Optimization of Fracture Parameters For Fractured Horizontal Well Considering Heterogeneity of Shale Reservoir

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ABSTRACT

Controlled by mineral composition, TOC, diagenesis and other factors, there are obvious microscopic and macroscopic heterogeneity in shale gas reservoir. On the basis of the study on the microscopic heterogeneity of shale gas reservoir, apparent permeability is used to describe different migration mechanisms of shale gas including diffusion, slippage and seepage flow. Comprehensively applying multidisciplinary approach, core, logging, seismic and other data are used to establish dual medium model of natural fractures in shale gas reservoir with method of stochastic modeling, which correctly reflects the heterogeneity of shale reservoir. According to extension orientation of artificial fractures for fractured horizontal well, discrete fracture network model is established, which can finely simulate pressure conformance characteristics of asymmetric irregular artificial fractures. Through fine numerical simulation research of fractured horizontal well in heterogeneous shale reservoir, sensitivity analysis and optimization design for fracture parameters are completed, which ensures the fracturing fracture can effectively communicate natural fractures to the greatest degree, and development effect of shale gas reservoir is improved obviously.

KEYWORDS: shale gas reservoir; fractured horizontal well; heterogeneity; geological modeling; numerical simulation; optimization of fracture parameters

INTRODUCTION

Shale is not only the source rock, but also the reservoir rock. There is not obvious source-reservoir-cap rock. Organic matter and inorganic matter coexist in shale[1-2], with complex and diverse pore structure. There are pores and rock particles of nanometer-millimeter scale[3-5], micro-fracture of micrometer scale, macroscopic fracture of centimeter-meter scale in the space of shale gas reservoir developed with fractured horizontal well.

Controlled by mineral composition, TOC, diagenesis and other factors, there are obvious microscopic and macroscopic heterogeneity in shale gas reservoir. Lateral distribution of reservoir, vertical lithology change and plane fracture distribution are main manifestation of macroscopic heterogeneity. Different characteristics of mineral components, micro pores and micro fractures are main manifestation of microscopic heterogeneity. Rich in mature organic matter is a key factor to form nano scale pores. As increase of organic matter content, nano pore volume in shale also increases, particle orientation is getting better[6]. Organic matter content directly control quality of shale gas reservoir and heterogeneity in the nano scale, and affect the characteristics of logging curves[7], which generate great difficulties for heterogeneity evaluation of shale gas reservoir. Scholars carried out a lot of research works for lithology, physical property, organic matter abundance TOC, organic matter maturity Ro, nano scale pore structure and favorable area selection of shale gas reservoir.

In order to accurately characterize and describe microscopic and macroscopic heterogeneity of shale gas reservoir, core observation and test is one of the important methods. Advanced instruments and techniques including small angle X-ray scattering (SAXS), field emission transmission electron microscope (FETEM), high resolution transmission microscope (HRTEM), atomic force microscope (AFM), X-ray nano CT[8-10] are used to research micro pore structure and heterogeneity of shale gas reservoir. Because of high costs of micro-examination, CT scan and restrictions of sample representation and test accuracy, methods of fractal, grey theory[11], digital core and reconstruction of 3D pore network are tried to research heterogeneity of shale gas reservoir.

According to easily obtained cores, logging data of shale reservoir, combining with other disciplines of petrophysics, logging interpretation and fluid mechanics in porous medium, heterogeneity of shale gas reservoir is researched in this paper. The micro heterogeneity is extended to the macro scale, which lays a foundation for the study of seepage mechanism and optimization of fracture parameters for fractured horizontal well in shale gas reservoir.

POROSITY AND PERMEABILITY CALCULATION FOR HETEROGENEOUS SHALE GAS RESERVOIR

The characteristics of shale gas reservoir is super tight, with ultra-low porosity and super-low permeability. Fractured horizontal well can efficiently improve deliverability of shale gas reservoir and it is key technology of developing shale gas successfully[12-13]. The flow of shale gas is a multi-scale process from microscopic nanometer pores to macroscopic large fracture, including mechanisms of desorption, diffusion, slippage, Darcy seepage and non-Darcy seepage[14-15].

