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Research Article

Mathematical Simulation about Gas Transport in a Dual-Porosity Tight Gas Reservoir considering Multiple Effects

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Threshold pressure gradient, gas slippage, and stress sensitivity have important effects on the production of a tight gas reservoir. But previous studies only focused on one or two of these effects. In this study, a mathematical model considering these three effects was established to describe gas transport in a dual-porosity tight gas reservoir. Threshold pressure gradient, gas slippage, and stress sensitivity are simultaneously considered in the velocity term of continuity equation which is mainly different from the previous research results. The partial differential equation and definite solution condition are discretized by a central difference method. A finite difference procedure was compiled and applied to solve this numerical model and predict the productivity of a production well in a dual-porosity tight gas reservoir. The difference between the predicted and tested cumulative production is less than 10%, which indicates that the proposed mathematical model can be used to describe the characteristics of gas flow in the dual-porosity tight gas reservoir. Then, gas productivity of five different scenarios considering these effects was compared. Results show that both stress sensitivity and threshold pressure gradient are negatively correlated with gas production, while gas slippage is positively correlated with gas production. Among them, stress sensitivity has the greatest impact on the production of a dual-porosity tight gas reservoir. Overall, these three effects have great influence on the development of the dual-porosity tight gas reservoir, which should be considered in the production prediction.

1. Introduction

With the increasing demand for oil and natural gas, tight gas is a kind of important supplement for fossil energy. Tight gas is one of the largest unconventional energy resources, which plays an indispensable role in natural gas supply [1, 2, 3].

Compared with conventional gas reservoirs, gas transport in tight gas reservoirs has three specific characteristics, including the threshold pressure gradient, gas slippage, and stress sensitivity. A tight gas reservoir shows the effect of threshold pressure gradient due to low porosity and permeability [4]. When the gas flows in the tight reservoir, the molecular force between gas and rock surface is far less than that between oil/water and rock surface. This phenomenon is called "gas slippage effect." This gas slippage is much more obvious when the gas flows in micropores [5, 6, 7]. The rock in the tight reservoir also undergoes elastic and plastic deformation with decreasing pore pressure. This phenomenon results in the decrease in porosity and permeability. This rock property change owns a significant impact on the fluid flow in the reservoir. Therefore, the permeability stress sensitivity needs to be considered in the mathematical model [8].

Previous researchers conducted a lot of work to study these three effects. Qanbari and Clarkson [8] introduced a new variable to solve the partial differential equation, which described the slightly compressible fluid transiently flow in a stress-sensitive reservoir. Zhang and Guo [9] established a mathematical model considering the gas slippage effect of a low-permeability gas reservoir and developed a pseudo-pressure function and pseudo-time function which made the mathematical model linearized. Based on the power function relationship between permeability and pressure, Ren and Guo [10] launched an unsteady flow model in the stress-sensitive reservoir to analyze the gas productivity.

Huang et al. [11] presented an unsteady flow model for a horizontal well considering both stress sensitivity and composite reservoir shape. They also discussed the effects of permeability coefficient and other relevant parameters on the transient pressure and the declining production rate of the horizontal well in stress-sensitive composite reservoirs.

At present, the published mathematical model of tight gas reservoirs mainly focused on one or two effects of threshold pressure gradient, gas slippage, and stress sensitivity. There is rarely a mathematical model taking all of them into account. This paper established a mathematical model of gas-water two-phase flow in the dual-porosity tight gas reservoir, which comprehensively considered the threshold pressure gradient, gas slippage, and stress sensitivity. A finite difference method was applied to solve this model by computer programming. Then, this model was applied to a tight gas well to verify the reliability of the model. Finally, the effects of these three effects on gas production were discussed.

2. Mathematical Model

The mathematical model of gas-water two-phase flow in the dual-porosity tight gas reservoir is divided into four parts, including gas equation of state, motion equation, continuity equation, and solution conditions. Some basic assumptions are made in the mathematical model to well depict the gas-water physical flow, including the linear Darcy flow of water and high-speed non-Darcy flow of gas in the dual-porosity tight gas reservoir. Threshold pressure gradient, gas slippage, and stress sensitivity were considered together into the continuity equation simultaneously.

