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A Reasonable Approach for the Development of Shale Gas Wells with Consideration of the Stress Sensitivity

Jin Pang[1, *], Di Luo[2], Haohong Gao[3], Jie Liang[4], Yuanyuan Huang[1] and Qi Liu[3]

Abstract: High-pressure deep shale gas reservoirs are usually highly stress-sensitive. When the reasonable production mode of shale gas well is built, the impact of strong stress sensitivity should be fully considered. First, this study calculated the relationship between permeability and formation pressure under different elastic modulus based on the shale lithology of Long Ma Xi formation in Sichuan Basin by testing and analysing the mechanical parameters of the rock. According to numerical simulation result, when the elastic modulus exceeds 14.0 GPa, the stress sensitivity of the matrix will slight affect the cumulative gas production of shale gas. Second, the changing relation between fracture conductivity and permeability with fracture pressure and the time of pressure acts were experimentally studied. The numerical simulation result suggested that the 30-year cumulative gas production considering the stress sensitivity was reduced by 13.5% compared with the 30-year cumulative gas production without considering the stress sensitivity. Finally, the production of different production modes under different stress sensitive characteristics was predicted using numerical simulation method. When the matrix and fractures are fixed with a same stress-sensitive curve, the initial production allocation will not significantly impact the cumulative gas production. When the fractured fractures are subjected to a varying stress sensitive curve, the lower production allocation will result in higher post-production and cumulative gas production.

Keywords: Shale, stress sensitivity, production mode, production allocation, fractures, matrix.

1 Introduction

The stress-sensitive phenomenon refers to the variations of rock and oil reservoirs' permeability and other physical properties with the effective stress. Usually, the external stress (external pressure) of oil and gas reservoir is a constant. When the fluid is extracted from the pores of the reservoir, the pore pressure (internal stress) will decrease from the original formation pressure to the current formation pressure, rock will be compressed, and the relevant physical parameters of the rock will be also changed.

The stress-sensitive study of gas well productivity was first conducted in sandstone and

[1] Chongqing University of Science and Technology, Chongqing, China.

[2] Shunan Gas Production Plant, PetroChina Southwest Oil & Gasfield Company, Luzhou, China.

[3] Southwest Gas Production Plant, PetroChina Zhejiang Oilfield Branch, Yibin, China.

[4] Linpan Drilling Branch, Sinopec Southwest Petroleum Engineering Co., Ltd., Linpan, China.

[*] Corresponding Author: Jin Pang. Email: crab1981@126.com.

carbonate reservoirs, in 1975, Jones et al. [Jones and Frank (1975)] concluded the relationship between permeability and pressure for the first time in the study of core samples in carbonate reservoirs, in which natural fractures were contained. In 2000, Jr [Jr (2000)] analyzed the production characteristics of fractured wells using the productivity model, in which the characteristics of formation and hydraulic fractures of fractured wells varied with the stress. In 2007, based on experimental data, [Friedel, Mtchedlishvili, Behr et al. (2007)] reported that the magnitude of hydraulic fracture permeability was dependent on reservoir pressure.

In 2009, Cipolla et al. [Cipolla, Lolon and Mayerhofer (2009)] used the numerical simulation method to simulate the well dynamic with propped fractures that were stress-sensitive in shale gas reservoir effectively, whereas the reliable stress-sensitive experimental data for propped fractures was lacked. In 2013, Sone et al. [Sone and Zoback (2013)] used Barnett shale samples and considered the simulated conditions with running water and the proppant. The fracture conductivity was tested by varying the effective stress, stress action time, temperature, proppant size, etc. In 2014, Zhang et al. [Zhang, Kamenov, Hill et al. (2014)] also performed an experiment to study the relationship between supported fracture permeability and pressure, as the results suggested that the fracture conductivity could be reduced several or even hundreds of times. In 2013, Cho et al. [Cho, Ozkan and Apaydin (2013)] tested the shale permeability on Barnett and Haynesville. They reported that: the closure of natural fractures led to a reduction in fracture permeability by more than 80%. Subsequently, Mckernan et al. [Mckernan, Rutter, Mecklenburgh et al. (2014); Guindon L.M. (2014); Zhang, Kamenov, Hill et al. (2014)] all performed long-term fracture conductivity tests of the fracture stress-sensitive on major shale in North America. The varying relation between the conductivity and permeability of fractures with the effective stress and the time of effective stress acted was studied. Wasaki et al. [Wasaki and Akkutlu (2015)] also studied the effects of proppant embedding fractures on gas well productivity by numerical simulation.

