INTRODUCTION

Natural gas hydrates, predominantly deposited in offshore environments (97%) and in onshore permafrost (3%), are solid crystalline compounds in which low-molecular-weight gases are trapped inside the lattices of ice-like crystal structures.\(^1\)\(^-\)\(^4\) As a potential and substantial energy resource, gas hydrates have drawn much attention worldwide.\(^5\)\(^-\)\(^7\)

Three basic techniques, including depressurization, thermal stimulation, and inhibitor injection, are widely...
employed to extract methane from gas hydrate reservoirs. In recent years, novel and promising approaches to natural gas production, such as CH₄-CO₂ replacement, fracturing technology, and depressurization with electrical heating, have been proposed. Although the above methods have the potential to address many of the attendant problems, such as high cost, low efficiency, environmental pollution, and limited application, depressurization is still accepted as the most economically promising technology for long-term exploitation because of its simplicity, and it is widely used in offshore methane hydrate field production tests.

Permeability is one of the most crucial properties governing fluid flow in a reservoir, which can greatly affect the propagation speed of pressure, heat, and mass transfers during depressurization-induced gas production. In addition, it is also an important indicator to judge whether a hydrate has gas production potential. As field trials carry a high cost, numerical simulations have thus far usually been employed to understand the behavior of gas hydrate systems. Simulations are an effective tool for evaluating hydrate dissociation and production response. Nonetheless, the permeability anisotropy of hydrate-bearing sediments in current studies has rarely been considered. In fact, it is a significant characteristic of hydrate-bearing sediments in nature, such as the gas hydrate deposits discovered in the India Krishna-Godavari and Mahanadi basins, Mallik permafrost, and the Nankai Trough in Japan. Recently, the permeability anisotropy of cores obtained during India's National Gas Hydrate Program Expedition 02 was also trapped, which indicates that the permeability anisotropy is <5. However, due to the few available field cores, the permeability anisotropy of hydrate reservoirs in many areas cannot be precisely determined. In addition, it is difficult to depict permeability anisotropy due to limitations in current measurement technology.

The effect of permeability anisotropy in gas hydrate reservoirs on hydrate dissociation and gas production has gradually attracted wide attention. According to data from sandy hydrate deposits in the Gulf of Mexico, Reagan et al indicated that greater permeability anisotropy results in a slower evolution of total gas productivity. Subsequently, Zhou et al simulated methane production with the geological data of sand-dominated hydrate reservoirs in the Eastern Nankai Trough. They suggested that permeability anisotropy influences both gas and water production, and the increasing horizontal permeability is conducive to hydrate dissociation and fluid movement in the lateral direction. Similarly, gas production predictions within the sandy layers in the Black Ridge also indicated that high horizontal permeability is helpful for transporting methane-charged fluid to high-permeability conduits. Recently, Han et al numerically investigated the effects of permeability anisotropy and magnitude on gas production by depressurization with a vertical well for three different reservoir lithologies (siltstone, sand, and clay) in the Shenhu area of the South China Sea. Their research showed that permeability anisotropy could negatively affect fluid flow in the perpendicular direction, thereby significantly changing the physical evolution. Feng et al investigated the effect of permeability anisotropy on gas production behavior from a horizontal well by depressurization in a sand-dominated hydrate reservoir in the Eastern Nankai Trough. The results indicated that permeability anisotropy can subsequently promote hydrate dissociation, leading to an increase in gas recovery during long-term gas production. Thus, the permeability anisotropy of hydrate-bearing sediments is vital to gas hydrate production. In other words, if permeability anisotropy in the production model is not considered, the simulation may inevitably misestimate the migration capacities of fluids in different directions, which results in unreliable numerical evaluations of gas deliverability. However, current studies have mostly focused on the effect of permeability anisotropy on sandy hydrate reservoirs with high intrinsic permeability, and their conclusions are slightly controversial. Therefore, it is necessary to expand the reservoir type and demonstrate whether the similar production response law is receivable in low absolute permeability formation. Furthermore, current studies have mainly assumed that the horizontal permeability is higher than that in the vertical direction, which may not fully illustrate the effects of permeability anisotropy on gas recovery.

In this study, we built a two-dimensional reservoir-scale production model based on the field data of SH2 drilling site, a candidate for field testing comprising a clayey silt reservoir in the Shenhu area in the South China Sea. Different horizontal/vertical permeability ratios (ie, the horizontal permeability divided by the vertical permeability) greater than 1 and less than 1 were employed to investigate the influence of absolute permeability anisotropy in different directions on gas production. Meanwhile, the influences of isotropic and anisotropic permeability on the spatial distribution of the main physical fields (ie, pressure, temperature, and saturation) and the evolution of gas and water production during depressurization were comparatively analyzed in detail. In addition, the hydrate saturation heterogeneity and low-permeability anisotropy were also specifically evaluated and discussed. Our simulation results can contribute to a clearer understanding of gas hydrate dissociation processes in heterogeneous reservoirs, which may offer valuable suggestions to similar areas.
2 | GEOLOGICAL SETTING AND NUMERICAL SIMULATION

