

Article

Analysis of the Wellbore Temperature Field and Influencing Factors During Shale Gas Fracturing Injection

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Abstract

During shale gas fracturing operations, large volumes of low-temperature fracturing fluid carrying proppant are injected into the high-temperature wellbore, resulting in intense transient heat exchange between the fracturing fluid, the wellbore structure and the surrounding formation. To predict the wellbore temperature field during fracturing, this paper treats proppant-laden slurry as a homogeneous fluid and considers the effects of temperature and proppant concentration on the fluid's equivalent thermal properties. Based on the energy conservation equation, a transient wellbore heat-transfer model was developed by coupling axial convective heat transfer within the casing, radial heat transfer through the multi-layer wellbore media, and transient thermal conduction in the formation. The radial heat-transfer process was solved using the equivalent thermal resistance method, and the model was validated through finite element simulation. The computational results indicate that under base operating conditions—with an injection temperature of 20 °C, an injection flow rate of 12 m³/min, and an injection duration of 90 min—the bottomhole temperature rapidly drops to the 20–25 °C range, subsequently entering a low-temperature quasi-steady-state phase; following pump shutdown, the bottomhole temperature gradually recovers, reaching approximately 40 °C 120 min after shutdown. The computational results of this theoretical model regarding the variation pattern of the bottomhole temperature, the vertical temperature distribution, and the radial temperature response show good agreement with the finite element simulation results. Parameter analysis indicates that increasing the injection rate from 8 to 16 m³/min shortens the cooling time to below 25 °C from approximately 13–14 min to 8–9 min, while the stable bottomhole temperature only decreases slightly from 23.0 to 21.3 °C. Increasing proppant concentration from 6% to 15% has a weak influence on temperature evolution. In contrast, injection temperature is the dominant factor: when the injection temperature is 5, 15, and 30 °C, the stable bottomhole temperatures are approximately 8, 17, and 31 °C, respectively. The sensitivity analysis indicates that injection temperature is the dominant factor affecting the wellbore temperature field, followed by injection rate, while proppant concentration is only weakly sensitive. The results provide theoretical support for wellbore temperature prediction and fracturing parameter optimization.



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1. Introduction

Global energy structure is accelerating its transition to low carbonization. As a clean, efficient and abundant unconventional oil and gas resource, shale gas has become a core energy source for ensuring energy security and achieving a smooth transition. Shale gas geological resources are among the world's leading ones, with the Sichuan Basin and Tarim Basin being the core areas for exploration and development. The main reservoir of the southern Sichuan shale gas block has a burial depth of 6000~7000 m, a vertical depth of 4100~4300 m, and a formation temperature of 136~156 °C, with the bottomhole circulation temperature of some ultra-deep wells exceeding 162 °C; the reservoir burial depth of the Kuqa Depression in the Tarim Basin ranges from 4000~8000 m, and the temperature reaches 180~200 °C [1,2]. The ultra-deep, extreme high temperature and high pressure geological environment makes the wellbore service conditions extremely harsh, becoming a key bottleneck restricting the large-scale and efficient development of deep shale gas in this region.

Hydraulic fracturing acts as the core technology for the reservoir stimulation of deep shale gas reservoirs. It connects natural fractures and reservoir spaces through artificially created fractures and effectively improves single-well production capacity and ultimate recovery factor. Large volumes of low-temperature fracturing fluid ranging from 10 to 30 °C are continuously injected into high-temperature wellbores during construction operations, which creates a temperature difference exceeding 100 °C between wellbores and surrounding formations. Such remarkable temperature difference triggers intense unsteady transient heat-transfer behavior, alters fluid temperature distribution inside wellbores and produces obvious temperature gradients within casings, cement sheaths and near-well formations. This phenomenon further induces various hidden dangers including casing thermal deformation, cement sheath sealing failure and deteriorated rheological properties of fracturing fluid. Under extreme operating conditions, this can even lead to serious engineering incidents such as casing damage and increased annular pressure, thereby reducing the success rate of fracturing operations and the effectiveness of reservoir enhancement. Accurately elucidating the evolution of transient temperature fields within the wellbore and formation throughout the entire fracturing process, and evaluating the impact of key operational parameters, hold significant practical engineering value for the safe and efficient development of deep shale gas resources.

The evolution of the wellbore temperature field is a complex multi-physics coupling problem involving fluid flow, convective heat transfer, formation heat conduction, and various heat generation processes. Fluid flow behavior and internal heat source effects dominate the overall temperature distribution patterns. Piroozian et al. [3] demonstrated that fluid viscosity and flow conditions jointly determine the energy dissipation patterns within the wellbore. Relevant experimental results indicate that, under turbulent conditions, a moderate increase in fluid viscosity can improve cutting transport efficiency by approximately 8%, providing reliable experimental evidence for the optimization of fracturing fluid formulations. Gong et al. [4] employed numerical simulation methods to analyses the coupled effects of viscous dissipation and the Joule–Thomson effect. Their research confirmed that in deep, high-temperature wells, the heat generated by viscous dissipation cannot be ignored and may even become a key factor influencing bottomhole temperature. Wang et al. [5] investigated the regulatory role of temperature–pressure coupling on fluid rheological properties. Changes in rheological properties, in turn, interfere with heat-transfer processes within the wellbore, forming a stable positive feedback relationship, which poses difficulties for accurate temperature field prediction.

Continuous in-depth understanding of wellbore heat-transfer mechanisms promotes abundant research on wellbore–formation coupled heat-transfer models among domestic

and overseas scholars. Current research achievements realize the technical development from steady state analysis to transient state analysis and from single-field research to multi-field collaborative research. Liu et al. [6] pioneered in establishing a wellbore temperature prediction model suitable for horizontal wells while taking reservoir stress sensitivity of shale formations into consideration. This model clarifies the coupling relation between stress-sensitive responses and temperature field evolution and provides innovative methods for the precise prediction of thermal behaviors inside shale gas horizontal wells. Li et al. [7] carried out transient wellbore temperature modeling and optimization research targeting shale oil horizontal wells. They took full account of variable physical properties of fracturing fluid changing with temperature and pressure as well as multi-heat-source effects, which laid solid theoretical foundations for dynamic temperature field prediction and fracturing process optimization in horizontal wells. Li et al. [8] launched temperature–pressure coupling research focusing on ultra-deep wells. The results demonstrate that synergistic effects of temperature and pressure significantly change mechanical response characteristics of tubular strings, which should not be ignored during tubular integrity assessment of ultra-deep wells. Zheng et al. [9] completed multi-factor coupling prediction analysis for wellbore temperature and pressure fields in high temperature and high-pressure gas wells and quantified the influence degree of different factors on dynamic variation rules of subsurface temperature and pressure.

The development of modern coupled numerical models relies on fundamental theoretical achievements proposed by early researchers. In the 1960s, Ramey and Willhite [10] combined axial convective heat transfer of internal wellbore fluid with radial transient heat conduction of surrounding formations and build classic analytical models for fluid temperature distribution in injection wells, which laid the basic theoretical foundation of wellbore heat-transfer discipline. Edward et al. [11] put forward temperature distribution models for circulating fluid inside wellbores and define unsteady variation features of formation temperature fields affected by circulating fluid disturbance. Holmes and Swift [12] constructed rapid prediction models for mud circulation temperature and confirmed that convective heat transfer between annulus spaces and drill strings occupies the leading position in the whole wellbore heat-transfer system, offering reasonable simplification directions for subsequent model establishment. Kutasov and Eppelbaum [13] designed an integrated transient heat-transfer model covering drilling and cementing stages to achieve continuous synchronous temperature prediction in the whole construction process. Zheng et al. [14] applied CFD numerical simulation technology to reveal the three-dimensional heterogeneous distribution characteristics of internal wellbore temperature. Cao et al. [15] established temperature–pressure coupled models for CO₂ injection wells considering unique thermophysical properties of supercritical carbon dioxide. He et al. [16] constructed novel prediction models for steam temperature fields formed by downhole multi-thermal fluid generators. Yu et al. [17] developed monitoring equipment capable of withstanding high temperatures and pressures for the purpose of collecting dynamic load data from downhole strings. Emami-Meybodi et al. [18] established a two-dimensional transient heat-transfer model that accounts for partial wellbore penetration effects and derived a semi-analytical solution for the temperature distribution in the formation.

Current research findings indicate that, under complex operating conditions, traditional single-heat-source models are unable to meet the practical requirements for temperature prediction; consequently, integrated multi-heat-source modeling is gradually becoming the mainstream research direction. Chen et al. [19] developed the most comprehensive wellbore integrated heat-transfer model so far. This model simultaneously considers annulus flow field heterogeneity caused by drill string eccentricity, shear heat generated from drill string rotation and heat release during rock breaking processes driven

by drill bits. Statistical data show that rock breaking behaviors and drill string rotation contribute about 22 °C and 13 °C to annulus temperature separately, which fully validates the core value of multi-source coupling mechanisms in improving prediction accuracy. Nguyen et al. [20] built wellbore temperature calculation models containing mechanical friction heat sources and realized quantitative risk evaluation of wellbore structural stability. Li et al. [21] analyzed both viscous dissipation heat and friction-induced heat through field measured data. They pointed out that these two types of heat sources are primary reasons why circulating bottomhole temperature exceeds original formation temperature, and confirmed that horizontal section length and fluid specific heat capacity are core control parameters determining bottomhole temperature values. The transition from single-heat-source modeling to multi-heat-source coupled modeling represents an inevitable developing tendency in wellbore temperature field research. Recent studies have also highlighted the complexity of injection-induced responses in unconventional reservoirs. Bigdeli et al. [22] reviewed fracture-driven interactions (FDIs) in unconventional wells and summarized the mechanisms, monitoring tools, and mitigation concepts associated with inter-well interference during hydraulic fracturing, including pressure hits, fluid migration, cross-well communication, fracture reactivation, and parent–child well effects. Moubarak et al. [23] reviewed gas-injection EOR in shale reservoirs and discussed huff-and-puff gas injection, cyclic gas recovery, lean-gas injection, and CO₂-based EOR, emphasizing the roles of gas diffusion, pressure buildup, miscibility, fracture conductivity, and reservoir heterogeneity. These studies indicate that injection operations in unconventional reservoirs can induce complex coupled responses involving fluid flow, fractures, pressure evolution, and production behavior.

Although the above studies have improved the understanding of injection-induced responses and wellbore heat-transfer processes in unconventional reservoirs, the transient temperature response during shale gas fracturing still requires further investigation, especially when the effects of proppant-laden fluid properties and multilayer wellbore heat transfer are considered. In this study, proppant-laden slickwater is treated as an equivalent homogeneous fluid, and the effects of temperature and proppant concentration on its effective thermophysical properties are incorporated into the wellbore temperature field model. Based on the energy conservation equation, a transient heat-transfer model is established by coupling axial convective heat transport in the tubing with radial heat transfer through the tubing, annulus, casing, cement sheath, and formation. This paper employs the equivalent thermal resistance method and transient heat conduction theory to solve the model and validates the results through finite element simulation. In addition, the study analyses the effects of fluid injection rate, proppant concentration and injection temperature on bottomhole temperature and the temperature distribution within the wellbore. The findings provide a theoretical basis for predicting wellbore temperatures and optimizing fracturing parameters in shale gas wells.

2. Prediction Model and Variation Analysis of Effective Thermophysical Properties of Proppant-Laden Slickwater

Fracturing fluid is a critical working fluid in hydraulic fracturing operations, used to create and propagate fractures in rock formations, transport proppants, and cool the rock. Its physical properties directly influence fluid flow within the wellbore, friction pressure drop, convective heat transfer, and heat exchange between the wellbore and the surrounding rock. Slippery-water fracturing fluid consists primarily of clean water and a small amount of additives, such as friction reducers and well-cleaning agents. Owing to the relatively low additive concentrations, their effects on thermophysical properties such as density, specific heat capacity, and thermal conductivity are limited. Therefore,

in the temperature field analysis, the influence of these minor additives is neglected, and the slickwater base fluid is approximated as fresh water. The proppant-laden fluid is then regarded as a liquid–solid two-phase mixture consisting of the slickwater base fluid and proppant particles.

To meet the requirements of wellbore temperature field calculation during fracturing fluid injection, the proppant-laden slickwater is treated as an equivalent homogeneous fluid. Its thermophysical characteristics are described using the effective density, effective specific heat capacity, effective thermal conductivity, and effective viscosity, which provide the basic physical-property inputs for the subsequent wellbore temperature field calculation.

2.1. Equivalent Homogeneous-Fluid Assumption for Proppant-Laden Slickwater

Proppant-laden slickwater is mainly composed of a slickwater base fluid and proppant particles. The slickwater base fluid acts as the continuous phase, whereas the proppant particles are treated as the dispersed phase. In this study, the variation in the wellbore temperature field during fracturing fluid injection is investigated, with emphasis on the heat-transfer process between the fluid and the wellbore. Therefore, the proppant-laden slickwater is treated as an equivalent homogeneous fluid with effective physical properties. Based on the above analysis, the following assumptions are made:

- (1) The slickwater base fluid is mainly composed of fresh water; therefore, the effects of small amounts of additives on density, specific heat capacity, and thermal conductivity are neglected.
- (2) The proppant particles are assumed to be uniformly dispersed in the slickwater base fluid, while particle settling, particle collision, and sand-bed formation are not considered.
- (3) Local thermal equilibrium is assumed between the base fluid and the proppant particles; that is, they share the same mixture temperature.
- (4) The density, specific heat capacity, and thermal conductivity of the proppant are approximated as constants within the investigated temperature range.

In this study, quartz sand was selected as the base-case proppant. Other proppant types were not considered in the base-case calculation, but the proposed equivalent-property model can be applied to these proppants by replacing the corresponding thermophysical parameters.

It should be noted that the equivalent homogeneous-fluid assumption is an engineering simplification for high-rate slickwater fracturing. Under such conditions, strong turbulent mixing helps maintain proppant suspension and promotes heat exchange between the liquid phase and proppant particles. Therefore, the effective properties calculated in this study represent apparent bulk properties of a well-mixed proppant-laden slurry. However, under large temperature differences, high sand ratios, low-flow-rate stages, or extended shut-in conditions, local liquid–solid thermal non-equilibrium, particle settling, and concentration non-uniformity may occur. These effects are not explicitly resolved in Equations (3)–(10) and should be further investigated using two-phase heat-transfer or CFD–DEM models in future work.

