Study on the Model and Law for Radial Leakage of Drilling Fluid in Fractured Formations

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Cite This: ACS Omega 2022, 7, 39840−39847

ABSTRACT: The economic loss caused by fracture leakage accounts for 90% of all leakage costs; thus, it is necessary to find the factors that affect the leakage and to study the leakage laws of fractured strata. The advantage of this article is that we introduced fracture index deformation and fracture tortuosity parameters to characterize fracture roughness and fracture characteristic parameters using the logging data analysis method. To explore the mechanism of leakage in essence, this paper, based on fluid mechanics, improves the radial leakage model by adopting the Herschel−Bulkey (H−B) flow-type drilling fluid with high calculation accuracy and comprehensively considering the factors such as drilling fluid performance parameters, fracture roughness characteristic parameters, pressure difference between the wellbore and formation, and radial extension length of the drilling fluid. The advantage of the model is that it is solved in an absolutely stable backward Euler difference format. The numerical simulation is carried out by MATLAB. The simulation results revealed that the leakage rate increased as the fracture index deformation coefficient and the fracture opening increased. The leakage rate also increased as the fracture tortuosity parameters decreased and as the fracture smoothened. However, the leakage rate decreased as the drilling fluid fluidity coefficient increased. Drilling fluid dynamic shear force had a minor effect on the leakage rate. The higher the pressure difference between the wellbore and the formation, the higher the leakage rate. As the drilling fluid intrusion depth increased, the leakage rate decreased until it reached 0. Two parameters were mainly controlled in order to control the degree of leakage: differential pressure and fracture static width, which has important guiding for adjusting the drilling fluid density and predicting leaks in the field. The solution method of the model in this paper has a certain reference value for the solution of other models in the future. The conclusion can provide reference for numerical simulation, laboratory test, and field application in the future.

1. INTRODUCTION

Drilling is currently progressing toward deep, high-temperature, and high-pressure fractured and complex formations. Great importance has been attached to the well leakage in fractured formations at home and abroad, and a lot of manpower, material, and financial resources have been invested. The essence of leakage in fractured formations is the flow of drilling fluids into the fractures, and the nature of the fracture surface has a significant influence on the flow of drilling fluid. In recent years, many scholars have proposed various models for the quantitative analysis of drilling fluid leakage. Lietard et al. have developed a single smooth fracture leakage model with infinite radial length and Newton flow-type and Bingham flow-type drilling fluid. Ozdemirtas et al. developed a two-dimensional (2D) Herschel−Bulkey (H−B) flow-type drilling fluid leakage model. Majidi et al. developed a smooth fracture radial leakage model for H−B flow-type drilling fluid and considered the fracture linear deformation. Shahri et al. developed a 2D H−B flow-type drilling fluid leakage model with smooth fractures. Li developed a one-dimensional (1D) linear leakage model and a 2D H−B flow-type drilling fluid leakage model and used fractal theory to describe their fracture roughness. Jia et al. developed a 2D power-law flow-type drilling fluid leakage model that considered fracture linear deformation and fracture roughness. Li et al. developed an H−B flow-type model for drilling fluids using 1D radial plates and 2D flat plates with fracture index deformation, but the effect of fracture roughness was not considered. Wang et al. developed a 2D Bingham flow-type drilling fluid leakage model, with the exponential fracture deformation and fracture roughness considered. Zhongxi et al. researched the fracture propagation and...
holds that it is related to the stress intensity factor at the fracture tip and the fracture opening width. Zhai et al.\textsuperscript{28} developed a model for induced fracture leakage dynamics caused by 1D fracture expansion, and this model considered fracture dynamic width variation and fracture opening.

According to research, the most realistic drilling fluid leakage models are the 1D radial and 2D flat plate models. Since it has been discovered that fracture inclination has a negligible effect on leakage, the current research on radial leakage models has progressed from Newton flow-type drilling fluid to power-law and H–B flow-type drilling fluid. The above studies on radial leakage models did not consider fracture index deformation, fracture surface filtration loss, fracture roughness, and other factors. Fracture surface filtration loss must be considered in relation to the actual formation. Therefore, the H–B model was used in this study to describe the non-Newtonian fluid properties of drilling fluids which has the advantage of increasing the accuracy of the calculations and H–B fluids that are more in line with the actual drilling fluid flow and to derive and establish a radial leakage equation based on the Navier–Stokes (N–S) equation. In addition to the effects of the fracture geometry and drilling fluid rheological parameters, the effects of fracture index deformation and fracture roughness on fracture leakage were also considered. The model is solved in an absolutely stable backward Euler difference format, and the result is absolute convergence. This study is to perfect the known radial model. The solution method of the model is a reference for the solution of other models in the future.

