

Article

Research on Sensitivity Factors of Wellbore Stability During Directional Well Construction in Deepwater Shallow Soft Hydrate Reservoirs

Ao Feng ¹, Yufa He ^{2,*}, Kexin Zhang ² and Chuanliang Yan ^{1,*}

¹ School of Petroleum Engineering, China University of Petroleum (East China), Qingdao 266580, China; s24020074@s.upc.edu.cn

² CNOOC Research Institute Co., Ltd., Beijing 100029, China; 19862260501@163.com

* Correspondence: heyf@cnooc.com.cn (Y.H.); yanchuanliang@163.com (C.Y.)

Abstract

To investigate wellbore stability evolution during directional drilling in deepwater shallow soft hydrate reservoirs, a coupled thermo–hydro–mechanical–chemical (THMC) model incorporating hydrate phase change was established. The effects of drilling time, drilling fluid temperature, density, and well inclination were analyzed. The results indicate that wellbore collapse alters heat transfer paths, thereby expanding hydrate dissociation and plastic zones. With increasing drilling time, accumulated plastic deformation significantly intensifies wellbore instability. Maintaining drilling fluid density within an optimal range is the most critical factor for stabilizing the wellbore, and lowering the drilling fluid temperature can effectively reduce the hydrate dissociation extent and the borehole enlargement rate. Notably, well inclination exhibits a strong nonlinear influence: as inclination increases from 0° to 75°, the maximum plastic strain increases from 0.0047 to 0.0262, and the borehole enlargement rate rises from 38.1% to 152.6%; stability deteriorates dramatically beyond 30°. Higher initial hydrate saturation and greater water depth are beneficial to wellbore stability, whereas increased overburden thickness intensifies stress concentration. These results provide a reference for the directional drilling design of hydrate formations in deepwater shallow soft reservoirs.

Keywords: natural gas hydrate; directional well; wellbore collapse; multi-physical field coupling

Academic Editor: Dicho Stratiev

Received: 13 June 2026

Revised: 19 July 2026

Accepted: 30 July 2026

Published: 3 August 2026

Copyright: © 2026 by the authors. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the [Creative Commons Attribution \(CC BY\)](https://creativecommons.org/licenses/by/4.0/) license.

1. Introduction

A scientific and rational energy supply structure is the fundamental guarantee for sustainable economic and social development. However, the development of conventional oil and gas in China has entered the middle and late stages, gradually failing to meet the increasing oil and gas demand of the industrial society, and the external dependence on oil and gas is rising year by year. Statistics [1,2] show that China's external dependence on oil and gas was 43.9% and 0.9% in 2005, and exceeded 70% and 40%, respectively, in 2025, as shown in Figure 1. In addition, the current global situation is complex and volatile, and energy security has become strategically more significant. Therefore, the efficient development of unconventional oil and gas resources such as natural gas hydrates is a research focus in the current oil and gas field [3].

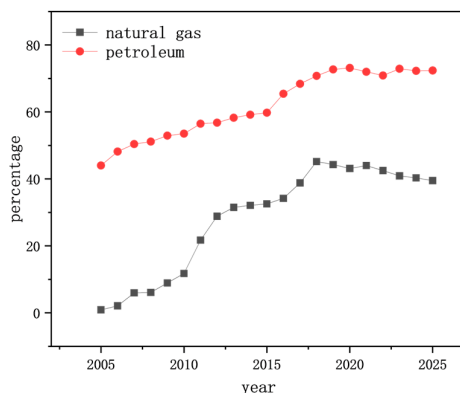


Figure 1. Distribution of external dependence on oil and gas in China.

Wellbore stability research is one of the key factors to ensure safe drilling operations, and a complete mechanical–chemical coupling research system has been formed for conventional formations [4–6]. However, relatively few drilling operations have been carried out for hydrate-bearing formations, and the research in this field is still in its initial stage. Since hydrates exist in shallow formations in deep water, they are subject to low overburden pressure and low consolidation degree [7]. At the same time, drilling disturbance can cause hydrate dissociation, which further reduces the bearing capacity of the formation and is very likely to cause wellbore collapse and instability [8–10]. Therefore, the analysis of wellbore stability in hydrate-bearing formations under the action of multi-physical field coupling is a current research hotspot.

In the early studies on wellbore stability in natural gas hydrate reservoirs, researchers made a large number of simplifications. For example, Birchwood et al. [11] assumed that the formation has the same in situ stress in different directions in their research; the study by Freij-Ayoub et al. [12] did not consider hydrate dissociation during drilling, which resulted in significant differences between these research results and actual working conditions. With the deepening understanding of the multi-physical field coupling effect of the formation during hydrate dissociation [13–16], researchers such as the team of Professor Cheng Yuanfang [17–20] and the team of Professor Ning Fulong [21–24] have gradually established a thermal–hydraulic–mechanical–chemical (THMC) multi-field coupled wellbore stability analysis model considering hydrate phase transition so as to explore the operation scheme for maintaining wellbore stability in hydrate reservoirs. Rutqvist et al. [25] proposed through numerical calculation that balanced drilling can effectively improve the stress distribution of the wellbore, reduce the range of the plastic zone, and inhibit wellbore collapse. Cheng et al. [26] pointed out that when the temperature and pressure conditions of drilling fluid deviate too much from the stable conditions of hydrate, the stability of the wellbore is greatly affected, and even severe wellbore collapse may occur in the early stage of drilling. Sun et al. [27] proposed that reducing the salinity of drilling fluid and reducing hydrate dissociation in the near-wellbore formation can effectively extend the wellbore stability period of hydrate formations. Wei et al. [28] suggested that measures such as cooling drilling fluid and reducing drilling time can be taken simultaneously to maintain wellbore stability. Li Qingchao et al. [29,30] provided a method for determining the bottom hole pressure and bottom hole temperature to maintain wellbore stability in hydrate formations. Li et al. [31] proposed that the great difference in mechanical properties between the hydrate dissociated zone and the undissociated zone leads to secondary stress concentration and new yield zones in the undissociated formation, which makes the hydrate dissociation range play a decisive role in the formation yield range. Liao et al. [32] analyzed the yield distribution law of the horizontal well section in hydrate formations, which provided guidance for the design of horizontal well

length. Hu et al. [33] proposed a fast solution method for transient wellbore stability. Mao et al. [34] studied the influence of in situ stress inhomogeneity on the plastic development law around the wellbore in hydrate formations, and pointed out that the increase in the degree of in situ stress inhomogeneity significantly increases the range of the plastic zone.

The above research results show that wellbore stability in hydrate-bearing formations is the result of the synergistic effect of multiple fields and factors. Meanwhile, due to its characteristics of weak cementation and easy hydrate dissociation, wellbore collapse is a damage process caused by a gradual accumulation of yield. Current studies have a relatively clear understanding of multi-physical field coupling during drilling. However, due to the difficulty in solving nonlinear solid mechanics, most mechanical modules for wellbore stability analysis of hydrate-bearing formations adopt elastic models or ideal elastoplastic models, ignoring the influence of their nonlinear mechanical response characteristics [35,36], which leads to certain differences between calculation results and actual results. At the same time, since the current main research still focuses on vertical wellbore stability, there is a lack of analysis on the drilling stability of complex well types such as directional wells, especially for the analysis of drilling stability in complex well types such as directional wells in deepwater shallow soft hydrate-bearing formations.

2. Mathematical Model

During the drilling process in hydrate-bearing formations, drilling fluid continuously transfers mass and heat to the formation through the wellbore, changing the distribution of formation temperature, pore pressure, stress, and chemical field. When the formation temperature and pore pressure do not meet the phase equilibrium conditions of hydrate, hydrate dissociation in the near-wellbore surrounding rock is caused. Hydrate dissociation further changes the heat transfer, seepage, and mechanical properties of the formation, affecting wellbore stability. Therefore, the analysis of wellbore stability in hydrate-bearing formations is a thermal-hydraulic-mechanical-chemical (THMC) multi-field coupling process involving hydrate phase transition, formation heat transfer, fluid migration, and skeleton deformation [37,38], as shown in Figure 2. In this chapter, a multi-field coupled mathematical model for wellbore stability during horizontal well drilling in hydrate-bearing formations is established based on the coupling mechanism between seepage, heat transfer, hydrate phase transition, and solid mechanics in hydrate-bearing formations.

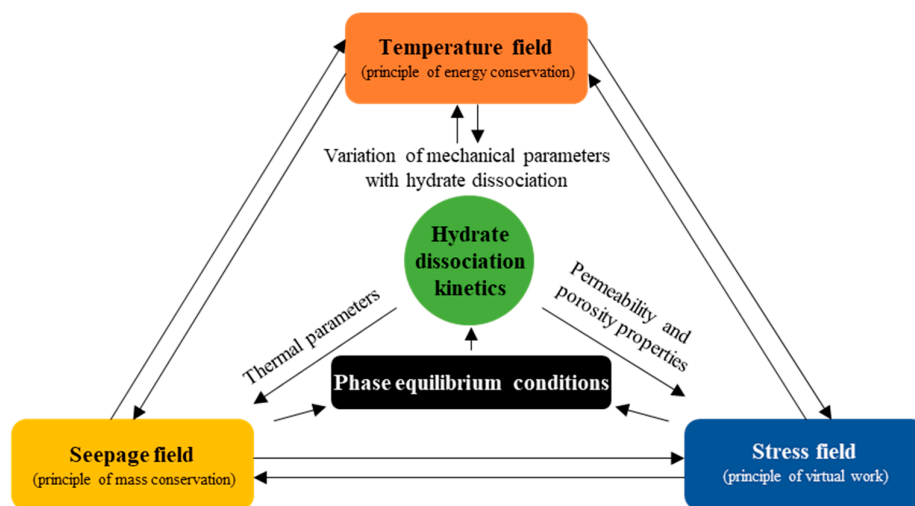


Figure 2. Multi-field coupling diagram of hydrate formation drilling.

