases. This is because enhanced permeability enables fracturing fluids or gases to infiltrate rock microfractures more easily. Consequently, pore pressure rises, and the effective stress within the rock decreases. The fracture pressure is also lowered by this, which promotes fracture initiation and propagation. Specifically, the pore pressure cloud maps further demonstrate that the high-pressure fluid disturbance zone expands outward with increasing initial permeability. Better matrix seepage capacity accelerates the diffusion of injected pressure away from the injection well. In addition, the displacement contours show that the magnitude and coverage of shale deformation continuously enlarge at higher initial permeability. More fluid infiltrates the surrounding rock and creates stronger rock deformation responses.

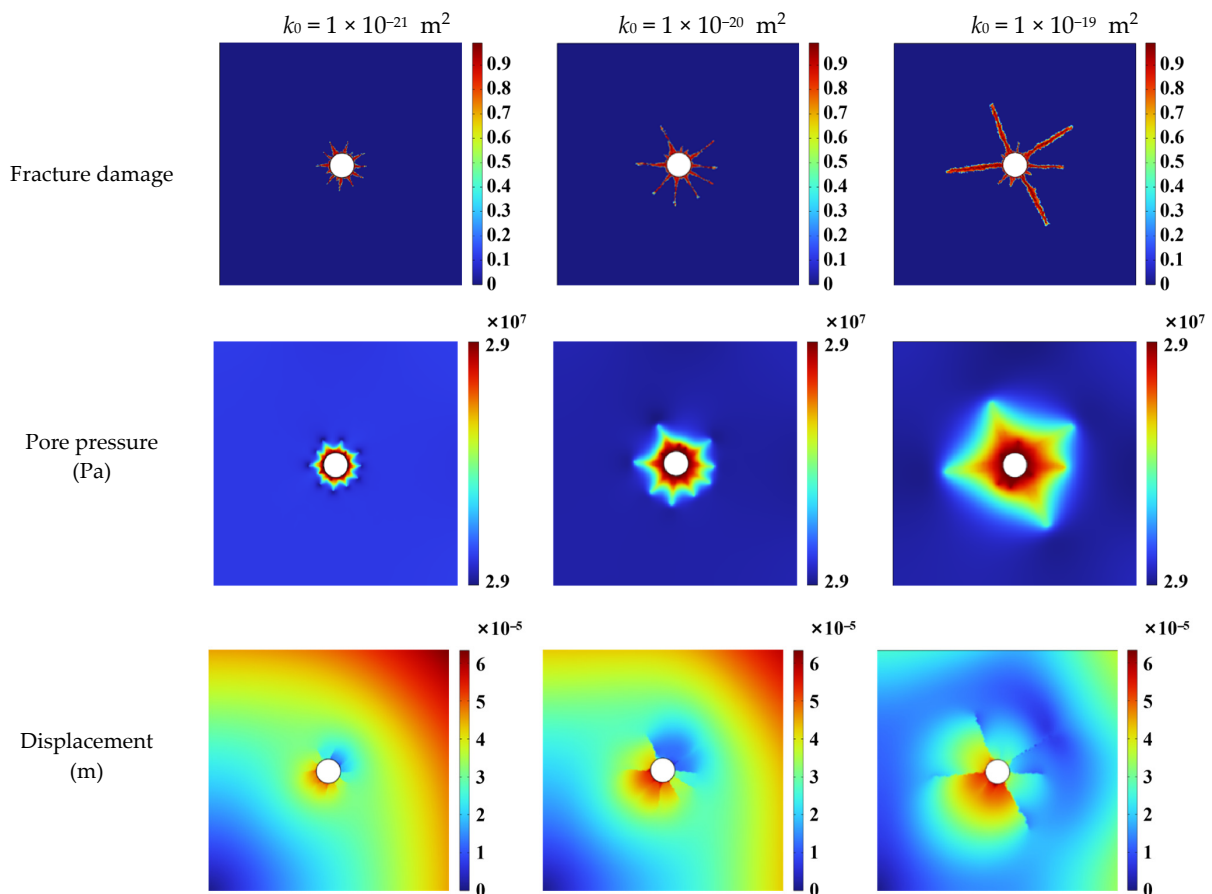


Figure 6. Contour plots of fracture damage, pore pressure, and displacement under three different initial permeability conditions.

4.2.3. Effect of Different In Situ Stresses on Fracture Propagation

The water pressure was set to 34 MPa, the water temperature to 293 K, and the initial permeability to $1 \times 10^{-20} \text{ m}^2$. Fracture propagation was simulated under three different in situ stresses (9, 10, and 11 MPa) and for the same duration. The resulting damage fracture diagrams are shown in Figure 7. The conclusions drawn from the pressure and displacement plots are consistent with previous findings. Only the qualitative analysis of the damage plot is presented here. It can be seen that fracture propagation becomes increasingly difficult as in situ stress increases. This is because the normal stress on the fracture surface is increased by rising in situ stress, necessitating a higher fluid pressure to overcome closure forces. Furthermore, fracture closure, increased frictional resistance, and the inhibition of the nucleation of new fractures are promoted by elevated in situ stress.

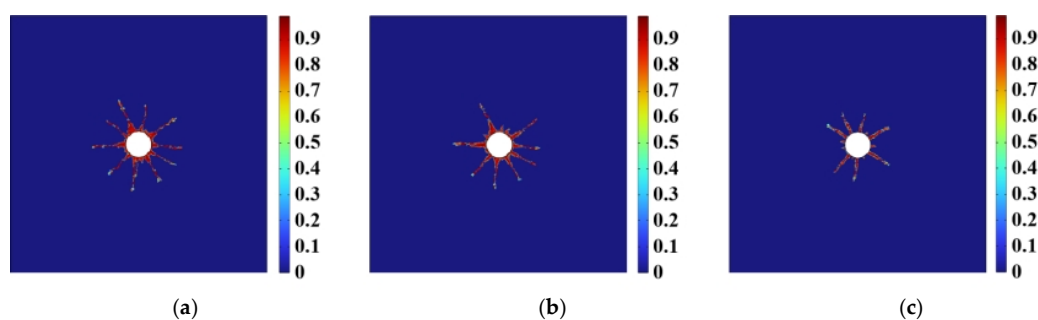


Figure 7. Fracture-damage contours under different in situ stress levels; (a) 9 MPa, (b) 10 MPa, (c) 11 MPa.

4.2.4. Model Validation

To evaluate the reliability of the thermo–hydro–mechanical–damage model, the baseline simulations at ambient temperature were compared with the experimental observations and numerical results published by Li [11]. The comparison was made using the processed results reported in that study, rather than the original raw experimental data. For this reason, the validation mainly focuses on whether the present model can reproduce the reported fracture patterns and the general response trends under different loading and reservoir conditions.

