# Feasibility Study of Fracturing of Water Bearing Sandstone Gas Reservoir on the North Slope of Lingshui

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**Abstract.** The Lingshui Beipo gas reservoir is located in the northern part of the Qiongdongnan Basin in the South China Sea, and is a typical high-temperature, high-pressure, and low-permeability sandstone gas reservoir developed in the Cenozoic fault basin at the junction of the ancient South China Platform and the ancient South China Platform. The main gas reservoir of this gas reservoir is the Meishan Formation, which is a typical medium porosity and low permeability reservoir with little natural production capacity. Based on the experience of onshore oil fields, hydraulic fracturing is an effective way to achieve industrial production in such reservoirs. However, the risk of fracturing in offshore gas reservoirs is extremely high, and feasibility studies on hydraulic fracturing are urgently needed. Therefore, this article analyzes the basic characteristics and main problems of the Meishan Formation gas reservoir, and conducts a feasibility study on hydraulic fracturing of the Meishan Formation from the aspects of fracture pressure, treatment pressure prediction, gas-water layer analysis relationship, and simulation of fracture height and permeability. Analysis suggests that the use of high pumping rate fracturing may lead to high treatment pressure, small stress differences between the reservoir and barrier layer, which can easily lead to uncontrollable fracture height, and the use of fracturing may lead to communication with the water layer, resulting in water flooding of the gas well. These are key issues that constrain the fracturing of this gas reservoir. A fracture pressure prediction model for the Lingshui North Slope gas reservoir was established using extended finite element method. The predicted fracture pressure of the Meishan Formation was 69-98 MPa, and the predicted treatment pressure was 70-100 MPa. The use of large-sized oil pipes is beneficial for reducing treatment risks. A three-dimensional fracture propagation model was established using the Cohesive pore pressure element. The simulation shows that the pumping rate and liquid volume are the key factors affecting the fracture height. When there is a water layer, the pumping rate should not exceed 6m$^3$/min and the liquid volume should not exceed 250 m$^3$. In the absence of a barrier between the gas and water layers, it is difficult to avoid hydraulic fracturing from communicating with the water layers. Therefore, hydraulic fracturing is not recommended for such reservoirs. The hydraulic fracturing treatment pressure of Lingshui North Slope Gas Reservoir is high, and the risk of communicating with water layers is high. It is necessary to moderately control the pumping rate and scale, optimize the combination of fracturing fluid and pipe string, and reduce the risk of offshore fracturing.


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## 1 Introduction

According to the national energy strategy requirements and the deepening of offshore oil and gas field exploration and development, low permeability offshore reservoirs are receiving increasing attention. The scale of China's offshore low-permeability reservoirs is huge, and the proven reserves of low-permeability crude oil are $5.41 \times 10^8$t, proven natural gas reserves $5435 \times 10^8 m^3$, but the degree of utilization of low permeability reserves is relatively low [1, 2]. The main measure to improve the development effect of low permeability reservoirs is reservoir transformation. On land, good results have been achieved through hydraulic fracturing, acidification and other measures. However, the application of reservoir transformation (especially hydraulic fracturing) in offshore oil and gas fields is limited due to limited operating sites, high costs, and high risks [3–5], which greatly affects the effective development of offshore low permeability reservoirs. In response to the characteristics of offshore low-permeability reservoirs, a large number of explorations have been carried out in offshore oil and gas fields [6–8], proposing a series of fracturing technologies such as deflagration fracturing [9–11], screen fracturing [12, 13], and hydraulic impact fracturing (hydrodynamic fracturing) [14, 15], which have been applied on-site and have achieved certain results. However, offshore fracturing is still in the exploratory stage. Given the unique nature of offshore fracturing, in order to successfully implement and achieve good results, it is essential to conduct a feasibility analysis of fracturing on the target reservoir before conducting fracturing. However, due to the lack of systematic feasibility analysis before fracturing in onshore low-permeability oil and gas fields, as a reference, there are also few studies on the feasibility of fracturing in offshore oil and gas fields, which also restricts the development of offshore fracturing.

The Lingshui Beipo gas reservoir is located in the northern part of the Qiongdongnan Basin in the South China Sea, and is a typical high-temperature, high-pressure, and low-permeability sandstone gas reservoir developed in the Cenozoic fault basin at the junction of the ancient South China Platform and the ancient South China Platform. The main gas reservoir of this gas reservoir is the Meishan Formation, which is a typical medium porosity and low permeability reservoir with little natural production capacity. Based on the experience of onshore oil fields, hydraulic fracturing is an effective way to achieve industrial production in such reservoirs. However, the risk of fracturing in offshore gas reservoirs is extremely high, and feasibility studies on hydraulic fracturing are urgently needed. Therefore, this article analyzes the basic characteristics and main problems of the Meishan Formation gas reservoir. In response to the main problems, a feasibility study on hydraulic fracturing of the Meishan Formation was conducted from the aspects of fracture pressure, treatment pressure prediction, gas-water layer analysis relationship, and fracture height penetration simulation. Measures and suggestions were proposed, which can provide reference for the transformation of similar offshore low-permeability gas reservoirs.

## 2 Analysis of Basic Features and Main Issues

### 2.1 Basic Characteristics of the Research Area

(1) Physical characteristics

The porosity ranges from 16.9% ~ 24.6% (median 19.6%), and the permeability ranges from 0.14 ~ 9.81mD (median 0.95mD), indicating a medium to low permeability reservoir. The burial depth of the target layer is 3000 ~ 3600 m, the formation temperature is 129 ~ 151.2 °C, the geothermal gradient is 3.73 ~ 3.8 °C/100 m, and the average is 3.745 °C/100 m. The formation pressure ranges from 59.64 ~ 73.11 MPa, and the pressure coefficient gradually increases towards the depth, from 1.81 ~ 1.97, indicating a strong overpressure system.