2.1 | Geological setting and permeability of the hydrate reservoirs

It is difficult to accurately measure the permeability anisotropy of a reservoir due to the limitations of current measurement techniques. Numerical models usually adopt a certain assumed value of $r_{xz} = k_h/k_v$ for the whole reservoir to approximately represent the permeability anisotropy. At present, the ratios of horizontal permeability to vertical permeability in most reservoir rocks generally range between 2 and 10. Therefore, we specify different values of $r_{xz}$ for the reservoir (ie, $r_{xz} = 1, 5, $ and 10) in our modeling to analyze the effect of permeability anisotropy on gas production (Table 1), which are similar to the actual permeability anisotropy values from tests on hydrate-bearing sediments as well as the general assumptions adopted in the majority of numerical simulations.

In addition, it should be noted that the vertical permeability could be greater than the horizontal permeability for the poorly consolidated hydrate-bearing reservoirs. According to research performed by Yoneda et al., the permeability anisotropy of hydrate reservoirs can decrease from 4 to 0.5 after hydrate dissociation. Furthermore, reservoir reformation technologies, such as fracturing techniques, have been increasingly applied in research on hydrate development. These novel technologies may promote the vertical permeability of hydrate reservoirs to become larger than the horizontal permeability. Thus, we also investigated such an effect (ie, $r_{xz} = 1, 5, $ and 1/10) on gas production processes and physical field evaluations (Table 1), providing fully theoretical support for future hydrate exploitation.

The sediments at site SH2 are clay and silt with an abundance of cankerous fossils and foraminifers. The average grain sizes of the clay and siltstone of the hydrate reservoirs are 0.003 and 0.009 mm, respectively, which have corresponding permeabilities of 7.14 and 64.23 mD, respectively. Furthermore, drilling and well-logging data from site SH2 show that the lithology of the hydrate-bearing sediments is clayey silt with a millidarcy-range intrinsic permeability (average intrinsic permeability is 10 mD).

### TABLE 1

| Case | Horizontal permeability (mD) | Vertical permeability (mD) | $r_{xz}$ |
|------|-----------------------------|---------------------------|---------|
| Case 1 | 10                          | 10                        | 1       |
| Case 2 | 50                          | 10                        | 5       |
| Case 3 | 100                         | 10                        | 10      |
| Case 4 | 10                          | 50                        | 1/5     |
| Case 5 | 10                          | 100                       | 1/10    |

absolute permeability values in this study were set between 10 and 100 mD according to the preliminary geological data for hydrate-bearing sediments at site SH2 (Table 1).

2.2 | Model construction

2.2.1 | The numerical simulation code

Numerical simulation in this paper was conducted using the TOUGH+HYDRATE code. This code is a member of the TOUGH+family developed by the Lawrence Berkeley National Laboratory and has been widely used in studies on gas hydrate production. Using either a kinetic model or an equilibrium model, this code accounts for nonisothermal multicomponent flows (methane, water, hydrate, and water-soluble inhibitors), multiphase fluids (gas-liquid-hydrate-ice), and heat transfer in complex geologic media, such as porous and fractured media. It should be noted that the fluid-solid coupling effects were not considered herein. We changed the absolute permeability in different directions to investigate the effect of permeability anisotropy on gas production from hydrate reservoirs instead. The aim of this work is to model long-term gas production in large-scale hydrate-bearing reservoirs, therefore, the thermodynamic equilibrium reaction model was invoked.

2.2.2 | System description

The simulated geological system is located in the Shenhua area (Figure 1), Pearl River Mouth Basin, northern South China Sea. Since the Middle Miocene, the Shenhua area has been undergoing tectonic subsidence. The high sedimentation rate has created suitable geological conditions for the presence of gas hydrate. In May 2007, gas hydrate samples were collected at sites SH2, SH3, and SH7 during a scientific expedition conducted by the China Geological Survey. Core sample analysis indicated that a hydrate-bearing layer with a thickness of 10-43 m occurs at 153-229 m below the seafloor (mbsf) with a water depth of 1108-1245 m. This type I methane hydrate, with a saturation of 26-48%, is distributed in a formation with a porosity of 33-48%. The gas produced from these hydrates consists of 96.1-99.82% methane, originally derived from microorganisms. In situ measurements showed that the bottom-water temperature of the sediments is 3.3-3.7°C, with a geothermal gradient of 43-67.7°C/km.

2.2.3 | Model construction

Here, an axisymmetric cylindrical hydrate reservoir model with a radius of 200 m and a thickness of 104 m was
employed for the model domain in TOUGH+HYDRATE (Figure 2). Most of the reservoir properties and characteristics were based on data from the methane hydrate zone at the SH2 site. Based on previous studies, both an overburden and underburden of 30 m are sufficient to provide accurate estimates of heat exchange and pressure propagation. A well with a radius of $r_w = 0.1 \text{ m}$ was arranged along the Z direction in the center of the simulated reservoir. Because of the relatively high hydrate saturation in the middle part of the hydrate-bearing layer, a well with a 23-m-deep completion interval was implemented in this range (Figure 2).

