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Research Article

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Study on Flow Model and Flow Equation of Shale Gas Based on Micro Flow Mechanism

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Abstract: Shale flow has microscale effects, and the flow is more complex. In this paper, the flow model and flow equation which can be used in the analysis of shale gas flow is established，which is based on the single nanotube model and combined with pore throat test results of the shale core by high-pressure mercury injection, and calculated the contributions of seepage, diffusion, transition flow and free molecular flow to shale gas flow. The contributions of seepage and diffusion were over 95%, and seepage and diffusion were the main flow patterns. Then, a coupled flow model and the coupled flow equation of shale gas with seepage and diffusion were established, which proposed a calculation method of shale permeability and diffusion by relationship between flow pressure and shale gas flow rate, and finally shale gas flow experiments were carried out and analyzed. The results show that the shale gas flow model and the flow equation established in this paper can describe shale gas flow very well. The shale gas flow rate is composed of seepage flow rate and diffusion flow rate, and the seepage flow rate is proportional to the pseudo pressure difference and is proportional to the pressure square difference at low pressure. The diffusion flow rate is proportional to the difference in shale gas density and is proportional to the pressure difference at low pressure. With shale gas reservoir pressure drops, the proportion of diffusion flow increases. The research results enrich the understanding of shale gas flow; they also have certain reference significance to the development of shale gas reservoirs.

Key Words: Shale gas, pore throat, seepage, diffusion, flow model, flow equation, permeability, diffusion coefficient

0. Preface

Shale pore throats are very small, mostly nanoscale pore throats[1-2], and gas flowing in nanopore throats is different from that of conventional pore throats[3], which has a microscale effect and includes seepage, diffusion, transitional flow and free molecular flow[4-14]. Researchers have studied shale gas flow by flow experiments and theoretical methods. For example, Xiong Wei et al[15-17] studied shale gas flow by flow experiments, and Yao et al[5-12] studied shale gas flow and given shale gas flow by the Boltzmann method or Knudsen law[4-12]. Although these studies emphasize various forms of flow in shale, in the analysis of shale gas flow, it is assumed that the pore throat radius is the same or a single flow pattern. In particular, reports on how to obtain shale coupled flow parameters by experimental methods are limited, and the shale permeability and diffusion coefficient are obtained from seepage models and diffusion models[15-17], respectively. Without consideration of the coupling process of shale gas flow. In this paper, based on a single nanotube flow model and combined with typical shale pressure mercury test results, the calculated contribution rate of various flow patterns in the shale gas flow rate was determined. The main flow pattern of shale was established, the shale gas flow model was established, the coupled flow equation of shale gas was derived, and the calculation method of permeability and diffusion coefficient was presented, which determined the shale gas coupled flow capability. The research results enrich the understanding of shale gas flow and solved the problem of the calculation of the shale coupled flow parameters. It also has certain reference significance to the development of shale gas reservoirs.

1. Shale gas coupled flow model

Nanopore throats are dominantly developed in shale, gas flow in shale has a microscale effect, and the Knudsen number (Kn) is a characteristic parameter of microscale flow. We defined the ratio of the molecular mean free path to the flow characteristic length:

$$K_n = \frac{\lambda}{d} \qquad (1)$$

Where: d- Pore throat diameter, nm. λ-Molecular mean free path，nm.λ-formulation is given by:

$$\lambda = \frac{\kappa_B T}{\sqrt{2}\pi \delta_m{}^2 P_m} \qquad (2)$$

where: k_B-Boltzmann constant，1.3805×10-23J/K；T- temperature，K；P_m-Average gas pressure，MPa；δm-gas molecular diameter，nm，which，methane molecular free path in Standard state is 40 nm.

Gas flow can be divided into 4 modes by Kn: No slip flow: Kn<0.001, Fluid can be regarded as a continuous medium and flow is no slip flow, the flow can be described by Navier-Stokes (N-S) equation with no slip. It is generally considered this flow as seepage in porous media, which follows Darcy's law, and the flow equation:

$$q_{1m} = A\frac{K}{\mu B_g}\rho_{sc}\frac{\partial P}{\partial x} \qquad (3)$$

Continuous flow of slip: 0.001<Kn<0.1. The flow has a microscale effect, but fluid can also be regarded as a continuous medium. There is a strong slip effect at the boundary, and the flow can be described by the Navier-Stokes (N-S) equation with a boundary effect. This flow is generally considered to be diffused in porous media, which follows Fick’s law, and the flow equation:

$$q_{2m} = AD\frac{\partial C}{\partial x} \qquad (4)$$

Transitional flow: 0.1<Kn<10. The continuous medium assumption is not appropriate, and the flow can be described by the Burnett equation.