All baseline simulations in Section 4.2 are performed at 293.15 K. The contours of damage, pore pressure, and displacement show consistent spatial patterns. Radial branched damage zones form around the wellbore. High pore pressure concentrates near the well and decays rapidly outward, while rock deformation decreases with the distance from the injection point. All these spatial characteristics match published ambient-temperature simulation results perfectly.

Three injection pressures (30 MPa, 32 MPa, 34 MPa) are adopted for parametric analysis. Higher injection pressure intensifies stress concentration around the wellbore. The stress at fracture tips more easily exceeds the rock tensile strength, generating more interconnected branch fractures and larger rock deformation. High-pressure fluids expand the range of disturbed pore pressure. The quantitative trend agrees well with our simulation results. In addition, three initial permeability groups ($1 \times 10^{-21} \text{ m}^2$, $1 \times 10^{-20} \text{ m}^2$, $1 \times 10^{-19} \text{ m}^2$) are also tested. Higher matrix permeability facilitates fluid migration and enlarges the region affected by pore pressure, leading to longer and more numerous fractures. Our predicted coupling relationship between porosity and damage aligns with previous findings. Furthermore, three in situ stress levels (9 MPa, 10 MPa, 11 MPa) are considered. Higher in situ stress applies stronger normal constraints on fracture surfaces and raises propagation resistance. The generation of microcracks is suppressed, and the overall damage area shrinks accordingly. This restraining effect of high confining stress matches existing numerical observations.

Li carried out CO₂ fracturing experiments on coal, shale, and tight sandstone samples, and clarified how bedding planes, natural fractures, and gravel alter fracture paths [11]. The simulated hydraulic fractures in this paper deflect and branch along weak planes, which reproduces the fracture-rock heterogeneity interaction observed in room-temperature tests from Ref. [11]. His numerical analysis also proves that horizontal stress differences limit vertical fracture growth, reaching the same conclusion as our multi-stress cases, which show that high confining stress restricts the formation of complex fracture networks.

Previous studies have reported similar qualitative trends for the effects of injection pressure, matrix permeability, and in situ stress on fracture development. The results obtained in this study are generally consistent with these published observations and numerical findings. This agreement suggests that the present thermo–hydro–mechanical–damage model can capture the main trends in stress redistribution, deformation, and damage evolution during shale hydraulic fracturing, which supports its use for the comparative simulations carried out here. It should be noted that the comparison is performed using post-processed data from the published literature, since the original raw experimental dataset is unavailable.

To further quantitatively assess the model performance, we carried out a semi-quantitative cross-comparison with the numerical results reported by Li [11]. For this purpose, a normalized fracture-area factor is introduced herein.

The fracture-area factor F_f is defined as $F_f = \frac{A_{fracture}}{A_{domain}}$, where $A_{fracture}$ is the area of high-damage fractured zones, and A_{domain} denotes the total area of the computational domain.

Note that the computational domain size adopted in this work is different from that in Li [11]. Therefore, this normalized factor F_f , instead of the absolute fracture area, is employed for fair comparison to eliminate the influence of domain dimension differences.

Using this fracture-area factor F_f , the comparison was conducted under varying temperature conditions. Within the temperature range of 303.15–473.15 K, the simulated F_f from the present model exhibited a consistent trend with the reference results, as illustrated in Figure 8. Small deviations were observed, yielding an average relative error of 2.06% and a maximum relative error of 5.18%. Moreover, the deviations gradually became stable in the high-temperature interval. This indicated that the proposed model could reasonably capture the temperature-dependent evolution of fracture development, demonstrating the reliability of the established thermo–hydro–mechanical–damage model.

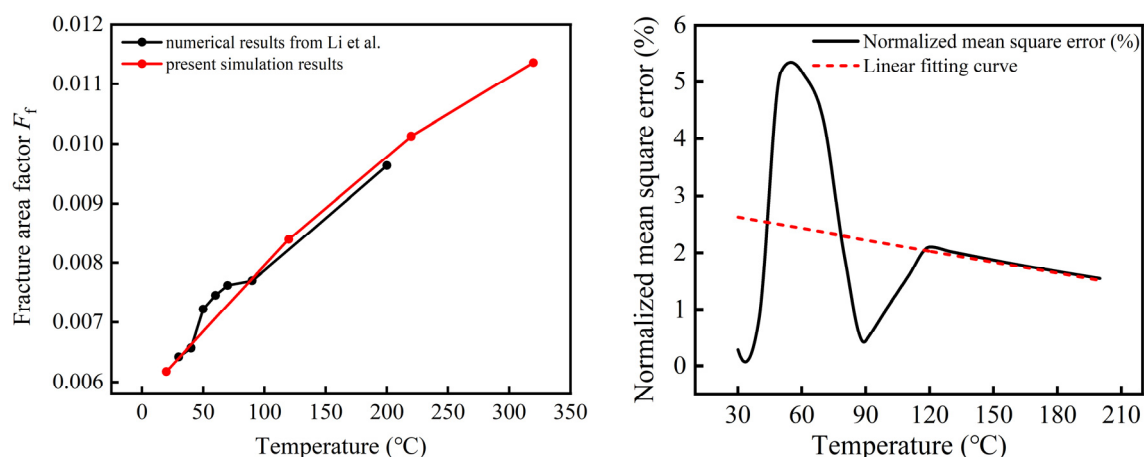


Figure 8. Comparison and error analysis of fracture-area factor between present simulation results and reference numerical results reproduced from Li et al. [11].

4.3. Effect of Different Temperatures on Fracture Propagation Under Hydraulic–Thermal Recovery Coupling

4.3.1. Effect of Water Temperature on Fracture Propagation

Numerical simulations were carried out with injection water heated to 393 K, 493 K, and 593 K, and the multifield contour results are illustrated in Figure 9. Based on conventional hydraulic fracturing methods, numerical simulations of fracture propagation were performed under fixed boundary conditions (confining pressure of 32 MPa, initial permeability of $1 \times 10^{-20} \text{ m}^2$, in situ stress of 10 MPa, and formation temperature of 373 K). Three injection water temperatures of 393 K, 493 K, and 593 K were adopted for comparative analysis, and the corresponding multifield contour results are presented in Figure 9.

The fracture morphology results in Figure 9a–c demonstrate a non-monotonic response of fracture propagation to the prescribed injection-water temperature. Compared with the 393 K case, fracture development is more pronounced at 493 K, whereas a further increase in the injection temperature to 593 K does not lead to a corresponding enhancement of fracture propagation. This result indicates that, under the coupled conditions considered in the present model, increasing the injection-water temperature does not necessarily result in a monotonic increase in fracture development. The enhanced fracture propagation at 493 K is associated with the coupled effects of the thermal disturbance on the stress, seepage, and damage fields predicted by the present thermo–hydro–mechanical model.

