Research Article

Effect of the Angle between Hydraulic Fracture and Natural Fracture on Shale Gas Seepage

Xiaoming Wang,1,2,3 Junbin Chen,2,3 Jianhong Zhu,2,3 and Diguang Gong2

1College of Geology and Environment, Xi’an University of Science and Technology, Xi’an, Shaanxi 710054, China
2Shaanxi Key Laboratory of Well Stability and Fluid & Rock Mechanics in Oil and Gas Reservoirs, Xi’an Shiyou University, Xi’an, Shaanxi 710065, China
3College of Petroleum Engineering, Xi’an Shiyou University, Xi’an, Shaanxi 710065, China

Correspondence should be addressed to Xiaoming Wang; wxm18392177016@sina.com and Junbin Chen; 1391927626@qq.com

Received 20 May 2020; Revised 25 November 2020; Accepted 11 December 2020; Published 23 December 2020

Academic Editor: S. A. Edalatpanah

Fracturing technology is an effective measure to exploit shale gas and the fractures improve the seepage ability of shale reservoir after fracturing. In this paper, taking Chang 7 of Yanchang Formation as the study area, a double porosity seepage model considering natural fracture was established and it was solved by finite element method of COMSOL5.5; then, shale gas seepage was analyzed under different angles between hydraulic fracture and natural fracture finally. Meanwhile, angles between hydraulic fracture and natural fracture were optimized by analyzing both the reservoir pressure distribution and bottom hole flowing pressure. Also, a permeability experiment with liquid was conducted to verify the accuracy of the numerical simulation result. Both numerical simulation and permeability measurement experiment get a uniform result that the optimal angle between hydraulic fracture and natural fracture is 90°. Permeability is the highest, shale gas seepage rate is the fastest, bottom hole flowing pressure is the highest, and also it is beneficial to the desorption of adsorbed gas in the matrix system and then effectively supplements reservoir pressure and bottom hole flowing pressure. The research results will provide some theoretical guidance for fracturing design.

1. Introduction

As one of the vital unconventional reservoirs, low porosity and very low permeability of shale reservoir make the development more difficult by traditional development method. Some research results show that horizontal well and fracturing technologies are effective measures to improve single well productivity of shale gas [1–3]. Hydraulic fracturing technology not only can control the orientation of hydraulic fracture but also can develop the target interval by controlling the extension direction of the hydraulic fractures effectively. A large number of hydraulic fractures with large scale and strong directional diversion are formed by hydraulic fracturing, which are the main seepage channels for shale gas production, greatly decrease shale gas flowing resistance, and improve the productivity of the horizontal well. In order to enable fractures to communicate with the reservoir effectively, it is necessary for the development of a low permeability oilfield to optimize the orientation of hydraulic fractures [4, 5]. Therefore, scholars have made the following research on the optimization of hydraulic fracture orientation.

In order to research the influence of fracture orientation on productivity, Lemon et al. [6] studied whether or not fracture orientation can improve the productivity of fractured well based on single-phase two-dimensional reservoir simulator technology. Research result shows that fracture orientation on 320-acre spacing is critical to affecting the productivity of fractured wells and fracture oriented with minor axis may preclude efficient drainage. Hydraulic fracture orientation does have a significant effect on production. To further determine the effect of fracture
orientation on productivity, Shah et al. [7] study the effect of fracture orientation relative to horizontal well on hydrocarbons production performance through theoretical difference analysis. The result shows that transverse fracture relative to horizontal well can provide extremely small areas of intersection between the fracture and wellbore, which increases the fluid velocity and has a greater impact on production performance. To confirm the conclusion proposed by Shah et al., Ostojic et al. [8] used a 3D homogeneous model with tight gas properties by Eclipse software to study the fracture orientation relative to vertical well quantitatively by using posthydraulic fracture production data. The result shows that fractures along the wellbore are far more effective than perpendicular fractures and have better production. Xu and Hoffman [9] studied the effect of fracture orientation relative to horizontal well on primary and secondary recovery based on the uniform grid model and local grid refinement model. Research results show that transverse fractures produce the most production. To overcome the limitations of only simulating transverse fracture and longitudinal fracture relative to wellbore on production and implement the analysis for the effect of any angle between hydraulic fracture and horizontal well on production, Liu et al. [10] and Qu et al. [11] studied the effect of the angle between hydraulic fracture and horizontal well on oil production by using PEBI grid refinement method and by electrolytic analogy experiments, respectively. Research results show that productivity is the highest when the angle between the hydraulic fracture and the horizontal wellbore is 90°.

However, all the aforementioned efforts ignored the two key geological factors affecting the production of horizontal well-maximum principal formation stress and principal permeability orientation. Tian et al. [12] established a production model and developed a generalized and pragmatic framework to study the effect of the orientation of horizontal well, maximum horizontal principal stress, and principal permeability on production. The result shows that the production of the horizontal well is the highest at any angle between the direction of hydraulic fracture and the direction of the principal permeability when the direction of the horizontal well is perpendicular to both the direction of the principal permeability and the hydraulic fracture.

