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# Study on Theoretical Model and Influencing Factors of High Propagation of Vertical Well Pressure Fractures in Block S

**Huohai Yang[1], Binghong Xie[1], Jingxin Ruan[1], Tao Wang[2]**

[1] School of petroleum and natural gas engineering, Southwest Petroleum University, Chengdu, China

[2] Sulige Gas Field Branch of CNPC Great Wall Drilling Engineering Co., Ltd

**Abstract:** The gas reservoir in block S is relatively thin, and the fracture height of the thin reservoir is out of control seriously, and the effective support efficiency in the fracture is less than 50%. In view of this problem, this paper investigates the application status of fracture control and high-pressure fracturing technology, and carries out the research on the theoretical model and influencing factors of high expansion of vertical well pressure fractures in block s. The research results show that the in-situ stress difference between reservoirs is the most critical factor to control the fracture height, which directly determines the success rate of fracturing construction. When the in-situ stress difference between reservoirs is greater than 4MPa, the fracture height can be effectively controlled. According to the in-situ stress profile and geological data of drilled wells in block s, it is suggested to select the interlayer reservoir with in-situ stress difference greater than 4MPa and low elastic modulus for fracturing construction.

**Keywords:** Tight gas reservoir, High technology of seam control, Numerical simulation, Analysis of influencing factors.

## 1. Introduction

Tight sandstone reservoir has the characteristics of "four low, two high and one strong", that is, low porosity, low permeability, low formation pore pressure, low natural production, high water saturation, high development cost and strong reservoir heterogeneity [1]. The gas reservoir in block S is relatively thin, and the larger the longitudinal communication area of fracturing fractures, the greater the risk of fracturing unidentified aquifers. Water and liquid will seriously affect the production of normal gas wells. Therefore, how to limit the vertical communication height of fractures is a key problem in block S fracturing at present. However, the development of high-tech fracturing and fracture control has stagnated for more than 10 years. Therefore, in recent years, domestic experts and scholars have developed a variety of technical means to control fracture height from the perspective of fracturing technology in Songliao Basin, Ordos Basin, Jianghan Basin, etc., mainly including artificial barrier technology, variable displacement technology, adjusting fracturing fluid density technology, injecting non proppant technology and secondary sand fracturing technology. Aiming at the problem that it is difficult to control the fracture height, this paper establishes a mechanism model, analyzes the influencing factors of fracture height expansion, and provides a theoretical basis for fracturing and layer selection of tight sandstone gas reservoir on the site according to the drilled in-situ stress profile and geological data in block S[2-3].

## 2. Application Status of Seam Control High Pressure Cracking Technology

The primary purpose of fracturing tight sandstone reservoir is to form effective fractures in the formation. Effective joint making includes increasing the length of the joint as much as possible within the limited range, connecting natural cracks and bedding structures, expanding the reconstruction volume as much as possible, and increasing the air release area. However, for thin-layer or water-bearing gas reservoirs, it is necessary to control the extension range and height of fractures and avoid water layers as much as possible. In order to solve the possible difficulties in fracturing engineering geology, the following fracture control high-pressure fracturing technology is investigated and summarized[4-5].

### 2.1. Artificial Partition Technology

During fracturing operation, floating agent and sinking agent are added to form a low permeability or impermeable artificial barrier, so as to control the fracture extending up and down. The applied oil and gas fields include Shengli, Sulige, Zhongyuan, Qinghai and other oil and gas fields. The field practice shows that the fracture stimulation effect after fracturing is obvious[6].

### 2.2. Variable Displacement Fracturing Technology

Through the instantaneous jump of displacement, the proppant can be transported to the deeper part of the fracture while controlling the downward extension of the fracturing fracture, and the length of the supporting fracture can be increased. It is widely used in the United States, including Changqing Oilfield and Jianghan Oilfield in China[7].

