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Review Article

Research Advance on Prediction and Optimization for Fracture Propagation in Stimulated Unconventional Reservoirs

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Multistage stimulation horizontal wells are prerequisite technologies for efficient development of unconventional reservoir. However, the induced fracture network morphology from hydraulic fracturing is very complex and affected by many factors, such as the in situ stress, rock mechanical properties, and natural fracture distribution. The large numbers of natural fractures and strong reservoir heterogeneity in unconventional reservoirs result in enhanced complexity of induced fractures from hydraulic fracturing. Accurate description of fracture network morphology and the flow capacity in different fractures form an important basis for production forecasting, evaluation (or optimization) of stimulation design, and development plan optimization. This paper focuses on hydraulic fracturing in unconventional reservoirs and discusses the current research advances from four aspects: (1) the prediction of induced fracture propagation, (2) the simulation of fluid flow in complex fracture networks, (3) the inversion of fracture parameter (fracture porosity, fracture permeability, etc.), and (4) the optimization of hydraulic fracturing in unconventional reservoirs. In addition, this paper provides comparative analysis of the characteristics and shortcomings of the current research by outlining the key technical problems in the study of flow characterization, parameter inversion, and optimization methods for stimulation in unconventional reservoirs. This work can provide a certain guiding role for further research.

1. Introduction

Unconventional reservoirs have played and increasingly important role in the portfolio of oil and gas exploration and development companies [1]. Unconventional oil and gas reservoirs have the characteristics of poor reservoir properties and low permeability, and it flows well, after stimulation. Therefore, hydraulic fracturing is needed to achieve economic and efficient development [2]. Multistage stimulation can produce hydraulic fractures with high conductivity and can communicate with natural fractures to form complex fracture networks, as shown in Figure 1. Due to the hydraulic fracturing, the original reservoir parameters have been significantly changed by the coupling effect of multiple factors, such as hydraulic fractures, natural fractures, and reservoir fluids. The reservoir porosity/permeability and hydraulic fracturing work system play a key role in the production forecasting and optimization guidance of unconventional reservoirs. Therefore, how to accurately and efficiently simulate the fracture network propagation morphology, characterize the flow conductivity, and optimize the production data is an important prerequisite for efficient development of unconventional reservoir [3].

The fracture network morphology of multistage stimulation horizontal wells in unconventional reservoirs is extremely complex and is affected by many factors. Currently, there is no unified understanding of fracture network propagation and morphology. The existing fracture network propagation simulation method is not mature enough; it poses many problems that it depends on the tools/software used. We can be accurate in a finite element analysis that models the fluid and even the thermal effects of the fluid

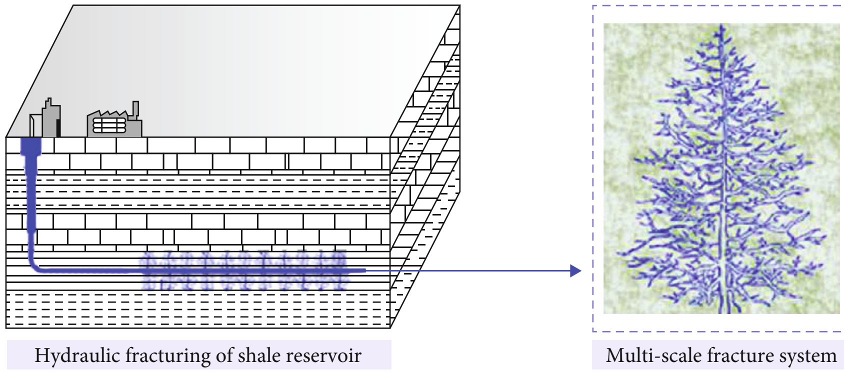


Figure 1: Multistage stimulation horizontal wells in unconventional reservoirs [4].

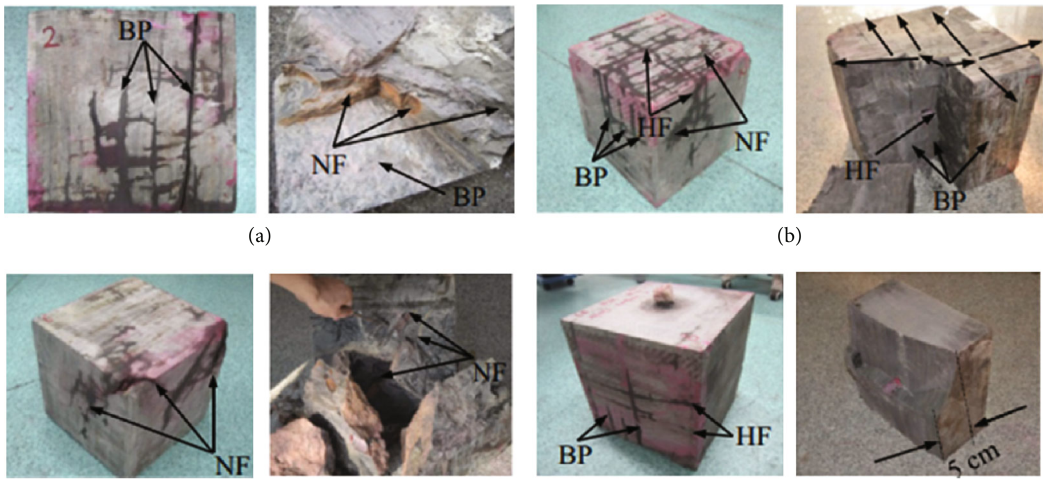
accurately through advanced fracture mechanics. That is computationally challenging to model a pad scale with multiple horizontal wells that have 15-30 stage completions along each well. A more efficient approach (for example, utilizing Kinetix (Schlumberger)) had limitations on the accuracy of the physics that tracks the propagation. We make tradeoffs, and these limitations are the issue. At the same time, the influence of well-developed natural fracture networks in unconventional reservoirs has significant impact on the spatial complexity of induced fractures formed by hydraulic fracturing. The fluid flow characteristics of the fractures and the matrix are quite different. Therefore, it is difficult to obtain the fracture conductivity and reservoir parameters using numerical simulations combined with production history matching. Notably, the optimization of hydraulic fracturing is the key to maximizing reservoir development. The serious interwell interference of unconventional reservoirs and the uncertainty of reservoir cognition has led to multiple solutions for hydraulic fracturing optimization in such reservoirs, which has reduced the accuracy of solving the objective function and often failed to achieve the best optimization results. Therefore, this review discusses the following four aspects; (1) the prediction of induced fracture propagation, (2) the simulation of fluid flow in complex fracture networks, (3) the inversion of fracture parameter (fracture porosity, fracture permeability, etc.), and (4) the optimization of hydraulic fracturing in unconventional reservoirs. Finally, the limitations of the study and the directions of future research are discussed.

2. Prediction of Induced Fracture Propagation

The characterization of fracture propagation and fracture network morphology simulation is crucial for understanding reservoir fracturing. Accurately predicting hydraulic fracture morphology plays a key role in predicting the production of unconventional reservoirs. Therefore, many scholars have used different methods to describe the fracture network morphology. The existing studies that predict fracture network morphology can be divided into laboratory experiments and numerical simulation methods [5].

2.1. Laboratory Experiment Simulation Method. In the laboratory experiment simulation method, rock samples were obtained in the field to simulate the fracture morphology by injecting a high-pressure fracturing fluid. Louis and Maini [6], Witherspoon and Gale [7], Tian [8], and Zhang et al. [9] were the pioneering researchers who used a variety of experimental materials to carry out plate fracture seepage experiments, using the cubic law to describe the fluid flow in rock fractures. However, the cubic law does not consider the influence of fracture surface roughness on fluid flow; therefore, the calculation results are quite different from the actual scenario [10]. Subsequently, scholars used continuous medium mechanics to conduct research on fracture propagation of hydraulic fracturing through macroscopic true triaxial experiments. Blair et al. [11] designed a macroscopic true triaxial experiment to study fracture propagation at the interface between the cement matrix and sandstone under hydraulic driving conditions. Ito and Hayashi [12] obtained the relationship between the fracture width and fluid pressure of the injected fracturing fluid with respect to its propagation in a rock matrix through an indoor true triaxial hydraulic fracturing experiment. Van Den Hoek et al. [13] conducted a triaxial hydraulic fracturing experiment on hard sandstone, and the results showed that, during the fracturing process in low-permeability rock, a radial fracture network morphology was generated. Zou et al. [14] conducted fracturing experiments on shale with natural fractures and used computerized tomography (CT) scanning technology to observe the fracture propagation morphology. It was found that some open natural fractures aided the formation of a complex fracture network morphology; when the vertical stress difference was less than 6 MPa, the number of vertical fractures decreased, and when the horizontal stress difference was less than 6 MPa, a complex fracture network morphology was easily formed, as shown in Figure 2.

Olson et al. [16] studied the influence of natural fractures on the fracture propagation morphology of hydraulic fracturing through laboratory experiments. The results showed that induced fractures pass through natural fractures in three ways. (1) the hydraulic fracture extends to a natural fracture; (2) hydraulic fractures continue to extend through the natural fractures; (3) hydraulic fractures and natural fractures extend at the same time. Casas et al. [17] studied the influence of rock discontinuity on the initiation and arrest of fractures using hydraulic fracturing laboratory experiments.



(a) (b) (c) (d)

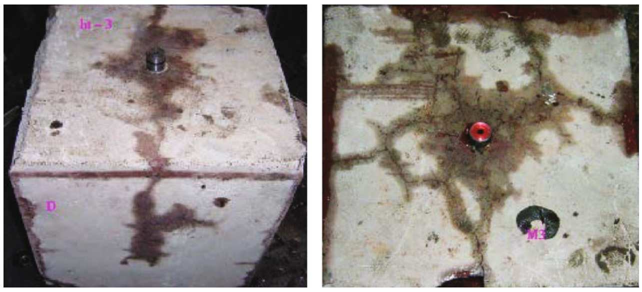
Figure 2: Fracture morphology with different horizontal stress difference [15].

(a) (b)

Figure 3: Experimental results of fracture morphology with different pump displacement [26]. (a) Pump displacement is 0.5 ml/s. (b) Pump displacement is 1.5 ml/s.

The experimental results showed that fracture arrest mainly occurred at the interface of different materials. Wu et al. [18] designed hydraulic fracturing laboratory experiments under vertical wells, considered the perforation positions of spiral and linear distributions, and studied the fracture propagation morphology under a polymer hydraulic drive. Their study showed that when the injection pressure of the fracturing fluid increased, the fracture initiation pressure increased, and the fracture propagation distance was also larger. Notably, the direction was determined mainly by the direction of the minimum principal stress. Athavale and Miskimins [19] used cement-wrapped homogeneous rock as the fracturing material to study the morphology of the fracture surface during the process of fracturing. Page and Miskimins [20] used hydraulic fracturing and gas fracturing equipment to study the initiation pressure of shale fracturing. The results showed that the initiation pressure was less than that of the stress concentration, which may be due to in situ stress heterogeneity. Zhang et al. [21] conducted a series of physical experiments on fracture propagation in shale reservoirs, as shown in Figure 3. An acoustic emission detection system was used to monitor the generation and propagation of hydraulic fractures, and the actual fracture morphology was observed after fracturing. Based on digital imaging of continuous slices after hydraulic fracturing, Li et al. [22] established the fracture network morphology under three-dimensional conditions. Guo et al. [23] conducted hydraulic fracturing physical simulation experiment with large tight sandstone outcrops to study the influence of natural fracture development degree, in situ stress condition, fracturing treatment parameters, and temporary plugging on fracture propagation. The results show that the natural fracture is the main factor affecting the hydraulic fracture morphology, and a low-viscosity fracturing fluid at a high rate facilitates further diffusion of temporary plugging agent (TPA), to achieve deep temporary plugging and fracture diversion. Higher horizontal differential stress leads to a smaller diversion radius of new hydraulic fractures, which is closer to the original hydraulic fractures, leading to poorer stimulation effect. According to the characteristics of glutamate reservoir, Rui et al. [24] established a coupled flow-stress-damage (FSD) model of hydraulic fracture propagation with gravels. The research shows that the hydraulic fracture is easy to expand around the gravel, and the fracture direction will deflect. Chen and Guangqing [25] analyzed the morphology of fracture propagation in water, under the influence of natural fractures, using true triaxial experiments and classified the fracture propagation into two forms: multibranch fractures (of the main fractures) and radial mesh fractures, as shown in Figure 4.

Physical experiments on hydraulic fracturing provide us a practical base for understanding the mechanism of rock fracturing. However, the size of rock used in the laboratory experiment is quite different from the actual reservoir scale, making it difficult to maintain consistency with the reservoir formation conditions. Therefore, the accuracy of the experimental results is limited, thereby constraining their application to practical hydraulic fracturing guidance. In future research, it will be necessary to develop equipment for true triaxial large hydraulic fracturing at the reservoir mass scale.



(a) (b)

Figure 4: Experimental results of fracture morphology with two fracture propagation modes [25]. (a) Multibranch propagation mode. (b) Radial mesh propagation mode.

2.2. Numerical Simulation for Fracture Propagation. Because it is difficult to replicate fracture networks under real conditions in laboratory experiments, hydraulic fracturing technology combined with numerical simulation methods has gradually become the focus of many studies. At present, the design of hydraulic fracturing is increasingly dependent on the results of numerical calculations and analyses. Many scholars have developed numerical simulation methods, such as the finite element method, extended finite element method, boundary element method, unconventional fracture propagation model, discrete fracture network model, and equivalent fracture model, to describe fracture propagation [27]. However, we have not been able to fully calibrate those simulation models with hard evidence from field data towards a full understanding of the complexity of the stimulated network. Therefore, these models require further in-depth study.

2.2.1. Finite Element Method. The finite element method (FEM) divides the continuous medium into several independent equivalent finite elements to solve a single element and simplify the complex problem. This method has the advantage of providing high precision and a simple solution for most practical problems and is an important analysis method for solving engineering problems. Based on the FEM, Guo et al. [28] embedded the coupling cohesive element of the seepage and deformation field into the finite element of a continuous medium and established a cohesive model of fracture propagation, as shown in Figure 5. This model does not require introducing fracture propagation and fracture criteria and can simulate the interaction between hydraulic and natural fractures and the final propagation morphology. However, the traditional FEM needs to remesh the deformation area at each time step when it is used to solve the problem of fracture displacement discontinuity, thereby increasing the calculation cost.