Previous experimental and numerical studies have shown that elevated temperature can alter the pore structure, thermophysical properties, and mechanical behavior of shale and may promote thermally induced damage and microcrack development [16,17]. How-

ever, these thermal responses depend strongly on the mineral composition, temperature, heating duration, and heating conditions. The temperature contours in Figure 9d–f further show that the prescribed injection-water temperature does not represent the temperature throughout the shale formation. Owing to heat exchange between the injected fluid and the surrounding shale, the thermal disturbance attenuates away from the injection region, and the simulated formation temperature is approximately 375–410 K under the investigated conditions. Therefore, the reduced fracture propagation predicted for the 593 K injection case cannot be directly attributed to clay dehydration or recrystallization based on the present numerical results. The current thermo–hydro–mechanical damage model does not explicitly incorporate mineral dehydration, recrystallization, or temperature-induced mineral phase transformations. Consequently, the observed non-monotonic response should be interpreted as a numerical prediction within the assumptions of the present coupled model. Further mineralogical characterization and high-temperature experiments are required to identify the underlying mineral-scale mechanisms.

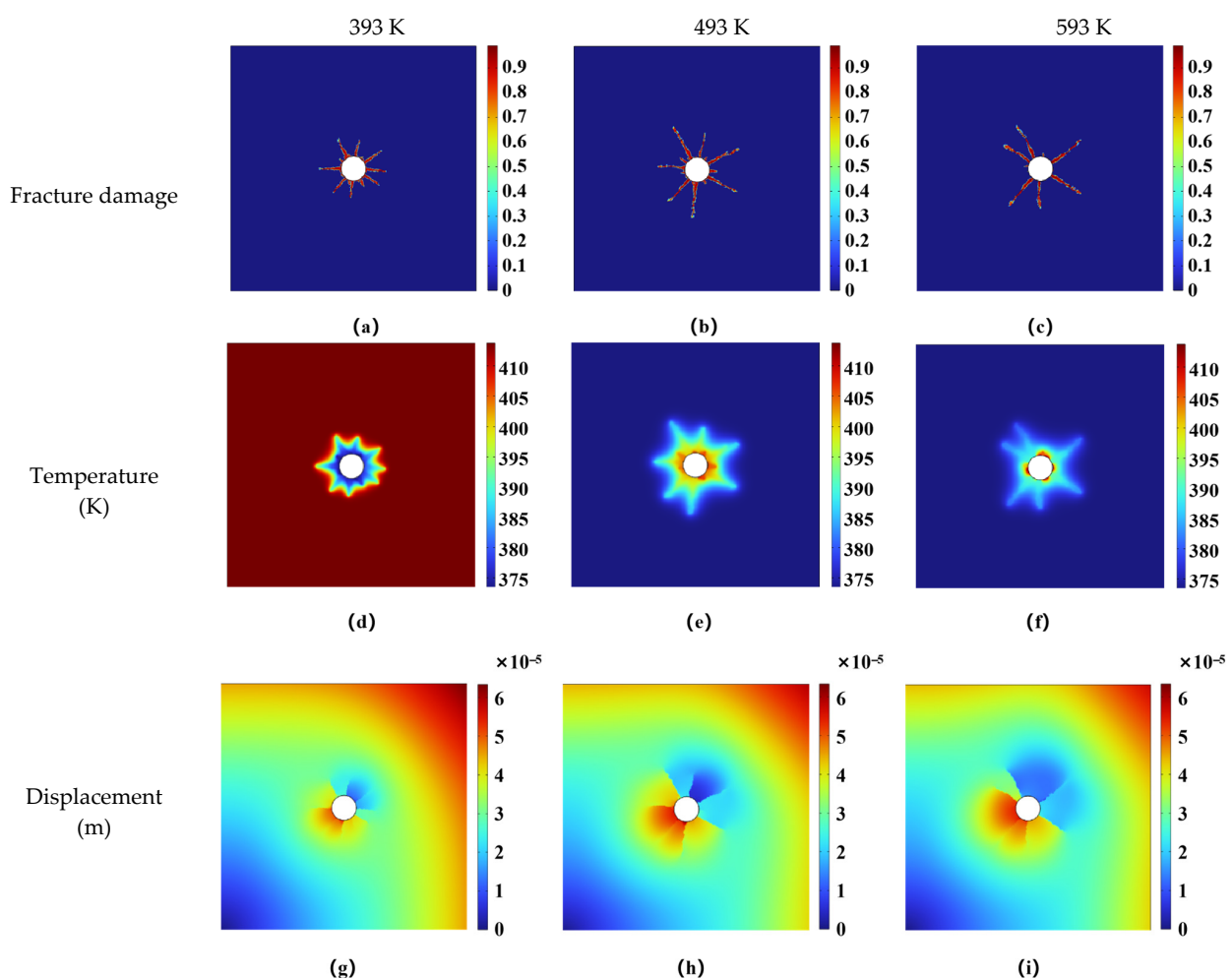


Figure 9. Contour plots of fracture damage, temperature field, and displacement under injection temperatures of 393 K, 493 K, and 593 K.

The displacement contours in Figure 9g–i, together with the polar coordinate displacement distribution data, reveal distinct near-well deformation differences across different temperature groups. The maximum near-well displacement occurs at 493 K, while the displacement magnitudes at 393 K and 593 K are relatively low and comparable. In summary, within the investigated numerical conditions, the 493 K injection case produces more pronounced fracture propagation and near-well deformation than the 393 K and 593 K cases.

This non-monotonic response indicates that increasing the prescribed injection-water temperature does not necessarily lead to a proportional enhancement of fracture development in the present coupled model.

As shown in Figure 9g–i, there are still significant variations in displacement around the injection hole. This assertion is further substantiated by the polar coordinate displacement diagram of the injection hole in Figure 10. The data in Figure 10c show that the wellbore displacement is slightly larger at 293 K than at 573 K, and the displacement values of these two temperature groups are relatively low and close to each other. However, Figure 10a,b show that displacement at the injection and pressure holes at 473 K is greater than at the other two temperatures. These results are consistent with the fracture patterns shown in Figure 9, indicating that the 493 K case produces the largest near-well deformation among the three investigated injection-temperature conditions. However, the non-monotonic temperature dependence observed in the present simulations should be interpreted within the assumptions and applicable range of the current coupled model.