2. FRACTURE CHARACTERIZATION

The fracture surface in a formation is typically uneven, and it is first necessary to understand the geometry of fracture surfaces in order to have a clear understanding of the leakage characteristics of rough fractures. The logging method can quantitatively describe the width, inclination, and orientation of fractures, as well as the degree of filling and opening of fractures.

The width of the fracture is the distance between the two walls of the fracture, and it has a significant impact on the leakage rate. The response of dual lateral logs is used to distinguish whether the fracture is vertical or horizontal, with a positive difference ($Y > 0.1$) indicating a vertical fracture and a negative difference ($Y < 0$) indicating a horizontal fracture.

When the fracture occurrence $Y < 0$, that is, when the fracture is horizontal, the fracture width\textsuperscript{29} $\xi$ is

$$\xi = \frac{C^a - C_b}{C_m[1.5(1 + \cos \alpha) - \sqrt{\cos \alpha}] \times 10^6}$$

(1)

When the fracture occurrence $Y > 0.1$, that is, when the fracture is vertical, the fracture width\textsuperscript{29} $\xi$ is

$$\xi = \frac{C_{LS}^{(a)} - C_{LD}^{(a)}}{C_m[1.5(1 + \cos \alpha) - \sqrt{\cos \alpha}] \times \frac{1}{g_e - g_d}}$$

(2)

where $C^a$ is the conductivity at an inclination angle of $a$, s/m; $C_b$ is the conductivity of the rock matrix, s/m; $C_m$ is the conductivity of the drilling fluid, s/m; $C_{LS}^{(a)}$ is the conductivity of the shallow lateral at the inclination angle of $a$, s/m; and $C_{LD}^{(a)}$ is the conductivity of the deep lateral at the inclination angle of $a$, s/m.

However, the use of logging to identify fractures has problems such as high costs, a quantitative solution that does not correlate well with the leakage rate, and numerous difficult-to-identify fractures. The characterization by the mathematical method not only increases the visualization of cracks but also meets the field requirements. An actual fracture surface has two to three dimensions, and the application of fracture simulation is more fractal theory and Monte Carlo theory. The fractal theory uses a fractal dimension (D) and the Hurst index\textsuperscript{30} to characterize fracture roughness. The closer the Hurst index is to 0, the rougher the fracture (generally, $H = 3−D$). The random midpoint displacement method was used in MATLAB programming to generate a rough fracture surface, as shown in Figure 1.

Different fractal dimensions can be used to characterize fractures and fracture widths at different locations, and the average width can be calculated. Several scholars have used the fractal method\textsuperscript{23} to describe fracture roughness in drilling fluid loss models, but this method cannot be used to characterize fractures with linear deformation regularity. Thus, fracture tortuosity parameters\textsuperscript{23} were used to characterize fracture roughness, as shown in eq 3, which also characterizes the effect of fracture roughness on fracture mechanical opening.

Figure 1. Schematic of the computer simulation of a fracture surface with different fractal dimensions. (a) D = 2.2; H = 0.8. (b) D = 2.8; H = 0.2.
\[ w = w_0 e^{\beta (g - P)/3} \]  
(3)

where \( w \) is the fracture mechanical opening, m; \( w_0 \) is the fracture hydraulic opening, m.

The fracture index deformation equation \(^{30,31}\) can describe changes in the dynamic behavior of fracture width better than the linear deformation equation.

\[ w_s = w_0 e^{-\beta (g - P)/3} \]  
(4)

where \( w_s \) is the fracture static width, m; \( \beta \) is the fracture index deformation, \( \text{Pa}^{-1} \); \( P \) is the intraseam pressure, Pa; and \( P_0 \) is the formation pore pressure, MPa.

3. DRILLING FLUID LEAKAGE MODEL

Since the filtration loss of drilling fluids \(^{32}\) on the fracture wall of fractured complex formations is negligible compared to the drilling fluid leakage in the fracture, a radial \( H-B \) flow-type drilling fluid leakage model was established to simulate the drilling fluid leakage in the fracture. Several factors such as the drilling fluid flow pattern, the drilling fluid consistency coefficient, the drilling fluid dynamic shear force, the drilling fluid intrusion depth, fracture index deformation, fracture roughness, fracture width, and pressure difference between the wellbore and the formation were all considered as the perfection of the radial model.