Due to the complexity of the multi-field coupling law of the near-wellbore surrounding rock during drilling in hydrate-bearing formations, certain assumptions need to be made for the mathematical model. These assumptions ensure that the model meets the requirements of actual working conditions, simplifies the calculation amount of the model, and improves the calculation efficiency of the model. According to the actual drilling conditions of hydrate-bearing formations, the following assumptions are made for the mathematical model [39,40]:

- (1) The deformation of the near-wellbore surrounding rock in hydrate-bearing formations satisfies the small deformation theory, while the phase transition and dissociation behavior of hydrates are controlled by user-defined subroutines;
- (2) The gas component in the hydrate layer is mainly methane. Therefore, it is assumed that all hydrates in the hydrate reservoir are methane hydrates, and the formation pores are completely filled with three phases: water, hydrate, and methane gas;
- (3) Hydrate only undergoes phase change during the entire drilling process and does not move relative to the rock skeleton in the pores;
- (4) During the drilling process, the formation fluid migration satisfies the generalized Darcy's law. At the same time, it is assumed that the water phase has a fixed compression coefficient, and the Klinkenberg effect of the gas phase is ignored;
- (5) The effects of drilling fluid infiltration on formation heat conduction and flow performance are neglected in the seepage module, and these physical characteristics are coupled within the user-defined hydrate phase transition subroutine;
- (6) The density and heat transfer characteristics of hydrate and formation skeleton do not change during the drilling process.

2.1. Seepage Field Equation

The mass change of each component fluid in the microelement of the hydrate-bearing formation is equal to the sum of the net mass flow rate of the component flowing into the microelement and the fluid mass generated by the source-sink term, as shown in Equations (1)–(3) [41,42]:

$$\text{methane gas phase: } -\nabla \cdot (\rho_g \mathbf{u}_g) = -\nabla \cdot (\phi \rho_g S_g \mathbf{v}_g) = \frac{\partial(\phi \rho_g S_g)}{\partial t} - \dot{m}_g \quad (1)$$

$$\text{water phase: } -\nabla \cdot (\rho_w \mathbf{u}_w) = -\nabla \cdot (\phi \rho_w S_w \mathbf{v}_w) = \frac{\partial(\phi \rho_w S_w)}{\partial t} - \dot{m}_w \quad (2)$$

$$\text{hydrate phase: } -\nabla \cdot (\rho_h \mathbf{u}_h) = -\nabla \cdot (\phi \rho_h S_h \mathbf{v}_h) = \frac{\partial(\phi \rho_h S_h)}{\partial t} - \dot{m}_h \quad (3)$$

In the equations, $\mathbf{v}_g$, $\mathbf{v}_w$, and $\mathbf{v}_h$ represent the velocity vectors of methane gas, pore water, and hydrate particles, respectively, in $\text{m}\cdot\text{s}^{-1}$.

Among them, the velocity vectors of the fluids can be decomposed into the velocity vector of the formation skeleton and the relative velocity vector of the fluid to the formation skeleton, as shown in Equations (4) and (5):

$$\mathbf{v}_g = \mathbf{v}_{rg} + \mathbf{v}_r \quad (4)$$

$$\mathbf{v}_w = \mathbf{v}_{rw} + \mathbf{v}_r \quad (5)$$

In the equations, $\mathbf{v}_{rg}$ is the relative velocity vector of methane gas to the formation skeleton, in $\text{m}\cdot\text{s}^{-1}$; $\mathbf{v}_{rw}$ is the relative velocity vector of formation pore water to the

formation skeleton, in $\text{m}\cdot\text{s}^{-1}$; $\mathbf{v}_r$ is the velocity vector of formation skeleton particles, in $\text{m}\cdot\text{s}^{-1}$.

During the drilling operation in hydrate-bearing formations, the formation skeleton will undergo a small amount of deformation and movement. Since the movement of the formation skeleton is much smaller than the movement velocity of formation fluids, the continuity equation followed by its skeleton particles is obtained through differential post-processing, as shown in Equation (6):

$$-[\rho_r(1-\varphi)]\nabla \cdot \mathbf{v}_r = \rho_r \frac{\partial(1-\varphi)}{\partial t} + (1-\varphi) \frac{\partial \rho_r}{\partial t} \quad (6)$$

The change of gas saturation is affected by the relative velocity of gas to the formation skeleton, the velocity of the formation skeleton, the gas production rate from hydrate dissociation, the change of formation pores, and the change of gas density. Moreover, since the South China Sea hydrate reservoir is a weakly cemented and underconsolidated formation, the bulk modulus of the formation skeleton is much higher than that of the formation. Therefore, the time derivative term of pore pressure can be ignored in the calculation process. In summary, the continuity equation under the coupling effect can be obtained by performing a differential operation and expanding Equation (1):

$$-\nabla \cdot (\varphi \rho_g S_g \mathbf{v}_{rg}) + \dot{m}_g = \rho_g S_g \alpha \frac{\partial \varepsilon_v}{\partial t} + \varphi \rho_g \frac{\partial S_g}{\partial t} + \varphi S_g \frac{\partial \rho_g}{\partial t} \quad (7)$$

When fluids move in formation pores, their flow law satisfies the generalized Darcy's law. Thus, the movement velocities of methane gas and pore water in hydrate-bearing formations can be expressed as:

$$\varphi S_g \mathbf{v}_{rg} = -\frac{k k_{rg}}{\mu_g} (\nabla P_g - \rho_g \mathbf{g}) \quad (8)$$

$$\varphi S_w \mathbf{v}_{rw} = -\frac{k k_{rw}}{\mu_w} (\nabla P_w - \rho_w \mathbf{g}) \quad (9)$$

In the equations, k is the absolute permeability of the formation, in m^2 ; k_{rg} is the gas relative permeability of methane gas, in m^2 ; μ_g is the gas viscosity of methane gas, in $\text{Pa}\cdot\text{s}$; P_g is the gas phase pressure of methane gas, in Pa ; $\mathbf{g}$ is the gravitational acceleration vector, in $\text{m}\cdot\text{s}^{-2}$; k_{rw} is the relative permeability of pore water, in m^2 ; μ_w is the viscosity of pore water, in $\text{Pa}\cdot\text{s}$; P_w is the liquid phase pressure of pore water, in Pa .

Pore water and methane gas are immiscible two-phase fluids. When flowing in porous media, due to the difference in wettability, a curved surface will be formed at the two-phase interface, resulting in capillary force. According to the definition of capillary force, the correlation between gas phase pressure and water phase pressure can be shown in Equations (10) and (11):

$$P_w = P_g - P_c \quad (10)$$

$$\nabla P_w = \nabla P_g - \nabla P_c = \nabla P_g - \frac{\partial P_c}{\partial S_w} \nabla S_w \quad (11)$$

In the equations, P_c is the capillary force, in Pa .

Substituting Equations (10) and (11) into Equation (7), the gas saturation control equation can be obtained as shown in Equation (12):

$$\left(\rho_g \frac{\partial \varepsilon_v}{\partial t} + \phi \frac{\partial \rho_g}{\partial t} \right) S_g + \phi \rho_g \frac{\partial S_g}{\partial t} = \nabla \cdot \left[\frac{\rho_g k k_{rg}}{\mu_g} (\nabla P_w - \rho_g \mathbf{g}) \right] + \nabla \cdot \left(\frac{\rho_g k k_{rg}}{\mu_g} \nabla P_c \right) + \dot{m}_g \quad (12)$$

Similarly, according to Equations (2) and (3), the water phase saturation control equation and the hydrate phase saturation control equation can be obtained as shown in Equations (13) and (14):

$$\left(\rho_w \frac{\partial \varepsilon_v}{\partial t} + \phi \frac{\partial \rho_w}{\partial t} \right) S_w + \phi \rho_w \frac{\partial S_w}{\partial t} = \nabla \cdot \left[\frac{\rho_w k k_{rw}}{\mu_w} (\nabla P_w - \rho_w \mathbf{g}) \right] + \dot{m}_w \quad (13)$$

$$\rho_h \frac{\partial \varepsilon_v}{\partial t} S_h + \phi \rho_h \frac{\partial S_h}{\partial t} = \dot{m}_h \quad (14)$$

Among them, the density and pressure of the liquid phase satisfy [43]:

$$\rho_w = \frac{1}{C} \frac{d\rho_w}{dP_w} \quad (15)$$

In the equation, C is the compressibility of the liquid, in MPa^{-1} .

Changes in formation pressure will change the gas density, and the two satisfy the non-ideal gas state equation, as shown in Equation (16):

$$\rho_g = \frac{P_g M_g}{n Z R T} \quad (16)$$

In the equation, Z represents the gas compressibility factor, which can be obtained by the Peng–Robinson equation of state and is dimensionless.

2.2. Temperature Field Equation

According to the principle of energy conservation, the sum of the heat obtained by the unit volume formation through heat conduction, the heat lost by pore fluid heat convection, and the heat source term should be equal to the rate of change of heat in the studied unit, and its expression is shown in Equation (17) [44]:

$$\underbrace{\frac{\partial}{\partial t} \left[(1-\phi) \rho_r H_r + \phi S_h \rho_h H_h + \phi S_g \rho_g H_g + \phi S_w \rho_w H_w \right]}_{\text{local rate of change}} = \underbrace{\nabla \cdot (\bar{\lambda} \nabla T)}_{\text{heat conduction}} - \underbrace{\nabla \cdot (\rho_g \mathbf{u}_g H_g + \rho_w \mathbf{u}_w H_w)}_{\text{convection}} + \underbrace{\underline{Q}}_{\text{heat source}} \quad (17)$$

In the equation, $\bar{\lambda}$ is the comprehensive thermal conductivity of the hydrate-bearing formation, in $\text{W} \cdot \text{m}^{-1} \cdot \text{K}^{-1}$; T is the formation temperature, in K; ρ_r , ρ_h , ρ_g , and ρ_w are the densities of formation skeleton, hydrate, methane gas, and pore water, respectively, in $\text{kg} \cdot \text{m}^{-3}$; H_r , H_h , H_g , and H_w are the enthalpies of formation skeleton, hydrate, methane gas, and pore water, respectively, in $\text{J} \cdot \text{kg}^{-1}$; S_h , S_g , and S_w are the saturations of hydrate, methane gas, and pore water, respectively, dimensionless; ϕ is the formation porosity, dimensionless; $\mathbf{u}$ is the fluid seepage velocity, in $\text{m} \cdot \text{s}^{-1}$; $\underline{Q}$ is the heat supplemented from the outside, in $\text{W} \cdot \text{m}^{-3}$.

