

Article

Wellhead Stability During Development Process of Hydrate Reservoir in the Northern South China Sea: Sensitivity Analysis

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Abstract: Natural gas hydrates are a promising alternative energy source for oil and gas in the future. However, geomechanical issues, such as wellhead instability, may arise, affecting the safe and efficient development of hydrates. In the present work, a sensitivity analysis was performed on sediment subsidence and wellhead instability during the development of marine hydrates using a multi-field coupled model. This is accomplished by adjusting the corresponding parameters based on the basic data of the default case. Meanwhile, the corresponding influencing mechanisms were explored. Finally, design recommendations for operation parameters were proposed based on the research findings regarding wellhead stability. It was found that the wellhead undergoes rapid sinking during a certain period in the early stage of hydrate development, followed by a slower, continued sinking. The sensitivity analysis found that when the depressurization amplitude is small, the wellhead sinking is also minimal. To maintain wellhead stability during the development process, it is recommended that neither the depressurization amplitude or drawdown pressure exceed 3.0 MPa. Although a high heating temperature can increase gas production to some extent, the accompanying excessive hydrate dissociation may compromise the stability of both the formation and wellhead. To balance gas production and wellhead stability, it is recommended that the heating amplitude does not exceed 50 °C. In addition, the permeability influences the distribution of pore pressure, which in turn affects sediment subsidence and wellbore stability. Wellhead stability deteriorates as permeability increases. Therefore, it is crucial to accurately determine the reservoir characteristics (such as permeability) before developing hydrates to avoid wellhead instability. Finally, the investigation results reveal that using different versions of the investigation model can impact the accuracy of the results, and neglecting certain physical fields may lead to an underestimation of the wellhead sinking.

Keywords: natural gas hydrates; hydrate dissociation; wellhead stability; geomechanical issues; deep-water area



Academic Editor: Abraham Kabutey

Received: 10 March 2025

Revised: 28 April 2025

Accepted: 16 May 2025

Published: 22 May 2025

Citation: 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. <https://doi.org/10.3390/pr13061630>

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1. Introduction

Fossil fuels, such as coal and oil, continue to serve as a critical energy source for supporting future social development [1–3]. Therefore, the efficient development and environmentally friendly utilization of fossil fuels are essential for fostering the rapid and sustainable development of society [4,5]. Nevertheless, the combustion and utilization of

these fossil fuels have resulted in severe global or regional environmental challenges (such as greenhouse effect and smog), which, in turn, undermine the sustainable development of human society [6–9]. Moreover, China’s energy situation has become increasingly tense in recent years, and its dependence on overseas crude oil and natural gas has been raising year by year [10–12]. In this context, natural gas—particularly unconventional natural gas—has emerged as a promising clean energy source in recent years, with its share in the energy mix steadily increasing [13–15]. As an unconventional natural gas resource, the efficient development of natural gas hydrates is poised to play a crucial role in alleviating this situation [16–18]. Many countries have regarded the development of hydrate resources as a strategic priority in order to ensure energy security and to promote sustainable development. To date, more than ten trial productions for hydrate extraction have been conducted worldwide. Most of these countries are energy-intensive, including China, Japan, India, and the United States.

Hydrate-bearing sediments are temperature-sensitive reservoirs that are highly unstable under conditions of elevated temperature and low pressure [19–22]. Figure 1 presents the crystal structure of methane hydrates. As can be seen in Figure 1, the methane molecule is securely encaged by the water molecules, forming a stable cage-like structure [23]. An increase in ambient temperature or a decrease in ambient pressure will destabilize the crystal structure, leading to the release of methane [24–26]. This forms the principal basis for the two widely studied development strategies: depressurization and hot fluid injection [27–29]. The development principle of the other two strategies, namely, carbon dioxide displacement and inhibitor injection, is distinct from this [30]. Nevertheless, the dissociation of gas hydrates can impact the cementation and strength of hydrate-bearing sediments, leading to significant geomechanical issues during long-term hydrate development [31–33]. Among these, wellhead instability/sinking is one of the key challenges that affect the continuous and efficient development of hydrate resources. This is due to the fact that wellhead instability can lead to uncontrollable deformation or damage to nearby subsea equipment, such as pipelines, thereby threatening subsequent production operation. Therefore, it is essential to investigate the instability behavior, mechanisms, and influencing factors of the wellhead during the long-term development of gas hydrates in marine environments.