Apparent permeability is used to describe different migration mechanisms of shale gas including diffusion, slippage and seepage flow, which transform microscopic flow of shale gas into macroscopic seepage.

Based on the Knudsen number K_n, Florence et al[16] proposed permeability formula suitable for non-Darcy flow of tight gas and shale gas. Through the Knudsen number, continuous flow and slip flow are coupled in the formula.

$$k_a = k_\infty \left(1+\frac{4K_n}{1-bK_n}\right)\left[1+\frac{128}{15\pi^2}\tan^{-1}(4K_n^{0.4})\cdot K_n\right] \tag{1}$$

$$K_n = \lambda / d \tag{2}$$

$$\lambda = \frac{k_B T}{\sqrt{2}\pi\delta^2 P} \tag{3}$$

where, k_a is apparent permeability including continuous flow and slip flow (m^2), k_∞ is absolute permeability of porous medium (m^2), b is slip factor, usually -1, λ is mean free path of the shale gas molecules (m), d is characteristic length of porous medium (m), k_B is the Boltzmann constant (1.3805×10^{-23}J/K), T is temperature (K), δ is diameter of gas molecules (m), P is pressure (Pa).

Javapour et al.[14] also proposed an apparent permeability formula including continuous flow and slip flow, which is

$$k_a = k_\infty[1+\sqrt{\frac{8\pi RT}{M}}\frac{\mu}{P_{avg}r}(\frac{2}{\alpha}-1)] \tag{4}$$

where, R is gas constant (8.314J/mol/K), M is molar mass (Kg/mol), μ is gas viscosity (Pa.s), p_{avg} is average pressure (Pa), r is pore radius (m), α is tangential momentum accommodation coefficient, fraction.

When mean free path of the gas is close to pore diameter, Knudsen diffusion must be considered, which can be shown in the form of apparent permeability.

$$k_d = \frac{2r\mu M}{3RT\rho_{avg}}\sqrt{\frac{8RT}{\pi M}} \tag{5}$$

where, k_d is apparent permeability of Knudsen diffusion (m^2), ρ_{avg} is average gas density (Kg/m^3).

Comprehensively considering continuous flow, slip flow and Knudsen diffusion, total apparent permeability k_{app} can be expressed as

$$k_{app} = k_a + k_d \tag{6}$$

Florence model:

$$k_{app}/k_\infty = (1+\frac{4K_n}{1-bK_n})[1+\frac{128}{15\pi^2}\tan^{-1}(4K_n^{0.4})\cdot K_n]+\frac{16\mu M}{3RT\rho_{avg}r}\sqrt{\frac{8RT}{\pi M}} \tag{7}$$

Javapour model:

$$k_{app}/k_\infty = 1+\sqrt{\frac{8RT}{\pi M}}\left[\frac{\pi}{P_{avg}}(\frac{2}{\alpha}-1)]+\frac{16M}{3RT\rho_{avg}}\right]\cdot\frac{\mu}{r} \tag{8}$$

Figure 1 presents the ratio of k_{app}/k_∞ with different average pore radius r. The ratio of k_{app}/k_∞ is higher in smaller pores. When pore size is smaller than 10 nm, the difference between apparent permeability and Darcy permeability is very big, which can explain the unusual gas production rate in shale gas reservoir. Along increase of tangential momentum accommodation coefficient α, which is usually fitted through experiments, result of Javapour model is gradually close to Florence model.