The effect of fracture orientation relative to wellbore on the production has been known. Meanwhile, fracture orientation relative to flow direction also has an effect. Liu and Liu [13], Shedid [14], and Rodionov et al. [15], respectively, studied the effect of fracture orientation relative to flow direction on water-oil displacement by using slice models in a physical simulation experiment and on oil production by water polymer flooding and by using the Discrete Fracture Network model. All the results show that fracture distribution is the most favorable for flooding effect when the hydraulic fracture is perpendicular to the flow and oil recovery is the highest when fracture orientation is perpendicular to the flow.

From the above, the effect of hydraulic fracture orientation relative to horizontal well and flow direction on production is the main research direction. And the characteristics of shale gas seepage can reflect the reservoir communication effect in real time, which was ignored in the research process. Meanwhile, natural fractures develop in shale reservoir and they play a critical role in the production of tight reservoirs all over the world. They connect the isolated pores to the throat, which greatly improve reservoir performance, so that they provide highly permeable channels for shale gas flowing [16–20]. However, the natural fracture is not taken into account during hydraulic fracture optimization. Natural fractures with different morphologies develop in shale reservoir and they are discrete but have a regularity, which are controlled by paleotectonic stress field, reservoir lithology, thickness of stratum, and other factors [21–26]. Considering this issue in fracture orientation optimization, Su et al. [27] established a volume fracturing model for horizontal well based on discrete fracture model and studied the effect of angles between horizontal well and natural fractures on production by numerical stimulation software Eclipse. The result shows that the development effect is the best when the horizontal well is parallel to natural fractures in a tight oil reservoir, but the influence of artificial fracture is ignored. Only if the horizontal well orientation, natural fracture orientation, and hydraulic fracture orientation match, maximum production can be achieved. And also increasing oil and gas production largely depends on fracture orientation relative to natural fractures. Therefore, the natural fracture should be fully considered in the process of hydraulic fracture orientation optimization so that an effective fracture network can be formed during fracturing design.

Based on previous research results, the goal of this paper is to establish a double porosity seepage model considering natural fractures and study the effect of angle between hydraulic fracture and natural fracture on shale gas seepage through the transient analysis of reservoir pressure and bottom hole flowing pressure by finite element analysis software Comsol5.5. Combine the permeability measurement experiment and numerical simulation to optimize the angles between hydraulic fracture and natural fracture, which can guide on-site fracturing design.

2. Modeling

2.1. Physical Model. Horizontal well multistage fracturing technology was adopted in shale reservoir. Three-stage fracturing technology was adopted and there are nine natural fractures. The dimension of the physical model is 400 m (length) × 240 m (width/2) × 38 m (thickness) in shale reservoir. It is assumed that hydraulic fracture is symmetrical about horizontal well, the hydraulic fracture is generally perpendicular to horizontal well, and half of the simulation area is selected for research. Blanton et al. [28] analyzed the fracture morphology after hydraulic fractures pass through natural fracture qualitatively and keep extending in the same direction under high stress and high approximation angle based on a physical simulation experiment. A typical matrix-fracture system was formed. The double porosity physical model after hydraulic fracturing is shown in Figure 1.
2.2. Assumptions. In order to establish the double porosity mathematical model, the following assumptions are listed:

(1) Gas seepage channels in shale reservoir are mainly matrix and discontinuous fractures.

(2) Shale gas reservoir is isotropic and only contains compressible single-phase gas. Meanwhile, the reservoir is slightly compressible and compressibility does not change with time.

(3) Gas flowing meets isothermal seepage.

(4) Langmuir isothermal adsorption equation is used to describe shale gas adsorption.

(5) Both free and dissolved gas in the initial shale reservoir are ignored; the free gas in matrix and fracture systems is from the desorption of adsorbed gas.

(6) The effect of pressure on gas viscosity is considered.

(7) Free shale gas flow in the matrix and fracture systems obeys pseudo-Darcy flow.

(8) Gas migrates from the matrix system to the fracture system and then enters the horizontal well from hydraulic fractures.

2.3. Establishment of Mathematical Model

2.3.1. Seepage Mathematical Model of Matrix System. The continuity equation of the matrix system considering adsorbed gas is as follows:

\[
\frac{\partial}{\partial t} \left( \phi_m \rho_g V_m + \rho_g V_E \right) = - \nabla \left( \rho_g \nabla V_m \right) - q, \tag{1}
\]

where \( \phi_m \) is the porosity of matrix system, \( \rho_g \) is the gas density in matrix system, \( V_E \) is the adsorption quantity of shale gas, \( \rho_g \) is the gas density at standard condition, \( V_m \) is the gas seepage velocity in matrix system, and \( q \) is the flow of interfacial flow between matrix and fractures.

