Modeling and Simulation of Shale Fracture Attitude
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ABSTRACT: A large number of natural fractures are distributed in shale gas reservoirs. In-depth studying of the attitude of fractures is of great significance for the efficient development of shale gas. In previous studies, the complex three-dimensional discrete fracture networks (DFNs) and transport mechanisms were often not fully considered. In this study, the fully coupled multimechanism transport model and the complex discrete fracture networks (DFNs) model are developed to incorporate these complexities. The comprehensive transport model can couple multiple mechanisms such as slippage, diffusion, adsorption, and dissolution of shale gas. Moreover, the mechanisms of two-phase flow, reservoir deformation, real gas effect, and fracture closure are also considered. The three-dimensional DFN model can flexibly characterize the fracture attitudes, which means that the construction of the discrete fracture network is easier and faster. Under these frameworks, a series of partial differential equations (PDEs) were derived to describe transport mechanisms of shale gas in the shale fracture-matrix system. These PDEs were numerically discretized and solved by the finite element method. The proposed models are verified against gas production data from the field and validated against others’ solutions. This study numerically simulates the influence of different fracture attitudes on shale gas transport and analyzes the sensitivity of the model. The results and sensitivity analysis reveal that both fracture dip angle and strike direction will significantly affect the gas production, and the smaller the angle between the strike direction and the flow direction, the higher the shale gas production. The length, density, area, and shape of fractures also play important roles in shale gas transport. There is an ideal fracture density in the fracture network, and the suggested excessive fracturing is not economic. The shale fracture-matrix system modeling and simulation methods can improve the development of shale gas reservoirs and increase the gas production of wells.

1. INTRODUCTION
Shale gas is an important unconventional natural gas resource, and it has become increasingly important in the global energy system. The scientific and efficient development of shale gas reservoirs can bring substantial economic benefits.1 Shale gas reservoirs have complex geological conditions and often have a large number of natural fractures.2 These fractures are essential storage spaces and transport channels for shale gas.3–5 Studying and understanding the distribution and attitude of natural fractures in shale gas reservoirs will help efficiently develop shale gas reservoirs and increase the shale gas production rate of wells.4 The attitude here refers to the dip angle and strike direction of a fracture. At present, engineers can learn about the distribution and attitude of fractures in shale formations by drilling cores, logging, and microseisms.6–8 A number of studies have been performed on shale fractures, mostly focusing on the distribution and permeability of fractures, but there are few detailed reports on how the attitude of fractures affects the flow of shale gas.

At present, there are many models that can simulate the flow of shale gas in the formation. Due to the obvious differences in the physical properties between shale matrix and fractures, and the uncertainty of natural fractures’ strike directions and dip angles, it is challenging to simulate shale gas transport in fractured porous media. Since the 1960s, scholars have
conducted in-depth research on fluid flow and transport behavior in fractured pore media and have made important progress in modeling fluid flow in fractured pore media. As shown in Figure 1, the types of models are roughly divided into discrete fracture models, continuous models, and hybrid models of discrete fracture models and continuous fracture models. The fracture geometry in discrete fracture models is the same as the fracture geometry in the real formation, such as the model of Bahrainian et al. The continuous model regards the fracture as the same continuous medium as the matrix, such as the models of Li et al. and Liu et al. In the hybrid model, some large-scale fractures are regarded as discrete fractures, and some small-scale fractures are regarded as continuous media, such as the model of Brenner et al. and Zhao et al.

The continuous (double porosity or triple porosity) model is an ideal fracture model, which has certain limitations for modeling complex fractures. For example, it is difficult to describe the fracture attitude. The discrete fracture model is a model different from the continuous model for simulating the fracture system. Unlike the continuous models, the discrete fracture model can handle three-dimensional (3D) complex fractures better and its local refinement of the grid can simulate real complex fracture geometry. This is because the shape of fractures in the discrete fracture method is similar to the real situation of shale formation. This method can describe the fracture geometry and the connectivity of the fracture network in detail, which can more accurately characterize the physical mechanism and perform reliable simulation and prediction of gas transport through shale fracture. However, in the continuum method, the real discrete fractures are equivalent to a continuous medium to simplify in a large-scale computing. Because the model constructed by the discrete fracture method is much more closer to the real situation in the formation, the results of the discrete fracture method are more accurate. Therefore, discrete fracture modeling has always received considerable attention.

The concept of discrete fractures was first proposed by Snow for rock hydraulics. At present, the discrete fracture model involved in reservoir numerical simulation was proposed by Noorishad et al. in 1982. The finite element method (FEM) is used to solve the two-dimensional (2D) solute diffusion-convection problem in fractured media. In the calculation, the bedrock is discretized by two-dimensional surface elements, and the fractures are reduced by one-dimensional line elements. The superposition principle is used to couple the two. In 1999, Kim et al. applied it to the numerical simulation of fractured reservoirs and studied the oil–water two-phase flow problem of the two-dimensional discrete fracture model. In recent years, discrete fracture models have made great progress in numerical simulation of fractured reservoirs.

The study of discrete fracture models of shale gas reservoirs is later than that of traditional oil and gas reservoirs. Mi et al. established a mathematical model of a shale gas discrete fracture network to characterize the diffusion effect, the adsorption–desorption effect, the slippage effect in nanopores, and the Knudsen diffusion effect. The simulation of fractured shale gas is more in line with the actual situation. Zhao et al. described the shale reservoir by a triple medium model composed of a double-continuous medium and a discrete fracture model and consider multiple migration mechanisms concerning compression and matrix shrinkage. Zhang et al. proposed a coupled MINC media and discrete fracture networks (DFNs) model for MFHW with a complex fracture geometry in a shale gas reservoir. Wei et al. presented a triple-continuum and discrete fracture model to describe a fractured shale reservoir embedded with an MFHW, and the discrete fracture networks (DFNs) are quantitatively constructed according to the fracture density and stimulated reservoir area (SRA). Zhong et al. constructed a high-resolution 3D reservoir model by upscaling the stochastic 3D DFN model into an equivalent continuum dual-porosity dual-permeability (DPDK) model and employed an apparent permeability (Kapp) model to model transport mechanisms in nano-sized pore systems.

Herein, a brief review on the outstanding studies in the area of pore network modeling in shale gas flow applications is presented in Table 1. In this table, different models are compiled in a chronological order in which strengths and limitations of each item are discussed. As shown in Table 1, the discrete fracture models of shale gas in previous studies have some limitations. The discrete fracture models of shale and the transport mechanisms of shale gas have not been comprehensively considered. The models cannot simultaneously consider the three-dimensional complex shape and closure of fractures, as well as the micro-scale effect of shale gas, two-phase flow, and so on.