Free molecular flow: Kn>10. Researchers have studied the flow by the molecular dynamics method.

Yao et al[5] presented that the flow capacity of pore throats can be described by equivalent permeability and gave an equivalent permeability formulation:

$$K_n = \frac{r^2}{8}\left(1 + \frac{6K_n}{1+K_n}\right) \tag{5}$$

so， the contribution of pore-throat (radius: r_i)in total flowing:

$$f\left(r_i\right) = \frac{\Delta S_i \frac{r_i^2}{8}\left(1+\frac{6K_n}{1+K_n}\right)}{\sum_{j=1}^{n} \Delta S_j \frac{r_j^2}{8}\left(1+\frac{6K_n}{1+K_n}\right)} \times 100 \tag{6}$$

To determine the contribution of the four flow patterns to shale gas flow, 6 shale rocks were selected from the Changning-Weiyuan national demonstration area of shale gas (permeability 0.004~0.02 mD, porosity 1.8~3.3%), and the pore throat radius was tested by high-pressure mercury t. The maximum mercury intake pressure was approximately 400 MPa, and the pore throats with radii larger than 2 nm were identified. Figure 1 shows the cumulative distribution curve of the pore throat radius. Figure 2 shows the cumulative contribution of pore throat flow (from the minimum size of the pore throat). The Knudsen number at a flow pressure of 1 MPa is given in the picture.

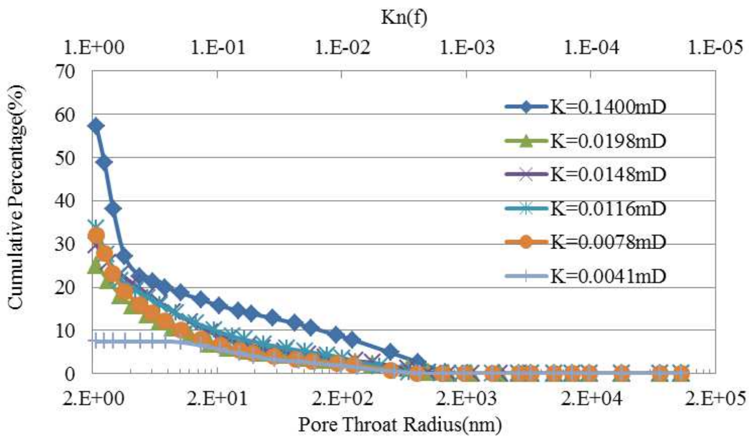


Fig. 1-Cumulative distribution curve of pore throat radius

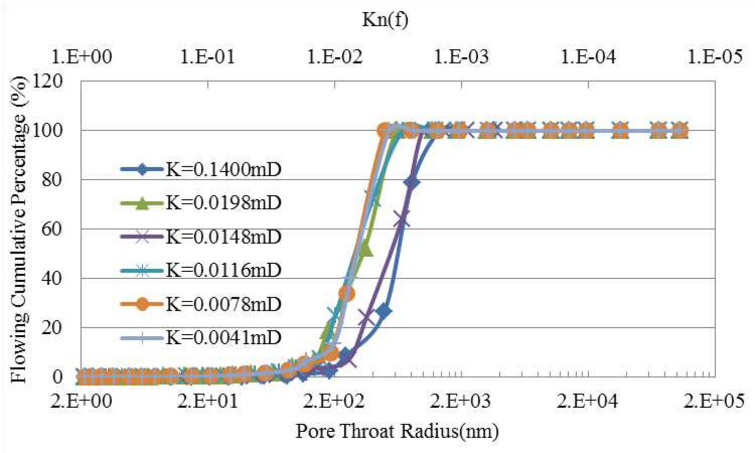


Fig. 2-Cumulative contribution of pore throat flow

Compare Fig. 1 and Fig. 2 shows: Shale pore throat is very small, The pore throat radius over