(2) Mineral and brittle characteristics

The main minerals of the Meishan Formation are quartz (47.2%), clay minerals (18.4%), potassium feldspar, and plagioclase (a total of 19.2%). The mineral brittleness index ranges from 51% ~ 72%, with significant differences among wells, with an average mineral brittleness of 63% and a relatively high brittleness.

(3) Ground stress characteristics

The vertical stress, minimum horizontal principal stress, and maximum horizontal principal stress gradients of Meishan Formation in Lingshui Beipo Gas Reservoir are 2.3 MPa/100 m, 1.93 MPa/100 m, and 2.46 MPa/100 m, respectively. After fracturing, typical vertical fractures will be formed. The vertical stress is 70 ~ 92 MPa, the maximum horizontal principal stress is 81 ~ 104 MPa, and the minimum horizontal principal stress is 66-83 MPa. The difference between the maximum and minimum horizontal principal stresses is large, making it difficult to form a fracture network.

(4) Natural fractures

The identification of Meishan formation fractures in the northern slope of Lingshui gas reservoir shows that most natural fractures are unfilled or semi filled fractures; Mainly horizontal and low angle fractures, with a fracture density of 2.66 pieces/m. The core fractures are mainly low angle and horizontal, mainly unfilled, with a length of 6-8cm and a density of 2.54 fractures/m. Scanning electron microscopy shows that micro fractures are developed in the core of the Meishan Formation, most of which are unfilled fractures, with a length of 0.1–0.3 mm and a width of 0.04–0.06 mm. Natural fractures are generally well-developed.

### 2.2 Analysis of Fracturing Problems

(1) The use of high pumping rate fracturing may result in high treatment pressure.
(2) The stress difference between the reservoir and the barrier layer is small, and the fracture height is easily out of control.

Using acoustic logging data, a typical well stress profile of the Lingshui North Slope gas reservoir was calculated, and it was found that the thickness of the upper barrier layer of the Meishan Formation is 26.9 m, with a stress of 68.2 MPa; The thickness of the lower partition layer is 11.4 m, and the stress is 69.7 MPa; The thickness of the gas layer is 11.2 m, and the stress is 67.3 MPa. The small stress difference in the reservoir compartment is not conducive to fracture height control.

(3) Water layers are commonly developed, and fracturing may lead to water flooding of gas wells due to communication with the water layers.

# 3 Prediction of Fracture Pressure and Treatment Pressure

## 3.1 Prediction of Fracture Pressure

### 3.1.1 Finite Element Simulation Model for Predicting Fracture Pressure

A two-dimensional extended finite element simulation model for predicting the fracture pressure of perforated wells in Meishan Formation of Lingshui Beipo Gas Reservoir was established using the extended finite element method, with a model size of 50 m × 50 m, with a unit grid size of 0.5 m. The model grid division is shown in Fig. 1, and the basic parameters of the finite element model are shown in Table 1.

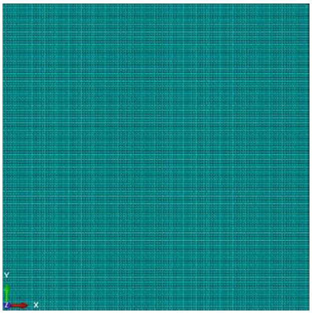



**Fig. 1.** Mesh division of finite element model for fracture pressure prediction of Meishan Formation

### 3.1.2 Prediction and Analysis of Fracture Pressure

(1)Influence of fracture Pressure

In order to study the effect of perforation azimuth on fracture pressure, six angles between initial fractures and maximum horizontal principal stress were set in the finite element model θ (0°, 15°, 45°, 60°, 75°, 90°), the initiation and propagation of hydraulic fractures are shown in Fig. 2. Further simulations were conducted to investigate the effects of Young's modulus, Poisson's ratio, and permeability on fracture pressure. The fracture pressure under different conditions is shown in Fig. 3. The simulation results show that when the perforation azimuth angle increases from 0° to 90°, the fracture

**Table 1.** Parameters of the finite element model for predicting the fracture pressure

| Parameter | Value |
|---|---|
| Young's modulus(GPa) | 12 |
| Tensile strength(MPa) | 6 |
| Permeability coefficient(m/s) | 3.5e-7 |
| Filter loss coefficient(m/min$^{0.5}$) | 1e-14 |
| Stress(MPa) | $\sigma h = 72.7$<br>$\sigma H = 89.1$<br>$\sigma v = 80.5$ |
| Fracturing fluid viscosity(mPa·s) | 50 |
| Pumping rate(m$^3$/min) | 4 |
| Poisson's ratio | 0.15 |

pressure increases approximately linearly. The fracture pressure at the 90° azimuth angle increases by 60.71% compared to the 0° azimuth angle, and the perforation azimuth angle has a significant impact on the fracture pressure. The perforation azimuth angle, Young's modulus, and permeability have a significant impact on the fracture pressure, while Poisson's ratio has almost no effect on the fracture pressure. The larger the perforation azimuth angle and Young's modulus, the higher the fracture pressure, the higher the permeability, and the lower the fracture pressure. The rupture pressure range is 69-98 MPa, and the rupture pressure under typical parameters is 74 MPa.