Based on the equivalent homogeneous-mixture assumption and the classical mixture-property modeling framework, the effective physical properties of proppant-laden slickwater can be expressed as functions of temperature and sand concentration as follows:

$$\begin{cases} \rho_m = \rho_m(T, C_s) \\ c_{p,m} = c_{p,m}(T, C_s) \\ k_m = k_m(T, C_s) \\ \mu_m = \mu_m(T, C_s) \end{cases} \quad (1)$$

where ρ_m is the effective density of proppant-laden slickwater, kg/m^3 ; $c_{p,m}$ is the effective specific heat capacity, $\text{J}/(\text{kg}\cdot\text{K})$; k_m is the effective thermal conductivity, $\text{W}/(\text{m}\cdot\text{K})$; μ_m is the effective viscosity, $\text{mPa}\cdot\text{s}$; T is the temperature, $^{\circ}\text{C}$; and C_s is the proppant mass concentration, also referred to as the sand concentration, kg/m^3 .

In fracturing operations, the sand concentration, denoted as C_s , is defined as the mass of proppant added per unit volume of base fluid, with a unit of kg/m^3 . In field engineering practice, the sand ratio is often expressed as a percentage. In this study, the sand ratio, denoted as R_s , is defined as the volume fraction of proppant in the proppant-laden slurry, namely $R_s = 100\phi_s$, where ϕ_s is the proppant volume fraction. Therefore, before establishing the effective thermophysical property model, the sand concentration C_s should be converted into the proppant volume fraction ϕ_s . Therefore, before establishing the model, the sand concentration should first be converted into the proppant volume fraction. The proppant volume fraction can be expressed as:

$$\phi_s = \frac{C_s/\rho_s}{1 + C_s/\rho_s} \quad (2)$$

where ϕ_s is the proppant volume fraction, dimensionless; and ρ_s is the proppant density, kg/m^3 . According to Equation (2), the proppant volume fraction gradually increases with increasing sand concentration.

2.2. Effective Density Model for Proppant-Laden Fluid

Density is an important parameter affecting fluid inertia in the wellbore, hydrostatic pressure, and heat-carrying capacity per unit volume. Since proppant-laden slickwater consists of a slickwater base fluid and proppant particles, its effective density can be calculated using the classical volume-weighted mixture rule [24]:

$$\rho_m = (1 - \phi_s)\rho_w(T) + \phi_s\rho_s \quad (3)$$

where $\rho_w(T)$ is the density of water at temperature (T), kg/m^3 . According to Equation (3), a higher proppant volume fraction results in a higher effective density of the proppant-laden fluid. This is because the density of the proppant is significantly higher than that of water. As the sand concentration increases, the mass per unit volume of the proppant-laden fluid increases accordingly. At a given sand concentration, increasing temperature reduces the density of water, thereby slightly decreasing the effective density of the proppant-laden fluid.

Figure 1 shows the effective density distribution of the proppant-laden fluid under different temperature and sand concentration conditions. As shown in the figure, at a given temperature, the effective density of the proppant-laden fluid increases significantly with increasing sand concentration. When the temperature is 20°C , as the sand concentration increases from 0 to $600 \text{ kg}/\text{m}^3$, the effective density of the proppant-laden fluid increases from $998.2 \text{ kg}/\text{m}^3$ to $1303.1 \text{ kg}/\text{m}^3$. At a given sand concentration, the effective density of the proppant-laden fluid gradually decreases with increasing temperature. This is mainly because an increase in temperature causes thermal expansion of the slickwater base fluid, thereby reducing the liquid-phase density and consequently decreasing the effective density. When the sand concentration is $300 \text{ kg}/\text{m}^3$, as the temperature increases from 5°C to 150°C , the effective density decreases from $1167.8 \text{ kg}/\text{m}^3$ to $1093.1 \text{ kg}/\text{m}^3$.

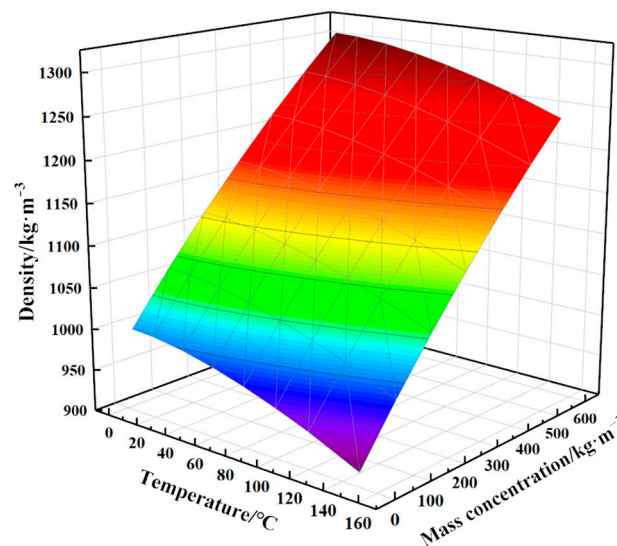


Figure 1. Distribution of the effective density of the proppant-laden fluid under different temperature and sand concentration conditions.

2.3. Effective Specific Heat Capacity Model for Proppant-Laden Fluid

Specific heat capacity represents the amount of heat absorbed per unit mass of fluid for a given temperature increase and is a key thermophysical parameter in temperature field calculations. For the proppant-laden fluid, the effective specific heat capacity should account for the contributions of both the slickwater base fluid and the proppant particles. Since specific heat capacity is a mass-based property, the effective specific heat capacity of proppant-laden slickwater can be calculated using the mass-weighted mixture rule [24]:

$$c_{p,m} = \frac{(1 - \phi_s)\rho_w(T)c_{p,w}(T) + \phi_s\rho_sc_{p,s}}{(1 - \phi_s)\rho_w(T) + \phi_s\rho_s} \quad (4)$$

where $c_{p,w}(T)$ is the specific heat capacity of water at temperature (T), J/(kg·K); and $c_{p,s}$ is the specific heat capacity of the proppant, J/(kg·K).

In temperature field analysis, the volumetric heat capacity is commonly used in the governing equation. According to Equation (4), it can be expressed as:

$$\rho_m c_{p,m} = (1 - \phi_s)\rho_w(T)c_{p,w}(T) + \phi_s\rho_sc_{p,s} \quad (5)$$

where $\rho_m c_{p,m}$ is the volumetric heat capacity of the proppant-laden fluid, J/(m³·K).

Equation (5) indicates that the volumetric heat capacity of the proppant-laden fluid is jointly determined by the slickwater base fluid and the proppant particles. Since the specific heat capacity of water is generally higher than that of proppants such as quartz sand, the mass-based specific heat capacity of proppant-laden slickwater decreases as the sand concentration increases. However, because the addition of proppant significantly increases the density of the mixture, the variation in volumetric heat capacity should be evaluated by considering both density and specific heat capacity.

Figure 2 shows the distribution of the effective specific heat capacity of the proppant-laden fluid under different temperature and sand concentration conditions. As shown in the figure, at a given temperature, the effective specific heat capacity of the proppant-laden fluid decreases markedly with increasing sand concentration. When the temperature is 20 °C, as the sand concentration increases from 0 to 600 kg/m³, the effective specific heat capacity decreases from 4182.0 J/(kg·K) to 2912.3 J/(kg·K). For slickwater without proppant, the effective specific heat capacity is mainly governed by the specific heat capacity of water and exhibits a gradual increasing trend with increasing temperature.

After the sand concentration increases, the overall level of the effective specific heat capacity of the mixture decreases significantly owing to the relatively low specific heat capacity of the proppant, and the fluctuation caused by temperature variation is also reduced. When the sand concentration is 300 kg/m³, the effective specific heat capacity increases from 3419.2 J/(kg·K) to 3444.6 J/(kg·K) as the temperature increases from 5 °C to 150 °C, indicating a relatively small variation.

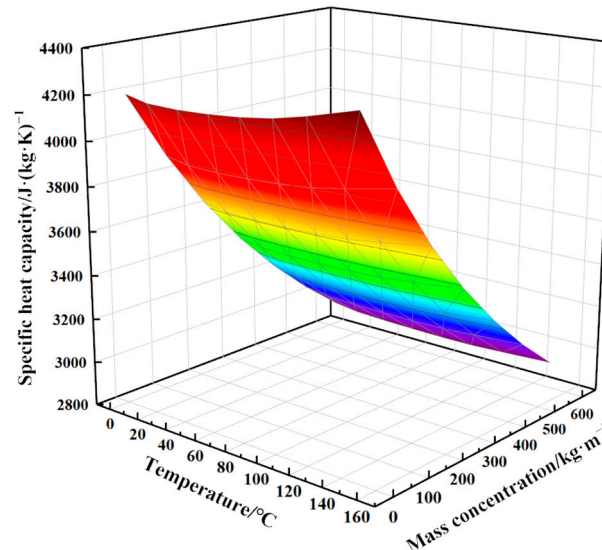


Figure 2. Distribution of the effective specific heat capacity of the proppant-laden fluid under different temperature and sand concentration conditions.

2.4. Effective Thermal Conductivity Model for Proppant-Laden Fluid

Thermal conductivity is an important parameter characterizing the heat-conduction capability of a fluid, and it has a significant influence on radial heat transfer in the wellbore and the calculation of the convective heat-transfer coefficient. In the proppant-laden fluid, the proppant particles are dispersed as a solid phase in the slickwater base fluid. Therefore, the Maxwell–Eucken effective thermal conductivity model is adopted in this study to calculate the effective thermal conductivity of the proppant-laden fluid [25]:

$$k_m = k_w(T) \frac{k_s + 2k_w(T) + 2\phi_s[k_s - k_w(T)]}{k_s + 2k_w(T) - \phi_s[k_s - k_w(T)]} \quad (6)$$

where k_m is the effective thermal conductivity of the proppant-laden fluid, W/(m·K); $k_w(T)$ is the thermal conductivity of water at temperature (T), W/(m·K); and k_s is the thermal conductivity of the proppant, W/(m·K).

According to Equation (6), the effective thermal conductivity of the proppant-laden fluid is mainly controlled by the thermal conductivity of water, the thermal conductivity of the proppant, and the proppant volume fraction. For the quartz sand proppant selected as the base-case proppant in this study, the thermal conductivity is higher than that of water. Therefore, the effective thermal conductivity of the proppant-laden fluid gradually increases with increasing sand concentration.

Figure 3 shows the distribution of the effective thermal conductivity of the proppant-laden fluid under different temperature and sand concentration conditions. As shown in the figure, the thermal conductivity of the proppant-laden fluid is strongly affected by the proppant volume fraction. At a given sand concentration, the effective thermal conductivity of the proppant-laden fluid generally increases with temperature and then tends to level off. When the sand concentration is 300 kg/m³, the effective thermal conductivity increases

from 0.724 W/(m·K) to 0.860 W/(m·K) as the temperature increases from 5 °C to 120 °C. As the temperature further increases to 150 °C, the effective thermal conductivity slightly decreases to 0.856 W/(m·K). At a given temperature, the variation in sand concentration has a more pronounced effect on the effective thermal conductivity. When the temperature is 20 °C, the effective thermal conductivity increases from 0.598 W/(m·K) to 0.908 W/(m·K) as the sand concentration increases from 0 to 600 kg/m³.

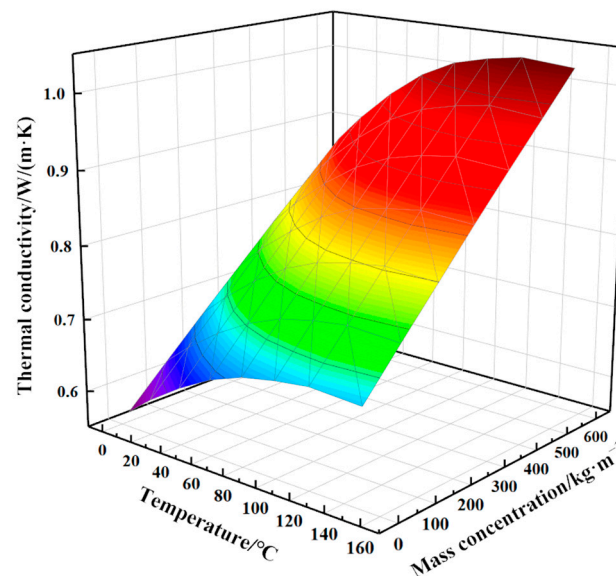


Figure 3. Distribution of the effective thermal conductivity of the proppant-laden fluid under different temperature and sand concentration conditions.

2.5. Effective Viscosity Model for Proppant-Laden Fluid

Viscosity is an important parameter affecting fluid flow resistance, frictional pressure loss, and convective heat-transfer capability. Owing to the low additive concentration in the slickwater system, the viscosity of the slickwater base fluid can be approximated as that of water in the temperature field analysis:

$$\mu_l(T) \approx \mu_w(T) \quad (7)$$

To account for the effect of proppant particles on the viscosity of the proppant-laden fluid, the Krieger–Dougherty suspension viscosity model is adopted [26]:

$$\mu_m = \mu_w(T) \left(1 - \frac{\phi_s}{\phi_{\max}} \right)^{-B} \quad (8)$$

where μ_m is the effective viscosity of the proppant-laden fluid, mPa·s; $\mu_w(T)$ is the viscosity of water at temperature (T), mPa·s; $\phi_{\max}$ is the maximum packing volume fraction of the proppant; and B is an empirical exponent.

When the proppant particles are approximated as rigid spherical particles, the empirical exponent B can be expressed as:

$$B = \eta \phi_{\max} \quad (9)$$

where η is the intrinsic viscosity. For approximately rigid spherical particles, η can be taken as 2.5. Taking $\phi_{\max} = 0.60$, Equation (8) can be further written as:

$$\mu_m = \mu_w(T) \left(1 - \frac{\phi_s}{0.60} \right)^{-1.5} \quad (10)$$

According to Equation (10), both temperature and sand concentration affect the effective viscosity of proppant-laden slickwater. An increase in temperature reduces the viscosity of water, thereby decreasing the viscosity of the proppant-laden fluid. In contrast, an increase in sand concentration enhances interparticle interactions and flow resistance, resulting in an increase in the effective viscosity of the proppant-laden fluid.

Figure 4 shows the distribution of the effective viscosity of the proppant-laden fluid under different temperature and sand concentration conditions. As shown in the figure, at a given temperature, the effective viscosity of the proppant-laden fluid gradually increases with increasing sand concentration. When the temperature is 20 °C, as the sand concentration increases from 0 to 600 kg/m³, the effective viscosity increases from 1.002 mPa·s to 1.739 mPa·s. At a given sand concentration, the effective viscosity of the proppant-laden fluid decreases significantly with increasing temperature. When the sand concentration is 300 kg/m³, as the temperature increases from 5 °C to 150 °C, the effective viscosity decreases from 2.00 mPa·s to 0.243 mPa·s. Compared with density, specific heat capacity, and thermal conductivity, viscosity is more sensitive to temperature variation.