The hydrate-bearing deposits at drilling site SH2 are at a depth of 185-229 mbsf, with a porosity of 40% and pore water salinity of 3.05%. The seafloor is at a water depth of 1235 m, with a temperature of 3.9°C. As a special type of class 3 deposit, the overburden and underburden of the reservoir are fully saturated with water, and their intrinsic permeability is 10 mD. Hydrate saturation estimated based on pore water freshening variations with depth is shown in Figure 3. In situ measurements indicated that the highest hydrate saturation reached 47%. A weighted average value of the hydrate saturation (16.5%) was adopted during the simulation to simply consider the influence of permeability anisotropy on gas recovery and to better mimic the actual field conditions (the detailed calculated process is provided in S4 in the Supplementary Information). The wet thermal conductivity and dry thermal conductivity of the deposits are 3.1 and 1.0 W/m/K, respectively. The main modeling reservoir parameters and physical properties are summarized in Table 2.

2.2.4 Domain discretization

We constructed a cylindrical reservoir-scale model ($r, z$), which is discretized into 90 (in the $r$ direction) $\times$ 319 (in the $Z$ direction) grid blocks. Consequently, 28,710 grids in total were generated for the whole computational domain, with
180 inactive elements assigned as boundary cells located in the uppermost and lowermost grids of the overburden and underburden, respectively. Meanwhile, the corresponding temperature and pressure of the inactive cells (ie, the uppermost and lowermost gridblock layers in TOUGH+HYDRATE) remain constant during the computational process. The computational domain of 200 m is divided nonuniformly along the radial direction. The radial direction \( r \) is divided into 90 grids, of which the first grid is 0.1 m followed by an exponential increase. Due to the significant heat and mass transfers in this region, fine discretization (\( \Delta Z = 0.1-0.2 \) m) was applied within the hydrate deposits (30 m < \( Z < 74 \) m), while coarser blocks (\( \Delta Z = 0.5-3 \) m) were used in the other domains far from the reservoirs (\( Z < 30 \) m and \( 74 \) m < \( Z < 104 \) m) in the perpendicular direction.\(^6^5\) In addition, no flow is assumed to occur across the outermost lateral boundary. Assuming an equilibrium reaction of hydrate dissociation, these grids result in 28 530 (active cells) \( \times 4 \) (number of equations per cell) = 114 120 coupled equations that are solved simultaneously.

2.2.5 | Initial conditions

Because gas hydrates are disseminated in poorly consolidated sediments near the seafloor in the South China Sea, the pore water in the sediments can be considered to undergo exchange with the sea bottom water, meaning that the sediment pore water pressure is hydrostatic.\(^6^6\) The following empirical formula can be used to calculate the initial hydrostatic pore water pressure:

\[
P_{pw} = P_{atm} + \rho_{sw} g (h + z) \times 10^{-6}
\]

where \( P_{pw} \) (Repetitive description) is the hydrostatic pore water pressure in MPa, \( P_{atm} \) is the standard atmospheric pressure of 0.101325 MPa, \( \rho_{sw} \) is the average seawater density in kg m\(^{-3}\), \( g \) is the acceleration of gravity in m/s\(^2\), \( h \) is the water depth in m, and \( z \) is the depth of the submarine sediments in m. Here, an average seawater density of 1054 kg/m\(^3\) was obtained by fitting an equation.\(^6^8\) The pressure distribution in the simulated system, including the pressure \( P_s \) (at \( z = -229 \) mbsf), can be determined by the water depth (water

![FIGURE 3](image-url) Hydrate saturation of the reservoir sediments at site SH2\(^28\)

| TABLE 2 | Main properties of the hydrate reservoir model |
|---|---|
| Parameter | Value | Parameter | Value |
| Hydrate zone thickness | 44 m | Porosity \( \phi \) (overburden) | 42% |
| Overburden and underburden thicknesses | 30 m | Porosity \( \phi \) (underburden) | 38% |
| Radius of the simulation domain | 200 m | Porosity \( \phi \) (hydrate zone) | 40% |
| Gas composition | 100% CH\(_4\) | Dry thermal conductivity \( K_{RD} \) | 1.0 W/m/K |
| Intrinsic permeabilities of the overburden and underburden | \( k_a = k_r = 1.0 \times 10^{-14} \) m\(^2\) (=10 mD) | Wet thermal conductivity \( K_{RW} \) | 3.1 W/m/K |
| Water salinity | 3.05% | Initial bottom pressure of gas hydrate-bearing sediments (\( P_B \)) | 1.524 \( \times 10^7 \)Pa |
| Grain density \( \rho_R \) (all formations) | 2600 kg/m\(^3\) | Initial bottom temperature of gas hydrate-bearing sediments (\( T_B \)) | 14.65 °C |
| Geothermal gradient | 46.953 °C/km | \( S_{ua} \) | 0.5 |
| Grain specific heat | 1000 J kg\(^{-1}\)°C\(^{-1}\) | \( S_{ug} \) | 0.05 |
| Compression coefficient | \( 1.00 \times 10^8 \) Pa\(^{-1}\) | \( nG \) | 3 |
| Pressure at well \( P_w \) | 4.5 \( \times 10^6 \) Pa | \( n \) | 5 |