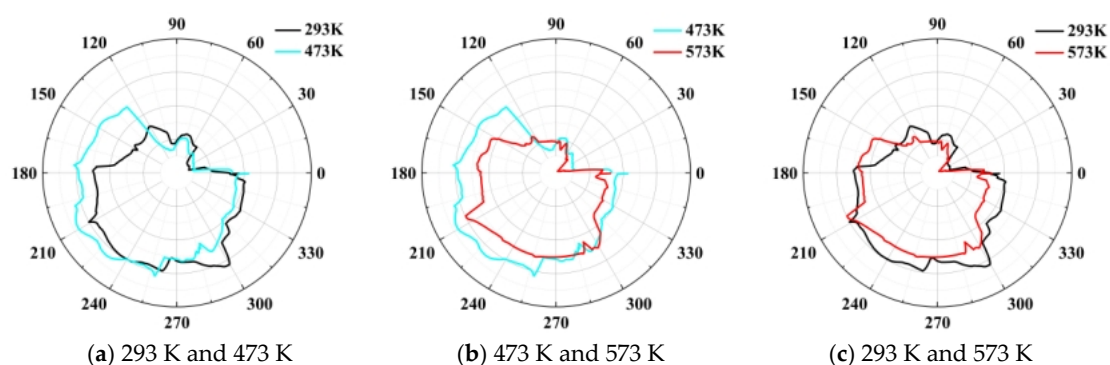


Figure 10. Polar coordinate diagrams of displacement around the injection well for comparison of different water temperatures.

Figure 11 shows that the average displacement through the injection hole indicates that fracture propagation is most effectively promoted when the water temperature reaches approximately 450 K. This highlights the limitations of using heated water alone to accelerate fracture growth. This scenario corresponds to conditions in which the shale undergoes no preheating treatment and the water is heated simultaneously during pressurization.

The seepage velocity at a point near the injection well is observed to gradually increase with rising water temperature. The maximum flow velocity was observed at 493 K, out of all the temperatures that were tested. If the temperature was increased beyond this point, the flow velocity decreased. At the beginning of the temperature rise, shale gas is mostly found adsorbed on the surface of organic matter (ignoring the effect of fracture propagation on flow velocity). As the temperature rises further, the pore fluid expands and partially vaporizes, raising pore pressure and disrupting the adsorption equilibrium. The desorption of methane into free gas is promoted by this. The desorbed gas is known to increase gas-phase saturation within the pores, forming continuous flow pathways and enhancing effective permeability. Furthermore, the viscosity of the pore fluids is significantly reduced by rising temperatures, thereby improving their mobility. However, as temperatures continue to rise, non-uniform thermal stresses are induced due to the differing thermal expansion coefficients of shale minerals. A deterioration in shale permeability can be caused by microfracture closure or pore compression. The peak shale flow rate is typically observed to occur within the 423–473 K range. Beyond this threshold, permeability degradation dominates and flow rates decline. Different time points within the same temperature range were analyzed, revealing that the permeability rate initially increases with time, but then begins to level off after 35 s. The acceleration of permeability is primarily driven by fracture

propagation, meaning that faster initial fracture growth results in higher permeability rates. However, after 30 s, the process of breaking down the fractures slows down, which delays the increase in permeability.

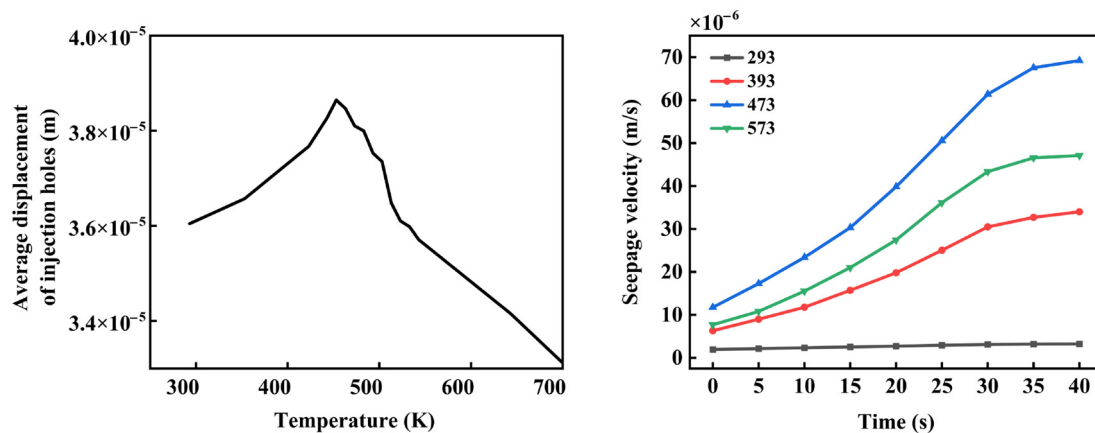


Figure 11. Displacement and seepage velocity of the injection hole.

4.3.2. Effect of Heating Pretreatment on Fracture Propagation

Conventional hydraulic fracturing conditions were built upon, with water temperature set at 293 K, water pressure at 32 MPa, initial permeability at $1 \times 10^{-20} \text{ m}^2$, and in situ stress at 10 MPa. This was done to model fracture propagation via simulations. Then, numerical simulations were performed with preheated shale temperatures of 373 K, 473 K, 573 K, 673 K, 773 K, and 873 K. In the simulations, preheating was only applied to the shale, with no additional heating occurring during fracturing. As shown in Figure 12, the simulated damage generally becomes more extensive as the preheating temperature increases from 373 K to 673 K, and the largest damage extent among the investigated cases is obtained at 673 K. Further increasing the preheating temperature to 773 K and 873 K, however, does not lead to a corresponding increase in fracture propagation, indicating a non-monotonic relationship between preheating temperature and the resulting damage pattern. In the present model, temperature affects damage through thermal deformation and the associated redistribution of the stress field. The resulting stress state is subsequently evaluated by the tensile and shear failure criteria; therefore, an increase in the prescribed preheating temperature does not necessarily produce a proportional increase in fracture damage.

It should be noted that the present model does not explicitly account for mineral dehydration, recrystallization, or temperature-induced mineral phase transformations. Therefore, the reduction in simulated fracture propagation above 673 K cannot be directly attributed to a specific mineralogical mechanism based on the present numerical results. In this study, the observed non-monotonic damage response is interpreted primarily from the thermo-mechanical response represented in the model. Within 373–673 K, increasing temperature elevates thermal stress magnitudes and drives damage expansion. Above 673 K, stiffness degradation and stress relaxation of damaged elements redistribute local stress and restrict further damage growth. Temperature changes induce thermal deformation and stress redistribution, and thereby modify the stress state governing tensile and shear damage. Accordingly, under the set of simulation conditions adopted in this work, 673 K is identified only as the temperature producing the largest simulated damage extent among the investigated preheating cases, rather than a mineralogical transition temperature or a universally optimal temperature.