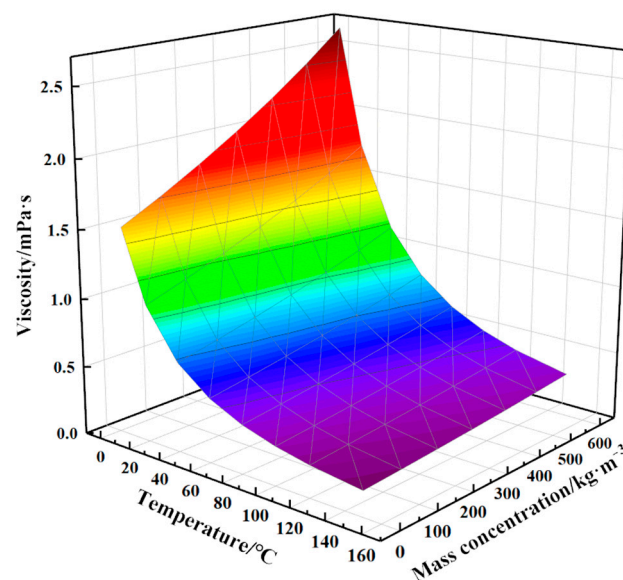


Figure 4. Distribution of the effective viscosity of the proppant-laden fluid under different temperature and sand concentration conditions.

Following the definition based on the characteristic turbulent time scale of the tubing flow, the particle Stokes number is written as:

$$Stk = \frac{\tau_p u_*}{d_t} \quad (10a)$$

The particle relaxation time can be estimated as:

$$\tau_p = \frac{\rho_s d_p^2}{18 \mu_w} \quad (10b)$$

For the reference condition of $Q = 12 \text{ m}^3/\text{min}$, $d_t = 0.076 \text{ m}$, and a sand ratio of 15%: For a representative fine quartz-sand proppant with $d_p = 0.30 \text{ mm}$, $StK = 0.24$. It indicates that particle inertia is not dominant at the tubing-flow scale and that the proppant particles can approximately follow the carrier-fluid motion. This supports the use of the equivalent homogeneous-fluid assumption under the reference high-rate injection condition.

3. Establishment of Wellbore Temperature Field Model for Shale Gas Fracturing

In this study, a typical shale gas fracturing well is selected as the research object. The wellbore structure consists of, from the inside outward, the tubing, A-annulus, production casing, cement sheath, and surrounding formation, as shown in Figure 5. During fracturing operations, proppant-laden slickwater flows axially downward through the tubing and is delivered to the bottom of the well. Forced convective heat transfer occurs between the fluid inside the tubing and the inner tubing wall. Heat is then transferred radially to the surrounding formation through the tubing wall, annular fluid, casing wall, and cement sheath, forming a typical radial heat-transfer system with a multilayer cylindrical structure.

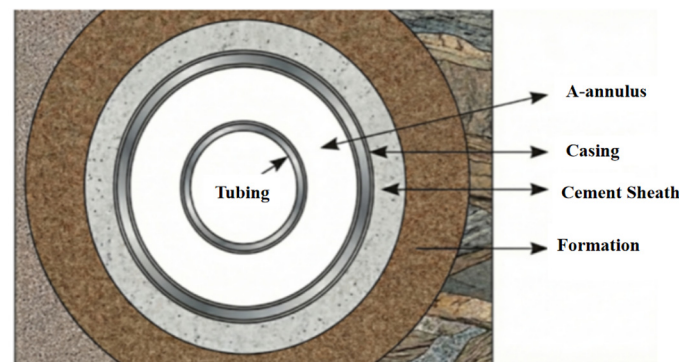


Figure 5. Schematic diagram of the wellbore structure.

In the axial direction, the temperature, pressure, and effective physical properties of the proppant-laden fluid vary with well depth and time. In the radial direction, the temperature gradient is mainly distributed across the tubing–annulus–casing–cement sheath–formation system. Therefore, the wellbore temperature field problem during shale gas fracturing involves both axial flow heat transfer inside the tubing and radial heat transfer through the multilayer wellbore–formation system.

During fracturing operations, the proppant-laden fluid is continuously injected into the wellbore under high-rate and high-pump-pressure conditions. The flow inside the tubing is usually turbulent, and heat transfer between the fluid and the tubing wall is dominated by forced convection. To improve model solvability while maintaining engineering accuracy, the following assumptions are made in this study: the proppant-laden fluid is treated as an equivalent homogeneous fluid; the fluid flows one-dimensionally along the axial direction of the tubing, and axial heat conduction in the fluid is neglected; and good thermal contact is assumed between adjacent media in each wellbore section, and interfacial contact thermal resistance is ignored.

3.1. Energy Conservation Equation for Proppant-Laden Fluid Injection

During shale gas fracturing operations, the proppant-laden fluid flows from the wellhead to the bottom of the well through the tubing at a high injection rate and high velocity, resulting in a pronounced transient temperature field within the wellbore. The wellbore heat-transfer process is shown in Figure 6 and mainly includes axial convective heat transport by the fluid inside the tubing, forced convective heat transfer between the tubing fluid and the inner tubing wall, radial heat conduction through solid media such as the tubing wall and casing, and transient thermal diffusion in the formation.

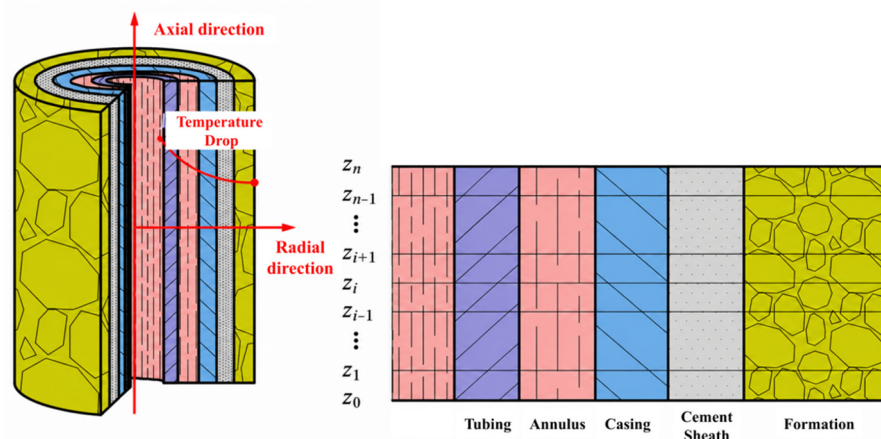


Figure 6. Schematic of wellbore heat transfer.

To describe the transient wellbore temperature field, the entire well is divided along the well depth into a series of wellbore elements with a length of (dz) . Each wellbore element consists of multiple radial media, including the tubing, A-annulus, production casing, cement sheath, and formation. Within each element, the fluid temperature varies along the axial direction and with time, whereas heat transfer dominates in the radial direction and radial mass flow is neglected. Taking the proppant-laden fluid inside the tubing as the research object, and based on the assumption of one-dimensional axial flow, the axial heat conduction term of the fluid is neglected. Based on the one-dimensional transient energy conservation equation for internal pipe flow and the classical wellbore heat-transfer modeling framework [10], the energy conservation equation for the proppant-laden fluid in the tubing can be written as follows:

$$A_t \rho_m c_{p,m} \frac{\partial T_f}{\partial t} + \rho_m c_{p,m} Q(t) \frac{\partial T_f}{\partial z} = -q_r + \Phi_f \quad (11)$$

where T_f is the temperature of the proppant-laden fluid in the tubing, K; t is time, s; z is the coordinate along the well depth, m, with the positive direction defined from the wellhead to the bottom of the well; A_t is the cross-sectional area of the tubing, m^2 ; $Q(t)$ is the wellhead injection rate, m^3/s ; q_r is the radial heat-transfer rate per unit well depth, W/m, defined as positive when heat is transferred from the wellbore fluid to the formation; and Φ_f is the frictional heat-generation term per unit well depth, W/m.

It should be noted that the axial heat conduction term in the fluid is neglected in Equation (11) because the present study focuses on high-rate fracturing fluid injection, where axial heat transport is dominated by forced convection. This assumption may become invalid under low-flow-rate or nearly stagnant conditions, during extended shut-in periods, in short laboratory-scale systems, or when strong axial temperature gradients exist. If axial heat conduction is retained, the governing equation becomes:

$$A_f \rho_m c_{p,m} \frac{\partial T_f}{\partial t} + \rho_m c_{p,m} Q(t) \frac{\partial T_f}{\partial z} = \frac{\partial}{\partial z} \left(k_m A_f \frac{\partial T_f}{\partial z} \right) + q_r + \Phi_f \quad (11a)$$

Introducing the dimensionless variables:

$$\zeta = \frac{z}{L_c}, \quad \tau = \frac{U_0 t}{L_c}, \quad \theta = \frac{T_f - T_{\text{ref}}}{\Delta T}, \quad \hat{u} = \frac{u}{U_0}, \quad \hat{k} = \frac{k_m}{k_0}, \quad \hat{C} = \frac{\rho_m c_{p,m}}{\rho_0 c_{p,0}}$$

Equation (11a) can be written as:

$$\hat{C} \left(\frac{\partial \theta}{\partial \tau} + \hat{u} \frac{\partial \theta}{\partial \xi} \right) = \frac{1}{Pe_z} \frac{\partial}{\partial \xi} \left(\hat{k} \frac{\partial \theta}{\partial \xi} \right) + S_r + S_f \quad (11b)$$

where

$$Pe_z = \frac{\rho_0 c_{p,0} U_0 L_c}{k_0} = \frac{U_0 L_c}{\alpha_0} \quad (11c)$$

When $Pe_z \gg 1$, axial convection dominates and the axial conduction term can be neglected. Under the high-rate fracturing fluid injection conditions considered in this study, Pe_z is very large; therefore, the simplification adopted in Equation (11) is reasonable. If axial conduction is included, the governing equation changes from a first-order transient convection–source equation to a transient convection–diffusion–source equation, requiring two axial thermal boundary conditions and a corresponding implicit finite-difference or finite-element solution.

After pump shutdown, the wellbore is treated as a shut-in system with no imposed axial flow. Thus, $Q(t) = 0$, $u(t) = 0$, and the frictional heat-generation term Φ_f is set to zero. This treatment is a simplified assumption because axial and radial thermal gradients in the tubing fluid may induce buoyancy-driven natural convection during shut-in. Such natural convection may persist for a relatively long time and influence the temperature recovery rate, but it is not explicitly resolved in the present one-dimensional model.

If natural convection causes significant axial recirculation or thermal stratification, the post-shutdown energy equation can be further modified by adding an effective axial thermal-dispersion term. In the present study, this mechanism is not explicitly resolved, and the post-shutdown recovery is interpreted as a radial-heat-transfer-dominated process. This simplification is reasonable for the engineering-oriented model, but a Boussinesq-based two-dimensional model or a transient natural-convection correlation would be required for more detailed post-shutdown circulation analysis.

The average flow velocity inside the tubing is expressed as:

$$u = \frac{Q(t)}{A_t} \quad (12)$$

The frictional heat-generation term is expressed based on the Darcy–Weisbach frictional pressure-loss formulation and the conversion of mechanical energy loss into heat [27]:

$$\Phi_f = \left(\frac{f \rho_m u^3}{8} \right) (\pi d_t) \quad (13)$$

where u is the average flow velocity inside the tubing, m/s; f is the Darcy friction factor, dimensionless; and d_t is the inner diameter of the tubing, m. In the calculation of the frictional heat-generation term, the effective properties of the proppant-laden fluid are evaluated consistently with those used in the heat-transfer calculation. Specifically, the local mixture density and effective viscosity are calculated using the local fluid temperature and sand concentration according to the effective-property models in Section 2. The Darcy friction factor f is then updated from the local Reynolds number, which is determined using $\rho_m(T_f, C_s)$ and $\mu_m(T_f, C_s)$. During the pump-shutdown stage, the injection rate and flow velocity are zero, and the frictional heat-generation term is set to zero.

For a real proppant-laden slurry, the mechanical energy dissipation may include several mechanisms. In a more general two-phase framework, the total frictional heat-generation rate per unit well depth can be decomposed as:

$$\Phi_f = \Phi_\mu + \Phi_{pp} + \Phi_{pw} \quad (13a)$$

The viscous dissipation term can be expressed in continuum form as:

$$\Phi_{\mu} = \iint_{A_f} \tau_{li} : \nabla u_l dA \quad (13b)$$

The interparticle dissipation can be written in a general form as:

$$\Phi_{pp} = \iint_{A_f} \tau_{pp} : \nabla u_s dA \quad (13c)$$

The particle–wall dissipation can be expressed as:

$$\Phi_{pw} = \frac{1}{\Delta z} \sum_i \dot{E}_{pw,i} \quad (13d)$$

In the present study, the proppant-laden slickwater is treated as an equivalent homogeneous fluid, and the effects of proppant loading on frictional heat generation are incorporated through the effective density, effective viscosity, Reynolds number, and Darcy friction factor. This simplification is reasonable when the proppant particles remain well suspended, the slurry behaves approximately as a homogeneous mixture, particle–particle and particle–wall collision losses are weak compared with the bulk turbulent friction loss, and no obvious particle settling or sand-bed formation occurs. However, Equation (13) may become inadequate under high sand-ratio conditions, low-flow-rate or transitional-flow regimes, strong liquid–solid slip, particle clustering, near-wall particle migration, severe particle–wall collisions, or sand-bed formation.

The forced convective heat-transfer coefficient between the proppant-laden fluid inside the tubing and the inner tubing wall was calculated using the Nusselt-number-based empirical correlation:

$$h_i = \frac{Nu_i k_m}{d_t} \quad (14)$$

where h_i is the forced convective heat-transfer coefficient inside the tubing, $W/(m^2 \cdot K)$; Nu_i is the forced convection Nusselt number inside the tubing, dimensionless; and k_m is the effective thermal conductivity of the proppant-laden fluid, $W/(m \cdot K)$.