2.1. Gas Equation of State. The PVT relationship of gas cannot be described exactly by using a static equation of state, because it can be influenced by pressure characteristic caused by the gas flow through porous media [12–13]. The gas flow is assumed in equilibrium, and its equation of state is written as follows.

$$(p + c)V = nRT\left(1 + \frac{N}{2V}\beta + \frac{\delta}{N}\right), \tag{1}$$

where c is the pressure characteristic, p is the system pressure, V is the system volume, N is the molecular number, β is the deviation coefficient between the actual gas and ideal gas, n is the mole number of gas, R is the gas constants, δ is the parameter related to c, and T is the system temperature.

For an ideal gas, β is 0 and σ is so small that can be ignored. Equation (1) can be simplified as follows:

$$(p + c)V = nRT. \tag{2}$$

Equation (2) represents the PVT relationship of flowing gas more accurately because the pressure characteristic parameter was added to the left side of the equation [14].

According to equation (2), the gas density can be expressed as follows:

$$\rho_{\mathrm{g}} = \frac{(p + c)M}{RT}, \tag{3}$$

where ρ_{g} is the gas density and M is the gas molecular weight.

2.2. Motion Equation. In the gas-water two-phase flow of the matrix and fracture system, the final motion equations were established based on Darcy's law, considering threshold pressure gradient, gas slippage, and stress sensitivity effect.

2.2.1. Threshold Pressure Gradient. Gas and water in the matrix and fracture system have to overcome the threshold pressure gradient to flow. Therefore, the influence of the threshold pressure gradient should be considered. At the same time, the high-speed non-Darcy effect of the gas in the fracture system also needs to be considered. The motion equations in the matrix and fracture system are, respectively, shown in equations (4)–(8) [15–20].

The motion equation in the matrix system is

$$v_{\mathrm{mg}} = \frac{K_{\mathrm{m}} K_{\mathrm{rmg}} \rho_{\mathrm{mg}}}{\mu_{\mathrm{mg}}} \left(\nabla p_{\mathrm{mg}} - \lambda_{\mathrm{mg}}\right), \tag{4}$$

$$v_{\mathrm{mw}} = \frac{K_{\mathrm{m}} K_{\mathrm{rmw}} \rho_{\mathrm{mw}}}{\mu_{\mathrm{mw}}} \left(\nabla p_{\mathrm{mw}} - \lambda_{\mathrm{mw}}\right), \tag{5}$$

where v_{mg} is the gas velocity in the matrix, v_{mw} is the water velocity in the matrix, K_{m} is the permeability of the matrix, K_{rmg} is the relative permeability of gas in the matrix, K_{rmw} is the relative permeability of water in the matrix, ρ_{mg} is the density of gas in the matrix, ρ_{mw} is the density of water in the matrix, μ_{mg} is the viscosity of gas in the matrix, μ_{mw} is the viscosity of water in the matrix, ∇p_{mg} is the pressure gradient of gas in the matrix, ∇p_{mw} is the pressure gradient of water in the matrix, λ_{mg} is the threshold pressure gradient of gas in the matrix, and λ_{mw} is the threshold pressure gradient of water in the matrix.