Most of the noted studies focused on the test of shale fracture conductivity and permeability caused by stress-sensitive, and the stress-sensitive features of shale matrix rock were ignored. The in-depth study has not been conducted on the impact of fracture stress sensitivity on the production capacity of shale gas wells, even there was no study of the reasonable production mode in stress-sensitive shale gas wells. Accordingly, this study will base on the Long Ma Xi stratigraphic shale in the south of Sichuan Basin, the main lithology of the shale is gray black-black silty shale and carbonaceous shale, and the thickness of the stratum is 100-130 m, the burial depth is over 3800 m, the formation pressure is 60 MPa, respectively. The stress-sensitive matrix and stress-sensitive fracture are considered, and the reasonable production mode of shale gas well is discussed based on the study of their stress sensitive characteristics.

2 Research methods

The research process of the present study is as follows. First, using drilling core technology, the required experimental samples from the different exploratory wells of the Long Ma Xi Formation shale are to be obtained; then the core samples are cut and processed, a circular core column with a diameter of 25×100 mm and a rectangular rock slab of 38×200×5 mm are to be prepared, respectively, the former core column will be used for the experiment of shale matrix stress sensitivity, and the latter rectangular rock slab will be used for the experiment of shale fractures stress sensitivity. Second, placing the circular core column with a diameter of 25×100 mm in a high temperature and high pressure permeability tester, from 0 to 50 MPa, per interval 5 MPa, different overlying pressures are to be applied on the core wall successively, the experimental data will be fitted to the regression using the permeability stress sensitivity equation of Seidle et al. [Seidle, Jeansonne and Erickson (1992)], the permeability sensitivity equation of the measured matrix core is obtained. Third: placing the 2 rock plates in parallel, different types of proppant are laid in the middle of the rock plates according to the sanding concentration of 5 Kg/m^2, the parallel shale rock plates are placed in a high temperature and high pressure fracture conductivity tester, and fracture conductivity under different overlying pressures will be tested and divided by width to calculate fracture permeability, the data are also fitted to the regression using the permeability stress sensitivity equation of Seidle et al. [Seidle, Jeansonne and Erickson (1992)], the measured core fracture permeability sensitivity equation is obtained. Fourth: the stress sensitivity equations of shale matrix and fracture will be introduced to the numerical simulation of shale gas single well, the effect of matrix and fracturing stress sensitivity on shale gas productivity is studied and compared to optimize the reasonable production mode.

3 Matrix stress sensitivity

In the formation containing natural fractures, reservoir permeability will vary with the stress or pore pressure. When the reservoir produces considerable amount of gas and leads to the pressure depletion, effective stress will gradually increase, thereby resulting in the closure of the fracture gradually, and then the reservoir permeability reduces gradually. However, in the shale reservoir, the pressure drop will also lead to desorption of methane, which is accompanied by a contraction of the matrix. Accordingly, the fractures are opened, and the permeability of the shale layer increases. These 2 reservoir effects will result in attenuation or increase in reservoir permeability.

Seidle et al. [Seidle, Jeansonne and Erickson (1992)] measured the amount of porosity change under stress-sensitive conditions by core experiments. Besides, the permeability stress -sensitive equation was derived.

$$\frac{K}{K_0} = \exp\left[3c_{fu}\left(P - P_0\right)\right] \tag{1}$$

In this equation: c_{fu} …… Pore volume compression ratio, MPa^{-1};

K …… Reservoir permeability, $10^{-3}\mu m^2$;

K_0 ... Reservoir permeability under initial pressure, $10^{-3}\mu m^2$;

P ...… Reservoir pressure, MPa;

P_0 … Reservoir initial pressure, MPa.