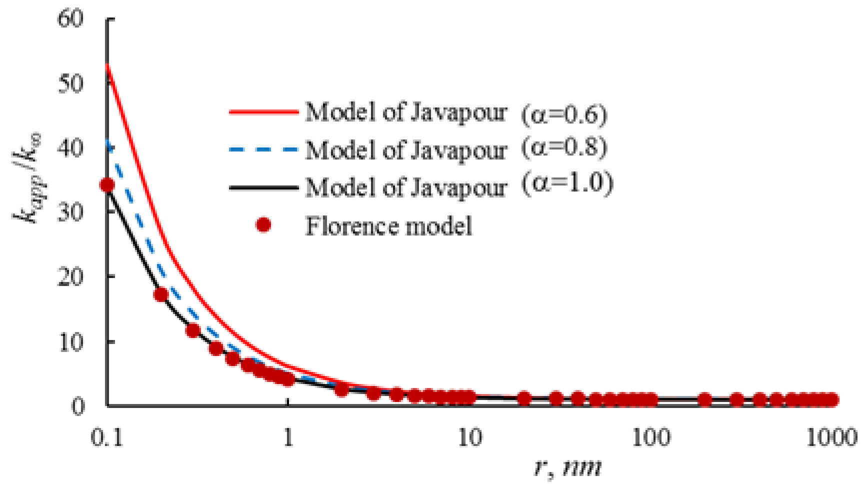

Figure 1: The relationship between k_{app}/k_∞ and radius r

ESTABLISHMENT OF HETEROGENEOUS GEOLOGICAL MODEL FOR SHALE RESERVOIR

Shale reservoir commonly has logging response characteristics of low density, high acoustictime (AC), high resistivity. Core porosity and permeability test results can be used to calibrate logging response in enriched shale gas layer. According to fracture interpretation results from core and logging data, fracture cumulative curve, fracture density curve and fracture property parameter are generated, which lays a foundation for inter well property prediction. Comprehensively considering issues including seismic attribute, sedimentary type, formation curvature, external stress distribution, and other geological experiences, through application of multidisciplinary approach, stochastic modeling method is used to establish heterogeneous geological model of shale reservoir.

For developed natural fractures, based on full tensor simulation method of fluid, considering all possible geometries of the flow system, constrainting every specific grid and simulating gas flow under pressure gradient, then permeability in each direction can be calculated. Through the coarsening of fine fracture model, continuous medium model for numerical simulation can be generated. For artificial fractures in large scale, discrete fracture network model is used to detailedly describe fracture geometric shape, position, length, orientation and seepage behavior, which can accurately reflect the characteristics of fractures and reservoir heterogeneity, reappear distribution of fractures, approximate to actual condition of fractured horizontal well in shale gas reservoir.

According to seismic, core analysis and logging interpretation data, natural fracture distribution model of a shale gas reservoir is established (Figure 2). Based on stochastic modeling technology, permeability model of natural fracture is established (Figure 3). There is a good correlation between the distribution of natural fractures and permeability distribution (Figure 4), which indicates that the model correctly reflects heterogeneity of shale reservoir.