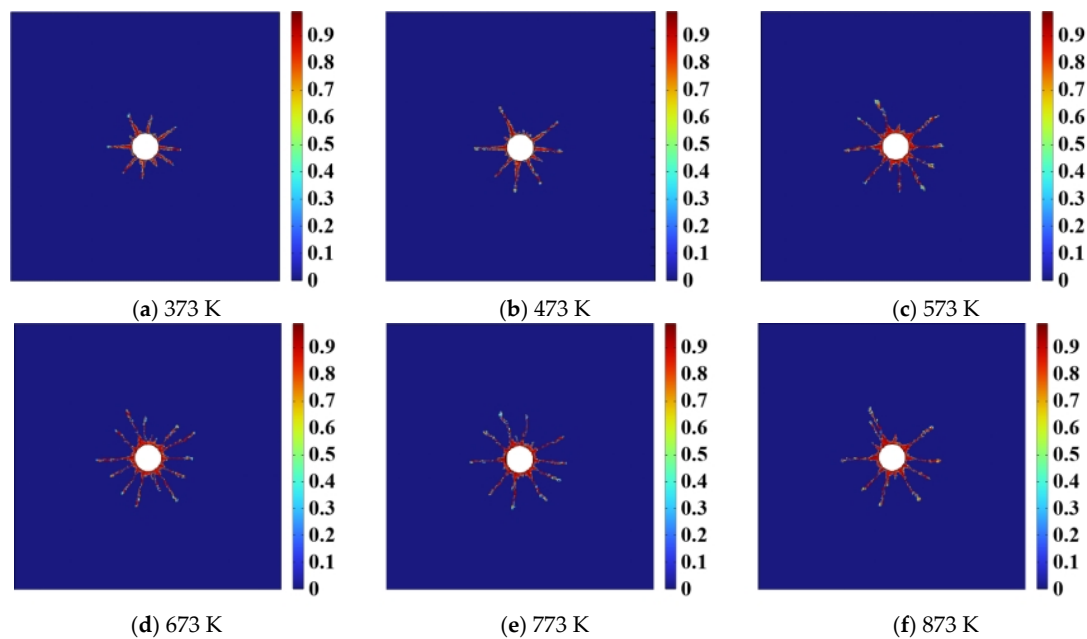


Figure 12. Contour of preheating damage under preheating treatments at different temperatures.

As Figure 13 shows, the displacement diagram of the injection hole indicates that the minimum and maximum displacements are higher after preheating treatment than after post-heating. The same is true of the peak temperature. Superior fracture propagation effects are achieved when preheating shale as opposed to heating during the pressurization process. The diagram in Figure 13 shows that the speed of seepage goes up and down with temperature. This is the same as in Figure 11. At any given temperature, seepage velocity is known to increase within a certain range, but decrease once the threshold temperature is exceeded. Nevertheless, the maximum temperature attained during the preliminary heating stage is considerably higher than that achieved during the final heating stage. In thermal-assisted shale gas extraction, preheating has been shown to be more effective than heating during fracturing. The main reason for this is that preheating can control rock properties better, spread heat more evenly, and reduce the adverse effects of different fields. This enables heat to diffuse uniformly into the deeper shale layers. Localized stress concentration is reduced by uniform thermal expansion, which minimizes microfracture closure. In contrast, insufficient degradation of mechanical properties is caused by in-process heating. Limited enhancement of brittleness is the result of short-term heating failing to adequately disrupt rock cementation structures. The fracture morphology is predominantly characterized by single fractures, and the cooling effect of the fracturing fluid counteracts the localized heating, resulting in unstable mechanical responses of the rock. The greatest increases in both fracture propagation rates and permeability rates are seen with post-heating treatment at the same temperature.

4.3.3. Effect of Temperature Duration

The setting of the confining pressure, permeability and pressure at 32 MPa is the purpose of this subsection. The shale was preheated to 673 K, and numerical simulations of fracture propagation were conducted. In these simulations, the water was heated continuously to temperatures of 393 K, 493 K, 593 K, and 693 K during fracturing. The diagram in Figure 14 shows the relationship between seepage velocity and temperature when heating is continuous. It was seen that the speed of the liquid getting through the rock was fastest when the heat kept the rock at about 540 K. As shown in Figure 15, the effect of encouraging fracture growth becomes stronger in a certain order when different

treatments are used together. These treatments include post-heating, preheating, and continuous heating.

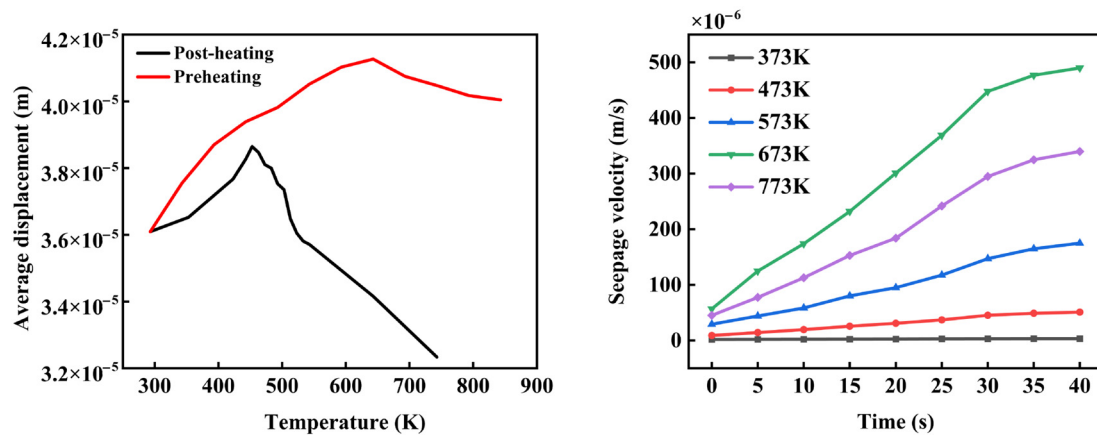


Figure 13. Displacement and seepage velocity of the injection hole.

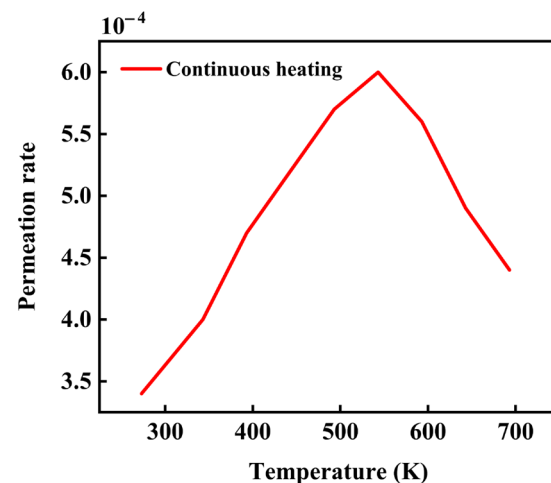


Figure 14. Seepage velocity–temperature diagram of continuous heating.