Under reservoir conditions, the pore volume compression coefficient c_{fu} is a variable, the pore volume compression coefficient is a composite function of constrained axial modulus, initial porosity, desorption characteristic parameter and pressure. Thus, the pore volume compression coefficient usually serves as a non-constant parameter. However, the particle matrix compression factor and matrix shrinkage are negligible, then:

$$c_{fu} = \frac{1}{\phi}\frac{d\phi}{dP} = \frac{1}{\phi M} \tag{2}$$

In this equation: M …… Constraint axial modulus, MPa;

Φ …… Porosity, dimensionless.

When the change in porosity is less than 30%, the pore volume compression factor is described by the following expression of basic reservoir parameters:

$$c_{fu} = \frac{1}{\phi M} = \frac{(1+\nu)(1-2\nu)}{(1-\nu)\phi_0 E} \tag{3}$$

In this equation: E …… Elastic Modulus, MPa;

N …… Poisson ratio, dimensionless;

φ_0 …... Reservoir porosity under initial pressure, dimensionless.

Using the mentioned method, the stress sensitive characteristics of shale permeability were calculated and analyzed, and the sample originated from a shale gas block in the Sichuan Basin. The value of elastic modulus is shown in Fig. 1. Since the reservoir rock Poisson's ratio is around 0.2, the elastic modulus ranges from 13~16 GPa, suggesting that the shale reservoir exhibits poor stress sensitivity.

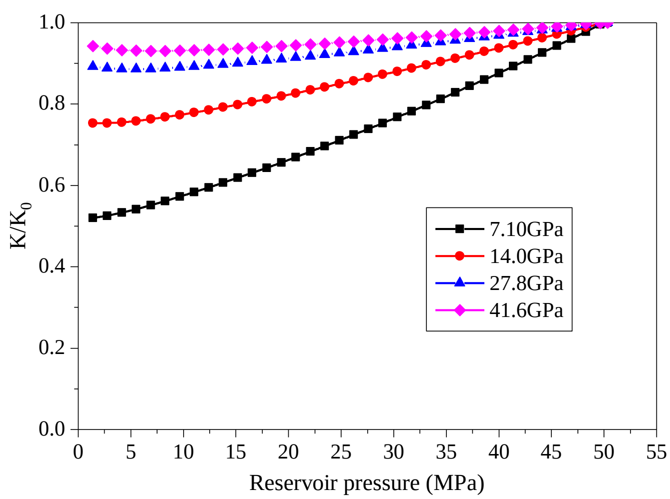

Figure 1: Comparison chart of permeability change under different elastic modulus

The range of Poisson's ratio of measured shale is small, and the range of elastic modulus is relatively large. Thus, when comparing the calculation of numerical simulation, given the variation of the cumulative production of Poisson ratio ν=0.2, elastic modulus E=7.1 GPa, 14.0 GPa, 27.8 GPa and 41.6 GPa, respectively, as shown in Fig. 2, the elastic modulus is higher, and the cumulative production is higher. This reveals the rock is harder, and the stress sensitivity is less sensitive. When E is greater than 14.0 GPa, the effect on the cumulative production is becoming increasingly small, and the cumulative production at E=41.6 GPa is only 7.8% higher than that at E=14.0 GPa.