For the high-rate fracturing fluid injection considered in this study, the flow inside the tubing is turbulent. Therefore, the Dittus–Boelter empirical correlation was adopted to determine the Nusselt number [28]:

$$Nu_i = 0.023 Re_m^{0.8} Pr_m^{n(z,t)} \quad (15)$$

Here, the exponent n should be selected according to the local heat-transfer direction between the bulk fluid and the inner tubing wall. It should be emphasized that when the low-temperature fracturing fluid cools the hot wellbore wall, the fluid itself is heated by the wall; therefore, this condition corresponds to the fluid-heating case in the Dittus–Boelter correlation. To account for possible transient heating/cooling transition, n can be expressed as a local time-dependent parameter:

$$n(z,t) = \begin{cases} 0.4, & T_{w,i}(z,t) > T_f(z,t) \text{ fluid heating,} \\ [4 \text{ pt}]0.3, & T_{w,i}(z,t) < T_f(z,t) \text{ fluid cooling.} \end{cases} \quad (15a)$$

where $T_{w,i}(z,t)$ is the inner tubing-wall temperature and $T_f(z,t)$ is the bulk temperature of the proppant-laden fluid. The characteristic time for the local heating/cooling transition

can be defined as the time $t_{tr}(z)$ at which the local wall-to-fluid temperature difference changes sign:

$$T_{w,i}(z, t_{tr}) - T_f(z, t_{tr}) = 0 \quad (15b)$$

Therefore, the initial local heat-transfer transition is mainly governed by the axial arrival of the injected fluid, whereas the longer bottomhole-temperature stabilization process is controlled by the coupled axial convection and radial heat transfer in the wellbore–formation system. In the reference case, $T_{w,i}$ remains generally higher than T_f during the injection stage, so the fluid-heating condition with $n = 0.4$ is dominant.

The effective properties ρ_m , $c_{p,m}$, μ_m , and k_m are evaluated at the local fluid temperature $T_f(z, t)$ and sand concentration C_s , ensuring consistency between the frictional heat-generation term and the convective heat-transfer calculation.

The Reynolds number and Prandtl number are expressed as follows:

$$\begin{cases} Re_m = \frac{\rho_m u d_{ti}}{\mu_m} \\ Pr_m = \frac{c_{p,m} \mu_m}{k_m} \end{cases} \quad (16)$$

where Re_m is the Reynolds number of the proppant-laden fluid, dimensionless; and Pr_m is the Prandtl number of the proppant-laden fluid, dimensionless.

3.2. Radial Heat-Transfer Model for Multilayer Media in the Wellbore

Radial heat transfer between the proppant-laden fluid in the wellbore and the formation occurs sequentially through multiple media, including the tubing wall, A-annulus fluid, production casing, cement sheath, and surrounding formation. To reduce model complexity, the equivalent thermal resistance method is adopted in this study, and the radial heat-transfer process in the wellbore is represented as a series thermal resistance network of multilayer cylindrical media.

Based on the equivalent thermal resistance method for multilayer cylindrical heat conduction [11], the radial heat-transfer rate per unit well depth can be expressed as:

$$q_r = \frac{T_f - T_{g,\infty}}{R_{tot}} \quad (17)$$

where T_f is the average temperature of the proppant-laden fluid in the tubing, K; $T_{g,\infty}$ is the far-field formation temperature, K; and R_{tot} is the total equivalent thermal resistance of the wellbore–formation system per unit well depth, (K·m)/W.

Under the unit well-depth condition, the total equivalent thermal resistance is obtained by summing the series thermal resistances of forced convection, cylindrical conduction through the tubing, casing and cement sheath, annular heat transfer, and transient formation heat transfer [10,11,29]:

$$R_{tot} = \frac{1}{\pi d_t h_i} + \frac{\ln(D_t/d_t)}{2\pi\lambda_t} + \frac{\ln(d_c/D_t)}{2\pi Nu_a \lambda_a} + \frac{\ln(D_c/d_c)}{2\pi\lambda_c} + \frac{\ln(D_{cem}/d_{cem})}{2\pi\lambda_{cem}} + R_g(t) \quad (18)$$

where d_t and D_t are the inner and outer diameters of the tubing, respectively, m; d_c and D_c are the inner and outer diameters of the production casing, respectively, m; d_{cem} and D_{cem} are the inner and outer diameters of the cement sheath, respectively, m; λ_t , λ_a , λ_c , and λ_{cem} are the thermal conductivities of the tubing, annular fluid, casing, and cement sheath, respectively, W/(m·K); Nu_a is the Nusselt number for natural convection in the annulus; and $R_g(t)$ is the transient equivalent thermal resistance of the formation.

The annular-fluid thermal resistance in Equation (18) incorporates natural convection through the annular Nusselt number Nu_a . In general, Nu_a depends on the Rayleigh number of the annular fluid and the annular geometry, rather than being a strict constant. For the

annulus between the tubing outer wall and the casing inner wall, the Rayleigh number can be written as:

$$Ra_a(z, t) = \frac{g\beta_a|T_{t,o}(z, t) - T_{c,i}(z, t)|\delta_a^3}{\nu_a\alpha_a} \quad (18a)$$

where $T_{t,o}$ and $T_{c,i}$ are the tubing outer-wall and casing inner-wall temperatures, respectively. The annular geometry can be characterized by the radius ratio:

$$\eta = \frac{r_i}{r_o} = \frac{D_t}{d_c} \quad (18b)$$

Thus, the natural-convection Nusselt number in the annulus can be generally expressed as:

$$Nu_a = F(Ra_a, Pr_a, \eta) \quad (18c)$$

where Pr_a is the Prandtl number of the annular fluid. When Ra_a is small, heat transfer in the annulus is mainly conduction-dominated and Nu_a approaches unity; as Ra_a increases, buoyancy-driven circulation is strengthened and Nu_a increases. During transient injection and pump-shutdown processes, the temperature difference across the annulus varies with time and depth, causing Ra_a and Nu_a to change accordingly. Therefore, treating Nu_a as a constant is an engineering approximation. In the present study, a representative Nu_a is used to maintain the simplicity of the equivalent thermal resistance model, while the transient variation in annular natural convection will be considered in future work.

Following the transient formation heat-transfer treatment commonly used in wellbore heat-transmission models [10,11,29], the transient equivalent thermal resistance of the formation is expressed using a time-dependent thermal influence radius:

$$R_g(t) = \frac{\ln[2r_e(t)/D_{cem}]}{2\pi\lambda_g} \quad (19)$$

where λ_g is the thermal conductivity of the formation, W/(m·K); and $r_e(t)$ is the time-dependent equivalent thermal influence radius of the formation, m.

To clarify its accuracy, the exact transient radial conduction solution for an infinite formation subjected to a constant heat flux at the borehole wall is briefly introduced. Let $r_b = D_{cem}/2$ be the borehole–formation interface radius, and let q_w be the heat-transfer rate per unit well depth imposed at $r = r_b$. The transient radial conduction problem can be written as:

$$\frac{\partial \Delta T_g}{\partial t} = \alpha_g \left[\frac{1}{r} \frac{\partial}{\partial r} \left(r \frac{\partial \Delta T_g}{\partial r} \right) \right], \quad r \geq r_b \quad (19a)$$

With the initial and boundary conditions:

$$\begin{cases} \Delta T_g(r, 0) = 0, \\ -\lambda_g \frac{\partial \Delta T_g}{\partial r} \Big|_{r=r_b} = \frac{q_w}{2\pi r_b}, \\ \Delta T_g(\infty, t) = 0, \\ \rho = \frac{r}{r_b}, \\ t_D = \frac{\alpha_g t}{r_b^2}, \\ \theta_b = \frac{2\pi\lambda_g \Delta T_g(r_b, t)}{q_w} \end{cases} \quad (19b)$$

The exact Laplace-domain solution for the dimensionless borehole-wall temperature response is:

$$\bar{\theta}_b(s) = \frac{K_0(\sqrt{s})}{s^{3/2}K_1(\sqrt{s})} \quad (19c)$$

where K_0 and K_1 are modified Bessel functions of the second kind. Therefore, the exact transient formation thermal resistance can be expressed as:

$$\begin{cases} R_{g,ex}(t) = \frac{1}{2\pi\lambda_g} G_{ex}(t_D), \\ G_{ex}(t_D) = \mathcal{L}^{-1} \left[\frac{K_0(\sqrt{s})}{s^{3/2} K_1(\sqrt{s})} \right] \end{cases} \quad (19d)$$

For comparison, the thermal-influence-radius approximation in Equation (19) gives:

$$\begin{cases} R_{g,app}(t) = \frac{1}{2\pi\lambda_g} G_{app}(t_D), \\ G_{app}(t_D) = \ln \left[\frac{r_e(t)}{r_b} \right] \end{cases} \quad (19e)$$

Thus, the thermal-influence-radius approximation underestimates the isolated formation thermal resistance by approximately 4.78% for the 90 min injection time.

This deviation reflects the limitation of representing transient cylindrical heat conduction using a single thermal influence radius, especially during relatively short-time transient processes. However, this error corresponds only to the isolated formation thermal resistance. In the complete wellbore–formation heat-transfer model, the total thermal resistance also includes the tubing wall, annular fluid, casing, cement sheath, and internal convective resistance. Therefore, the influence of this approximation on the predicted wellbore temperature is partly reduced by the other resistance components. This is also supported by the finite element validation results presented in Section 4. Nevertheless, the above comparison indicates that the thermal-influence-radius approximation should be regarded as an engineering simplification.

3.3. Specification of Initial and Boundary Conditions

To solve the wellbore temperature field, the initial and boundary conditions of both the wellbore fluid and the formation must be specified. The initial formation temperature can be expressed according to the geothermal gradient as:

$$T_{g,0}(z) = T_s + Gz \quad (20)$$

where T_s is the surface temperature, K; and G is the geothermal gradient, K/m.

The initial conditions and wellhead injection boundary conditions can be written as:

$$\begin{cases} T_f(z, 0) = T_{g,0}(z) \\ T_f(0, t) = T_{in}(t) \\ Q = Q(t) \\ C_s = C_s(t) \end{cases} \quad (21)$$

where $T_{in}(t)$ is the wellhead injection temperature, K; $Q(t)$ is the injection rate, m^3/s ; and $C_s(t)$ is the sand concentration, kg/m^3 . For the one-dimensional convection equation during the injection phase, the wellhead inlet temperature, injection rate and sand concentration are the primary boundary conditions, whilst the wellbore outlet may be treated as a free-outflow boundary condition.

According to the above equations, the density and specific heat capacity of the proppant-containing fluid directly influence the thermal accumulation and axial convective heat-transfer terms in the wellbore fluid. Thermal conductivity and viscosity, in turn, affect the forced convective heat transfer coefficient within the casing via the Reynolds number, Prandtl number and Nusselt number. Consequently, the effects of sand concentration and temperature on the effective physical properties of the proppant-laden fluid can be

further incorporated into the calculation of the wellbore temperature field. This enables the coupling of the effective physical property model of the proppant-laden fluid with the wellbore temperature field model, thereby allowing for a more accurate analysis of the evolution of wellbore temperature during the proppant-laden fluid injection process.

The governing equation was solved using a finite-difference marching scheme along the well depth. During the injection stage, the axial convective term was discretized using a first-order upwind scheme according to the flow direction from the wellhead to the bottomhole, while the transient and radial heat-transfer source terms were treated using a semi-implicit time-marching method. The wellhead injection temperature was imposed as the inlet boundary condition, and the temperature field was updated sequentially from the wellhead to the bottomhole at each time step. During pump shutdown, the injection rate and axial velocity were set to zero, and the temperature recovery was calculated mainly from the radial heat-transfer term. To ensure numerical stability and sufficient resolution of the cooling front, the time step and axial grid size were selected so that the Courant number CFL remained below unity under the maximum injection rate. In the reference calculation, $\Delta z = 35$ m and $\Delta t = 0.5$ s were used, giving $CFL_{\max} < 1$.

To verify that the numerical solution of the theoretical model is independent of the selected time step and spatial discretization, a grid-independence test was conducted under the reference operating condition. Three discretization schemes were considered: a coarse grid with $\Delta z = 70$ m and $\Delta t = 1.0$ s, a medium grid with $\Delta z = 35$ m and $\Delta t = 0.5$ s, and a fine grid with $\Delta z = 17.5$ m and $\Delta t = 0.25$ s. The bottomhole temperature at 90 min was selected as the comparison variable.

As shown in Table 1, the calculated bottomhole temperatures for the coarse, medium, and fine grids are 21.393 °C, 21.379 °C, and 21.372 °C, respectively. The relative deviation between the medium and fine grids is only 0.031%, indicating that further refinement has little influence on the calculated wellbore temperature. Therefore, the medium discretization scheme with $\Delta z = 35$ m and $\Delta t = 0.5$ s was adopted in this study to balance computational accuracy and efficiency.

Table 1. Grid independence verification of wellbore temperature calculation.

Δz (m)	Δt (s)	T_b at 90 min (°C)	Relative Deviation from Fine Grid (%)
70	1.0	21.393	0.094
35	0.5	21.379	0.031
17.5	0.25	21.372	/

4. Validation of the Wellbore Temperature Field Model

4.1. Finite Element Simulation

To verify the accuracy and engineering applicability of the transient wellbore heat-transfer model developed in this study, numerical simulations of the wellbore temperature field were carried out using COMSOL Multiphysics 6.4. The effectiveness of the proposed prediction method for the transient wellbore temperature field during the entire fracturing process was evaluated by comparing the theoretical calculation results with the numerical simulation results. A representative shale gas fracturing well was selected as the case well for model validation. The main tubing and casing structural parameters used in the finite element model are listed in Table 2, and the principal wellbore–formation thermal parameters and calculation conditions are summarized in Table 3.

Table 2. Tubing and casing structural parameters of the case well.

Component	Inner Diameter (mm)	Outer Diameter (mm)	Wall Thickness or Radial Thickness (mm)
Tubing	76.0	88.9	6.45
A-annulus	88.9	118.6	14.86
Production casing	118.6	139.7	10.54
Cement sheath	139.7	215.9	38.10

Table 3. Main calculation parameters of the case well.

Well Depth (m)	Geothermal Gradient ($^{\circ}\text{C}/\text{m}$)	Density of Formation Rock (kg/m^3)	Thermal Diffusivity of Formation Rock (m^2/s)	Thermal Conductivity of Formation Rock ($\text{W}/(\text{m}\cdot^{\circ}\text{C})$)	Thermal Conductivity of Cement Sheath ($\text{W}/(\text{m}\cdot^{\circ}\text{C})$)
3500	0.03	2240	1.01×10^{-6}	2.1	0.4
Density of Annular Protective Fluid (kg/m^3)	Thermal Conductivity of Annular Protective Fluid ($\text{W}/(\text{m}\cdot^{\circ}\text{C})$)	Specific Heat Capacity of Annular Protective Fluid ($\text{J}/(\text{kg}\cdot\text{K})$)	Specific Heat Capacity of Proppant ($\text{J}/(\text{kg}\cdot\text{K})$)	Thermal Conductivity of Proppant ($\text{W}/(\text{m}\cdot\text{K})$)	Proppant Density (kg/m^3)
955	0.6	4180	800	7.7	2650

Considering the cylindrical symmetry of wellbore heat transfer, a two-dimensional axisymmetric geometric model was developed for numerical analysis. In the axial direction, the computational domain extended from the wellhead to the bottomhole, with a total well depth of 3500 m. In the radial direction, the computational domain included the complete wellbore structure, consisting of the tubing, annulus, casing, and cement sheath. The surrounding formation was extended radially to a far-field boundary located 5 m from the wellbore center. Since this distance exceeds the effective thermal influence range of wellbore heat transfer during fracturing, the outer boundary of the formation was treated as a constant-temperature far-field boundary without thermal interference.