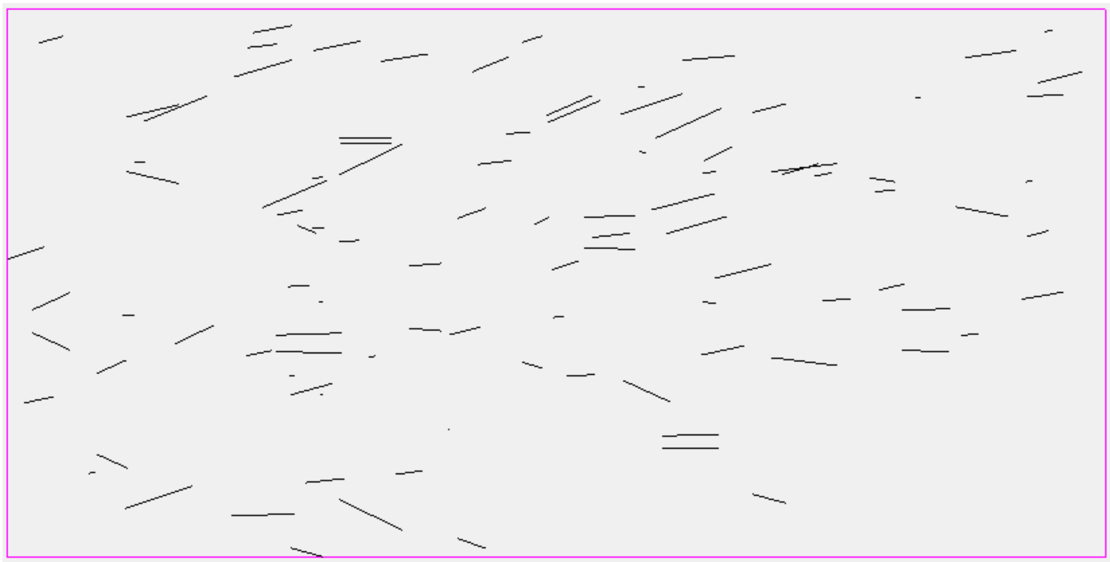

Figure 2: Natural fracture distribution model

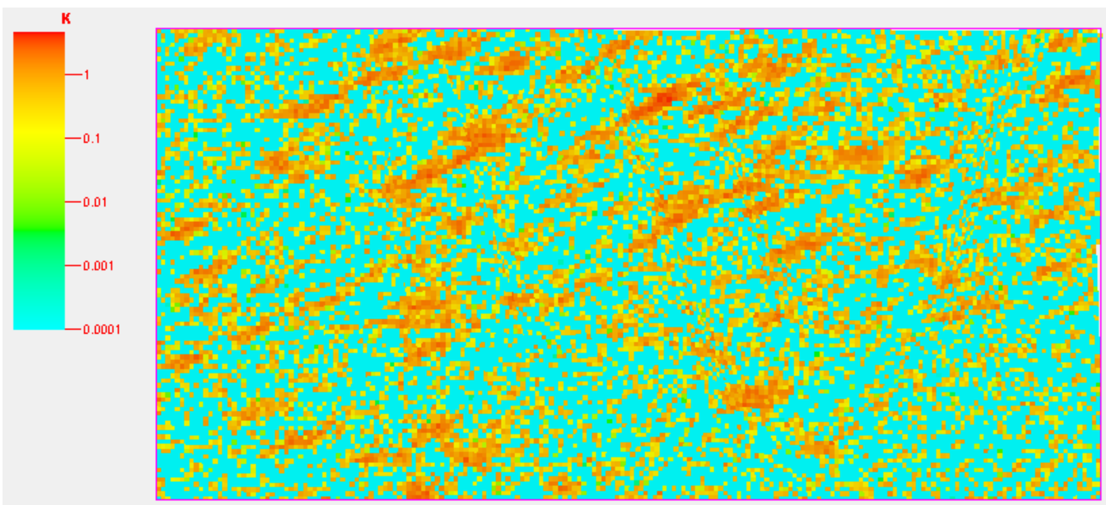

Figure 3: Natural fracture permeability model

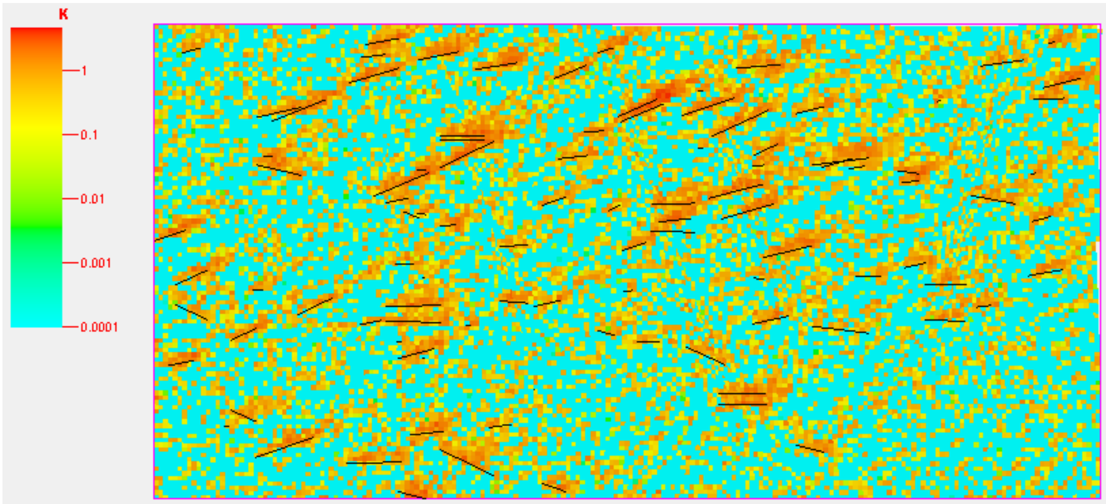

Figure 4: Correlation between natural fracture distribution and permeabilty distribution