Due to the different heat conduction efficiencies of heat in solid, liquid, and gas materials, the heat conduction performance of hydrate reservoirs is affected by the

composition of pore-filling substances. Therefore, the comprehensive thermal conductivity of hydrate reservoirs is shown in Equation (18):

$$\bar{\lambda} = \varphi(\lambda_w S_w + \lambda_g S_g) + (1 - \varphi_0)\lambda_r + (\varphi_0 - \varphi)\lambda_h \quad (18)$$

In the equation, λ_r , λ_w , λ_g , and λ_h are the thermal conductivities of formation, pore water, methane gas, and hydrate, respectively, in $\text{W}\cdot\text{m}^{-1}\cdot\text{K}^{-1}$; φ_0 is the initial porosity of the formation, dimensionless.

Since the local rate of the change term and convection term of the energy conservation equation shown in Equation (17) are characterized in the form of enthalpy, further derivation is needed to express enthalpy as a function of temperature, forming a temperature field control equation with temperature as the unknown term. During hydrate dissociation, hydrate, methane gas, and pore water satisfy the law of mass conservation. Since the influence of temperature change on the volume of methane hydrate (solid phase) is extremely small, the influence of solid volume change on heat convection is ignored. The mass conservation of each phase is shown in Equations (19)–(21):

$$\frac{\partial}{\partial t}(\varphi S_g \rho_g) + \nabla \cdot (\rho_g \mathbf{u}_g) = \dot{m}_g \quad (19)$$

$$\frac{\partial}{\partial t}(\varphi S_w \rho_w) + \nabla \cdot (\rho_w \mathbf{u}_w) = \dot{m}_w \quad (20)$$

$$\frac{\partial}{\partial t}(\varphi S_h \rho_h) = \dot{m}_h \quad (21)$$

The expressions of the hydrate phase change's latent heat are shown in Equations (22) and (23) [45]:

$$\sum_{i=h,g,w} -\dot{m}_i H_i = Q_h \quad (22)$$

$$Q_h = -\frac{\dot{m}_g}{M_g}(56599 - 16.744T[\text{K}]) \quad (23)$$

In the equations, Q_h is the latent heat of hydrate phase change, in $\text{W}\cdot\text{m}^{-3}$.

Solving the temperature field equation, one can obtain the formation temperature field distribution during drilling. The simplified form can be obtained by performing a differential operation and expansion on Equation (17) and substituting Equations (19)–(21) into Equation (24):

$$\begin{aligned} & (1 - \varphi) \frac{\partial}{\partial t}(\rho_r H_r) + (\varphi S_h \rho_h) \frac{\partial}{\partial t}(H_h) + (\varphi S_g \rho_g) \frac{\partial}{\partial t}(H_g) + (\varphi S_w \rho_w) \frac{\partial}{\partial t}(H_w) \\ & = \nabla \cdot (\bar{\lambda} \nabla T) - (\rho_g \mathbf{u}_g) \nabla H_g - (\rho_w \mathbf{u}_w) \nabla H_w + Q + Q_h \end{aligned} \quad (24)$$

The enthalpy H_g of gas is related to temperature and pressure. The total differential of H_g with respect to temperature and pressure is shown in Equation (25):

$$H_g = \frac{\partial H_g}{\partial T} dT + \frac{\partial H_g}{\partial P_g} dP_g = C_{pg} dT + \sigma_g dP_g = C_{pg} dT \quad (25)$$

In the equation, C_{pg} is the specific heat capacity of methane gas, in $\text{J}\cdot\text{kg}^{-1}\cdot\text{K}^{-1}$; σ_g is the Joule–Thomson coefficient of methane gas, in $\text{J}\cdot\text{kg}^{-1}\cdot\text{Pa}^{-1}$. Since the order of

magnitude of the Joule–Thomson coefficient of methane gas is small, the Joule–Thomson effect of methane gas can be ignored.

A formation's pore water, hydrate, and skeleton's thermodynamic behavior can be regarded as an isobaric process. Therefore, the simplified calculation equation of the temperature field in hydrate-bearing formations can be obtained as shown in Equation (26):

$$\left[(1-\varphi)\rho_m C_{pm} + \varphi S_h \rho_h C_{ph} + \varphi S_g \rho_g C_{pg} + \varphi S_w \rho_w C_{pw} \right] \frac{\partial T}{\partial t} - \nabla \cdot (\lambda_{\text{eff}} \nabla T) + (\rho_g \mathbf{u}_g C_{pg} + \rho_w \mathbf{u}_w C_{pw}) \cdot \nabla T = Q + Q_h \quad (26)$$

2.3. Deformation Field Equation

A microelement will reach a static equilibrium state under the combined action of internal and external forces, and the tensor form of its static equilibrium differential equation can be expressed as shown in Equation (27) [46,47]:

$$\sigma_{ij,j} + f_i = 0 \quad (27)$$

In the equation, $\sigma_{ij,j}$ is the total stress tensor borne by the hydrate formation skeleton, in Pa; f_i is the body force tensor borne by the formation, in Pa.

When considering the supporting effect of formation pore fluid on the formation skeleton, according to Terzaghi's effective stress principle, the effective stress borne by the hydrate formation skeleton can be expressed as follows (tension is positive, compression is negative):

$$\sigma_{ji} = \sigma'_{ij} - \alpha \bar{P} \delta_{ij} \quad (28)$$

In the equation, σ'_{ij} is the effective stress tensor of the hydrate formation skeleton, in Pa; δ_{ji} is the Kronecker delta.

Substituting Equation (28) into Equation (27), the static equilibrium equation of porous media materials considering pore pressure can be obtained as shown in Equation (29):

$$\sigma'_{ij,j} + f_i - (\alpha \delta_{ij} \bar{P})_{,i} = 0 \quad (29)$$

Under the premise of the small deformation assumption, the tensor form of the geometric equation of the hydrate-bearing formation can be expressed as:

$$\varepsilon_{ij} = \frac{1}{2} (u_{i,j} + u_{j,i}) \quad (30)$$

In the equation, ε_{ij} is the strain tensor; $u_{i,j}$ is the displacement tensor.

For the elastic part of the stress–strain relationship of the hydrate-bearing formation, the incremental form of its constitutive equation can be expressed as:

$$\{d\sigma\} = [D^e] \{d\varepsilon^e\} \quad (31)$$

In the equation, $\{d\sigma\}$ is the stress increment; $[D^e]$ is the elastic matrix, which is determined by Young's modulus and Poisson's ratio.

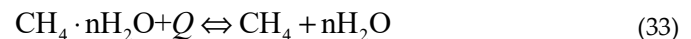
For the elastoplastic part of the stress–strain relationship of the hydrate-bearing formation, its strain is related not only to the stress magnitude but also to the stress path. The incremental form of the elastoplastic constitutive model of the hydrate-bearing formation can be expressed as:

$$\{d\sigma\} = [D^{ep}] \{d\varepsilon\} \quad (32)$$

In the equation, $[D^{ep}]$ is the elastoplastic stiffness matrix of the hydrate-bearing formation, which is determined by $[D^{ep}] = [D^e] - [D^p]$; $[D^p]$ is the plastic stiffness matrix of the hydrate-bearing formation, which is related to the yield surface function, hardening rule, and flow direction.

2.4. Hydrate Phase Transition and Dissociation Equation

To more accurately describe the dynamic process of hydrate dissociation in the near-wellbore surrounding rock during drilling, a dynamic hydrate phase transition model is adopted in this paper. Natural gas hydrate is a clathrate crystal compound formed by methane gas and water under low-temperature and high-pressure conditions, and the equation of hydrate phase transition reaction is:



In the equation, n is the hydration number of methane hydrate, with a value range of 5.5–7.65, and 6.00 is adopted in the subsequent calculations of this paper; Q is the latent heat of methane hydrate phase transition, in $\text{kJ} \cdot \text{mol}^{-1}$.

The correlation between the phase equilibrium temperature and pressure of methane hydrate is shown in Equation (34) [48]:

$$\begin{aligned} \ln(P_{eq}) = & 1.94 \times 10^5 + 3.31 \times 10^3 T - 2.26 T^2 \\ & + 7.68 \times 10^{-2} T^3 - 1.30 \times 10^{-4} T^4 + 8.86 \times 10^{-8} T^5 \end{aligned} \quad (34)$$

In the equation, P_{eq} is the phase equilibrium pressure of hydrate at temperature T , in MPa.

When a hydrate inhibitor is present in the solution, a temperature correction value needs to be added to the temperature term in Equation (34), and its calculation method is shown in Equation (35) [48,49]:

$$\Delta T_D = \Delta T_{D,r} \frac{\ln(1 - x_w^i)}{\ln(1 - x_{w,r}^i)} \quad (35)$$

In the equation, ΔT_D is the temperature correction value caused by the hydrate inhibitor, in $^\circ\text{C}$; $\Delta T_{D,r}$ is the reference temperature correction value caused by the inhibitor, in $^\circ\text{C}$; x_w^i is the mole fraction of the hydrate inhibitor in the liquid phase; $x_{w,r}^i$ is the reference mole fraction of the hydrate inhibitor in the liquid phase.

According to the Kim–Bishnoi hydrate dissociation kinetic model, the calculation method of the rate of methane gas generated by hydrate dissociation per unit volume of porous media is shown in Equation (36) [50]:

$$\dot{m}_g = K_{rd} M_g A_{dec} (P_{eq} - P_g) \quad (36)$$

In the equation, M_g is the molar mass of methane, in $\text{kg} \cdot \text{mol}^{-1}$; A_{dec} is the specific surface area of hydrate phase transition in porous media, in $\text{m}^2 \cdot \text{m}^{-3}$; K_{rd} is the hydrate dissociation rate constant, in $\text{mol} \cdot \text{s}^{-1} \cdot \text{Pa}^{-1} \cdot \text{m}^{-2}$; $\dot{m}_g$ is the rate of methane gas generated by hydrate dissociation per unit volume of porous media, in $\text{kg} \cdot \text{m}^{-3} \cdot \text{s}^{-1}$; P_{eq} is the hydrate phase equilibrium pressure, in Pa; P_g is the gas phase pressure of methane, in Pa.