3.1. Mathematical Model. As shown in Figure 2, it is assumed that the fracture extends infinitely into the formation and that the \( H-B \) flow-type drilling fluid has a laminar flow in the fracture. The drilling fluid leakage rate in the \( z \)-direction of the fracture is lower than the leakage rate in the \( r \)-direction of the fracture extension and can be neglected, and the fracture width is \( w \). The drilling fluid is viscous, and the flow law conforms to the N–S equation. The following assumptions were made for this model: regardless of the compressibility of drilling fluid, the flow pattern is laminar flow, and fracture width is much smaller than the fracture height and length.

The intrinsic equation of the \( H-B \) flow pattern is

\[ \tau_z = \tau_s + K \gamma^{n/3} \]  
(5)

where \( n \) is the flow pattern index, unfactored; \( K \) is the consistency factor, \( \text{Pa} \cdot \text{s}^3 \); \( \gamma \) is the shear rate, \( \text{s}^{-1} \); \( \tau_s \) is the dynamic shear force, Pa; and \( \tau_z \) is the shear stress, Pa.

3.2. Drilling Fluid Leakage Model.

1. The continuity equation is as follows

\[ \frac{\partial \rho}{\partial t} - \frac{1}{r} \frac{\partial}{\partial r} (r \rho v_r) = 0 \]  
(6)

where \( w \) is the fracture width, m; \( v \) is the flow rate in the fracture, m/s.

2. The conservation of momentum equation is

\[ \rho \frac{Dv}{Dt} = -\frac{\partial p}{\partial r} \left( \frac{1}{r} \frac{\partial (r v_r)}{\partial r} + \frac{1}{r} \frac{\partial v_r}{\partial \theta} + \frac{\partial v_\theta}{\partial z} - \frac{\tau_{r\theta}}{r} \right) + \rho f \]  
(7)

where \( \tau_{r\theta} \) is the surface force component, Pa; \( \partial p/\partial r \) is the pressure gradient, \( \text{Pa/m} \); and \( f \) is the mass force acting on a unit volume of fluid, \( \text{N/kg} \).

3. For viscous fluids, when inertial and gravitational forces are neglected and the flow velocities of the fracture in the \( z \) and \( \theta \) directions are substantially lower than those in the \( r \) direction and can be neglected, the momentum equation can be incorporated into the \( \text{N–S} \) equation

\[ -\frac{\partial p}{\partial r} = \frac{d \tau_{z}}{dz} \]  
(8)

The average flow velocity of the fluid in the fracture was obtained by associating and integrating the fluid instanton equation, omitting the higher-order terms after Taylor expansion

\[ \tau = \left( \frac{n}{2n + 1} \right) \left( \frac{w}{2} \right)^{1+n/3} \left( \frac{1}{k} \right)^{1+n/3} \frac{\partial p}{\partial r} \]  
\[ - \frac{2n + 1}{n + 1} \frac{\tau_z}{w} \]  
(9)

Incorporating eq 7 into the continuity equation yields as follows
3.3. Model Solving. The model was difficult to solve because the model control equation was a nonstationary second-order equation with a fractional order. Although the model is easier to solve using the display method, the step ratio (a step ratio greater than 1/2 is unstable) limitation must be considered, and different step ratios will result in different errors as the number of computational layers increases. Thus, the implicit difference method was used to solve the model to obtain absolutely convergent results, with the flow-type index \((n = 1)\) being used to simplify the calculation. For this equation, the difference was obtained as follows

\[
\frac{\partial (\rho \omega \delta^{1/3} e^{-\beta (\delta - P)/3})}{\partial t} = \frac{1}{r} \frac{\partial}{\partial r} \left( \rho \omega \delta^{1/3} e^{-\beta (\delta - P)/3} \right) \frac{1}{2^{1+1/n}}
\]

\[
= \left( \frac{n}{2n + 1} \right) \frac{1}{2^{1+1/n}} \frac{1}{\kappa^{1/n}}
\]

\[
\frac{\partial}{\partial r} \left[ \rho (\omega \delta^{1/3} e^{-\beta (\delta - P)/3}) \right]^{2+1/n} + \frac{1}{r} \frac{\partial}{\partial r} \left[ \rho (\omega \delta^{1/3} e^{-\beta (\delta - P)/3}) \right]^{1/n}
\]

\[
\left( \frac{dp}{dr} - \frac{2n + 1}{n + 1} \frac{2\tau_c}{\rho \omega \delta^{1/3} e^{-\beta (\delta - P)/3}} \right)^{1/n}
\]

\[
(10)
\]