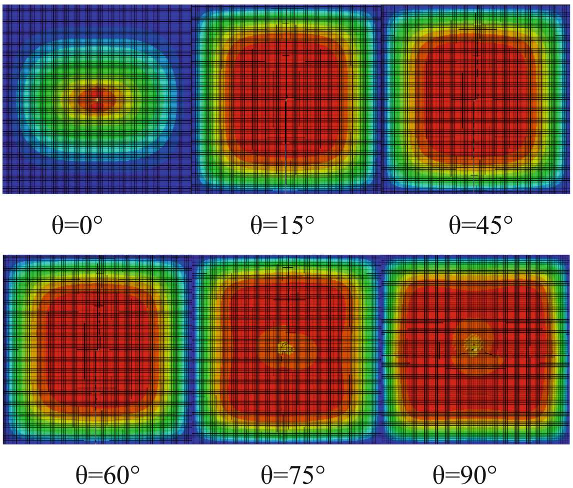



**Fig. 2.** Simulation diagram of fracture initiation and propagation under different perforation azimuth

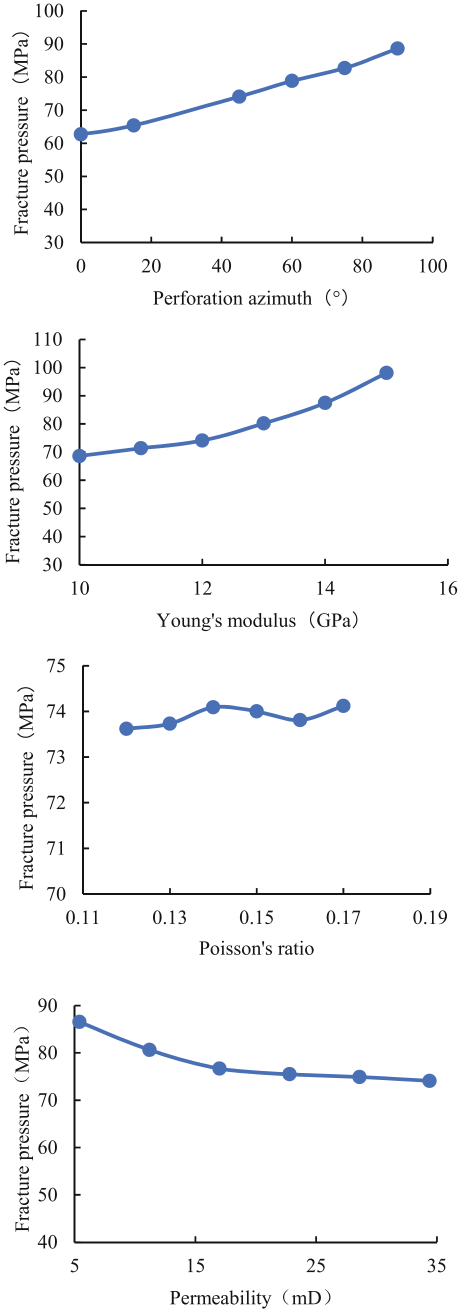



**Fig. 3.** Prediction value of fracture pressure under different conditions

## 3.2 Treatment Pressure Prediction

### 3.2.1 Treatment Pressure Prediction Model

The surface treatment pressure of hydraulic fracturing is composed of wellbore fluid static pressure, wellbore fluid frictional pressure, perforation hole and near wellbore frictional pressure, and formation fracture pressure (or bottom hole operating pressure).

$$P_{stp} = P_{bhtp} + P_f + P_{pnwb} - P_h \tag{1}$$

In Eq. (1), the formation fracture pressure has been predicted in the previous section. The wellbore fluid static pressure can be calculated by the density of the fracturing fluid and the depth in the middle of the reservoir, and the wellbore frictional pressure can be calculated by Eq. (2).

$$P_f = \sum_{i=1}^{N} \lambda_i \frac{L_i}{D_i} \frac{\rho_i v_i^2}{2} \times 10^{-6} \tag{2}$$

### 3.2.2 Prediction and Analysis of Treatment Pressure

The parameters such as treatment pumping rate, inner diameter of fracturing string, and diameter of perforation hole have a significant impact on treatment pressure. Based on the prediction model of treatment pressure, the fracturing treatment pressure of Lingshui Beipo gas reservoir was calculated under different parameters. The pumping rate and tubing size have a significant impact on the fracturing treatment pressure. If the $3^1/_2$ ″ tubing commonly used on land is used, and the pumping rate above 6m3/min is used, the surface treatment pressure will exceed 100 MPa, making it impossible to implement. Combining with the commonly used casing structure in offshore gas fields, a $4^1/_2$ ″ oil pipe can be lowered. When using a pumping rate of 6m3/min, the ground treatment pressure can be controlled at around 70 MPa, and large-scale and high pumping rate fracturing can be successfully carried out offshore (Fig. 4).

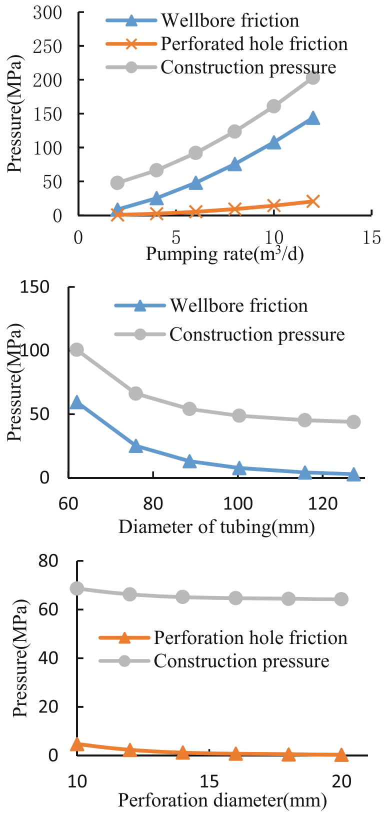



**Fig. 4.** Prediction value of ground treatment pressure under different conditions

# 4 Analysis of Hydraulic Fracture Height Penetrating Water Layers

## 4.1 Distribution of Gas and Water Layers

According to the logging interpretation results, the gas, water layer, and barrier layer conditions were statistically analyzed (Table 2). It was found that there are generally water layers in the gas reservoirs on the northern slope of Lingshui, and the distance between the gas and water layers is relatively close, greatly increasing the risk of gas fracturing connecting the water layers.