Since the occurrence mode of hydrates in the South China Sea is a pore-filling type, during hydrate formation, the hydrate formation rate is related to the saturations of hydrate, pore water, and methane gas; during hydrate dissociation, the hydrate dissociation rate is related to the hydrate radius. Therefore, its specific surface area A_{dec} can be calculated according to Equation (37):

$$A_{\text{dec}} = 10^6 \Gamma_s [\text{m}^2/\text{m}^3] \quad \Gamma_s = \begin{cases} \phi S_h & \text{for } P_{\text{eq}} > P_g \\ S_g S_w (1 - S_h) & \text{for } P_{\text{eq}} \leq P_g \end{cases} \quad (37)$$

In the equation, S_h is the hydrate saturation, dimensionless; S_g is the methane gas saturation, dimensionless; S_w is the pore water saturation, dimensionless.

According to Equations (33) and (36), the hydrate dissociation rate and pore water generation rate per unit volume of formation can be expressed as shown in Equations (38) and (39) [51]:

$$\dot{m}_w = \left(\frac{nM_w}{M_g} \right) \dot{m}_g \quad (38)$$

$$\dot{m}_h = -(\dot{m}_g + \dot{m}_w) \quad (39)$$

In the equations, $\dot{m}_w$ is the pore water generation rate per unit volume of formation, in $\text{kg} \cdot \text{m}^{-3} \cdot \text{s}^{-1}$; $\dot{m}_h$ is the hydrate dissociation rate per unit volume of formation, in $\text{kg} \cdot \text{m}^{-3} \cdot \text{s}^{-1}$.

2.5. Criterion for Wellbore Collapse in Hydrate-Bearing Strata

During drilling operations in hydrate-bearing strata, the near-wellbore formation inevitably undergoes plastic deformation. Owing to the weak cementation and under-compacted characteristics of hydrate reservoirs, conventional shear failure does not occur immediately under mechanical loading. Accordingly, a moderate magnitude of plastic deformation in the near-wellbore zone is tolerable. Structural formation failure and wellbore collapse only occur when the accumulated plastic deformation exceeds a critical threshold. In view of this unique mechanical behavior, a targeted criterion for evaluating wellbore collapse in hydrate-bearing strata is proposed in this study.

Once the wellbore formation enters the strain-softening stage, its bearing capacity degrades continuously with further strain accumulation, leading to a significantly increased risk of wellbore instability. Therefore, the critical strain corresponding to the initiation of the strain-softening stage is adopted as the collapse threshold. Based on the tri-axial mechanical test results of hydrate-bearing rock samples, a critical plastic strain is determined for wellbore collapse judgment. On this basis, the wellbore enlargement ratio of hydrate-bearing strata is defined, as shown in Equation (40).

$$\xi = (D_{\text{new}} - D) / D \quad (40)$$

where ξ is the wellbore enlargement ratio, in %; D is the initial outer diameter of the wellbore, in m; and D_{new} is the maximum outer diameter of the wellbore after collapse, in m.

3. Numerical Model for Wellbore Stability of Directional Wells in Deepwater Shallow Soft Hydrate Formations

3.1. Establishment of the Numerical Model

For horizontal well drilling in hydrate-bearing formations, the formation at the heel of the horizontal section is the first region to be drilled, with the longest exposure time to drilling fluid and the highest risk of wellbore instability. Therefore, a wellbore stability model for directional well drilling in deepwater shallow soft formations was established using numerical simulation software. The schematic diagram of the simulated working condition is shown in Figure 3, and the material parameters of the model are listed in Table 1.

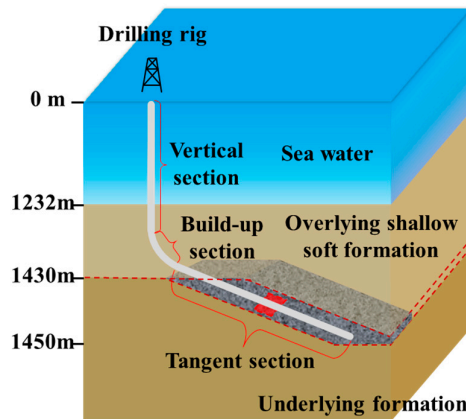


Figure 3. Simulated working conditions.

Table 1. Calculation parameters of wellbore stability model for directional wells in hydrate reservoirs.

Parameter	Value	Unit	Parameter	Value	Unit
overburden pressure	16.83	MPa	underlying formation pressure	18.16	MPa
tectonic stress coefficient of maximum effective horizontal in situ stress	0.66	—	tectonic stress coefficient of minimum effective horizontal in situ stress	0.70	—
pore pressure (upper boundary)	13.83	MPa	pore pressure (lower boundary)	14.33	MPa
formation temperature (upper boundary)	12.28	°C	formation temperature (lower boundary)	14.58	°C
depth of hydrate layer below mudline	180	m	geothermal gradient	0.046	°C·m ⁻¹
thermal conductivity of water	0.6	W·m ⁻¹ ·°C ⁻¹	specific heat capacity of water	4.2	kJ·kg ⁻¹ ·°C ⁻¹
density of water	1000	kg·m ⁻³	thermal conductivity of methane	0.00335	W·m ⁻¹ ·°C ⁻¹
specific heat capacity of methane	2.093	kJ·kg ⁻¹ ·°C ⁻¹	thermal conductivity of hydrate	0.4	W·m ⁻¹ ·°C ⁻¹
specific heat capacity of hydrate	2.1	kJ·kg ⁻¹ ·°C ⁻¹	density of hydrate	910	kg·m ⁻³
thermal conductivity of formation	1.5	W·m ⁻¹ ·°C ⁻¹	specific heat capacity of formation	1.6	kJ·kg ⁻¹ ·°C ⁻¹
density of formation	2700	kg·m ⁻³	permeability	0.000987	μm ²
initial void ratio	0.605	—	initial hydrate saturation	0.45	—
initial water saturation	0.55	—	initial free gas saturation	0	—
Biot coefficient	1	—	drilling fluid salinity	3.05	wt%
drilling time	240	h	drilling fluid density	1.00	g·cm ⁻³

3.2. Validation of the Wellbore Stability Numerical Model for Directional Wells in Hydrate-Bearing Formations

The working condition simulated by the validation model is drilling in the hydrate layer at Site SH2 in the Shenhu area of the South China Sea. The depth of the formation below the mudline is 217.5 m, the overburden pressure is 16.70 MPa, and the horizontal in situ stress is 15.74 MPa. The initial pore pressure, temperature, and hydrate saturation are 14.689 MPa, 14.175 °C, and 0.27, respectively. The drilling fluid pressure and temperature used are 14.975 MPa and 15.2 °C. According to the drilling fluid composition, the phase equilibrium temperature of hydrate under the drilling fluid pressure is 14.865 °C, and the wellbore diameter is 228.6 mm [17,27]. Figure 4 shows the geometric model and mesh generation of the validation model for hydrate dissociation around the wellbore.

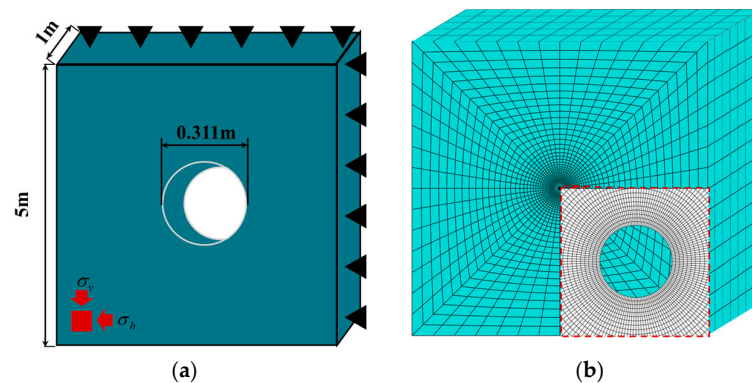


Figure 4. Diagram of geometric model and meshing of hydrate decomposition around borehole. (a) Schematic diagram of geometric model. (b) Mesh generation.

Figure 5 shows the hydrate saturation distribution around the wellbore at 2 h, 12 h, and 24 h after wellbore drilling. It can be seen that when affected by heat transfer and seepage of the drilling fluid, hydrate in the formation around the wellbore gradually dissociates, and the dissociation range expands continuously with the increase of exposure time. The solid line in the figure represents the results calculated by Sun et al. [27] using TOUGH+HYDRATE, and the dashed line represents the results calculated by the model in this paper. It can be seen from the comparison that the hydrate saturation distribution calculated in this paper is in good agreement with the results from TOUGH+HYDRATE. The maximum error of the complete hydrate dissociation zone is 5.38%, and the maximum error of the hydrate dissociation front is 5.60%. Meanwhile, the numerical simulation data are validated against the measured dissociation degree data obtained from physical experiments of surrounding wellbore reservoirs. A favorable consistency can be observed between the numerical predictions and experimental measurements. Accordingly, the proposed program possesses high accuracy and is capable of simulating and analyzing wellbore stability during drilling operations in hydrate-bearing reservoirs.

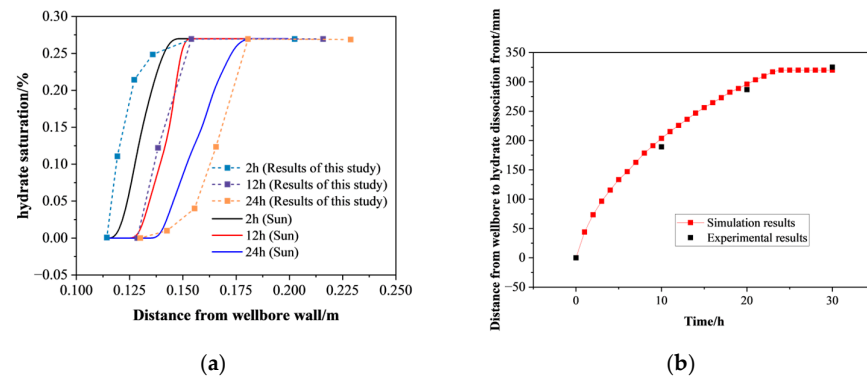


Figure 5. Model accuracy validation. (a) Hydrate validation [17,27]. (b) Validation of wellbore hydrate dissociation degree and model accuracy.

4. Influencing Factors of Wellbore Stability in Directional Wells in Deepwater Shallow Soft Formations

4.1. Effect of Hydrate Dissociation Degree on Wellbore Stability

Hydrate dissociation degree directly changes the solid cementation structure and pore fluid occurrence state of the formation, thereby significantly weakening the overall mechanical strength and structural integrity of deepwater shallow sediments. The inherent characteristics of hydrate-bearing formations, such as weak cementation, low bearing capacity, and high sensitivity to temperature and pressure variations, result in a close correlation between hydrate dissociation degree and wellbore stability. In this section, a wellbore stability model considering hydrate dissociation is established in which the dissociation degree is characterized by drilling time, namely 0 h, 0.125 h, 6 h, and 240 h.