2.2.2. Extended Finite Element Method. To solve the problem of multiple remeshing of grids around fractures, scholars have proposed the extended finite element method (XFEM). In this method, the grid structure is independent of its internal geometric size and physical interface. Notably, remeshing is not required in this simulation. Therefore, the difficulty caused by high stress concentration at the fracture tip is overcome [29]. XFEM showed unique advantages in the analysis of the fracture propagation model of heterogeneous reservoirs. Taleghani [30] used XFEM to simulate the fracture propagation of hydraulic fracturing vertical wells in shale reservoirs. The results show that XFEM can accurately characterize the complexity of fracture networks, as shown in Figure 6. Gordeliy and Peirce [31] studied the influence of hydraulic fracture tips and boundary effects on fracture propagation in elastic media based on the XFEM. Furthermore, based on XFEM, Sheng et al. [32] established a hydraulic fracture propagation model in anisotropic continuous media and studied the influence of in situ stress parameters on fracture propagation during the fracturing process. Shi et al. [33] established a fracture propagation model when hydraulic fractures encountered natural fractures and used the Renshaw and Pollard criteria to determine the propagation direction of hydraulic and natural fractures. Keshavarzi and Mohammadi [34] studied the propagation mechanism of hydraulic and natural fractures using XFEM. The results show that the in situ stress and the direction of natural fractures are the main factors affecting the propagation morphology of hydraulic fractures. Zou et al. [35] established a hydraulic fracture initiation and steering model in unconventional oil and gas reservoirs and studied the hydraulic fracture propagation morphology under the anisotropy of reservoir stress and fracture toughness. Wang [36] used XFEM to study the fracture morphology under different perforation directions and carried out field verification. The wellhead pressure obtained by their simulation method is in good agreement with the field pump pressure curve. XFEM simulation retains the advantages of the traditional FEM simulation (with respect to the calculation of problem decomposition) and solves the shortcomings of the FEM [37]. This makes XFEM one of the most effective methods to solve discontinuous problems [38–43].

2.2.3. Boundary Element Method. The boundary element method (BEM) transforms the problem into a boundary integral equation and discretely solves the approximate solution on the boundary [44]. BEM solves the regional solution using an analytical equation to improve the accuracy; it also solves the singular field at the fracture tip using a singular basic solution. This method is more suitable for dealing with complex fracture network problems. Based on BEM, Olson and Taleghani [45] compared the fracture morphology of vertical and horizontal wells after fracturing and pointed out that the static pressure coefficient and the contact angle between the hydraulic and natural fractures are important factors affecting fracture morphology. Sesetty and Ghassemi [46] studied fracture propagation morphology and the relationship between fracture width and internal pressure using the boundary element displacement discontinuity method. Additionally, based on BEM, Shi et al. [47] established a fracture synchronous propagation model and studied the influence of in situ stress, perforation number, and wellbore azimuth on fracture morphology; this study showed that the pressure interference between fractures greatly increased the

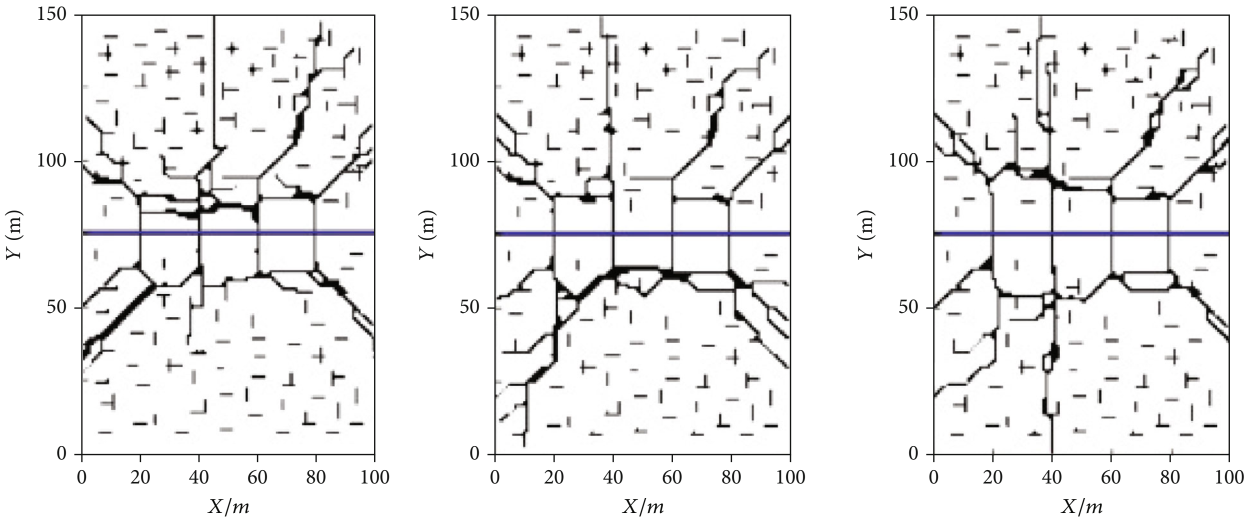


Figure 5: Finite element fracture morphology with multiple perforation conditions [28].

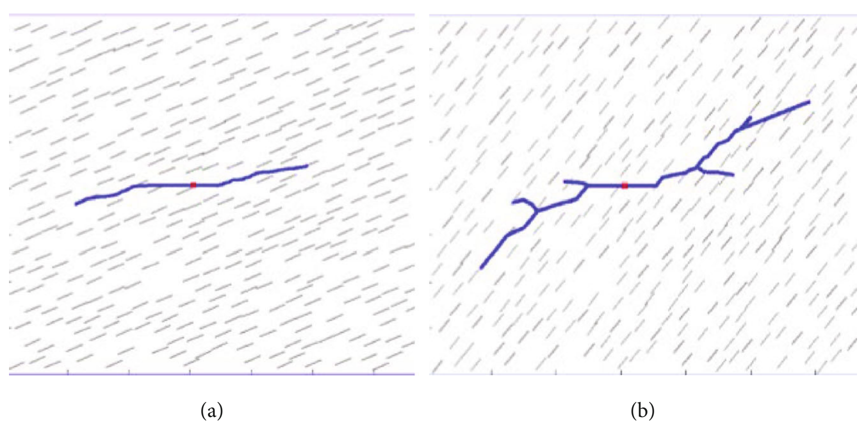


Figure 6: Simulation of fracture morphology based on extended finite element method [30]. (a) Contact angle of natural fracture is 30 degrees. (b) Contact angle of natural fracture is 60 degrees.

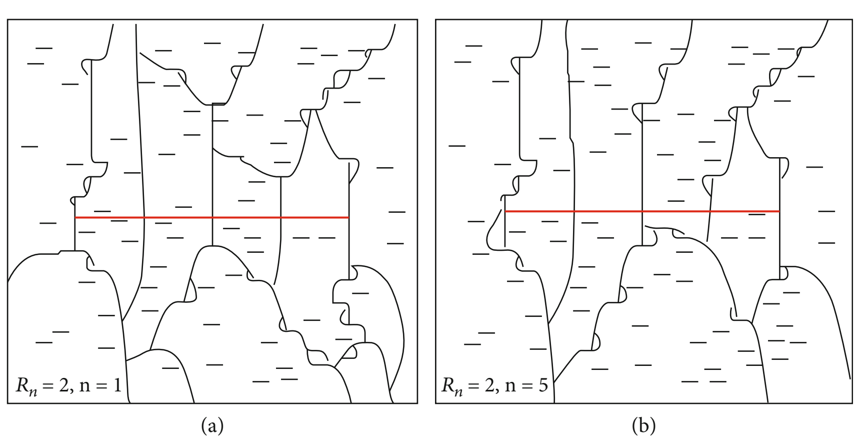


Figure 7: Simulation of hydraulic fracture propagation based on boundary element method [47].

complexity of the fractures, as shown in Figure 7. Cheng [48] studied the in situ stress distribution of fractured horizontal wells in shale gas reservoirs by combining BEM with linear elastic fracture mechanics and established a three-dimensional hydraulic fracture propagation model. Zhao [49] solved seepage mathematical models of different

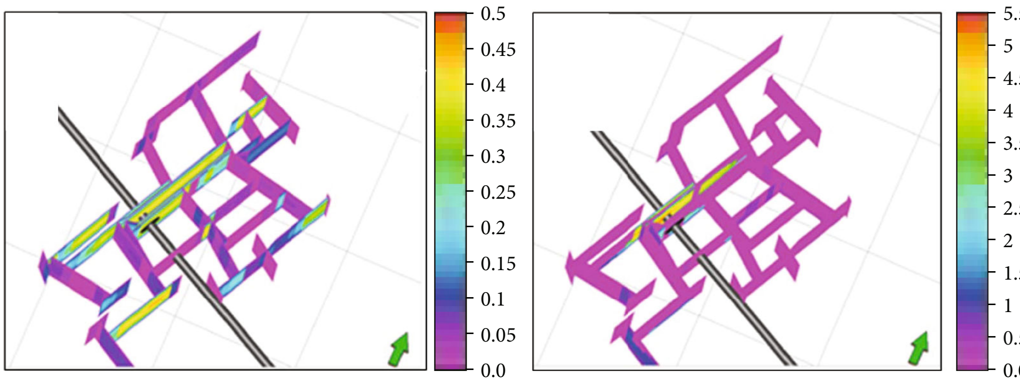


Figure 8: Fracture morphology of the unconventional fracture model [57].

well types by using the line source function and BEM and studied the influence of hydraulic fracture morphology on reservoir productivity. BEM has unique advantages in solving the propagation problem of complex fracture networks. However, because of the need to solve a large number of boundary integral problems, difficulty in simulating fluid–solid coupling problems, and the complexity of calculation, this method is difficult to apply to the simulation of large hydraulic fracture network propagation in the actual field [50].

2.2.4. Unconventional Fracture Propagation Model. The unconventional fracture model (UFM) was first proposed by Kresse et al. [51, 52], and this method is mainly used to simulate the propagation of hydraulic fracture networks in unconventional reservoirs, as shown in Figure 8. The UFM is based on the displacement discontinuity method (DDM), and the rock deformation and fluid in the fracture are fully coupled. The model not only extends in a single layer but also extends through the caprock [53]. Compared with the conventional fracture model, UFM can deal with the propagation problem of the interaction between hydraulic and natural fractures under the influence of natural fractures, thus forming a complex fracture network system. The fracture intersection in the UFM adopts the modified R&P criterion [54, 55], and the mutual interference between the fractures is considered. Notably, compared with the DDM, the UFM method has a faster calculation efficiency and can generate fracture networks that are consistent with the actual situation. But the limitation is that the physical properties of the rock reservoir considered by the UFM model are assumed to be homogeneous [56]; therefore, the UFM can only be applied to the simulation of fracture networks in homogeneous reservoirs or a single reservoir having roughly the same physical properties. Moreover, key limitation of the UFM method is not very accurate under the condition of a complex vertical stress distribution; therefore, the use cases of the model are greatly limited (Kresse and Weng, [57, 58]). This method relies on the results of discrete fracture geological modeling, and the accuracy of the input parameters is low.

2.2.5. Discrete Fracture Network Model. The discrete fracture network model (DFM) was first proposed by Meyer et al. [59]. Based on the self-similarity principle and the Warren–Root dual-medium model, a mesh model was established to simulate fracture propagation. This method has great advantages in simulating discontinuous medium problems, such as the discrete element method (DEM), ternary discrete element method, and particle flow method. Rogers et al. [60] proposed a DFNM based on the DEM and established a discrete element numerical simulation considering the multistage full hydraulic-mechanical coupling mode of horizontal wells. Thallak et al. [61] established a fluid–solid coupling fracture model by using DEM and simulated the hydraulic fracture propagation morphology under staged fracturing. The study showed that the fracture propagation was affected by the stress distribution at the fracture tip, and the remote stress was not the dominant factor affecting the fracture propagation. Based on previous simulations of fracturing fluid flow characteristics, Nagel et al. [62] investigated the influence of in situ stress distribution, fracturing fluid viscosity, and rock physical parameters on shale fracture network morphology and reservoir effective permeability. Chen et al. [63] established a numerical model of shale reservoir fracturing considering fluid–solid coupling based on a ternary discrete element model and studied the influence of perforation parameters on fracture morphology. This discrete fracture model can simulate the fracture propagation of heterogeneous reservoirs effectively and consider the problems of filtration and interfracture interference. However, the results of the model are subjective, with poorly constrained conditions, which cannot deal with the problem of random fracture propagation.

2.2.6. Equivalent Fracture Model. The equivalent fracture model is a new method proposed by Zhao et al. [64] to simulate the fracture network morphology of unconventional reservoirs. Based on lightning breakdown theory, this method equates various physical parameters in the process of fracture propagation in reservoirs to the corresponding parameters in the lightning breakdown path simulation. Considering the reservoir geological parameters, the in situ stress distribution, stress shadow effect, and fracturing operation parameters, the difference between the circumferential stress and the critical stress that initiates fracturing, and fractal probability index is introduced to jointly determine the

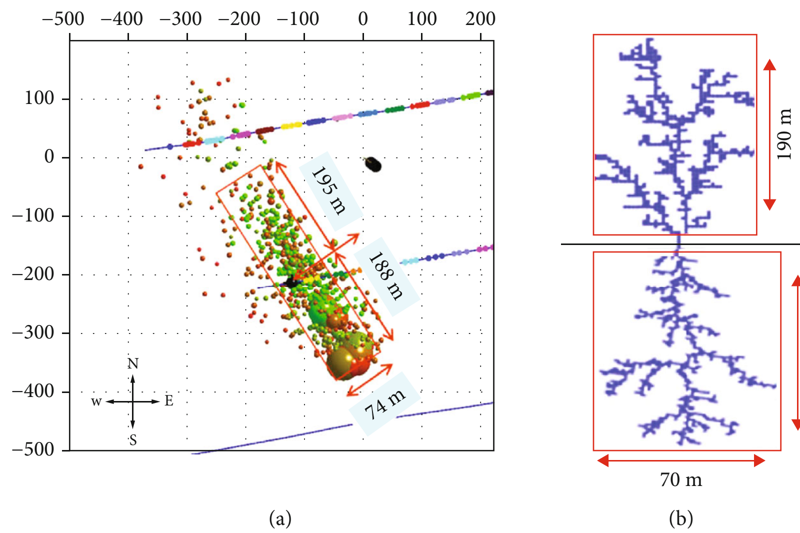


Figure 9: Fracture morphology of the equivalent fracture model [64]. (a) Actual microseismical data. (b) Fracture network morphology.

fracture propagation direction. Notably, a random function is introduced in this model to characterize the random distribution characteristics of fracture propagation, as shown in Figure 9.