Based on the idea of discrete fractures and in view of the shortcomings of the current research, this study proposes a modeling and simulation method for shale three-dimensional fracture attitude. The modeling method can flexibly describe the attitude of three-dimensional discrete fractures in shale gas reservoirs. Through the derived mathematical model of the fracture attitude and the program constructed therefrom, the method can quickly generate and modify the specific posture of...
| Model description | Strengths | Limitations |
|-------------------|-----------|-------------|
| Mi et al.19 | build mathematical models to characterize gas flow in both fractures and shale matrix on the basis of DFNs | took into account multiple transport mechanisms of shale gas, the model is two-dimensional, and the two-phase flow was not considered |
| Fan et al.27 | introduced a fully coupled gas flow and deformation model | considered the stress-strain relationship, and density of the fracture properties |
| McClure et al.26 | developed a hydraulic-fracturing simulator that implicitly couples fluid flow with the stresses induced by fracture deformation in large, complex, 3D DFNs | described the propagation of hydraulic fractures and opening and shear stimulation of natural fractures, rough fractures were not considered, and changing the attitude of fractures was not easy |
| Cao et al.28 | proposed a multiscale-multiphase simulation model, which defines the whole domain as three sections | considered the gas-water two-phase flow, reservoir deformation was not considered |
| Karimzade et al.29 | developed a computer code for a three-dimensional discrete fracture network modeling of water flow into underground excavations | fracture properties such as size, orientation, and density of the fracture were modeled by their respective probability distribution, the algorithm was complex, and the coupling of transport mechanisms was ignored |
| AlTwaijri et al.30 | a fast EDFM method was developed to model complex fracture geometries in shale gas reservoirs | considered two-phase performance and a complex natural network reservoir deformation was not considered |
| Liu et al.31 | developed a fractal permeability model that defines coal permeability as a function of effective stress and fractures in coal seam | applied the fractal permeability model to fully couple coal reservoir properties and coal-rock deformation, the model was two-dimensional, and surface diffusion was not considered |
| Zhang et al.32 | proposed a scheme for coupling stress-dependent matrix apparent permeability and matrix permeability, as well as modeling pressure-dependent fracture closure | proposed a scheme for coupling stress-dependent matrix apparent permeability and matrix permeability, as well as modeling pressure-dependent fracture closure |
| Zhong et al.33 | proposed a scheme for coupling stress-dependent matrix apparent permeability and matrix apparent permeability, as well as modeling pressure-dependent fracture closure | proposed a scheme for coupling stress-dependent matrix apparent permeability and matrix apparent permeability, as well as modeling pressure-dependent fracture closure |
the fracture instead of manually remodeling and importing fractures as in some software. At the same time, the shale gas transport mechanism is more comprehensively considered. The factors considered by the model are the coupling of slippage flow and diffusion, multiscale effects, real gas effects, and stress sensitivity of fractures. Moreover, the model also considers the dissolved gas stored in organics of shale, which was often ignored by other similar models. The above factors are the novelty of this article. Then, through the finite element numerical solution method to solve the model, one can simulate the effect of fracture attitude on shale gas transport and predict the production of shale gas. The results of this study can be used for developing a scheme design and for production prediction of shale gas reservoirs. It has a certain guiding role for fracturing artificial fractures in shale gas reservoirs. In addition, after obtaining the fracture information in the formation through seismic interpretation and logging methods, the study can be used for well location optimization and drilling trajectory design.

2. RESEARCH METHODS

In this section, the shale three-dimensional fracture attitude model and the shale gas transport model in the shale matrix and fracture are derived, and then, the finite element calculation format is also derived.

2.1. Establishment of the Shale Fracture-Matrix Geometric Model. 2.1.1. Model Definition. Natural fractures are widely distributed in shale formations, and the attitude of fractures is variable. In addition to natural fractures, hydraulic-fracturing methods are often used to create artificial fractures to improve the permeability of the shale layer near the bottom of production wells for increasing the production rate of shale gas wells. To accurately describe the attitude of fractures, it is necessary to define some fracture geometric characteristics. As shown in Figure 2, the strike direction of a fracture can be defined as the angle between the fracture strike line and the true north. The trend line of a fracture is the intersection of the horizontal plane and the fracture plane. The dip direction of a fracture is perpendicular to the strike line. The dip angle is the angle between the horizontal plane and the fracture surface.

2.1.2. Expression Equation of the Fracture Surface. To establish a digital model, it is necessary to characterize the attitude of fractures based on mathematical equations. Assuming that the dip angle of the fracture is \( \theta \), the strike direction of the fracture is \( \phi \), while the true north direction is the positive direction of the \( y \)-axis on the \( x-y \) plane. Based on the knowledge of solid geometry, the mathematical expression of the fracture attitude is as follows

\[
\alpha \beta \gamma \cdot -x + \cdot -y + \cdot -z = 0
\]

where \((x_0, y_0, z_0)\) is a point on the fracture plane. Angles \( \alpha, \beta, \) and \( \gamma \) are the angles between the normal vector of the fracture surface and the \( x \)-axis, \( y \)-axis, and \( z \)-axis of the Cartesian coordinate system, respectively. According to the geometric relationship of triangles, the relationships between the dip angle and strike direction of the fracture and \( \alpha, \beta, \) and \( \gamma \) are as follows

\[
\cos \alpha (x - x_0) + \cos \beta (y - y_0) + \cos \gamma (z - z_0) = 0
\]
The geological modeling of shale gas reservoirs is a complex process that requires a comprehensive geological model required for shale gas transport. 

2.1.3. Geometric Model of the Fracture-Matrix System. A single discrete fracture-matrix system is used to illustrate the construction method of discrete fractures in the shale formations. The geometric model of discrete fractures in a shale matrix block is shown in Figure 3, where the cube represents the shale matrix block. The matrix of the shale is very dense, and the permeability is extremely low; however, a large number of micro-nano pores and kerogen organic matter are developed, which are the main storage spaces for the shale gas. The blue circular plate in the model represents a discrete fracture located in the center of the matrix block.

In such a geometric model, the simplified circular fracture plate is obtained by the intersection of the fracture plane and the sphere. The size of the fracture can be determined by the diameter of the sphere.

The dip angle \( \varphi \) and strike angle \( \theta \) of the fracture can be easily changed by adjusting their parameters. Surface A represents the inlet end of the shale gas, while surface B represents the outlet end of the shale gas. In this discrete fracture-matrix unit, the shale gas flows from surface A to surface B.

2.1.4. Geological Modeling of Real Shale Gas Reservoirs. The geological modeling of shale gas reservoirs is a complex and specialized technology. The geological model should integrate as much information as possible to build a geological model close to the actual one. The modeling work mainly adopts the technological process of progressive superposition modeling. First, based on the subdivision and comparison data of the drilling sublayers, as well as the fine structure interpretation of the seismic data, a shale gas reservoir stratigraphic framework can be established. Then, based on the stratigraphic framework, the attribute models of the shale matrix can be established from the sampled geological experiment data, logging data, and interpretation results as well as the prediction results of seismic prestack and poststack data. The parameters of the attribute model include thickness, organic geochemistry, porosity, permeability, gas content, and brittleness index. Then, based on the quantitative characterization of fractures in the core and outcrop sections, the distribution characteristics of the fracture network can be established.

The natural fracture model can be built based on logging fracture interpretation, multiscale, multimethod seismic fault, and fracture prediction. Large fractures can be determined based on seismic interpretation and downhole imaging logging, while small fractures can be determined based on the geostatistics. Under the constraints of the previously established matrix attribute model and the natural fracture model, the artificial fracture distribution model can be obtained based on the interpretation results of microseismic data, combined with the analysis of the fracturing process. Finally, the above models are gradually merged. Superimposing the natural fracture model and the artificial fracture model and then combining them with the matrix attribute model can form a comprehensive geological model required for shale gas numerical simulation.

2.2. Mathematical Model of the Transport Mechanism in the Shale Fracture-Matrix System. After establishing the geometric model of the shale fracture-matrix system, it is necessary to establish mathematical models that can characterize the complex transport mechanism of shale gas in the discrete fractures and matrix blocks. Compared with the conventional sandstone natural gas reservoirs, the mechanisms of shale gas transport in shale formations are much more complicated. This paper comprehensively considers the multiple transport mechanisms of shale gas, bringing the model more in line with the real shale gas reservoir situation. In the transport model, the coupling transport mechanisms of shale gas slippage and diffusion; the storage mechanisms of the free state, adsorbed state, and dissolved state; and the real gas effect and fracture sensitivity are considered. The detailed derivation process and description will be expanded as follows.

2.2.1. Model Assumptions. Before establishing a mathematical model, reasonable assumptions about shale gas transport models are required. These assumptions help simplify the model and reduce the calculation of the model, without affecting the description of the shale gas transport mechanism. In this paper, based on the properties and fluid characteristics of shale gas reservoirs, the following assumptions are made for the shale gas transport models: (a) ignore gas gravity; (b) no phase change occurs; (c) isothermal flow process; (d) two-phase flow; (e) consider the closure of fractures during the production process; and (f) the produced gas is ideal gas or nonideal gas.

2.2.2. Establishment of Motion Equations of Shale Gas. The establishment of shale gas motion equations focuses on the mechanisms of shale gas slippage and diffusion, as well as their interaction effects. These transport mechanisms are suitable for gas transport in micro-nano-scale pores and fractures in shale formations. The micro-nano-scale pores and fractures are widely developed in shale formations, and these pores and fractures are interconnected to form complex transport channels. During the diagenesis process, shale will form natural bedding, and geological tectonic movement will cause structural cracks in the formation. In addition, artificial hydraulic fracturing will form a fracture network near the wellbore.