| Relative permeability model\(^{56}\) | \( K_A = (S_A)^r \) | \( K_G = (S_G)^r \) |
|---|---|---|
| \( S_A = (S_A - S_{ua}) / (1 - S_{ua}) \) | \( S_G = (S_G - S_{ug}) / (1 - S_{ug}) \) | Capillary pressure model (Van Genuchten et al\(^{64}\)) |
| \( P_{cap} = -P_0 [S^*]^{-1/4} - 1 \) | \( S^* = (S_A - S_{ua}) / (S_{max} - S_{ua}) \) | \( P_{cap} = -P_0 [S^*]^{-1/4} - 1 \) |
depth of 1235 m). Combined with the geothermal gradient (Table 2), the initial temperatures at the upper and lower boundaries of the model can be determined. That is to say, at the bottom of the hydrate layer, the pressure is \( P = 15.24 \) MPa and the temperature is \( T = 14.65^\circ C \). According to the hydrate pressure-temperature (\( P-T \)) equilibrium curve\(^{56} \) (ie, the
equilibrium pressure of hydrate at this temperature is about 14.98 MPa), it can be found that hydrates can maintain stability under the above initial conditions.

Dissociation pressure is an important factor of gas production from natural gas hydrate-bearing sediments.69 The first factor for choosing dissociation pressure is gas production capacity, and the second one is the production safety. Here, we just choose it according to the cases in the field trials. In previous studies,70,71 the favorable exploitation scheme in the case of a vertical well is to maintain a constant bottom hole pressure. Some field trials performed also show this availability.72-74 For example, the bottom hole pressure in the first offshore production trial in Japan is approaching to 4.5 MPa. Therefore, we used the constant bottom hole pressure (ie, \(P_w = 4.5\) MPa) in this study. The constant bottomhole pressure production is applicable to most hydrate-bearing sediments with different permeabilities.75 In addition, this method is beneficial to controlling the borehole pressure (eg, the well pressure is higher than the pressure at the quadruple point) to eliminate the possibility of secondary hydrate, and even ice formation due to the temperature decrease. The constant well pressure \(P_w = 4.5\) MPa, that is, slightly above the pressure of the quadruple point of \(CH_4\)-hydrates (≈2.7 MPa), precluding the formation of ice and secondary hydrate. Therefore, a constant pressure of 4.5 MPa was adopted for gas hydrate dissociation in this study. Darcian flow through a pseudomedium of the well interior was used to describe the borehole flow.65 This pseudomedium has a very high permeability (\(k_r = k_z = 5.0 \times 10^{-9} m^2 (=5 \times 10^6\ mD)\)), with a porosity of 1.0 and a capillary pressure of 0 MPa.

3 | RESULTS AND ANALYSIS

3.1 | Gas and water production

Figure 4 shows the evolutions of (A) the volumetric rate of gas production in the well \((Q_p)\), (B) volumetric rate of water production in the well \((Q_w)\), (C) accumulated volume of the total gas released from the reservoir \((V_R)\), (D) accumulated volume of gas production in the well \((V_P)\), (E) accumulated volume of water production in the well \((M_w)\), and (F) water-to-gas ratio \((R_{WGC})\) when assuming different values for \(r_{rz}\).

Gas production rates in the well \((Q_p)\) in different cases can be seen to drop over time (Figure 4A). In the early period, they are very high because the high-pressure difference between the production well and the reservoir causes rapid hydrate dissociation around the wellbore. As production proceeds, the hydrate dissociation zone radially expands when gas hydrates in the vicinity of the production well dissociate completely. During the later period, the gas release rate decreases due to the low-pressure gradient at the dissociation front located far from the wellbore. In addition, the released gas may dissolve into the formation water or even escape through the permeable overburden, which both cause the gas production rate to decrease. It is clear that gas hydrates have dissociated at the dissociation front, but there is no free gas observed in the upper part (Figure 6A,C). This speculation can also be demonstrated by the previous studies.20,21,34,57,75 Additionally, the overburden is permeable and the pressure in the lower reservoir is higher than that in the upper part (Figure 5), so the released free gas may escape through permeable overburden except buoyancy.
As shown in Figure 4A, the gas production rates in Case 2 ($r_{rz} = 5$) and Case 3 ($r_{rz} = 10$) are markedly higher than those in Case 1 ($r_{rz} = 1$), Case 4 ($r_{rz} = 1/5$), and Case 5 ($r_{rz} = 1/10$). A higher ratio of horizontal permeability to vertical permeability (i.e., $r_{rz} \geq 1$) contributes to a higher gas production rate. However, when the vertical permeability is larger than horizontal one, it has no distinct influence on the gas production rate. This phenomenon occurs mainly because the burdens (overburden and underburden) of the hydrate-bearing sediments are permeable, so a large amount of water from the burdens will flow into the reservoirs, weakening the depressurization effect on gas recovery (Figure 6B). However, a higher horizontal permeability is beneficial in assisting hydrates to dissociate horizontally and to hinder the water in the overburden and underburden from flowing into the production well, thereby improving the depressurization effect (Figure 5A).