NUMERICAL SIMULATION AND FRACTURE PARAMETER OPTIMIZATION FOR FRACTURED HORIZONTAL WELL IN SHALE GAS RESERVOIR

Permeability of shale reservoir is very low and flow resistance is too big, fractured horizontal well greatly improve productivity of shale gas well, which is a key technology for successfully developing shale gas reservoir[17-19]. Because of heterogeneity of shale reservoir, difference of rock stress and the restriction of fracturing technology, fractures with different length, width, angle, and conductivity will be generated in the formation. In order to improve development effect of shale gas reservoir, it is need to optimize fracture parameters in fractured horizontal well by combining geological characteristics and fracture development condition in shale gas reservoir.

As shown in Figure 5, six stage fracturing was carried out in horizontal well according to orientation of natural fractures. Because natural and artificial fractures are not distributed symmetrically and regularly, pressure conformance is non-uniform in the process of shale gas development. Pressure can effectively sweep the area around the fractured fractures and effectively communicated natural fractures. As increase of production time, pressure sweep area gradually spread (Figure 6 ~ Figure 8), but basic shape of pressure drop area remains unchanged.

Fracture parameters are important factors affecting productivity of fractured horizontal well. Because of mutual interference and influence of fractures, numeirical simulation method is uesd to optimize and design fracture parameters of fractured horizontal well. As shown in Fig.5, Size of simulation area is 1600m×800m×80m, top depth 2500m, pressure at the middle of gas reservoir 30MPa，OGIP(original gas in place)$11.88\times10^8 m^3$， among which OGIP of adsorbed gas and free gas are $6.45\times10^8 m^3$, $5.43\times10^8 m^3$ respectively， with proportion of 54.3%, 45.7% to total OGIP.

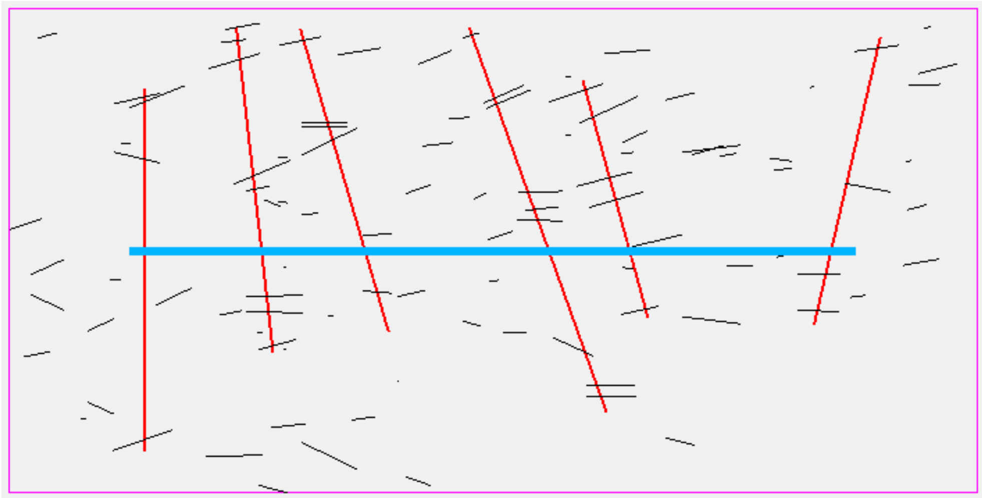

Figure 5: Fracture parameters design for fractured horizontal well in shale gas reservoir