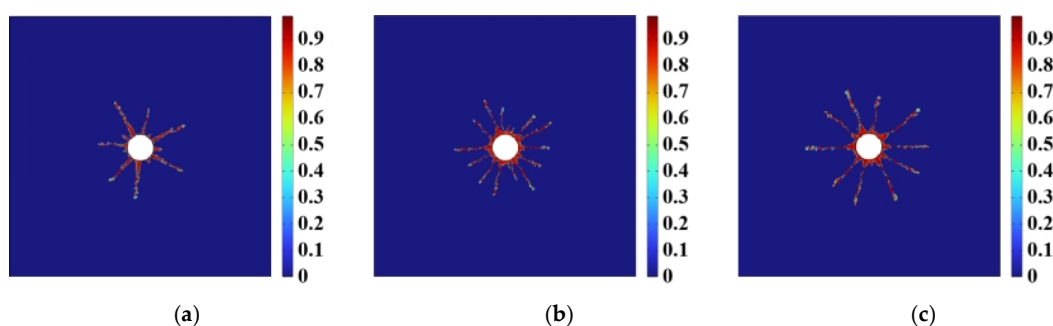


Figure 15. Comparison contours of fracture damage under three heating treatments: (a) post-heating; (b) preheating; and (c) continuous heating.

Furthermore, it has been confirmed by the polar displacement diagram of the injection hole in Figure 16 that continuous heating is more effective at promoting fracture propagation than the other two heating methods. The thermal stress field's stability is maintained by continuous post-heating, which is based on the preheating treatment. At the same time, the primary fracture is driven to propagate in the direction of the maximum principal stress, while its closure is prevented. Under sustained heating, the increased volume of desorption gas, combined with fluid thermal expansion, elevates pore pressure. Natural fractures are

activated by local pressure pulses, or secondary branch fractures are induced. As a result, heat is transferred via convection to the fracture tip, which softens the rock and reduces its tensile strength. This makes it easier for the fracture to spread.

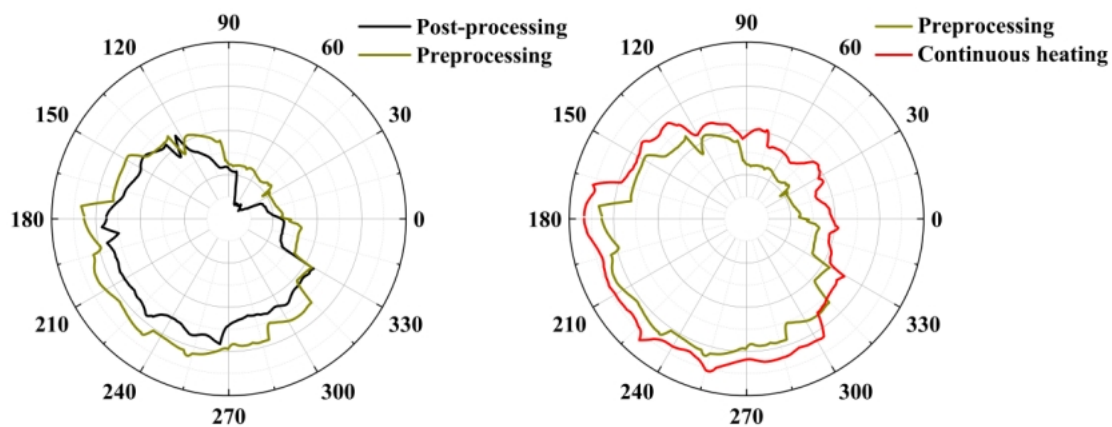


Figure 16. Polar coordinate displacement diagram of the injection hole.

5. Productivity Analysis of Shale Gas Under Temperature–Hydraulic Coupling

5.1. Production Capacity Under Conventional Water Pressure

The model parameters were set to the following standard hydraulic conditions: a water pressure of 32 MPa, a water temperature of 293 K, an initial permeability of $1 \times 10^{-20} \text{ m}^2$, a stress of 10 MPa, and a geothermal temperature of 373 K. The evolution of porosity and permeability during fracture propagation was simulated. Figure 17 shows that changes in porosity and permeability are more pronounced than the propagation of the fracture itself during fracturing. This is because, as the main fracture propagates, natural microfractures and pores are rapidly connected to form a flow network. Increases in both permeability and porosity are triggered by accelerated fracture growth.

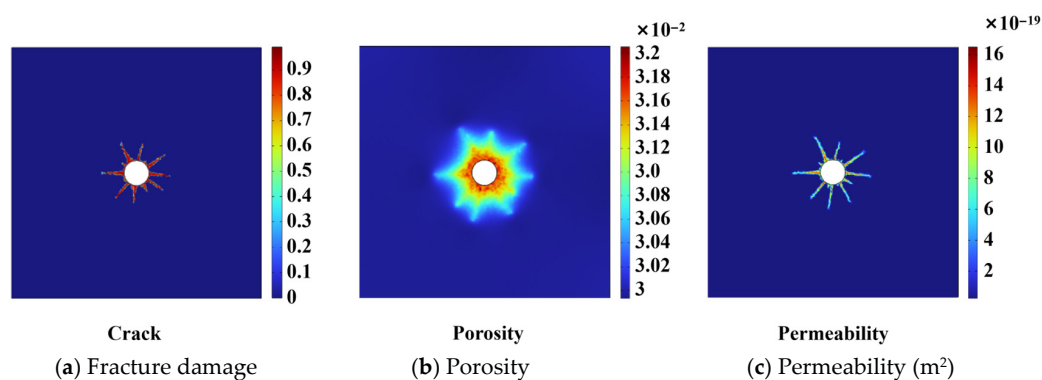


Figure 17. Contour distribution of fracture damage, porosity, and permeability by conventional water pressure stimulation.

The production curves of shale gas under conventional hydraulic fracturing are displayed in Figure 18. The average matrix porosity of fractured shale is calculated to be 0.03014, and the average permeability is $3.98 \times 10^{-20} \text{ m}^2$. The gas production rate decreases continuously with time, and an obvious inflection point appears at 1000 days, after which the production rate tends to be stable. In the early production stage, a large amount of shale gas is extracted, which reduces the pore pressure in the shale matrix. The pressure difference between the reservoir and atmosphere accordingly shrinks, resulting in a sus-

tained decline in gas production rate. After 6000 days of production, the cumulative gas output reaches 50.6839 million cubic meters.

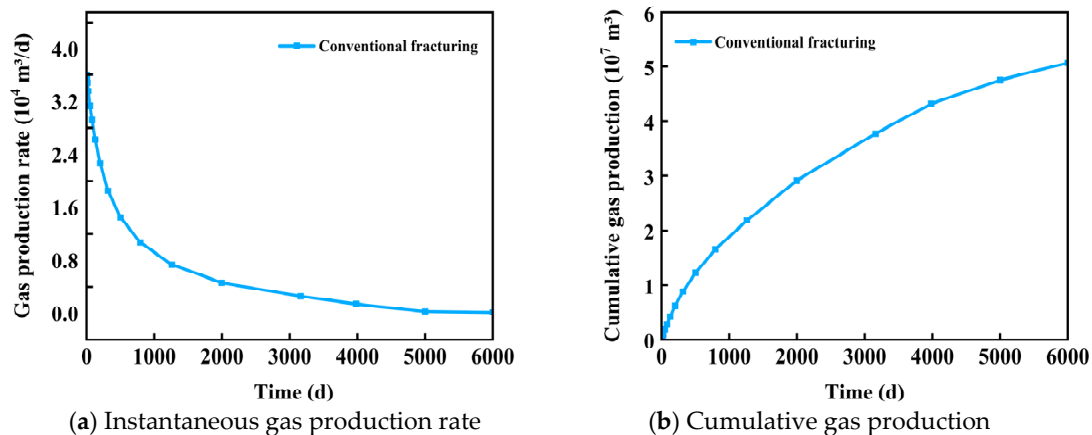


Figure 18. Gas production of conventional shale gas extraction.

