The effects of time variable fracture conductivity on gas production of horizontal well fracturing in natural gas hydrate reservoirs

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Abstract

Hydrate reservoirs in the South China Sea belong to muddy silt-type hydrate reservoirs with low permeability. Horizontal well fracturing is one of the main stimulation methods for low-permeability oil and gas reservoirs. For muddy silt-type hydrate reservoirs, the stability and effectiveness of hydraulic fractures may be a severe problem due to poor reservoir cementation, reservoir deformation, and sand production. In this paper, the time variability of fracture conductivity is considered for the first time. According to the geological data at offshore gas hydrate production test site in the South China Sea, a multilayer hydrate reservoir model was established, and the influence of the time variable fracture conductivity on the production behavior in the process of horizontal well fracturing was analyzed. The simulation results show that, compared with the case of constant fracture conductivity, the gas production rate with the case of time variable fracture conductivity is greatly reduced, and the 5-year cumulative gas production is reduced by 49.9%. Sensitivity analysis shows that the larger the initial fracture conductivity, the higher the peak gas production rate; the larger the attenuation magnitude of the fracture conductivity, the lower the gas production rate in the late production period; the larger the decline rate coefficient of the fracture conductivity, the higher the gas production rate in the early production period. The analysis of the orthogonal experimental design shows that the influence of the attenuation magnitude of fracture conductivity, the initial conductivity of fracture, and the decline rate coefficient of fracture conductivity on the cumulative gas production decreases in order. The actual production process should try to avoid excessive attenuation magnitude of fracture conductivity, while improving the initial fracture conductivity as much as possible to ensure high cumulative gas production.
INTRODUCTION

Natural gas hydrates (NGH) are ice-like crystalline compounds consisting of light hydrocarbons, CO$_2$, H$_2$S, and water under certain temperature and pressure conditions. NGH are formed under relatively low temperature and high-pressure conditions and are usually found in permafrost zones and deep-sea sediments. Compared to other traditional fossil energy sources (e.g., coal and oil), natural gas hydrates are a new clean fossil fuel that produces less CO$_2$. As an abundant future energy resource, the global natural gas reserves in gas hydrates are about $2.1 \times 10^{16}$ m$^3$, and the total carbon content of the energy contained in gas hydrates is twice the carbon content of proven fossil energy sources, exceeding all known oil and gas resources. If gas hydrate can be extracted economically and efficiently, it will be of great importance to the world’s energy security.

Although gas hydrate resources are abundant, more than 90% of the world’s gas hydrates are found in muddy silt deposits. Muddy hydrate reservoirs are characterized by low permeability, resulting in low gas production for long-term production. Common methods used to recover gas hydrate reservoirs include depressurization, thermal stimulation, chemical inhibitor injection, and carbon dioxide replacement. In March 2002, Canada successfully test-mined permafrost gas hydrate in the Mallik 5L-38 well using the thermal injection method. In 2011, the United States used the CO$_2$-CH$_4$ replacement method for the first time in the North Slope of Alaska to achieve combustible ice mining. In 2013, Japan used the depressurization method and produced $1.2 \times 10^5$ m$^3$ methane gas. In 2017, Japan conducted the second trial production and produced a total of $2.4 \times 10^5$ m$^3$ of methane gas. In 2017, China carried out the first trial production test of combustible ice in Shenhu area of the South China Sea. The trial production took the depressurization method as the core, with a continuous production of 60 days and a cumulative gas production of $30.9 \times 10^5$ m$^3$, daily average gas production $5151$ m$^3$. From October 2019 to April 2020, China conducted its second gas hydrate trial in the South China Sea at a water depth of 1225 m in the Shenhu Sea. The trial production has produced gas continuously for 42 days, with total gas production of $149.86 \times 10^4$ m$^3$ and average daily gas production of $3.57 \times 10^3$ m$^3$. Although test mining of hydrate reservoirs has been conducted in many countries, current average gas production is lower than the commercial extraction standards. It is reported that the commercial production level is $3.0 \times 10^5$ m$^3$/day. Therefore, for the development of hydrate reservoirs, more effective production measures should be taken to increase the natural gas production of low-permeability hydrate sediments, so as to achieve long-term economic and feasible hydrate gas production.

Hydraulic fracturing technology is widely used in unconventional low-permeability oil and gas reservoirs such as shale gas reservoirs, and increased oil and gas production has been achieved through hydraulic fracturing technology. Therefore, hydrate reservoirs as low-permeability gas reservoirs also have the potential to enhance production through hydraulic fracturing techniques. Through hydraulic fracturing, high conductivity channels can be formed in low permeability hydrate reservoirs to increase hydrate decomposition area and accelerate hydrate decomposition. At the same time, fracturing increases reservoir permeability and accelerates gas and liquid production. In recent years, some scholars have studied the effect of hydraulic fracturing on gas production from hydrate reservoirs through indoor experiments and simulation.

Current experimental studies have focused on whether hydrates can be fractured and less on the impact of fracturing on enhancing gas production. Ito et al. simulated a hydrate formation and its overburden formation with a combination of sand and kaolinite, and injected fracturing fluid into an injection tube buried in the sample; when the injection pressure reached 3.8 MPa, the sample showed obvious fractures, and the fracturing fluid extended the primary fracture between the two formations, while secondary fractures penetrated further into the interior of both formations, which demonstrated the potential for hydraulic fracturing between hydrate reservoirs and different media formations. Konno et al. conducted hydraulic fracturing experiments on methane hydrate-bearing sediments and measured permeability, and observed the process of fracture generation in the sediments through an X-ray CT scanner, and this result demonstrated the feasibility of fracturing hydrate-bearing sediments. Too et al. found that fracturing of hydrate-bearing sediments extends existing fractures and creates new ones. At the same time, hydrate-bearing sediments with hydrate saturation larger than 40% can be fractured.