Substitute the equation of motion \( V_m = -K_m/\mu \nabla \rho_g \text{grad} P_m, \) the equation of state \( \phi_m = \phi_{mao} + C_m \left( P_m - P_f \right), \) the equation of real gas \( \rho_g V_m = PM/\text{ZRT}, \) the equation of state for desorption gas \( V_E = V_m P/P_L + P, \) the equation of gas compressibility \( C_{gm} = 1/P_m - 1/\text{ZRT}/\partial P_m, \) and the equation of interfacial flow \( q = aK_m/\mu \rho_o \left( P_m - P_f \right) \) into equation (1); then, it can be got as follows:

\[
\frac{M_P}{\text{ZRT}} \left[ C_m + C_{gm} \phi_{mao} + C_m C_{gm} \left( P_m - P_f \right) + \frac{\rho_g V_m P_L}{(P_L + P_m)} \right] \frac{\partial P_m}{\partial t} = -MK_m \frac{1}{RT} \left( \frac{P}{Z} \nabla \rho_g \right) - \frac{aK_m}{\mu} \rho_o \left( P_m - P_f \right). \tag{2}
\]

where \( M \) is the molecular weight of shale gas, \( Z \) is the compressibility factor, \( R \) is the universal gas constant, \( T \) is the reservoir temperature, \( P_m \) is the pressure of matrix system, \( P_L \) is the Langmuir pressure constant, \( V_m \) is the Langmuir volume, \( C_m \) is the pore compressibility of matrix system, \( C_{gm} \) is the gas compressibility in matrix system, \( K_m \) is the matrix permeability, \( \phi_{mao} \) is the initial porosity of matrix system, \( \mu \) is the gas viscosity in reservoir, \( a \) is the shape factor, and \( \rho_o \) is the shale gas density at the pressure of \( P_f \).

Because both \( C_m \) and \( C_{gm} \) are of a smaller order of magnitude, \( C_m C_{gm} \) can be ignored; equation (2) can be simplified as follows:

\[
\frac{P_m \phi_{mao}}{Z} \left[ C_{gm} + C_m \phi_{mao} + \frac{\rho_g V_m P_L}{\phi_{mao} (P_L + P_m)} \right] \frac{\partial P_m}{\partial t} = -K_m \frac{1}{RT} \left( \frac{P}{Z} \nabla \rho_g \right) - \frac{aK_m}{\mu} \rho_o \left( P_m - P_f \right). \tag{3}
\]

Let the total compressibility of matrix system be \( C_{tm} = C_{gm} + C_m \phi_{mao} + \rho_g V_m P_L / \phi_{mao} (P_L + P_m); \) then equation (3) can be simplified as follows:

\[
\frac{P_m C_{tm} \phi_{mao}}{Z} \frac{\partial P_m}{\partial t} = -K_m \frac{1}{RT} \left( \frac{P}{Z} \nabla \rho_g \right) - \frac{aK_m}{\mu} \rho_o \left( P_m - P_f \right). \tag{4}
\]

where \( C_{tm} \) is the total compressibility of the matrix system.

The known condition is \( \psi_{m} = \int_0^P \frac{2P}{\mu Z} dp; \) substitute the known condition into equation (4); then, it can be obtained as follows:

\[
\frac{\partial \psi_{m}}{\partial t} = - \frac{K_m}{\phi_{mao} C_{tm}} \nabla \left( \frac{\partial \psi_{m}}{\partial t} \right) - 2a \frac{K_m}{\phi_{mao} C_{tm}} \left( \psi_{m} - \psi_{m} \right), \tag{5}
\]

where \( \psi_{m} \) is the pseudopressure function of the matrix system.

When the gas viscosity is related to pressure, \( \mu C_{tm} \) cannot be treated as a constant, and the pseudotime function \( t_{a} = \int_0^P \frac{1}{\mu C_{tm}} dp \) is introduced to linearize the equation. So equation (5) can be simplified as follows:

\[
\frac{\partial \psi_{m}}{\partial t_a} = - \frac{K_m}{\phi_{mao} C_{tm}} \nabla \left( \frac{\partial \psi_{m}}{\partial t_a} \right) - 2a \frac{K_m}{\phi_{mao} C_{tm}} \left( \psi_{m} - \psi_{f} \right), \tag{6}
\]

where \( t_{a} \) is the pseudotime function of the matrix system.

Since the coefficients \( K_m/\phi_{mao} \) and \( 2a(K_m/\phi_{mao}) \) are constants, a seepage mathematical model of matrix system can be obtained:
where \( a_1 \) and \( a_2 \) are the constant coefficients, \( a_1 = K_m/\phi_{mo} \), and \( a_2 = 2aK_m/\phi_{mo} \).

### 2.3.2. Seepage Mathematical Model of Fracture System

The continuity equation of the fracture system is as follows:

\[
\frac{\partial \phi_f \rho_{gf}}{\partial t} = -\text{div}(\nabla \psi_m) - a_2(\psi_m - \psi_f),
\]

(7)

where \( \phi_f \) is the porosity of the fracture system, \( \rho_{gf} \) is the gas density of the fracture system, and \( \psi_f \) is the gas seepage velocity in the fracture system.