In addition, the interaction of sand and mud in the longitudinal direction leads to rapid changes in the small layers, further increasing the complexity of hydraulic fractures extending in the longitudinal direction.

**Table 2.** Statistical table of relationship between gas layer and water layer in Meishan Formation

| Well | Depth of gas layer (m) | Gas layer thickness (m) | Water layer thickness (m) | Spacing between gas and water layers(m) |
|---|---|---|---|---|
| LS13–2-1 | 3605.0 ~ 3618.5 | 13.5 | 14.0 | 0 |
| LS13–2-2 | 3778.2 ~ 3795.3 | 17.1 | 9.3 | 0 |
| LS13-2N-1 | 3216.5 ~ 3225.7 | 9.2 | 8.6 | 46.3 |
| LS13-2W-1 | 3869.9 ~ 3879.1 | 9.2 | 1.8 | 35.2 |
| LS13-2W-2 | 3833.2 ~ 3838.1 | 4.9 | 3.4 | 0 |

## 4.2 Simulation of Hydraulic Fracture Height Penetrating Water Layers

### 4.2.1 Hydraulic Fracturing 3D Model

Based on the logging interpretation results, preliminary geological data, and reservoir thickness and stress conditions of the Meishan Formation in the Lingshui Beipo Gas Reservoir, the fracturing model of the Meishan Formation in the Lingshui Beipo Gas Reservoir is divided into two categories to determine whether there is a clear barrier between the gas and water layers. Model A shows a clear barrier between the gas and water layers, while Model B shows no barrier between the gas and water layers. Using 3D finite element simulation software to establish a 3D fracturing simulation model, see Fig. 5, and the relevant input parameters are shown in Table 3.

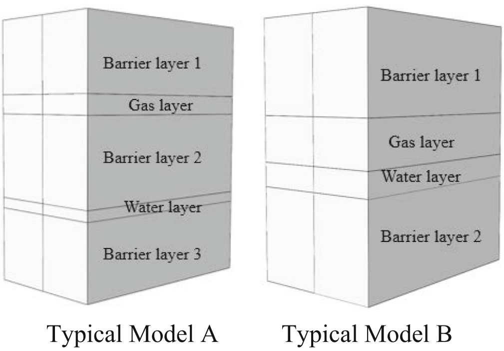



**Fig. 5.** Schematic diagram of typical fracturing simulation model of Meishan Formation

**Table 3.** Model input parameters

| Input parameter | Water layer | Barrier layer 1 | Barrier layer 2 | Barrier layer 3 | Gas layer |
|---|---|---|---|---|---|
| Young's modulus(GPa) | 17 | 17 | 17 | 17 | 10 |
| Tensile strength (MPa) | 3 | 3 | 3 | 3 | 2 |
| Breaking energy (m·Pa) | 8000 | 8000 | 8000 | 8000 | 4000 |
| Permeability coefficient (m/s) | 1e-8 | 1e-8 | 1e-8 | 1e-8 | 1e-7 |
| Filter loss coefficient (m/min $^{0.5}$) | 1e-14 | 1e-14 | 1e-14 | 1e-14 | 1e-13 |
| Stress(MPa) | $\sigma h = 71.9$ $\sigma H = 97.2$ $\sigma v = 74.7$ | $\sigma h = 66.9$ $\sigma H = 83.9$ $\sigma v = 75.8$ | $\sigma h = 70.4$ $\sigma H = 92.8$ $\sigma v = 77.2$ | $\sigma h = 70.2$ $\sigma H = 92.5$ $\sigma v = 76.7$ | $\sigma h = 65.9$ $\sigma H = 83.7$ $\sigma v = 72.8$ |
| Fracturing fluid viscosity (Pa.s) | 0.05 | | | | |
| Pumping rate(m $^3$ /min) | 4 | | | | |
| Poisson's ratio | 0.138 | 0.138 | 0.138 | 0.138 | 0.147 |

### 4.2.2 Simulation Analysis of Hydraulic Fracture Height Extension

(1)Typical Model A (with good barrier between gas and water layers) simulation of fracture height extension.

①Analysis of three-dimensional morphology of hydraulic fracture height extension.

Figure 7 simulates the effects of fracturing fluid viscosity, pumping rate, fluid volume, and reservoir stress difference (minimum horizontal principal stress difference between gas and reservoir) on fracture height. It is found that the viscosity of fracturing fluid (Fig. 6a) has little effect on fracture height, but high viscosity can cause hydraulic fractures to expand downwards; The treatment pumping rate (Fig. 6b) has a significant impact on the fracture height. The larger the pumping rate, the greater the fracture height. When the pumping rate exceeds 8m$^3$/min, the hydraulic fracture penetrates the water layer and extends downwards; The liquid volume (Fig. 6c) has a significant impact on the fracture height. The larger the liquid volume, the greater the fracture height. However, when the liquid volume does not exceed 300 m$^3$, the fracture height will not extend to the water layer; The stress difference between reservoir compartments has a significant impact on the fracture height (Fig. 6d). The larger the stress difference, the easier it is to control the fracture height, and hydraulic fracture will not extend to the water layer.