In terms of numerical simulation, many scholars have studied the stimulation effect of hydraulic fracturing. Chen et al. calculated the variation of CH$_4$ gas production and cumulative production under different fracturing conditions. They found that CH$_4$ production increased with the number of fractures. Sun et al. evaluated the gas production...
performance of horizontal well depressurization assisted by hydraulic fracturing through numerical simulations based on field data of the hydrate reservoirs in the South China Sea. They found that hydraulic fracturing technique can greatly reduce the number of operating wells, shorten the drilling operation time and improve economic benefits. Through numerical simulation, Shang et al.\(^4,41\) studied the influence of fracture length and fracture conductivity on the production performance of artificial fracturing type 3 hydrate reservoir. They found that fracture length can increase gas production, but fracture conductivity has limited effect on improving natural gas production. Ma et al.\(^4,42\) conducted a feasibility study on hydraulic fracturing of hydrate reservoirs at China's first offshore hydrate production site and studied the effect of horizontal well location on gas production. They found that gas production increased by 60.29\% when the horizontal well was in a mixed layer compared to the case without fracturing. Yu et al.\(^4,43\) established a multilayer hydrate reservoir model with low permeability and studied the effect of horizontal well fracturing fractures on improving gas recovery. They found that horizontal fractures can greatly promote the long-term recovery of the reservoir, while vertical branch fractures play a significant role in short-term recovery.

From the above experimental and numerical simulation studies, it can be seen that most scholars have focused on fracturing feasibility, fracturing scales, and fracturing parameters for fracturing hydrate reservoirs. However, for muddy silt hydrate reservoirs, the stability and effectiveness of hydraulic fracturing may be a severe problem due to poor reservoir cementation, reservoir deformation, and sand production of the formation. In the conventional oil and gas field, there are many research on the time variable parameters of conductivity (initial fracture conductivity) to carry out experimental research on the embedment of proppant in formation cores. Through the regression of experimental data, the change law of conductivity with time was obtained. Wang et al.\(^4,44\) believe that in the production process of tight gas wells, the fracture conductivity will change continuously, with time-varying effect. Yuan et al.\(^4,46\) believe that the fracture conductivity decreases continuously with time due to the influence of formation stress, and the decreasing law is affected by various factors such as stress size, rock property, and laying thickness. At present, the research on fracture stability of fractured hydrate reservoir is not clear. The decrease of reservoir pressure in depressurization production will lead to the increase of effective stress and vertical deformation of the reservoir. Because of the poor cementation and low strength of the natural gas hydrate reservoir, the hydrate acts as a cement between the sediment particles in the reservoir, and the decomposition of hydrate caused by depressurization will reduce the strength of the reservoir. The reservoir will be very easy to deform,\(^4,47,48\) which will influence the flow-conducting ability. Sand production\(^4,49,50\) is also an essential factor affecting conductivity. In the process of depressurization mining, when the reservoir pressure is lower than the hydrate phase equilibrium pressure, the natural gas hydrate as the cementing material between the formation sandstones begins to decompose. When the pore fluid flow rate in the hydrate reservoir exceeds the critical velocity of sand,\(^5,52\) the formation starts to produce sand. The reservoir pressure drops too fast can lead to a large amount of sand production of the formation, and the flowing sand can be carried into the fracture, blocking the fracture channel and reducing the flow conductivity. Moreover, factors such as proppant breakage, embedded formation, and rock debris plugging will also lead to the change of fracture conductivity with time.\(^53\) These conditions tend to lead to gradual changes in fracture conductivity over time. In serious cases, it will lead to the closure of fractures and even the failure of conductivity. Therefore, we need to study the effects of the time variable fracture conductivity on production during hydrate reservoir extraction.

In this study, we aimed to study the effects of time variable fracture conductivity on production performance during horizontal well fracturing to exploit hydrate reservoirs through numerical simulation. First, based on the parameters of a trial hydrate reservoir in the South China Sea, we fitted the trial gas production data of hydrate reservoir in the South China Sea by vertical well depressurization to verify the reliability of the numerical simulation method. Then, a numerical simulation model of horizontal well fracturing was built. The horizontal well was located in the mixed layer, and the fracture was vertical fracture. The production under the condition of constant fracture conductivity and time variable fracture conductivity was compared. Furthermore, the sensitivity of time variable parameters of conductivity (initial fracture conductivity, attenuation magnitude of fracture conductivity, and decline rate of fracture conductivity) was analyzed to provide certain valuable suggestions for the process of fracturing exploitation of hydrate reservoirs.

## 2 | Numerical Simulation

### 2.1 | Geological background

The first gas hydrate production test area in the South China Sea is located in the middle of the land slope in the southeastern part of the Shenhua area, between the Xisha Trough and the Dongsha Islands in the northern part of the South China Sea (Figure 1).\(^5,4\) The area has a water depth of 1000–1700 m, the seafloor temperature is about
3.3–3.7°C, and the geothermal gradient is 45–67°C/km. According to the log interpretation and SHSC-4 core analysis results, the overburden formation is from the seafloor to 1495 m (water depth 1266 m). The hydrate reservoir in the area consists of three parts: hydrate layer A (water depth 1495–1530 m), which contains only hydrate and water in the pore space; three-phase layer B (water depth 1530–1545 m), which is filled with three phases in the pore space: solid NGH, free hydrocarbon gas and liquid water; and free gas layer C (water depth 1545–1572 m), which contains only free hydrocarbon gas and liquid water in the pore space. The reservoir rock type is muddy silt, the average effective porosity of section “A” is 35%, the average hydrate saturation is 34%, and the average permeability is 2.9 mD; the average effective porosity of section “B” is 33%, the average hydrate saturation is 31%, and the average permeability is 1.5 mD; the average effective porosity of section “C” is 32%, the average hydrate saturation is 7.8%, and the average permeability is 7.4 mD. The parameters of Shenhua NGH reservoir in South China Sea involved in the model are shown in Table 1.