In addition, it can be observed that the CH$_4$ extraction rates in the well for cases where $r_{rz} = 1$ (Case 1) outpace that of the $r_{rz} = 1/5$ (Case 4) and the $r_{rz} = 1/10$ case (Case 5) after $t = 230$ days (Figure 4A). However, it is opposite in the early stage. The main reason is that driving force for vertical hydrate dissociation is greater when the vertical permeability is higher than the horizontal one in the early period. Thus, the hydrates above and below the completion interval can dissociate more quickly, which results in a maximum production rate in Case 5 at the beginning (<230 days). However, as the hydrate saturation in these regions is relatively low, a large amount of water flows into the production well because of higher vertical permeability after full hydrate dissociation, inhibiting effective depressurization (Figure 6B). At the same time, high vertical permeability also favors methane escape due to buoyancy. Therefore, the opposite situation can be observed after 230 days.

The water production rates in the well ($Q_w$) for each of the five cases ($r_{rz} = 10$, 5, 1/5, and 1/10) are shown in Figure 4B. $Q_w$ was found to increase gradually throughout the simulation. It is obvious that the higher horizontal permeability contributes to fluid flow and hydrate dissociation, resulting in an increase in water production rates. Although the influence of vertical permeability on gas production is small for three cases ($r_{rz} = 1$, 1/5, and 1/10), an increase in vertical permeability increases water extraction to a certain extent. This is because an increase in vertical permeability can increase water extraction from permeable burdens. Additionally, the water production rate can increase sharply when horizontal permeability is significantly higher than vertical permeability. This phenomenon appears because a higher horizontal permeability favors a better depressurization effect (Figure 5A), resulting in more free water released from hydrate dissociation.

The corresponding total gas released from the reservoir ($V_R$) rises dramatically in the early production period (Figure 4C). However, as production proceeds, $V_R$ increases.
slowly in the later stage. This occurs mainly because a constant bottom hole pressure was employed in the simulations. Initially, the high-pressure difference forms between the production well and the sediments, causing rapid hydrate dissociation. As pressure transfers, the hydrate dissociation zone expands due to the gradual pressure reduction over the large area of the reservoir. However, the pressure gradient decreases at the dissociation front because it is far from the borehole. Meanwhile, a large amount of water gradually flows into the reservoir, especially from permeable burdens, weakening the depressurization effect (Figure 6B). Therefore, the tendency toward increasing gas release in the later period is not obvious. In addition, the total gas release from the reservoir is also influenced by permeability anisotropy. It is clear that an increase in horizontal permeability can sharply accelerate hydrate dissociation, while an increase in vertical permeability does not noticeably affect hydrate dissociation. This is because higher horizontal permeability increases the depressurization effect and expands the dissociation zone in the hydrate-bearing sediments (Figures 5A, 6A).

Depending on hydrate dissociation, a similar phenomenon of total gas produced in the well ($V_p$) during production can be observed in Figure 4D. According to the results, some released gas may remain in the reservoir due to the higher permeability anisotropy or escapes because of buoyancy (Cases 4 and 5) (Figure 6C): some dissolved CH$_4$ may play an important role in gas recovery (Cases 2 and 3), which is similar to the results of Moridis$^{20}$ and Zhang, obtaining from hydrate production study on the Ulleung Basin of Korea and Liwan 3 area of the SCS, respectively. This is mainly determined by different production reservoirs. Specifically, a cumulative gas volume of 7 455 298 m$^3$ in Case 3 ($r_z = 10$) was trapped within 5 years, where the low $r_z$ cases ($r_z = 1/5$, and 1/10) appear to have unfavorable CH$_4$ extraction volumes (869 093, and 870 768 m$^3$, respectively).

In addition, a higher $r_z$ (ie, $r_z = 10$ and 5) results in a larger water production volume if the other conditions are the same (Figure 4E). This is also attributed to a better depressurization effect caused by a higher horizontal permeability. A comparison between different vertical permeabilities ($r_z = 1$, 1/5, and 1/10) indicates that a higher vertical permeability can also increase water production because more water from permeable burdens can invade into the reservoir after the increase in vertical permeability.

The water-to-gas ratio ($R_{WGC}$) is a relative criterion for evaluating the efficiency of production from methane hydrate reservoirs, which is mainly used to economically assess production potential. According to Figure 4F, it is clear that $R_{WGC}$ increases rapidly over time because of the fast supply for water from permeable burdens after the increase in the vertical permeability. In contrast, an increase in horizontal permeability exhibits a different behavior. After 360 days, although the high-pressure gradient induced by depressurization increases the water production rate in the $r_z = 5$ case and $r_z = 10$ case, the increase in gas production rate is more pronounced. Therefore, the growth trend in the water-to-gas ratio mainly decreases with increasing $r_z$. In conclusion, the high $r_z$ case has a better production performance than the low $r_z$ case using a vertical well within 5 years in terms of the relative criterion at this site. The simulation results are consistent with research performed by Feng et al$^{19}$ in the sandy reservoir in the Nankai Trough.