### 2.3. Technology of Adjusting Fracturing Fluid Density

Vertical pressure distribution is achieved by controlling the density of fracturing fluid. Higher density fracturing fluid is conducive to limiting the upward extension of fractures, while lower density fracturing fluid can limit the downward extension of fractures. It is rarely used alone on site, and is often used in combination with other high-tech seam control[8].

## 2.4. Cooling Formation Control Fracture High Technology

Injecting cold water into the high-temperature formation makes the formation produce thermoelastic stress, so as to reduce the formation stress, and then control the fracture height. The application effect of Zhongyuan, Changqing and other oilfields in China is good[9].

## 2.5. Secondary Sand Fracturing Technology

The fracturing and sand adding process is optimized into two stages for fracturing construction. After the proppant completely enters the formation in the first stage, stop the pump, wait for the proppant to completely sink and form a plug to prevent the fracture from extending downward, and start the pump for the second stage sand fracturing construction. Foreign oil fields and domestic Dagang oil fields, Xinjiang oil fields, Changqing oil fields have a large number of applications[10].

**Table 1**. Summary and comparison of control seam height technology

| High pressure crack control technology | Advantage | Shortcoming | Applicable conditions |
|---|---|---|---|
| Artificial partition technology | It has wide adaptability and is applied in all major oilfields in the world | Incomplete flowback will cause certain reservoir damage, and the requirements for temporary plugging agent are high | It is applicable to most reservoir conditions |
| Variable displacement fracturing technology | The process is simple, and the fracture height can be controlled through accurate fracturing construction procedures to effectively prevent bottom water from channeling | The requirements for surface exposed equipment are high, and it is not applicable to reservoirs with large upper and lower stress difference | It is suitable for bottom water reservoirs with a certain thickness; The cementing quality is good, and the construction equipment can meet the requirements of displacement and sand ratio change |
| Technology of adjusting fracturing fluid density | The construction process is simple, and the requirements can be met without large-scale equipment | It is not suitable for controlling the fracturing fracture height of thin interbedded reservoirs | It is suitable for oil and gas reservoirs with single reservoir form and large thickness |
| Cooling formation control fracture high technology | Simple process and low requirements for equipment | Not applicable to normal temperature formation | It is applicable to the formation with poor cementation and the oil and gas reservoir without water damage |
| Secondary sand fracturing technology | It can effectively improve the sand laying profile and reduce the risk of sand plugging | The construction process is complex and requires accurate fracturing construction design | It is applicable to thin oil and gas reservoirs and reservoirs prone to water channeling, and has good applicability to conventional reservoirs |

# 3. Theoretical Model of Crack Height Expansion

## 3.1. Numerical Model

The calculation area and boundary conditions used in this simulation are: the calculation area is 20m × 10m rectangle. The thickness of the reservoir is $h_{center}$, the thickness of the upper and lower compartments are $h_{cover}$, and there is an initial fracture with a length of 1.5m parallel to the Y direction in the center of the calculation area. Fracturing fluid is injected from the injection point located in the center of the calculation area. The displacement in the X direction of the left boundary of the calculation area is fixed at 0, and the displacement in the Y direction of the lower boundary is fixed at 0. The upper boundary is loaded with compressive stress in the negative direction along the Y axis σ y. The right boundary of the reservoir and the interlayer is loaded with compressive stress along the negative direction of the X axis respectively σ cover_ X and σ center_ X. The initial pressure of the fluid at the outer boundary of the calculation area and in the pore is 15 MPa. The calculation area is divided by a square element with a side length of 0.25 m, and the length scale parameter l0 is set to 0.5 m.

## 3.2. Software Model

According to the microseismic monitoring and logging interpretation results of fracturing wells in block s of Ordos Basin and the previous geological data, it is found that the natural fractures in this block are not developed, and the hydraulic fractures during fracturing construction are mainly plane fractures. The following model is established.