### Table 1: Main properties and models used in the simulations

| Parameter                              | Value and model               | Parameter                              | Value and model               |
|----------------------------------------|-------------------------------|----------------------------------------|-------------------------------|
| Initial pressure, $P_0$ (at bottom of TPL-B) | 15.1 MPa                      | Gas saturation of FHGL $S_{GC}$         | 0.078                         |
| Initial temperature, $T_0$ (at bottom of TPL-B) | 16.4°C                       | Initial permeability of FGL $k_x = k_y = k_z$ | 7.4 mD                       |
| Borehole radius, $r_w$                 | 0.1 m                         | Production pressure $P_w$              | 3 MPa                         |
| Geothermal gradient, $\Delta T$        | 0.054°C/m                     | Fracture conductivity                  | 800 mD·m                      |
| Grain density                          | 2650 kg/m$^3$                 | Fracture length                        | 100 m                         |
| Overburden thickness, $H_0$            | 30 m                          | Fracture spacing                       | 60 m                          |
| Underlying thickness, $H_u$            | 30 m                          | Relative permeability mode             | $K_{rw} = [(S_w - S_{irw})/(1 - S_{irw})]^{n_w}$ |
| HBL-A thickness, $H_A$                 | 34 m                          |                                        | $K_{rg} = [(S_g - S_{irg})/(1 - S_{irg})]^{n_g}$ |
| Initial hydrate saturation of HBL-A, $S_{HA}$ | 0.34                          | $n_w$                                  | 3.5                           |
| HBL-A porosity, $\phi$                | 0.35                          | $n_g$                                  | 2.5                           |
| Initial permeability of HBL-A, $k_x = k_y = k_z$ | 2.9 mD                       | $S_{irw}$                              | 0.50                          |
| TPL-B thickness, $H_B$                 | 14 m                          | $S_{irg}$                              | 0.05                          |
| Initial hydrate saturation of TPL-B, $S_{HB}$ | 0.31                          | Capillary pressure model               | $P_{cap} = -P_0 [S^{n-1/4} - 1]^{-1}$ |
| TPL-B porosity, $\phi$                | 0.33                          |                                        | $S^* = (S_w - S_{irw})/(1 - S_{irw})$ |
| Initial permeability of TPL-B, $k_x = k_y = k_z$ | 1.5 mD                       | $P_0$                                  | $10^5$ Pa                     |
| FGL thickness, $H_C$                  | 28 m                          | $\lambda$                              | 0.45                          |
functions of the simulator are powerful. The CMG-STARS is primarily developed for thermal recovery. The simulator considers the coupling effect of fluid flow, heat transfer, and fines transport in porous media and wellbore. Many scholars use this software to simulate hydrate. In 2006, Uddin et al. extended the kinetic formula of hydrate formation and decomposition and embedded it into CMG-STARS. Using this model, they simulated the formation and decomposition of methane and carbon dioxide hydrate. The results are in good agreement with the published literature, which proves the reliability of the model. In 2008, Gaddipati et al. conducted a detailed study on the application of CMG-STARS module in hydrate mining simulation, and compared its simulation results with those of other hydrate simulators, indicating the feasibility of CMG-STARS module in hydrate mining simulation. In 2016, when Myshakin et al. studied Prudhoe Bay Hydrate reservoir on the northern slope of Alaska, they established a three-dimensional heterogeneous geological model based on Geostatistics using a large number of well logging data, and then used CMG-STARS to conduct productivity numerical simulation. In 2020, Wang et al. used CMG-STARS numerical simulation software to analyze production dynamic and evaluate the influence of the main production parameters of heat injection combined depressurization in Shenhu hydrate reservoir. CMG-STARS has become one of the main hydrate simulators.

### 2.3 Numerical model and simulation parameters

As shown in Figure 2, based on the SHSC-4 well offshore gas hydrate reservoir in the Shenhu area of the South China Sea, the hydrate extraction simulation software CMG-STARS was used to establish its reservoir geological model. The model is assumed to have a water depth of 1266 m. The thickness of the overburden and the underlying layer is set to 30 m. The methane hydrate reservoir is divided into three sublayers from top to bottom, including the hydrate layer (HBL)-A layer (thickness = 34 m), three phase layer (TPL)-B layer (thickness = 14 m), and FGL-C layer (thickness = 28 m), representing the hydrate layer, three-phase layer and free gas layer, respectively. The reservoir geological model size is 400 m x 400 m x 136 m, and the corresponding grid division is 40 x 40 x 58. In the vertical direction, the thickness of the grid is not uniform, with a grid block thickness of 2 m for the hydrate layer and 3 m for the overburden and underlying layers. The parameters and numerical models of each layer are shown in Table 1.

### 2.4 Mechanism of hydrate decomposition

In porous media, the equilibrium or stability of natural gas hydrate mainly depends on pressure and temperature. Li et al. obtained the hydrate phase equilibrium formula in porous media based on the experimental measurement and data regression of natural gas hydrate. The formula is expressed as:

$$ P_e = 8 \times 10^{-13} \times e^{0.1052T_e} $$

where $P_e$ is the phase equilibrium pressure, MPa; $T_e$ is the phase equilibrium temperature, °C. The phase equilibrium curve is shown in Figure 3.

The initial state of the hydrate reservoir is in a stable state, and when it is produced under low pressure, the hydrate reservoir pressure is reduced, breaking the initial phase equilibrium state, and the hydrate starts to decompose. The following formula usually expresses the kinetic decomposition process of natural gas hydrate:

$$ CH_4(g) + nH_2O(w) \rightleftharpoons CH_4nH_2O(s). $$

Typically, one mole of methane hydrate (CH$_4$ nH$_2$O) consists of 46 water molecules and eight wrapped gas molecules. The ratio of these water molecules to gas molecules is called the hydrate number $n$, with an average $n = 5.75$. Theoretically, 1 m$^3$ NGH can be decomposed into about 0.8 m$^3$ water and 164 m$^3$ natural gas at standard atmospheric pressure.

Currently, the kinetic equation for hydrate decomposition proposed by Kim-Bishnoi is mainly used for calculations domestically and internationally.

$$ \frac{dn_h}{dt} = k_d A_s (P_{eq} - P_g), $$

where $n_h$ is the amount of substance per unit volume of natural gas hydrate at time $t$, mole; $A_s$ is the total surface area of hydrate particles, m$^2$; $k_d$ is the rate constant of hydrate decomposition, temperature-dependent, (mole/min-m$^2$-Pa); $P_{eq}$ is the natural gas hydrate three-phase equilibrium pressure, Pa; $P_g$ is the gas-phase pressure, Pa.