In addition, the model uses microseismic constraints combined with a simultaneous perturbation stochastic approximation algorithm (SPSA) to further optimize the specific morphology of fractures, and the fracture morphology inverted by the model has a high matching rate with the actual microseismic data, as shown in Figure 10. The model uses an analytical method to determine the direction of induced fracture propagation, which can greatly improve the efficiency of the fracture propagation simulation. At the same time, considering the uncertainty of the fracture propagation direction to apply to an unclear understanding of reservoir geological characteristics, it can fully adapt to the actual reservoir simulation. However, because the model is relatively new, the relevant technology is not mature enough, and the influence of fluid–solid coupling and fracturing fluid filtration on the propagation of the fracture networks are not considered; thus, the accuracy of the model inversion must be studied further.

In view of the propagation of fracturing fractures and the inversion of fracture morphology in unconventional reservoirs, many scholars have made considerable progress and understanding, but there are some shortcomings in the methods used [65]. The physical experiment method can reflect the real fracture morphology, which has high research value for clarifying the mechanism of fracture propagation and compensates for the deficiency of numerical simulation methods in theoretical research and visualization. However, the physical experiment cannot simulate the actual reservoir-scale fracture network propagation under reservoir conditions. Therefore, this method is difficult to achieve large-scale simulation [66]. Although large-scale simulations can be carried out, there are limitations due to large amount of calculation and complex operation [67]. Therefore, there is an urgent need for an extended simulation method that can combine numerical simulations and physical experiments. Simultaneously, optimization algorithms, such as SPSA, are used to constrain the morphology of fracture networks. Therefore, the comprehensive fracture simulation model can reduce the uncertainty of inversion and improve the inversion efficiency to simulate the actual field fracture morphology.

3. Simulation of Fluid Flow in Complex Fracture Network

Owing to the complex distribution of reservoir fracture networks and complex geological conditions, conducting efficient numerical simulations of flow through complex fracture networks is the key to predicting reservoir production [68]. Notably, there are multiscale components involved in flow through unconventional reservoirs, including nanoscale pores, micron pores, and large-scale hydraulic fractures formed by natural fractures, and artificial fracturing [69]. The complex fracture networks formed after reservoir fracturing and a tight reservoir matrix constitute the main seepage medium of unconventional reservoir oil and gas. The pore sizes of the natural fractures, hydraulic fractures, and matrix are very different, and the permeability difference is approximately three orders of magnitude. Notably, the reservoir fluid is no longer limited to the flow form between a single matrix [70].

Conventional flow simulation methods cannot consider the flow patterns between the organic and inorganic matter and between the matrix and fracture; therefore, it is necessary to establish a simulation method that considers the coupling of fractures and matrix flow [71]. At present, the numerical simulation methods for fracture network flow simulation of unconventional reservoir fracturing mainly use the dual-medium model and discrete fracture model to characterize the fracture network flow mechanism [72]. The continuous medium model includes a dual-medium model (dual-porosity, single-permeability, dual-porosity,

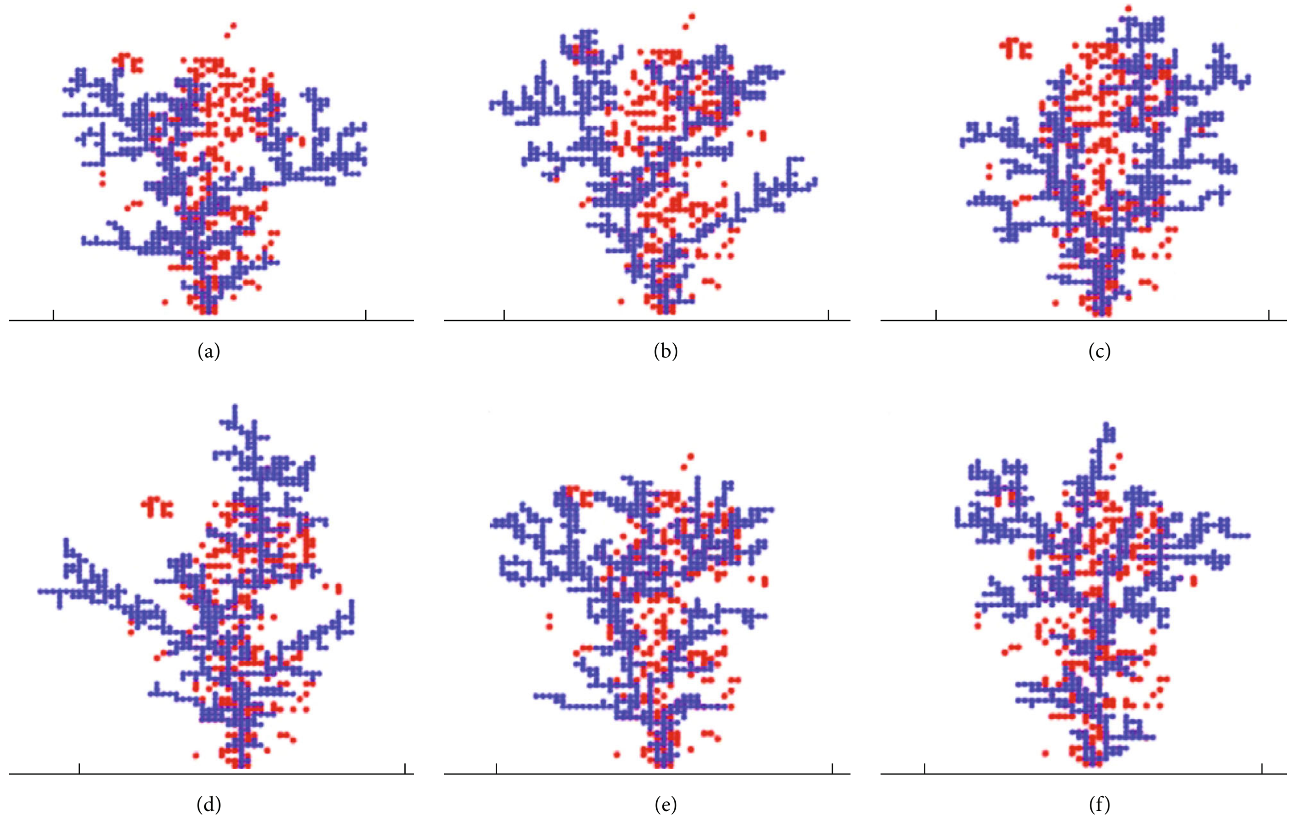


Figure 10: Morphology constraints of microseismic fracture networks [64].

and double-permeability), multiple medium model, and equivalent continuous medium model [73].

3.1. Dual-Medium Model. The dual-medium model is one of the most widely used mathematical models of fracture network flow coupling. Barenblatt et al. [74] proposed the concept of a dual medium for the first time by studying the single-phase fluid flow in reservoirs that developed natural fractures. The theory assumes that the reservoir is composed of two pore modes: matrix and fracture, and the two systems overlap in space; the matrix is the main reservoir space, and the fracture is the main seepage channel. Subsequently, Duguid and Lee [75] considered the elastic compressibility characteristics of dual media based on Barenblatt's theory, established the control equation in the matrix-fractured media, coupled the two control equations through the interaction of two pore media fluids, and proposed a dual-medium model of single-phase microcompressible fluid. Based on Barenblatt's dual-medium theory, Warren and Root [76] established a dual-medium model of dual-porosity and single-permeability and further studied the geometric characteristics and seepage process of a matrix-fracture dual-medium reservoir, as shown in Figure 11. However, the Warren–Root dual-medium model does not consider the unsteady flow of a fractured reservoir. Aiming at the problem of the Warren–Root double medium model, Odeh [77] modified the "orthogonal fracture networks" assumption in a dual-porosity and single-permeability model so that the model could consider the unsteady seepage problem. Kazemi [78] proposed a single-phase flow dual-media layered model, which assumes that the formation is stacked by fractures of different sizes and matrix rocks. In layered reservoirs, an unsteady fluid can only flow radially in the layer and vertically between the layers. This model can obtain similar results for the Warren–Root dual-porosity and single-permeability models. Perkins and Collins [79] modified the assumptions of the model based on Kazemi's layered model, considering the influence of surface resistance when the matrix flows into the fracture layer, and the heterogeneity of the skin factor at the fracture layer, and proposed a new dual-medium model. In view of the different seepage modes of production wells in unidirectional flow reservoirs, based on the Warren–Root model, De Swaan [80] considered the concentrated distribution of matrix-fracture dual media near the wellbore and proposed an unsteady dual-media model. Prado et al. [81] also studied the seepage problem of a fractured reservoir with production wells, assuming that the near-wellbore area is treated as a Warren–Root dual-medium model, and the far wellbore area is treated as a homogeneous model, thus establishing a dual-medium composite model.

To apply the concept of dual media to the simulation of natural fractured reservoirs, many scholars have proposed multiphase flow models in fractured reservoirs [73, 82]. Yamamoto et al. [83] proposed a two-dimensional two-phase mathematical model to simulate the seepage process of a single matrix in fractured reservoirs. The model when combined with the component characterization of the

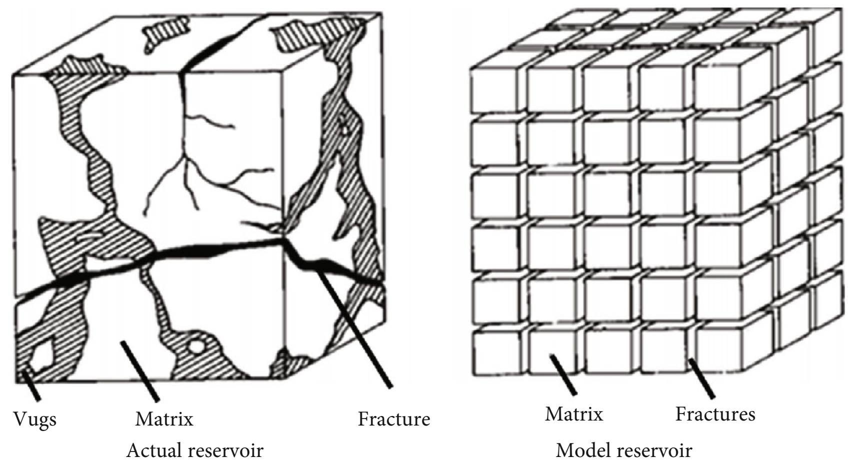


Figure 11: Simplified schematic diagram of the dual-medium model [76].

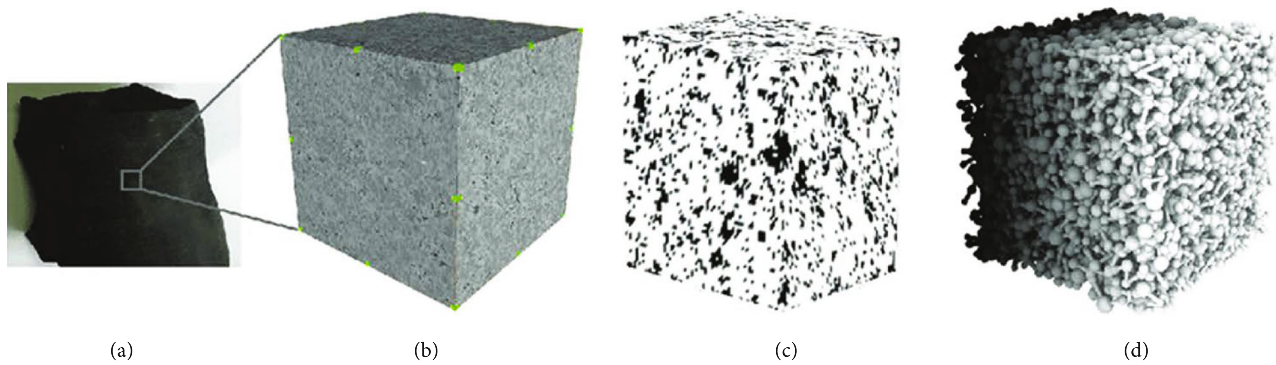


Figure 12: Real three-dimensional dual-medium model [88]. (a) Shale matrix. (b) Micro-CT image. (c) Digital core. (d) Pore network.

reservoir fluid can evaluate the effect of various displacement processes, as shown in Figure 12. AMM Bustin and RM Bustin [84] established a two-dimensional dual-medium model to describe the two-phase flow of gas and water in shale by considering the gas flow in the shale matrix and fractures with different configurations. Based on De Swaan's unsteady dual-porosity model, Humberto et al. [85] proposed a dual-porosity model that can quantitatively describe the characteristics of unsteady pressure distribution in natural fractured reservoirs. Wang et al. [86] classified fractures into two types: main fracture networks and fractured rock blocks, and established a seepage model for the dual fracture system. This method can comprehensively consider the extreme heterogeneity of the fracture system structure, anisotropy of the seepage space, and the discontinuity of the seepage.

Additionally, Thomas et al. [87] proposed a three-dimensional dual-porosity finite-difference three-phase model to simulate natural fractured reservoirs. The implicit equation was used to solve the pressure saturation of oil–gas–water three-phase; the influence of relative permeability, viscosity, and gravity on seepage characteristics was considered. This model can be used to simulate primary oil recovery and gas and water injection in naturally fractured reservoirs.