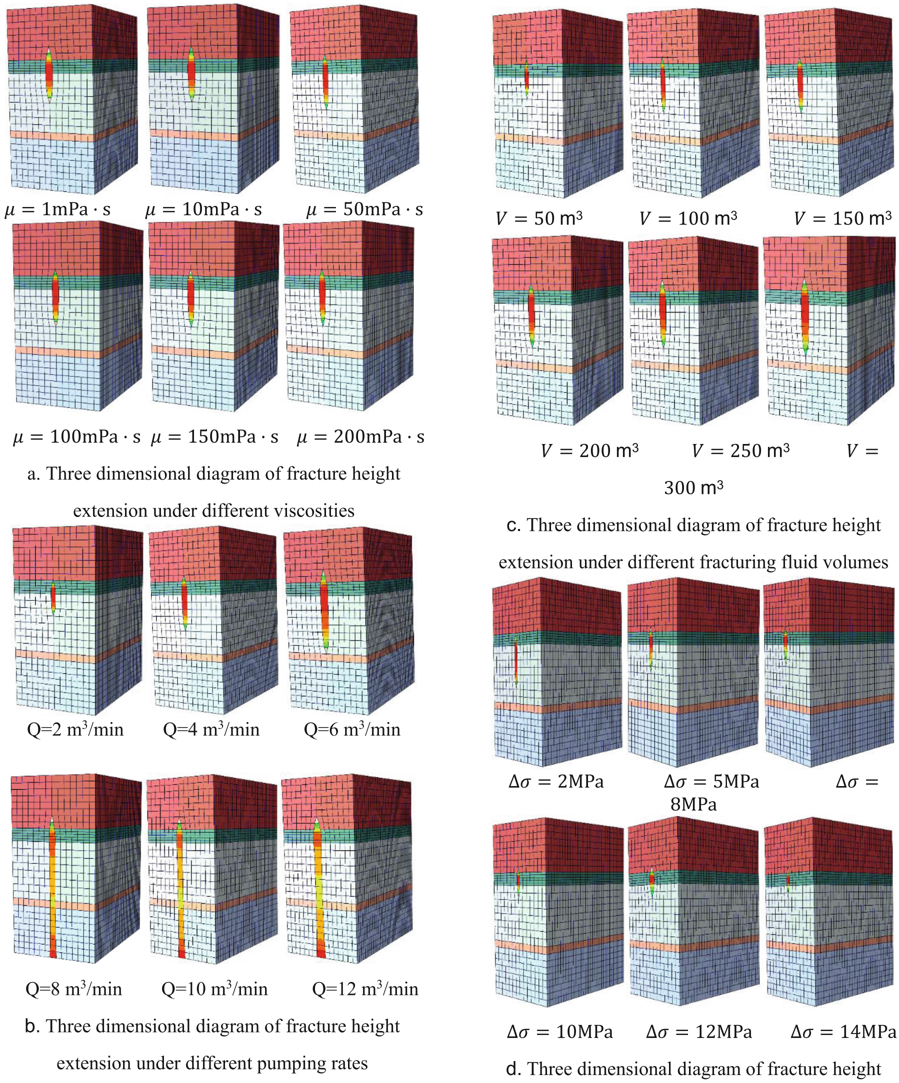



**Fig. 6.** Shape diagram of fracture height extension under different conditions (typical model 1)

②Analysis of factors affecting fracture height and fracture width.

Figure 7 shows the variation curves of fracture width and fracture height for typical model 1 under different conditions based on the above simulation results. The influence of pumping rate and fluid volume on fracture width and fracture height is similar, both of which increase fracture height and fracture width, but the influence of pumping rate is higher than that of fluid volume. The greater the stress difference in the reservoir, the smaller the fracture height and the larger the fracture width. The effect of viscosity on fracture height and width is relatively small.

③Analysis of fracture height passing through the barrier layer.