5.2. Analysis of Shale Gas Production Capacity Under Hydraulic–Thermal Recovery Coupling

5.2.1. Production Capacity Under Preheating Treatment

A preheating treatment at a temperature of 673 K was used to simulate the impact of porosity and permeability on fracture propagation. This was based on conventional hydraulic pressure parameters. As shown in Figure 19, changes in porosity and permeability are primarily influenced by the extent of fracture propagation. Furthermore, as previously observed, heat-treated shale exhibits more intense fracture propagation, resulting in increased porosity and permeability after treatment.

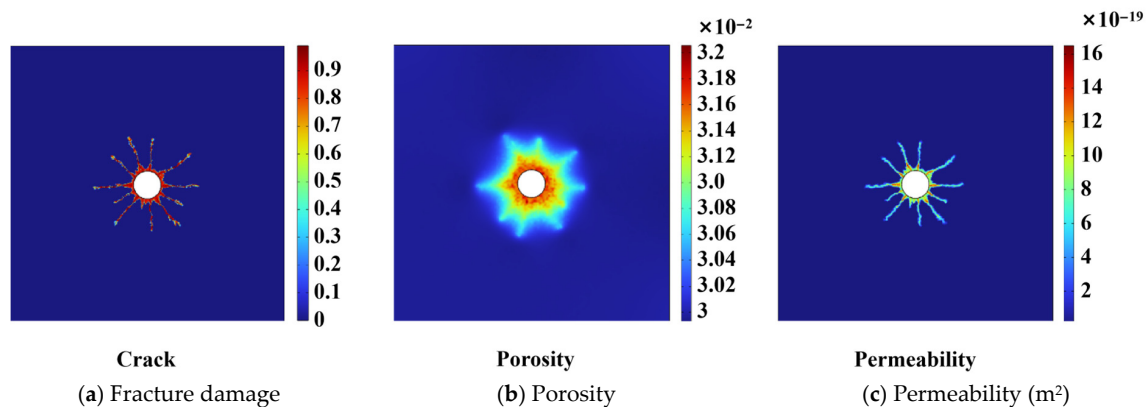


Figure 19. Contour distributions of fracture damage, porosity, and permeability under preheating stimulation.

A comparative analysis of shale gas production performance under preheating extraction and conventional extraction is presented in Figure 20 on the basis of measurement and calculation results. After fracturing, the average porosity of the shale matrix is 0.03019 , and the average permeability is $5.26 \times 10^{-20} \text{ m}^2$. The gas production rate curve exhibits an inflection point at approximately 1000 days. Compared with conventional mining, the preheating extraction method shows a much milder production decline. The two curves share similar variation trends, and the gas production rates of both schemes gradually stabilize after 6000 days of exploitation. After 6000 days, the cumulative gas production of the preheating scheme reaches 73.2167 million cubic meters, which is nearly 45% higher than that of the conventional scheme. It is demonstrated that surface preheating treatment can

remarkably improve shale gas recovery efficiency and deliver prominent enhancement in total gas output, making it a promising technical measure for field shale gas development.

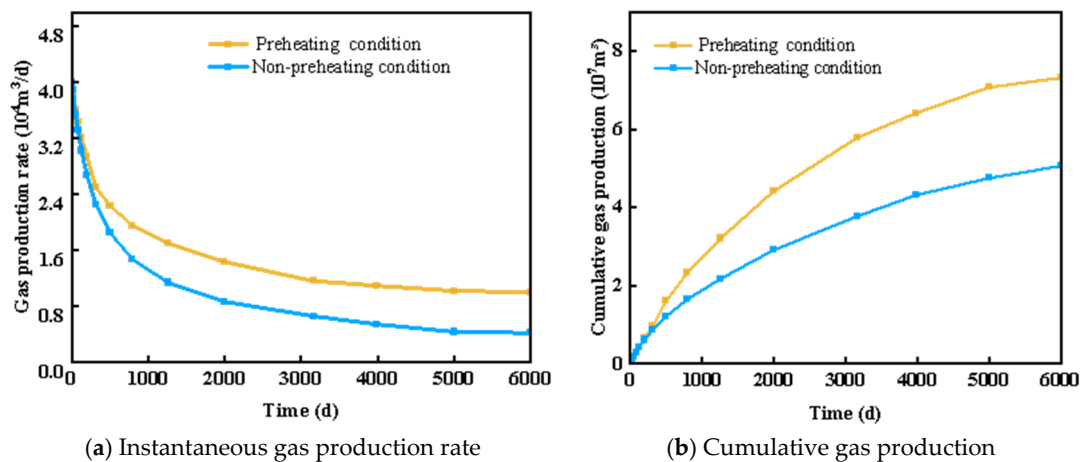


Figure 20. Comparative analysis of preheated mining and conventional mining.

5.2.2. Production Capacity Under Continuous Heating After Pretreatment

The equivalent confining pressure and permeability are established in this subsection. The porosity and permeability values during fracture propagation were determined by conducting simulations. These were conducted under conditions of preheating shale to 673 K, continuous heating to maintain the water temperature at 540 K, and a pressure of 32 MPa. The results are shown in Figure 21. Compared to conventional hydraulic pressure and pretreated porosity and permeability, there was an increase in both porosity and permeability under multi-factor conditions.

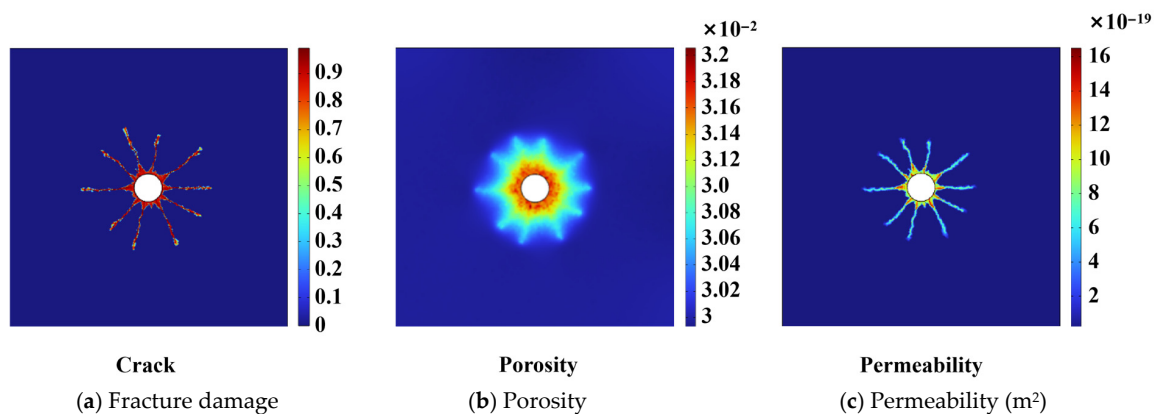


Figure 21. Contour distributions of fracture damage, porosity, and permeability under continuous heating stimulation after pretreatment.