Uddin derived a general form of hydrate decomposition rate based on the Kim-Bishnoi model, and this equation was applied to the CMG-STARS numerical simulator. The final form of the hydrate decomposition rate can be written as:
\[ \frac{dn_h}{dt} = A \exp\left(-\frac{E}{RT}\right) (\phi S_w \rho_w)(\phi S_H \rho_H) 
\left(\gamma_P^w \left(1 - \frac{1}{K(P, T)}\right)\right), \]  

(4)

where \( A \) is the hydrate reaction frequency factor, (mole/m³)⁻¹/(d·KPa), “\( \phi S_w \rho_w \)” is the oxygen concentration factor, “\( \phi S_H \rho_H \)” is the hydrate concentration; the factor \( \left(1 - \frac{1}{K(P, T)}\right) \) is the driving force of hydrate decomposition, \( K(P, T) \) is the hydrate equilibrium value at pressure \( P \) and temperature \( T \), and \( E \) is the hydrate activation energy.

### 2.5 Initial conditions

The temperature distribution of the whole hydrate formation can be calculated from the empirical equation based on the seafloor's measured temperature and temperature gradient in the area.

\[ T = T_0 + \Delta T Z, \]  

(5)

where the seabed temperature \( T_0 \) is 3.6°C, the temperature gradient \( \Delta T \) is 0.054°C/m, and \( Z \) is the depth below the seabed.
Gas hydrates in Shenhu area of the South China Sea are mainly distributed in poorly consolidated fine-grained sediments. Since the methane hydrate reservoir in this area is permeable, it is reasonable to assume that the pore water in natural gas hydrate reservoir of this area could be exchanged with seawater. Therefore, it is assumed that the pore water pressure in the reservoir follows the hydrostatic pressure and can be calculated by empirical equation as below:

$$P_p = P_0 + \rho_{sw} g (H + Z),$$

where $P_p$ is the pore pressure at any point in the model, MPa, and $P_0$ is the standard atmospheric pressure, considered to be 0.101325 MPa. The seawater density $\rho_{sw}$ is set to 1000 kg/m$^3$ and $g$ is the acceleration of gravity, 9.806 m/s$^2$. The distance from the top of hydrate A to sea level is 1495 m (Figure 2) and is denoted by $H$. $Z$ is the distance from the top of HBL-A. The upper part of HBL-A is negative and the lower part is positive.

2.6 Production well design

As shown in Figure 2, in one case, the vertical production well is located at the center of the hydrate reservoir model, $r_w = 0.1$ m. The length of the perforation section of the production well is set to 52 m, the hydrate layer and the three-phase layer are all perforated, and the free gas layer is partially perforated. In the other case, the horizontal well is fractured at the top of the three-phase layer. The length of the horizontal well is 200 m, the number of fracture segments is 4, the half-length of fracture is 100 m, the fracture height is 18 m, and the initial fracture conductivity is 800 mD·m. Referring to the 2017 Shenhu production test well, the bottom pressure of the production well was set to 3 MPa and the production time was 5 years.

2.7 Time variable fracture conductivity

In the conventional oil and gas field, many indoor experiments have proved that the fracture conductivity formed by hydraulic fracturing is constantly changing with time. Many factors influence fracture conductivity and are difficult to describe using a typical mathematical formula. At present, the fracture variable conductivity effect is mainly measured based on the indoor proppant conductivity test, and then regression analysis of the test data is performed to obtain the empirical equation for the time variable conductivity.

Most fracturing experiments have studied the fracturing feasibility of the hydrate reservoir and the expansion law of the fracturing fracture. There are few indoor studies on the time variable fracture conductivity. Sun et al. mentioned in his paper that for hydrate reservoirs, the positive effect of fracturing in the initial stage is evident, but considering the dissociation of hydrates and compaction of formation due to depressurization, the sediments adjacent to the fractures and conduits will lose cementation and collapse, artificial fractures are likely to degenerate in the later stage. Therefore, we believe that in the actual production process, due to the weak cementation of hydrate reservoir, formation deformation, sand production, proppant fragmentation, and other factors, the fracture conductivity is prone to change with time. We believe that the time variable law of conductivity after hydraulic fracturing is similar between muddy silty sand hydrate reservoir and conventional oil and gas reservoir. The main difference is the decline rate and attenuation magnitude of conductivity.

Scholars have done many proppant conductivity experiments to study the effect of fracture variable conductivity, and there are mainly two types of variations of time variable conductivity, logarithmic and exponential relationships. For the logarithmic time variable conductivity formula, the conductivity is affected by three parameters: the initial fracture conductivity, time-varying parameter, and time. For the exponential time variable conductivity formula, the conductivity is affected by four parameters: initial fracture conductivity, time, attenuation magnitude, and decline rate. The time variable fracture conductivity laws of these two formulas are similar. The logarithmic formula is simpler and the exponential formula is more complicated. However, the exponential formula is more detailed in explaining the time variable fracture conductivity. Considering the effect of the attenuation magnitude and decline rate coefficient of fracture conductivity to be analyzed in this study, the following exponential relationship equation was selected:
\[ F_{ct} = F_{ci} \left( \eta e^{-\frac{t}{b}} + 1 - \eta \right) \]  

(7)

\( F_{ct} \) is the initial fracture conductivity, mD·m, \( F_{ci} \) is the fracture conductivity at a certain time, mD·m, \( t \) is the production time, \( \eta \) is the coefficient that controls the attenuation magnitude of the conductivity, and the coefficient \( b \) controls the decline rate of the conductivity, \( y \).

3 | RESULTS AND DISCUSSIONS

3.1 | Model validation

As shown in Figure 2A, we have established a three-layer hydrate reservoir geological model. The initial temperature and pressure of the model are the temperature and pressure at the bottom of the three-phase layer, which are 16.4°C and 15.1 MPa, respectively. The vertical well is located in the center of the model, and the hydrate layer and three-phase layer are all perforated, and the free gas layer is partially perforated. The diameter of the vertical well is 0.1 m, the bottom hole pressure is 3 MPa, and the production time is 60 days.