The motion equation in the fracture system is

$$v_{\mathrm{fg}} = \frac{B K_{\mathrm{f}} K_{\mathrm{rfg}} \rho_{\mathrm{fg}}}{\mu_{\mathrm{fg}}} \left(\nabla p_{\mathrm{fg}} - \lambda_{\mathrm{fg}}\right), \tag{6}$$

$$v_{\mathrm{fw}} = \frac{K_{\mathrm{f}} K_{\mathrm{rfw}} \rho_{\mathrm{fw}}}{\mu_{\mathrm{fw}}} \left(\nabla p_{\mathrm{fw}} - \lambda_{\mathrm{fw}}\right), \tag{7}$$

where v_{fg} is the gas velocity in the fracture, v_{fw} is the water velocity in the fracture, K_{f} is the permeability of the fracture, K_{rfg} is the relative permeability of gas in the fracture, K_{rfw} is the relative permeability of water in the fracture, ρ_{fg} is the density of gas in the fracture, ρ_{fw} is the density of water in the fracture, μ_{fg} is the viscosity of gas in the fracture, μ_{fw} is the viscosity of water in the fracture, ∇p_{fg} is the pressure gradient of gas in the fracture, ∇p_{fw} is the pressure gradient of water in the fracture, λ_{fg} is the threshold pressure gradient of gas in the fracture, and λ_{fw} is the threshold pressure gradient of water in the fracture.

The non-Darcy coefficient of high-speed non-Darcy flow of gas in the fracture system is

$$B = \frac{1}{1 + \left(a\rho_g K_f/\mu_{fg}\right) v_{fg} + \left(h\rho_g K_f/\mu_{fg}\right) {v_{fg}}^2}, \tag{8}$$

where B is the gas non-Darcy coefficient and a and h are constants.

2.2.2. Gas Slippage Effect. The gas slippage effect usually occurs in tight porous media. Because the fracture permeability is much greater than the matrix, the gas slippage effect in the fracture is very weak. In order to solve the motion equation easily, the gas slippage effect in the fracture can be ignored. At the same time, because there is no gas slippage effect for water, only the gas slippage effect in the matrix system needs to be considered [21].

The permeability equation considering the gas slippage effect is shown in

$$K = K_\infty \left(1 + \frac{b}{\bar{p}}\right), \tag{9}$$

where K_∞ is the Klinkenberg permeability, b is the slippage factor of the matrix, $\bar{p}$ is the average formation pressure, and $K_{m\infty}$ is the Klinkenberg permeability of the matrix.

The motion equation in the matrix system is

$$v_{mg} = \frac{K_{m\infty} K_{rmg} \rho_{mg}}{\mu_{mg}(1 + (b/\bar{p}))} \left(\nabla p_{mg} - \lambda_{mg}\right), \tag{10}$$

$$v_{mw} = \frac{K_m K_{rmw} \rho_{mw}}{\mu_{mw}} (\nabla p_{mw} - \lambda_{mw}). \tag{11}$$

2.2.3. Stress Sensitivity Effect. The stress sensitivity effect means that the permeability decreases with the increase in the effective pressure during the production process. Because the fracture is the main permeable path, the stress sensitivity effect of the fracture system is considerable, while that of the matrix system is not obvious. Therefore, only the stress sensitivity effect of the fracture system is considered in the dual-porosity tight gas reservoir.

The relationship between permeability and effective stress is shown in

$$K = K_0 {p_e}^{-m}, \tag{12}$$

where K_0 is the initial permeability, p_e is the effective pressure, m is the stress sensitivity index, and K_{f0} is the initial permeability of the fracture.

The motion equation in the fracture system is

$$v_{fg} = \frac{B K_{f0} {p_e}^{-m} K_{rfg} \rho_{fg}}{\mu_{fg}} \left(\nabla p_{fg} - \lambda_{fg}\right), \tag{13}$$

$$v_{fw} = \frac{K_{f0} {p_e}^{-m} K_{rfw} \rho_{fw}}{\mu_{fw}} (\nabla p_{fw} - \lambda_{fw}). \tag{14}$$

Considering the above factors, motion equations of the matrix and fracture system are launched, shown in equations (10), (11), (13), and (14).

2.3. Continuity Equation. According to the law of mass conservation, the continuity equation of the gas-water two-phase system can be obtained which takes into account threshold pressure gradient, gas slippage, and stress sensitivity effect.