### 3.2 | Spatial distributions of physical properties

To visually determine the difference between the five cases ($r_z = 10$, 5, 1, 1/5, and 1/10), the spatial distributions of physical properties at $t = 1800$ days are shown in Figures 5 and 6. This paper mainly focuses on the effect of permeability anisotropy on depressurization-induced gas production. Therefore, the evolutions of physical properties are included in the Supplementary Information to better explain the production process.

### 3.2.1 | Spatial distribution of pressure and temperature

The spatial distribution of pressure in different cases at $t = 1800$ days is shown in Figure 5A. The pressure around the wellbore decreases significantly due to the drop in bottom hole pressure. It can be observed that a higher $r_z$ (ie, $r_z = 10$ and 5) contributes to the pressure drop, thereby accelerating hydrate dissociation. However, the pattern is obviously different when $r_z$ is less than 1. The reason is that higher vertical permeability helps to accelerate pressure propagation in the vertical direction, resulting in a low-pressure front that expands preferentially in this direction rather than in the horizontal direction. Additionally, water from permeable burdens can also flow into the hydrate reservoir easily, weakening the depressurization effect for these cases (ie, $r_z = 1/5$ and 1/10) (Figure 6B), Figures S1 and S2 shown in the Supplementary Information). These results directly support our previous analysis of gas and water production (Figure 4).

Figure 5B shows the simulated temperature distribution in the sediments at $t = 1800$ days. In the upper dissociation front, the temperature "subsidence" is notable because hydrate dissociation consumes a large amount of heat in this region. In the lower part, the isotherms move upward and merge together near the wellbore. This is because the higher-temperature fluid in the underburden enters into the production well (Figure 6B). In addition, the simulated formation with higher horizontal permeability exhibits a greater temperature "subsidence." This occurs mainly because the higher horizontal
permeability contributes to the more obvious depressurization effect (Figure 5A) and causes a more significant endothermic dissociation reaction (Figure 5B; Figure S2 shown in the Supplementary Information). Conversely, indistinctive temperature changes are observed in Figure 5B for the cases at \( r_{xz} = 1, 1/5, \) and 1/10 because of the relatively weak depressurization effect.

### 3.2.2 Spatial distributions of \( S_{\text{hyd}}, \ S_{\text{aqu}}, \) and \( S_{\text{gas}} \)

The hydrate saturation distributions in the five cases \((r_{xz} = 10, 5, 1, 1/5, \) and 1/10\)) indicate that hydrate dissociation proceeded with a mostly well-regulated dissociation front for a homogenous hydrate reservoir (Figure 6A). A higher \( r_{xz} \) is conducive to horizontal pressure propagation (Figure 5A), which accelerates hydrate dissociation. In addition, secondary hydrates may form at the dissociation front during depressurization because a small area of high hydrate saturation can be observed in this region (Figure 6A; Figure S3 shown in the Supplementary Information). This is mainly attributed to a large amount of free gas that is released from hydrate layers after depressurization. Because of the endothermic nature and dilution effect of hydrate dissociation, both temperature and salinity in the dissociation front are dramatically reduced,\(^7\) which helps to form “secondary hydrate” in this area. Furthermore, hydrate saturation changes slightly even though the vertical permeability increases significantly \((i.e., r_{xz} < 1)\) because of the similar depressurization effect (Figure 5A).

The spatial distribution of water is shown in Figure 6B. The water saturation in the vicinity of the production well is quite high, and it is almost the same as that of the permeable burdens. This phenomenon illustrates that a large amount of water may enter into the reservoirs from the permeable burdens under depressurization except hydrate dissociation. Besides, the whole area with high water saturation around the production well can be significantly expanded when \( r_{xz} (\geq 1) \) increases. It is obvious that higher horizontal permeability gives rise to a better depressurization effect and hydrate dissociation. However, when \( r_{xz} \) decreases from 1/5 to 1/10, there is little variation of water saturation distribution. The possible reason is that the free water in permeable burdens can enter into the hydrate-bearing sediments more easily with increasing vertical permeability. Therefore, the effective depressurization in the hydrate-bearing sediments is distinctly weakened, resulting in little difference between them.

The spatial distributions of free gas in different scenarios are shown in Figure 6C. It can be observed that high saturated free gas is mainly located in the vicinity of the production well. Because higher horizontal permeability gives rise to a better depressurization effect, higher gas saturation can be observed in a wider area. Based on the same reasons, there is also no difference in the gas saturation distribution when \( r_{xz} \) decreases from 1/5 to 1/10. In addition, free gas can only be observed in the lower dissociation front but not in the upper space. A possible reason for this phenomenon is that high-temperature fluid in the underburden flows into the hydrate-bearing sediments and accelerates hydrate dissociation with the help of significant convective heat transfer.