In the Warren–Root model, the flow pattern in the fluid matrix is ignored. This model assumes that the fluid in the matrix block can only flow from the matrix into the fractures and then flowing into the wellbore through the fractures. Therefore, the dual-porosity single-permeability model is generally only applicable to cases in which the permeability in the fractures is much larger than that of the matrix porosity, and the flow in the fracture is dominant. To solve this problem, Deruyck et al. [89] proposed a dual-porosity and dual-permeability model and classified the reservoir into two seepage systems: fracture and matrix. In the dual-porosity and dual-permeability models, the flow in the matrix pores is no longer ignored. The fluid in the matrix not only flows to the wellbore after the fracture but also directly into the wellbore in the matrix. This is applicable to the case where the permeability difference between the matrix and the fracture is small, and the fluid flow from inside the matrix cannot be completely ignored. Hill and Thomas [90] established a component model containing oil, gas, and water phases based on Deruyck's dual-porosity dual-permeability model. At the same time, Chen et al. [91] established a steam thermal recovery model of dual-porosity and dual-permeability dual medium based on this model. Based on the seepage characteristics of fluids in

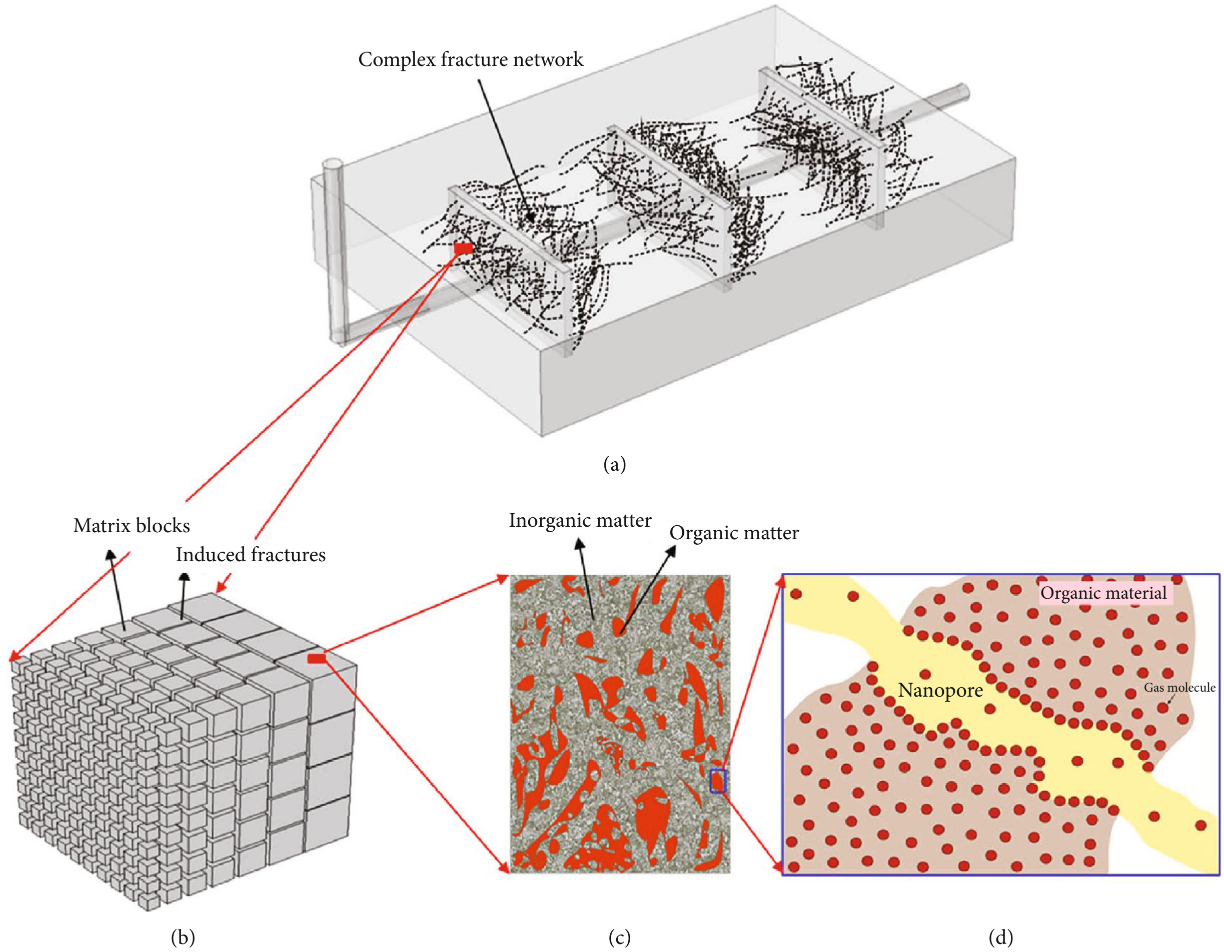


Figure 13: Dual-medium method for a shale gas reservoir [93].

different media, Choi et al. [92] assumed that the Forchheimer equation was used to describe the nonlinear seepage of fluid in fractures, and the Darcy equation was used to describe the linear seepage in the matrix. Based on this, a dual-porosity and dual-permeability model was proposed, and a high-speed non-Darcy flow in dual media was simulated. This dual-porosity and dual-permeability model compensates for the deficiency in which the fluid cannot flow in the matrix in the dual-porosity and single-permeability model, which makes the factors considered in the model more comprehensive and lays the foundation for the development of the subsequent local grid refinement method, as shown in Figure 13.

3.2. Local Grid Refinement Method. To further describe the fluid flow in the matrix in the dual-porosity and dual-permeability model, some scholars have proposed a dual-medium model with local refinement in the rock matrix. Wu et al. [94] proposed a dual-medium model of multiple interactions that does not consider the influence of gravity. The matrix rock is divided into several annular networks from inside to outside; fluid exchange can be carried out between adjacent networks. Owing to the matrix grid refinement, this model can more accurately describe the unsteady flow inside the matrix block. Kalantari [95] proposed a method to simulate flow from fractures to matrix and believed that the pressure of artificial fractures and the variation characteristics of related parameters can be accurately simulated by using a certain mathematical method to locally refine the grid. Chaudhary et al. [96] and Agboada and Ahmadi [97] used the logarithmic grid refinement method to simulate the fluid seepage characteristics of fracture matrix networks. This method is more flexible than the local grid refinement and has the characteristics of a small workload, along with good characterization of fracture pressure, saturation, and other parameters. At the same time, it can accurately simulate the seepage law of complex fracture networks in shale reservoirs. Wang et al. [98] proposed a double-medium equivalent refinement method to simulate hydraulic fracture network morphology. This method can reflect the state relationship between artificial main fractures and induced fractures and can accurately simulate the macroscopic seepage characteristics of fractures. Lee and Tan [99] refined the matrix vertically grid (VR model) by considering the crossflow effect between the refinement grids and adjacent fractures in the horizontal direction. This refinement method can reflect the vertical matrix flow and is suitable for gravity displacement flow in highly fractured reservoirs. The grid refinement method is based on the dual-medium model, which increases the number of grids

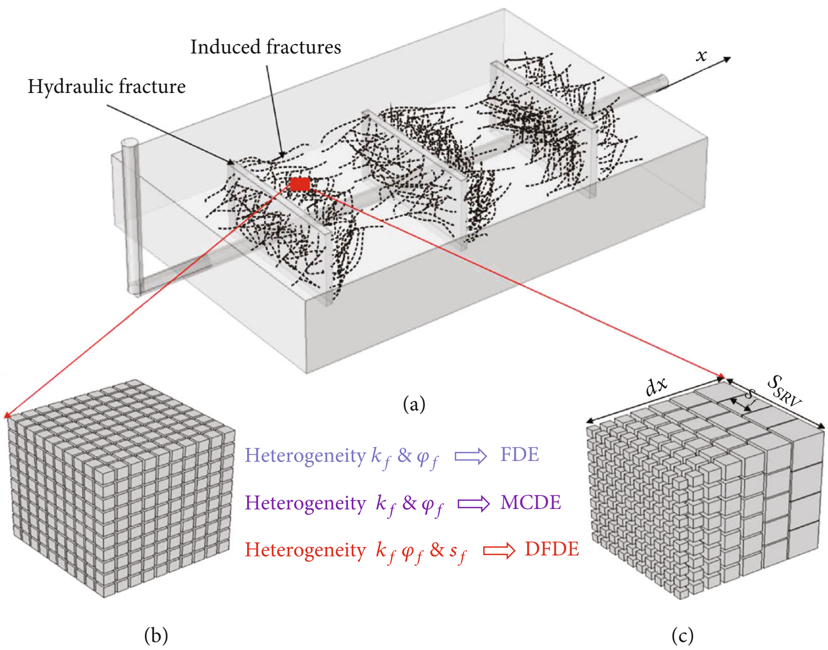


Figure 14: Governing equations for fluid flow in multiple media [109]; MCDE: modified conventional diffusion equation; FDE: fractal diffusion equation; CDE: conventional diffusion equation. (a) Reservoir with induced fractures. (b) Homogeneous dual-medium model based on CDE. (c) Fracture spacing and porosity/permeability heterogeneous dual-media model.

by regionally increasing the fractures and matrix network to achieve the purpose of fine description of seepage signs; however, it has high computational complexity.

3.3. Multiple Continuum Medium Model. According to the fluid exchange form between different scale media, considering the complex multiscale fracture medium problem of unconventional reservoirs, the traditional dual-medium model cannot be accurately described. Therefore, scholars have proposed a multiple continuum medium model to describe the multiscale medium coupling migration mechanism of unconventional reservoirs [100–102]. To simulate the unsteady flow characteristics between matrix and fracture, Pruess and Narasimhan [82] proposed multiple continuous medium models. The model divided the matrix grid into multiple nested grids and stipulated that the fluid flowed from the internal grid to the outer grid and then to the fracture grid. Gilman and Kazemi [103] established a reservoir numerical simulator based on the Multiple–Interacting–Continua (MINC) model. The matrix grid is divided into nested rectangular grids and divided vertically into different regions, so the influence of gravity can be considered. Wu et al. [94] compared multiple continuous medium models with a dual-medium model; this study showed that the calculation accuracy of the MINC model was higher than that of the dual-medium model. Du et al. [104] proposed a multifracture network seepage model to highlight the dominant role of fractures in fluid seepage to distinguish rock mass structures, such as reservoir fractures, porous media, and faults. This model combines the traditional continuous medium model and Wittke's discrete method to process the studied reservoir fracture structure into a discrete main fracture network system, induced fracture network system, and generalized equivalent network system.

Owing to the significant influence of fracture network morphology and flow capacity on the production dynamics, Cinco-Ley et al. [105], Reis [106], Ranjbar et al. [107], and other scholars proposed a modified conventional diffusion equation (MCDE) based on the conventional diffusion equation (CDE) to describe the fluid seepage characteristics between fractures and matrix. The method considers the nonuniform distribution of fracture spacing and uses normal distribution, linear, and exponential functions to describe the distribution of fracture spacing. At the same time, scholars have also proposed the fractal diffusion equation (FDE) to describe the fluid flow law, which considers the fractal distribution characteristics of evenly distributed fracture spacing and fracture network porosity/permeability in reservoirs. Cossio et al. [108] proposed a semianalytical solution for finite conductivity vertical fracture seepage by combining FDE with a trilinear flow model. The distribution of fracture network morphology and flow capacity are relatively simple in the multiple continuum model, while the heterogeneity of fracture network morphology and flow capacity in unconventional reservoirs is strong. Notably, large errors are produced when fracture network parameters are considered equivalently in the multiple continuum model, as shown in Figure 14.

3.4. Discrete Fracture Model. Many studies have shown that there are significant differences in the fracture height, length, opening, and spatial distribution in reservoirs. However, the assumption of a homogeneous distribution of fractures in multiple continuous medium models is quite different from

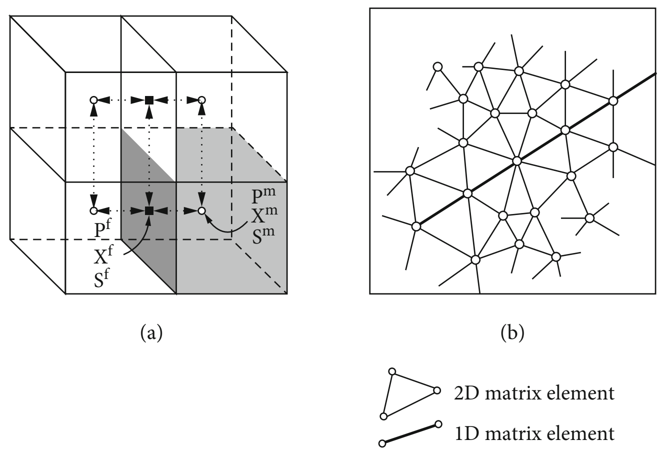


Figure 15: Matrix-fracture coupling diagram of discrete fracture model. (a) 2D fracture and 3D matrix diagram [114]. (b) 2D discrete fracture model diagram [21].

the actual reservoir situation. Therefore, scholars have proposed the discrete fracture model (DFM) to describe fractures [110–113], as shown in Figure 15. This model reduced the dimensions of the fracture and placed it on the interface between the matrix grids. Compared with the dual-medium model, the DFM can describe the geometric characteristics of the fracture more accurately and has a higher calculation accuracy. However, because of the complex fracture network morphology, it is difficult to match the fracture morphology with a high-quality unstructured grid. Based on this problem, many scholars have developed DFMs with different numerical methods to simulate multiphase flow in a discrete fracture medium. Slough et al. [114] established two-dimensional and three-dimensional DFMs of multiphase flow in fractured media using the finite difference method. This method uses orthogonal structural grids; therefore, the distribution of fractures is significantly limited. Additionally, Noorishad and Mehran [112] simulated solute dispersion and convection in fractured media using Galerkin's finite element method based on the variational principle. However, in Galerkin's finite element method, the degrees of freedom of the fractures and the matrix at the common sensors must be consistent; therefore, this method does not satisfy the law of conservation of local matter.

To solve the law of conservation of the local matter problem of matrix-fracture nodes in the Galerkin finite element method, Zhang et al. [26] proposed a multiscale finite element discrete fracture model satisfying local material conservation and used this model to simulate fluid flow in fractured reservoirs. Granet et al. [115] used the block center finite volume method to simulate oil-water two-phase flow in fractures and established a block center finite volume method DFM. However, the model is the same as the finite difference method and is only suitable for orthogonal fracture simulations. Monteagudo and Firoozabadi [116] proposed a DFM for two-phase flow simulation based on the controlled volume finite element method, which characterizes the discontinuity of saturation at the junction of matrix grids and fracture grids. Lim and Aziz [102] also established a DFM suitable for a component model, based on the control volume finite element method (CVFEM). Additionally, Reichenberger et al. [117], Matthai et al. [118], Geiger et al. [119], and Marcondes and Sepehrnoori [120] studied the DFM of multiphase flow, based on the CVFEM, as shown in Figure 16. Alboin et al. [121] used a mixed FEM to solve the fluid diffusion equation in fracture media. Martin et al. [122] extended the work of Alboin et al. so that the method can be applied to cases where the fracture permeability is less than that of the matrix. Hoteit and Firoozabadi [123] combined the mixed FEM and the discontinuous Galerkin method to simulate the multiphase flow and improved the estimation method of the center pressure of the matrix grids adjacent to the fracture grids to avoid the requirement of fine grid generation around fractures.

