Study on the Influence of Fracture Geological Characteristics on the Shale Gas Flow

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***Abstract*—The development of unconventional gas reservoirs has become an increasing component of the world natural gas supply. Shale gas has become an important new energy, and more and more scientists are studying it. Many scientific studies have shown that the fractures play a vital role in the development of shale gas reservoir, and the precise impacts need additional analysis. This paper aims to check the influence of fracture geological characteristics on shale gas flow using the numerical simulation method. We established mathematical models and geological model of shale gas matrix block and fractures respectively. The geological model consists of the shale matrix block and fractures. After discretization of the model, we use the finite element method to solve the model. In this paper, we tend to analyse the influence of geological features such as fracture dip, fracture density, and fracture area on shale gas flow. The results showed that the gas flow rate performance varies with the fracture geological features. Therefore, when we develop shale gas reservoirs, the fracture geological characteristics ought to be taken seriously.**

***Index Terms*—shale gas, fracture, new energy, matrix, mathematical model, numerical simulation**

I. Introduction

Nowadays shale gas reservoirs are becoming more and more vital because of the growing energy demand [1]. Sedimentary mud rock gas is fossil fuel that's found generated and trapped among shale formations [2]. Sedimentary mud rock could be a fine-grained stone that forms once silt and clay-size mineral particles are compacted, and it's simply broken into skinny, parallel layers [3]. The pores within the sedimentary rock are terribly small, and therefore the pore size of the sedimentary rock matrix is especially within the 200 nm [4]. The gas in sedimentary mud rock gas reservoirs includes absorbable gas on the surface of matrix pores and free gas in each fracture and matrix pores [4-6]. The shale gas transport in sedimentary mud rock layers could be a combination of many flow mechanisms as well as viscous flow, Knudsen diffusion and molecular diffusion [6]. The existence of natural fractures in sedimentary rock formation is useful to extend the assembly of shale gas [7-9].

Many scholars have studied the fractures in the shale formation. Most of the research is on artificial fractures in horizontal wells. Ozkan et al. proposed hybrid numerical-analytical model of finite-conductivity vertical fractures intercepted by a horizontal well [9]. Raghavan et al. used vertical well fracture models to approximate the pressure-transient responses of fractured horizontal wells [9]. Many models have been proposed, most of which are ideal and do not take into account the actual shape of the fractures. At present, there are few studies on natural fractures in shale, and most of them regard fractures as continuous media [11]. Natural fractures are widely found in shale as shown in Fig. 1. The existence of fractures can be observed from the macro-scale to the micro-scale. The different fractures have different geological features. So we need to understand how the geological features of fractures in shale formations affect shale gas flow and development. The geological features of fractures usually include dip, fracture density, fracture area etc. [12-14]. The impact of fracture geological features on gas flow requires in-depth study.

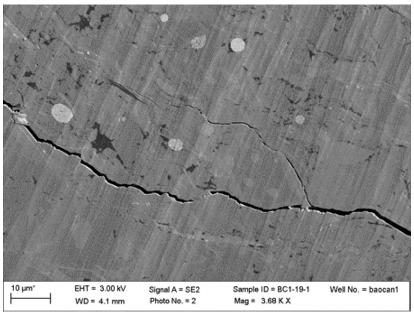

Figure 1. Scanning electron micrograph of shale core

In this paper, we focus on developing a mathematical mode and aim to study the impact of geological features such as fracture dip, fracture density, and fracture area on shale gas production rate. We conducted a series of numerical simulation experiments, explained its features, and generate solutions. We found that the fracture dip and strike affects the flow rate of shale gas. The flow of shale gas varies with the dip and strike. Our findings indicate

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that the role of the fracture geological characteristics in shale gas production cannot be ignored.

II. Model Establishment

In this section we mainly discuss the establishment of mathematical models and geological geometric models. First, we make reasonable assumptions about the mathematical model and then establish mathematical models for the shale gas flow in the matrix and fracture system.

A. Mathematical Model Assumptions

According to the characteristics and properties of shale gas reservoir and flow behaviour, the subsequent assumptions are given below for the sedimentary rock gas flow model: (a) Assume reservoir homogeneity; (e) Gas diffuses from the matrix pore to fractures; (b) Ignore the impact of gravity; (c) The gas is compressible; (d) Assume the flow process is isothermal.