Shale gas has both slip flow and diffusion flow in the shale formation. The Knudsen number is an important parameter for

\[
\begin{align*}
\cos \alpha &= \sin \left( \theta - \frac{3\pi}{2} \right) \cos \left( \frac{\pi}{2} - \varphi \right) \\
\cos \beta &= \cos \left( \theta - \frac{3\pi}{2} \right) \cos \left( \frac{\pi}{2} - \varphi \right) \\
\cos \gamma &= \sin \left( \frac{\pi}{2} - \varphi \right) 
\end{align*}
\]
characterizing shale gas transport. It is the ratio of the free path of shale gas molecules to the characteristic diameter of shale pores. When the Knudsen number is small, collisions between gas molecules dominate the gas transport and gas molecules have a slip effect at the walls of pores. Based on the Darcy formula, the viscous flow velocity considering slippage is given as follows

\[ v_s = -\frac{\kappa_m}{\rho_g} F \nabla P_m \]  \hspace{1cm} (6)

where \( \mu_g \) is the viscosity of shale gas, \( \kappa_m \) is the permeability of the shale matrix, and \( P_m \) is the gas pressure in the shale matrix storage space. For a shale matrix with strong anisotropy, \( \kappa_m \) can be written as the following tensor form

\[ \kappa_m = \begin{bmatrix} \kappa_{mx} & 0 & 0 \\ 0 & \kappa_{my} & 0 \\ 0 & 0 & \kappa_{mz} \end{bmatrix} \]  \hspace{1cm} (7)

where \( \kappa_{mx}, \kappa_{my}, \) and \( \kappa_{mz} \) represent the permeability components along the \( x, y, \) and \( z \) directions, respectively.

To account for the reservoir deformation when pressure drops in the formations, this study uses stress-dependent permeability in our matrix model. Here, following the principle of reservoir deformation, we define the stress-dependent matrix permeability by

\[ \kappa_m = \kappa_{mo} e^{-d_s(T_m-P_m)} \]  \hspace{1cm} (8)

where \( \kappa_{mo} \) is the permeability at initial conditions and \( d_s \) is a characteristic parameter of the shale matrix, which is determined experimentally. \( P_m \) is the pore pressure at initial conditions in the shale matrix.

\( F \) is the slippage correction factor. Slip correction is required since gas molecules have a slip effect at the pore wall, and the correction factor is as follows

\[ F = \left( 1 + \frac{2\alpha_s K_n^\beta}{\pi} \right) \tan^{-1}\left( \frac{\alpha_s K_n^\beta}{b} \right) \left( 1 + \frac{4K_n}{1 - b K_n} \right) \]  \hspace{1cm} (9)

where \( b \) is the slippage factor, \( \alpha_s \) is the effective coefficient of the lean gas, and \( \alpha_1 \) and \( \beta \) are the fitting coefficients.

When the Knudsen number becomes larger, the diffusion effect of shale gas becomes obvious, and the diffusion rate of shale gas cannot be ignored. The diffusion velocity \( v_d \) of shale gas molecules can be expressed by Fick’s law

\[ v_d = -\frac{D_m}{\rho_g} \nabla \rho_g = -\frac{D_m}{\rho_g} \nabla \rho_g \]  \hspace{1cm} (10)

where \( D_m \) is the shale gas diffusivity coefficient and \( \rho_g \) is the shale gas concentration in the matrix. In this study, the following equation is given to compute the gas diffusivity constant in the shale matrix blocks

\[ D_m = \frac{\delta \phi}{3 \tau} \sqrt{\frac{8R T}{\pi M}} \]  \hspace{1cm} (11)

In eq 11, \( \delta \) is the characteristic diameter of the pore. It is expressed as \( \delta_m \) in the matrix system and expressed as \( \delta_f \) in the fracture system. \( M \) is the molar mass of shale gas molecules, \( R \) is the ideal gas constant, and \( T \) is the shale gas reservoir temperature. \( \phi \) is porosity, and \( \tau \) is tortuosity. Just like the permeability of the matrix, for the shale matrix with a strong anisotropy, the diffusion coefficient in different axis directions will also be different, which can be characterized by the following tensor form

\[ D_m = \begin{bmatrix} D_{mx} & 0 & 0 \\ 0 & D_{my} & 0 \\ 0 & 0 & D_{mz} \end{bmatrix} \]  \hspace{1cm} (12)

In the process of shale gas transport, there is a coupling phenomenon between gas slippage and diffusion flow. Therefore, the weight of coupling is needed to be considered when superposing the slippage and diffusion speed. The comprehensive transport speed of shale gas in shale can be expressed as follows

\[ v_m = \mathbf{m}_g v_s + \mathbf{m}_v v_d \]  \hspace{1cm} (13)

The shale gas flow velocity \( v_m \) in the matrix is the sum of the components of the slip velocity \( v_s \) and the Darcy velocity \( v_d \). The \( \mathbf{m}_g \) and \( \mathbf{m}_v \) are the coupling coefficients of slip flow and diffusion flow, respectively, and their expressions are

\[ \mathbf{m}_g = \frac{1}{1 + K_n}; \quad \mathbf{m}_v = \frac{K_n}{1 + K_n} \]  \hspace{1cm} (14)

Substituting eqs 6–12 and 14 into eq 13, the comprehensive velocity equation of shale gas transport in the shale matrix is

\[ v_m = \left( \frac{K_n \phi_m}{3(1 + K_n) \rho_g} \sqrt{\frac{8M}{\pi R T}} + \frac{k_m F}{\mu_g (1 + K_n)} \right) \nabla \rho_m \]  \hspace{1cm} (15)

2.2.3. Establishment of Storage State Equations of Shale Gas. Shale gas exists in shale formations in three forms: free state, adsorption state, and dissolved state. Shale gas is stored in the matrix pore space in the free state. The amount of free gas in the matrix pores can be expressed as the product of gas density and matrix porosity

\[ q_b = \rho_g \phi_m = \frac{\phi_m M_{p_m}}{RT} \]  \hspace{1cm} (16)

There are also a number of shale gas molecules adsorbed on the surface of shale organic matter in the shale matrix. It can be assumed that the adsorption type of adsorbed gas in the shale matrix is the Langmuir adsorption because the adsorption or desorption of shale gas is a very quick physical process during depressurization development of shale gas reservoirs. Therefore, the amount of adsorbed gas can be calculated using the Langmuir adsorption equation.59–41 The gas mass concentration of the adsorbed gas \( q_a \) in the shale matrix can be written as follows

\[ q_a = \left( 1 - \phi_m \right) \frac{M_{p_m}}{V_m} \frac{V_s P_m}{P_L + P_m} \]  \hspace{1cm} (17)

where \( V_L \) is the Langmuir volume, which is the maximum gas volume of adsorption at infinite pressure; \( P_L \) is the Langmuir pressure, referred to as the pressure corresponding to one-half Langmuir volume; and \( V_m \) is the molar volume at standard conditions (273.15 K and 101.325 kPa).

In addition to free gas and adsorbed gas, a small amount of shale gas is dissolved in shale kerogen.42 This study used Henry’s law to describe the behavior of dissolved shale gas in kerogen. Based on Henry’s law, the dissolved gas produced by kerogen can be expressed as follows
\[ q_v = V_b e H_l p_m \]  

(18)

where \( V_b \) is the volume of shale block and \( H_l \) is Henry's constant. \( e \) is the content of organic matter in the shale.