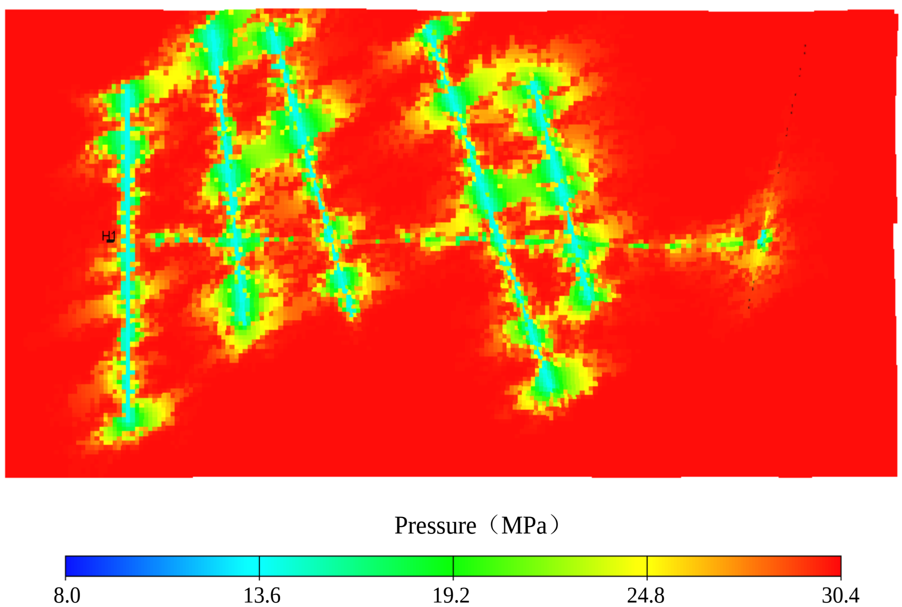

Figure 6: Pressure distribution of fractured horizontal well in shale gas reservoir (2 years later)

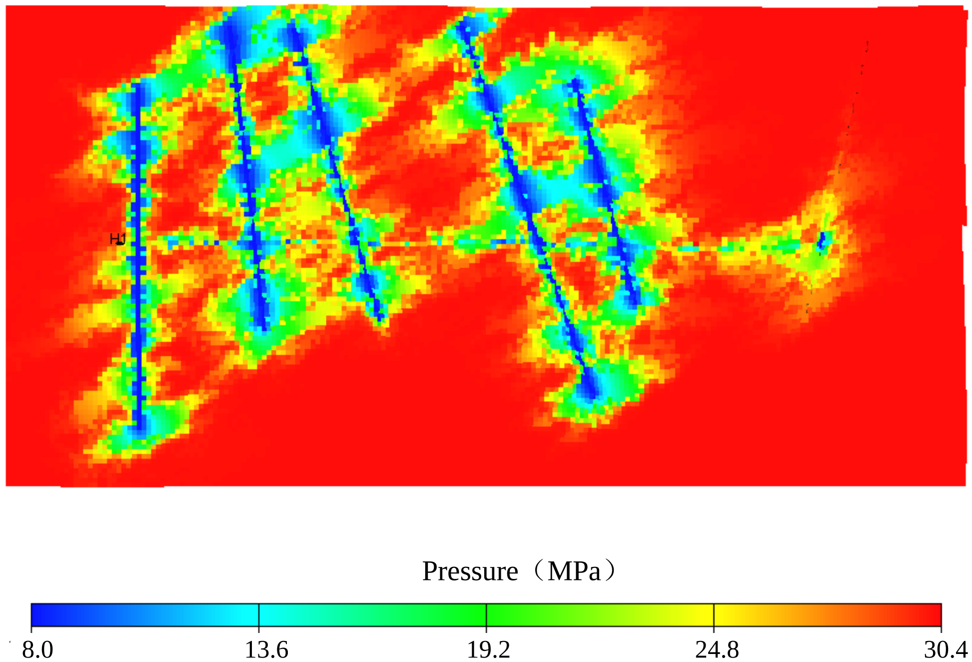

Figure 7: Pressure distribution of fractured horizontal well in shale gas reservoir (5 years later)