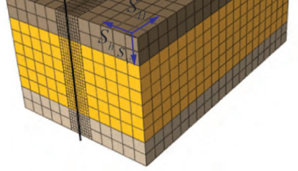


**Figure 1**. Software model

## 3.3. Geologic Model

**Table 2.** Sample table of geological model parameters

| Parameters | mathematical model |
|---|---|
| Elastic modulus of reservoir /GPa | 20 |
| Elastic modulus of interlayer /CPa | 20 |
| Poisson's ratio of reservoir | 0.2 |
| Partition Poisson's ratio | 0.2 |
| Compressive strength of reservoir /MPa | 58 |
| Compressive strength of interlayer /MPa | 37 |
| Tensile strength of reservoir /MPa | 6 |
| Tensile strength of interlayer /MPa | 4 |
| Fracture toughness of reservoir /(MPa.m$^{1/2}$) | 0.995 |
| Fracture toughness of interlayer /(MPa-m$^{1/2}$) | 0.416 |
| Formation pore pressure /MPa | 13.5 |
| Overburden pressure /MPa | 40 |
| Minimum horizontal in-situ stress of reservoir /MPa | 26 |
| Horizontal minimum in-situ stress of interlayer /MPa | 28 |
| Maximum horizontal in-situ stress of reservoir /MPa | 30 |
| Horizontal maximum in-situ stress of interlayer /MPa | 34 |
| Fracturing fluid viscosity /(mPa*s$^{-1}$) | 5 |
| Fracturing fluid viscosity fracturing fluid displacement /(m$^{3}$.s$^{-1}$) | 3 |
| Perforation position | Middle part of reservoir |

# 4. Analysis of Influencing Factors of Seam Height Expansion

## 4.1. Stress Difference of Reservoir

This part will simulate the longitudinal extension of fracturing fractures under the condition of minimum horizontal stress difference of three different reservoir compartments. In three different calculation examples, the minimum horizontal stress of the reservoir is set to 25MPa, and the minimum horizontal stress of the upper and lower compartments are 27mpa (calculation example 1) and 31mpa (calculation example 2) respectively.

Under the condition that the minimum horizontal stress difference of the reservoir is 2MPa (calculation example 1) and 6Mpa (calculation example 2), the distribution cloud diagram of fracture phase field at different times is shown respectively. It can be seen that the evolution nephogram of fracture facies field under the condition of minimum horizontal stress difference of three different reservoir compartments has common characteristics. That is, with the increase of injection time, the fracture will extend linearly along the Y direction, and the fracture will not extend along the interlayer interface. However, the greater the minimum horizontal stress difference of the reservoir, the smaller the fracture height at the end of injection.