To accurately characterize the geometry of fracture networks in reservoirs, discrete fracture models need to generate high-quality unstructured grids to match the complex distribution of fracture networks in reservoirs. It is very difficult to mesh high matching for complex fracture network structures under three-dimensional conditions. The embedded discrete fracture model (EDFM) can avoid the subdivision of unstructured grids. It only needs to mesh the matrix. The discrete fracture is embedded in the matrix grids, and the fracture is treated as the source and sink term in the matrix grids, thus greatly reducing the difficulty of grid generation. Lee et al. [124] proposed for the first time the embedding of fractures in matrix grids and used a similar method to that of the Peaceman's formula to deal with the crossflow of matrix to fractures. Li and Lee [125] extended Lee et al.'s idea and proposed the concept of an EDFM. Fang et al. [126] obtained a new method of mass transfer from the matrix grid to the fracture grid based on the steady-state seepage control equation and proposed a two-dimensional mixed boundary element EDFM, which has a higher accuracy than the original EDFM. Aarnes et al. [127] established a multiscale embedded discrete fracture model using the cyclic multiscale finite volume method, which is suitable for the case of a large reservoir area requiring more grid processing. Moinfar te al. [128] extended the two-dimensional EDFM to three dimensions and analyzed

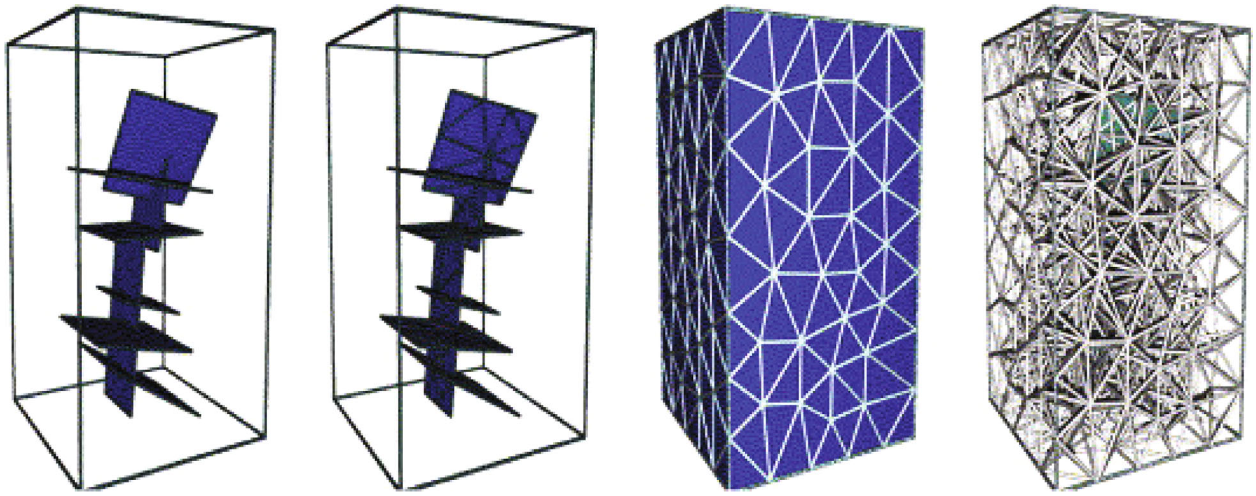


Figure 16: Control volume finite element discrete fracture model of multiphase flow [117].

the influence of natural fractures and artificial fractures on fluid seepage. Since the formation has more complex geological conditions (there are interlayers, faults, or complex reservoir boundary shapes in the formation), EDFM often cannot be accurately and efficiently processed, and DFM matches the fracture morphology through unstructured grids, so that the fracture is located on the intersection surface between the matrix grids, which is in line with the actual physical significance. So, some scholars proposed pEDFM [129–131]. The pEDFM projects the fracture grid to the intersection line or intersection surface of the matrix grid around it and adds an additional connection between the projection fracture grid and the matrix. Thus, it not only contains the characteristics of high efficiency of EDFM and solves the limitations of traditional EDFM, but also has the advantages of DFM that can effectively deal with more extensive reservoir development. Tene et al. [131] pointed out that EDFM cannot effectively deal with the case of fracture grid permeability lower than matrix permeability and proposed an embedded discrete fracture model based on projection (PEDFM), as shown in Figure 17. In this model, the fracture grids are projected onto the interface of the matrix grids, which increases the matrix-fracture connection and weakens the transmission coefficient between the original adjacent matrix grids. Jiang and Younis [129] make several improvements upon the original pEDFM method. A physical constraint on the preprocessing stage is proposed to overcome the limitation in a "naive implementation" of pEDFM. Rao et al. [130] point out that there are still some previous pEDFM needs to be resolved, guiding on lack of a practical method to select projection faces, the qualification in the transmissibility formula of f-m connections, and poor connections in some cases. Based on this, propose a practical algorithm called "microtranslation method" to select surfaces. However, the complex pore space structure in unconventional reservoirs has a significant influence on fluid flow, and relevant numerical simulation research has not been fully considered. Therefore, it is necessary to comprehensively consider the discrete fracture model and the complex flow mechanism of multiple media to realize the numerical calculation of multiple media mass transfer in unconventional reservoirs.

4. Inversion of Fracture Parameters

Accurate description of fracture network morphology and fracture flow capacity at all levels is an important basis for dynamic analysis, fracturing evaluation, and production system formulation of production wells [132]. Unconventional reservoir natural fracture distribution is complex, and reservoir heterogeneity and complex in situ stress make the distribution of induced fractures more difficult to describe. For unconventional reservoir fracturing, fracture network inversion methods can only simulate reservoir fracture morphology; in these methods, reservoir porosity, permeability, pressure distribution, and other related parameters cannot be accurately characterized. Therefore, it is necessary to conduct the inversion of fracturing fracture parameters combined with the actual production data to accurately describe the fracture network morphology and the distribution of fracture flow capacity at all levels. At present, the inversion methods of fracture parameters are mainly divided into four categories: microseismic data inversion method, fractal fracture network inversion method, well-testing analysis inversion method, and production dynamic parameter inversion method.

4.1. Microseismic Data Inversion Method. With the development of microseismic monitoring technology, researchers have begun to use microseismic signals to study the characteristics of the hydraulic stimulation [133–137], as shown in Figure 18. The inversion of fracture network morphology using microseismic data can avoid the disadvantages of low computational efficiency of existing physical experiments and fracture propagation simulation methods, which are difficult to apply to actual reservoirs [138]. Microseismic monitoring technology draws fracture space images by analyzing microseismic waves generated during hydraulic fracturing

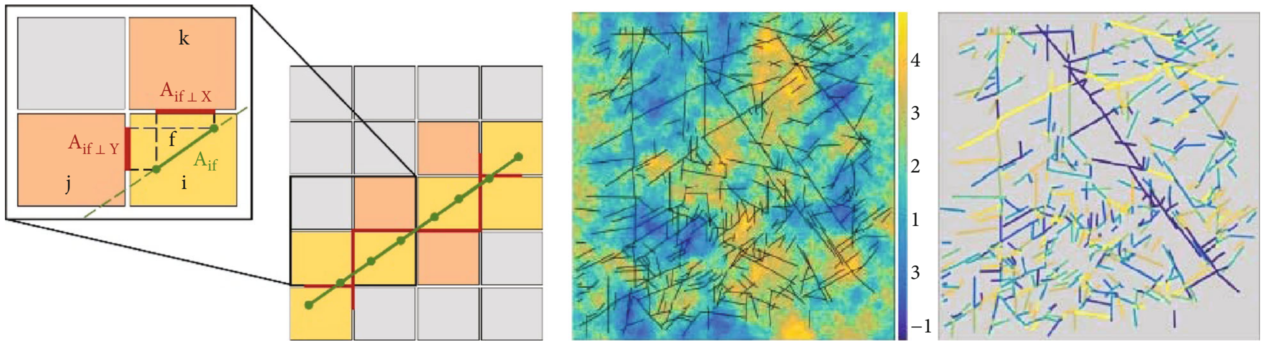


FIGURE 17: Fracture morphology of embedded discrete fracture model [129]. (a) Embedded discrete fracture model. (b) Fracture distribution morphology.

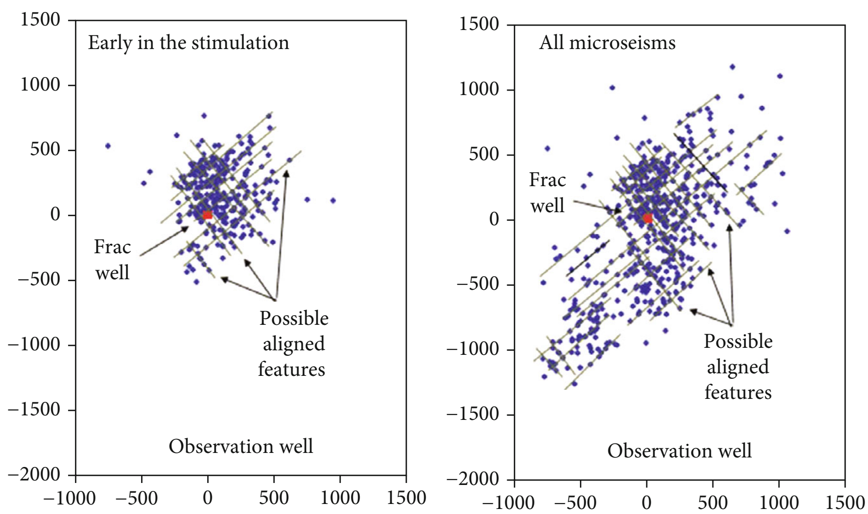
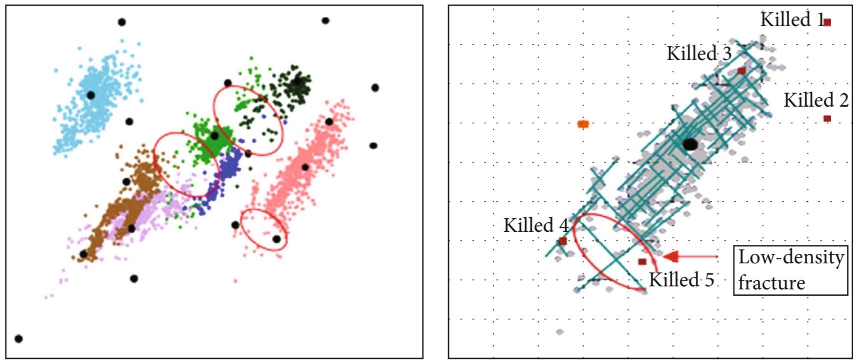


FIGURE 18: Fractures morphology inversion based on microseismic data characteristics [140].

operations to achieve the purpose of monitoring the entire development process of fractures [139].

In 1997, the US Energy Agency obtained effective seismic wave signals in the fracturing microseismic monitoring experiment in Cotton Valley, which laid the foundation for subsequent large-scale hydraulic fracturing microseismic monitoring [141]. The Los Alamo National Laboratory of the United States conducted underground microseismic monitoring experiments in hot dry rock for three years. A large number of microseismic monitoring data show that microseismic monitoring can be used to determine the fracture orientation of hydraulic fracturing [142]. Subsequently, a microseismic monitoring experiment of hydraulic fracturing was successfully carried out in the Barnett Oilfield of the United States, and the geometrical morphology of fractures after the fracturing process was obtained [143]. Since then, many scholars have studied the microseismic inversion method, causing the microseismic data inversion technology to develop rapidly.

Microseismic inversion technology has developed from simple source location inversion to source spatial location distribution, reservoir permeability parameters, stimulated reservoir volume, and rock deformation inversion and interpretation [144]. Warpinski et al. [140] pointed out that fractures develop relatively along the orthogonal direction and easily formed complex fracture networks based on microseismic image analysis. Based on a physical simulation experiment of hydraulic fracturing in shale gas reservoirs, Fisher et al. [145] evaluated the fracturing effect of the Barnett shale horizontal well using microseismic fracture monitoring technology, as shown in Figure 19. Zhang et al. [26] used an acoustic emission monitoring system to monitor the generation and propagation of shale fracturing fractures in real time and recorded the fracture morphology of hydraulic fracturing. However, the inversion method based on microseismic data can only retrieve the approximate geometrical morphology of hydraulic fractures and cannot effectively describe the dynamic parameters, such as fracture porosity, permeability, oil saturation, and fracture conductivity. The microseismic signal (cloud) only represents <10% of the total energy and cannot obtain the accurate fracture distribution. There are location errors in microseismic datasets,



(a) (b)

Figure 19: Fracture morphology evaluation based on microseismic data [145]. (a) Microseismic data point. (b) Planar fracture structure.

especially in Z direction. All these uncertainties really complicate the utilization to derive accurate fracture morphology.

4.2. Fractal Fracture Network Inversion Method. A large number of hydraulic fracturing experiments have shown that the fractal fracture propagation model can better fit the fracture network morphology and dynamic characteristics simulated by fracturing experiments [146], and the fractal scale model can be used to characterize fractures for different scales and types [147, 148]. In 1985, Katz and Thompson [149] experimentally showed that the space of porous media has fractal characteristics, and that the pore volume has the same fractal dimension as the pore surface of the rock. Williams and Dawe [150] and Wagdany et al. [151] explored the fractal characteristics of porous media and the fractal phenomenon in the process of fluid transmission in porous media, indicating that the fractal theory can effectively describe the transmission characteristics of fluids in heterogeneous porous media. Sahimi [152] considered fractal theory to be an effective method for calculating complex fracture networks by studying the fractal characteristics of fracture networks in reservoirs. He also pointed out that even if the natural fracture distribution of the actual reservoir does not have strict self-similarity, the fracture network distribution can still be calculated using the fractal method, and the fracture morphology of such reservoirs after fracturing also has fractal characteristics.