200 nm (Kn less than 0.01, seepage) accounts for 1.8~7.9%, Average 3.7%, the contribution of flow accounts for 67~93%, Average 83%, a little proportion of pore throat flowing belongs to seepage, but this proportion of pore throat belongs to Dominant channel and account the maximize proportion of shale gas flow, so Seepage is the main flow pattern from the contribution of shale gas flow. Pore throats with radii between 20 and 200 nm (Kn: 20~200 nm, diffusion) account for 3~8%, with an average of 3.7%, and the contribution of flow accounts for 6~22%, with an average of 16.5%. A small proportion of pore throats flowing belong to diffusion, but diffusion is an important flow pattern from the contribution of shale gas flow. Most pore-throat radii less than 20 nm (Kn over 0.1) account for 90%, and most pore-throat flow is transitional flow or free molecular flow. However, the contribution of flow only accounts for 0.5%, and it can be ignored. Therefore, considering that the contributions of flow, seepage and diffusion are the main flow patterns of shale gas, the flow model can be expressed as follows:

$$q_m = A\frac{K}{\mu B_g}\rho_{sc}\frac{\partial P}{\partial x} + AD\frac{\partial C}{\partial x} \quad (7)$$

Where: q_m- shale gas flow rate, mg/s. The first right item in the formula is the seepage flow rate. The second is diffusion flow rate

2. Shale gas flow equation and parameter inversion method

2.1physical model

Shale gas flow is the linear flow of vertical fractures after volume fracturing; shale gas flow can be recognized by studying shale gas linear flow. According to the abovementioned flow mechanism and the results of model research, given these assumptions about shale gas flow:
Flow belongs to linear, isothermal and stable flow, the flow line distance is L, the cross-sectional area is A, the inlet pressure is P_1, and the outlet pressure is P_2, as shown in Fig. 3.
2. Seepage and diffusion are the main flow patterns of shale gas, seepage follows Darcy's law and diffusion follows Fick’s law

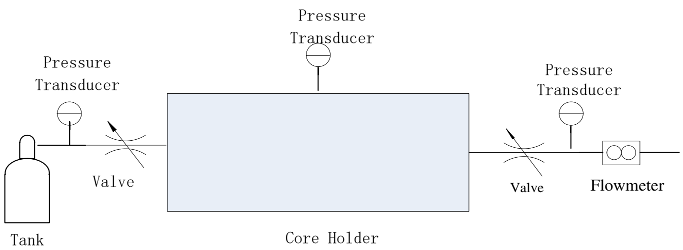


Fig. 3-Sketch map of shale gas flow

2.2 Mathematical model and derivation

Considering the shale gas flow physical model of hypothesis 2.1, the shale gas flow rate q_m can be expressed by Eq. 7, rewritten in the form, introducing the gas state equation:

$$B_g = \frac{ZTP_{sc}}{T_{sc}P} \quad (8)$$

$$C=\phi\frac{PM}{ZRT} \tag{9}$$

Where:P_{sc}- Standard atmospheric pressure,0.101MPa. T_{sc}- Standard temperature,273.15K. T- Formation or flow experiment temperature,K. Z- Gas compressibility factor,f. M- Gas molecular weight,f. R- Gas constant,8.314J/(mol. K), Φ- Shale porosity.f.

8 and Eq. 9 are brought into Eq. 7, and the shale gas mass flow qm can be expressed in the following form:

$$q_m=\frac{AT_{sc}K}{T}\frac{P}{\mu ZP_{sc}}\rho_{sc}\frac{\partial P}{\partial x}+\frac{A\phi DM}{RT}\frac{\partial}{\partial x}\left(\frac{P}{Z}\right) \tag{10}$$

Introducing pseudo pressure function β and density function δ, expressions are as follows:

$$\beta = 2\int_{P_{sc}}^{P}\frac{p}{\mu Z}dp \tag{11}$$

$$\delta = \int_{P_{sc}}^{P}\frac{\phi M}{ZRT}dp \tag{12}$$

Eq.11and Eq.12 are brought into Eq.10， the shale gas flow q_m can also be expressed in the form from the integral of Eq.10:

$$q_m=\frac{A\rho_{sc}T_{sc}K}{2LTP_{sc}}\left(\beta_1-\beta_2\right)+\frac{AD\left(\delta_1-\delta_2\right)}{L} \tag{13}$$

Where: β_1-inlet pseudo pressure,$MPa^2/(mPa.s)$. β_2- inlet pseudo pressure,$MPa^2/(mPa.s)$. δ_1-inlet density, kg/m^3. δ_2-outlet density, kg/m^3. Eq.11 shows that shale flow is made up of seepage flow rate and diffusion flow rate, seepage flow rate is proportional to the pseudo pressure difference between inlet and outlet, diffusion flow rate is proportional to the density difference between inlet and outlet.