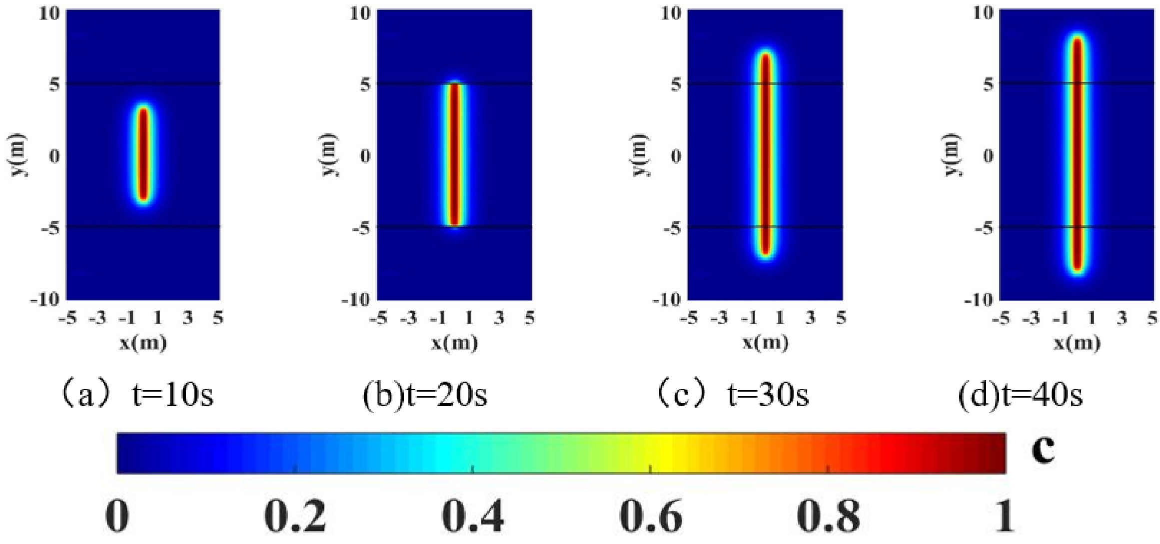
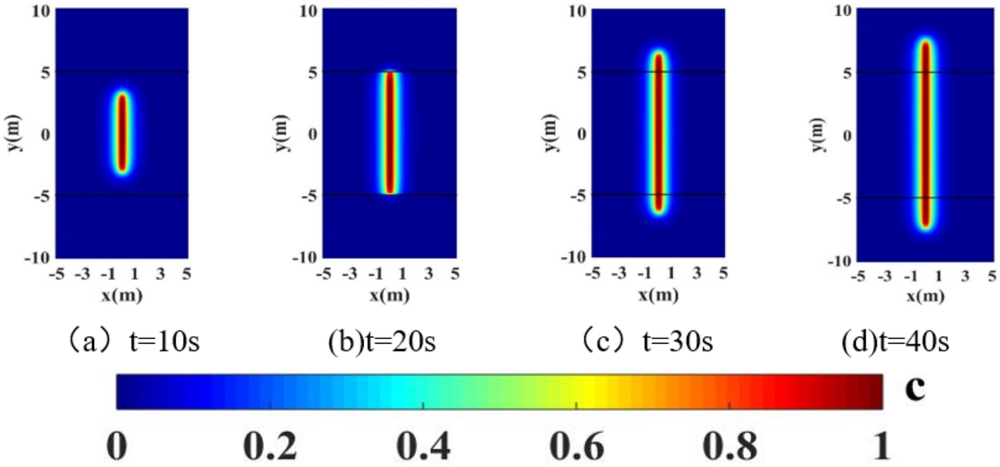


**Figure 2**. Cloud diagram of phase field distribution at different times under the condition that the minimum horizontal stress difference of the reservoir is 2MPa (calculation example 1)



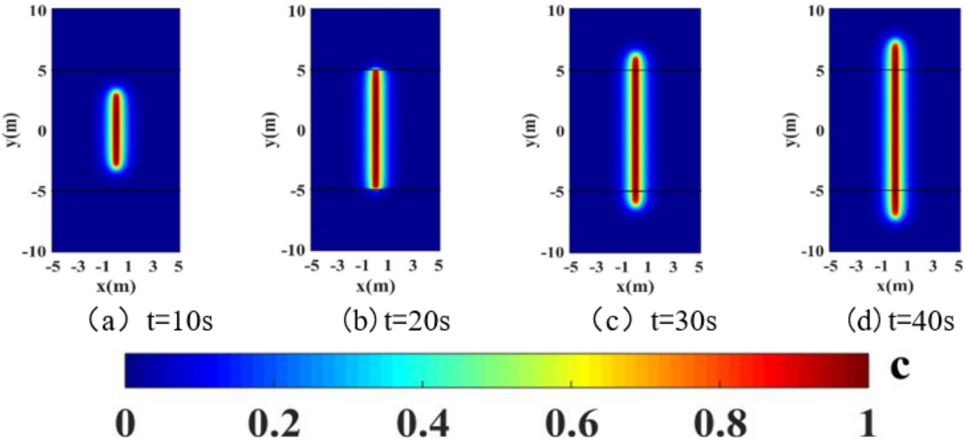
（a）t=10s (b)t=20s （c）t=30s (d)t=40s

**Figure 3.** Cloud diagram of phase field distribution at different times when the minimum horizontal stress difference of the reservoir is 6Mpa (calculation example 2)