3.4. Initial and Boundary Conditions. The following initial and boundary conditions were used for the simulation.

1 Initial value

\[
t = 0, P = P_0, r = r_w
\]

where \(P_0\) is the formation pore pressure, MPa; \(r_w\) is the radius of the borehole, m.

2 Boundary conditions

\[
\frac{dp}{dr} = 0: r = r_1
\]

where \(r_1\) is the radius of the fracture tip, m.

The following \(1\)–\(11\) were solved in an absolutely stable backward Euler difference format.

4. DRILLING FLUID LEAKAGE LAWS

Table 1 shows the initial data for analyzing the factors of each parameter in the mathematical model for the fracture-based leakage of H–B drilling fluids.

| parameters | take value | parameters | take value |
|------------|------------|------------|------------|
| stratigraphic pressure, \(p_1/\)MPa | 20 | fracture tortuosity, \(\delta\) | 1.5 |
| wellbore pressure, \(p_w/\)MPa | 30 | fracture static width, \(w_c/\)mm | 1 |
| normal stress, \(\sigma_n/\)MPa | 20 | fracture length in the \(r\) direction, \(n/m\) | 100 |
| fracture index deformation, \(\beta\) | 8.6 \times 10^{-3} | time step size, \(\Delta t/s\) | 0.01 |
| flow pattern, \(n\) | 1 | simulation time, \(t/s\) | 20 |
| dynamic shear force, \(\tau_c/\)Pa | 10 | the \(r\) direction step size, \(\Delta r/m\) | 3 |
| consistency coefficient, \(K/(Pa\cdot s^n)\) | 0.1 | gravitational acceleration, \(g/m\cdot s^{-2}\) | 9.8 |

4.1. Effect of the Drilling Fluid Consistency Coefficient \((K)\) on Leakage. Other parameters were kept constant, and the drilling fluid consistency coefficient \((K)\) was set to 0.3 \(Pa\cdot s^n\), 0.5 \(Pa\cdot s^n\), 0.7 \(Pa\cdot s^n\), and 0.9 \(Pa\cdot s^n\), and then MATLAB was used to simulate the leakage rate of the drilling fluid at each moment with the different drilling fluid consistency coefficient, as shown in Figure 3.

![Figure 3. Effect of the drilling fluid consistency coefficient on the leakage rate.](https://pubs.acs.org/doi/10.1021/acsomega.2c03895)

As shown in Figure 3, the leakage rate was low and decreased slowly when the drilling fluid consistency coefficient was high at the initial moment of leakage. The the value of the leakage rate is higher when it finally stabilizes. This is because the increase in the consistency coefficient will result in the increase in the plastic viscosity of the drilling fluid, and the corresponding resistance to the drilling fluid flow in the fracture will be greater, resulting in a lower leakage rate.

4.2. Effect of Drilling Fluid Dynamic Shear Force \((\tau_c)\) on the Leakage Rate. Other parameters were kept constant to simulate the leakage rate curves of drilling fluids at dynamic shear force of 10, 12, 15, and 20 Pa, as shown in Figure 4.
As shown in Figure 4, when the drilling fluid dynamic shear force is high at the initial moment of leakage, the leakage rate is low and decreases faster. Since the dynamic shear force of the drilling fluid reduces the initial leakage rate to a certain extent, adjusting it can effectively reduce the degree of well leakage. However, the leakage rate curves corresponding to different drilling fluid dynamic shear force were observed to have similar morphology. This is because the magnitude of dynamic shear force ($10^{-20}$ Pa) differed from the pressure gradient by several orders of magnitude, and its effect on the flow was negligible, and therefore the effect on the leakage rate is not significant.

4.3. Effect of Fracture Static Width ($w_0$) on Leakage.
Other parameters were kept constant, and the leakage rate curves were simulated when the fracture static width were 1, 1.2, 1.5, and 1.8 mm. Figure 5 depicts the results.