In this section, we calculated the gas production results of the gas hydrate reservoir in the South China Sea for 60 days through the numerical simulation software, and compared them with the first trial production data of the South China Sea hydrate reservoir to verify the reliability of the simulation model established in this paper.

The 60-day simulation results of vertical well depressurization exploitation of hydrate reservoirs in the South China Sea can be seen in Figure 4. It can be seen from the figure that the simulated gas production peak is \( 3.63 \times 10^4 \) m³/d, the gas production rate at the end of 60 days is \( 3991.31 \) m³/d, the cumulative gas production in 60 days is \( 3.05 \times 10^5 \) m³, and the average gas production rate in 60 days is \( 5083 \) m³/d.

The peak gas production rate in the actual trial production in the South China Sea is \( 3.5 \times 10^4 \) m³/d, the cumulative gas production in 60 days is \( 3.09 \times 10^5 \) m³, and the average daily gas production is \( 5151 \) m³. \(^{29}\) It can be seen that the simulation results are in good agreement with the actual test production data, which verifies the reliability of the simulation model established in this paper, and provides effective support for the subsequent study of horizontal well fracturing to exploit hydrate reservoirs in the South China Sea.

3.2 | Production performance under time-varying conductivity

3.2.1 | Gas and water production

Figure 5 illustrates the variation trend of the fracture conductivity. The initial conductivity \( F_{ci} \) is \( 800 \) mD·m, the conductivity decay rate \( b \) is 0.2 year, the conductivity attenuation magnitude \( \eta \) is 0.95, and the fracture conductivity decays from \( 800 \) to \( 40 \) mD·m in 1 year. If the time variable effect of conductivity is not considered, the conductivity of the entire production process is constant. We will compare the gas production, water production behavior, and production performance in the two cases below.
Figure 6 illustrates the evolution of the gas production rate and cumulative gas production under the two cases of constant and time variable fracture conductivity. As shown in the figure, the peak gas production rate at constant conductivity is slightly higher than that at time variable conductivity, and the peak gas production rates are $7.27 \times 10^4$ and $7.04 \times 10^4$ m$^3$/d, respectively. In both cases, the gas production rate decreased to a low level at the end of 1 year. The gas production rate is $2.70 \times 10^4$ m$^3$/d at the end of 5 years with constant conductivity, and $1.34 \times 10^4$ m$^3$/d at the end of 5 years with time variable conductivity. It can be seen from the figure that the gas production rate decreases faster when the time variable conductivity is considered, and the gas production rate is lower at the same time. The cumulative gas production is $5.19 \times 10^7$ m$^3$/d with constant conductivity, the cumulative gas production is $2.60 \times 10^7$ m$^3$/d with time variable conductivity, and the cumulative gas production is attenuated by 49.9%.

Figure 7 illustrates the evolution of the water production rate and cumulative gas production under the two cases of constant and time variable fracture conductivity. Similar to the gas production behavior, the peak water production rate with constant conductivity is slightly higher than that with time variable conductivity, and the peak water production rates are 109 and 106 m$^3$/d, respectively. The former declined more slowly, and the water production rates at the end of the 5 years were 42.8 and 28.5 m$^3$/d, respectively. The cumulative water production under the constant conductivity is also much higher than that under the time variable conductivity, which is $1.14 \times 10^5$ and $6.48 \times 10^4$ m$^3$/d, respectively.

3.2.2 Distribution characteristics of the physical properties

The spatial evolutions of the pressure in two cases (Case 1: constant fracture conductivity; Case 2: time variable fracture conductivity) are shown in Figure 8. Since the horizontal well is located at the top of the TPL and the fracturing fractures are vertical fractures, both the HBL and the TPL are fractured, to form channels with high conductivity. When horizontal wells are produced with constant bottom flow pressure, gas, and liquid are produced rapidly at the initial stage of production due to the relatively large production pressure difference ($P_w = 3$ MPa). In addition, the pressure at the fracture begins to drop first because of the existence of fracture channels with high conductivity. As the production progresses, the TPL is the first to produce gas and hydrate decomposition due to the high initial gas saturation. Due to the effect of gravity, the FGL transports gas upward and produces, while the HBL breaks the initial phase equilibrium conditions as the formation pressure reduces, and the hydrate starts to decompose, which can also increase the formation permeability and expand the range of pressure reduction.

In Case 1 (constant fracture conductivity), the formation fluid can keep a high rate of production because the fracture keeps a high conductivity channel. Furthermore, the existence of high conductivity fracture promotes hydrate decomposition, which increases the formation permeability and accelerates the gas–liquid production, so the reservoir pressure reduces more rapidly. In Case 2 (time variable fracture conductivity), the fracture conductivity decreases rapidly within 1 year and remains stable in the following years. As shown in Figure 8, the reservoir pressure in Case 1 is lower than
that in Case 2 during the same gas production period. This is because the lower the fracture conductivity, the lower the gas and water production rate. Moreover, in Case 2, the slow decomposition of hydrate has limited effect on the increase of formation permeability, so the pressure drops slowly. In both cases, the hydrate reservoir pressure is gradually reducing.

The spatial evolutions of the temperature in two cases (Case 1: constant fracture conductivity; Case 2: time variable fracture conductivity) can be seen in Figure 9.
As shown in Figure 9, the temperature of the reservoir gradually decreases due to the decomposition endothermic effect of gas hydrate in the HBL-A and the TPL-B. In both cases, the temperature of the HBL-A reduced relatively rapidly, and a wide range of low-temperature region appears in HBL-A at the end of 5 years. This is because the horizontal well is set at the top of the TPL-B, the thickness of the HBL-A is higher than that of the TPL-B, and the hydrate solid concentration of the HBL-A is higher than that of the TPL-B. Because more hydrates are stored in HBL-A, more heat needs to be absorbed from the reservoir during the depressurization decomposition process, so the reservoir temperature in HBL-A decreases faster, and the final temperature is also lower. Meanwhile, hydrate decomposition in TPL-B also causes the temperature to decrease, and the decomposition of hydrate in TPL-B does not only absorb heat from TPL-B. It can be seen that the temperature of FGL-C decreases gradually with time, and the heat of the hydrate reservoir itself cannot meet the energy required for decomposition at the late production stage. Therefore, the heat of both the FGL-C and underlying layer starts to transport to the hydrate layer, and the temperature of the overburden layer also decreases.