Due to the significant aspect ratio between the axial well depth and the radial dimensions of the wellbore–formation system, a structured mapping grid was employed to discretize the computational domain, thereby maintaining numerical stability and adequate spatial resolution for the transient heat-transfer calculation. Considering the large difference between the axial well depth and the radial thickness of the wellbore components, the model was discretized using quadrilateral elements. A relatively fine mesh was assigned to the tubing, annulus, casing, cement sheath, and near-wellbore–formation region to accurately capture the steep radial temperature gradient. In contrast, a gradually coarsened mesh was used in the far-field formation region to reduce unnecessary computational cost while maintaining sufficient accuracy near the wellbore. The axial mesh was refined near the wellhead and bottomhole regions, whereas the radial mesh was refined at the interfaces between different materials. The final finite element model contained 6000 mesh elements in total.

In terms of physical field settings, the ‘Solid Heat Transfer’ and ‘Fluid Heat Transfer’ interfaces are coupled with the ‘Non-Newtonian Pipe Flow’ interface to simulate the coupling between axial fluid flow within the wellbore and transient radial heat conduction in the surrounding formation. This modeling strategy comprehensively captures the heat-transfer mechanisms during the fracturing process, including forced convective heat transfer between the fluid and the pipe wall, radial heat transfer through the multi-layer cylindrical wellbore structure, and transient thermal diffusion into the formation. The model construction process is illustrated in Figure 7.

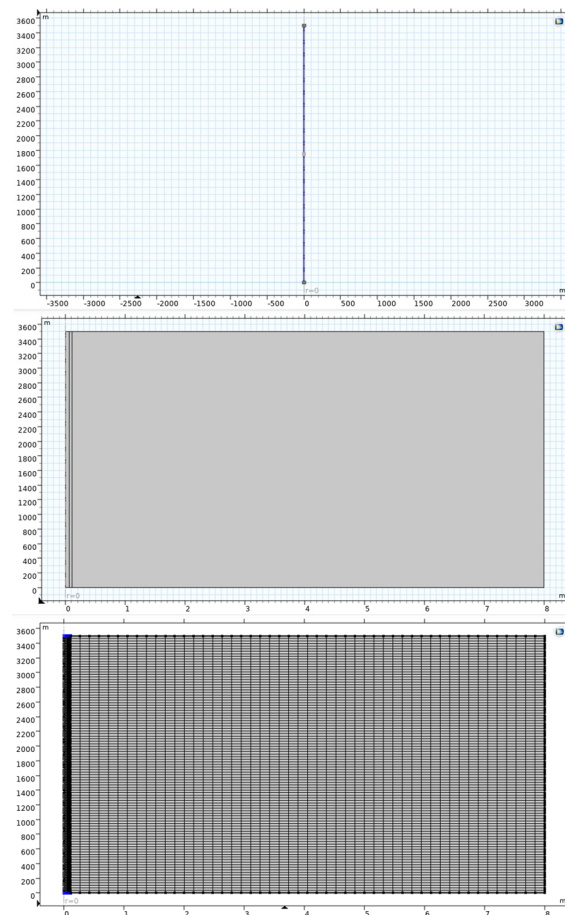


Figure 7. Establishment and meshing process of wellbore heat-transfer finite element model.

To ensure the engineering representativeness of the simulation conditions, the stable injection stage of fracturing operation was selected as the research working condition: the wellhead injection temperature of the fracturing fluid was 20 °C, the construction displacement was 12 m³/min, the sand ratio of the proppant-carrying fluid was 15%, and the total injection duration was 90 min. Under this condition, the pipe flow has reached a fully developed turbulent state, which is consistent with the high Reynolds number flow assumption in the previous model, thus effectively verifying the prediction accuracy of the model under typical engineering conditions.

4.2. Validation and Analysis of the Temperature Field Model

A comparative analysis was conducted between the finite element simulation results and the analytical solution obtained from the proposed transient wellbore heat-transfer model. As shown in Figure 8, the two curves exhibit highly consistent temperature evolution characteristics during the entire fracturing process. At the initial stage of fracturing fluid injection. During the initial rapid-cooling stage, defined as the first 10 min after the start of fracturing fluid injection, the bottomhole temperature decreases rapidly from the initial formation temperature to approximately 20–25 °C within a short period. This sharp drop in temperature is primarily attributed to intense forced convective heat transfer caused by the continuous injection of low-temperature fracturing fluid. Subsequently, during the steady-state injection phase, the bottomhole temperature remains largely constant, indicating that thermal equilibrium has gradually been established between the axial heat conduction of the injected fluid and the radial heat transfer within the surrounding wellbore–formation system. After the pump is stopped, the flow field within the wellbore

gradually stabilizes, and the bottomhole temperature rises slowly due to continuous radial heat conduction within the formation.

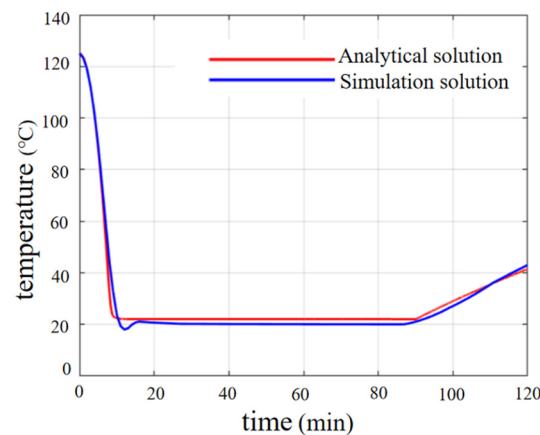


Figure 8. Bottomhole temperature variation with time.

In this study, the quasi-steady-state phase is identified using a bottomhole temperature-change-rate criterion. Specifically, the bottomhole temperature is considered to enter the quasi-steady-state phase when the absolute value of the temperature-change rate remains lower than $0.1\text{ }^{\circ}\text{C}/\text{min}$, namely $|\Delta T_b/\Delta t| < 0.1\text{ }^{\circ}\text{C}/\text{min}$. Therefore, the term “quasi-steady-state” does not indicate a strictly time-independent state, but a stage in which the bottomhole temperature changes only slowly after the initial rapid cooling period.

It can be observed that, compared with the analytical solution, the finite element simulation predicts a slightly faster rate of temperature decline during the early transient cooling phase. This subtle difference is primarily evident in the initial stage, where the temperature gradient is greatest and the transient heat-transfer process is most intense. The finite element simulation solved for the local temperature distribution within the tubing string, annulus, casing, cemented casing and near-wellbore–formation through spatial discretization, whereas the proposed theoretical model described the coupled axial convection and radial transient heat-transfer processes from the perspective of the overall wellbore heat-transfer mechanism. Consequently, slight differences in cooling rates may arise during the rapid transient phase. However, as the water injection process continues, the two curves gradually converge and almost coincide during the steady-state injection and post-pump-stop temperature recovery phases.

Overall, the analytical solutions agree well with the finite element simulation results. Minor discrepancies between the two methods are primarily observed during the initial rapid cooling phase, whilst the overall temperature trends, steady-state temperature levels and post-pump-shutdown recovery behavior show a high degree of consistency. This indicates that the proposed transient wellbore heat-transfer model is capable of accurately capturing the dominant heat-transfer characteristics during fracturing fluid injection and pump shutdown. The comparison results validate the reliability, accuracy and engineering applicability of the theoretical model developed. The finite element simulation is used here for model validation rather than for computational-runtime benchmarking; therefore, the proposed model is described as a simplified engineering-oriented calculation framework.

As shown in the comparison of the longitudinal wellbore temperature distributions in Figure 9, the bottomhole temperature recovers to approximately $40\text{ }^{\circ}\text{C}$ at $t = 120\text{ min}$, corresponding to 30 min after pump shutdown. Both the analytical solution obtained from the proposed model and the finite element simulation result show a similar increasing temperature trend with well depth. Compared with the initial formation temperature profile, the wellbore temperature after pump shutdown remains significantly lower, indicating that

the cooling effect induced by the previous injection of low-temperature fracturing fluid still persists in the wellbore–formation system.

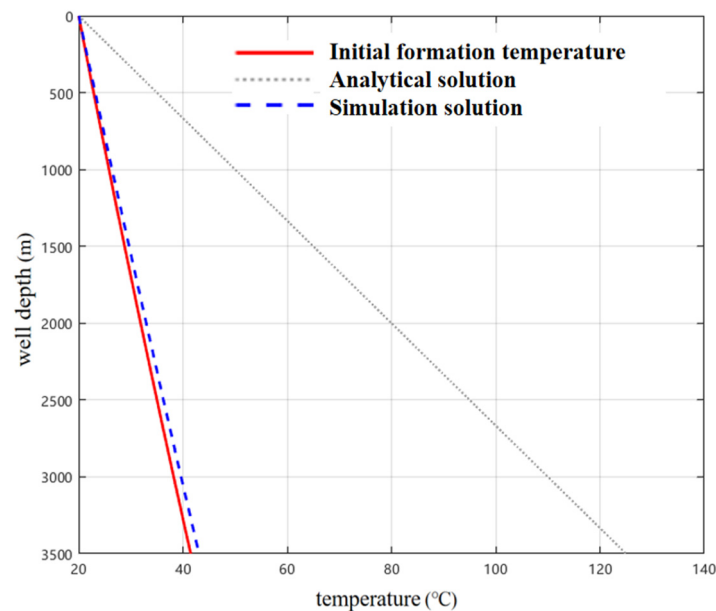


Figure 9. Comparison of longitudinal wellbore temperature distributions at $t = 120$ min, corresponding to 30 min after pump shutdown.

The analytical and simulation results are in good agreement along the entire wellbore depth. The two curves are nearly coincident in the shallow and middle sections, and only a slight deviation is observed near the lower part of the wellbore. This difference is mainly related to the different treatments of wellbore heat-transfer parameters in the two methods. In the proposed theoretical model, the convective heat-transfer coefficient is determined using an empirical correlation, whereas the finite element model resolves the coupled heat-transfer process through spatial discretization of the tubing, annulus, casing, cement sheath, and surrounding formation. Therefore, minor discrepancies may occur in regions where the temperature gradient is relatively large.

Overall, the longitudinal temperature distribution predicted by the proposed theoretical model is in close agreement with the results of the finite element simulation. The minor discrepancies between the two methods fall within the acceptable range for engineering calculations, indicating that the transient wellbore heat-transfer model developed is capable of accurately predicting the longitudinal temperature distribution following the injection of fracturing fluid and the cessation of pumping.

As shown in Figure 10, the analytical model agrees well with the finite element simulation results in predicting the radial temperature distribution. Figure 10a shows the radial temperature profile at a well depth of 2000 m. The temperature rises rapidly with radial distance in the near-wellbore region and then gradually approaches the undisturbed formation temperature. This behavior indicates that the cooling effect induced by low-temperature fracturing fluid injection is mainly concentrated near the wellbore, while the far-field formation is only slightly affected.

Figure 10b further compares the radial temperature distributions at 500 m, 2000 m, and 3500 m at the pump-shutdown moment of 90 min under the reference condition. The results show that the overall temperature level increases with well depth due to the geothermal gradient. At 500 m, the radial temperature gradient is relatively weak, and the analytical and simulation curves are almost coincident. At 2000 m, a slightly larger temperature gradient appears near the wellbore. At 3500 m, the higher undisturbed formation temperature

results in the strongest near-wellbore radial temperature gradient, and the discrepancy between the analytical and simulation results becomes slightly more evident.

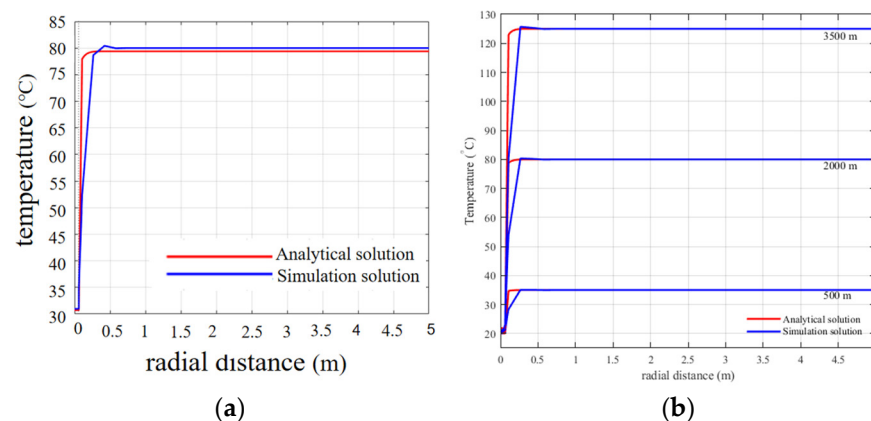


Figure 10. Comparison of radial temperature distributions between the analytical model and finite element simulation under the reference condition: (a) radial temperature distribution at a well depth of 2000 m at the pump-shutdown moment of 120 min; (b) radial temperature distributions at well depths of 500 m, 2000 m, and 3500 m at the pump-shutdown moment of 90 min.

These discrepancies are mainly attributed to the different treatments of local radial heat transfer. The finite element model directly resolves the temperature gradients in each radial layer, including the tubing, annulus, casing, cement sheath, and formation, whereas the analytical model represents the multilayer radial heat-transfer process using an equivalent thermal resistance formulation. Therefore, small deviations may occur in the near-wellbore region where the radial temperature gradient is large. However, the overall agreement between the two methods is good, especially in the far-field formation, confirming the reliability of the proposed transient wellbore heat-transfer model for predicting radial temperature distributions during fracturing fluid injection.

To further substantiate the agreement between the proposed theoretical model and the finite element simulation, quantitative deviation metrics were calculated for the three validation cases shown in Figures 8–10. The finite element simulation results were taken as the reference values, the mean absolute error (MAE), root mean square error (RMSE), and mean relative deviation were then calculated. The results are shown in Table 4.

Table 4. Quantitative deviation metrics between the proposed model and finite element simulation results.