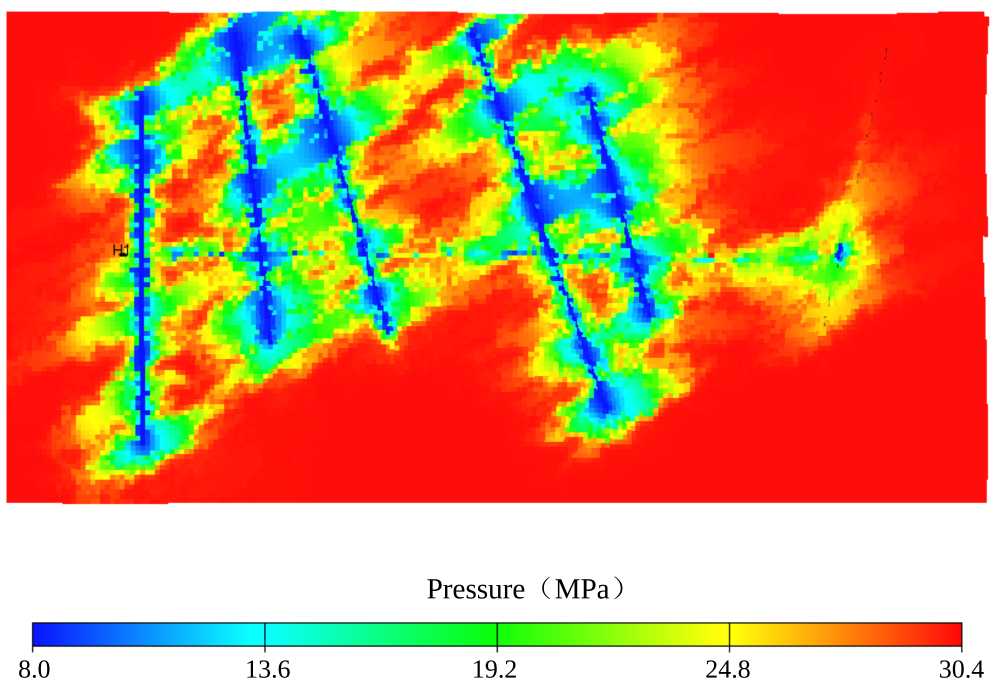

Figure 8: Pressure distribution of fractured horizontal well in shale gas reservoir (10 years later)

Setting total length of fractured fracture is 1500m, 2100m, 2700m, 3220m separately, predicted cumulative gas production rate after 30 years is shown in Table 1 and Figure 9. Along with increase of fracture length, cumulative shale gas production rate also increases with linear amplitude. This is mainly because longer fracture length communicates more natural fractures and increases production rate of shale gas.

Making orientation of fractured fractures in Figure 5 as reference, rotating the fractures 15°, 30° and 45° to the right separately, predicted cumulative shale gas production rate after 30 years is shown in Table 2 and Figure 10. Along with increase of rotation degrees, the number of natural fractures effectively communicated by fractured fracture decreases, cumulative shale gas production rate declines.

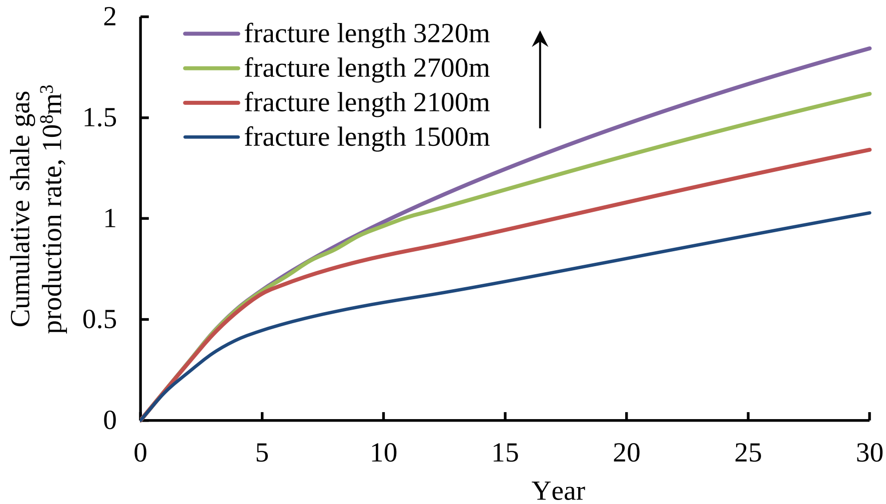

Figure 9: Influences of fracture total length on cumulative shale gas production rate