### 4 DISCUSSION

#### 4.1 Effect of hydrate saturation heterogeneity

Hydrate saturation is recognized as an important factor for gas hydrate production. Selecting the correct saturation value is vital for demonstrating the accuracy of the simulation results. As mentioned above, a weighted average value of hydrate saturation was adopted in this study. To investigate the influence of the different saturations (weighted average value of the whole hydrate reservoir (16.5%) and heterogeneous hydrate saturation (Figure 3) on gas production from oceanic reservoirs with isotropic and anisotropic permeabilities, another five cases (Cases 6 to 10) were discussed in this section (Table 3). For comparison, the other physical properties of the hydrate reservoir remain unchanged.

The production performance of each case is shown in Figure 7. It is clear that there is a significant difference between the homogeneous (uniform hydrate saturation) and heterogeneous reservoir when simulating gas production in a vertical well. However, the different cases present a similar evolution trend. It can be found that both the gas production

| Case | Horizontal permeability (mD) | Vertical permeability (mD) | Hydrate saturation (%) |
|------|------------------------------|----------------------------|------------------------|
| Case 6 | 10                           | 10                         | 0-47                   |
| Case 7 | 50                           | 10                         | 0-47                   |
| Case 8 | 100                          | 10                         | 0-47                   |
| Case 9 | 10                           | 50                         | 0-47                   |
| Case 10 | 10                           | 100                        | 0-47                   |
rate and volume in the well for the average saturation cases (Cases 1-5) are overestimated than those in the other five cases (Cases 6-10) (Figure 7A and B). Specifically, there is no distinct difference between these cases in the early stage. While in the later period, the prediction results in the homogeneous hydrate reservoir are higher than that in the
heterogeneous hydrate reservoir. This is mainly attributed to the initial high hydrate saturation near the borehole, which can maintain rapid hydrate dissociation after depressurization at the beginning. As production progresses, the hydrate dissociation front continuously expands. The effective permeability is relatively low in the intermediate heterogeneous reservoirs because of the high hydrate saturation, which inhibits gas recovery.\textsuperscript{40} Meanwhile, as the production proceeds the hydrates in the upper and lower part of the heterogeneous hydrate reservoir almost dissociate under the depressurization (Figure 8A). Compared to the homogeneous reservoir, the depressurization effect of the heterogeneous reservoir is more easily weakened due to the relatively low hydrate saturation around the interfaces between permeable burdens and the hydrate reservoir (because the hydrate dissociation in pores can increase the effective permeability according to Masuda’s equation\textsuperscript{78}), decreasing the gas production. Consequently, an obvious difference of gas production can be observed. In addition, it can be found that the higher the $r_{rz}$ (≥1) is, the more significant the gas production difference is. The volumetric rate of gas production in Cases 3 and 8 at 1800 days are approximately 3678.84 m$^3$/d and 2478.50 m$^3$/d, respectively. This is mainly caused by the hydrate distribution in the upper and lower part of the heterogeneous hydrate reservoir because the effective permeability can be obviously varied in these regions.

The corresponding water production rates and volumes in the well for the ten cases are shown in Figure 7C and D. Compared with the heterogeneous hydrate reservoir, the homogeneous hydrate reservoir adopted for the depressurization-induced simulations seems to overestimate the water production in the early stage. A possible reason is that the depressurization effect in the homogeneous hydrate reservoir is better (because gas hydrate saturations in the homogeneous reservoir are relatively higher at the upper and lower boundaries), which can release more water at the beginning. Meanwhile, the heterogeneous hydrate reservoir has many layers with different initial hydrate saturations, so their dissociation extent in the radial direction is different because of diverse effective permeabilities. The high hydrate saturation layer initially releases more free methane gas due to depressurization, which may affect the water flow in adjacent layers. However, the opposite phenomenon can be found in the later period. This is because the blocking effect gradually disappears (the hydrate saturation is relatively low at the upper and lower boundaries of the hydrate reservoir), which is conducive to increasing water recovery from permeable burdens (Figure 8B). Additionally, the initial effective permeability is relatively high in the low hydrate saturation formation of the heterogeneous reservoirs, which may also increase water production to some extent. Meanwhile, the water production volumes of the two types of reservoirs with different hydrate saturation also show some differences. The volume of water production in Cases 1 and 6 at 1800 days are approximately 245 446.87 and 272 377.82 m$^3$, respectively. The corresponding water extraction rates approach 155.18 and 173.36 m$^3$/d, respectively. This finding confirms our above observations.
analysis of the distinction between gas production rates and volumes between the homogeneous reservoir and the heterogeneous reservoir with permeability anisotropy.

As mentioned above, the depressurization effect varies in the two reservoirs. Thus, gas release from the homogeneous reservoir is also different from that in the heterogeneous reservoir during production (Figure 7E). According to Figure 7F, the production efficiency will be overestimated when the mean hydrate saturation is applied to the simulations regardless of the assigned value of $r_{rz}$. Based on the simulation results, we suggest that heterogeneous hydrate saturation in the reservoir-scale model should be employed in future predictions.