Comparison Case	MAE (°C)	RMSE (°C)	Mean Relative Deviation (%)
Bottomhole temperature variation with time	1.849	2.302	8.003
Shutdown recovery stage	1.260	1.385	4.460
Longitudinal wellbore temperature distribution	0.904	1.012	2.683
Radial temperature distribution at 2000 m at 120 min	2.404	5.683	4.553
Radial temperature distribution at 500 m at 90 min	0.421	1.280	1.581
Radial temperature distribution at 2000 m at 90 min	1.602	4.988	3.444
Radial temperature distribution at 3500 m at 90 min	2.764	8.557	4.271

In addition to the overall validation over the entire 0–120 min process, the shutdown recovery stage from 90 to 120 min was separately evaluated. As shown in Figure 8, the vertical dashed line denotes pump shutdown at 90 min. After pump shutdown, the bottomhole temperature gradually recovers, mainly driven by radial heat transfer from the surrounding high-temperature formation to the cooled wellbore fluid. In the present model, the wellbore fluid is assumed to be stagnant after shutdown, and no imposed axial flow exists. Therefore, the axial forced-convection term is removed. Although buoyancy-driven natural convection may occur in a vertical shut-in wellbore due to temperature-induced density differences, this mechanism is not explicitly resolved in the present one-dimensional equivalent-fluid model. The post-shutdown recovery predicted in this study should therefore be interpreted as a radial-heat-transfer-dominated recovery process. The quantitative error analysis shows that, during the 90–120 min recovery period, the RMSE between the analytical model and FEM simulation is 1.385 °C, respectively. This confirms that the proposed model can also reproduce the post-shutdown temperature recovery behavior with acceptable accuracy.

It should be noted that the model validation in this study is based on a single reference operating condition, namely an injection temperature of 20 °C, an injection rate of 12 m³/min, a sand ratio of 15%, and an injection duration of 90 min. Therefore, the comparison with the FEM simulation mainly verifies the consistency and accuracy of the proposed model under the reference condition. The validation does not fully cover all parameter combinations investigated in the subsequent parametric analysis, especially more extreme conditions such as lower injection temperature or higher injection rate. Accordingly, the parametric analysis in Section 5 should be interpreted as an engineering sensitivity analysis based on the validated reference model, rather than as a fully validated prediction over the entire operating-parameter space. Further validation under wider operating conditions will be conducted in future work.

5. Analysis of Influencing Factors on Wellbore Temperature Field During Shale Gas Fracturing

5.1. Effect of Fracturing Fluid Injection Rate on Wellbore Temperature

The fluid injection rate is a key operational parameter affecting wellbore temperature during shale gas fracturing. To analyze its impact on the evolution of bottomhole temperature, the fracturing fluid injection temperature was fixed at 20 °C, the proppant concentration was set at 12%, and the continuous injection time was set at 90 min. Five typical injection rates—8, 10, 12, 14 and 16 m³/min—were selected for comparative analysis. The corresponding changes in bottomhole temperature are shown in Figure 11.

As shown in Figure 11, following the injection of low-temperature fracturing fluid, the bottomhole temperature began to drop rapidly from an initial formation temperature of approximately 125 °C. The cooling process is significantly influenced by the injection rate. When the injection rate was increased from 8 m³/min to 16 m³/min, the time required for the bottomhole temperature to fall below 25 °C was reduced from approximately 13–14 min to about 8–9 min. This indicates that increasing the injection rate can significantly accelerate the arrival of low-temperature fracturing fluid at the bottomhole and enhance the early-stage cooling effect. At the same time, the temperature decline curve becomes steeper with increasing injection rate, indicating that the bottomhole cooling rate is markedly improved under high-rate injection conditions.

During the stable injection stage, the bottomhole temperature under all injection-rate conditions gradually approaches the fracturing fluid injection temperature. However, the stable temperature still shows slight differences among different injection rates. For the injection rates of 8, 10, 12, 14, and 16 m³/min, the bottomhole temperature stabilizes

at approximately 23.0, 22.5, 22.0, 21.6, and 21.3 °C, respectively. Therefore, increasing the injection rate not only shortens the cooling response time, but also slightly reduces the stable bottomhole temperature. This is because a higher injection rate increases the axial flow velocity and Reynolds number of the fracturing fluid in the tubing, thereby strengthening forced convective heat transfer between the fluid and the pipe wall. As a result, more heat is carried away from the wellbore–formation system, and the bottomhole temperature is maintained closer to the injection temperature.

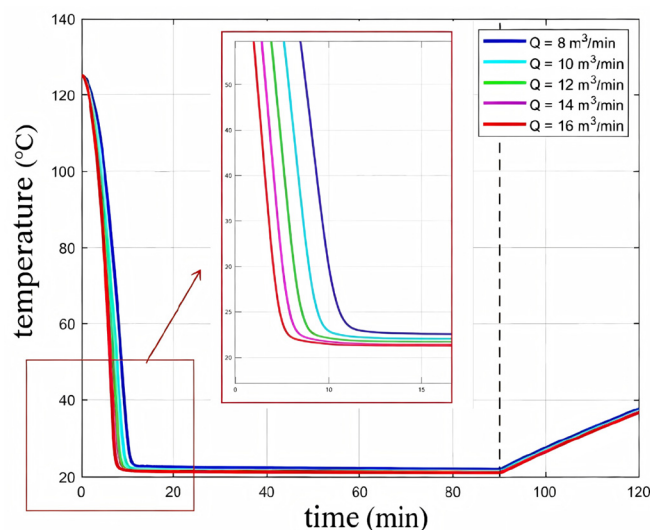


Figure 11. Bottomhole temperature variation with time under different injection rates.

After pump shutdown at 90 min, the axial flow of fracturing fluid in the wellbore rapidly weakens, and the dominant heat-transfer mechanism changes from forced convection to radial heat conduction from the surrounding formation. Consequently, the bottomhole temperature begins to recover gradually. By 120 min, the bottomhole temperature rises to approximately 37–39 °C under different injection-rate conditions. The temperature recovery curves after pump shutdown are relatively close to each other, indicating that the post-pump-shutdown temperature recovery is less affected by the previous injection rate and is mainly controlled by the heat supply capacity of the formation. Overall, increasing the injection rate mainly affects the early cooling rate and stable injection temperature, while its influence on the later pump-shutdown temperature recovery is relatively limited.

Figure 12 shows the longitudinal wellbore temperature profiles under different injection rates at the moment of pump shutdown. Compared with the initial formation temperature profile, the wellbore temperature after 90 min of continuous fracturing fluid injection is significantly reduced along the entire well depth. The initial formation temperature increases approximately linearly with depth, reaching about 125 °C at the bottomhole. However, at the pump-shutdown moment, the temperature profiles under all injection-rate conditions are concentrated near the injection temperature, indicating that the low-temperature fracturing fluid has reached the bottomhole and has produced a strong cooling effect throughout the wellbore.

The enlarged view in Figure 12 further shows that the longitudinal temperature profiles differ slightly under different injection rates. At the same well depth, a higher injection rate corresponds to a lower wellbore temperature. When the injection rate increases from 8 to 16 m³/min, the wellbore temperature at the pump-shutdown moment decreases from approximately 25 °C to about 22 °C. This indicates that increasing the injection rate enhances the axial heat-carrying capacity of the fracturing fluid and strengthens the forced

convective heat transfer between the fluid and the wellbore wall. As a result, more heat is removed from the wellbore–formation system during the same injection period.

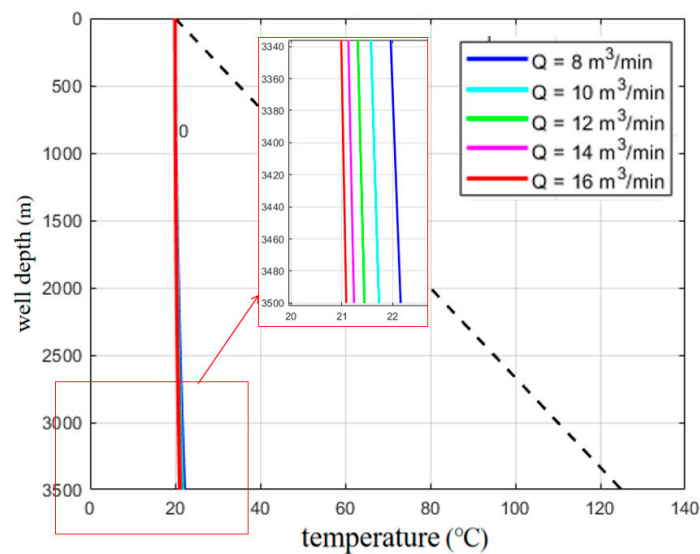


Figure 12. Longitudinal wellbore temperature profiles at the pump-shutdown moment under different injection rates.

Overall, the temperature difference among different injection-rate conditions is relatively small at the pump-shutdown moment, but the decreasing trend with increasing injection rate is clear. This demonstrates that after 90 min of continuous injection, the wellbore temperature field has entered a low-temperature quasi-stable state. The injection rate mainly affects the final cooling level of the wellbore, while the overall longitudinal temperature distribution is primarily controlled by the continuous axial convection of low-temperature fracturing fluid.

5.2. Effect of Fracturing Fluid Sand Ratio on Wellbore Temperature

To investigate the effect of sand ratio on bottomhole temperature evolution, the injection temperature, injection duration, and injection rate were fixed at 20 °C, 90 min, and 12 m³/min, respectively. Five sand ratios of 6%, 8%, 10%, 12%, and 15% were selected for comparative analysis. According to the definition in Section 2.1, these percentage values represent the proppant volume fraction in the slurry. The converted sand concentrations were then used in the effective thermophysical property model. The calculated bottomhole temperature curves are shown in Figure 13.

As shown in Figure 13, during the initial phase of fracturing fluid injection, the bottomhole temperature drops rapidly from the initial formation temperature to a low-temperature state. Under all proppant concentration conditions, the bottomhole temperature falls to approximately 22–24 °C within about 10 min, after which it gradually stabilizes at a level close to the injection temperature. The overall temperature trends for different proppant concentrations are highly similar, indicating that, under conditions of constant injection rate and injection temperature, proppant concentration has a negligible effect on bottomhole temperature.

During the rapid cooling phase, the curves for different proppant concentrations exhibited only minor differences. As the proppant concentration increased, the rate of decline in bottomhole temperature accelerated slightly, and the steady-state temperature was slightly lower. This phenomenon is primarily related to changes in the effective thermophysical properties of the sand-containing fracturing fluid. The addition of proppant particles alters the effective density, specific heat capacity, thermal conductivity and viscosity of the fluid,

thereby affecting the Reynolds number, Prandtl number and convective heat-transfer coefficient within the casing. However, within the studied range of proppant concentrations (6–15%), the resulting changes in heat-transfer capacity are limited, and the temperature differences remain small under various conditions.

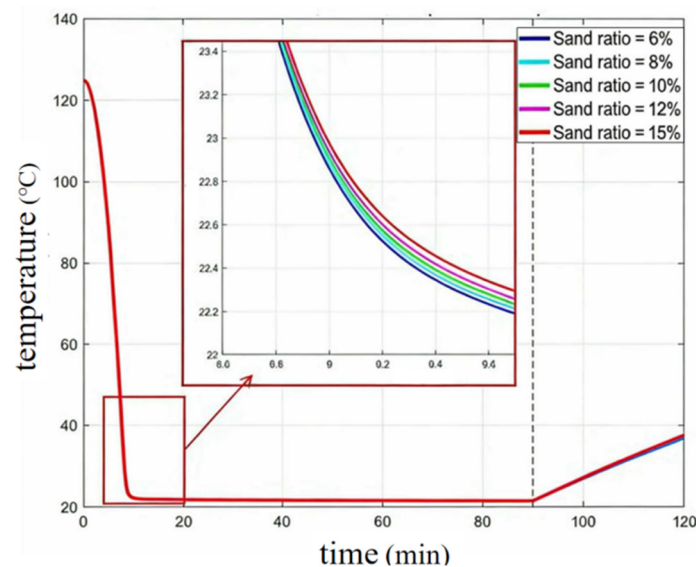


Figure 13. Curves of bottomhole temperature variation with time under different sand ratios.

After 90 min, the pump was stopped, and the temperature at the bottom of the well gradually rose due to radial heat conduction in the surrounding formation. The post-pump-shutdown recovery curves under different proppant concentrations are almost coincident, indicating that the later temperature recovery process is mainly controlled by formation heat conduction rather than the previous proppant concentration. Overall, proppant concentration is a weakly sensitive parameter for the wellbore temperature field compared with injection rate. Its influence is mainly reflected in a slight change in the early cooling rate and stable bottomhole temperature, but it does not alter the overall temperature evolution pattern during fracturing fluid injection and pump shutdown.

Figure 14 shows the longitudinal wellbore temperature profiles at the pump-shutdown moment under different proppant concentrations. Compared with the initial formation temperature profile, the wellbore temperature after 90 min of continuous fracturing fluid injection is significantly reduced along the entire well depth. The temperature of the wellbore under all proppant concentration conditions remains close to the fracturing fluid injection temperature, indicating that the low-temperature sand-carrying fracturing fluid has produced a strong cooling effect on the wellbore–formation system.

As shown in the enlarged view, the longitudinal temperature profiles under different proppant concentrations are very close to each other, and only slight differences can be observed near the lower part of the wellbore. With the increase in proppant concentration from 6% to 15%, the wellbore temperature at the pump-shutdown moment decreases slightly. This is mainly because the addition of proppant particles changes the effective thermophysical properties of the fracturing fluid, such as density, heat capacity, thermal conductivity, and viscosity, thereby slightly affecting the convective heat-transfer capacity of the fluid in the tubing.

However, the temperature difference among different proppant concentration conditions is small. The overall longitudinal temperature distribution is still primarily controlled by the injection temperature and injection rate of the fracturing fluid, while the influence of proppant concentration is relatively limited. Therefore, proppant concentration can be

regarded as a weakly sensitive parameter affecting the longitudinal wellbore temperature field at the pump-shutdown moment.

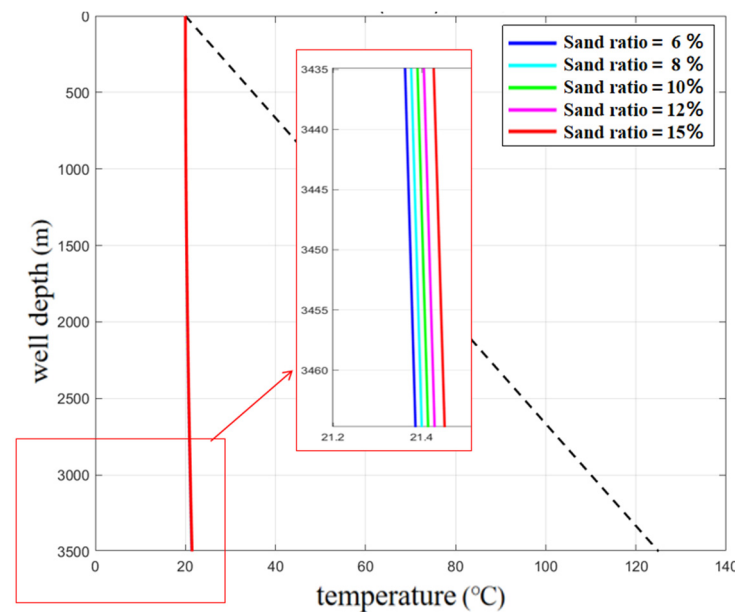


Figure 14. Longitudinal wellbore temperature profiles at the pump-shutdown moment under different sand ratios.