The simulation results revealed that the drilling fluid leakage rate increased as the fracture static width increased. At the initial moment of leakage, the drilling fluid leakage rate curve instantly displayed a large leakage rate peak, then decreased rapidly, and finally decreased gradually before becoming stable. This is because the fracture was the main flow channel of the drilling fluid at the beginning of leakage, and the wider the fracture opening at this time, the higher the drilling fluid leakage rate. According to eq 3, an increase in the initial fracture opening under the same intracrack pressure condition will cause the fracture opening to become larger, providing a larger leakage channel for the drilling fluid and aggravating the leakage.

4.4. Effect of the Fracture Index Deformation Factor ($\beta$) on Leakage. Other parameters were kept constant, and the leakage rate curves were simulated when the fracture index deformation coefficients were $8.6 \times 10^{-8}$, $1.1 \times 10^{-7}$, $1.3 \times 10^{-7}$, and $1.5 \times 10^{-7}$; the results are depicted in Figure 6.

The simulation results revealed that the drilling fluid leakage rate and the leakage rate value that tended to level off increased as the fracture index deformation coefficient increased, while the leakage rate curve changed significantly less when the fracture index deformation coefficient decreased. The larger the fracture index deformation coefficient, the greater the variation of the fracture width with the fluid pressure inside the fracture, and the easier it is for the fracture to deform and expand. However, an increase in $\beta$ can alleviate the pressure rise caused by fluid flow inside the fracture. Therefore, the larger the $\beta$, the easier it is for the fracture to deform and the larger the fracture width variation.

4.5. Effect of Fracture Tortuosity ($\delta$) on Leakage.
Other parameters were kept constant, and the leakage rate curves were simulated when the fracture tortuosity was 1.5, 2, 2.5, and 3. The results are shown in Figure 7.

The simulation results revealed that the drilling fluid leakage rate and the leakage rate value that tended to level off increased as the fracture index deformation coefficient increased, while the leakage rate curve changed significantly less when the fracture index deformation coefficient decreased. The larger the fracture index deformation coefficient, the greater the variation of the fracture width with the fluid pressure inside the fracture, and the easier it is for the fracture to deform and expand. However, an increase in $\beta$ can alleviate the pressure rise caused by fluid flow inside the fracture. Therefore, the larger the $\beta$, the easier it is for the fracture to deform and the larger the fracture width variation.
The simulation results revealed that the lower the fracture tortuosity, the higher the drilling fluid leakage rate. During the initial stages of leakage, the leakage rate decreased rapidly and then gradually decreased to a stable state. As time progressed, the influence of fracture tortuosity on the leakage rate decreased. This is because the lower the fracture tortuosity, the smoother the fracture, the faster the fluid percolates in the fracture, and the higher the leakage rate. Although the curve patterns were similar, the effect of fracture roughness on the drilling fluid leakage rate could not be ignored; thus, it was necessary to supplement the radial model with the effect of fracture roughness.

4.6. Effect of Pressure Difference between the Wellbore and the Formation (Δp) on Leakage. Other parameters were kept constant, and the initial pressure in the fracture was kept constant at 20 MPa. Thereafter, the leakage rate curves were simulated at 30, 35, 40, and 45 MPa in the well. The results are presented in Figure 8.

The simulation results revealed that as the differential pressure at the bottom of the well increased, the drilling fluid leakage rate increased significantly. The drilling fluid leakage rate curve instantly displayed a large peak leakage rate during the initial moment of leakage. The leakage rate that eventually stabilized also varied greatly as the pressure difference increased, and the leakage rate increased. This is because the pressure difference between the wellbore and the formation was the main driving force of the drilling fluid leakage, and the larger the differential pressure at the bottom of the well, the more severe the drilling fluid leakage. Moreover, excessive pressure will increase the fracture opening and fracture extension length, providing a larger leakage channel for the drilling fluid and intensifying the leakage.

4.7. Effect of the Drilling Fluid Intrusion Depth (r) on Leakage. Other parameters were kept constant, and the drilling fluid intrusion depth of the simulated drilling fluid, namely, the leakage rate curves for the drilling fluid intrusion depth, were set to 1, 6, 12, and 24 m. The results are presented in Figure 9.