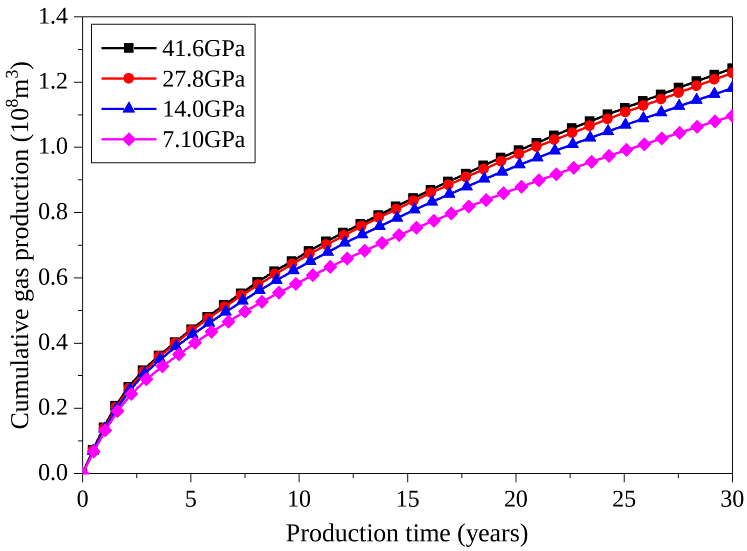

Figure 2: Comparison chart of cumulative production under different elastic modulus

4 Stress sensitivity of fracturing fracture

The stress sensitivity of the matrix will lead to a decrease in reservoir permeability, and the increased effective stress will also affect the fracture properties. With the increase in the effective stress, the flow conductivity of the main fracture will gradually decrease. Likewise, the stress sensitivity of the fracturing fracture can be interpreted that the fracture will gradually close during the pressure depletion due to the increase in the effective stress around the well.

By using shale rock samples from Long Ma Xi formation in Sichuan Basin, the relationship between the conductivity ability and the effective stress of different proppants is quantitatively studied. The experimental curves for short-term fracture conductivity and permeability changes of the shale are shown in Fig. 3.

According to the effective stress Equation:

$$\bar{\sigma}=\sigma-\alpha p_p \tag{4}$$

In this Equation: $\bar{\sigma}$ …… Effective stress, MPa;

Σ …… Formation in-situ stress, MPa;

P_p ...… Pore fluid pressure, MPa;

A …… Biot coefficient.

Due to the fracturing sand and rock properties are very different, and the former can be considered the very loose porous media. Thus, the value of α can be approximated by 1.

Here, the increase in the closing pressure in the experiment, which is equivalent to the reduction of the internal pressure in the fracture. Based on the experimental data, the decrease in fracture conductivity and permeability is between 8% and 20% for each 10 MPa of closed pressure increase, which is considered a moderate stress sensitive feature, as shown in Fig. 3.

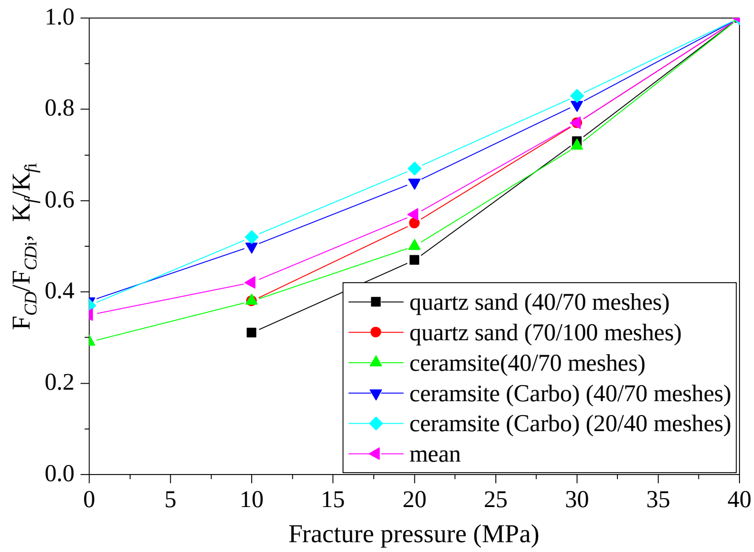

Figure 3: Permeability and conductivity variation chart of fracture under different proppants

According to the stress-sensitive characteristics of different proppants, based on the same geological model, the numerical simulation method is employed to compare the research, as shown in Fig. 4. Since the stress sensitive features of several types of proppants that are currently used in the field are similar, numerical simulation results show that when using different proppant stress sensitive curves, the cumulative production difference is small, the 30-year cumulative gas production with considering the stress sensitivity, compared with the 30-year cumulative gas production without considering the stress sensitivity, which is reduced by 13.5%.