The model considers the various flow characteristics within the matrix and also the fracture, such as the gas diffusion and action mechanism of adsorbate gas. The biggest difference between the discrete fractures model and traditional continuous model is that the discrete fractures model can deal with the fractures more accurately [18]. The subsequent part will introduce the transfusion mathematical model and the subscript f and m represent the fracture system and the matrix system severally.

B. Shale Gas Flow in the Matrix Block

Based on the assumptions, the Time-dependent shale gas flow in the matrix block is controlled by the mass conservation equation, which can be expressed as:

$$\frac{\partial}{\partial t}\left(q_m\right) = -\nabla\left(\rho_g v_t\right) \tag{1}$$

In (1), ρ_g is the shale gas density in the matrix; ϕ_m is the matrix porosity; q_m is the shale gas mass concentration in the matrix; we define the shale gas flow velocity v_m in the matrix as the sum of the components of the slip velocity v_s and the Darcy velocity (or viscous flow) v_d, that is

$$v_t = v_d + v_s = -\frac{\kappa_m}{\mu_g}\nabla p_m + -\frac{D_m}{\rho_g}\nabla\rho_g \tag{2}$$

Where κ_m is the matrix permeability; p_m is the gas pressure in the matrix; μ_g is the gas viscosity. The slip velocity v_s in Equation is written by the modified form of the Fick's Law. D_m is the shale gas diffusivity coefficient. In this research, we used the following form given by Ertekin et al. to compute the gas diffusivity constant in the formula [15].

$$D_m = \frac{0.339}{\sqrt{M_g}}\kappa_\infty \tag{3}$$

Because the total gas in the matrix block is composed of free gas contained in the pores and adsorbed gas on the pore surface. Among them the amount of adsorbed gas can be calculated using Langmuir adsorption [18]. The total concentration of shale gas in the shale matrix can be expressed as the following equation:

$$q_m = q_{ads} + \rho_g\phi_m = \left(1-\phi_m\right)\frac{\rho_g M}{V_m}\cdot\frac{V_L p_m}{p_m + p_L} + \frac{Mp_m}{RZT}\phi_m \tag{4}$$

Equation (2) combined with (11), and the flow governing equation of shale gas in the matrix can be written as:

$$\begin{aligned}&\frac{\partial}{\partial t}\left[\left(1-\phi_m\right)\frac{\rho_g M}{V_m}\cdot\frac{V_L p_m}{p_m + p_L} + \frac{Mp_m}{RZT}\phi_m\right] \\ &= -\nabla\left[\rho_g\left(-\frac{\kappa_m}{\mu_g}\nabla p_m - \frac{D_m}{\rho_g}\nabla\rho_g\right)\right]\end{aligned} \tag{5}$$

C. Shale Gas Flow in the Fracture

Because of the high porosity and permeability in fractures, the viscous flow dominates shale gas transmission in fractures, and the main type of gas is free gas [21]. The conservation equation in the fracture is given as follows:

$$\frac{\partial}{\partial t}(\rho_g\phi_f) = -\nabla(\rho_g v_f) \tag{6}$$

In term of the state equation of real gas, the density of shale gas in fracture can be expressed as follows:

$$\rho_g = \frac{Mp_f}{RTZ} \tag{7}$$

Because the Darcy flow dominates the gas transmission in the fracture, the velocity of gas flow in the fracture is expressed as:

$$v_f = \frac{k_f}{\mu_g}\nabla p_f \tag{8}$$

Substituting (8) and (7) into (6), we can obtain the governing equation of shale gas in the fracture, and the equation shown as follows:

$$\frac{\partial}{\partial t}(\phi_f\cdot\frac{Mp_f}{RTZ}) = \nabla(\frac{Mp_f}{RTZ}\cdot\frac{\kappa_f}{\mu_g}\nabla p_f) \tag{9}$$

D. Geometric Model

Based on the mathematical model, we need to build a geological geometry model for numerical simulation. First, we simplified the problem by setting a cube to represent the shale matrix, and the side length of the cube is set to 1 meter. To facilitate the setting of the study parameters, the fracture was reduced to a circular plate with thickness. Assume that the fluid flows from the front end to the back end of the cube, and the remaining end faces have no fluid flow.

The parameters of the model are from the shale gas reservoir in southern China as shown in Table I.

There are many ways to solve this mathematical model. In this paper, the finite element method is used to solve the problem.