Figures 6 and 7 show the contours of plastic strain around the wellbore and the corresponding hydrate saturation contours under different dissociation degrees, and Figure 8 shows the borehole diameter expansion ratio under different dissociation degrees. It can be observed that with the increase of hydrate dissociation degree, the maximum plastic strain of the wellbore rapidly reaches a peak value, while the wellbore enlargement ratio continues to increase slowly. At 0 h of drilling, the maximum plastic strain is 0.01130 and the wellbore enlargement ratio is 78.2%. At 0.125 h, the maximum plastic strain rises to 0.01347, and the enlargement ratio increases to 113.6%. After drilling time exceeds 0.125 h, the maximum plastic strain remains constant at 0.01347, whereas the enlargement ratio still increases gradually. When drilling time reaches 6 h and 240 h, the enlargement ratios are 128.6% and 135.7%, respectively.

The fundamental mechanism underlying such variation is as follows. On the one hand, hydrate dissociation converts solid hydrate into gas and liquid phases, which reduces the effective stress of the formation, drastically attenuates the cementation strength, and significantly lowers the bearing capacity of the formation skeleton, making plastic yielding and deformation more likely to occur under the same stress condition. On the other hand, massive fluids generated by dissociation elevate the pore pressure, further reducing the effective confining pressure of the wellbore and aggravating stress concentration and local instability risk. In addition, a higher hydrate dissociation degree corresponds to a larger formation weakening zone and poorer uniformity, which destabilizes the wellbore stabilization and stress transfer effects of drilling fluid and tends to induce stress exceeding the limit and erosional enlargement locally. Consequently, the plastic strain accumulates continuously, and the risk of wellbore instability increases sharply.

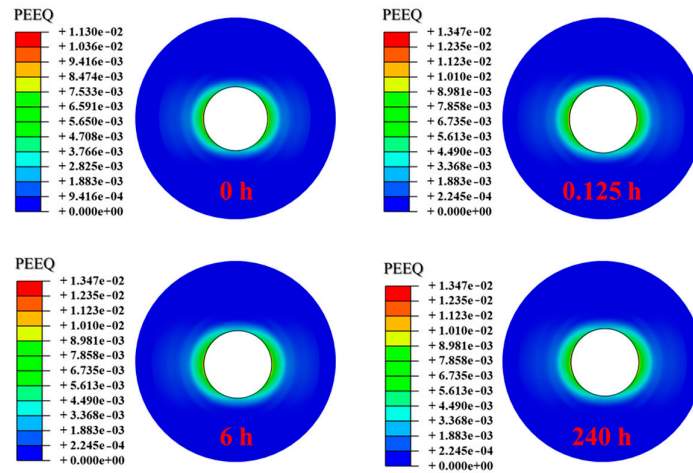


Figure 6. Contours of plastic strain around the wellbore under different dissociation degrees.

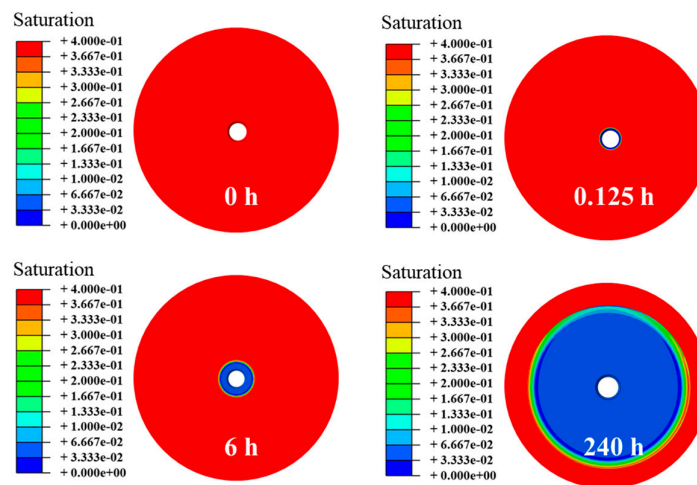


Figure 7. Hydrate saturation contours under the corresponding dissociation degrees.

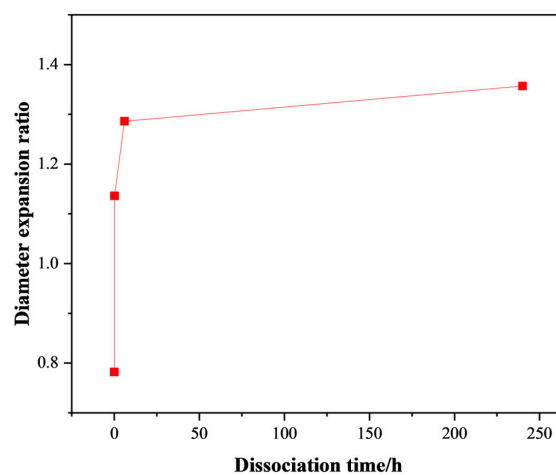


Figure 8. Diameter expansion ratio under different dissociation degrees.

4.2. Effect of Inclination Angle of Directional Wells on Wellbore Stability in Hydrate Reservoirs

The inclination angle of a directional well directly alters the interaction between the wellbore and the in situ stress field, thereby affecting the distribution and intensity of stress concentration around the wellbore. Due to the weak cementation and easy dissociation characteristics of deepwater ultra-shallow hydrate formations, wellbore stability exhibits higher sensitivity to variations in inclination angle. In this section, wellbore stability models with different directional well inclination angles are established, with the angles set to 0° , 15° , 30° , 45° , 60° , and 75° , respectively.

Figure 9 presents the contour distributions of equivalent plastic strain around the wellbore under different inclination angles. It can be seen that the plastic distribution region around the wellbore gradually expands with the increase of directional well inclination angle. Figures 10 and 11 show the numerical variation laws of the maximum plastic strain and wellbore enlargement ratio under different inclination angles. It is observed that both the maximum plastic strain and the wellbore enlargement ratio increase nonlinearly with the rise of the inclination angle, and the plastic strain around the wellbore gradually decreases along the direction away from the wellbore, corresponding to the minimum horizontal in situ stress. At an inclination angle of 0° , the maximum plastic strain is 0.0047 and the wellbore enlargement ratio is 38.06%. When the angle increases to 30° , the maximum plastic strain is 0.0087 and the enlargement ratio rises to 105.65%. As the angle reaches 75° , the maximum plastic strain reaches 0.0262 and the enlargement ratio is as high as 152.64%.

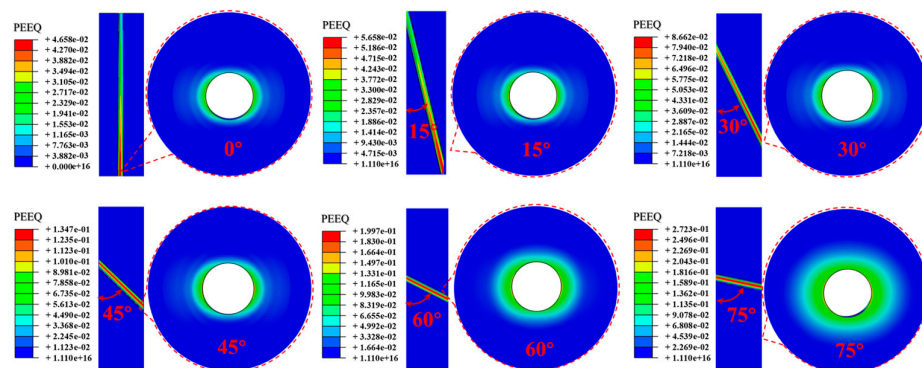


Figure 9. Distribution of equivalent plastic strain contours around the wellbore under different directional well inclination angles.

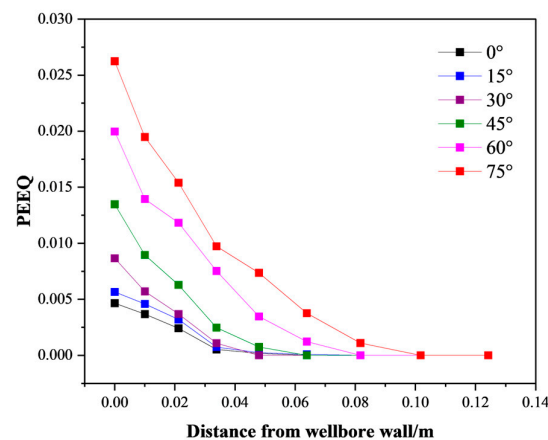


Figure 10. Equivalent plastic strain distribution around the wellbore under different directional well inclination angles.

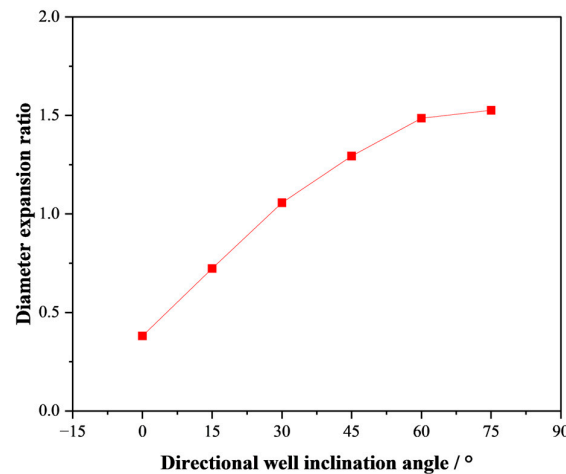


Figure 11. Distribution of diameter expansion ratio under different directional well inclination angles.

The core mechanism of this variation is as follows. On the one hand, the increase in directional well inclination angle enlarges the hydrate dissociation zone and the weakened region of formation mechanical properties, reducing the bearing capacity of the wellbore and resulting in larger plastic deformation under the same stress condition. On the other hand, a larger inclination angle intensifies the stress concentration around the wellbore, causing the stress in local regions of the wellbore to exceed the yield strength of the formation and leading to continuous accumulation of plastic strain. In addition, a larger inclination angle corresponds to a larger contact area between the wellbore and the formation, which results in a more non-uniform support effect of drilling fluid on the wellbore and insufficient support pressure in local areas, further promoting the development of plastic deformation and wellbore enlargement.