Matrix system:

Gas:

$$\nabla \left[\frac{K_{m\infty} K_{rmg} \rho_{mg}}{\mu_{mg}(1 + (b/\bar{p}))} \left(\nabla p_{mg} - \lambda_{mg}\right)\right] - F_g - q_{mg} = \frac{\partial}{\partial t}\left(\phi_m \rho_{mg} S_{mg}\right). \tag{15}$$

Water:

$$\nabla \left[\frac{K_m K_{rmw} \rho_{mw}}{\mu_{mw}} (\nabla p_{mw} - \lambda_{mw})\right] - F_w - q_{mw} = \frac{\partial}{\partial t} (\phi_m \rho_{mw} S_{mw}), \tag{16}$$

where q_{mg} is the gas production in the matrix, q_{mw} is the water production in the matrix, p_{mg} is the gas pressure in the matrix, p_{mw} is the water pressure in the matrix, S_{mg} is the gas saturation in the matrix, and S_{mw} is the water saturation in the matrix.

Cross-flow in the matrix and fracture system:

$$F_g = \frac{\sigma K_m}{\mu_g} \left(p_{mg} - p_{fg}\right), \tag{17}$$

$$F_w = \frac{\sigma K_m}{\mu_w} (p_{mw} - p_{fw}), \tag{18}$$

where F_g is the gas crossflow from the matrix system to the fracture system, F_w is the water crossflow from the matrix system to the fracture system, and σ is the shape factor.

Fracture system:

Gas:

$$\nabla \left[\frac{B K_{f0} {p_e}^{-m} K_{rfg} \rho_{fg}}{\mu_{fg}} \left(\nabla p_{fg} g - \lambda_{fg}\right)\right] + F_g - q_{fg} = \frac{\partial}{\partial t}\left(\phi_f \rho_{fg} S_{fg}\right). \tag{19}$$

Water:

$$\nabla \left[\frac{K_{f0} {p_e}^{-m} K_{rfw} \rho_{fw}}{\mu_{fw}} (\nabla p_{fw} - \lambda_{fw})\right] + F_w - q_{fw} = \frac{\partial}{\partial t} (\phi_f \rho_{fw} S_{fw}), \tag{20}$$

where q_{fg} is the gas production in the fracture, q_{fw} is the water production in the fracture, p_{fg} is the gas pressure in the fracture, p_{fw} is the water pressure in the fracture, S_{fg} is the gas saturation in the fracture, and S_{fw} is the water saturation in the fracture.

The main difference between the continuity equations (15)–(19) and the previous research results is that threshold pressure gradient, gas slippage, and stress sensitivity are simultaneously considered in the velocity term of the continuity equation. In equations (15)–(19), the velocity term includes the threshold pressure gradient of the matrix and fracture system. The slip factor b in equation (15) represents the gas slippage effect of gas in the matrix system. The m stress sensitivity index in the velocity term in equations (19) and (20) represents the stress sensitivity effect of the fracture system. Continuity equations (15)–(19) comprehensively characterize the interaction of these three effects in tight dual-porosity gas reservoirs.

2.4. Solution Conditions. The solution conditions should be given to solve the mathematical model, including boundary and initial conditions.

2.4.1. Boundary Conditions. Because the edge water of the tight gas reservoir has no obvious complementary effect on the formation pressure, the outer boundary pressure of the reservoir can be approximately regarded as closed. Then, it is considered as a known function of time and space, as shown in

$$p_E = \varphi(x, y, z, t). \tag{21}$$

The constant bottom hole pressure is adopted for the inner boundary condition. It is considered a known function of time and space, as shown in

$$p|_{rw} = \varphi_1(x, y, z, t). \tag{22}$$

2.4.2. Initial Conditions. The initial pressure is also a necessary parameter to solve the model. The pressure distribution in the gas reservoir is a known function at the initial time, as shown in

$$p(x, y, z, 0) = \phi(x, y, z, t). \tag{23}$$

The initial distribution of fluid saturation is needed when calculating the gas-water two-phase flow. The distribution of water saturation in the gas reservoir is a known function at the initial time, as shown in