Substitute equation of motion \( v_f = -K_f/\mu \text{grad}P_f \), equation of state \( \psi_f = \psi_{fo} + C_f(P_f - P) \), compressibility coefficient \( C_{gf} = 1/\rho_f - 1/\rho_{gf}/\partial P_f/\partial P_f \) of the fracture system, and equation of interfacial flow \( q = aK_m/\mu_{gf}(P_m - P_f) \) into equation (8); then, it can be simplified as follows:

\[
\frac{\phi_{fo}P_f}{Z} \left[ \frac{C_f}{\phi_{fo}} + \frac{C_{gf}(P_f - P)}{\phi_{fo}} \right] \frac{\partial P_f}{\partial t} = -K_f \text{div}\left( \frac{P_f}{Z\mu} \text{grad}P_f \right) + \frac{RT}{M} aK_m/\mu \rho_{of}(P_m - P_f),
\]

(9)

where \( P_f \) is the pressure of fracture system, \( C_f \) is the pore compressibility of fracture system, \( C_{gf} \) is the gas compressibility in fracture system, \( K_f \) is the permeability of fracture system, and \( \phi_{fo} \) is the initial porosity of fracture system.

Because the order of magnitude of \( C_f \) and \( C_{gf} \) is small, \( C_fC_{gf} \) can be ignored; let equation \( C_{gf} = C_{of} + C_f/\phi_{fo} \) be the total compressibility of the fracture system; then, equation (9) continues to be simplified as follows:

\[
\frac{\phi_{fo}P_f}{Z} \frac{\partial P_f}{\partial t} = -K_f \text{div}\left( \frac{P_f}{Z\mu} \text{grad}P_f \right) + \frac{RT}{M} aK_m/\mu \rho_{of}(P_m - P_f),
\]

(10)

where \( C_{of} \) is the total compressibility of the fracture system.

The known condition is \( \psi_f = \int_0^P 2P/\mu ZdP; \) substitute it into equation (10); then, the equation can be simplified as follows:

\[
\frac{\partial \psi_f}{\partial t} = -\frac{K_f}{\phi_{fo}C_{of}} \text{div}(\nabla \psi_f) + 2a - \frac{K_f}{\phi_{fo}C_{of}}(\psi_m - \psi_f),
\]

(11)

where \( \psi_f \) is the pseudopressure function of the fracture system.

When considering that the gas viscosity is related to pressure, \( \mu_{C_{of}} \) cannot be treated as a constant, and the pseudotime function \( t_b = \int_0^t \mu_{C_{of}} dt \) is introduced to linearize the equation. So equation (11) can be simplified as follows:

\[
\frac{\partial \psi_f}{\partial t_b} = -\frac{K_f}{\phi_{fo}} \text{div}(\nabla \psi_f) + 2a - \frac{K_f}{\phi_{fo}}(\psi_m - \psi_f),
\]

(12)

where \( t_b \) is the pseudotime function of the fracture system.

Since the coefficients \( K_f/\phi_{fo} \) and \( 2aK_f/\phi_{fo} \) are constants, a seepage mathematical model of fracture system can be obtained:

\[
\frac{\partial \psi_f}{\partial t_b} = -b_1 \text{div}(\nabla \psi_f) + b_2(\psi_m - \psi_f),
\]

(13)

where \( b_1 \) and \( b_2 \) are the constant coefficients, \( b_1 = K_f/\phi_{fo} \), and \( b_2 = 2aK_f/\phi_{fo} \).

### 2.3.3. Boundary and Original Conditions

Both the boundary conditions and the initial conditions are constructed to satisfy the discrete fractured reservoir according to the actual production of the gas field and physical model.

1. **Outer boundary condition-constant pressure is as follows:**

\[
\psi_m(x, y, t) \mid \Gamma_1 = \psi_o(x, y, t), \ (x, y) \in \Gamma_1,
\]

(14)

where \( \psi_o \) is the initial pseudopressure function.

2. **Inner boundary condition-constant production is as follows:**

\[
\frac{\partial \psi_f}{\partial n} \mid \Gamma_3 = 2QP/KA\psi(x, y) \in \Gamma_3,
\]

(16)

where \( Q \) is the half gas flow rate, \( P \) is the boundary pressure, \( K \) is the reservoir permeability, \( A \) is the cross-sectional area of shale gas passing through the reservoir, and \( Z \) the is deviation factor.

3. **Initial condition is as follows:**

When the shale gas reservoir is closed, the reservoir pressure is the original reservoir pressure as follows:

\[
\psi_m(x, y, t = 0) = \psi_f(x, y, t = 0) = \psi_o(x, y, t = 0).
\]

(17)

4. **Inner boundary conditions at the fracture are as follows:**

\[
\psi_m(x, y, t) = \psi_f(x, y, t) \mid \Gamma_4, \ (x, y) \in \Gamma_4,
\]

(18)

\[
K_m \frac{\partial \psi_m}{\partial n} \mid \Gamma_4 = K_f \frac{\partial \psi_f}{\partial n} \mid \Gamma_4, \ (x, y) \in \Gamma_4,
\]

(19)

where \( n \) is the outer normal direction of the boundary.
3. Model Solution

3.1. Basic Parameter. The well depth is 2000 m and the wellbore radius is 0.1 m. The reservoir and gas parameters involved in the solution process of the model are partly from the experimental and production data of the shale gas reservoir as shown in Table 1.