TABLE I. SHALE GAS RESERVOIR PARAMETERS FOR NUMERICAL SIMULATION

Parameters	Value
Real gas viscosity, μ_g (Pa·s)	1.81E-5
Langmuir pressure constant, P_L (Pa)	3.41E6
Gas compressibility factor, Z (1)	0.88
Langmuir volume constant, V_L (m^3/kg)	8.82E-4
Initial Pressure, p_i (Pa)	1.8E7
Inlet Pressure, p_{in} (Pa)	1.8E7
Outlet Pressure, p_{out} (Pa)	1.6E7
Porosity for the matrix, φ_m	0.05
Matrix permeability, k_m (m)	2.52E-18
Fracture permeability, k_f (m)	4.95E-13
Porosity for fracture, φ_f	0.8
Reservoir temperature, T(K)	335
Universal gas constant, R (J/(mol·K))	8.314
The fracture aperture, d_f (m)	2.00E-3
Molecular weight, M (kg/mol)	1.68E-3
Gas diffusion coefficient, D_g (m^2/s)	2.41E-13

III. RESULTS AND DISCUSSION

A. The Impact of Fracture Dig Angle

To work out the impact of fracture dip angle on shale gas flow, we have a tendency to design the subsequent simulation cases. Beneath the condition that the fracture dip direction coincides with the direction of gas flow, we modified the fracture dip angle and studied the gas production rate through the outlet end.

We set up 6 sets of experiments, and their fracture dip angles were set to 0, 15, 30, 45, 60, 75, 90 degrees respectively. As is shown in Fig. 2, the fracture dip angle was set to 60 degrees. In addition, we also set up a control group which did not contain fracture. It can be seen from Fig. 6. that the existence of the fracture affects the distribution of pressure within the matrix block.

As is shown in Fig. 3, with the experiment progresses, the cumulative production at the outlet end increases the rate of increase gradually slows down. By comparing the line without fracture and other lines, it is easy to see that the presence of the fracture significantly increases the gas cumulative production. By comparing lines with different fracture dip angles, we can observe that the larger the fracture dip angle, the higher the gas cumulative production and the gap between lines are more obvious over time. This trend can be more clearly in Fig. 4. As the dip angle of fracture increases, the gas cumulative production will show a downward trend. When the dip angle is about 45 degrees, the gas cumulative production drops the fastest.

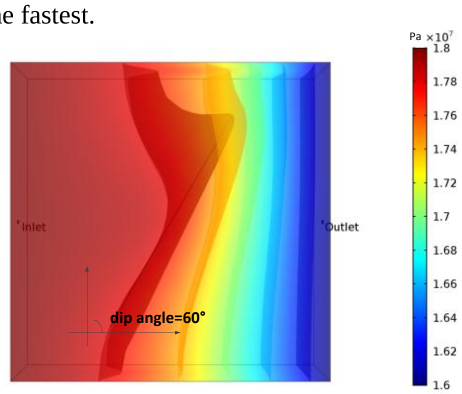

Figure 2. The distribution of pressure waves in matrix block.

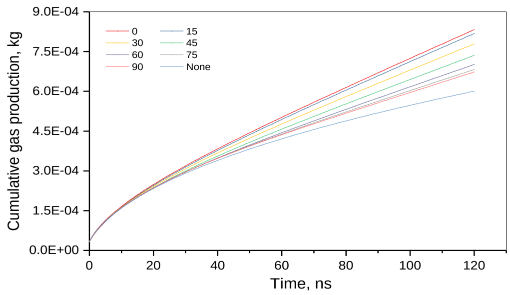

Figure 3. Effects of the fracture dip angle on shale gas cumulative production rate at the outlet section.

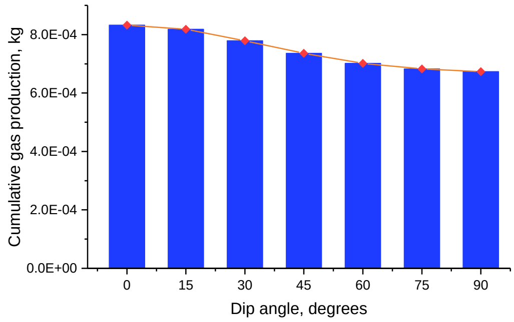

Figure 4. Gas cumulative production at different dip angles

B. The Impact of Fracture Density

In these experiments, the fracture density is expressed by the number of fractures per unit length. We used the side length of the matrix block as the unit length, and tested the gas cumulative production at fracture density of 1, 2, 3, 4, and 5, respectively. For example, when the fracture density is 3, the distribution of pressure in the matrix block is as shown in Fig. 5. It can be seen from the figure that the fracture density has an effect on the pressure distribution, and the flow rate at the outlet end has increased.