A comparative analysis of preheated and conventional extraction methods is presented in Figure 22, with the analysis based on measurements and calculations. The average porosity of the fractured shale matrix was found to be 0.030201 under these conditions, with an average equivalent permeability of $6.20 \times 10^{-20} \text{ m}^2$. As shown in Table 3, porosity and permeability were improved by both preheating and continuous heating in comparison with conventional fracturing. A comparative analysis of continuous heating extraction and conventional extraction is presented in Figure 22. It is clear that the gas production rate decay is less pronounced for continuous heating than for other methods. In addition, the cumulative gas production reaches 80.403 million cubic meters after 6000 days, which

is 60.6% higher than that under conventional mining conditions. The simulation results indicate that thermal stimulation can significantly enhance shale gas recovery efficiency, and staged heating is the optimal treatment scheme. This phenomenon is mainly attributed to the thermal effect of continuous heating: it optimizes reservoir physical properties and promotes smooth gas seepage while cutting energy loss. Preheating improves reservoir permeability, whereas continuous heating elevates thermal convection efficiency and stabilizes reservoir temperature fields. Stable temperature avoids the re-adsorption of desorbed gas caused by temperature fluctuations, which ultimately optimizes fracture propagation efficiency and lifts shale gas output.

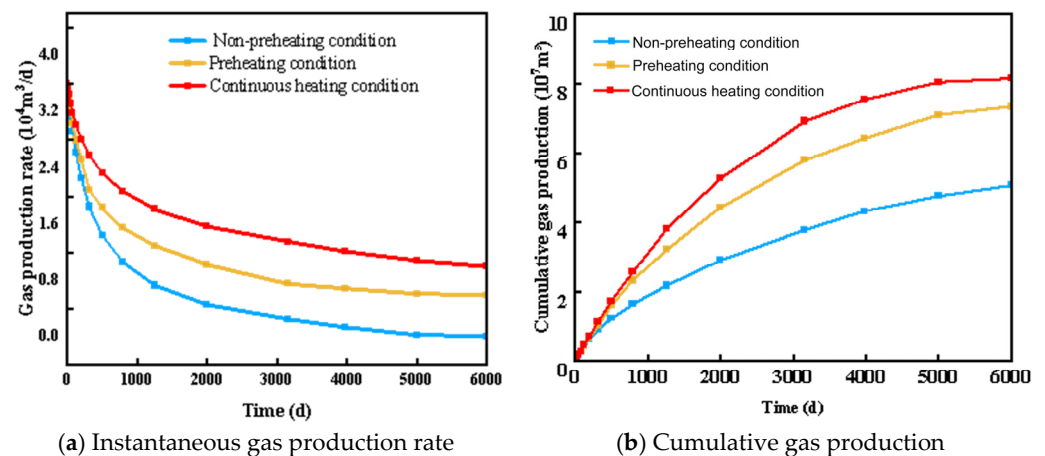


Figure 22. Comparative analysis of continuous heating mining and conventional mining.

Table 3. Variation table of porosity and permeability.

Conditions	Average Porosity	Equivalent Permeability
Initial	0.03	$1 \times 10^{-20} \text{ m}^2$
Conventional fracturing	0.03014	$3.98 \times 10^{-20} \text{ m}^2$
Preheating	0.030185	$5.26 \times 10^{-20} \text{ m}^2$
Continuous heating	0.030201	$1.87 \times 10^{-19} \text{ m}^2$

6. Conclusions

In this study, a THM coupling model was developed to simulate fracture propagation and shale gas production capacity under varying reservoir conditions. Three stimulation scenarios were systematically analyzed—preheating-assisted fracturing, post-heating fracturing, and continuous heating stimulation—with a focus on fracture propagation patterns and shale gas output evolution. The key conclusions are as follows:

- (1) The effects of different initial conditions on fracture propagation were analyzed. The initial variables include injection pressure, initial permeability, and in situ stress. As the injection pressure increases, the rate of fracture propagation accelerates, and the number of fractures grows. When the initial permeability is lower, fracture propagation becomes faster, and the fractures become wider. However, the propagation of fractures is significantly hindered in shale matrices with high in situ stress.
- (2) The influence of temperature on fracture propagation was analyzed by comparing different thermal stimulation-assisted fracturing methods with conventional fracturing, including conventional fracturing, preheated fracturing, and continuous heating. Preheated fracturing was found to significantly accelerate fracture propagation compared to conventional fracturing, with optimal results achieved at a preheating temperature of around 673 K. Moreover, it was found that fracture propagation intensified

further during continuous heating after preheating, with optimal fracture propagation performance observed when the continuous heating temperature was maintained at around 540 K.

- (3) The effects of heat treatment on porosity, permeability, and shale production capacity were also investigated. The consequences of fractures gradually increase under conventional fracturing, preheated fracturing, and ongoing heating step by step. The porosity and permeability of shale are also increased by all these extraction measures. All three shale-gas production scenarios exhibit declining production rates over time. However, the production rate under preheated fracturing increases by 44.5% after 6000 days compared to conventional fracturing, while a 60.6% higher production rate is achieved under continuous heating. These results show that the production rate of shale gas can be enhanced by thermal stimulation. In addition, the best results are observed when the shale wells are continuously heated again after preheating treatment.

The present THM-damage model is mainly intended to interpret the coupled near-well response of shale during hydraulic and thermal stimulation. By combining fluid seepage, heat transfer, mechanical deformation, and tensile–shear damage evolution, the model can describe how changes in pressure and temperature alter the local stress state and subsequently affect rock damage and fracture development. Therefore, the model is suitable for comparing the relative responses of different heating and fracturing strategies and for identifying the main coupling mechanisms involved. However, the present study still has several limitations. The model represents a localized reservoir region using an equivalent-continuum description and does not explicitly include reservoir-scale heterogeneity, natural fracture networks, mineral-scale thermal reactions, or large-scale fault responses. Future work should extend the present framework toward three-dimensional and multiscale reservoir modeling and incorporate more realistic geological structures and advanced fracture approaches, such as phase-field methods, to improve its applicability to field-scale conditions.

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Abbreviation

The following abbreviation is used in this manuscript:

THM thermo–hydro–mechanical

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