5.3. Effect of Fracturing Fluid Injection Temperature on Wellbore Temperature

During fracturing operations, the fracturing fluid stored in surface tanks is injected into the wellbore after being pressurized by fracturing pump trucks. Due to seasonal variations in ambient temperature, the initial temperature of the fracturing fluid may vary significantly. To investigate the influence of fracturing fluid injection temperature on bottomhole temperature evolution, the proppant concentration, injection duration, and injection rate were fixed at 12%, 90 min, and 12 m³/min, respectively. Three injection temperatures of 5 °C, 15 °C, and 30 °C were selected for comparative calculation, and the corresponding bottomhole temperature curves are shown in Figure 11.

As shown in Figure 15, the bottomhole temperature decreases rapidly at the early stage of fracturing fluid injection under all three injection-temperature conditions. After the low-temperature fracturing fluid reaches the bottomhole, the temperature drops sharply within a short period and then gradually enters a stable stage. When the injection temperatures are 5 °C, 15 °C, and 30 °C, the bottomhole temperatures stabilize at approximately 8 °C, 17 °C, and 31 °C, respectively. This indicates that the stable bottomhole temperature during continuous injection is mainly controlled by the injection temperature of the fracturing fluid. A lower injection temperature produces a larger cooling amplitude and a lower stable bottomhole temperature.

During the continuous injection stage from approximately 10 to 90 min, the bottomhole temperature under each working condition remains nearly unchanged, indicating that a quasi-stable heat-transfer state is gradually established in the wellbore–formation system. Compared with the case of 30 °C injection temperature, reducing the injection temperature to 15 °C decreases the stable bottomhole temperature by approximately 14 °C, while reducing it to 5 °C further decreases the stable bottomhole temperature by approximately 23 °C. Therefore, the effect of injection temperature on bottomhole temperature is direct and significant, and its influence is much stronger than that of proppant concentration.

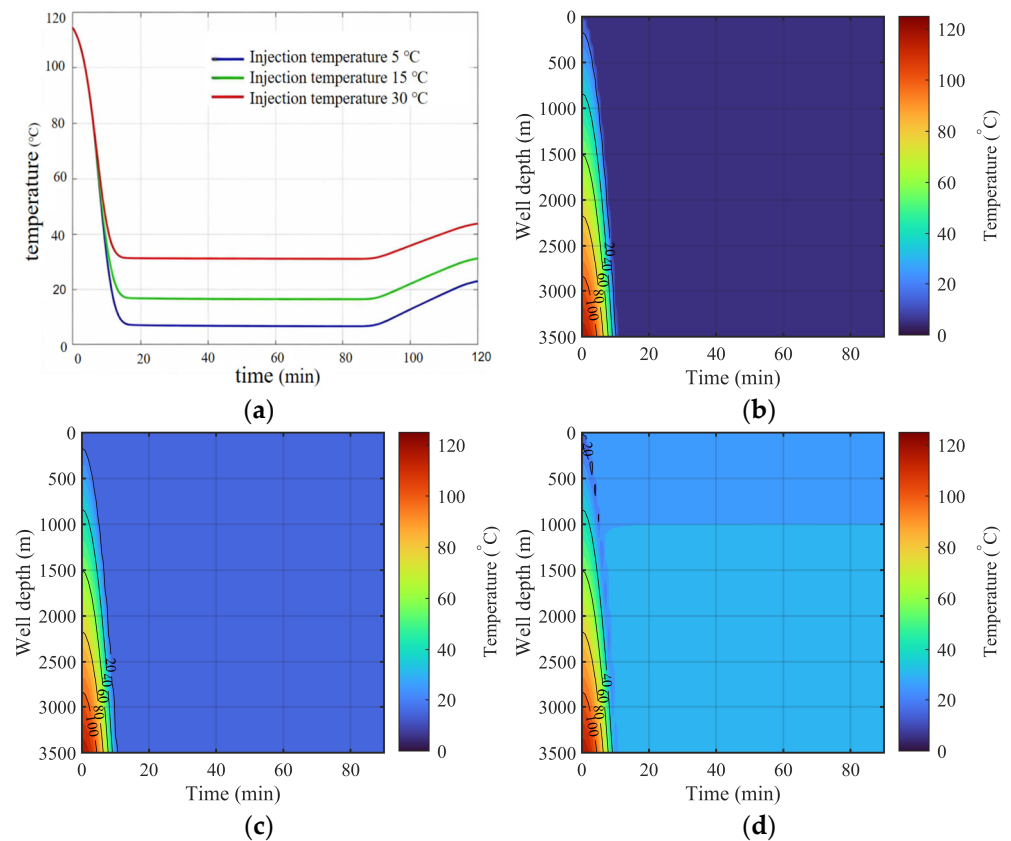


Figure 15. Effect of injection temperature on bottomhole temperature and spatiotemporal wellbore temperature distribution during fracturing fluid injection: (a) bottomhole temperature variation with time; (b) wellbore temperature contour at an injection temperature of 5 °C; (c) wellbore temperature contour at an injection temperature of 15 °C; (d) wellbore temperature contour at an injection temperature of 30 °C.

After pump shutdown at 90 min, the forced convective heat transfer caused by axial fluid flow weakens rapidly, and radial heat conduction from the surrounding formation becomes the dominant heat-transfer mechanism. As a result, the bottomhole temperature under all injection-temperature conditions begins to recover gradually. By 120 min, the bottomhole temperatures increase to approximately 23 °C, 32 °C, and 44 °C for injection temperatures of 5 °C, 15 °C, and 30 °C, respectively. Although the temperature recovery trends are similar after pump shutdown, the temperature differences caused by different injection temperatures remain evident.

Overall, the fracturing fluid injection temperature is a highly sensitive parameter affecting the bottomhole temperature field. Lower injection temperature significantly enhances the cooling effect during fracturing fluid injection and results in a lower bottomhole temperature after pump shutdown, whereas higher injection temperature weakens the cooling effect and leads to a higher temperature level during both injection and pump-shutdown stages. Therefore, seasonal variations in fracturing fluid temperature should be fully considered in transient wellbore temperature prediction and fracturing operation design.

Figure 16 shows the longitudinal wellbore temperature profiles at the pump-shutdown moment under different fracturing fluid injection temperatures. The dashed line represents the initial formation temperature profile, which increases gradually with well depth and reflects the undisturbed geothermal condition before fracturing. The solid lines represent the wellbore temperature distributions at the pump-shutdown moment for different injection-temperature conditions. These different injection temperatures correspond to

fracturing operations conducted in different seasons, during which the surface ambient temperature and the initial temperature of the fracturing fluid may vary significantly.

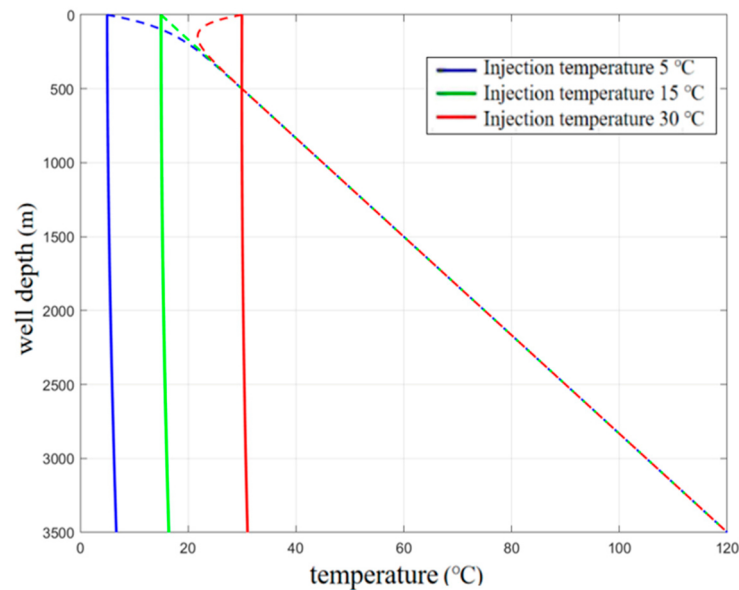


Figure 16. Longitudinal wellbore temperature profiles at the pump-shutdown moment under different injection temperature.

As shown in Figure 16, after 90 min of continuous fracturing fluid injection, the wellbore temperature along the entire depth is markedly lower than the initial formation temperature. This indicates that the injected low-temperature fracturing fluid produces a strong cooling effect on the wellbore–formation system. Moreover, the longitudinal temperature profiles under different seasonal injection-temperature conditions are clearly separated. When the injection temperatures are 5 °C, 15 °C, and 30 °C, the corresponding wellbore temperatures at the pump-shutdown moment are approximately 8 °C, 17 °C, and 31 °C, respectively. This demonstrates that the injection temperature directly controls the final cooling level of the wellbore during fracturing.

It can also be observed that the three temperature profiles are nearly parallel along the well depth, indicating that the effect of injection temperature is transmitted throughout the entire wellbore during continuous injection. A lower injection temperature, which typically corresponds to winter or low-ambient-temperature operations, results in a stronger cooling effect and a lower wellbore temperature profile. In contrast, a higher injection temperature, which may correspond to summer or high-ambient-temperature operations, leads to a weaker cooling effect and a relatively higher wellbore temperature profile.

Overall, seasonal variation in fracturing fluid injection temperature has a significant influence on the longitudinal wellbore temperature distribution at the pump-shutdown moment. Therefore, the effect of seasonal surface temperature changes on fracturing fluid temperature should be fully taken into account in transient wellbore temperature prediction and fracturing operation design.

5.4. Sensitivity Analysis of Factors Influencing Wellbore Temperature During Fracturing

To quantitatively evaluate the influence of different operating parameters on the wellbore temperature field, two normalized sensitivity coefficients were introduced in this study. One was used to characterize the sensitivity of bottomhole temperature, and the other was used to evaluate the sensitivity of the longitudinal wellbore temperature profile at the pump-shutdown moment.

The sensitivity coefficient of bottomhole temperature is defined as:

$$S_{b,i} = \frac{|\Delta T_b|/\bar{T}_b}{|\Delta X_i|/\bar{X}_i} \quad (22)$$

where $S_{b,i}$ is the sensitivity coefficient of parameter X_i to the bottomhole temperature, ΔT_b is the variation range of the stable bottomhole temperature under different values of parameter X_i , $\bar{T}_b$ is the average stable bottomhole temperature, ΔX_i is the variation range of parameter X_i , and $\bar{X}_i$ is the average value of parameter X_i .

To further investigate the transient evolution of parameter sensitivity during the injection stage, the sensitivity coefficients $S_{b,i}$ defined in Equation (22) were calculated at three representative times: 10 min, 45 min, and 90 min. The corresponding results are shown in Figure 17.

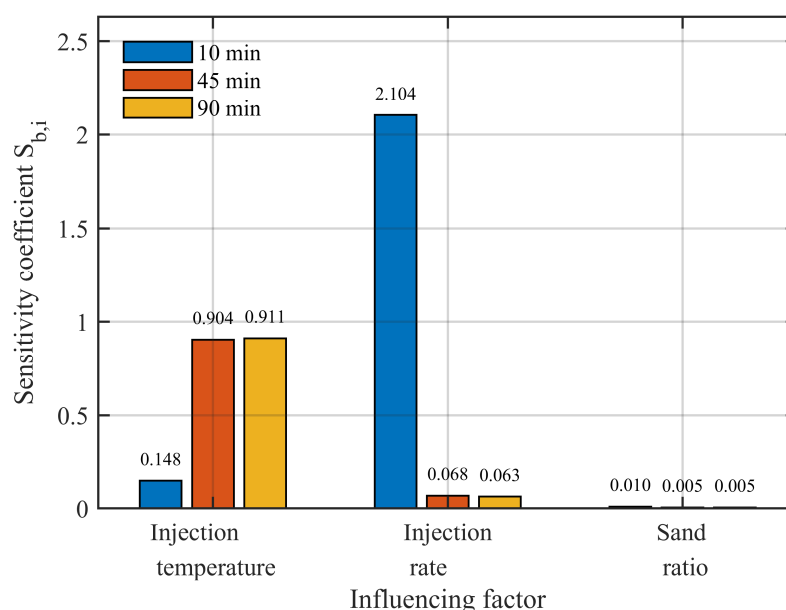


Figure 17. Time-dependent sensitivity coefficients of bottomhole temperature at different injection times.

As shown in Figure 17, the relative importance of the influencing factors changes with injection time. At 10 min, the sensitivity coefficient of injection rate is the largest, reaching 2.104, while the sensitivity coefficient of injection temperature is 0.148. This indicates that, during the early injection stage, bottomhole temperature is more sensitive to injection rate. This is mainly because the low-temperature front has not yet fully propagated to the bottomhole, and the axial convective transport capacity controlled by injection rate plays a dominant role in determining the early thermal response.

At 45 min and 90 min, the sensitivity coefficient of injection temperature increases significantly to 0.904 and 0.911, respectively, and becomes the dominant factor affecting bottomhole temperature. This is because, after the cooling front has propagated along the wellbore, the bottomhole temperature is primarily controlled by the thermal boundary condition imposed at the wellhead. In contrast, the sensitivity coefficient of injection rate decreases to 0.068 at 45 min and 0.063 at 90 min, indicating that its influence weakens after the flow and heat-transfer process gradually approaches a quasi-stable state.

The sensitivity coefficient of the sand ratio remains very small at all three time points, with values of 0.010, 0.005, and 0.005 at 10 min, 45 min, and 90 min, respectively. This indicates that sand ratio has a much weaker influence on bottomhole temperature than injection temperature and injection rate. The reason is that the sand ratio affects the temperature field mainly through changes in the equivalent thermophysical properties of the proppant-laden

fluid, such as density, heat capacity, viscosity, and thermal conductivity, rather than directly controlling the inlet thermal boundary condition or the axial transport rate.

Overall, the transient sensitivity analysis shows that injection rate dominates the early-stage bottomhole temperature response, whereas injection temperature becomes the most important factor during the middle and late injection stages. The sand ratio has only a secondary influence throughout the injection process.