Chilingarian et al. [153] used the self-similar fractal method to calculate the fractal dimension of the natural fracture distribution, described the natural fracture distribution density in a rock matrix, and introduced the anomalous diffusion coefficient to calculate the connectivity within the fractures, as shown in Figure 20. Yu et al. [154] established the transport properties of deterministic self-similar fractal networks and discussed the seepage characteristics of fractal fracture network models, including the correlation between dynamic parameters, such as pressure, flow, resistance, permeability, porosity, and fracture network structure parameters. The research teams studying Newtonian fluids and non-Newtonian fluids [155], non-Darcy seepage fractal analytical solution [156], flow resistance fractal analytical solution [157], starting pressure gradient fractal analytical solution [158], flow tortuosity [159], porous media infiltration phenomenon [160], and the development of fractal geometry theory have made outstanding achievements. Cai [156] used the fractal method to quantitatively characterize the fracture distribution, proposed the fractal analysis method of fracture networks, and used the improved box-counting method to measure the flow mechanism of porous media in fracture networks to characterize the complexity of fracture networks. Chang and Yortsos [161] embedded fractal fracture networks into the matrix and obtained the analytical solution expression of the instantaneous pressure in fractal-fractured reservoirs. Tong and Ge [162] studied the fractal seepage model of fractured reservoirs and provided an analytical solution of seepage dynamic characteristics in the formation under constant bottom hole pressure and constant production. Wang and Yu [155] studied the seepage characteristics of bifurcation fracture networks (with random distribution) using the fractal method and obtained an analytical solution expression for the permeability of bifurcation fracture networks with random distribution. Kong et al. [163] studied the fluid flow in porous and fractured fractal reservoirs and obtained the basic formula of fractal permeability, porosity, and seepage velocity by introducing the differential relationship of flow path length and established the single-phase fluid seepage pressure diffusion equation in fractured reservoirs. He and Xiang [164], Xiang [165], Ning et al. [166], and others have carried out a series of studies on fractal reservoirs with non-Darcy low velocity, unstable seepage, and double-medium fractal reservoirs and established relevant mathematical models. Tao [167] established an unsteady flow model of fractal double medium combined with the four microscopic migration mechanisms of shale gas flow and solved the seepage mathematical model of fractured horizontal wells to obtain the matrix fractal apparent permeability considering diffusion and slippage migration processes.

To a certain extent, fractal fracture morphology reflects the mechanical mechanism of fracture propagation. Scholars have proposed a method to describe the fracture propagation rule using fractal theory and matched it with microseismic data to invert fracture networks [37]. Based on the principle of seismic waves traveling along the shortest

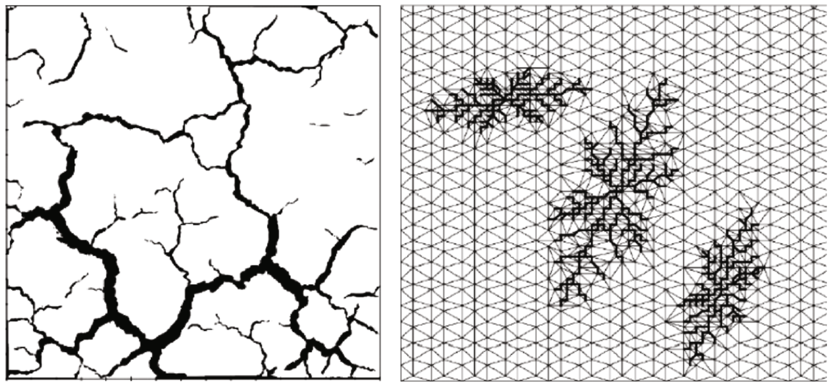


Figure 20: Fractal characterization of fractures. (a) Fractal characteristics of fractures in soil [168]. (b) Fractal characteristics of induced fractures [169].

propagation path, Zhang et al. [37] used the ray tracing method of Snell's law to analyze microseismic data, inversed the complex fracture network morphology, and evaluated the fractal parameters of fracture networks combined with the production history. Sheng et al. [170] established a random fractal inversion method for fractured horizontal wells based on microseismic data and fractal bifurcation fractures, as shown in Figure 21. However, the fractal fracture growth algorithm (used in their study), which is based on microseismic monitoring, does not consider the influence of in situ stress, rock mechanical parameters, and natural fracture heterogeneity on fracture growth; therefore, the accuracy of the fracture morphology needs to be further verified.

4.3. Parameter Inversion Method Based on Well-Testing Analysis. Well-testing analysis can effectively obtain the complex seepage law of unconventional fractured reservoirs, fracturing characteristic parameters (such as fracture half-length and fracture conductivity), and reservoir physical parameters (such as permeability and skin factor), which lays a foundation for the design of efficient development schemes for oil and gas reservoirs. At present, there are three main methods to establish a well-testing interpretation model of fractured horizontal wells: point-source function, elliptical seepage, and linear seepage.

4.3.1. Point-Source Function Method. In 1961, Rushing et al. [171] first proposed a multilayer reservoir seepage model. Assuming that the production is constant and there is no cross flow between layers, the point-source function method is used to analyze the variation in production and pressure in each layer. The theory lays a foundation for the subsequent well-testing seepage analysis of unconventional reservoirs. Subsequently, Gringarten et al. [172] introduced the point-source solution in the heat conduction equation into the well-testing problem and successfully applied it to the analysis of the pressure instability characteristics of fractured wells with infinite conductivity. Based on previous models, Cinco et al. [173] proposed a well-testing model for infinite formation fracturing wells and established the relationship between the dimensionless fracture conductivity and dimensionless wellbore pressure. Li [174] analyzed the seepage process of vertically fractured horizontal wells in homogeneous reservoirs, established a mathematical seepage model of a fractured horizontal well, drew a pressure drop curve, provided a theoretical chart for well-testing analysis, and calculated the average half length of the fractures, fracture conductivity, and average permeability parameters of the formation. Li [29] used the Green function to solve the point-source solution under different boundary conditions and used the superposition principle to solve the well-testing problem of fractured horizontal wells under the condition of limited conductivity. Fan [175] studied the well-testing theory and interpretation method of staged fracturing horizontal wells, used the point-source idea to solve the spatial arbitrary point-source solution, and used the superposition principle to solve the fracture well-testing problem of multiple fractures in single medium and dual-medium reservoirs. Wang [176] established a physical model of horizontal well fracturing seepage (considering the heterogeneous distribution of hydraulic fractures), solved the seepage model using a well-testing method, and obtained the dynamic analytical expression of pressure. Yao et al. [177] combined the point-source function and Green function to establish a seepage well-testing model for a multistage fractured horizontal well. Considering the influence of the fluid pressure drop, the influence of the fluid on the seepage model under wellbore pressure loss was analyzed. Based on the point-source method, discrete method, and superposition principle, Gu et al. [178] used fractal theory to consider the influence of complex natural fracture networks on seepage and established the well-testing model for multistage stimulation horizontal wells in unconventional reservoirs, while considering the distribution of natural fractures. This method can solve well-testing problems at any angle, as shown in Figure 22.

The point-source function method can easily solve the complex problems of different fracture spacings, fracture

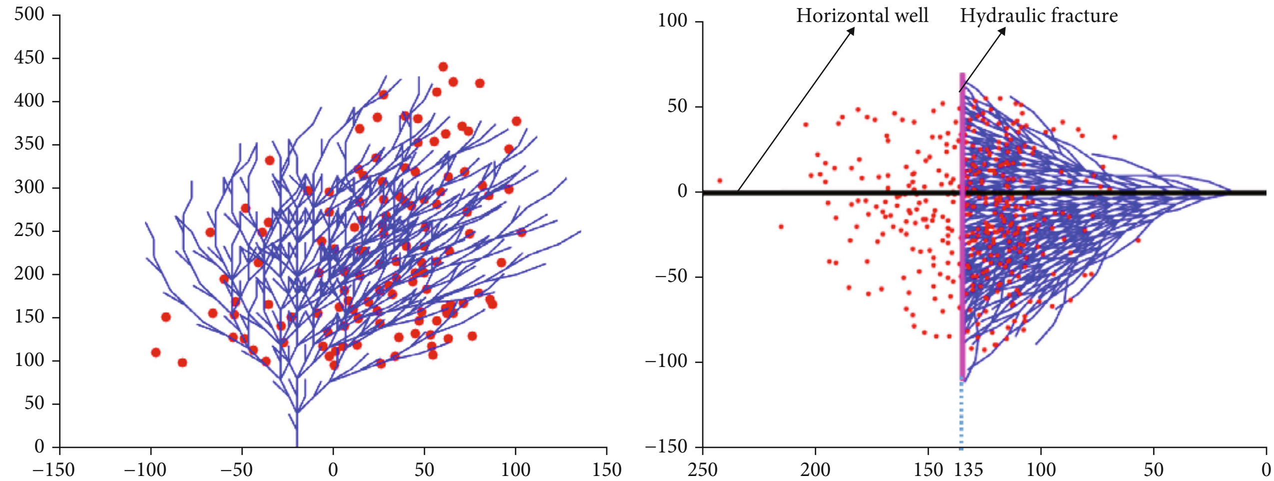


FIGURE 21: Fracture morphology under microseismic constraint [170].

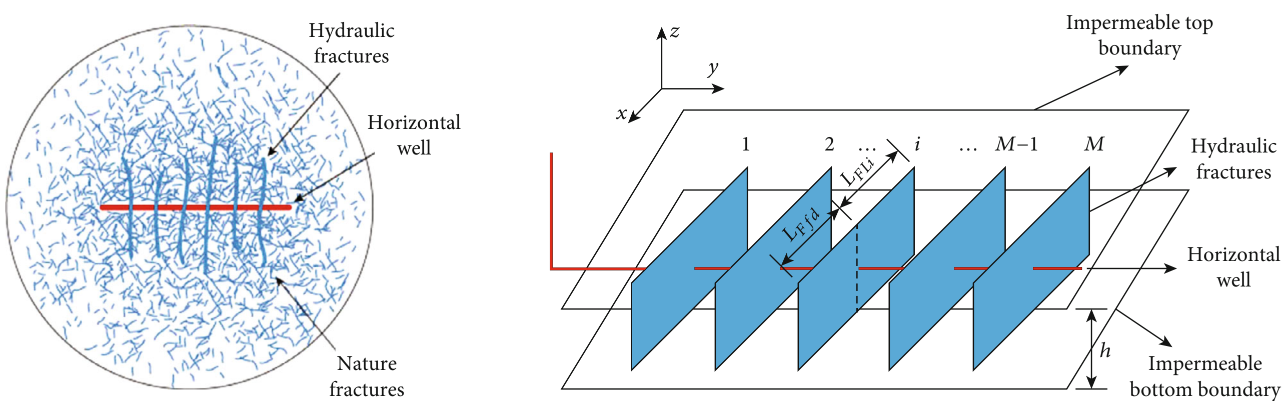
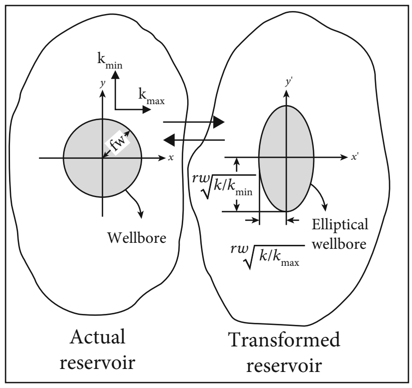


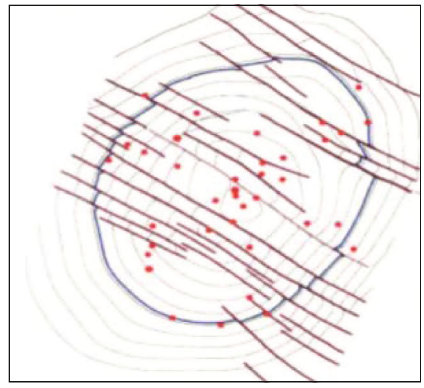
FIGURE 22: Simplified fractures distribution model based on point-source function [178].

lengths, and different boundary combinations. However, point-source function method has limitations in solving complex microfractured reservoirs; additionally, it cannot be applied to the dynamic analysis of fracturing well production and pressure in tight oil and gas reservoirs.

4.3.2. Elliptic Seepage Theory. Elliptic seepage theory can consider the fluid flow characteristics around complex fractures and can be used to solve the well-testing problem of fractured wells in large-scale hydraulic fracturing, as shown in Figure 23. While studying the influence of pollution caused by fracturing on fluid seepage, Prats et al. [179] found that fluid flow around the fractures is elliptical. The elliptical equation can be used to describe the fluid seepage process, thus leading to the application of elliptical seepage theory in the well-testing analysis of fractured reservoirs. Kucuk and Brigham [180] considered the problem of well testing in anisotropic fractured reservoirs, considering that an elliptical fluid morphology would be formed around the wellbore, and solved it by using the theory of elliptical seepage. Igbokoyi and Tiab [181] considered that the initial flow around the fractures was linear and then turned to an elliptical flow when solving the heterogeneous seepage problem of natural fractured reservoirs. The elliptical seepage theory can be used to solve the natural fracture well-testing problem by considering the pressure loss in the fractures. Wattenbarger and Ramey [182] extended the method of Prats when solving the well-testing problem of fractured wells and introduced the coordinate transformation method to convert the elliptical seepage problem into a rectangular problem of elliptical coordinates, which simplified the seepage equation. Chen [183] used elliptic flow theory to solve the well-testing problem of fractured wells. In the elliptic flow equation, the fluid in the fracture is considered to have finite and infinite conductivity. Corresponding to this issue, Obuto and Ertekin [184] and Stanislav et al. [185] established a well-testing problem-solving model using elliptic seepage theory that considered combined reservoirs. Li et al. [186] used the continuous steady seepage method to solve the problem of the discharge radius of fractured vertical wells. For each stable seepage area, the elliptic seepage theory was used to solve the nonlinear double-porosity model by considering the permeability and stress sensitivity. Apte and Lee [187] applied the elliptical seepage theory to solve the well-testing problem of multistage fractured horizontal wells and believed that there were two flow patterns



(a)



(b)

Figure 23: Elliptic seepage theory. (a) Elliptic seepage solution in real reservoir [179]. (b) Elliptic seepage zone with natural fractures [181].

in the flow process of fractured horizontal wells: SEF (sustain elliptical flow) and BIEF (boundary influence elliptical flow). The well-testing method established based on the elliptical seepage theory can effectively calculate the fluid flow characteristics when the fracture distribution of unconventional reservoirs is complex, but this method does not consider the mutual interference between fractures. Therefore, further research is needed to solve this problem.