2.2.4. Real Gas Effect. The real gas under high-temperature and high-pressure environments of shale formation is quite different from the shale gas in the ideal state. Therefore, to accurately describe the transport mechanisms of shale gas under formation conditions, the real gas effect of shale gas needs to be considered. Gas compression factors \( Z \) are often used to correct the transport equation. The gas compression factor is a function of formation pressure and temperature, and it changes with the change in reservoir conditions. The calculation expression is as follows\(^4^5\)

\[ Z = (0.702 e^{-2.57T})P_r^2 - (5.524 e^{-2.57T})P_r + (0.0444T_r^2 - 0.1644T_r + 1.15) \]  

(19)

where \( P_r \) and \( T_r \) are relative formation pressure and relative formation temperature, respectively, and the expressions are

\[ P_r = \frac{P}{P_c}, \quad T_r = \frac{T}{T_c} \]  

(20)

where \( T_c \) and \( P_c \) represent the critical temperature and the critical pressure, respectively. According to the real gas state equation, the corrected real gas density expression is

\[ \rho_b = \frac{M_p}{RTZ} \]  

(21)

The gas viscosity considering the real gas effect can also be expressed as a function of relative pressure and relative temperature. The calculation equation is as follows\(^4^4\)

\[ \mu_b = \mu_{bg} \left[ 1 + A_1 \left( \frac{P_r^4}{T_r^{20} + P_r^4} \right) + A_2 \left( \frac{P_r}{T_r} \right)^2 + A_3 \left( \frac{P_r}{T_r} \right) \right] \]  

(22)

where \( \mu_{bg} \) is the gas viscosity in the ideal state and \( A_1, A_2, \) and \( A_3 \) are the fitting coefficients.

2.3. Establishment of the Comprehensive Transport Equation of Shale Gas. Based on the motion equation, state equation, and real gas effect established above, the comprehensive transport equation of shale gas in the shale matrix and discrete fractures will be derived separately.

2.3.1. Comprehensive Transfer Equation of Shale Gas in the Shale Matrix System. According to the principle of mass conservation, the gas transport of shale gas in the matrix is controlled by the mass conservation equation, which can be written as

\[ \frac{\partial}{\partial t}(q_g + q_s + q_l) = -\nabla (\rho_b q_{mg}) + q_{mgd} \Gamma \]  

(23)

where \( q_g \) is the mass concentration of shale gas adsorbed on the surface of organic matter, \( q_s \) is the free gas mass concentration of shale gas in the micro-nano pores of the shale matrix, and \( q_l \) is the dissolved gas mass concentration of shale organic matter. \( q_{mgd} \) represents the gas transport mass flux between the discrete fracture and the matrix, and \( \Gamma \) represents the interface between the discrete fracture and the shale matrix zone.

When eqs 15–22 are substituted into eq 23, the comprehensive transport equation of shale gas in the matrix can be written in the following form

\[ \left( \frac{M_{ph}}{RTZ} + \frac{M^2 V_i (1 - \phi_m) p_m (p_m + 2p_f)}{RTZ V_m (p_m + p_f)^2} \right) \frac{\partial p_m}{\partial t} = V_i \left( \frac{k_m F p_m}{3(1 + K_n)} \sqrt{\frac{8M}{\pi RT}} + \frac{k_m F p_m}{\mu_g RTZ (1 + K_n)} \right) V p_m \]  

(24)

2.3.2. Comprehensive Transfer Equation of Water in the Shale Matrix System. Based on the mass balance principle, the transport equation of the water phase in the shale matrix can be written in the following form

\[ \frac{\partial}{\partial t} (\rho_w S_{mw} \phi_m) = -\nabla (\rho_w v_{mw}) + q_{wmd} \Gamma \]  

(25)

where \( \rho_w \) is the density of the water phase, \( \phi_m \) is the porosity in the shale matrix, \( q_{wmd} \) is the water exchange between the shale matrix system and the fracture system, and \( S_{mw} \) is the saturation of the water phase in the matrix. Because there are two fluids in the matrix, it is easy to know that \( S_{mw} \) is equal to 1 minus the saturation of the gas phase \( S_{mg} \) in the matrix. Based on the generalized Darcy equation, the transport velocity of the water phase in the shale matrix can be written in the following form

\[ v_{mw} = -\frac{k_{wmo} K_{mw}}{\mu_w} \nabla p_{mw} \]  

(26)

where \( k_{wmo} \) is the permeability when the shale matrix is saturated with water, \( K_{mw} \) is the relative permeability of the water phase in the shale matrix, and \( p_{mw} \) is the pressure of the water phase in the shale matrix. Considering the slip effect of formation water in the micro-nano pores of the shale matrix, the inherent permeability of the shale matrix when the matrix is saturated with formation water is as follows

\[ k_{wmo} = \frac{r^2}{8} (1 + 4 \frac{l}{r}) \]  

(27)

where \( l \) is the slip length of the formation water. In addition, due to the small pore size in the matrix, the capillary force between the gas phase and the liquid phase in the matrix cannot be ignored. The capillary pressure in the shale matrix can be written in the following form

\[ p_{cm} = p_{mg} - p_{mw} = \frac{2\sigma \cos \theta}{r} \]  

(28)

where \( \sigma \) is the surface tension, \( \theta \) is the contact angle, and \( r \) is the radius of the pores in the matrix.

2.3.3. Comprehensive Transport Equation of Shale Gas in the Discrete Fracture System. The shale gas transport in fractures is dominated by viscous flow, supplemented by shale gas diffusion and slippage effect. Due to the small amount of organic matter in the shale gas fracture system, the occurrence of shale gas in the fractures is mainly free. According to the principle of conservation of mass, the conservation equation of shale gas in a discrete fracture system can be written as

\[ \frac{\partial}{\partial t} (w_i S_{gf} \phi_i) = -\nabla (w_i v_{gf}) + q_{gfd} \Gamma \]  

(29)

In eq 29, \( S_{gf} \) is the saturation of the gas phase in the fracture, \( v_{gf} \) is the transport speed of shale gas in the fracture.
system, $q_{gas}$ is the mass of shale gas exchange between the fractures and the shale matrix, and $w_f$ is the width of fractures.

Since fractures in the shale rock are stress-sensitive, when the pore pressure in the fracture decreases, the permeability of the fracture decreases accordingly. Therefore, the permeability of fractures needs to be corrected during the simulation process. In consideration of the stress sensitivity, the fracture permeability is given by

$$k_f = k_{fo} e^{-d(p_f - p_o)}$$  \hspace{1cm} (30)

At the same time, the fracture conductivity will also decrease as the pore pressure decreases in the fracture system. When the pore pressure in fractures is less than the fracture closure pressure, the fracture in the shale matrix will be closed due to confining pressure. At this time, the closure pressure of the fracture approximately is the minimum horizontal stress, which can be obtained either from a diagnostic fracture injection test (DFIT) or using eq 31 as follows

$$P_{closure} = \sigma_{min} = \frac{v}{1-v}(\sigma_v - \alpha p_f) + \sigma_v + P_{Tectonic}$$  \hspace{1cm} (31)

where $v$ is the Poisson ratio, $\sigma_v$ is the vertical stress (Pa), $\alpha$ is the Biot constant and is a dimensionless value, $p_f$ is the pore pressure (Pa), and $P_{Tectonic}$ is the tectonic stress (Pa).

Based on the solid mechanics, the relationship between the fracture width and the pore pressure in the fracture system can be derived. The fracture width decreases with the decrease in pore pressure in the fracture system. When the pore pressure in a fracture is less than the closing pressure, the fracture will be completely closed. The expression equation reflecting this change is shown as follows

$$w_f = \begin{cases} \frac{w_{fo}}{P_{fo}} (P_f - P_{closure}), & P_{closure} \leq P_f < P_{fo} \\ 0, & P_f < P_{closure} \end{cases}$$  \hspace{1cm} (32)

where $w_{fo}$ is the fracture width in the initial state, $P_{closure}$ is the closure pressure of the fracture, $P_{fo}$ is the pore pressure in the initial state, and $P_f$ is the pore pressure in fractures.