$$S_{w0} = S_w(x, y, z). \tag{24}$$

3. Model Solution

The mathematical model is a set of the partial differential equation which is very complex and nonlinear. It is difficult to be solved by an analytical method. In this paper, the partial differential equation and definite solution condition are discretized by the central difference method and are calculated by computer programming. The solution is solved by the IMPES method. The key approach of IMPES is that the pressure is solved implicitly for each cell and the saturation is solved explicitly. So the pressure and saturation are solved alternately. The advantage of the IMPES method is that it needs less computation time at each time step and the computation speed is relatively fast. The key technology of this method is that the conductivity is taken as an explicit value, and the pressure and saturation are solved alternately. The programming design diagram is shown in Figure 1.

4. Model Validation

The numerical model was applied for a vertical well located in the high structure of a dual-porosity tight gas reservoir to test the validity of the model. In the numerical simulation, the following parameters were used: cell size is $20\,\text{m} \times 20\,\text{m} \times 1\,\text{m}$, cell dimension is $25 \times 25 \times 5$, initial reservoir pressure is 4500 psi, average matrix porosity is 6%, average fracture porosity ϕ is 0, average matrix permeability is 0.0915×10^{-3} μm^2, average fracture permeability is $100 \times 10^{-3}\,\mu\text{m}^2$, irreducible water saturation is 35%, and residual gas saturation is 10%. The other parameters, such as threshold pressure gradient parameter, gas slippage parameter, stress sensitivity parameter, and relative permeability curve, also were input into the program. The actual well schedule and production data were put into the model. Gas production of the well was calculated according to the actual well schedule. The results are shown in Figures 2 and 3.

The calculated and actual gas production is shown in Figure 2. The overall results show that the calculated gas production is well consistent with the actual one, although some data points could not be matched well. Figure 3 shows the comparison of the calculated and actual cumulative gas production. These two sets of data have the same trend. At the early stage, two lines almost overlap together. From the middle stage, a little gap began to appear between them, which is caused by failing to be matched well on some daily production data. The deviation of cumulative gas production is less than 10%. In conclusion, the matching result indicates that the numerical simulation result well fits with the production data.

5. Results and Discussion

In order to understand how the threshold pressure gradient, gas slippage, and stress sensitivity influence the gas production, five scenarios were designed. Three effects, none, and only one were considered, respectively. Daily and cumulative gas production for the five scenarios was calculated, as shown in Figures 4 and 5.

From Figure 4, it can be seen that threshold pressure gradient and stress sensitivity have a negative effect on gas production while gas slippage has a positive effect. At the early stage of production (before 700 days), the gas productions of five scenarios are almost equivalent to each other. Because gas saturation of the reservoir is high and the reservoir energy is sufficient at the early stage, the threshold pressure gradient effect is not significant. At the same time, the flow velocity of gas in the reservoir is relatively high. The positive effect of gas slippage on gas production is just offset by the negative stress sensitivity. At the middle stage of production (700-1700

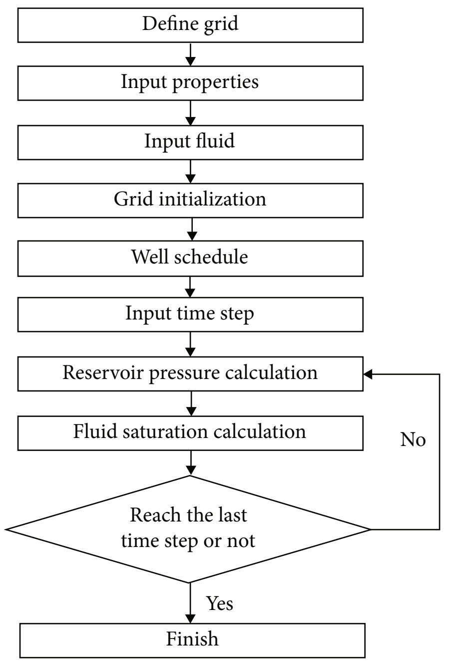

Figure 1: The programming design diagram.