### 4.2 Effect of low-permeability anisotropy

In 2017, the first gas hydrate production trial was conducted in a clayey silt formation in the South China Sea. The logging interpretations and core analysis indicated a mean permeability of the hydrate formations of 2.9 mD. To fully discuss the effect of permeability anisotropy on the low-permeability strata in the South China Sea, another five cases (Cases 11-15) with permeabilities ranging from 1 to 10 mD (Table 4) were investigated.

It is easy to understand that reducing the formation permeability will decrease the gas production because of the different driving forces for hydrate dissociation. Compared with the low-permeability reservoirs, a higher permeability accelerates pressure transfer and results in more significant hydrate dissociation in medium-permeability reservoirs. However, the effects on fluid (gas and water) production rate and volume are similar between medium-permeability formations (10-100 mD) (Figure 4) and low-permeability formations (Figure 9).

As shown in Figure 9A and Figure 9B, the gas and water flow rates in the well increase with increasing $r_{rz} (\geq 1)$ in the low-permeability formations. In addition, a relatively high vertical permeability has little distinct influence on gas production when $r_{rz}$ is below 1, which is similar to the results described for medium-permeability reservoirs (Figure 4A and B). Comparing the effects of permeability anisotropy on gas release from medium-permeability reservoirs (Figure 4C), the influence of permeability anisotropy on the accumulated volume of gas released is more prominent when the vertical permeability is larger than the horizontal permeability (Figure 9C). This occurs mainly because permeability anisotropy would have a more obvious effect in low-permeability reservoirs because of the relatively weak hydrate reaction. Figure 9D shows that a higher horizontal permeability of the formations corresponds to a higher gas production volume in the well due to the better depressurization effect (Figure 10A). A similar evolution tendency can be observed from the simulation results in Figure 4D. According to Figure 9C and D, the amount of gas released from hydrate-bearing sediments with a high vertical permeability is much higher than the amount of gas produced from the well, which indicates that most of the released gas remains in the sediments or escapes to the permeable overburden. However, higher horizontal permeability is beneficial for gas extraction from reservoirs. This is mainly because high permeability in the horizontal direction accelerates fluid flow and improves the depressurization effect (Figure 10). Figure 9E shows the water production volume over time corresponding to different values of $r_{rz}$. Permeability anisotropy in low hydrate formations may affect water production more noticeably (Figure 10D). The possible reason is that the hydrate dissociation rate is relatively slow in the low-permeability formations, so a slight increase in permeability can greatly accelerate hydrate dissociation.

Although the effects on fluid production rate and volume are similar between medium-permeability formations and low-permeability formations, a high horizontal permeability in the low-permeability reservoir results in a low gas-to-water ratio even though the gas production is high (Figure 9F). The augmentation of the water production rate in the low-permeability reservoir with permeability anisotropy is more obvious than that of the gas production rate.

### 5 SUMMARY AND CONCLUSIONS

In this study, a reservoir-scale model was built to numerically investigate the effect of permeability anisotropy on depressurization-induced gas production from a hydrate reservoir in the Shenhu area, the South China Sea. The influence of hydrate saturation heterogeneity and low-permeability

| Case  | Horizontal permeability (mD) | Vertical permeability (mD) | Hydrate saturation (%) |
|-------|-----------------------------|---------------------------|------------------------|
| Case 11 | 1                           | 1                         | 16.5                   |
| Case 12 | 5                           | 1                         | 16.5                   |
| Case 13 | 10                          | 1                         | 16.5                   |
| Case 14 | 1                           | 5                         | 16.5                   |
| Case 15 | 1                           | 10                        | 16.5                   |
anisotropy on gas production was also discussed. Based on the simulation results, the following conclusions are drawn:

1. Permeability anisotropy has significant impacts on gas production. Increasing the vertical permeability of hydrate reservoirs has a limited influence on gas recovery, and a large amount of water will be extracted in this situation, resulting in a high water-to-gas ratio and low gas recovery rate. Additionally, both gas and water production increase during depressurization as the ratio of...
horizontal permeability to vertical permeability increases (i.e., $r_{rz} \geq 1$).

2. The predicted gas production using heterogeneous hydrate saturation is different from that employing homogeneous hydrate saturation in the long term. The gas production potential will be overestimated in a homogeneous reservoir under the same conditions. The distinction is more obvious when the horizontal permeability is higher than the vertical one. Therefore, heterogeneous hydrate saturation in the reservoir-scale model should be employed in future predictions.

3. A high horizontal permeability is more favorable for improving productivity in the medium-permeability (10-100 mD) reservoir, but in the low-permeability (1-10 mD) reservoir, a high horizontal permeability results in a low gas-to-water ratio even when the gas production is high. Therefore, it is necessary to consider the effect of permeability anisotropy when deploying suitable hydrate production regulations in the clayey silt formation of the South China Sea. Furthermore, we can apply stimulation technology to increase the horizontal permeability of medium-permeability hydrate reservoirs as far as possible. However, for hydrate exploitation in low-permeability reservoirs, sediments with isotropic permeability may be more suitably selected as targets.

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Additional supporting information may be found online in the Supporting Information section.

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