According to the definition of fracture conductivity, the fracture conductivity expression considering pressure changes can be derived as follows

$$c_f = k_{fo} w_f = \begin{cases} k_{fo} \frac{w_{fo}}{P_{fo}} (P_f - P_{closure}), & P_{closure} \leq P_f < P_{fo} \\ 0, & P_f < P_{closure} \end{cases}$$  \hspace{1cm} (33)

The pore space of the fractures is also compressible. As the gas pressure in the fracture decreases, the porosity of the fracture also decreases. This process can be expressed as

$$\phi_f = \phi_{fo} e^{-d(p_f - p_o)}$$  \hspace{1cm} (34)

The comprehensive transport speed of shale gas in fractures can be written as

$$v_g = -k_{fg} \left( \frac{Fk_{fo}}{\mu_k} + \frac{m_f}{\mu_k} \frac{D_m}{\beta^2} \right) \nabla P_g$$  \hspace{1cm} (35)

Substituting eqs 22 and 35 into eq 29, the comprehensive transport equation of shale gas in discrete fractures is

$$\frac{\partial}{\partial t} \left( \frac{w_f w_{fg} \phi_f}{P_{fg}} \right) = -\nabla \left( -w_f k_{fg} \left( \frac{Fk_{fo}}{\mu_k} + \frac{m_f}{\mu_k} \frac{D_m}{\beta^2} \right) \nabla P_g + q_{gas} \right)$$  \hspace{1cm} (36)

Parameters $Z$ and $\mu_k$ are regarded as a function of pore pressure during the derivation process.

2.3.4. Comprehensive Transfer Equation of Water in the Discrete Fracture System. Based on the principle of material balance, the transport equation of the water phase in a unit length fracture can be written in the following form

$$\frac{\partial}{\partial t} (w_f S_{tw} \rho_w) = -\nabla (w_f \mu_w v_w) + q_{water}$$  \hspace{1cm} (37)

Here, $S_{tw}$ is the water saturation in fractures, and it is easy to know that the sum of water-phase saturation $S_{tw}$ and gas-phase saturation $S_{fg}$ is equal to 1. $\rho_w$ is the water transport speed in fractures. $\rho_w$ is the density of the water phase. Since it is extremely difficult to compress water, $\rho_w$ can be regarded as a constant in the simulation process. $q_{water}$ represents the mass exchange of water between the shale fracture system and the matrix system. Assuming that the transport of the water phase in fractures is a viscous flow, the transport speed of the water phase based on the generalized Darcy formula can be written as the following form

$$v_w = -k_{fwn} \frac{w_f}{\rho_w} \nabla P_w$$  \hspace{1cm} (38)

where $k_{fwn}$ is the relative permeability of the water phase, $\mu_w$ is the viscosity of water, $k_{fwn}$ is the permeability of the fracture when saturated with water, and $P_w$ is the pressure of the water phase in the fracture. Based on the cubic law of fractures, the inherent permeability $k_{fwo}$ of the water phase in the fractures can be written as the following form

$$k_{fwo} = \frac{w_f^2}{12}$$  \hspace{1cm} (39)

In addition, the capillary pressure existing between the gas and water phases in the fracture needs to be considered. The specific equation is as follows

$$p_{cap} = p_g - p_w = \frac{\sigma \cos \theta}{w_f}$$  \hspace{1cm} (40)

where $\sigma$ is the surface tension, $\theta$ is the contact angle, and $w_f$ is the width of the fracture.

2.4. Numerical Simulation Method. The finite element method (FEM) is a numerical method usually used for solving mathematical, physical, and engineering problems. The finite element analysis process in this manuscript is shown in Figure 4. The method can be split into several basic steps. First, we create a geometry model and then assign shale properties to create a geometry model and then assign shale properties to the geometry domain based on problem description. Next, the finite element model is generated by assigning the
mathematical equations and finite element formulations to the model. The following step is to solve a set of algebraic equations, and then, the physics-related nodal solutions of the model can be found. Once the solutions to this problem are determined, it can help us evaluate the results by means of data visualization and data analysis.

Now, we illustrate the finite element solution procedure. Equations 24 and 36 describe the mathematical model of the physical problem. They are expressed in terms of partial differential equations, which are the descriptions of physical laws for space-time problems, and can be simplified to the following form

$$A(p) \frac{\partial p}{\partial t} + \nabla (B(p) \nabla p) + q = 0$$  \hspace{1cm} (41)

It is necessary to derive a weak formulation from these equations. The first step is to multiply a test function \( \psi \) to both sides of eq 41 and then integrate them on the definition domain \( \Omega \). There is an assumption that the equation solution \( p \) and the test function \( \psi \) belong to Hilbert spaces. By requiring eq 41 to hold for all test functions \( \psi \), the weak formulation can be obtained. With the weak formulation, the mathematical equations above can be discretized to obtain numerical equations for numerical simulation. Using Green’s first identity, the equation derived from eq 41 can be shown as follows

$$\int_\Omega \psi A(p) \frac{\partial p}{\partial t} \, dV + \int_\Omega \psi B(p) \nabla p \cdot \nabla \psi \, dV - \int_\Omega \nabla \psi B(p) \nabla p \, dV + \int_\Omega \psi q \, dV = 0$$  \hspace{1cm} (42)

This discretization form means finding an approximate solution \( p_h \) in a finite dimensional subspace of a Hilbert space, so that the exact solution \( p \) is approximated by \( p_h \). The Galerkin method is usually used for numerical discretization because of its simplicity. The standard Galerkin finite element method is based on the weighted residual method. The approximate equation solution \( p_h \) represented as a linear combination of a set of basis functions \( \psi_i \) can be shown as follows

$$p = \sum_i^n c_i \psi_i$$  \hspace{1cm} (43)

where \( n \) is the number of discrete nodes, \( \psi_i \) is a shape function of pressure, and \( c_i \) is an unknown coefficient. By substituting eq 43 into eq 42, we obtain

$$\frac{\partial c_i}{\partial t} \int_\Omega \psi_i A(\sum_i^n c_i \psi_i) \psi_i \, dV + \sum_i^n c_i \int_{\partial \Omega} \psi_i B(\sum_i^n c_i \psi_i) \psi_i \, dS + \sum_i^n c_i \int_\Omega \psi_i q \psi_i \, dV + \int_\Omega \psi_i q \, dV = 0$$  \hspace{1cm} (44)

The coefficients \( c_i \) in eq 44 are unknown. Similarly, we can obtain the discrete format of PDE in the fracture. Through the discrete format of the simultaneous fracture system and matrix system equations, a system of \( n \) equations can be obtained. After applying the boundary conditions, the corresponding nonlinear equations can be obtained by the following expressions

$$Kc = b$$

where \( K \) is the system matrix and \( c \) is the vector of unknown coefficients. Iterative algorithms can be used to solve the system of \( n \) equations and to obtain the solution of the unknown coefficient \( c \), which is substituted into eq 43 to obtain an approximate solution of the pressure in the shale fracture-matrix system.

Due to the strong nonlinearity of PDEs, we use numerical methods to solve them. In this study, the finite element software COMSOL Multiphysics is used to solve mathematical PDE and visualization. The transport mechanism models and the generation of the DFNs are realized by self-programming using MATLAB. The authors of this manuscript have the right to use these relevant software.

3. MODEL VALIDATION

To ensure the accuracy and reliability of the simulation results, it is necessary to use field data history to match the simulation results of the model. In the research of this article, field data of Marcellus shale is used to verify the model. The horizontal wells in this block are stimulated by multistage hydraulic fracturing, which is performed in a 640 m horizontal section with seven stages of treatment. In this simulation study, we established a reservoir with a capacity of 1200 m × 2000 m × 60 m. The hydraulic fracture spacing and half-length are set to 91.4 and 97.5 m, respectively. Table 2 lists some reservoir data, while the simulation result without considering the fracture network is lower than the field data. This shows that the fracture network generated by hydraulic fracturing is beneficial to the transport of shale gas and cannot be ignored.
in practical applications. The simulation results of the model proposed in this paper have a good fit with the real gas production of the gas reservoir, which means that the transport mechanisms and influencing factors considered by the proposed model are accurate and reliable, and therefore it can be used in subsequent research. Using this model in practice, it can also accurately predict the shale gas productivity and effectively guide the development of shale gas reservoirs.