After the deposition and compaction, the physical properties of deep underground rock are relatively stable in the case of certain physical properties of the rock. Its relationship between deformation and effective stress is fixed one by one, i.e., regardless of the way the formation pressure drops, the variation in permeability at the same pressure drop is the same, and the stress-sensitive is only one curve (the reservoir rock is looked as a unified whole).

However, fracturing fractures and formation are very different, because the artificial fractures are not a stable state, and primarily showed in the following 2 aspects.

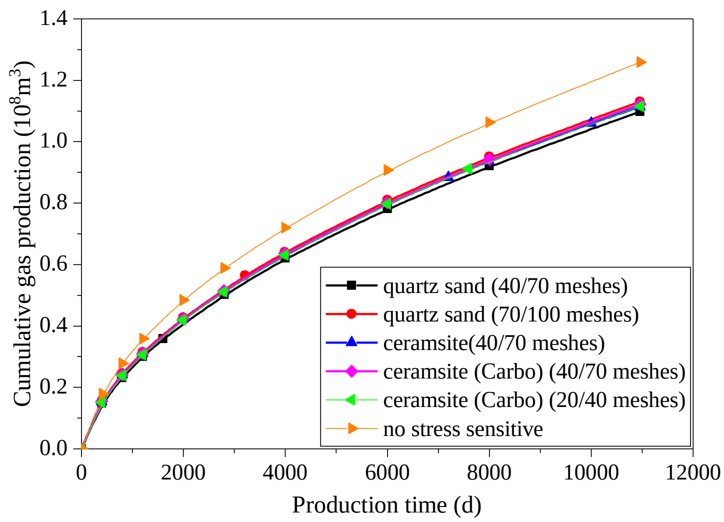

Figure 4: Comparison chart of cumulative gas production under different proppants

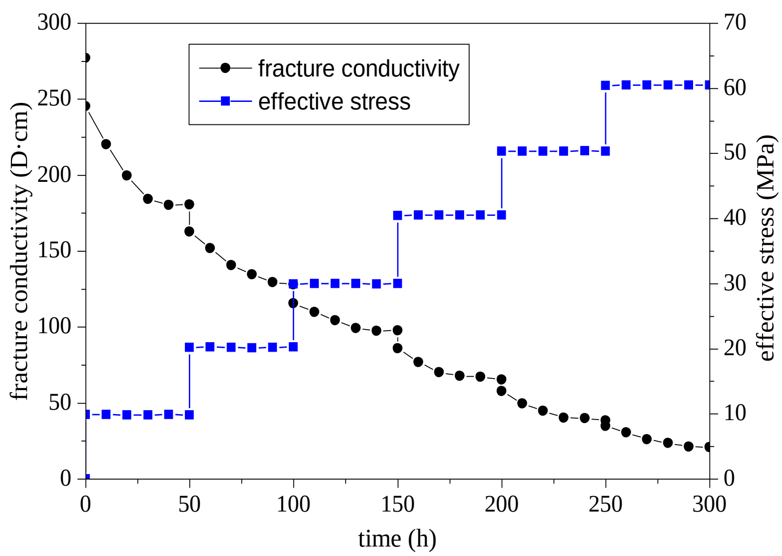

Figure 5: The change curve of long-term fracture conductivity with closed pressure and time