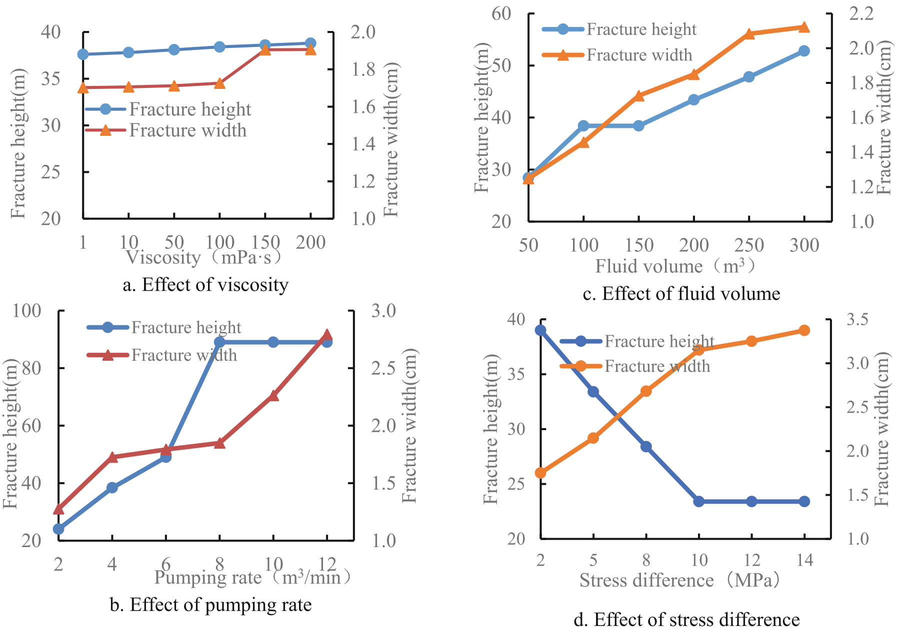
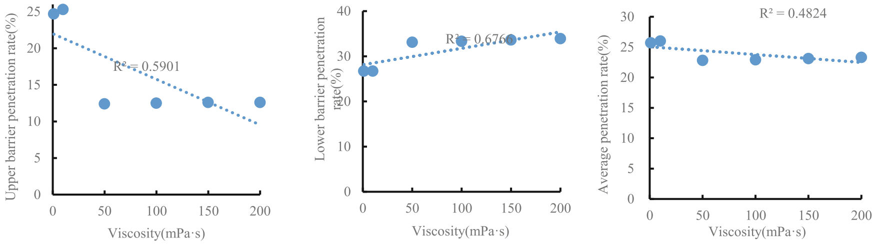
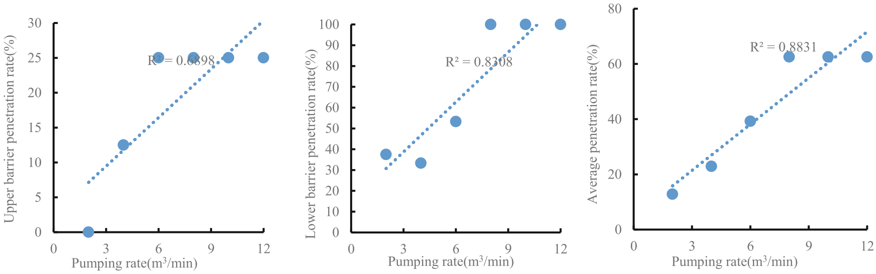



**Fig. 7.** Curve of fracture width and fracture height under different conditions (typical model 1)

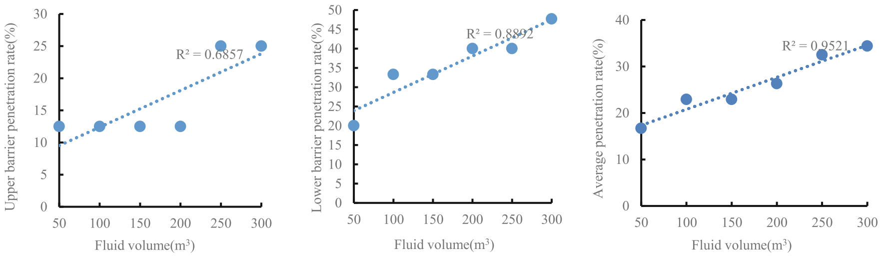
Figure 8 shows the variation curve of the barrier layer penetration rate of typical model 1 under different conditions. The barrier layer penetration rate is defined as the ratio of the extension height of the fracture height within the barrier layer to the thickness of the barrier layer. It was found that the correlation between viscosity (Fig. 8a) and barrier layer penetration rate is not strong. The pumping rate (Fig. 8b) has a strong correlation with the penetration rates of the upper and lower compartments. The larger the pumping rate, the higher the penetration rate of the compartment. When the pumping rate reaches 8m$^3$/min, the penetration rate of the lower compartment will reach 100%, leading to complete penetration of the lower compartment and communication with the water layer. The influence of liquid volume on the penetration rate of the barrier layer is consistent with the pumping rate (Fig. 8c), but the degree of influence is relatively small. Under different liquid volumes, the penetration rate of the barrier layer does not exceed 100% (i.e., the water layer is not communicated). The stress difference in the reservoir compartment is negatively correlated with the permeability of the compartment (Fig. 8d). The larger the stress difference in the reservoir compartment, the less likely the compartment is to be penetrated. The correlation between the stress difference in the reservoir compartment and the penetration rate of the upper compartment is not strong, but it is extremely strong with the penetration rate of the lower compartment. The larger the stress difference in the reservoir compartment and the smaller the penetration rate of the lower compartment, the more conducive it is to controlling the height of the fractures.



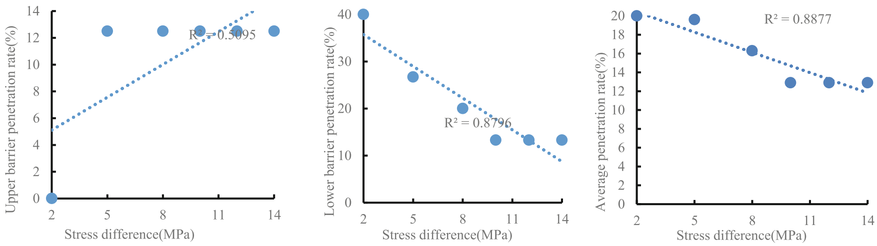

a. Effect of viscosity




b. Effect of pumping rate




c. Effect of fluid volume




d. The influence of stress difference between reservoir and barrier layer

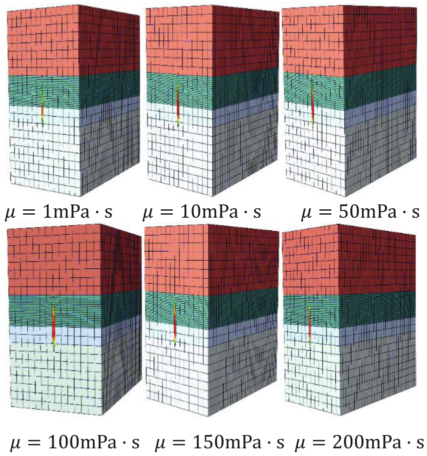
**Fig. 8.** Curve of barrier layer penetration under different conditions (typical model 1)

It can be seen that in the Meishan Formation on the northern slope of Lingshui, where there is a good separation layer between gas and water layers, moderate control of pumping rate can effectively control the height of fractures, prevent hydraulic fractures from extending to the water layer, and have the basic conditions for hydraulic fracturing.