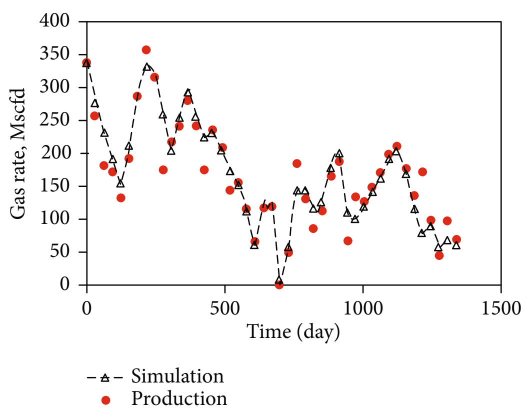

Figure 2: Comparison of calculated and actual gas production.

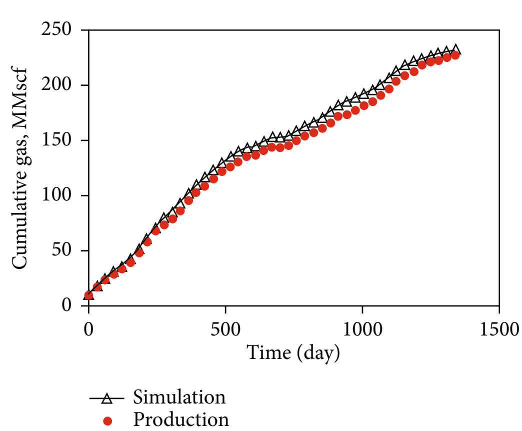

Figure 3: Comparison of calculated and actual cumulative gas production.

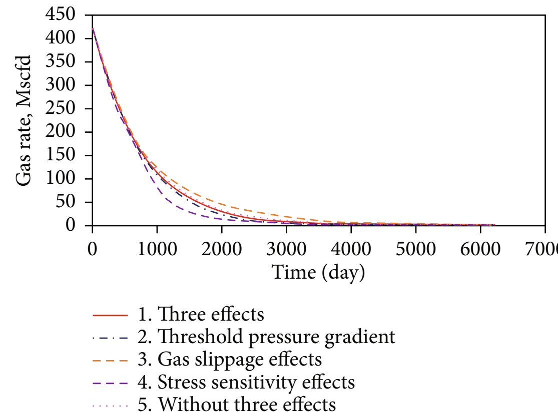

Figure 4: Daily gas production for different scenarios.

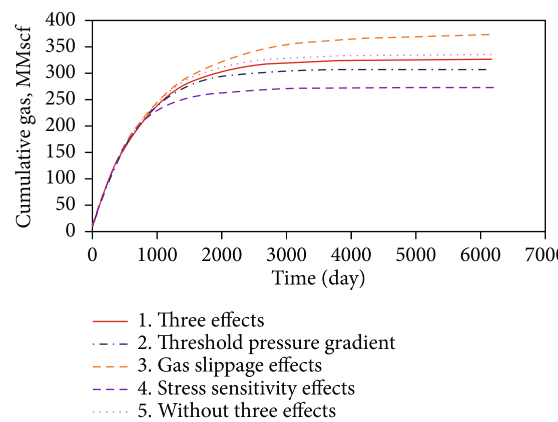

Figure 5: Cumulative gas production for different scenarios.

days), the production difference between scenario 1 (three effects) and scenario 5 (without three effects) is getting bigger due to the closure of fractures caused by the reservoir pressure depletion. Both stress sensitivity and threshold pressure gradient effects are strong. In the meantime, positive effect of gas slippage on gas production cannot make up for the negative effect of threshold pressure gradient and stress sensitivity. At the late stage of production (1700 days later), the reservoir pressure continues to deplete, and the gas slippage effect plays a major role gradually. However, because the gas production is at a low level, the impact of the three factors on the production is not as obvious as that at the middle stage. As the formation pressure drops, gas production with three effects is gradually close to that with no effect.