3.2. Solution Procedure. The established double porosity model was solved by the finite element method through numerical simulation software COMSOL5.5. Select the physical field of Darcy’s law, establish a geometric model with the length of 400 m, width of 240 m, and thickness of ×38 m, set boundary conditions of flow and pressure, and the free triangular mesh was used as the computing grid to solve the solution domain (Figure 2). In order to solve the differential equations and obtain the change of pressure with time, the numerical method of backward finite difference approximation and the time-dependent solver of the software COMSOL5.5 were used for calculation.

3.3. Calculation Results. Figures 3–8 show the reservoir pressure distribution both in the fracture system and in the matrix system at 6 types of angles between hydraulic fracture and natural fracture from 0 day to 100 days. In the first stage of gas production (t = 0 d; t = 20 d), the pressure drop in the fracture system is fast and obvious, while pressure in the matrix system is basically unchanged, and there is no difference in reservoir pressure at different angles between hydraulic fracture and natural fracture. It can be explained that free shale gas in fracture system makes a major contribution at the beginning of shale gas extraction with fixed production rate, gas migrates through a highly conductive fracture system, and different angles between hydraulic fracture and natural fracture have no interference with shale gas seepage. Meanwhile, the matrix system of shale gas reservoir has low porosity and extremely low permeability, which is not conducive to the migration of free shale gas in matrix system and reservoir pressure propagation affected by starting pressure in an instant. Therefore, reservoir pressure distributions at 6 types of angles between hydraulic fracture and natural fracture are basically the same. To the second stage of gas production (t = 40 d; t = 60 d), reservoir pressure drop becomes more and more obvious both in the matrix region near the fracture system and in the fracture system with the angle between hydraulic fracture and natural fracture increasing. It can be explained that a large amount of free shale gas is exploited from the fracture system in the first stage of shale gas production, so the adsorbed shale gas in the matrix area near the fracture system is gradually desorbed in order to supplement formation pressure. Meanwhile, drainage radius and fracture interference increased gradually due to the increase of the angle between hydraulic fracture and natural fracture, which is conducive to gas migration from the matrix to fracture and enters horizontal well through the fracture in a short distance. In the third stage of gas production (t = 80 d; t = 100 d), it shows that pressure sweep region in matrix system gradually increases, pressure drops much faster and more obvious both in fracture system and in matrix system, and pressure field interference is enhanced in fracture system and strengthened in the middle fracture region with the angle between hydraulic fracture and natural fracture increasing. It can be explained that a large amount of adsorbed shale gas was desorbed at the far end of the well and the pressure sweep region gradually expands in the matrix system in order to further balance formation pressure under the condition that is produced at a fixed production with a closed boundary. Therefore, both the effect of shale gas seepage and fracture communication are the best when the angle between hydraulic fracture and natural fracture is 90° based on the above three stages.

Figure 9 represents the relationship between bottom hole flowing pressure and time under 6 types of angles between hydraulic fracture and natural fracture. It shows that the angles between hydraulic fracture and natural fracture have a significant influence on bottom hole flowing pressure. Angles between hydraulic fracture and natural fracture have no effect on bottom hole flowing pressure at the first stage (Stage1). Free shale gas in fractures makes a major contribution during shale gas extraction at this time, so there is no difference in bottom hole flowing pressures at 6 types of angles between hydraulic fracture and natural fracture, and bottom hole flowing pressures decrease rapidly with time. As production time increases (Stage2), due to the production of

| Parameter                              | Value   | Unit |
|----------------------------------------|---------|------|
| Reservoir temperature                  | 333.15  | K    |
| Length of reservoir                    | 400     | m    |
| Width of reservoir                     | 480     | m    |
| Natural fracture width                 | 0.002   | m    |
| Hydraulic fracture width               | 0.005   | m    |
| Matrix permeability                    | 5.622 × 10^{-3} | mD |
| Natural fracture permeability          | 1.5 × 10^{8} | mD |
| Hydraulic fracture permeability        | 2.5 × 10^{7} | mD |
| Matrix compressibility                 | 3.10^{-4} | MPa^{-1} |
| Natural fracture compressibility       | 2.5 × 10^{-4} | MPa^{-1} |
| Hydraulic fracture compressibility     | 4 × 10^{-4} | MPa^{-1} |
| Matrix porosity                        | 2       | %    |
| Natural fracture porosity              | 0.4     | %    |
| Hydraulic fracture porosity            | 0.4     | %    |
| Initial reservoir pressure             | 30      | MPa  |
| Half-length of hydraulic fracture      | 200     | m    |
| Half gas flow rate                     | 3000    | m^{3}/d |
| Reservoir thickness                    | 38      | m    |
| Gas density on ground                  | 0.717   | kg/m^{3} |
| Gas density underground                | 176.794 | kg/m^{3} |
| Langmuir volume                        | 2       | m^{3}/t |
| Molecular weight of methane            | 16      | g/mol |
| Gas constant                           | 8.34    | J/(K·mol) |
| Langmuir pressure                      | 10      | MPa  |
| Shape factor                           | 0.76    | m^{-2} |
| Deviation coefficient of methane       | 0.89    | /    |
| Viscosity of methane                   | 0.0004P + 0.0119 | mPa·s |
free shale gas in fracture system, the adsorbed shale gas is desorbed largely in the matrix system and then free shale gas migrates to fractures and enters horizontal well through the fractures to supplement bottom hole flowing pressure. Moreover, drainage radius increased gradually with the angle between hydraulic fracture and natural fracture increasing, the interference between hydraulic fracture and natural fracture increases, which is more favorable for gas desorption and migration. Therefore, bottom hole flowing pressures decrease and its drop rates decrease with the angle between hydraulic fracture and natural fracture increasing. Bottom hole flowing pressure is the lowest when the angle between hydraulic fracture and natural fracture is 85°.