4.3.3. Linear Seepage Theory. Ei-Banbi et al. [188] believed that linear flow played a dominant role in tight oil and gas reservoirs, especially in fractured horizontal wells. Therefore, productivity equations considering dual porous media under two impermeable boundary conditions were established. Bello and Wattenbarger [189] pointed out that in low-permeability tight oil and gas reservoirs, a large number of well-testing curves show the characteristics of linear flow, and it is the only type of flow that can be observed. Therefore, a linear flow can be used to describe the fluid flow process in fractured reservoirs. Ozkan et al. [190] compared and analyzed the fluid flow patterns of fractured horizontal wells in conventional and unconventional reservoirs and found that multilinear flow can be used for the dynamic analysis of unconventional reservoirs and the optimization design of fracture parameters. Li et al. [191] proposed for the first time a trilinear flow model of fractured wells with finite conductivity in infinite strata. The model divided the flow area into a hydraulic fracture flow area, linear flow area (perpendicular to the fracture wall), and frontal linear flow area (in the far well zone). Brown et al. [192] studied the linear flow model of fractured horizontal wells in detail and analyzed the typical well test curve of the three linear flow models, which laid the foundation for the practical application of the multilinear flow model of fractured wells. Stalgorova and Mattar [193] extended the trilinear flow model, established a multilinear flow seepage model, and discussed its applicability. Ozkan et al. [190] divided the flow pattern of the well-testing curve of the three linear flow models and provided the asymptotic expression of each stage, as shown in Figure 24. Zeng et al. [194] extended the five-zone multilinear flow, established a seven-zone multilinear flow seepage model, and obtained the dynamic curves of production and pressure. Subsequently, many scholars, such as Ali et al. [195] and Escobar et al. [196], have conducted research on the multilinear flow model of fractured horizontal wells in tight reservoirs. Multilinear flow is a simple model for solving the seepage model of fractured horizontal wells. This method mainly considers the main flow form of fluid in tight oil and gas reservoirs and considers the seepage problem of combined reservoirs caused by complex fracture distribution after fracturing, suitable for the dynamic analysis of production and pressure after large-scale fracturing of horizontal wells in tight oil reservoirs.

4.4. Inversion Method Based on Production Dynamic Parameters. History matching based on production dynamic data can further constrain fracture morphology and flow capacity. (a) In terms of analytical/semianalytical models, scholars used the dual-medium model to equivalently characterize the fracture networks and established a seepage model of fractured horizontal wells by using the trilinear flow theory. Combined with the actual unstable pressure response characteristics of wells, the fracture parameters, such as fracture length, fracture conductivity, and fracture network width, were inverted [197, 198], as shown in Figure 25. To further improve the reliability of parameter inversion results, Chen et al. [199] proposed a dynamic inversion method for the comprehensive analysis of microseismic data, production data, and well-testing data, which further reduced the multisolution of fracture parameter inversion results. (b) With respect to numerical simulation, Mayerhofer et al. [200] used the historical matching method to evaluate the scale of fracture networks, fracture spacing, and total fracture length based on microseismic data and production dynamic data. Based on the numerical fracture model and production dynamic data of automatic gridding technology, Cipolla et al. [201] established a fracture parameter inversion method considering microseismic data and production data. However, most of the above works are based on the assumption of single fractures or orthogonal

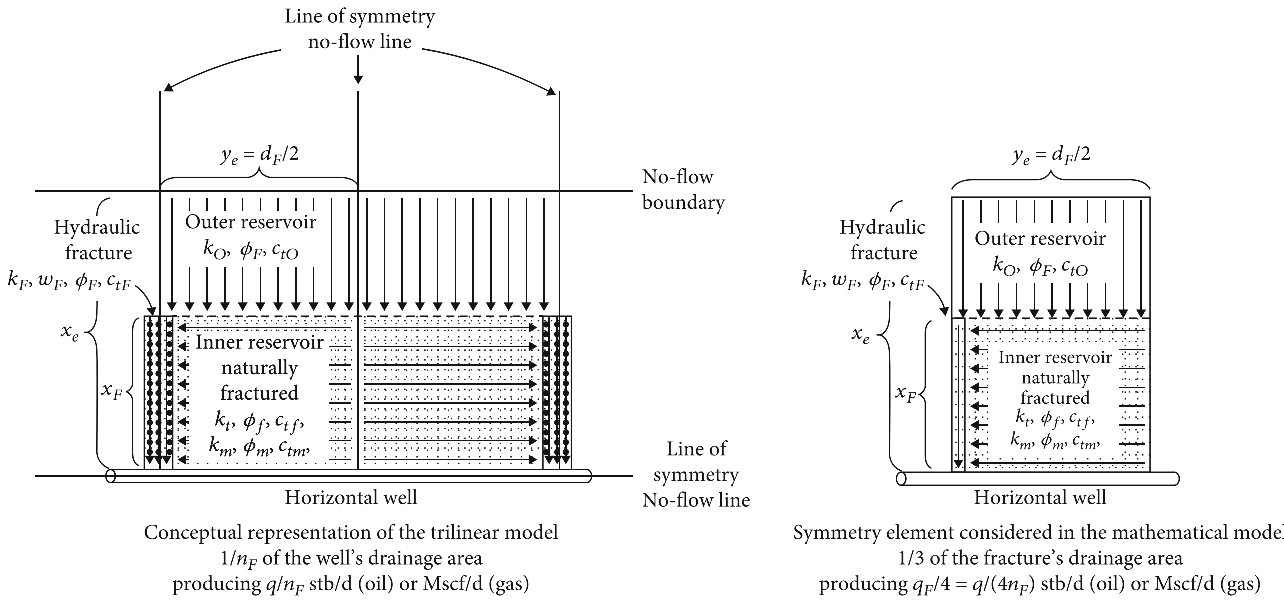


FIGURE 24: Schematic of trilinear-flow model used for analytical solution of multiple-fractured horizontal-well performance [190].

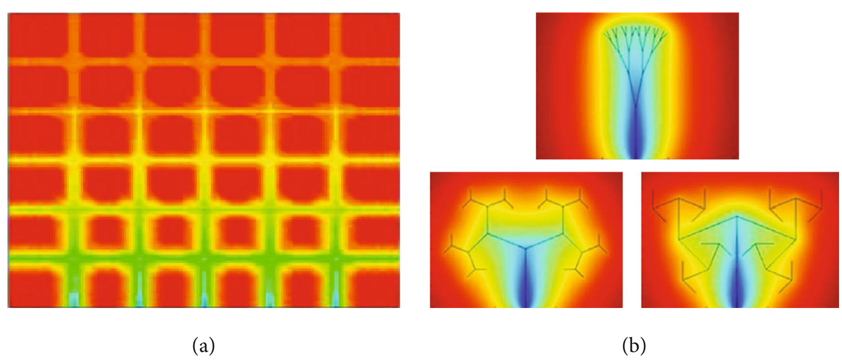


FIGURE 25: Numerical simulation method of fracture inversion. (a) Fracture network inversion based on orthogonal fractures [14]. (b) Fracture network inversion based on bifurcated fractures [203].

fractures, without considering the actual fracture network morphology, resulting in low accuracy and poor efficiency of inversion results, and cannot realize the inversion of complex fracture networks. In recent years, automatic history-matching technology has made important breakthroughs and developments, realizing large-scale parameter inversion, including gradient-free algorithms and data assimilation. Additionally, Zhao et al. [202] made progress in the intelligent inversion. Based on the self-developed large-scale parameter dimension reduction algorithm and gradient-free algorithm, an intelligent historical fitting theory was established. However, most of the methods are not combined with actual field monitoring data, and the accuracy of the inversion characteristic parameters needs to be further improved. Therefore, the complex morphology of fracturing fracture networks in shale gas reservoirs has brought serious multisolution to the inversion of fracture flow capacity at all levels. It is urgent to establish a fracture inversion optimization method that integrates the fracture growth algorithm, microseismic data, and production dynamic history matching to reduce the multisolution of inversion results and improve the inversion efficiency.

5. Optimization of Hydraulic Fracturing in Unconventional Reservoirs

As an important means for the development of unconventional oil and gas reservoirs, hydraulic fracturing can significantly increase the discharge area of reservoirs, increase oil and gas production, and improve the development efficiency of oil and gas fields. However, owing to the increase in well pattern and fracture network variables caused by the fracturing operation, efficiently obtaining the well pattern distribution of fractured horizontal wells and the optimal development scheme of fracture variable parameters, and realizing the integrated optimization of unconventional reservoir fracturing are important research directions for relevant scholars. The main idea of hydraulic fracturing

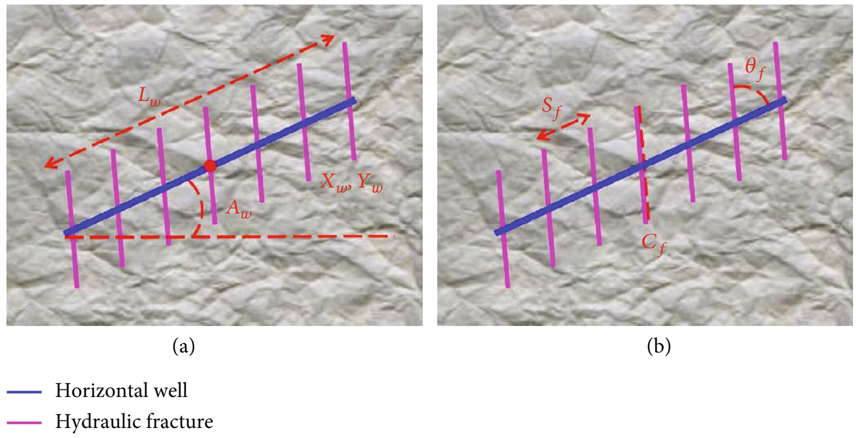


FIGURE 26: Horizontal well perforation azimuth optimization [217].

optimization is economic optimization and relative maximum production as objective functions. Thus, parameters, such as fracture half-length, fracture spacing, fracture complexity, and fracture conductivity, were optimized [204]. At present, the integrated optimization technology of fracturing and fracture mainly includes three types: artificial single-factor optimization, artificial multifactor optimization, and intelligent optimization algorithm optimization [205].

5.1. Artificial Single-Factor Optimization Method. The artificial single-factor optimization was mainly based on the single fracture parameter as the optimization variable. This type of method has a low requirement for the complexity of fractures; therefore, it is suitable for the fracturing optimization design of most unconventional reservoirs. Valko and Economides [206] proposed a novel optimization of fracture length with fracture conductivity as the objective function, under a given proppant content. This method can be applied to the morphology optimization design of fracture networks in medium-high permeability and low-permeability reservoirs. The main idea is that under the condition of a given proppant content, there is an optimal fracture conductivity, so that the single-well production index can be maximized, and on this basis, the optimal fracture geometry can be obtained [207, 208]. Because the method proposed by Valko and Economides is only applicable to conventional reservoir description, Martin and Economides [209] and Daal and Economides [210] improved the method based on the research of Valko and Economides and applied it to the optimization design of fracturing fracture parameters in low-permeability reservoirs with different drainage areas. At the same time, Wei and Economides [211] and Guo [212] applied this method to the optimization design of fracture network parameters of multistage fractured horizontal wells and achieved good results.

The optimization method based on Economides provides an optimization idea with proppant as a variable for hydraulic fracturing. However, this method can only optimize the fracture length parameters, and the model does not consider the mutual interference between other relevant factors; therefore, the accuracy of the model calculation is low [213, 214]. Subsequently, scholars proposed an optimization method for fracture network parameter matching using production data. This method constrains the model parameters through actual production data, reducing the interference between the parameters. Pope et al. [215] established a multistage fracturing optimization model for horizontal wells using numerical simulation software. This model mainly simulates the complexity of shale reservoir fracturing fracture networks by arranging longitudinal fractures in the near-wellbore area, modifies model parameters to optimize fracture morphology, and analyzes the sensitivity of fracturing parameters combined with actual production data. Jiang et al. [216] used the fracturing method to optimize the fracture morphology, based on actual fracturing construction data and the matching relationship between the reservoir sand body distribution and fractures. Huang [217] established an unsteady optimization model for horizontal fracture transverse interference in fractured horizontal wells, as shown in Figure 26. This method analyzed the mutual interference between horizontal fractures and obtained the optimal design and construction scheme by simulating the horizontal well productivity under different fracture parameters. The method based on dynamic production constraints can better optimize the fracture parameters, but this method does not consider the influence of fracture conductivity on productivity over time. Therefore, Yang et al. [218] converted the fracture width and permeability into a function of time, combined with the physical experimental results of fracture conductivity, and optimized the geometric parameters of fractures with the maximum dimensionless cumulative production index as the optimal objective function. Thus, the optimization results were closer with the actual situation. In previous studies, the optimization design of fracture networks mostly focused on the single-well fracturing design and the impact on the single-well production effect and only analyzed the production of a single well. The factors affecting the production are the fracture length and conductivity, and the factors considered in the model are relatively simple. There are many factors affecting production of unconventional oil and gas reservoirs with strong heterogeneity and complex fracture development. Therefore, single-factor optimization cannot achieve the best optimization effect. It is necessary to use a

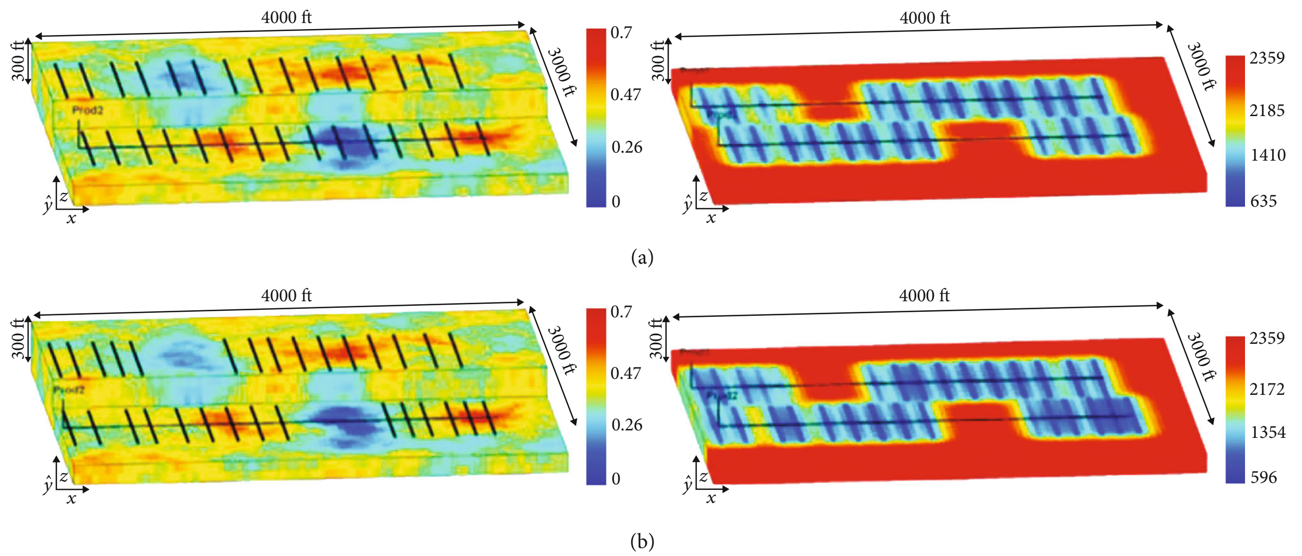


Figure 27: Location of fracture stages in the reservoir [227]. (a) Brittleness map with evenly spaced fractures (left) and pressure distribution after 10 years of production (right). (b) Brittleness map with optimal fracture locations (left) and pressure distribution after 10 years of production (right).

multifactor optimization method to comprehensively analyze the influencing factors to obtain the overall optimal development schemes.