On the one hand, the conductivity of proppant in artificial fractures varies with the effect of pressure and pressure acted time. As shown in Fig. 5, the short-term conductivity of the proppant is also a curve that decline with the pressure of the formation decreases. But unlike stratigraphic rock, the fracturing sand in the fracture is not diagenetic, the structure of the filling space is very unstable, as the closing pressure increases, the embedding and fragmentation of the proppant in the rock has a great effect on the conductivity of the proppant, this structural deformation is the main cause which leads to fracture stress sensitivity. Especially in low elastic modulus and high Poisson ratio reservoir, compaction embedding may be more serious. In the meantime, according to the long-term conductivity experiment (Fig. 5), fracturing sand conductivity and closing pressure is not a one-to-one corresponding relationship, but with the pressure action time increases, fracture conductivity continues to decrease at the same closing pressure. On the condition of high closed and low closed stress, the trend of change in conductivity is not the same. This indicates that there is a different stress-sensitive curve under different pressure drop production.

On the other hand: the high velocity of gas may cause fracturing sand migration. A large number of studies have shown that, if the gas production of well is relatively large after fracturing, the impact of the high speed airflow will cause fracturing sand migration in the fracture, and flow back to the bottom of the well, which making the fractures lost support and close, and lose the high conductivity, even the sand, which is flowing with the air from the bottom to the ground, it will also pierce the equipment. This migration of fracturing sand causes the fracturing structure to be more unstable. Therefore, if the gas well production is relatively large, will result in sand production; under different production conditions, the change trend of fracture permeability is not the same, in this case, it also indicates that there are many permeability stress sensitivity curves in the fracture.

5 Prediction of production allocation under different stress sensitivity

Because there are so many influencing factors, and the mechanism is complex, whether the stress sensitivity affects the production of gas well, and reduces the recoverable reserves of gas reservoirs, in actual production, we should conduct field trials to determine whether it has happened or not. If it is certain that the situation is real, and the effect cannot be ignored, then we should carry out targeted work. We try to explore the reasonable production mode of gas well with considering the stress sensitivity.

5.1 Simulation of fixed stress sensitivity curve

In the first part analysis, it is believed that the stress sensitivity curve of the reservoir should be only one curve, from the results of short-term conductivity test of fracturing fractures, and shows the characteristic of a curve, however, from the results of long-term conductivity test of fracturing fractures, there is not only one stress sensitivity curve. The simulation for both cases has been done. If the stress sensitivity curve of the reservoir and the stress sensitivity curve of the fractures are fixed with one curve, its connotation expresses the permeability decrease with the formation pressure, according to a fixed function.

It can be found after analysis that if the formation and fractures are using a fixed permeability decline curve, permeability decreases by the same value, the average formation pressure also decreases the same value, while the average formation pressure reduction is equivalent, i.e., the amount of gas produced should also be equivalent.

In the case of stratigraphic and fracturing fractures using a fixed permeability sensitivity equation (using the average curve between formation permeability sensitivity curve and 5 types of fracturing sand short-term conductivity curve), the simulation is conducted. Fig. 6 compares the changes in production and cumulative production at different initial production allocation (initial production are 0.4, 0.6, 0.8, 1 times of the Q_{AOF}, respectively), the same permeability reduction equation is taken use of when we carry out the simulation, as shown in Fig. 6, the production of the gas well, regardless of the production mode, has little impact on the 30-year cumulative production. Only when we produce at a very low production ($0.2Q_{AOF}$), can it result in a significant reduction in cumulative production. Though we cannot conclude that the limited production can improve the cumulative production of gas wells, if we consider the production of gas well last a long stable time, still can choose to produce at a lower production in the early production stage, thereby ensuring stable supply for the downstream gas. When the gas well is taken $0.4\sim0.6Q_{AOF}$ as the initial production, it can stably produce for a long time, and 30-year cumulative production is almost equivalent, as listed in Tab. 1.