Figure 6 shows the fracture distribution near the shale hydraulic-fractured horizontal well after 150 days of production. Figure 6a shows the situation without considering the fracture network generated by hydraulic fracturing. It can be seen that the contours of pressure are relatively smooth and symmetrical. The pressure drop generated by each fracture superimposes to form an oval-like drainage area. In Figure 6b, the model takes into account the fracture network formed near the shale horizontal well after hydraulic fracturing. The hydraulic fractures, secondary fractures, and the original natural fractures connect with each other and form a complex fracture network. Compared with Figure 6a, it can be seen that the fracture network affects the pressure distribution near the horizontal well. The contour lines are rough and asymmetric. Some secondary fractures are connected with the main hydraulic fractures to form transport channels, which will help transport shale gas.

To further verify our comprehensive model, we used more field data from the study area to verify our model, combined with the commercial reservoir numerical simulation software CMG and other researchers’ models to assist in verifying our model.52

As shown in Figure 7, further verification shows that the simulation results of this model are in good agreement with the field data and the simulation results of CMG software and the prediction of other researchers’ models. It means that the model in the study is correct and credible, and it can be used in the following section.

4. CONCLUSIONS

In this manuscript, we mainly study the modeling and simulation of shale fracture attitude and the fracture network. First, this paper studies a fracture-matrix model that can flexibly represent the three-dimensional geometry space of the fracture. Based on the study of shale gas transport mechanisms, a comprehensive shale gas transport model is derived. Compared with previous transport models, this transport model is more comprehensive and considers more influencing factors such as two-phase flow, the slippage of formation water, the coupling of transport mechanisms, fracture closure, and reservoir heterogeneity. The finite element discretization format calculated for the numerical simulation is also derived in this work. After that, this model is verified through real field data, and the fitting results show that this model is reliable and can be used for more study. The following conclusions can be drawn from this research work.

(1) In this study, a geometric model of the discrete fracture-matrix system is established, which can be used to describe the spatial shape of fractures, fracture networks, and real fractures. A comprehensive transport model that can describe the complex transport mechanisms of shale gas in fractures and the matrix is established.

(2) In the fracture-matrix system of shale, the smaller angle between the strike direction of a single fracture or
fracture network and the fluid flow direction indicates that the fracture or fracture network is more conducive to shale gas transport. The smaller the dip angle is, the more advantages the gas transport can gain.

(3) The length, area, shape, strike direction, and dip angle of the fractures can affect the transport of shale gas. The two-dimensional fracture-matrix model is a special form of the three-dimensional fracture-matrix model. The two-dimensional fracture-matrix model cannot simultaneously simulate the strike direction and dip angle of the fracture, nor can it reflect the shape of the fracture.

(4) In the fracture network, the connectivity between fractures is more important. Generally, the greater the fracture density is, the better the connectivity of the fracture network can be. However, the excessive fracture density cannot effectively increase gas production. There is a more economical fracture density in the fracture network, and we do not suggest excessive fracturing in shale horizontal wells.

5. EXPERIMENTAL SECTION

Based on the modeling and simulation methods established and the shale gas reservoir data in southern China, the effect of the attitude of fractures in shale gas reservoirs on shale gas transport was studied. The effect of fracture dip angle and strike angle on shale gas production was analyzed and solved by the finite element method.

5.1. Simulation Conditions and Parameters. To conduct numerical simulation experiments, real shale reservoir data and initial and boundary conditions are all needed. All of the data and simulation parameters are from real shale gas reservoirs. These data are used for the simulation studies, which are given in Table 3.

Assuming that the initial pressure in a shale matrix block is \( p_i \), the initial condition of the model can be written as

\[
 p_{in} \big|_{t=0} = p_{f} \big|_{t=0} = p_i
\]

where surf A and surf B are the inlet boundary and outlet boundary, respectively. In this case, the inlet boundary condition and the outlet boundary condition are defined by

\[
 p_{in} \big|_{surf_A} = p_{inlet}
\]

and

\[
 p_{in} \big|_{surf_B} = p_{outlet}
\]

5.2. Model Discretization and Mesh Refinement. When the geometric model is discretized into grids, the triangular mesh discretization method is usually used to discretize the geometric model. Generally, the finer the grid division, the more accurate is the numerical solution obtained, and the closer it is to the actual situation. In this practical application, the model is divided into 90499 grid cells. The average grid cell scale is 0.65, and the scale of the smallest cell is 0.05 (as shown in Figure 8). To more accurately reflect the attitude characteristics of the discrete fracture, the meshes of the discrete fracture and its surrounding area need to be refined. Figure 9 shows the degree of refinement of the discrete grid of the model.

5.3. Numerical Simulation Scheme Design. To study the influence of fracture dip angle and strike angle on shale gas transport, the specific simulation scheme is designed as follows. Simulation Scheme 1: When the strike direction is 0°, the dip angles of the designed discrete fractures are 0, 18, 36, 54,
Table 3. Parameters Used for Numerical Simulation Studies from BC Shale Gas Reservoir

| parameters                        | value   | source          |
|-----------------------------------|---------|-----------------|
| size of the matrix block, m       | 1       | modeling        |
| porosity of the matrix, φm        | 0.03    | laboratory tests|
| matrix permeability, k_m (m²)     | 1.97 × 10⁻¹⁶ | laboratory tests|
| fracture permeability, k_f (m²)   | 4.94 × 10⁻¹⁵ | laboratory tests|
| porosity of the fracture, φ_f     | 0.002   | laboratory tests|
| reservoir temperature, T (K)      | 334     | field data      |
| fracture strike direction, θ (degrees) | 0–360 | well logging data|
| fracture dip angle, φ (degrees)   | 0–90    | well logging data|
| molecular weight, M (kg/mol)      | 1.68 × 10⁻³ | laboratory tests|
| gas diffusion coefficient, D_g (m²/s) | 2.40 × 10⁻¹⁵ | literature 59 |
| universal gas constant, R (J/(mol·K)) | 8.314 | literature 58  |
| fracture characteristic parameter, d_f (1/Pa) | 7.25 × 10⁻⁸ | well logging data|
| gas viscosity of ideal gas, μ_g (Pas) | 6.09 × 10⁻⁹ | core tests      |
| Langmuir pressure constant, P_L (Pas) | 3.45 × 10⁶ | laboratory tests|
| tortuosity of the shale matrix pore, τ | 1.3 | laboratory tests|
| Langmuir volume constant, V_L (m³/kg) | 8.80 × 10⁻⁴ | laboratory tests|
| Henry’s constant, Hc (kg/(Pa·m³)) | 3.2 × 10⁻⁷ | literature 60  |
| organic matter content, ε         | 7 × 10⁻³ | laboratory tests|
| characteristic diameter, δ_m (m)  | 5 × 10⁻⁸ | laboratory tests|
| characteristic diameter, δ_f (m)  | 1 × 10⁻³ | laboratory tests|
| slippage factor, h                | 1       | literature 61  |
| initial pressure, p_i (Pa)        | 1.8 × 10⁷ | field data      |
| inlet pressure, p_in (Pa)         | 1.8 × 10⁷ | field data      |
| outlet pressure, p_out (Pa)       | 1.6 × 10⁷ | field data      |
| fitting coefficient, A_1          | 7.9     | literature 62  |
| fitting coefficient, A_2          | -9 × 10⁻⁶ | literature 62  |
| fitting coefficient, A_3          | 0.28    | literature 62  |
| rarefaction coefficient, α_e      | 1.19    | literature 63  |
| fitting constant, α_L             | 4.0     | literature 64  |
| fitting constant, β               | 0.4     | literature 65  |

Figure 8. Finite element discretization of a shale block.

Figure 9. Mesh size of the discrete fracture.

6. RESULTS AND DISCUSSION

The research purpose of this paper is to study the effect of the fracture in the shale matrix on gas transport in a shale matrix through modeling and simulation methods. Based on the established model and simulation scheme established in the computational method section, the paper uses the finite element numerical simulation method to solve the simulation experiment scheme. According to the simulation results, the effects of fracture dip angle and strike direction on shale gas transport were studied.

6.1. Effect of Fracture Dip Angle on Shale Gas Transport. 6.1.1. Effect of Fracture Dip Angle on Gas Pressure Distribution. The simulation solution results of Scheme 1 are shown in Figure 10. In Figure 10, the existence of a fracture affects the pressure distribution in the shale block. The pressure distribution of shale gas in the stable state in the shale block is different. As the dip angle of the fracture increases, it can be seen from the figure that the pressure waves near the outlet end of the shale block are relatively sparse, which means a smaller pressure gradient. A possible explanation is that as the fracture dip angle increases, the shale gas in the fracture becomes farther from the outlet end. Because of the low permeability of the shale matrix, the gas transport resistance increases and then the pressure gradient becomes smaller, which causes the pressure wave to become sparse.