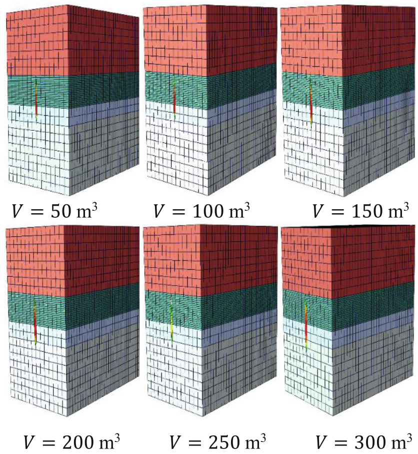
(2) Typical Model B (no barrier layer between gas and water layers) simulation of fracture height extension.

① Analysis of three-dimensional morphology of hydraulic fracture height extension.

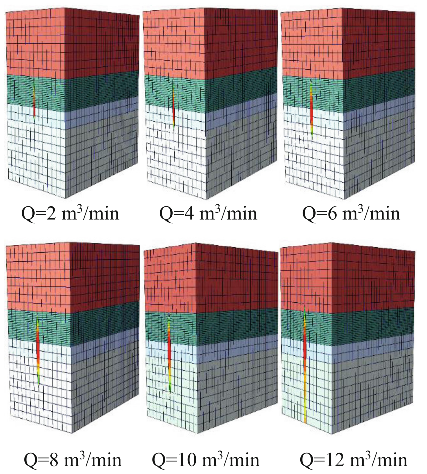
Figure 9 simulates the effects of fracturing fluid viscosity, pumping rate, fluid volume, and reservoir stress difference on fracture height. It is found that the viscosity of fracturing fluid (Fig. 9a) has little effect on fracture height, but the fracture height extends to the



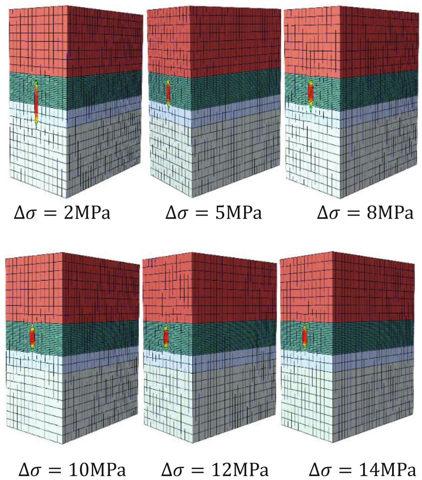

a. Expansion morphology of fracture height under different viscosities




c. Expansion morphology of fracture height under different fluid volumes




b. Expansion morphology of fracture height under different pumping rates




d. Expansion morphology of fracture height under different stress differences

**Fig. 9.** Shape diagram of fracture height extension under different conditions (typical model 2)

water layer under different viscosities; The pumping rate (Fig. 9b) has a significant impact on the fracture height. The larger the pumping rate, the greater the fracture height. When the pumping rate exceeds 4m$^3$/min, the hydraulic fracture penetrates the water layer and enters the lower barrier layer and extends downwards; The liquid volume (Fig. 9c) has a significant impact on the fracture height. The larger the liquid volume, the harder it is to control the fracture height extension. Under different liquid volumes, the fracture height extends to the water layer. When the liquid volume is $\geq$ 100 m$^3$, the fracture height passes through the water layer; The greater the stress difference between the reservoir compartments (Fig. 9d), the easier it is to control the height of the fractures. When the stress difference is 2-8 MPa, the depth of the fractures extending towards the barrier layer gradually decreases, but all fractures extend to the water layer; When the stress difference is greater than or equal to 10 MPa, the fracture height is suppressed and only extends in the reservoir.

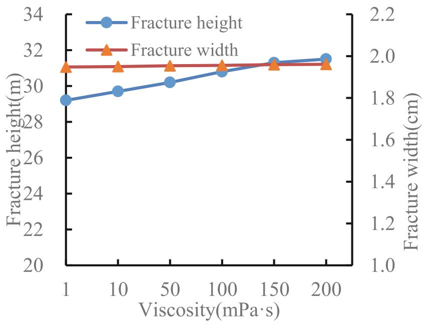
②Analysis of factors affecting fracture height and fracture width.

Figure 10 shows the variation curves of fracture width and fracture height for typical model 2 under different conditions based on the above simulation results. The influence of pumping rate and liquid volume on fracture width and fracture height is similar, and both increase fracture height and fracture width, but the influence of pumping rate is higher than that of liquid volume. The greater the stress difference in the reservoir, the smaller the fracture height and the larger the fracture width. The effect of viscosity on fracture height and width is relatively small.

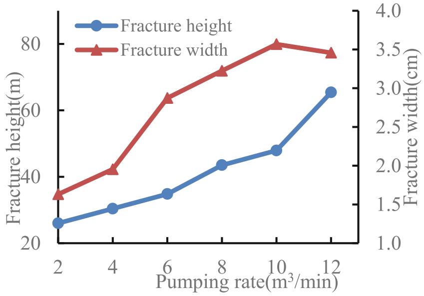
③Analysis of fracture height passing through the barrier layer.