In addition, according to the analysis of the gas high pressure physical property, gas viscosity and compressibility factor are almost constant when the pressure is low.for example, methane viscosity(ranged from 0.018 and 0.019 mPa.s)[18]and compressibility factor(ranged from 0.99 and 1.00) are almost constant if pressure is less than 10MPa, the temperature is room temperature, approximately 25 degrees Celsius.so,Eq.11 can be modified further and replaced the expression:

$$q_m=\frac{A\rho_{sc}T_{sc}K}{2\mu ZLTP_{sc}}\left(P_1^2-P_2^2\right)+\frac{\phi ADM\left(P_1-P_2\right)}{ZRTL} \tag{14}$$

The shale gas flow rate under low pressure can also be expressed by Eq. 14, which shows that the seepage flow rate is proportional to the pressure square difference between the inlet and outlet and that the diffusion flow rate is proportional to the pressure difference between the inlet and outlet when shale flows in a low-pressure formation. Shale gas flow patterns can be determined by the relationship between the shale gas flow rate and the pressure difference or pressure square difference between the inlet and outlet. Seepage and diffusion are the main flow patterns when the flow of shale gas is proportional to the pressure square difference and pressure difference, respectively.

If outlet pressure is constant pressure, for example, outlet pressure is usually the standard atmospheric pressure (P_2=0.101 MPa) when shale gas displacement experiments are performed in the laboratory. The relationship between shale gas flow and inlet pressure is a binomial relationship, and permeability K and diffusion coefficient D can be obtained from the binomial fitting between shale gas flow and inlet pressure. Specific expressions are as follows:

$$K=\frac{2\mu ZLTP_{sc}}{A\rho_{sc}T_{sc}}a \tag{15}$$

$$D=\frac{ZRTL}{\phi AM}b \tag{16}$$

where a is the -two term coefficient of binomial and b is the one term coefficient of binomial, as shown in Fig. 4.

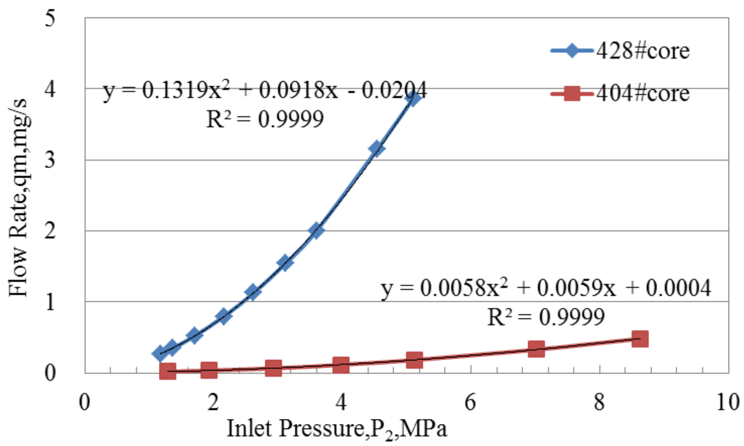


Fig. 4-Shale gas flow characteristic curve

Furthermore, the contribution of seepage or diffusion to shale gas rate can also be obtained from Eq.11 or Eq.12, right-first item is seepage contribution, right-second item is diffusion contribution, Furthermore, it can be determined which flow is the main flow in shale reservoir. Considering only the seepage or Darcy model, Eq. 14 can be simplified to the normal pressure square equation17:

$$q_m=\frac{A\rho_{sc}T_{sc}K}{2\mu ZLTP_{sc}}\left(P_1^2-P_2^2\right) \tag{17}$$