As shown in Fig. 6, the cumulative productions of different fracture densities change with time. As the density of fractures increases, the cumulative production increases gradually, and this can be seen more clearly in Fig.6. Simultaneously comparing with Fig. 6 and Fig. 7, it can be summarized that the fracture density has a greater improvement in gas cumulative production than the fracture dip angle. At the same time, we also noticed that as the density of the fracture increases, the curve tends to be flat, and this may be affected by the border.

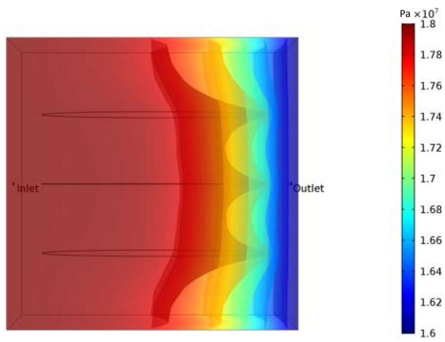

Figure 5. The distribution of pressure waves in matrix block (fractures density = 3/m).

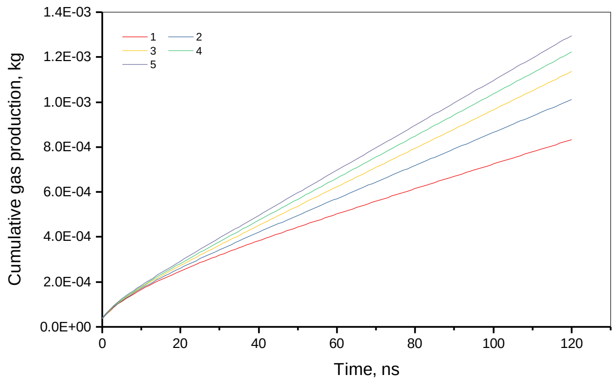

Figure 6. Effects of the fracture dip angle on shale gas cumulative production rate at the outlet section.

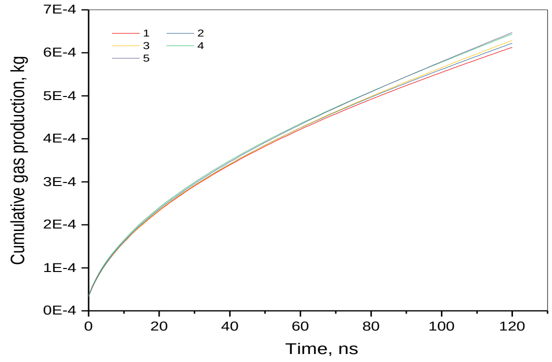

Figure 9. Effects of the fracture area on shale gas cumulative production rate at the outlet section.