Additionally, the comparison of the temperature distribution of constant fracture conductivity case and time variable fracture conductivity case shows that the reservoir temperature in Case 1 decreases more rapidly than that in Case 2 during the same gas production period. Meanwhile, the final low-temperature region range in Case 1 is larger than that in Case 2 and the temperature in Case 1 is lower than that in Case 2 at the end of 5 years. In Case 1, the whole hydrate reservoir temperature decreases to a relatively low level. The main reason is that, when considering the time variable conductivity, it will lead to the formation fluid cannot be produced quickly, the formation pressure decreases slower, the driving force of hydrate decomposition decreases, the rate of hydrate decomposition becomes slower, and the less heat is absorbed, and the reservoir temperature decreases less.

Detailed analyses of the spatial distributions of hydrate solid-phase concentration evolution in two cases are depicted in Figure 10. As shown in the figure, due to low bottom hole pressure and high conductivity fractures, hydrates near the fractures begin to decompose first. The closer to the wellbore and fracture area, the faster the hydrate decomposes, the faster the hydrate solids content decreases, and the less hydrate ultimately remains. Meanwhile, we found that the hydrate solid concentration in the TPL-B is less than the hydrate solids concentration in the HBL-A during the same gas production period in both cases. On the one hand, the initial solid concentration of hydrate in HBL-A is higher than that in TPL-B; on the other hand, due to the high initial gas saturation in the TPL-B, the fluid is produced rapidly during production, and the pressure in TPL-B reduces faster, and the temperature in TPL-B is also higher, so the hydrate in TPL-B decomposes faster.

**Figure 10** Evolution of the hydrate solid phase concentration distribution in two cases (Case 1: constant fracture conductivity; Case 2: time variable fracture conductivity).
At the same time, it can be seen in Figure 10 that the content of hydrate solid phase in HBL-A and TPL-B with constant conductivity case is lower than that in HBL-A and TPL-B with time variable conductivity case. Moreover, the degree of hydrate decomposition near fractures in Case 2 (time variable conductivity) is much smaller than that in Case 1 (constant conductivity). In Case 2 (time variable conductivity), the fracture conductivity has decayed greatly in 1 year. In 1 year, the hydrate decomposition area of HBL-A (hydrate layer) in Case 2 is smaller than that in Case 1 (constant fracture conductivity), and the decomposition degree and range of hydrate at and near the fracture in Case 2 is smaller than that in Case 1. In addition, there is no obvious difference in the decomposition of hydrate in TPL-B under the two conditions of 1 year, because the thickness of the TPL-B itself is small, and the fluid flow speed and pressure propagation speed of the TPL-B are fast due to the presence of gas. The decomposition of hydrate in the TPL-B is weakly affected by the attenuation of fracture conductivity in a short period of time.

In the later stage of production, the influence of time variable fracture conductivity on hydrate decomposition becomes more and more obvious. In the 3rd and 5th years, the decomposition range and degree of HBL-A and TPL-B are obviously smaller in Case 2 than in Case 1, and the difference between them is obvious in the upper and lower regions of the horizontal well section. In the 5th year, the hydrate in Case 1 has been decomposed in a large range, and the degree of hydrate decomposition around the horizontal well is much higher than that in Case 2. This is because the conductivity in Case 2 has been attenuated to a very low level in the 3rd year, while the fracture in Case 1 has maintained a relatively high conductivity. In general, under the condition of time variable conductivity, the decomposition degree and decomposition range of hydrate at the same time are much smaller than that under the condition of constant conductivity, especially at the horizontal well section and fracture. The main reason is that the larger the fracture conductivity, the higher the rate of formation fluid production, the faster the pressure wave diffusion. Therefore, in Case 1, the reservoir formation pressure reduces rapidly, and the average formation pressure is also lower. In addition, in Case 1, the larger the driving force of hydrate decomposition, the faster the hydrate decomposition, and the lower the solid phase concentration. Moreover, hydrate decomposition increases the formation permeability and accelerates the formation gas and liquid production.

The spatial evolutions of the permeability of the reservoir in two cases (Case 1: constant fracture conductivity; Case 2: time variable fracture conductivity) are shown in Figure 11. The initial permeability of HBL-A is 2.9 mD and that of TPL-B is 1.5 mD. As shown in the figure, due to the continuous decomposition of hydrate, the permeability of the reservoir continues to increase. In the 5th year, the reservoir permeability in some areas of HBL-A and TPL-B has expanded to twice the initial value. And the permeability increases most rapidly in the
vicinity of horizontal wells and fractures. This is because hydraulic fracturing improves the permeability of the reservoir, reduces the reservoir pressure, and accelerates the decomposition of hydrate. Hydrate decomposition will lead to the increase of effective porosity in formation pores, so the reservoir permeability will increase.

At the same time, it can be seen from Figure 11 that in the first year, the permeability difference between the two cases is not particularly obvious, because the production time is short, the hydrate decomposition range is limited, the hydrate decomposition amount is not large, and the improvement of reservoir permeability is limited. In the 3rd year, it can be clearly seen that the increase range and amplitude of reservoir permeability in Case 1 (constant conductivity) is higher than that in Case 2 (time variable fracture conductivity). In the 5th year, the difference of reservoir permeability distribution in the two cases is more and more significant. In this case, the closer to the fracture, the faster the permeability of the reservoir increases, and the larger the growth range. The formation permeability at the middle of two fractures is less than that at the fracture. In the 5th year, in Case 1 (constant conductivity), the permeability of the upper and lower formations of the horizontal well increases in a large range, and the range and amplitude of permeability increase are much higher than that in Case 2 (time variable fracture conductivity). This is because in Case 2, the fracture conductivity has been reduced to a relatively small level in the later stage of production due to the rapid decline rate and large attenuation magnitude of fracture conductivity. The smaller the fracture conductivity is, the slower the production of formation fluid will be, which will lead to a slower drop of formation pressure near the wellbore and affect the decomposition of hydrate. When hydrate decomposition in reservoir pores is slow, the improvement of formation permeability is also limited.