Considering only the diffusion or Fick diffusion model, Eq. 14 can be simplified to the normal gas diffusion equation18:

$$q_m=\frac{\phi ADM\left(P_1-P_2\right)}{ZRTL} \tag{18}$$

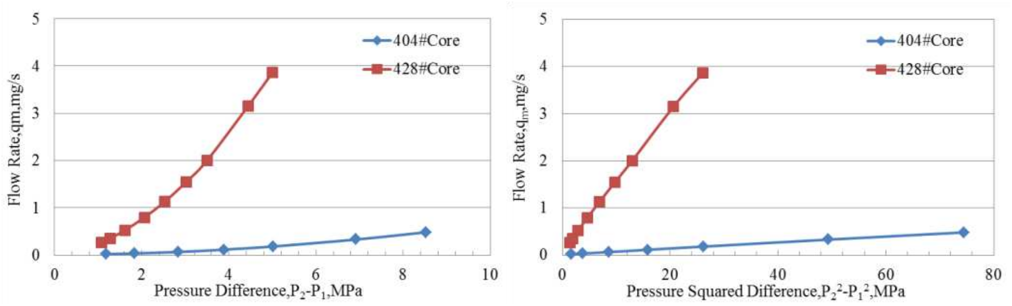
3. Case analysis

Carried on coupled flow experiment with Shale cores at Diameter 2.5 cm, which selected from longmaxi formation of changing-weiyuan gas reservoir, Experimental temperature is 26 degrees Celsius, the outlet pressure is standard atmosphere, Tested Shale gas flow rate under different inlet pressure, Other experimental parameters, experimental results and analysis results are shown in Table 1. Due to inlet pressure lower 10MPa, gas viscosity and compressibility factor are constant, so, shale permeability is calculated according to Eq.15 base on Darcy model. Shale diffusion is calculated according to Eq. 16 based on the Fick diffusion model, and the shale permeability and diffusion coefficient by the fitting method are calculated according to Eq. 12 based on the coupled flow model.

Table 1- Results of experimental analysis for shale coupled flow

Core NO	Length (cm)	Porosity (%)	Inlet pressure (MPa)	flow rate （mL/s）	Conventional model		coupled model	
					permeability (μD)	diffusion coefficient （mm^2/s）	permeability （μD）	diffusion coefficient (mm^2/s)
404	3.21	2.40	1.29	0.0117	1.69	2.7	1.15	1.73
			1.93	0.0253	1.63	3.8		
			2.93	0.0562	1.57	5.5		
			3.98	0.0991	1.50	7.0		
			5.12	0.1575	1.44	8.7		
			7.02	0.2835	1.38	11.3		
			8.63	0.4147	1.33	13.4		
428	2.59	2.60	1.17	0.232	40.9	55.2	27.2	19.0
			1.37	0.301	38.6	60.4		
			1.71	0.451	37.1	71.4		
			2.16	0.684	35.2	84.5		
			2.62	0.968	33.8	97.9		
			3.12	1.327	32.7	111.9		
			3.60	1.722	31.9	125.3		
			4.54	2.706	31.5	155.3		
			5.10	3.316	30.6	169.0		

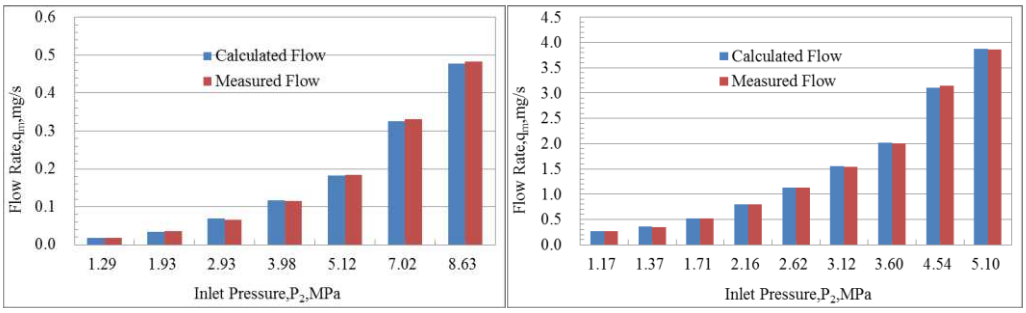
Table 1 suggests that the larger the flow pressure is, the smaller the permeability of shale calculated according to the Darcy model and the larger the diffusion coefficient of shale calculated according to the Fick diffusion model. Furthermore, the variation of gas permeability and diffusion coefficient under different flow pressure is large, especially diffusion coefficient, the test results under different flow pressure differ by 5 times, the permeability variation is also up to 30%，The shale permeability and diffusion coefficient obtained by laboratory experiments cannot be directly applied to the shale reservoir, The conventional flow equation and diffusion equation have some limitations in the prediction of shale gas flow. The relationship between the gas rate and pressure difference (pressure square difference) has a significant deviation from the linear relationship. The former curves fall down, and the latter curve falls upwards (Fig. 5), which shows that there are two kinds of flow patterns in shale: seepage and diffusion. and, these two kinds of flow are obvious.