4.3. Effect of Initial Hydrate Saturation on Wellbore Stability

Initial hydrate saturation is a core parameter determining the mechanical strength of deepwater ultra-shallow hydrate reservoirs, directly controlling the formation cementation characteristics and bearing capacity. Due to the reservoir's inherent weak cementation and significant response to thermal-hydraulic-mechanical-chemical (THMC) coupling, wellbore stability is extremely sensitive to changes in initial saturation. In this section, multiple groups of numerical simulations on wellbore stability are carried out with different initial hydrate saturation conditions, where the initial saturations are set to 0.1, 0.2, 0.3, and 0.4, respectively. The contour distribution of the equivalent plastic strain region of the reservoir around the wellbore is shown in Figure 12.

Figures 13 and 14 show the variation laws of the maximum plastic strain of the wellbore and the wellbore enlargement ratio under different initial hydrate saturations. It can be observed that with the increase of initial hydrate saturation, both the maximum plastic strain of the wellbore and the wellbore enlargement ratio show a significant decreasing trend: when the saturation is 0.1, the maximum plastic strain is 0.02723 and the wellbore enlargement ratio is as high as 201.7%; when the saturation increases to 0.2, the maximum plastic strain is 0.01997 and the enlargement ratio decreases to 124.5%; when the saturation reaches 0.4, the maximum plastic strain is only 0.00866 and the enlargement ratio is as low as 76.3%.

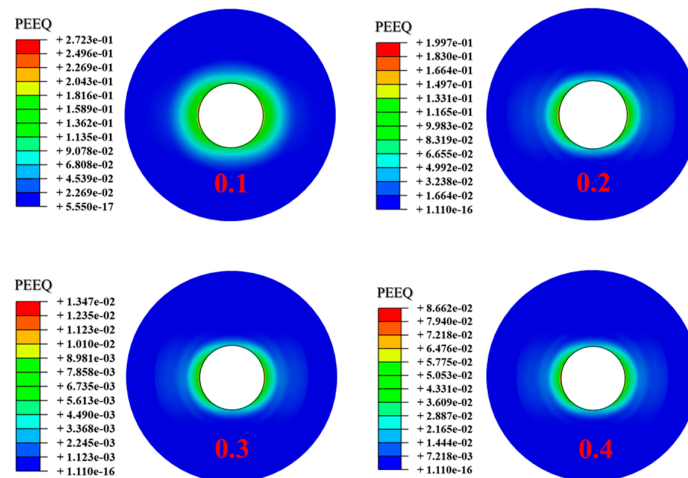


Figure 12. Contours of plastic strain distribution around the wellbore under different initial saturations.

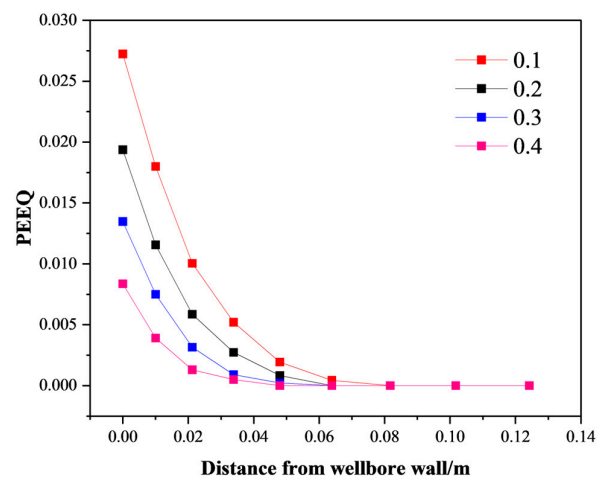


Figure 13. Plastic strain distribution around the wellbore under different initial saturations.

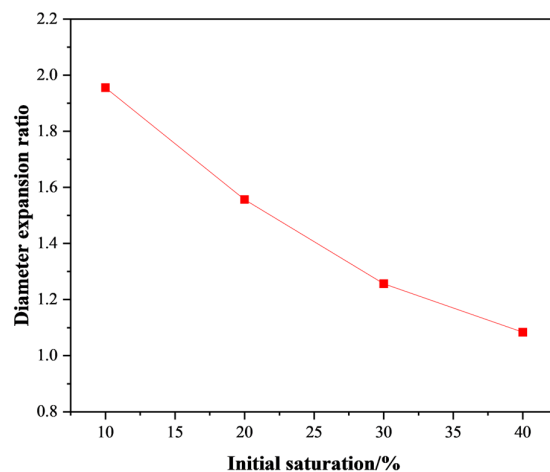


Figure 14. Distribution of borehole diameter expansion ratio under different initial saturations.

The intrinsic mechanism behind this variation is as follows. On the one hand, the higher the initial hydrate saturation, the stronger the cementation and filling effect of

hydrate in the sediment pores, which significantly improves the formation elastic modulus, cohesion, and shear strength; enhances the overall bearing capacity of the wellbore; and makes plastic yielding less likely to occur under the same stress and drilling fluid disturbance. On the other hand, the reservoir with high hydrate saturation has higher thermal stability and phase equilibrium stability, resulting in a smaller dissociation range and weaker dissociation degree of hydrate under the same temperature and pore pressure conditions, and the range of the mechanical weakening zone is significantly reduced. In addition, the formation with high saturation has weaker pore connectivity, which inhibits fluid infiltration and pore pressure diffusion effects, makes the effective stress distribution more uniform, and further slows down the expansion of the plastic zone around the wellbore and the wellbore enlargement deformation.

4.4. Effect of Hydrate Reservoir Thickness on Wellbore Stability

The thickness of the overburden above the hydrate layer directly controls the magnitude of the effective confining pressure and the in situ stress state of the formation, thereby changing the stress distribution characteristics around the wellbore and the wellbore instability mode. In this section, wellbore stability models with different overburden thicknesses are established for analysis. The overburden thicknesses are set to 150 m, 165 m, and 180 m, and the corresponding boundary conditions are listed in Table 2.

Table 2. Boundary conditions corresponding to the thickness of overlying layer.

Overburden Thickness/m	Pore Pressure at Upper Boundary/MPa	Pore Pressure at Lower Boundary/MPa	Drilling Fluid Hydrostatic Pressure/MPa	Temperature at Upper Boundary/°C	Temperature at Lower Boundary/°C	Overburden Pressure at Upper Boundary/MPa	Overburden Pressure at Lower Boundary/MPa
150	13.54	14.03	13.79	10.90	13.20	2.50	3.33
165	13.69	14.18	13.94	11.59	13.89	2.75	3.58
180	13.84	14.33	14.08	12.28	14.58	3.00	3.83

Figures 15 and 16 show the plastic strain distribution in the horizontal in situ stress direction under different overburden thicknesses. It can be seen that both the range of the plastic zone and the maximum plastic strain increase with the increase of overburden thickness. The range of the plastic zone is affected by the hydrate dissociation range, while the significant difference in the maximum plastic strain is attributed to the fact that a larger overburden thickness corresponds to higher effective in situ stress, resulting in more severe stress concentration around the wellbore. This also leads to an approximately linear increase in the wellbore enlargement ratio with the increase of overburden thickness, as shown in Figure 17. When the overburden thickness is 150 m, the wellbore enlargement ratio is 101.2% after 240 h; when the overburden thickness is 180 m, the wellbore enlargement ratio reaches 165.0%. Therefore, when the mechanical properties of formations at different depths are similar, drilling in shallower formations can greatly improve wellbore stability.

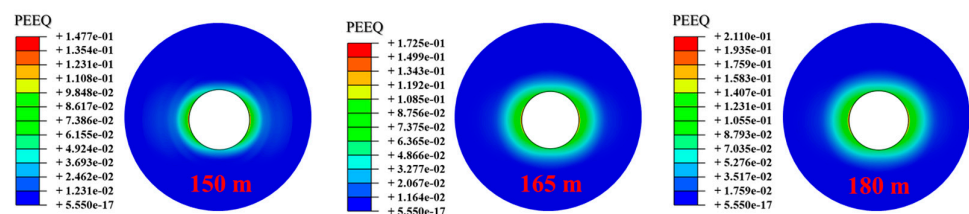


Figure 15. Contours of plastic strain distribution around the wellbore under different overlying strata thicknesses.

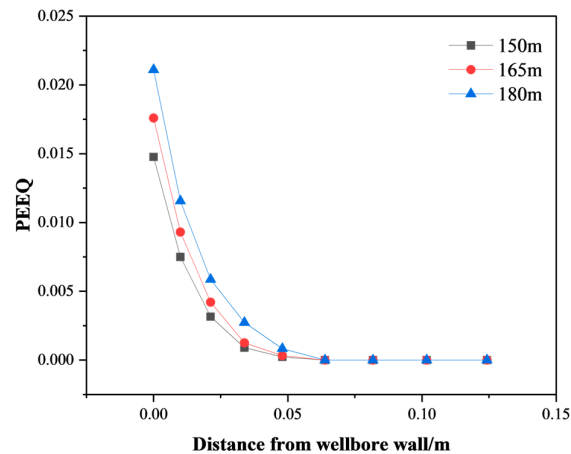


Figure 16. Plastic strain distribution near the wellbore under different overburden thicknesses.

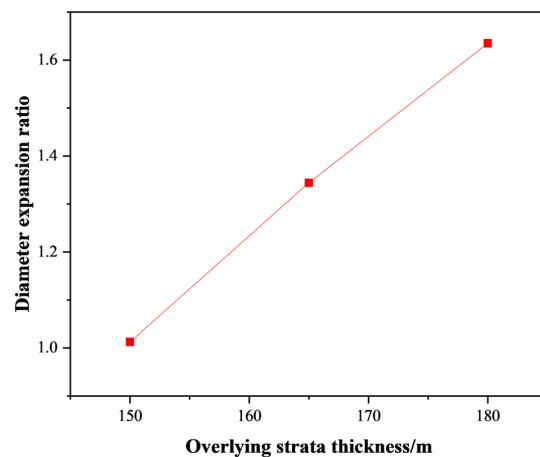


Figure 17. Distribution of diameter expansion ratio under different overburden thicknesses.