3.3 | Sensitivity analysis of time variable parameters of fracture conductivity

From the above section, we found that the cumulative gas production in the time variable conductivity case is significantly attenuated compared with the cumulative gas production in constant conductivity case. From the time variable formula (Equation 7) of fracture conductivity described in this paper, it can be known that the factors affecting fracture conductivity are: initial fracture conductivity ($F_{ci}$), fracture conductivity attenuation magnitude ($\eta$), fracture conductivity decline rate coefficient ($b$). We have carefully analyzed the impact of these three parameters on production below.

3.3.1 | Effect of initial fracture conductivity

To study the effect of initial fracture conductivity, we kept the other two influencing parameters constant (fracture conductivity attenuation magnitude $\eta$ is 0.9 and fracture conductivity decline rate coefficient $b$ is 0.2 $y^{-1}$) and studied the production behavior for three cases with initial fracture conductivity $F_{ci}$ of 200, 400, and 800 mD-m, respectively. Figure 12 shows the conductivity variation with time for three different initial fracture conductivities. As shown in the figure, the higher the initial conductivity of the fracture, the higher the conductivity during the entire production process.

The gas production rates and cumulative gas production behavior for these three cases (Case 1: $F_{ci} = 200$ mD-m, Case 2: $F_{ci} = 400$ mD-m, Case 3: $F_{ci} = 800$ mD-m) are shown in Figure 13. The gas production rate peaked rapidly at the beginning of production, then decreased rapidly to the lowest value within 1 year, and then increased slowly. The peak gas production rates in the cases of $F_{ci} = 200$ mD-m, $F_{ci} = 400$ mD-m, and $F_{ci} = 800$ mD-m are about $4.17 \times 10^4$, $5.41 \times 10^4$, and $7.27 \times 10^4$ m$^3$/d, respectively. After continuous depressurization for 5 years, the gas production rates in the cases of $F_{ci} = 200$ mD-m, $F_{ci} = 400$ mD-m, and $F_{ci} = 800$ mD-m are about $1.21 \times 10^4$, $1.34 \times 10^4$, and $1.53 \times 10^4$ m$^3$/d, respectively. The 5-year cumulative gas production in the cases of $F_{ci} = 200$ mD-m, $F_{ci} = 400$ mD-m, and $F_{ci} = 800$ mD-m are approximately $2.20 \times 10^7$, $2.49 \times 10^7$, and $2.93 \times 10^7$ m$^3$, respectively. The effect of the initial conductivity on the peak gas production rate is relatively significant, and it also has a specific effect on the gas production rate in the late production period. The higher the initial conductivity, the higher the cumulative gas production.
conductivity of the fracture, the higher the peak gas production rate, and the higher the cumulative gas production.

3.3.2 | Effect of the attenuation magnitude of fracture conductivity

To study the effect of the attenuation magnitude of conductivity ($\eta$), we kept the other two influencing parameters constant (the initial fracture conductivity $F_{ci} = 800 \text{mD-m}$ and the decline rate coefficient of conductivity as $b = 0.2 \text{years}$) and studied the production behavior for three cases with the attenuation magnitude of conductivity of 0.6, 0.8 and 1, respectively. Figure 14 shows the conductivity variation with time for three different fracture conductivity attenuation magnitudes. As shown in the figure, the larger the attenuation magnitude, the smaller the final fracture conductivity, and the larger the difference of fracture conductivity in the three conditions in the late production period.

The gas production rates and cumulative gas production for these three cases (Case 1: $\eta = 0.6$, Case 2: $\eta = 0.8$, Case 3: $\eta = 1.0$) are shown in Figure 15. The gas production rate reaches the peak at the initial stage (1 month), then decreases rapidly, drops to a relatively low level after about 1 year, and then rises slowly. It can be seen from the figure that at the

FIGURE 13  Evolution of gas production and cumulative gas production in 5 years under different initial fracture conductivity.

FIGURE 14  Time variable curves of fracture conductivity with different fracture conductivity attenuation magnitude.

FIGURE 15  Evolution of gas production and cumulative gas production in 5 years under different conductivity attenuation magnitudes.

FIGURE 16  Time variable curves of fracture conductivity with different decline rate coefficients of fracture conductivity.
beginning of production, the initial fracture conductivity is the same and the attenuation magnitude of conductivity $\eta$ has little effect on the peak gas production rate. But there are obvious differences in the gas production rates during the whole production period. The larger the attenuation magnitude of fracture conductivity $\eta$, the smaller the fracture conductivity at the later stage of production, so the lower the gas production rate during the same gas production period. Moreover, the larger the attenuation magnitude of the conductivity, the lower the cumulative gas production.

3.3.3 | Effect of decline rate coefficient of fracture conductivity

To study the effect of the decline rate coefficient of fracture conductivity, we kept the other two influencing parameters constant (the initial conductivity of the fracture $F_{ci}$ is 800 mD·m and the attenuation magnitude of conductivity $\eta$ is 0.9) and investigated the production behavior for the three cases with the decline rate coefficient of the conductivity of 0.2, 0.4, and 0.6 y, respectively. Figure 16 shows the conductivity variation with time for three different fracture conductivity decline rate coefficients. As shown in the figure, the initial conductivity of the fracture is the same, and the decline of the fracture conductivity is slower when the decline rate coefficient $b$ is larger, the larger the fracture conductivity at the initial production stage, but the final conductivity is the same.