Bottom hole flowing pressures are almost the same when the angles between the hydraulic fracture and the natural fracture are 30°, 45°, 60°, and 75°. Bottom hole flowing pressure is the highest when the angle between the hydraulic fracture and the natural fracture is 90°, so the angle between hydraulic fracture and natural fracture is optimal. As production continues (Stage3), the interference between hydraulic fracture and natural fracture continues to increase over time; a large amount of adsorbed gas is desorbed in the matrix system and then migrates from the matrix to fracture and enters the horizontal well through fracture under the condition that is produced at a fixed production with a closed boundary. Although bottom hole flowing pressures
Figure 4: Pressure nephograms with the angle of $30^\circ$ between hydraulic fracture and natural fracture. (a) $t = 0$ d. (b) $t = 20$ d. (c) $t = 40$ d. (d) $t = 60$ d. (e) $t = 80$ d. (f) $t = 100$ d.

Figure 5: Pressure nephograms with the angle of $45^\circ$ between hydraulic fracture and natural fracture. (a) $t = 0$ d. (b) $t = 20$ d. (c) $t = 40$ d. (d) $t = 60$ d. (e) $t = 80$ d. (f) $t = 100$ d.
| Width of reservoir (m) | Surface: pressure (MPa) |
|----------------------|------------------------|
| 100                  | 30                     |
| 120                  | 30.9                   |
| 140                  | 30.9                   |
| 160                  | 30.9                   |
| 180                  | 30.9                   |
| 200                  | 30.9                   |
| 220                  | 30.9                   |
| 240                  | 30.9                   |

**Figure 6:** Pressure nephograms with the angle of 60° between hydraulic fracture and natural fracture. (a) $t = 0$ d. (b) $t = 20$ d. (c) $t = 40$ d. (d) $t = 60$ d. (e) $t = 80$ d. (f) $t = 100$ d.

| Width of reservoir (m) | Surface: pressure (MPa) |
|----------------------|------------------------|
| 100                  | 30.5                   |
| 120                  | 30.5                   |
| 140                  | 30.5                   |
| 160                  | 30.5                   |
| 180                  | 30.5                   |
| 200                  | 30.5                   |
| 220                  | 30.5                   |
| 240                  | 30.5                   |

**Figure 7:** Pressure nephograms with the angle of 75° between hydraulic fracture and natural fracture. (a) $t = 0$ d. (b) $t = 20$ d. (c) $t = 40$ d. (d) $t = 60$ d. (e) $t = 80$ d. (f) $t = 100$ d.
Figure 8: Pressure nephograms with the angle of 90° between hydraulic fracture and natural fracture. (a) $t = 0$ d. (b) $t = 20$ d. (c) $t = 40$ d. (d) $t = 60$ d. (e) $t = 80$ d. (f) $t = 100$ d.

continue to decrease, the amount of desorption increased with the angle between hydraulic fracture and natural fracture increasing, so the bottom hole flowing pressure is the highest when the angle between hydraulic fracture and natural fracture is 90°. In conclusion, both communication effect and seepage effect are the best when the angle between hydraulic fracture and natural fracture is 90° through a comprehensive analysis of bottom hole flowing pressure curves under 6 types of angles between hydraulic fracture and natural fracture.

4. Model Validation

The permeability measured with liquid was conducted in order to verify the accuracy of the numerical simulation optimization result. The angles between hydraulic fracture and natural fracture were optimized by analyzing the permeability to determine the optimal angle between hydraulic fracture and natural fracture.

4.1. Experimental Device. The main devices used in this permeability measurement experiment are HXDL-2C fracture evaluation system (Figure 10) and linear flow guide chamber that conforms to API standards (Figure 11).

4.2. Experimental Material and Purpose. The selection of experimental materials is particularly important for both the feasibility and the accuracy of the experiment. The materials selected in this experiment mainly include high strength marble, high density ceramsite proppant, guar gum, and distilled water. Firstly, high strength natural marble was selected to simulate the physical properties of shale reservoir and its size is $17.9 \times 3.8 \times 4.7$ cm. Secondly, high density ceramsite proppant was selected to increase the flow resistance and net pressure in the hydraulic fracture to simulate the actual formation and also distinguish hydraulic fracture and natural fracture; the size of ceramsite proppant is 30/50 mesh (maximum bearing pressure of ceramsite

Figure 9: Curves of bottom hole flowing pressure.
proppant is 60 MPa). Thirdly, guar gum was selected to seal the proppant around the hydraulic fracture to prevent the proppant from breaking, falling, and blocking the chamber after pressurization. Finally, because of stable property, distilled water was used to simulate formation water and conduct seepage experiment.