For the longitudinal wellbore temperature profile at the pump-shutdown moment, the average wellbore temperature along the well depth is first calculated as:

$$\bar{T}_{w,j} = \frac{1}{L} \int_0^L T_j(z, t_s) dz \quad (23)$$

where $\bar{T}_{w,j}$ is the average wellbore temperature at the pump-shutdown moment under the (j)-th working condition, L is the well depth, and $T_j(z, t_s)$ is the wellbore temperature at depth (z) and pump-shutdown time t_s . The corresponding sensitivity coefficient is defined as:

$$S_{w,i} = \frac{|\Delta \bar{T}_w| / \bar{T}_w}{|\Delta X_i| / \bar{X}_i} \quad (24)$$

where $S_{w,i}$ is the sensitivity coefficient of parameter X_i to the longitudinal wellbore temperature profile at the pump-shutdown moment, $\Delta \bar{T}_w$ is the variation range of the average wellbore temperature among different working conditions, and $\bar{T}_w$ is the mean value of the average wellbore temperatures.

According to the above definitions, the sensitivity of fracturing fluid injection temperature, injection rate, and proppant concentration can be quantitatively compared from two aspects: bottomhole temperature response and longitudinal wellbore temperature distribution at pump shutdown.

Figure 18 presents the sensitivity coefficient of the main factors affecting the wellbore temperature field during fracturing. Here, S_b represents the sensitivity coefficient of bottomhole temperature and S_w represents the sensitivity coefficient of wellbore temperature at the pump-shutdown moment. The three influencing factors considered are injection temperature, injection rate, and proppant concentration.

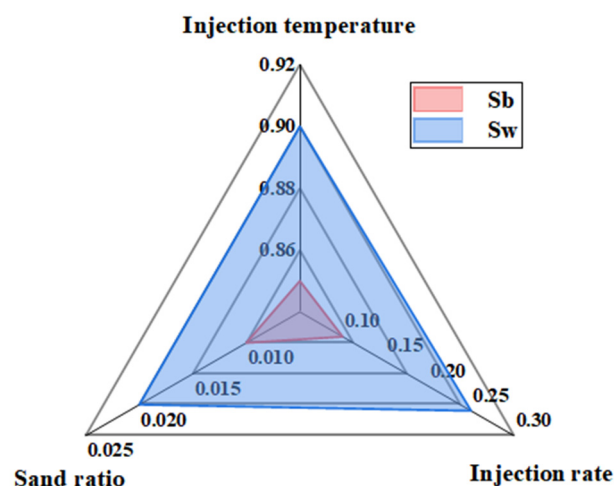


Figure 18. Sensitivity coefficient of influencing factors on wellbore temperature during fracturing.

As shown in Figure 18, within the investigated parameter ranges, the fracturing fluid injection temperature exhibits the highest normalized sensitivity with regard to both the bottomhole temperature and the wellbore temperature at the pump-shutdown moment. The sensitivity coefficient of the injection temperature is approximately 0.30 for bottomhole

temperature and approximately 0.90 for the temperature distribution in the wellbore when the pump is stopped. This indicates that the injection temperature is the primary factor controlling the thermal state of the wellbore during the fracturing process. This is because the injection temperature directly determines the temperature level of the low-temperature fluid entering the wellbore, and during continuous injection, its influence can propagate along the entire wellbore depth.

The injection rate exhibits moderate sensitivity. The sensitivity coefficient is approximately 0.10 for bottomhole temperature and approximately 0.25 for the temperature distribution within the wellbore when the pump is stopped. This indicates that increasing the injection rate mainly affects the migration velocity of the low-temperature fracturing fluid and enhances the forced convective heat-transfer intensity, thereby accelerating the cooling response of the wellbore. However, its influence on the final temperature level is weaker than that of injection temperature.

In contrast, proppant concentration has the lowest sensitivity, with sensitivity coefficients of only approximately 0.01 and 0.02 for bottomhole temperature and pump-shutdown wellbore temperature, respectively. Although the addition of proppant particles changes the effective thermophysical properties of the fracturing fluid, its influence on the overall wellbore temperature field is limited within the investigated concentration range.

The normalized sensitivity coefficients in Figure 18 further reveal the physical control mechanisms of the wellbore temperature field during fracturing fluid injection. The injection temperature has the highest sensitivity because it directly determines the thermal boundary condition of the fluid entering the wellbore. Under continuous high-rate injection, the injected fluid rapidly replaces the original high-temperature fluid in the tubing, and the thermal effect of the inlet temperature is transmitted along the entire well depth through axial convection. Therefore, even a moderate variation in injection temperature can directly shift the overall temperature level of both the bottomhole and the longitudinal wellbore profile.

The injection rate shows a moderate sensitivity. Increasing the injection rate enhances the axial convective heat-carrying capacity of the fracturing fluid and increases the Reynolds number, which further strengthens the forced convective heat transfer between the fluid and the tubing wall. As a result, a higher injection rate accelerates the early cooling response and slightly lowers the quasi-steady bottomhole temperature. However, once the injected low-temperature fluid has fully reached the bottomhole and the wellbore enters a low-temperature quasi-steady state, the final temperature level is mainly constrained by the injection temperature. Therefore, the normalized sensitivity of injection rate is lower than that of injection temperature.

In contrast, the sand ratio exhibits the lowest sensitivity. Although increasing the sand ratio changes the effective density, specific heat capacity, thermal conductivity, and viscosity of the proppant-laden slickwater, these property variations only indirectly affect the heat-transfer process through the Reynolds number, Prandtl number, and convective heat-transfer coefficient. Within the investigated sand-ratio range, the resulting changes in the overall heat-carrying capacity and radial heat exchange are limited. Consequently, the sand ratio has only a weak influence on the bottomhole temperature and the longitudinal wellbore temperature profile.

From an engineering perspective, the sensitivity coefficients indicate that controlling the injection temperature is the most effective way to regulate the wellbore thermal state during fracturing. The injection rate mainly affects the cooling response time and can be optimized to improve operational efficiency, whereas the sand ratio has a limited effect on temperature control and should be selected primarily according to reservoir stimulation and proppant-transport requirements.

It should be noted that the sensitivity analysis in this study was conducted using a one-factor-at-a-time (OFAT) approach. That is, the injection rate, sand ratio, and injection temperature were varied separately while the other operating parameters were kept constant. Therefore, the sensitivity coefficients shown in Figure 18 represent normalized local sensitivities under the selected reference conditions, rather than global sensitivity indices that include all possible parameter interactions.

The interaction effects among operating parameters were not systematically tested in the present study. Within the investigated parameter ranges, these interactions are assumed to be secondary compared with the individual effects of the main parameters. This assumption is based on the different physical roles of the three parameters in the heat-transfer process. The injection temperature directly controls the inlet thermal boundary condition, the injection rate mainly affects axial convective heat transport and the forced convective heat-transfer coefficient, and the sand ratio influences the temperature field indirectly through the effective thermophysical properties of the proppant-laden fluid. Therefore, the dominant sensitivity ranking obtained in this study is expected to remain valid under the investigated engineering conditions.

Nevertheless, parameter interactions may become more significant under wider operating ranges, such as simultaneous low-temperature and high-rate injection, or high sand-ratio conditions combined with strong changes in fluid viscosity. A full factorial design, response-surface method, or global sensitivity analysis can be adopted in future work to quantitatively evaluate such interaction effects.

5.5. Discussion on Potential Thermal-Shock Effect

The present study focuses on transient wellbore heat transfer and does not explicitly consider the thermo-mechanical response of the surrounding rock. Under large temperature differences between low-temperature fracturing fluid and high-temperature formation, rapid near-wellbore cooling may generate thermal stresses and induce thermal micro-cracking, which can further affect rock strength, permeability, and fracture complexity. Previous studies [30] have shown that thermal shock in rocks is related to temperature difference, heating or cooling rate, mineral composition, water saturation, confining stress, and thermal cycling; commonly used thresholds such as a temperature-change rate of about $2\text{ }^{\circ}\text{C}/\text{min}$ and a critical temperature of about $75\text{ }^{\circ}\text{C}$ are still not universal. Therefore, the temperature results obtained in this study should be regarded as thermal input for future thermo-mechanical damage analysis. The coupling among heat transfer, thermal stress, rock damage, and permeability evolution will be considered in future work.

6. Conclusions

In this study, a transient wellbore temperature field model for shale gas fracturing was established by coupling the effective thermophysical properties of proppant-laden slickwater, axial convective heat transport in the tubing, radial heat transfer through multilayer wellbore structures, and transient heat conduction in the formation. The model was verified using COMSOL finite element simulations, and the effects of injection rate, proppant concentration, and injection temperature on the wellbore temperature field were analyzed. The main conclusions are as follows:

- (1) The proposed model effectively describes the transient temperature evolution during fracturing fluid injection and pump shutdown. Under reference conditions—with an injection temperature of $20\text{ }^{\circ}\text{C}$, an injection rate of $12\text{ m}^3/\text{min}$, and an injection duration of 90 min—the bottomhole temperature rapidly drops to approximately $20\text{--}25\text{ }^{\circ}\text{C}$, after which it enters a low-temperature quasi-steady state. Following pump shutdown, influenced by radial heat conduction through the for-

mation, the bottomhole temperature gradually rises to approximately 40 °C by 120 min. The theoretical results show acceptable agreement with the finite element simulation results in terms of bottomhole temperature variation, vertical temperature distribution, and radial temperature response, indicating that the model has good reliability and can serve as a simplified engineering-oriented tool for wellbore temperature prediction.

- (2) The injection rate primarily influences the early cooling response of the wellbore. When the injection rate was increased from 8 m³/min to 16 m³/min, the time required for the bottomhole temperature to fall below 25 °C was reduced from approximately 13–14 min to 8–9 min, whilst the steady-state bottomhole temperature decreased only slightly from approximately 23.0 °C to 21.3 °C. By contrast, the proppant concentration has a weaker effect on the borehole temperature field. When the proppant concentration is increased from 6% to 15%, the bottomhole temperature curve almost coincides with the vertical temperature profile at pump stop.
- (3) Within the investigated parameter ranges, the fracturing fluid injection temperature exhibits the highest normalized sensitivity to the wellbore temperature field among the three operating parameters considered. When the injection water temperatures are 5 °C, 15 °C and 30 °C respectively, the steady-state bottomhole temperatures are approximately 8 °C, 17 °C and 31 °C; 120 min after the pump is stopped, the corresponding bottomhole temperatures recover to approximately 23 °C, 32 °C and 44 °C. Sensitivity analysis indicates that fracturing fluid temperature exhibits the highest sensitivity, followed by fracturing rate, whilst proppant concentration shows relatively low sensitivity. Therefore, in wellbore temperature prediction and fracturing parameter optimization, priority should be given to the seasonal variation in fracturing fluid temperature and the selection of fracturing rate.
- (4) It should be noted that the present model treats proppant-laden slickwater as an equivalent homogeneous fluid. Therefore, particle settling, local concentration non-uniformity, and possible liquid–solid thermal non-equilibrium are not explicitly resolved and should be considered in future two-phase model extensions.

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Nomenclature

Symbol	Description	Unit
A_t	Cross-sectional area of the tubing	m^2
B	Empirical exponent in the suspension viscosity model	/
C_s	Sand concentration, defined as the mass of proppant added per unit volume of base fluid	kg/m^3
$c_{p,m}$	Effective specific heat capacity of proppant-laden slickwater	$\text{J}/(\text{kg}\cdot\text{K})$
$c_{p,s}$	Specific heat capacity of proppant	$\text{J}/(\text{kg}\cdot\text{K})$
$c_{p,w}(T)$	Specific heat capacity of water as a function of temperature	$\text{J}/(\text{kg}\cdot\text{K})$
d_t	Inner diameter of the tubing	m
D_t	Outer diameter of the tubing	m
d_c	Inner diameter of the casing	m
D_c	Outer diameter of the casing	m
d_{cem}	Inner diameter of the cement sheath	m
D_{cem}	Outer diameter of the cement sheath	m
f	Darcy friction factor	/
G	Geothermal gradient	K/m
h_i	Forced convective heat-transfer coefficient inside the tubing	$\text{W}/(\text{m}^2\cdot\text{K})$
k_m	Effective thermal conductivity of proppant-laden slickwater	$\text{W}/(\text{m}\cdot\text{K})$
k_s	Thermal conductivity of proppant	$\text{W}/(\text{m}\cdot\text{K})$
$k_w(T)$	Thermal conductivity of water as a function of temperature	$\text{W}/(\text{m}\cdot\text{K})$
L	Well depth	m
Nu_i	Nusselt number for forced convection inside the tubing	/
Nu_a	Nusselt number for natural convection in the annulus	/
Pr_m	Prandtl number of proppant-laden slickwater	/
$Q(t)$	Wellhead injection rate	m^3/s
q_r	Radial heat-transfer rate per unit well depth	W/m
$r_e(t)$	Time-dependent equivalent thermal influence radius of the formation	m
$R_g(t)$	Transient equivalent thermal resistance of the formation	$\text{K}\cdot\text{m}/\text{W}$
R_{tot}	Total equivalent thermal resistance of the wellbore–formation system per unit well depth	$\text{K}\cdot\text{m}/\text{W}$
Re_m	Reynolds number of proppant-laden slickwater	/
t_s	Pump-shutdown time	s
T_f	Temperature of the proppant-laden fluid in the tubing	K
$T_{g,\infty}$	Far-field formation temperature	K
$T_{g,0}(z)$	Initial formation temperature at depth z	K
$T_{in}(t)$	Wellhead injection temperature	K
T_s	Surface temperature	K
ΔT_b	Variation range of stable bottomhole temperature	K
u	Average flow velocity inside the tubing	m/s
η	Intrinsic viscosity of proppant particles	/
λ_a	Thermal conductivity of annular fluid	$\text{W}/(\text{m}\cdot\text{K})$
λ_c	Thermal conductivity of production casing	$\text{W}/(\text{m}\cdot\text{K})$
λ_{cem}	Thermal conductivity of cement sheath	$\text{W}/(\text{m}\cdot\text{K})$
λ_g	Thermal conductivity of formation	$\text{W}/(\text{m}\cdot\text{K})$
λ_t	Thermal conductivity of tubing	$\text{W}/(\text{m}\cdot\text{K})$
μ_m	Effective viscosity of proppant-laden slickwater	$\text{mPa}\cdot\text{s}$
$\mu_w(T)$	Viscosity of water as a function of temperature	$\text{mPa}\cdot\text{s}$
ϕ_s	Proppant volume fraction	/
ρ_m	Effective density of proppant-laden slickwater	kg/m^3
ρ_s	Density of proppant	kg/m^3
$\rho_w(T)$	Density of water as a function of temperature	kg/m^3

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