The gas production rates and cumulative gas production for these three cases (Case 1: $b = 0.2$ years, Case 2: $b = 0.4$ years, Case 3: $b = 0.6$ years) are shown in Figure 17. It can be seen from the figure that the decline rate coefficient of conductivity $b$ has little effect on the peak gas production rate. However, the smaller $b$ is, the faster the gas production rate decreases and the smaller the gas production rate at the same time. Moreover, the influence of decline rate is mainly reflected in the early gas production rate decline stage, but in the later gas production stage, the decline rate has little effect on the gas production rate. In terms of cumulative gas production, the larger the decline rate coefficient of fracture conductivity $b$ is, the smaller the cumulative gas production.$\overline{\lambda}$

![Figure 17: Evolution of gas production and cumulative gas production in five years under different fracture conductivity decline rate coefficients.](image)

| Test number | $F_{ci}$ (mD·m) | $\eta$ | $b$ (y) | Cumulative gas production/$10^7$ m³ |
|-------------|-----------------|-------|--------|----------------------------------|
| 1           | 200             | 0.6   | 0.2    | 2.71                             |
| 2           | 200             | 0.8   | 0.4    | 2.44                             |
| 3           | 200             | 1.0   | 0.6    | 2.15                             |
| 4           | 400             | 0.6   | 0.4    | 3.33                             |
| 5           | 400             | 0.8   | 0.6    | 2.95                             |
| 6           | 400             | 1.0   | 0.2    | 2.04                             |
| 7           | 800             | 0.6   | 0.6    | 4.22                             |
| 8           | 800             | 0.8   | 0.2    | 3.42                             |
| 9           | 800             | 1.0   | 0.4    | 2.35                             |

$\overline{\lambda}$

| $K$          | Cumulative gas production/$10^7$ m³ |
|--------------|-----------------------------------|
| $K_1$        | $2.43 \times 10^7$                |
| $K_2$        | $2.77 \times 10^7$                |
| $K_3$        | $3.33 \times 10^7$                |

| Range        | Cumulative gas production/$10^7$ m³ |
|--------------|-----------------------------------|
| $9.0 \times 10^6$ | $4.0 \times 10^6$ |

Prioritization

| Prioritization | Cumulative gas production/$10^7$ m³ |
|----------------|-----------------------------------|
| 2              | 1                                 |
| 1              | 3                                 |
conductivity, the higher the cumulative gas production, but the effect on cumulative gas production is not very significant. This is because the gas production in the stable stage in all three cases accounts for a relatively large proportion of the total 5-year gas production, and the gas production rates in the stable stage are not very different, so the decline rate coefficient \( b \) does not have a significant effect on the cumulative gas production.

### 3.3.4 Prioritization of influencing factors

In the previous sections, we analyzed the effects of initial fracture conductivity, fracture conductivity attenuation magnitude, and fracture conductivity decline rate coefficient on gas production. To investigate the influence of these three factors on cumulative gas production, we conducted an orthogonal test design, as shown in Table 2. The study found that the influence of fracture conductivity attenuation magnitude, fracture initial conductivity, and fracture conductivity decline rate coefficient on cumulative gas production decreased in sequence. Therefore, the main influencing factors should be given priority in the actual fracturing of hydrates. In actual production, the fracture conductivity attenuation cannot be avoided, but it should be avoided that the conductivity attenuation magnitude is too large, and the initial conductivity of the fracture can be increased to ensure higher gas production.

### 4 CONCLUSIONS

In this paper, we established a multilayer gas hydrate model based on the geological data at offshore gas hydrate production test site in the Shenhua sea of South China Sea by through the hydrate numerical simulation software CMG-STARs. Combined with the empirical formula of fracture conductivity time-variability, we studied the effects of the time variable fracture conductivity on the production behavior during the production of hydrate reservoirs by horizontal well fracturing for the first time. The main conclusions of this study are as follows:

1. With the condition of horizontal well fracturing production, compared with the constant fracture conductivity, the time variable fracture conductivity will have significant influence on the production behavior. The peak gas production rate in the case of time variable conductivity is slightly lower than that in the case of constant conductivity. After 1 year of production, the gas production rate in the time variable conductivity case decreased by more than half compared with the gas production rate in the constant conductivity case, and the gas production rate at the end of 5 years decreased by 50.4%, and the cumulative gas production for 5 years decreased by 49.9%.

2. The sensitivity analysis of the time variable parameters of fracture conductivity shows that: the larger the initial fracture conductivity, the higher the peak gas production rate, the higher the gas production rate during the whole production process, and the higher the cumulative gas production; the larger the attenuation magnitude of fracture conductivity, the lower the gas production rate at the later production stage, and the lower the cumulative gas production; the larger the decline rate coefficient of fracture conductivity, the higher the gas production rate at the early stage, and the higher the cumulative gas production.

3. The analysis of the orthogonal experimental design shows that the influence of the attenuation magnitude of fracture conductivity, the initial conductivity of fracture, and the decline rate coefficient of fracture conductivity on the cumulative gas production decreases in order. Therefore, in the fracturing exploitation process, it is necessary to avoid excessive attenuation magnitude of fracture conductivity, and at the same time, try to improve the initial conductivity of fractures to ensure a higher cumulative gas production.

However, there are many limitations in this study. In this study, there is no direct experimental support for the time variable fracture conductivity of hydrate, and there is no relevant experimental data on the attenuation magnitude and decline rate coefficient of fracture conductivity. At present, the reliability of the numerical simulation model is verified by fitting the vertical well trial production data, and there is no reliable data of horizontal well fracturing laboratory test and field test to verify the model. In addition, in the actual fracturing process, the fracture conductivity changes not only with time, but also with the fracture space position.

In future work, on the one hand, we can carry out laboratory experiments on the fracture conductivity of muddy-silty sand hydrate reservoirs, summarize the time variable law of fracture conductivity, and provide effective support for numerical simulation research. At the same time, the space variability of fracture conductivity can be studied through indoor experiments, and the time variability and space variability of fracture conductivity can be combined, which will be more in line with the actual situation. On the other hand, fracturing
field experiments can be carried out to ensure the reliability of the model by fitting the field data.

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CONFLICT OF INTEREST
The authors declare no conflict of interest.

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