4.5. Analysis of the Effect of Water Depth on Wellbore Stability

Different water depths change the initial pore pressure distribution of the formation and also affect the magnitude of the drilling fluid hydrostatic pressure. In this section, wellbore stability models with different water depths are established to analyze the influence of water depth on the wellbore stability of horizontal wells in hydrate-bearing formations. The pore pressure boundaries corresponding to different water depths are shown in Table 3.

Table 3. Pore pressure boundary conditions at different seawater depths.

Water Depth/m	Pore pressure at Upper Boundary/MPa	Pore Pressure at Lower Boundary/MPa	Drilling Fluid Hydrostatic Pressure/MPa
1232	13.84	14.33	14.08
1332	14.82	15.31	15.06
1432	15.80	16.28	16.04

Figures 18 and 19 presents the formation's plastic strain distribution in the horizontal in situ stress direction. It can be observed that the affected range in the near-wellbore area and the maximum plastic strain of the wellbore decrease with increasing water depth. For example, when the water depth is 1232 m, the maximum plastic strain is 0.211; when the water depth is 1432 m, the maximum plastic strain is 0.191. Furthermore, the wellbore

enlargement ratios at different water depths can be obtained according to the intersection points between the critical plastic strain line and the plastic strain distribution curves, as listed in Figure 20. Therefore, when the hydrate reservoir is located on a submarine slope, drilling at the deeper slope bottom can effectively reduce the risk of wellbore instability.

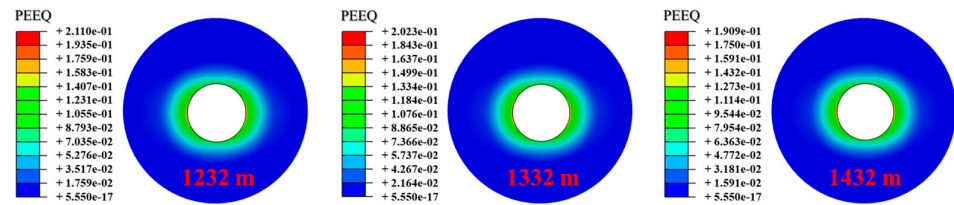


Figure 18. Contours of plastic strain distribution around the wellbore under different water depths.

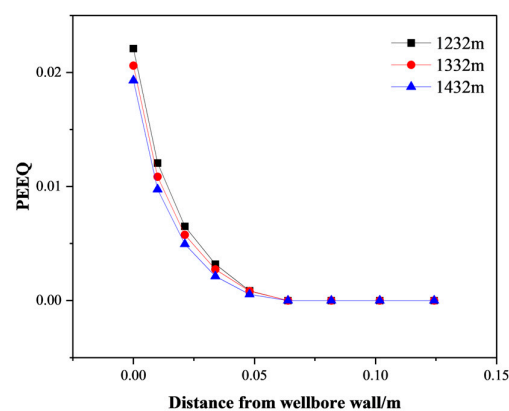


Figure 19. Formation plastic strain distribution under different water depths.

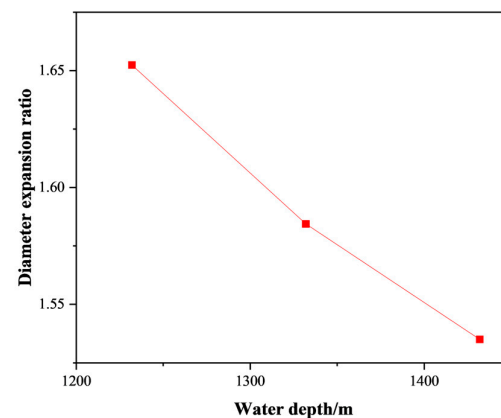


Figure 20. Borehole diameter expansion ratio under different water depths.

It is worth noting that deterministic single-factor analysis cannot capture the interactive effects between different parameters or quantify the wellbore instability risks originating from parametric uncertainty. As such, the results obtained in this study only reflect the independent influence of each individual parameter. Furthermore, deepwater shallow hydrate reservoirs exhibit pronounced heterogeneity in hydrate saturation, porosity, permeability, and cementation quality. The homogeneous numerical model adopted in this work is incapable of characterizing local instability hazards induced by spatial parameter heterogeneity, which may overestimate the reliability of the current prediction results to a certain extent. To address the above limitations, global sensitivity analysis and

heterogeneous modeling methods will be incorporated in future studies to further optimize and refine the analytical framework for wellbore stability evaluation.

5. Conclusions

- (1) The wellbore stability of directional wells in deepwater shallow soft hydrate reservoirs is highly sensitive to the inclination angle. The maximum plastic strain and wellbore enlargement ratio increase nonlinearly with the increase of inclination angle, and the stability deteriorates sharply when the angle exceeds 30°;
- (2) Initial hydrate saturation is a core factor controlling the mechanical strength of the reservoir. Higher saturation leads to stronger formation-bearing capacity, smaller hydrate dissociation range, and significantly reduced plastic deformation and wellbore enlargement ratio;
- (3) Hydrate dissociation has an immediate and significant effect on wellbore stability. With the increase of drilling time (dissociation degree), the maximum plastic strain of the wellbore rapidly reaches a peak value, and the wellbore enlargement ratio continues to rise even after the strain stabilizes;
- (4) Overburden thickness and water depth impose opposite effects on wellbore stability. A thicker overburden aggravates stress concentration around the wellbore and increases collapse risk, while greater water depth optimizes pore pressure distribution and effectively improves wellbore stability.

Author Contributions: Methodology, Y.H. and C.Y.; Writing—original draft, A.F. and K.Z.; Writing—review and editing, Y.H. and C.Y.; Funding acquisition, Y.H. and C.Y. All authors have read and agreed to the published version of the manuscript.

Funding: This research was funded by the CNOOC Group Science and Technology Project (KJZH-2025–1301), the National Natural Science Foundation of China (U2244223, U25B20163), the Science Foundation Project of Shandong Province (ZR2025QB55), the Taishan Scholars Program of Shandong Province (tsqn202408102), and the Key Research and Development Program of China (2023YFC2811004).

Data Availability Statement: The raw data supporting the conclusions of this article will be made available by the authors on request.

Conflicts of Interest: The authors declare no conflicts of interest. Authors Yufa He and Kexin Zhang were employed by CNOOC Research Institute Co., Ltd. The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest. The funder had no role in the design of the study; in the collection, analyses, or interpretation of data; in the writing of the manuscript, or in the decision to publish the results.

References

1. Li, J.; She, Y.; Gao, Y.; Li, M.; Yang, G.; Shi, Y. Natural gas industry in China: Development situation and prospect. *Nat. Gas Ind. B* **2020**, *7*, 604–613.
2. Wang, Y.; Zheng, Z.; Han, Z.; Li, W.; Bai, Y.; Fan, D. Analysis of global and domestic oil and gas resource dynamics in 2025 and outlook. *China Min. Mag.* **2026**, *35*, 30–40.
3. Jia, C.; Zheng, M.; Zhang, Y. Unconventional hydrocarbon resources in China and the prospect of exploration and development. *Pet. Explor. Dev.* **2012**, *39*, 129–136.
4. Wen, H.; Chen, M.; Jin, Y.; Wang, K.; Xia, Y.; Dong, J.; Niu, C. A chemo-mechanical coupling model of deviated borehole stability in hard brittle shale. *Pet. Explor. Dev.* **2014**, *41*, 817–823.
5. Deng, Y.; He, S.; Deng, X.; Peng, Y.; He, S.; Tang, M. Study on wellbore instability of bedded shale gas horizontal wells under chemo-mechanical coupling. *Pet. Drill. Tech.* **2020**, *48*, 26–33.