From Fig. 11, it is found that unless the stress difference in the reservoir compartment is greater than 8 MPa, the water layer will be penetrated, and different parameters will affect the depth of the fracture height penetrating the water layer and entering the lower compartment (represented by the penetration rate of the lower compartment). Hydraulic fractures rarely enter the upper partition layer, so the focus is on analyzing the influence of various parameters on the penetration rate of the lower partition layer. Figure 11 shows the variation curve of the penetration rate of the partition layer under different conditions for typical model 2. The viscosity and liquid volume are positively correlated with the penetration rate of the lower compartment, but the penetration rate is not significant. The two parameters have a relatively small impact on the extension of the fracture height within the lower compartment. The pumping rate and stress difference of the reservoir have a relatively significant impact on the penetration rate of the lower reservoir. Both high pumping rate and low stress differences can lead to a 100% penetration rate of the lower reservoir.

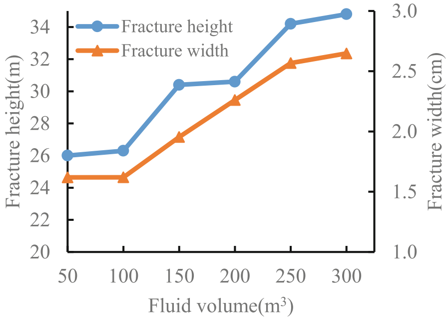
It can be seen that in the Meishan Formation of the Lingshui North Slope Gas Reservoir, without a barrier between the gas and water layers, hydraulic fracturing will be difficult to avoid hydraulic fractures communicating with the water layers. Therefore, it is not recommended to carry out hydraulic fracturing in such reservoirs.



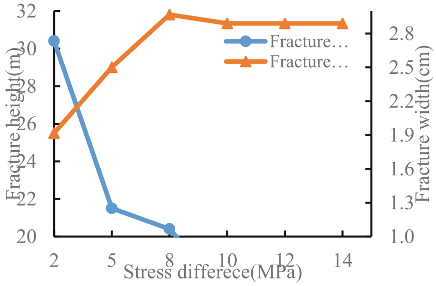

a. Effect of viscosity




b. Effect of pumping rate




c. Effect of fluid volume




d. Effect of stress difference

**Fig. 10.** Curve of fracture width and fracture height under different conditions (typical model 2)

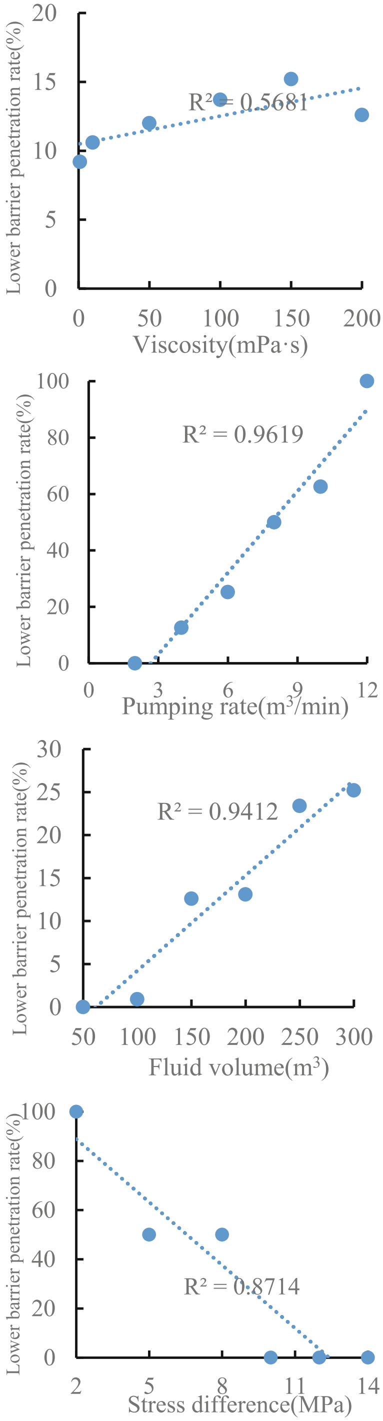



**Fig. 11.** Curve of barrier layer penetration under different conditions (typical model 2)

## 5 Conclusion

The use of large pumping rate fracturing may lead to high treatment pressure, small stress differences between the reservoir and the barrier layer, which can easily lead to uncontrolled fracture height, and the use of fracturing may lead to communication with the water layer, resulting in water flooding of the gas well. These are key issues that constrain the fracturing of the Lingshui North Slope gas reservoir. The fracture pressure of the Meishan Formation in the Lingshui North Slope Gas Reservoir is 69 ~ 98 MPa, and the predicted treatment pressure is 70 ~ 100 MPa. The use of large-sized oil pipes is beneficial for reducing treatment risks. For the situation where there is a good barrier layer between the gas and water layers, the pumping rate and liquid volume are the key factors affecting the height of the fracture. It is necessary to control the pumping rate not to exceed 6m3/min and the liquid volume not to exceed 250 $m^3$. In the absence of a barrier between the gas and water layers, it is difficult to avoid hydraulic fracturing from communicating with the water layers. Therefore, hydraulic fracturing is not recommended for such reservoirs.

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## Symbol Description

$P_{stp}$ Ground treatment pressure, MPa
$P_{bhtp}$ Bottom hole operating pressure or formation fracture, MPa
$P_f$ Wellbore friction pressure, MPa
$P_{pnwb}$ Perforated hole and wellbore friction, MPa
$P_h$ Wellbore hydrostatic pressure, MPa
$P_f$ Frictional resistance of the entire wellbore, MPa
$\lambda_i$ Friction coefficient of the well section
$L_i$ Length of the well section, m
$D_i$ Diameter of the well section, m
$v_i$ Fluid velocity in the well section, m/s

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