Gas production with stress sensitivity is less than that with no effect. The gas production declines fast before the fracture is closed. The gas production with the gas slippage effect is higher than that with no effect. It means that the gas slippage effect is positively related to production. Because the threshold pressure gradient increases the flow resistance, the production with it is lower than that with no effect.

From Figure 5, it is easy to be found that the cumulative gas production with only the gas slippage effect is the largest. That with only stress sensitivity is the smallest. Therefore, the above results fully show that stress sensitivity has a greater impact on production, followed by the gas slippage effect and threshold pressure gradient. Stress sensitivity and threshold pressure gradient have a negative correlation with gas production, while the gas slippage effect is positive. They comprehensively affect the gas flow ability in dual-porosity tight gas reservoirs.

6. Conclusion

In this paper, a new mathematical model of the gas-water two-phase flow in the dual-porosity tight gas reservoir is established. The finite difference approach is used to solve the model combined with computer programming. The conclusion can be summarized as follows.

(1) A mathematical model was established to comprehensively characterize the integrative influence of threshold pressure gradient, gas slippage, and stress sensitivity on gas flow in dual-porosity tight gas reservoirs

(2) The daily and cumulative gas production predicted by the proposed model is well matched with the tested production data. The difference between the calculated and actual cumulative production is less than 10%

(3) The stress sensitivity and threshold pressure gradient are negatively correlated with gas production, while the gas slippage effect is positive. The combination of these effects greatly influences the gas flow ability in dual-porosity tight gas reservoirs

Nomenclature

c: Pressure characteristic (N/m^2)
V: System volume (m^3)
N: Molecular number
B: Deviation coefficient between the actual gas and ideal gas
n: Mole number of gas (mol)
R: Gas constant = 8.314 J/(K · mol)
δ: Parameter related to c
T: System temperature (°C)
ρ_g: Gas density (kg/m^3)
M: Molecular weight of gas (kg/mol)
B: Gas non-Darcy coefficient
K_0: Initial permeability ($10^{-3}\ \mu m^2$)
K_∞: Klinkenberg permeability ($10^{-3}\ \mu m^2$)
K_m: .Permeability of the matrix ($10^{-3}\ \mu m^2$)
$K_{m\infty}$: Klinkenberg permeability of the matrix ($10^{-3}\ \mu m^2$)
K_f: Permeability of the fracture ($10^{-3}\ \mu m^2$)
K_{f0}: Initial permeability of the fracture ($10^{-3}\ \mu m^2$)
b: Slippage factor of the matrix (MPa)
p: System pressure (N/m^2)
$\bar{p}$: Average formation pressure (MPa)
p_e: Effective stress (MPa)
m: Stress sensitivity index
σ: Shape factor
v_m: Matrix velocity (m/s)
v_f: Fracture velocity (m/s)
λ_m: Matrix threshold pressure gradient (MPa/m)
λ_f: Fracture threshold pressure gradient (MPa/m)
K_{rm}: Matrix relative permeability
K_{rf}: Fracture relative permeability
ρ_m: Matrix fluid density (kg/m^3)
ρ_f: Fracture fluid density (kg/m^3)
μ_m: Matrix fluid viscosity (mPa·s)
μ_f: Fracture fluid viscosity (mPa·s)
∇p_m: Matrix system pressure gradient (MPa/m)
∇p_f: Fracture system pressure gradient (MPa/m)
F: Gas and crossflow from the matrix system to the fracture system (m^3/s)
q_m: Matrix fluid production (m^3/d)
q_f: Fracture fluid production (m^3/d)
p_m: Matrix system pressure (MPa)
p_f: Fracture system pressure (MPa)
S_m: Matrix fluid saturation
S_f: Fracture fluid saturation

Data Availability

The data used to support the findings of this study are included within the article.

Conflicts of Interest

The authors declare that there are no conflicts of interest regarding the publication of this paper.

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