6.1.2. Effect of Fracture Dip Angle on Gas Production. The influence of a fracture dip angle on the cumulative production and production rate is shown in Figure 11. As illustrated in Figure 11a,b, the fracture dip angle has a great impact on the gas production rate and the cumulative production rate in the shale matrix block. As shown in Figure 11a, the production rate of the fractured shale matrix block is more than twice that of a shale block without a fracture in it. This indicates that the existence of a fracture in the shale matrix is beneficial to the flow rate of shale gas. Figure 11a presents the production rate as a function of time for different dip angles ranging from 0 to 90°. The gas production rate decreases with time, and it becomes smaller at a larger dip angle of the fracture. This shows that at the same moment a smaller value of the fracture dip angle has a greater production rate of the shale gas, i.e., a smaller fracture dip angle contributes more to the shale gas flow in the matrix block.

6.2. Effect of Fracture Strike Direction on Shale Gas Transport. 6.2.1. Effect of Fracture Strike Direction on Gas Pressure Distribution. The simulation results of Scheme 2 are shown in Figure 12. It can be seen from Figure 12 that the...
strike direction of the fracture affects the pressure distribution in the shale block. As the strike angle of the fracture increases, it can be seen that the pressure wave changes periodically, with a change period of $0^\circ - 180^\circ$. From $0^\circ$ to $90^\circ$, the pressure wave at the outlet gradually becomes denser, while from $90^\circ$ to $180^\circ$, the pressure wave at the outlet gradually becomes sparse.

6.2.2. Effect of Strike Direction on Gas Production. Figure 13 shows the cumulative gas production at the B end of the matrix block when the simulation time is 10 h. It can be seen from Figure 13 that in the range of $0^\circ - 360^\circ$, the cumulative gas production shows a periodic change, which is from $0^\circ$ to $180^\circ$ for a cycle. In this cycle, the cumulative gas production reaches the lowest when the trend is $0^\circ$ and $180^\circ$ and reaches the highest when the trend is $90^\circ$. This means that the fracture strike direction is consistent with the gas flow direction, and the gas production is the largest. The strike direction of the fracture is perpendicular to the direction of the gas flow, and the cumulative gas production is the smallest.

6.3. Effect of Fracture Attitude on Gas Transport under Different Water Saturations. Water phases often exist in shale formations, and most of them exist in shale pores in the form of bound water. To study the effect of fracture occurrence on gas transport under different water saturations in shale formations, the study sets up several sets of experiments for calculation and analysis. The study keeps the other parameters in the simulation process unchanged and sets the water saturation parameters in the models to 0, 30, 60, and 90%. The relevant simulation parameters are obtained from core experiments in the research unit.

Figure 14 shows the effect of fracture occurrence on gas transport under different water saturations. In Figure 14a, under different water saturations, the effect of the fracture dip angle on cumulative gas production is also different. With the increase in water saturation in the pore space, the curve gradually moves down, and the cumulative gas production decreases rapidly. When the water saturation is at a low level, the curve’s change is obvious, but as the water saturation increases, the curve starts to become flat. The same is true in Figure 14b. The results show that when the water saturation is at a high level, the change in fracture occurrence has little effect...
on gas transport. However, when the water saturation is at a low level, the fracture attitude has an unignored effect on gas transport. Compared with fracture occurrence, the water saturation significantly affects the shale gas transport in the formations. This is because the increase in water saturation will reduce the flow area of the fluid in the pore space and block part of the transport channel in formations.

### 6.4. Effect of Reservoir Deformation on Gas Transport

In the process of shale gas production, as the pore pressure in the formation decreases, shale matrix pores and microfractures will deform. The study simulated the effect of reservoir deformation on gas transport.

Figure 15 shows the effect of reservoir deformation on gas transport. Figure 15a shows the change curve of matrix permeability and fracture conductivity with formation pressure. It can be seen from the figure that as the pore pressure in the formation decreases, both matrix permeability and fracture conductivity show a downward trend. Among them, the conductivity of fractures decreases faster, which indicates that the fracture stress sensitivity is stronger, and reservoir

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Figure 12. Pressure distribution diagram of the shale fracture-matrix system under different fracture strike directions.
deformation has a greater impact on gas transport in fractures. When the pore pressure is less than the fracture closure pressure, the fracture conductivity becomes zero and no longer changes. Figure 15b shows the effect of reservoir deformation on cumulative gas production. It is obvious that the lower the pore pressure, the lower the gas cumulative production. Before the fractures are closed, the gas cumulative production drops faster as the pore pressure decreases. When the pore pressure is less than the closure pressure, the gas cumulative production decreases slowly. At this time, the main reason for production decrease is the microdeformation of the matrix.

6.5. Comparison of the 2D Discrete Fracture Model and the 3D Discrete Fracture Model. To illustrate the difference between the two-dimensional fracture model and the three-dimensional model of discrete fracture, this study simulated several examples for comparison and analysis. The basic simulation parameters set in the examples are the same. As shown in Figure 16, Case (a) is a two-dimensional fracture-
matrix model, while Case (b) is an equivalent three-dimensional model. Case (c) replaces the rectangular fracture surface in Case (b) with a round fracture surface, and the diameter of the circular fracture surface is equal to the length of the fracture in the two-dimensional model Case (a). The rectangular fracture surface of Case (d) does not penetrate the front and back surfaces of the matrix block. Case (e) has a circular fracture surface with the same area as Case (b). Case (f) has a rectangular fracture surface with the same dip angle and different directions.

The simulation results of the above six cases are shown in Figure 17. It can be seen that Case (a) and Case (b) are equivalent, while the others are different. In Case (c), although the diameter of the circular fracture surface is the same as the length of fracture in Case (b), its area is relatively small and the gas production is not high. Compared with Case (b), the fracture surface of Case (d) is relatively narrower, and it does not penetrate back and forth surfaces of the matrix block. Compared with Case (b), the gas production of Case (b) is lower due to the smaller fracture area. In Case (e), the area of the circular fracture surface is the same as the area of the rectangular fracture surface in Case (b), but the final yield of Case (e) is higher, which may have been caused by the larger diameter of the circle. In Case (f), the rectangular fracture has a different strike direction, and the gas production is higher than that of Case (b), which shows that the strike direction has an important influence on gas production. In summary, the two-dimensional discrete fracture model has certain limitations, and it can only simulate the special case in the three-dimensional discrete fracture model. The two-dimensional

Figure 16. Pressure distribution and streamline diagrams of different simulation cases. (a) Two-dimensional simulation examples. (b) Equivalent three-dimensional simulation cases. (c) Circular fracture surfaces. (d) Rectangular fracture surfaces that do not penetrate the matrix. (e) Circular fracture surfaces of equal area. (f) Rectangular fracture faces with the same dip angle but different strike direction.
model cannot consider the shape of the fracture, the influence of the fracture attitude, and whether it penetrates the matrix block or not. On the contrary, the shape, area, direction, and length of the three-dimensional fracture surface have an impact on the shale gas transport.

6.6. Effect of Real Fractures on Gas Transport. To simplify the problem, the above research idealized the fracture surface as a rectangular or circular surface, while the fracture section in the real formation is rough and irregular. For irregular fracture sections, three-dimensional scanning of real fracture surfaces can be used for construction. To study the deviation between the real fracture and the ideal fracture surface, the study performed the following simulation. The roughness of real fractures can be characterized by spatial frequency. The larger the spatial frequency is, the rougher and more irregular the fracture surfaces are. As shown in Figure 18, the digital fracture surface generated by the 3D scan of the real fracture surface is placed in the shale matrix block model. Then, we can simulate fluid transport in the real fracture-matrix system.