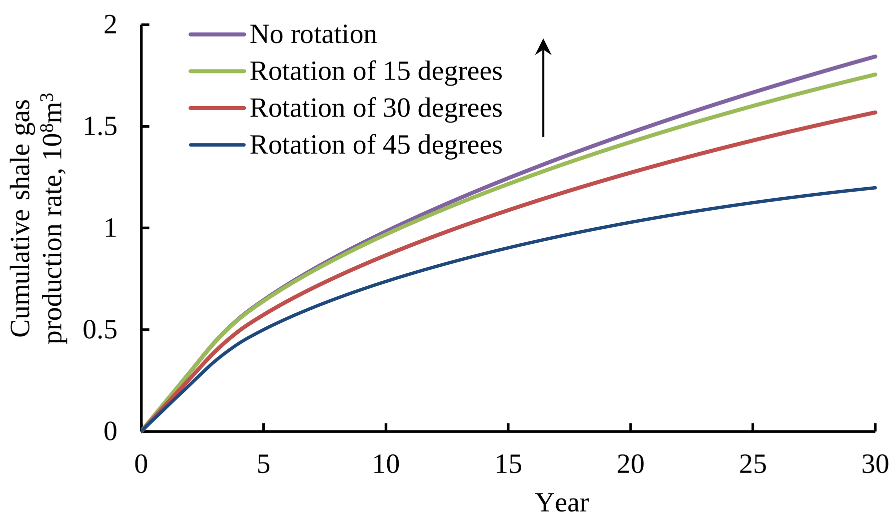

Figure 10: Influences of fracture orientation on cumulative shale gas production rate

Table 1: Cumulative shale gas production rate under different fracture total length

fracture total length /m	cumulative shale gas production rate /$10^8 m^3$
1500	1.028
2100	1.341
2700	1.618
3220	1.843

Table 2: Cumulative shale gas production rate under different fracture orientation

rotation degrees of fracture/°	cumulative shale gas production rate /$10^8 m^3$
0	1.843
15	1.755
30	1.569
45	1.198

CONCLUSIONS

(1) Micro and nano pore types in shale reservoir are various, where organic pore, inorganic pore and natural fracture are developed with obvious heterogeneity. On the basis of the study on the microscopic heterogeneity of shale gas reservoir, apparent permeability is used to describe different migration mechanisms of shale gas including diffusion, slippage and seepage flow, which transform microscopic flow of shale gas into macroscopic seepage.

(2) Core porosity and permeability test results are used to calibrate logging response characteristics of shale reservoir. Comprehensively analyzing core, logging, seismic data, natural fractures of shale reservoir are recognized. Through application of multidisciplinary approach, dual medium heterogeneous model for natural fractures of shale gas reservoir is established with method of stochastic modeling. For large-scale artificial fractures of fractured horizontal well, discrete fracture network model is established according to extension orientation of fractures.

(3) Asymmetric irregular artificial fractures are easily generated in fractured horizontal well of shale gas reservoir. Pressure can effectively sweep the area around the fractured fractures and effectively communicated natural fractures. According to orientation of natural fractures, fine numerical simulation method is used to research the influences of fracture parameters on development effect of fractured horizontal well in shale gas reservoir, which lays a foundation for optimal design of fracture parameters.

ACKNOWLEDGEMENTS

The research is supported by the National Natural Science Foundation of China (51574052,51374269), Chongqing Basic Science and Advanced Technology Research Project (cstc2016jcyjA0607), Science and Technology Research Project of Chongqing Municipal Education Committee (KJ1601319, KJ1601313, KJ1601333), University Innovation Team Project of Chongqing Municipal (CXTDX201601033).

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Editor's note.
This paper may be referred to, in other articles, as:

Yingzhong Yuan, Wende Yan, Qianhua Xiao, Zhilin Qi, and Xiaoliang Huang: "Optimization of Fracture Parameters For Fractured Horizontal Well Considering Heterogeneity of Shale Reservoir" Electronic Journal of Geotechnical Engineering, 2017 (22.01), pp 375-386. Available at ejge.com.