4.3. Experimental Principle. In order to ensure that the liquid passes through the rock sample in laminar flow, the experiment was designed according to linear flow and the permeabilities under 6 types of angles between hydraulic fracture and natural fracture were measured according to equation (20) measured with liquid based on the Darcy formula of planar one-dimensional seepage.

\[ K_f = \frac{Q_0 \mu L}{A(P_1 - P_2)} \]

where \( Q_0 \) is the liquid volume flow rate under the atmospheric pressure, cm\(^3\)/s; \( A \) is the area on the side of the inlet, cm\(^2\); \( L \) is the sample length, cm; \( P_1 \) and \( P_2 \) are, respectively, the absolute pressure at the inlet and outlet, MPa; \( K_f \) is the permeability measured with liquid, \( \mu \)m\(^2\); \( \mu \) is the liquid viscosity, mPa.s.

4.4. Experimental Scheme

4.4.1. Experiment Conditions. In this experiment, only the near-well section of the shale gas reservoir was studied. Hydraulic fractures were vertical fractures with 5 mm width. The effects of injected fluid flow and fracture length on permeability were ignored.

4.4.2. Experiment Design. The temperature is 24°C during the experiment. Permeabilities were measured with liquid according to API linear flow and single point method, and the stable pressure test point of permeability is 30 MPa. The permeabilities (Figure 12) are measured with the liquid flow rate of 2.5 mL/min after stabilizing pressure for 60 min; then, the average permeability was taken as the final measurement result.

4.4.3. Operation Procedure. Figure 13 shows the flowchart of the experimental operation. Firstly, put the assembled chamber on the hydraulic device, connect the pressure measuring device and the pipelines, open the test system, and fill in the parameters such as closing pressure and proppant thickness. Secondly, open the liquid test valves, valve A, and another three valves 2#, 3#, and 4#; then add closing pressure. Thirdly, set the liquid flow for testing and record the pressure data after the pressure difference sensor is approximately stable. Finally, stop the flow, open the emptying valve of the oil pump, close the power supply of the oil pump, remove the chamber, and change the rock sample for the next group of experiments at the end of the experiment.

4.5. Data Analysis. Figure 14 represents the relationship between fracture orientation and permeability measured with fluid. It shows that the angle between hydraulic fracture and natural fracture has a good linear relationship with permeability, the goodness of fit is 0.854, and the permeability increases with the increase of the angle between hydraulic fracture and natural fracture obviously. Angles between hydraulic fracture and natural fracture affect the reservoir permeability to some extent in general. It has minimal permeability when the angle between hydraulic fracture and natural fracture is 15°. When the angles between hydraulic fracture and natural fracture are, respectively, 30°, 45°, and 60°, the permeabilities are almost equal. It has maximal permeability when the angle between hydraulic fracture and natural fracture is 90°, which is conducive to liquid seepage. Therefore, the angle of 90° between hydraulic fracture and natural fracture is optimal and it has the best communication effect between hydraulic fracture and natural fracture.

4.6. Model Accuracy Analysis. The numerical simulation result shows that when the angle between hydraulic fracture and natural fracture is 90°, it not only improves the gas migration speed but also facilitates the desorption of adsorbed gas in the matrix system, improves the pressure
sweep region, and thus effectively complements the for-

mation and bottom hole flowing pressure. Meanwhile, the

permeability result measured with liquid shows that the

permeability is the highest when the angle between hydraulic

fracture and natural fracture is 90°. Therefore, the angle of

90° between hydraulic fracture and natural fracture is op-
timal by comparing and analyzing numerical simulation and

experimental results and the communication effect is the

Figure 12: Angles between hydraulic fracture and natural fracture. (a) $a = 15°$. (b) $a = 30°$. (c) $a = 45°$. (d) $a = 60°$. (e) $a = 75°$. (f) $a = 90°$.

Figure 13: Flowchart of experimental operation.
best at his time when the angle between hydraulic fracture and natural fracture is 90°. The numerical simulation result agrees well with the experimental result.

5. Conclusions

Based on studying the effect of angles between hydraulic fracture and natural fracture on shale gas seepage, the following major conclusions can be obtained:

1. A double porosity mathematical model considering natural fracture, shale gas occurrence, and gas viscosity after fracturing was established to study shale gas seepage law among matrix, fracture, and horizontal well.

2. Based on the established double porosity model, the seepage law and migration mechanism were studied by comparing the reservoir pressure and bottom hole flowing pressure of six types of angles between hydraulic fracture and natural fracture (15°, 30°, 45°, 60°, 75°, and 90°) through numerical simulation. It can be found that gas flow is the fastest, pressure sweep region is the widest, and it is beneficial for desorption of adsorbed gas in the matrix system when the angle between hydraulic fracture and natural fracture is 90°, which can effectively supplement formation pressure and bottom hole flowing pressure. Therefore, the angle of 90° between hydraulic fracture and natural fracture is optimal.

3. To verify the accuracy of the established double medium model, the permeability experiment measured with liquid at six types of angles between hydraulic fracture and natural fracture was carried out. It can be found that the permeability is the highest when the angle between hydraulic fracture and natural fracture is 90°, so the communication effect among matrix, natural fracture, and hydraulic fracture is the best. Meanwhile, the established double medium model is accurate.