The simulation results revealed that the drilling fluid leakage rate decreased gradually as the drilling fluid intrusion depth increased. The drilling fluid leakage pattern was significantly noticeable when the drilling fluid intrusion depth was 1 m during the initial leakage moment. The leakage rate and peak value decreased as the leakage time increased, while the radial extension length increased. This is because the fracture was rough, and there was resistance and pressure loss during the drilling fluid flow. Finally, when the drilling fluid intrusion depth reached a certain point, the pressure tended to reach the formation pressure, the differential pressure at the bottom of the well became 0, and the leakage stopped. Figure 10 depicts the leakage in the fracture more visually. As the time and depth of intrusion increased, the pressure gradually decreased until it reached the formation pressure.

5. CONCLUSIONS

A high-accuracy and realistic H–B flow-type drilling fluid model was chosen for this study. First, the fracture was characterized, with the assumption that the fracture opening satisfies the exponential deformation law. Thereafter, the radial model was supplemented with the effect of fracture roughness. A nonstationary radial leakage model was derived from the continuity equation, momentum conservation equation, and N–S equation, and the model was solved by implicit difference. The effects of the fracture geometry parameters, drilling fluid rheological parameters, fracture exponential deformation, and fracture surface roughness on leakage were quantitatively calculated using the absolutely stable backward Euler difference format. The following conclusions were finally made.

1. The larger the β and the larger the fracture opening, the higher the leakage rate. The smaller the fracture tortuosity and the smoother the fracture, the higher the leakage rate. The leakage rate decreases as the drilling fluid consistency factor increases. Drilling fluid dynamic shear force has a minor effect on the leakage rate. The higher the pressure difference between the wellbore and the formation, the higher the leakage rate. As the drilling fluid intrusion depth increases, the leakage rate gradually decreases and eventually becomes zero.

2. The effect of fracture roughness must be included in the radial fractured stratum leakage model because it controls the degree of leakage mainly by controlling the pressure differential and fracture opening parameters.

3. The current simulation of leakage dynamics does not systematically consider the influence of multiple factors,
and most studies focus on 1D and 2D models. In this study, the radial leakage model was improved, and the difference method was chosen to make the simulation results more accurate, which simplified the computational difficulty and increased the stability of the results.

The future direction should be to find an implicit solution method for the complex unsteady leakage control equation when the flow pattern index is not 1. Different influencing factors should be added and the simulation rules should be applied to the field practice according to different strata, and simulation laws should be applied to the field reality to predict leakage using fracture parameters and field data.

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This manuscript was written through the contributions of S.B. and Y.Z. All authors have approved the final version of this manuscript.

**Funding**

This work was supported by Sinopec Key Laboratory of Marine Oil & Gas Reservoir Development Open Fund (no. 33550000-22-FW2099-0004).

**Notes**

The authors declare no competing financial interest.

**ACKNOWLEDGMENTS**

The authors acknowledge the valuable research ideas and writing assistance of Dr. Zhang of Yangtze University.

**NOMENCLATURE**

- $C^\alpha$ the conductivity at an inclination angle of $\alpha$, s/m
- $C_b$ the conductivity of the rock matrix, s/m
- $C_m$ the conductivity of the drilling fluid, s/m
- $C_{LLS}^\alpha$ the conductivity of the shallow lateral at an inclination angle of $\alpha$, s/m
- $C_{LLD}^\alpha$ the conductivity of the deep lateral at an inclination angle of $\alpha$, s/m
- $w$ the fracture mechanical opening, m

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**Figure 10.** Variations in the radial extension length and time of the drilling fluid in the fracture versus leakage pressure.
the fracture hydraulic opening, m
\( w_h \)

the fracture static width, m
\( w_0 \)

the fracture width exponential deformation factor, Pa\(^{-1} \)
\( \beta \)

the formation pore pressure, Pa
\( P_0 \)

the flow pattern index, unfactored
\( n \)

the consistency factor, Pa\(^s\)
\( K \)

the shear rate, s\(^{-1} \)
\( \gamma \)

the dynamic shear force, Pa
\( \tau_z \)

the shear stress, Pa
\( \tau_{rz} \)

the flow rate within the fracture, m/s
\( \dot{v} \)

the surface force component, Pa
\( \tau_0 \)

the pressure gradient, Pa/m
\( \frac{dp}{dr} \)

the mass force acting on a unit volume of fluid, N/kg
\( f \)

the borehole radius, m
\( r_w \)

the radius of the fracture tip, m
\( r_1 \)

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