5.2. Artificial Multifactor Optimization Method. The orthogonal experimental method is a commonly used multifactor comprehensive analysis method [219]. Because of the same test times of different levels of any factor in the orthogonal experimental method and the comprehensive experiment of cross-group between any two factors, it is convenient to analyze the experimental data to compensate for the deficiency of single-factor analysis [220]. Feng et al. [221] used an orthogonal experiment combined with numerical simulation to optimize the fracture parameters of fractured reservoirs, obtained the best hydraulic fracture-related parameters, and realized a reasonable match between the well pattern system and the fracture system. Yu and Sepehrnoori [222] systematically studied an optimization method for the completion parameters of shale gas reservoirs. Taking shale gas productivity as the objective function, the orthogonal experimental method was used to comprehensively analyze the influence weights of the completion parameters. Studies have shown that fracture conductivity is the main factor affecting productivity, and the influence of fracture spacing on productivity is more important than that of fracture half-length at the early stage of production. Lu [223] obtained a sample database of the main factors of refracturing wells based on actual field data, optimized the fracture parameters of refracturing wells by combining the orthogonal experimental method, and established an optimization method for the dimensionless parameters of refracturing wells and the yield increase evaluation model. The results show that the dimensionless parameter optimization method can fully consider the influence of geological characteristics, fluid characteristics, fracturing construction, and production dynamics on the effect of repeated fracturing, and there is an optimal range of parameters to increase production. Although the orthogonal experimental method can analyze many factors at the same time, it can only judge the degree of influence of related factors on the objective function and cannot comprehensively optimize multiple problems to obtain the optimal scheme. Therefore, scholars have proposed a multifactor combinatorial optimization method [224].

C. Zhao and T. Zhao [220] established a fracturing well pattern and a fracture optimization model. Taking the reservoir sweep coefficient of fracturing wells as the objective function, the optimal matching relationship between the fractures and fracturing well pattern parameters was fully considered. Combined with the numerical simulation method, a comprehensive optimization design of the comprehensive optimization design of the well patterns and stimulated fracture design were realized. This method can be applied to both conventional low-permeability reservoirs and complex fault-block low-permeability reservoir optimization. Wei et al. [225] established a horizontal well fracturing parameter optimization model using a numerical simulation method. On this basis, the effects of horizontal fracture effective radius and fracture conductivity on oil well production, water content, and oil recovery were studied, and the fracture parameters (fracture length, fracture spacing, etc.) were optimized, as shown in Figure 27. Additionally, Cai et al. [226] studied the influence of the horizontal well pattern and well spacing on the development effect based on numerical simulations combined with the geological characteristics of low-permeability reservoirs.

At the same time, other relevant scholars have developed new multifactor optimization methods with different ideas and have achieved good results [228]. Sui and Zhang [229] applied the perpendicular bisector (PEBI) grid in numerical

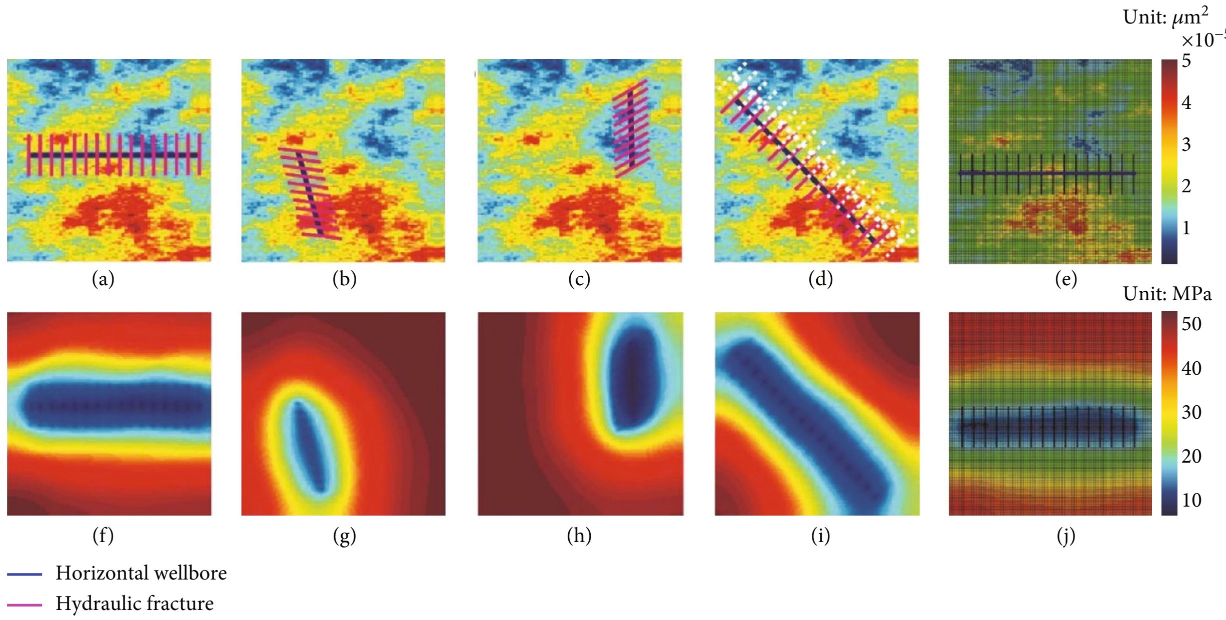


Figure 28: Multifactor simultaneous optimization of well position and fracture angle [246].

simulation to the overall fracturing optimization design, realized the simulation of fractures in any direction under the condition of irregular well patterns, and confirmed the superiority of the PEBI grid in the optimization of hydraulic fracture parameters compared with the traditional grid method. Zhang et al. [230] established a simple fracturing optimization design calculation method based on the equivalent similarity principle of hydropower. This method is simple and applicable and can analyze the influence of well patterns and fracturing parameters on the productivity of stimulated production wells. Most traditional artificial multifactor optimization methods are based on the manual adjustment of parameters to complete the parameter optimization simulation. Although this method can approximately optimize the optimal solution of the objective function, the simulation accuracy is low, and the artificial operation is complex. This method requires considerable manpower and time, and the simulation efficiency is low for the design of a large hydraulic fracturing parameter optimization scheme for unconventional reservoirs. Therefore, it is necessary to eliminate the disadvantages of artificially adjusting parameters and combine then with the idea of a computer optimization algorithm to automatically optimize single or multiple factors to greatly improve calculation accuracy and efficiency.

5.3. Multifactor Synchronous Automatic Optimization Method. With the increasing application of numerical simulation technology in reservoirs, optimization algorithms have great advantages. Many scholars have applied various optimization algorithms to the integrated simulation of unconventional fracture networks [231], as shown in Figure 28. Carroll [232] applied a polyhedron algorithm to the optimization of injection parameters in reservoirs and realized the application of an optimization algorithm in reservoirs. However, the optimization algorithm used in this model has a slow convergence speed and cannot consider the interference of a single factor to generate multiple solutions of the objective function. Beckner and Song [233] described the well location optimization problem as a mathematical traveling salesman problem and used an annealing algorithm to automatically optimize the objective function to achieve the maximum economic goal. Yeten et al. [234] used a genetic algorithm to optimize the perforation direction and well pattern of unconventional reservoir stimulation and established an optimization method for unconventional fracturing wells with cumulative oil production as the objective function. The study shows that the optimal well type varies with the reservoir type and the objective function and ultimately depends on whether single or multiple reservoir geological conditions are considered. Güyagüler and Horne [235] extended the method of Carroll and Yeten et al., combined a genetic algorithm with a polyhedron algorithm and agent method, proposed a new hybrid genetic algorithm, and used this method to solve the well location optimization problem; thus, they solved the problem of multiple solutions in single-factor optimization. Badru [236] improved the hybrid genetic algorithm based on Güyagüler and Horne's research and applied this method to the well location and well trajectory optimization of horizontal wells. In the same year, Yeten et al. [234] obtained a new hybrid genetic algorithm by combining a genetic algorithm, mountain climbing algorithm, artificial neural network algorithm, and near-well coarsening technology and carried out optimization research on the well type, well location, and well trajectory of unconventional reservoir fracturing wells. Compared with the hybrid genetic algorithm proposed by Badru, this method has the advantages of high computational efficiency and fast convergence speed, which can be applied to large-scale fracturing parameter optimization of unconventional reservoirs. Subsequently, many scholars have studied the combination of optimization target orientations and algorithms. Handels et al. [237] proposed a location optimization method based on the adjoint method. Kraaijevanger et al. [238] considered a variety of gradient algorithms combined with the adjoint method to optimize water flooding injection parameters. Additionally, Wang et al. [239] used a gradient algorithm to study the closed-loop optimization management of reservoirs and compared the optimization performance of various gradient algorithms. Furthermore, Onwunalu and Durlofsky [240] proposed an automatic well-pattern optimization method for large-scale reservoirs. The basic unit of the well pattern was automatically optimized and adjusted by shearing and rotating operations and solved using the particle swarm optimization algorithm. Based on the above optimization algorithms based on the research of the gradient algorithm to solve the problem, the model needs to solve the directional derivative of the objective function in each iteration step. For some complex practical problems, it is difficult to solve the gradient of the objective function; therefore, the gradient algorithm is relatively strict for describing the optimization problem. Based on this type of problem, scholars have further studied a gradient-free optimization algorithm to optimize the objective function. Isebor et al. [241] carried out research on generalized oil field development and production optimization using a gradient-free algorithm and combined the particle swarm optimization algorithm and generalized pattern search algorithm to optimize the well number, well location, and production data synchronously. Shuai et al. [242] applied the multiscale regularization method to the optimization of injection parameters and their control strategies in actual reservoirs. This method finely divided the time steps of each iteration into two steps; thus, the gradient information was not needed, and the optimization calculation was simpler. Li and Jafarpour [243] used the stochastic disturbance gradient approximation algorithm to study the well location and injection optimization problem. In the gradient approximation process, this method only needs to use the estimated value of the objective function, which greatly reduces the number of measurements of the objective function by estimating the gradient information. The results show that the method can consider the uncertainty of the reservoir at the same time, and the results are better than those of the joint optimization sequence method. Gradient/nongradient optimization algorithms to deal with unconventional fracturing well patterns and injection optimization problems after long-term development have made some achievements as well [244–246].

However, from the selection of optimization variables, most of the current optimization algorithms can only deal with single-objective optimization. For multiobjective synchronous optimization problems, the uncertainty of reservoir cognition and multiobjective synchronous interference problems cannot be effectively studied. In the calculation of optimization objectives, the current optimization method requires a long time to simulate a single value, and the optimization objectives often converge to the local optimal solution. For large-scale reservoirs, thousands of objective function schemes need to be evaluated at the cost of time and computational complexity and often fail to achieve the best optimization results. Therefore, for the optimization of fractured horizontal wells in unconventional reservoirs, it is urgent to consider a gradient-free optimization method, multifactor synchronous optimization method of well pattern, and a multiobjective function synchronous search as a whole. This can help solve the problem of local convergence of the objective function and multiparameter synchronous optimization and realize the integrated optimization technology of unconventional reservoir fracturing.

6. Conclusion

The current unconventional reservoir fracture network flow characterization and inversion optimization research mainly have the following problems:

(1) Experiments of hydraulic fracture propagation can visually describe fracture propagation processes, but it cannot characterize the fracture network morphology in actual reservoirs. The numerical simulation method can be applied in actual reservoirs; however, the current simulation methods generally require large calculation cost, which cannot be applied to the simulation of multiple well

(2) The traditional multimedia flow models cannot fully consider the mass transfer between different scale media in shale reservoirs. Therefore, it is necessary to combine the discrete fracture model and multimedia models to describe fluid flow in unconventional reservoirs

(3) The current inversion method cannot effectively invert the fracture parameters. It is necessary to comprehensively consider the fracture network propagation simulation algorithm, microseismic monitoring data, production data, and optimization algorithm to constrain the fractures morphology

(4) The automatic synchronous optimization method cannot well consider the interference between multiple factors. There is an urgent need to consider a gradient-free optimization method, multifactor synchronous optimization method, and a multiobjective function synchronous search as a whole. This can help solve the problem of local convergence of the objective function and multiparameter synchronous optimization and realize the integrated optimization technology of unconventional reservoir fracturing.

Conflicts of Interest

The authors declare no conflicts of interest.

Acknowledgments

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