(a) Pressure squared difference (b) Pressure difference

Fig. 5-Shale gas flow test curve

Fitting the shale gas flow rate and inlet pressure based on the coupled flow equation (i.e., eq. 12), the result is shown in Fig. 4. The fitting accuracy is high, and the correlation coefficient is close to 1, which suggests that the shale gas flow equation derived in this paper is suitable for the analysis of shale gas flow. shale permeability K and diffusion coefficient D are calculated by the fitting of the two terms and the first term coefficient(fig. 4&table 1),then, Calculating gas flow rate by coupled flow equation(i.e.eq.12) and comparing it with measured flow rate(fig. 6),it shows that calculated flow base on coupled equation is in good agreement with measured flow, The maximum relative error is 5percent, the vast majority of the error is less than 3percent(fig. 6).so, In the analysis and prediction of shale gas flow, it is advisable to use the shale coupled flow equation.



(a) core#404 (b) core#428

Fig. 6-Comparison of calculated and measured flow rates

Fig. 7 shows the proportion of the total flow for core diffusion flow based on the coupled flow model. It can be seen that the larger the inlet pressure (flow pressure) is, the greater the proportion. If the inlet pressure is above 10 MPa, the diffusion flow of core 404 accounts for only 10% of the total flow, seepage is the main pattern flow, and shale gas flow can be analyzed and predicted by the pressure square equation. However, with increasing flow pressure, the diffusion contribution also increases; if the flow pressure is lower than 2 MPa, the diffusion contribution is over 50%, and diffusion is the main flow pattern.

Compared with core #428 with core #404, the larger the core permeability is, the smaller the diffusion contribution is, which is due to the higher the permeability and the greater number of large pore throats. According to Knudsen's law, shale gas flowing in large pore throats seeps, so the seepage contribution increases and diffusion contribution decreases with increasing permeability. This view is consistent with the existing view[4,15] and further suggests that our model is correct.

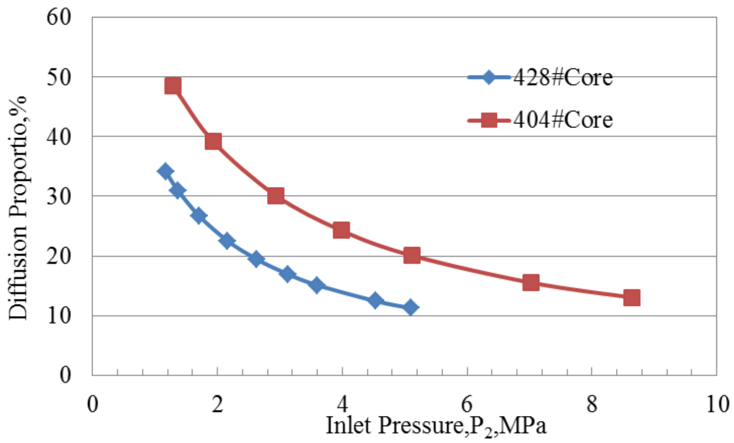


Fig. 7. Diffusion's contribution under different inlet pressure

4. Conclusion

(1) There are four flow patterns (seepage, diffusion, transitional flow and free molecular flow) in shale, but the effects of these four modes on shale gas flow are different, and the difference is great. Therefore, when establishing the model of shale gas flow, the main flow pattern should be determined first;

(2) The shale permeability and shale diffusion coefficient obtained by the conventional flow equation are related to the flow pressure, with large variations. The calculated flow based on the coupled flow equation and test flow match well, so we can analyze shale gas flow by the coupled flow equation, and the permeability and diffusion coefficients obtained from the coupled flow equations are used to characterize the flow capacity of shale reservoirs.

(3) Seepage and diffusion are the main flow patterns in domestically developed shale gas reservoirs; well productivity is determined by the difference in production pressure and the difference in production squared pressure. The influence of the production pressure difference on well productivity increases as the gas reservoir pressure decreases.

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