As shown in Figure 19, the study simulated the impact of real fractures of different roughnesses on shale gas transport. There are five sets of fracture surfaces with different roughnesses. From fracture surface a to fracture surface e, the roughness increases in order. From the results of numerical simulation, it can be seen that the rough fracture surface can help transport shale gas. The gas production in the ideal plane fracture model is smaller than that in the real rough fracture. We have a reasonable explanation for this situation. Compared with the flat fracture surface, the rough fracture surface has a larger contact area with the shale matrix, and the shale gas in the matrix can easily flow into the fracture. Therefore, the gas production in real rough fractures is a bit higher, and the difference is about 1−3%.

6.7. Effect of Discrete Fracture Network on Gas Transport. In a real shale formation, multiple fractures in the shale matrix often form a complex network, forming complex transport channels. This study considered the influence of a complex fracture network on gas transport based on the single fracture-matrix media.

Based on the geological research of the fracture network, the statistical characteristics of the parameters of the fracture network can be determined, which includes the width, size, strike direction, dip angle, and density of the fracture.

These parameters can be used to generate fractures one by one or generate a random fracture network at once. As shown in Figure 20, the study generated a shale fracture network-matrix model through this method and simulated shale gas transport in the fracture network-matrix model. The number of fractures in the fracture network is 100. The length of the fractures ranges from 1 to 20 cm.

Figure 20 shows the pressure distribution and streamline diagram of shale gas in the fracture network-matrix model. The red arrow in the figure represents the fluid velocity on the fracture surface. The longer the arrow, the faster the velocity of shale gas. At the bottom right of the shale block, it can be seen that the velocity of shale gas is the fastest on several connected fracture surfaces, which shows that in the flow direction, the connected fractures can compose important flow channels for shale gas transport.

6.7.1. Influence of Different Inclinations and Direction of Fracture Network on Gas Transmission. The study in the single fracture-matrix system of shale shows that the dip angle and strike direction of the fracture have an effect on gas transport. However, whether this rule is also applicable to the multifracture system needs further discussion. Here, the study generated a fracture network with specific dip and strike through algorithms.

Figure 21 shows fracture network-matrix models with specific dip angles and strike directions. Keeping the other properties of the fractures in the fracture network and only changing the dip angle and strike direction of the fractures, we
designed 13 sets of experiments for studying the strike direction of the fracture network and six sets of experiments for the dip angle of the fractures.

The results of the numerical simulation are shown in Figure 22. It can be seen from the figure that the influence of dip angle and strike direction of the fracture network on shale gas transport has the same rule as the single fracture-matrix model.

The strike direction of the fracture network has a periodic effect on gas transport. When the strike direction of the fracture network is perpendicular to the flow direction, the gas production reaches the highest value. The dip angle of the fracture network also has an important influence on gas transport. The smaller the dip angle of the fracture network, the higher the shale gas production. Based on the above
Figure 22. Influence of strike direction and dip angle of the fracture network on shale gas transport. (a) Influence of fracture network strike direction on cumulative gas production. (b) Influence of fracture network dip angle on cumulative gas production.

Figure 23. Fracture network system of a shale block with different fracture densities.

Figure 24. Influence of different fracture densities on shale gas transport.
research conclusions and geometric principles, it can be inferred that when the angle between the fracture surface and the flow direction of the fluid is smaller, the fracture is more conducive to shale gas transport.

6.7.2. Influence of Fracture Network Density on Gas Transport. For the fracture network system of shale, fracture density is an important characterization parameter. In practical work, fracture density in a shale formation can be obtained using methods such as field outcrop measurement, well imaging logging, and shale core observation. To study the influence of fracture density of the fracture network on shale gas transport, this paper conducted a series of simulation experiments for different fracture densities. For convenience, fracture density is defined by the number of fractures in the shale matrix block. The more the fractures in the matrix block, the higher the fracture density. In this study, the fracture density was set to 10, 30, 50, 100, 200, 300, and 400 in seven groups, in which fracture network models with fracture densities of 30, 200, 300, and 400 are shown in Figure 23.

The results of the numerical simulation are shown in Figure 24. It can be seen from the figure that the gas production of shale gas increases as the fracture density of the fracture network increases. When the fracture density is low (the fracture density is about less than 30), the gas production increases slowly. This may be because the fracture network is sparse and there are fewer connections between fractures. The fractures are relatively isolated, which can be seen in Figure 23. When the fracture density is higher (the fracture density is about 200), the production of shale gas increases rapidly. This shows that the fractures in the matrix block are fully connected, forming several main transport channels. However, when the fracture density was too high (the fracture density was more than 300), the production of shale gas began to increase slowly, which indicates that the number of fractures in the fracture network is close to saturation, and the redundant fractures have little effect on the increase of gas production.

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Notes

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**NOMENCLATURE**

| Symbol  | Description                              | Unit          |
|---------|------------------------------------------|---------------|
| $\Phi_f$ | fracture porosity (dimensionless)        |               |
| $\Phi_m$ | matrix porosity (dimensionless)          |               |
| $\Phi_{ref}$ | fracture porosity at reference pressure (dimensionless) |               |
| $T$    | reservoir temperature (K)                |               |
| $M$    | methane molar mass (kg/mol)              |               |
| $P_m$  | fracture pressure (Pa)                   |               |
| $P_i$  | fracture pressure (Pa)                   |               |
| $P_0$  | reference fracture pressure (Pa)         |               |
| $D_m$  | gas diffusion coefficient (m$^2$/s)      |               |
| $R$    | universal gas constant (J/(mol·K))       |               |
| $\theta$ | strike direction of the fracture (degrees) |               |
| $\varphi$ | dip angle of the fracture (degrees)     |               |
| $\rho_m$ | gas density in the matrix (kg/m$^3$)    |               |
| $\rho_f$ | gas density in the fractures (kg/m$^3$)  |               |
| $Z$    | gas compressibility factor (dimensionless) |             |
| $q_m$  | gas mass concentration in the matrix (kg/m$^3$) |           |
| $P_{Langmuir}$ | Langmuir pressure constant (Pa)        |               |
| $q_b$  | free gas mass concentration (kg/m$^3$)  |               |
| $q_a$  | adsorption gas mass concentration (kg/m$^3$) |             |
| $q_d$  | dissolved gas mass concentration (kg/m$^3$) |          |
| $V_L$  | Langmuir volume constant (m$^3$/kg)     |               |
| $V_m$  | gas molar volume at standard condition (m$^3$) |           |
| $V_b$  | volume of shale block (m$^3$)            |               |
| $d_f$  | fracture characteristic parameter (1/Pa) |               |
| $\mu_g$ | gas viscosity for ideal gas (Pa·s)       |               |
| $P_r$  | reduced temperature (dimensionless)      |               |
| $T_r$  | reduced pressure (dimensionless)         |               |
| $P_c$  | critical temperature (K)                |               |
| $T_c$  | critical pressure (Pa)                  |               |
| $\kappa_m$ | matrix permeability (m$^2$)            |               |
| $\kappa_f$ | fracture permeability (m$^2$)           |               |
| $\kappa_{ref}$ | matrix permeability at reference pressure (m$^2$) |         |
| $A_1$  | fitting constant (dimensionless)         |               |
| $A_2$  | fitting constant (dimensionless)         |               |
| $A_3$  | fitting constant (dimensionless)         |               |
| $\mu_k$ | viscosity of real gas (Pa·s)             |               |
| $\varepsilon_{fr}$ | compression coefficient of fracture porosity (1/Pa) |           |
| $K_n$  | Knudsen number (dimensionless)           |               |
| $d_m$  | characteristic diameter of pore in the shale matrix (m) |       |
| $a_t$  | characteristic width of the fracture in fractures (m) |         |
| $p_i$  | initial pressure (Pa)                   |               |
| $P_m$  | inlet pressure (Pa)                     |               |
| $P_{out}$ | outlet pressure (Pa)                    |               |
| $b$    | slippage factor (dimensionless)          |               |
| $\alpha_0$ | rarefaction coefficient (dimensionless) |             |
| $\alpha_t$ | fitting constant (dimensionless)        |               |
| $\beta$ | fitting constant (dimensionless)         |               |
| $\tau$ | tortuosity (dimensionless)              |               |

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