## 4.2. Effect of Elastic Modulus of Interlayer on Longitudinal Propagation of Fracturing Fracture

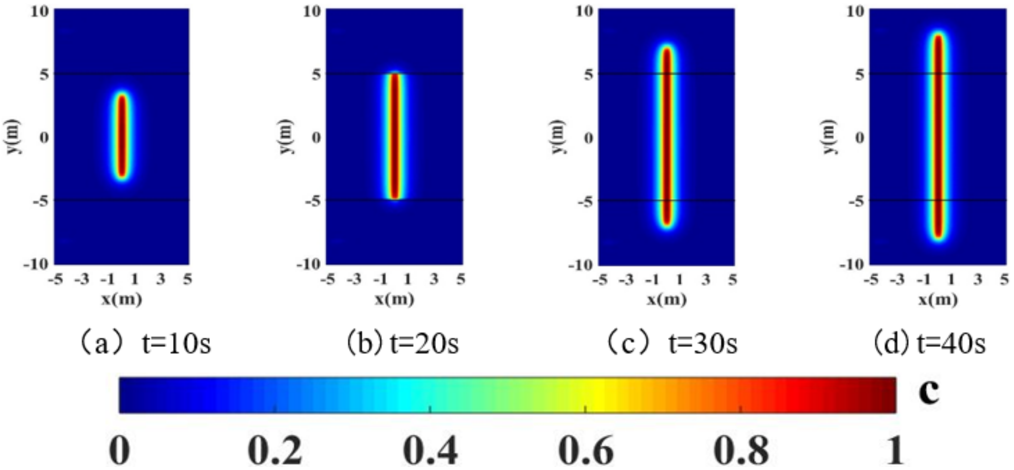
This part will analyze the influence of the elastic modulus of the interlayer on the longitudinal extension of the fracturing fracture. Similarly, example 2 in the previous section is taken as the benchmark example (the elastic modulus of the interlayer in this example is 22.5 Gpa), and the longitudinal extension of the fracturing fracture is simulated when the elastic modulus of the interlayer is 15 Gpa (example 3) and 30 Gpa (example 4) respectively. Other input parameters are the same as those in example 1.

Under the condition that the elastic modulus of the interlayer is 15Gpa and 30Gpa respectively, the phase field distribution nephogram of the crack at different times is shown in the figure respectively. The comprehensive comparison shows that the change of the elastic modulus of the interlayer will not affect the fracture height extension trajectory of the fracturing fracture, but the greater the elastic modulus of the interlayer, the longer the fracture height after the fracturing fracture penetrates the layer.



（a）t=10s (b)t=20s （c）t=30s (d)t=40s

**Figure 4.** Cloud diagram of phase field distribution at different times under the condition that the elastic modulus of the interlayer is 15Gpa (example 3)



（a）t=10s (b)t=20s （c）t=30s (d)t=40s

**Figure 5.** Cloud diagram of phase field distribution at different times when the elastic modulus of the interlayer is 30Gpa (example 4)

# 5. Conclusions and Recommendations

(1) The greater the minimum horizontal stress difference of the reservoir compartment, the smaller the elastic modulus of the compartment, and the more difficult it is for the fracture to extend through the interlayer interface in the upper and lower compartments;

(2) The difference of in-situ stress between reservoirs is the most critical control factor, which directly determines the success rate of fracturing operation. The research shows that when the ground stress difference between reservoirs is greater than 4MPa, the pressure fracture height can be effectively controlled. According to the in-situ stress profile and geological data drilled in block s, it is recommended to select tight sandstone gas reservoir with in-situ stress difference greater than 4MPa for fracturing construction during on-site fracturing and layer selection.

(3) The interlayer with low elastic modulus is beneficial to control the fracture height. Before the fracture penetrates the reservoir interface, the higher the elastic modulus of the interlayer, the greater the inhibition of the fracture entering the interlayer; After the crack passes through the layer, the interlayer with low elastic modulus inhibits the high compressive crack.

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