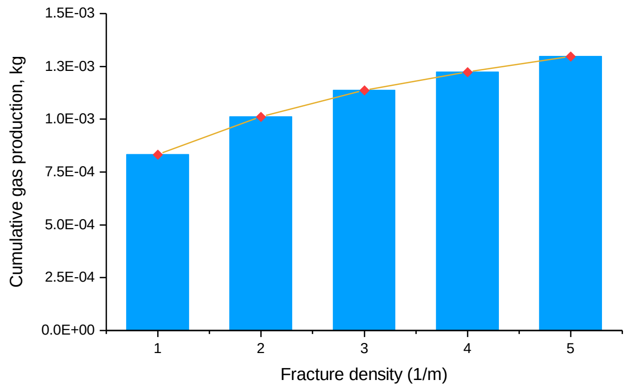

Figure 7. Gas cumulative production at different fracture densities

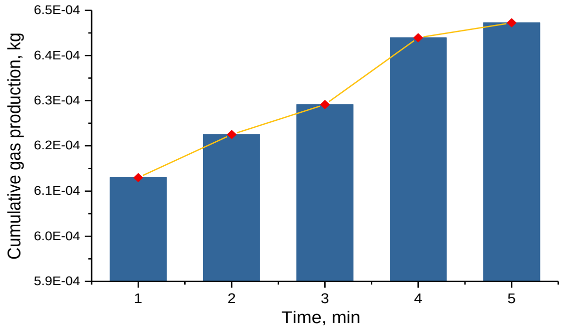

Figure 10. Gas cumulative production at different fracture areas

C. *The Impact of Fracture Area*

In this part, we mainly study the effect of fracture area on the gas flow. The specific experimental method is to gradually increase the fracture area to observe the change of gas production. First, we set a benchmark, and its multiple is recorded as 1. As shown in Fig. 7, the fracture area's multiple is 1. Then we gradually increased its multiple until the multiple is 5, and counted the cumulative production under different multiples.

As shown in Fig.8 and Fig.9, we can see that as the area of the fracture increases, the gas production increases gradually, but the incensement is not significant. It can be inferred that the increase in the fracture area has a small increase in gas production.

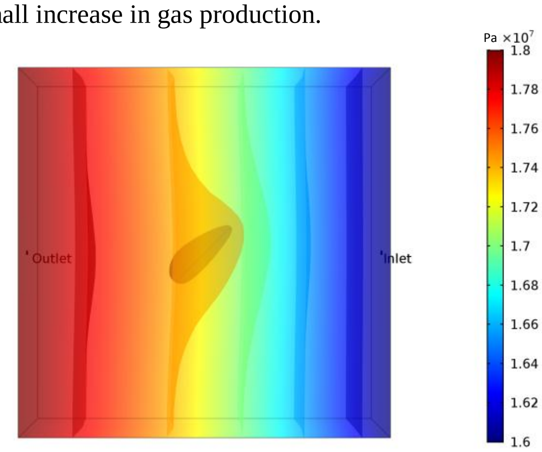

Figure 8. The distribution of pressure in matrix block(multiple=1).

IV. Conclusions

In this paper, we investigated shale gas flow mechanisms in the shale matrix block and discrete fractures. The shale gas flow mathematical model and geological geometric model were developed to investigate the influence of geological characteristics on the gas flow performance in the shale formations. The reservoir properties parameters come from typical shale gas reservoirs and the results could be equally applicable in many other situations. The following major conclusions can be drawn from this research work.

1. The existence of fractures in the shale matrix block contributes to gas flow. These fractures have a large impact on shale gas production performance.

2. The fracture dip angle affects the shale gas flow in the matrix. In the direction of gas, the smaller dip anger is favourable for the gas flow, and it is most advantageous when the fracture is parallel to the flow direction.

3. The effect of fracture density on the shale gas flow is significant. The higher the fracture density causes the higher the gas production. However, as the fracture density increases, the effect of crack density on gas production is gradually weakened.

4. The larger fracture area is also conducive to the gas flow. Relatively speaking, the influence of fracture area on gas flow is not significant, but it still deserves us to consider.

Conflict of Interest

The authors declare no conflict of interest.

AUTHOR CONTRIBUTIONS

Qichao Gao and Pingchuan Dong conceived of the presented idea; Qichao Gao and Chang Liu developed the theory and performed the computations; Chang Liu analyzed the data; Qichao Gao wrote the paper; All authors had approved the final version

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NOMECLATURE

q_m	gas mass concentration in the matrix (kg/m^3)
P_L	Langmuir pressure constant (Pa)
q_f	free gas mass concentration (kg/m^3)
q_a	adsorption gas mass concentration (kg/m^3)
V_L	Langmuir volume constant (m^3/kg)
d_f	fracture width (m)
μ_g	gas viscosity (Pa·s)
P_r	reduced temperature (dimensionless)
P_c	critical temperature (K)
T_c	critical pressure (Pa)
κ_m	matrix permeability (m^2)
T_r	reduced pressure (dimensionless)
κ_f	Fracture permeability (m^2)
Φ_f	fracture porosity (dimensionless)
Φ_m	matrix porosity (dimensionless)
T	reservoir temperature (K)
M	methane molar mass (kg/mol)
p_m	fracture pressure (Pa)
p_f	fracture pressure (Pa)
D	gas diffusion coefficient (m^2/s)
R	universal gas constant (J/(mol·K))
ρ_m	gas density in the matrix (kg/m^3)
ρ_f	gas density in the fractures (kg/m^3)
Z	gas compressibility factor (dimensionless)

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