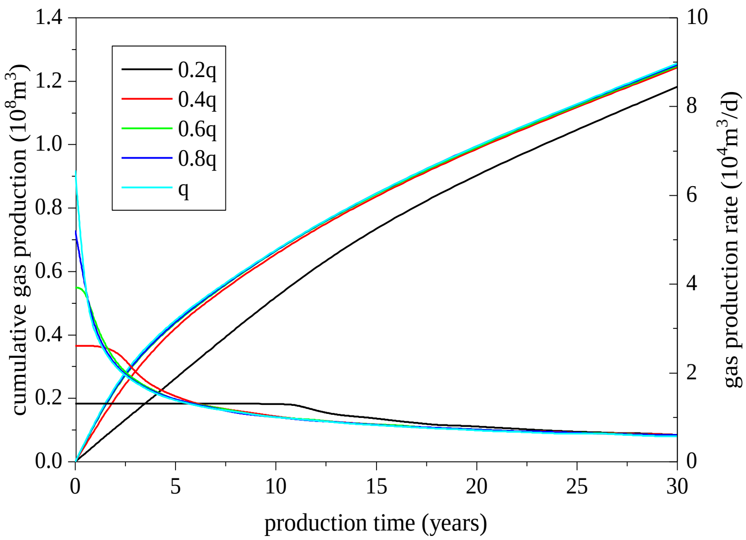

Figure 6: The curve of the variation of production and cumulative production in different initial production allocation

Table 1: Production table with different initial production allocation

Initial production allocation (the value is the times of Q_{AOF})	$0.2\ Q_{AOF}$	$0.4\ Q_{AOF}$	$0.6\ Q_{AOF}$	$0.8\ Q_{AOF}$	Q_{AOF}
30-year cumulative production ($10^8\ m^3$)	1.18	1.24	1.24	1.25	1.26
Stable production period (year)	10	2	0.5	0	0

The mentioned simulation draws a conclusion, that is, if the permeability of the shale gas well changes in a constant pattern, then the production of production is not limited, the impact on the final cumulative production is very small, it is not necessary to control the initial production.

However, through the actual production data studying in some shale gas fields, it can be easily found that the control of the production plays a positive role for the abnormal high pressure, strong plasticity, the large initial production capacity shale gas well, compared with the non-limited production well, the production capacity of limited production well is better, therefore, another case will be considered.

5.2 Simulation of variable fracture stress sensitivity curve

According to the second part of the mentioned discussion, the stress sensitivity curves of fractures should vary with production mode. Thus, the different stress sensitivity curves are employed to simulate the different initial production allocation.

The Yilmaz and Nur relational expressions introduced a concept of "permeability modulus" [Yilmaz, Nur and Nolen-Hoeksema (2010)], usually known as the permeability sensitivity constant. The reservoir pressure equation for permeability attenuation was described, which was equivalent to the concept of compression coefficient. The relationship equation is very suitable for the model exhibiting high temperature, high pressure and a high pressure drop as gas reservoir permeability varies with the pressure:

$$\gamma = \frac{1}{k}\frac{dk}{dp} \tag{5}$$

$$k = k_o e^{-\gamma \Delta p} \tag{6}$$

In these Equations: k_o ..... reservoir initial permeability, mD;

k …... Stratigraphic permeability at a formation pressure, mD;

γ ... Permeability modulus (permeability sensitivity constant), MPa^{-1}.

Eq. (6) shows that the permeability of the system varies exponentially with the reservoir pressure drop, and the low permeability sensitivity constant corresponds to low permeability attenuation.

The stress sensitivity characteristics of fracture permeability are considered synthetically. In the non-limited production scheme, the higher permeability sensitivity constant (0.02 MPa^{-1}) is adopted; in the limited production scheme, the lower permeability sensitivity constant (0.01 MPa^{-1}) is used. During simulation, the same reservoir parameters are used, and the minimum bottom hole pressure limit is 2 MPa.

As shown in Fig. 7, the greater the permeability sensitivity constant, the more the ratio of permeability decreases as the formation pressure drops. Fig. 8 compares the daily production and cumulative gas production at an earlier production 0.4 times, 0.8 times of unimpeded flow. It can be found: The well that produces at a large production in the early stage, and the cumulative gas production in the early stage is very large, the cumulative gas production in the late stage is lower than the small production well; The well that produces at a large production in the early stage, daily gas production in the early stage is large, the daily gas production in the late stage is lower than the small production well. The simulation results are consistent with the actual situation of the Haynesville shale reservoir with high pressure and high production.