This work helps in understanding the mechanism of shale gas seepage under different angles between hydraulic fracture and natural fracture, which will benefit fracturing design in unconventional tight shale reservoir.

Data Availability

The data used to support the findings of this study are available from the corresponding author upon request.

Conflicts of Interest

The authors declare no potential conflicts of interest with respect to the research, authorship, and/or publication of this paper.

Authors’ Contributions

Dr. Xiaoming Wang contributed to data curation, data analysis, writing original draft, and numerical simulation. Dr. Junbin Chen developed methodology and reviewed and edited the manuscript and supervised the experiment. Dr. Jianhong Zhu contributed to modifying the mathematical model. Dr. Diguang Gong polished the language.

Acknowledgments

This work was supported by the National Natural Science Foundation of China (Project no.51874239) and by the special scientific research project of Education Department of Shaanxi Provincial Government (Project no.17JK0609).

References

[1] H. Zhang and J. Sheng, “Optimization of horizontal well fracturing in shale gas reservoir based on stimulated reservoir volume,” Journal of Petroleum Science and Engineering, vol. 190, 2020.

[2] M. H. Rammay and A. A. Awotunde, "Stochastic optimization of hydraulic fracture and horizontal well parameters in shale
gas reservoirs,” Journal of Natural Gas Science and Engineering, vol. 36, pp. 71–78, 2016.

[3] Y. Tang, X. Tang, G. Y. Wang, and Q. Zhang, “Summary of hydraulic fracturing technology in shale gas development,” Geological Bulletin of China, vol. 30, no. 2/3, pp. 393–399, 2011.

[4] J. Van Dam, “Planning of optimum production from a natural gas field,” Journal of the Institute of Petroleum, vol. 54, no. 531, pp. 55–67, 1968.

[5] M. McGinley, “The effects of fracture orientation and elastic property anisotropy on hydraulic fracturing conductivity in the Marcellus shale,” in Proceedings of the SPE Annual Technical Conference and Exhibition, Houston, TX, USA, September 2015.

[6] R. F. Lemon, H. J. Patel, and J. R. Dempsey, “Effects of fracture and reservoir parameters on recovery from low permeability gas reservoirs,” in Proceedings of the SPE Fall Meeting of the Society of Petroleum Engineers of AIME, Houston, TX, USA, October 1974.

[7] S. N. Shah, M. C. Vincent, R. X. Rodríguez et al., “Fracture orientation and proppant selection for optimizing production in horizontal wells,” in Proceedings of the SPE Oil and Gas India Conference and Exhibition, Mumbai, India, January 2010.

[8] J. Ostojic, R. Rezaee, and H. Bahrami, “Production performance of hydraulic fractures in tight gas sands, a numerical simulation approach,” Journal of Petroleum Science and Engineering, vol. 88-89, pp. 75–81, 2012.

[9] T. Xu and T. Hoffman, “Hydraulic fracture orientation for miscible gas injection EOR in unconventional oil reservoirs,” in Proceedings of the SPE Unconventional Resources Technology Conference, Denver, CO, USA, August 2013.

[10] M. Liu, S. C. Zhang, and X. Lei, “Influence of the angle between artificial fracture and horizontal wellbore on development result,” Journal of Xi’an Shiyou University (Natural Science Edition), vol. 27, no. 2, pp. 58–62+120, 2012.

[11] Z. Q. Qu, G. Z. Qu, L. M. He et al., “The impact of fracture distribution on the productivity of a fractured horizontal well: a study based on electrolytic analog experiments,” Natural Gas Industry, vol. 33, no. 10, pp. 52–58, 2013.

[12] L. Tian, D. Y. Yang, S. X. Zheng, and B. Feng, “Parametric optimization of vector well patterns for hydraulically fractured horizontal wells in tight sandstone reservoirs,” Journal of Petroleum Science and Engineering, vol. 162, 2018.

[13] J. F. Liu and X. G. Liu, “On the effect of different fractural distribution on water-oil Displacement,” Xinjiang Petroleum Geology, vol. 23, no. 2, pp. 146-147+86, 2002.

[14] A. S. Shedid, “Influences of fracture orientation on oil recovery by water and polymer flooding processes: an experimental approach,” Journal of Petroleum Science and Engineering, vol. 50, no. 3–4, pp. 285–292, 2006.

[15] S. P. Rodionov, A. A. Pyatkov, and V. P. Kosyakov, “Influence of fractures orientation on two-phase flow and oil recovery during stationary and non-stationary water flooding of oil reservoirs,” AIP Publishing, vol. 2027, no. 1, Article ID 030044, 2018.

[16] X. L. Wan, C. N. Gao, Y. K. Wang et al., “Couple relationship between created and natural fractures and its implication to development,” Journal of Geomechanics, vol. 15, no. 3, pp. 245–252, 2009.

[17] D. Z. Dong, C. N. Zou, J. Z. Li et al., “Resource potential, exploration and development prospect of shale gas in the whole world,” Geological Bulletin of China, vol. 30, no. 2, pp. 324–336, 2011.