6. Liu, H.; Xu, J.; Xie, T. Study on fluid-solid coupling for borehole wall stability of medium-deep wellbore in Bohai Sea. *China Pet. Mach.* **2019**, *47*, 1–7.
7. Liu, J.; Wang, S.; Jiang, M.J.; Wu, W. A state-dependent hypoplastic model for methane hydrate-bearing sands. *Acta Geotech.* **2021**, *16*, 77–91.
8. Liu, W.; Hu, J.; Li, X.; Sun, F.; Sun, Z.; Zhou, Y. Research on evaluation method of wellbore hydrate blocking degree during deepwater gas well testing. *J. Nat. Gas Sci. Eng.* **2018**, *59*, 168–182.
9. Li, L.; Cheng, Y.; Zhang, Y.; Cui, Q.; Zhao, F. A fluid-solid coupling model of wellbore stability for hydrate bearing sediments. *Procedia Eng.* **2011**, *18*, 363–368.
10. Lu, J.; Xiong, Y.; Li, D.; Shen, X.; Wu, Q.; Liang, D. Experimental investigation of characteristics of sand production in wellbore during hydrate exploitation by the depressurization method. *Energies* **2018**, *11*, 1673.
11. Birchwood, R.; Noeth, S.; Hooyman, P.; Winters, W.; Jones, E. Wellbore stability model for marine sediments containing gas hydrates. In Proceedings of the American Association of Drilling Engineers National Conference and Exhibition, Houston, TX, USA, 5–7 April 2005; Volume 5, p. e7.
12. Freij-Ayoub, R.; Tan, C.; Clennell, B.; Tohidi, B.; Yang, J. A wellbore stability model for hydrate bearing sediments. *J. Pet. Sci. Eng.* **2007**, *57*, 209–220.
13. Wan, Y.; Wu, N.; Hu, G.; Xin, X.; Jin, G.; Liu, C.; Chen, Q. Reservoir stability in the process of natural gas hydrate production by depressurization in the Shenhu area of the South China Sea. *Nat. Gas Ind. B* **2018**, *5*, 631–643.
14. Li, Q.C.; Liu, L.L.; Yu, B.H.; Guo, L.N.; Shi, S.; Miao, L.C. Borehole enlargement rate as a measure of borehole instability in hydrate reservoir and its relationship with drilling mud density. *J. Pet. Explor. Prod.* **2021**, *11*, 1185–1198.
15. Li, L.D.; Cheng, Y.F.; Mei, W.; Li, Q.P.; Gao, L.C. Finite element simulation of temperature impact on wellbore stability of gas-hydrate-bearing sediments. *Nat. Gas Ind* **2012**, *32*, 74–78.
16. Huang, L.H.; Xu, C.S.; Xu, J.L.; Zhang, X.; Xia, F. The depressurization of natural gas hydrate in the multi-physics coupling simulation based on a new developed constitutive model. *J. Nat. Gas Sci. Eng.* **2021**, *95*, 103963.
17. Li, Y.; Cheng, Y.F.; Yan, C.L.; Wang, Z.Y.; Zhang, Q.X. Multi-physical field coupling model of hydrate formation and analysis of wellbore collapse law in Shenhu area of South China Sea. *J. Cent. South Univ. Sci. Technol* **2022**, *53*, 976–990.
18. Li, Q.; Cheng, Y.; Ansari, U.; Han, Y.; Liu, X.; Yan, C. Experimental investigation on hydrate dissociation in near-wellbore region caused by invasion of drilling fluid: Ultrasonic measurement and analysis. *Environ. Sci. Pollut. Res.* **2022**, *29*, 36920–36937.
19. Song, B.; Chen, Y.; Li, Q.; Han, Z.; Lv, Y. Simulation of submarine slope stability related to hydrate dissociation. *Mar. Geol. Quat. Geol.* **2019**, *39*, 182–192.
20. Yan, C.L.; Li, Y.; Cheng, Y.F.; Wei, J.; Tian, W.; Li, S.; Wang, Z. Multifield coupling mechanism in formations around a wellbore during the exploitation of methane hydrate with CO₂ replacement. *Energy* **2022**, *245*, 123283.
21. Ning, F.L.; Zhang, K.N.; Wu, N.Y.; Jiang, G.S.; Zhang, L.; Liu, L.; Yu, Y.B. Invasion of water-based drilling mud into oceanic gas-hydrate-bearing sediment: One-dimensional numerical simulations. *Chin. J. Geophys.* **2013**, *56*, 204–218.
22. Jiang, G.S.; Ning, F.L.; Li, Z.W.; Zhang, L.; Xiang, X.C.; Dou, B. Inhibition and induction decomposition of gas hydrates on drilling procedure. *Geol. Prospect.* **2001**, *37*, 86–87.
23. Klar, A.; Deerberg, G.; Janicki, G.; Schicks, J.; Riedel, M.; Fietzek, P.; Mosch, T.; Tinivella, U.; De La Fuente, M.; Gatt, P.; et al. Marine gas hydrate technology: State of the art and future possibilities for Europe. *WG2 Rep.* **2019**, *3*, 61.
24. Wang, R.; Ning, F.; Liu, T.; Zhang, L.; Sun, H.; Peng, L.; Guo, D.; Jiang, G. Dynamic simulation of hydrate formed from free methane gas in borehole. *Acta Pet. Sin.* **2017**, *38*, 963.
25. Rutqvist, J.; Moridis, G.J.; Grover, T.; Silpnagarmert, S.; Collett, T.S.; Holdich, S.A. Coupled multiphase fluid flow and wellbore stability analysis associated with gas production from oceanic hydrate-bearing sediments. *J. Pet. Sci. Eng.* **2012**, *92*, 65–81.
26. Cheng, Y.F.; Li, L.D.; Mahmood, S.; Qing, C. Fluid-solid coupling model for studying wellbore instability in drilling of gas hydrate bearing sediments. *Appl. Math. Mech.* **2013**, *34*, 1421–1432.
27. Sun, J.X.; Ning, F.L.; Lei, H.W.; Gai, X.; Sánchez, M.; Lu, J.; Li, Y.; Liu, L.; Liu, C.; Wu, L.; et al. Wellbore stability analysis during drilling through marine gas hydrate-bearing sediments in Shenhu area: A case study. *J. Pet. Sci. Eng.* **2018**, *170*, 345–367.
28. Wei, J.; Cheng, Y.F.; Yan, C.L.; Li, Q.; Han, S.; Ansari, U. Decomposition prevention through thermal sensitivity of hydrate formations around wellbore. *Appl. Therm. Eng.* **2019**, *159*, 113921.
29. Li, Q.; Cheng, Y.; Shao, C. Lower limit of safe mud weight window with considering moderate borehole collapse. *Fault-Block Oil Gas Field* **2019**, *26*, 657–661.
30. Wu, J.; Ansari, U. From CO₂ Sequestration to Hydrogen Storage: Further Utilization of Depleted Gas Reservoirs. *Reserv. Sci.* **2025**, *1*, 19–35.

31. Li, Y.; Cheng, Y.F.; Yan, C.L.; Song, L.; Liu, H.; Tian, W.; Ren, X. Mechanical study on the wellbore stability of horizontal wells in natural gas hydrate reservoirs. *J. Nat. Gas Sci. Eng.* **2020**, *79*, 103359.
32. Liao, Y.Q.; Wang, Z.Y.; Chao, M.Z.; Sun, X.; Wang, J.; Zhou, B.; Sun, B. Coupled wellbore–reservoir heat and mass transfer model for horizontal drilling through hydrate reservoir and application in wellbore stability analysis. *J. Nat. Gas Sci. Eng.* **2021**, *95*, 104216.
33. Hu, T.; Wang, H.N.; Jiang, M.J. Analytical approach for the fast estimation of time-dependent wellbore stability during drilling in methane hydrate-bearing sediment. *J. Nat. Gas Sci. Eng.* **2022**, *99*, 104422.
34. Mao, P.; Wan, Y.; Sun, J.; Li, Y.; Hu, G.; Ning, F.; Wu, N. Numerical study of gas production from fine-grained hydrate reservoirs using a multilateral horizontal well system. *Appl. Energy* **2021**, *301*, 117450.
35. Liu, Z.; Dai, S.; Ning, F.; Peng, L.; Wei, H.; Wei, C. Strength estimation for hydrate-bearing sediments from direct shear tests of hydrate-bearing sand and silt. *Geophys. Res. Lett.* **2018**, *45*, 715–723.
36. Song, B.J.; Cheng, Y.F.; Yan, C.L.; Lyu, Y.; Wei, J.; Ding, J.; Li, W. Seafloor subsidence response and submarine slope stability evaluation in response to hydrate dissociation. *J. Nat. Gas Sci. Eng.* **2019**, *65*, 197–211.
37. Wu, P.; Li, Y.; Wang, L.; Sun, X.; Wu, D.; He, Y.; Li, Q.; Song, Y. Hydrate-bearing sediment of the South China Sea: microstructure and mechanical characteristics. *Eng. Geol.* **2022**, *307*, 106782.
38. Li, G.; Tang, C.A.; Liang, Z.Z. Development of a parallel FE simulator for modeling the whole trans-scale failure process of rock from meso- to engineering-scale. *Comput. Geosci.* **2017**, *98*, 73–86.
39. Li, Q.; Li, Q.; Wu, J.; He, K.; Xia, Y.; Liu, J.; Wang, F.; Cheng, Y. Wellhead Stability During Development Process of Hydrate Reservoir in the Northern South China Sea: Sensitivity Analysis. *Processes* **2025**, *13*, 1630.
40. Hu, Y.; Yang, Y. A Comparative Study on Drag Reduction Methods for Continental Shale Drilling in the Fuxing Block, South-eastern Sichuan Basin. *Reserv. Sci.* **2026**, *2*, 81–96.
41. Li, P.C.; Kong, X.Y.; Lu, D.T. Mathematical modeling of flow in saturated porous media on account of fluid-structure coupling effect. *J. Hydrodyn.* **2003**, *18*, 419–426.
42. Xiangyan, K.; Daolun, L.; Xianzhi, X.; Detang, L. Study on the mathematical models of coupled thermal-hydrological-mechanical (THM) processes. *J. Hydrodyn.* **2005**, *20*, 269–275.
43. Yang, Y.; Huang, F.; Kang, S. Mechanism of Penetration Rate Improvement in Hot Dry Rock Under the Coupling of Impact Load and Confining Pressure Release. *Reserv. Sci.* **2026**, *2*, 52–64.
44. Feng, A.; Li, Q.C.; Li, Q.; Wu, J.J.; Wang, F.L.; Yan, C.L. Numerical Simulation Investigation of Fracture Propagation Behavior Patterns and Sensitivity Factors of Oil Shale Reservoirs in the Xunyi Region Considering the Influence of Natural Fracture. *Geofluids* **2025**, *2025*, 2762142.
45. Shan, Z.; Wang, X.; Li, Z.; Gong, Z.; Ma, N.; Zhang, J.; Wang, Z.; Sun, B. Research on Key Parameters of Wellbore Stability for Horizontal Drilling in Offshore Hydrate Reservoirs. *Appl. Sci.* **2024**, *14*, 10922.
46. Gao, J.J.; Lau, H.C.; Sun, J. A semianalytical poroelastic solution to evaluate the stability of a borehole drilled through a porous medium saturated with two immiscible fluids. *SPE J.* **2020**, *25*, 2319–2340.
47. Xu, J.L.; Wang, R.; Xu, C.S.; Wang, Y.; Zhang, J. Application and improvement of a stress partition framework-based methane hydrate-bearing sediment constitutive model for wide range confining stress. *Comput. Geotech.* **2023**, *159*, 105463.
48. Mostafaei, H.; Gilani, M.S.; Ghaemian, M. Scientia Iranica Stability analysis of arch dam abutments due to seismic loading. *Trans. A Civ. Eng.* **2017**, *24*, 467–475.
49. Dickens, G.R.; Quinby-Hunt, M.S. Methane hydrate stability in pore water: A simple theoretical approach for geophysical applications. *J. Geophys. Res. Solid Earth* **1997**, *102*, 773–783.
50. White, M.D.; Kneafsey, T.J.; Seol, Y.; Waite, W.F.; Uchida, S.; Lin, J.S.; Myshakin, E.M.; Gai, X.; Gupta, S.; Reagan, M.T.; et al. An international code comparison study on coupled thermal, hydrologic and geomechanical processes of natural gas hydrate-bearing sediments. *Mar. Pet. Geol.* **2020**, 104566.
51. Li, Q.; You, D.; Li, Q.; Wang, F.; Wang, Y.; Yang, Y. Analysis of Sedimentation Behavior and Influencing Factors of Solid Particles in CO₂ Fracturing Fluid. *Processes* **2025**, *13*, 4049.

Disclaimer/Publisher’s Note: The statements, opinions and data contained in all publications are solely those of the individual author(s) and contributor(s) and not of MDPI and/or the editor(s). MDPI and/or the editor(s) disclaim responsibility for any injury to people or property resulting from any ideas, methods, instructions or products referred to in the content.