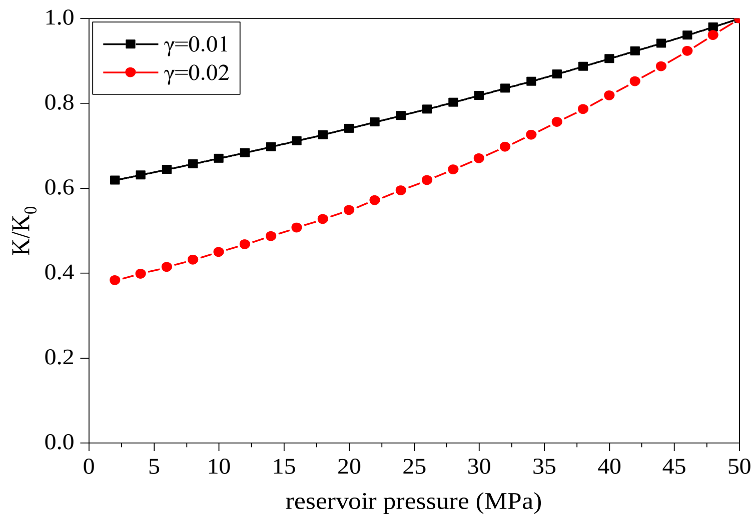

Figure 7: Variation chart of permeability with formation pressure under different stress sensitivity constants

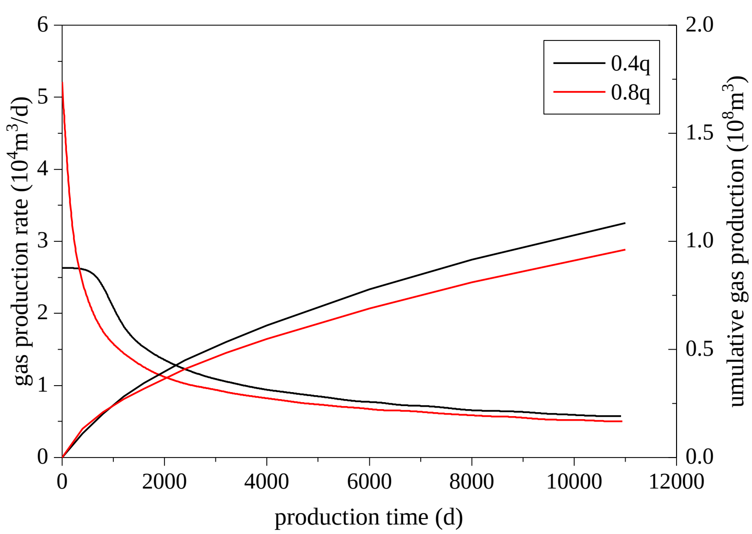

Figure 8: Chart of the variation of production and cumulative production in different initial production allocation

6 Conclusions

(1) The stress sensitivity of the matrix will affect the cumulative production of shale gas wells, whereas there is not significant guidance for the production allocation.

(2) The fracturing fractures significantly impact the cumulative gas production. However, if the permeability of the fracturing fractures is a constant with the varying pressure difference, the production allocation will not affect the cumulative gas production.

(3) Since fracturing sand is broken or embedded in the rock, in different pressure drop

schemes, the permeability sensitivity curve is not the same, and the production allocation significantly impacts the cumulative gas production.

(4) The fracturing sand migrates with the high-speed airflow, leading to the instability of the fracture, which makes the permeability sensitivity curve not the same in different production allocation schemes. The production allocation significantly impacts the cumulative gas production.

(5) For the production allocation with the strong stress sensitivity shale gas wells, the fracture stress sensitivity is primarily considered. To determine a reasonable working pressure difference, it is also necessary to research in-depth with the long-term conductivity of proppant should be also studed in-depth under different pressure drops.

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