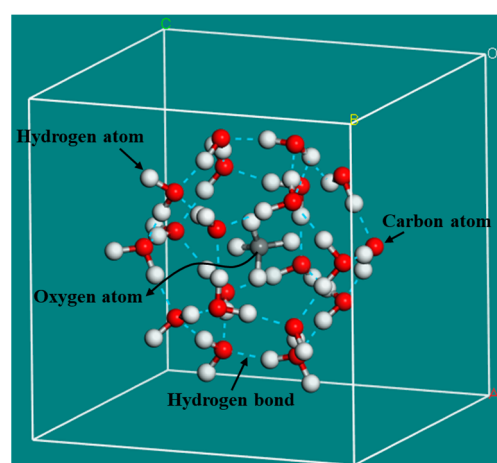


Figure 1. Crystal structure of methane hydrates.

Some researchers have conducted relevant experimental and numerical investigations in recent years, leading to notable progress. To name a few, Liu et al. (2014) developed a finite element model to study the movement of offshore oil and gas wellheads, validating its accuracy through an analysis of field case studies [34]. The research showed that the

wellhead experiences subsidence during both drilling and completion, and the theoretical predictions were in strong agreement with the observed wellhead stability measurements. Wang et al. (2015) developed a theoretical model to assess the lateral displacement and vertical bearing capacity of underwater wellheads during drilling operations, providing insights into their stability [35]. The findings underscored significant stability issues, prompting the authors to recommend targeted engineering measures designed to substantially enhance the safety and stability of subsea wellheads during drilling operations. Yan et al. (2015) developed a numerical model based on the ANSYS 16.0 software to comprehensively investigate the stability of subsea wellheads during drilling operations [36]. The study unequivocally demonstrated that an increased tension ratio significantly undermines the stability of the subsea wellhead, posing serious risks to development operation. Qiu et al. (2022) developed a fully coupled dynamic model incorporating the drilling platform, riser, wellhead, and casing, and used it to evaluate the dynamic stability of the subsea wellhead system [37]. The study revealed that achieving stable performance of the wellhead system under dynamic loading is extremely difficult. In addition, the subsea wellhead system experiences reverse-direction vibrations close to the seabed. Li et al. (2025) conducted a numerical study on the instability behavior and underlying mechanisms of the wellhead during the long-term exploitation of gas hydrates in the northern South China Sea. It was found that wellhead subsidence is not only manifested as natural sinking associated with sediment settlement, but also occurs as sliding caused by the failure of bonding between the wellhead and the sediments surrounding the wellbore [38]. Although these studies provide valuable insights into the instability behavior and mechanisms of the wellhead system during the long-term development operation of natural gas hydrates, several limitations remain. On the one hand, an in-depth examination of wellhead instability behavior during hydrate development has not yet been undertaken, nor have the underlying mechanisms of this instability been thoroughly investigated. On the other hand, no sensitivity analysis has been performed to investigate the influence of various factors on wellhead instability behavior during this process. This leaves a critical gap in understanding the interactions between these factors and their impact on stability.

Inspired by the previous investigations, an investigation method for studying the instability behavior of wellhead systems during the development of hydrate-bearing sediments was proposed, based on the ABAQUS platform. Concurrently, the instability behavior and mechanism of the wellhead are discussed. In the third section, a comprehensive analysis is conducted on the impact of various factors influencing wellhead instability, and engineering recommendations are proposed based on the derived research findings.

2. Methodology

The necessary assumptions are crucial for simplifying and expediting simulation under the premise of ensuring the accuracy of the numerical simulation results [39–45]. The assumptions made here are as follows: (1) As sediment deformation is included in the model, the deformation follows the principles of small deformation theory in solid mechanics. (2) The sediment within the investigation model is saturated with hydrate, water, and natural gas, with these three phases existing in a stable state. (3) In sediment pores, only water and gas can flow, while the hydrate phase undergoes dissociation or formation but does not seep. (4) The characteristics of the reservoir skeleton and pore fluids remain unaffected by temperature. (5) The temperature variation in the reservoir is primarily attributed to heat conduction and convection, with the effect of thermal radiation being neglected.

2.1. Study Area and Basic Data

The study area is the Shenhu area. As this study is a follow-up to our previous research, the study area and basic simulation parameters have been broadly described in the earlier publication [38]. To avoid redundancy, this part is not repeated here and interested readers may refer to our earlier work (<https://www.mdpi.com/2227-9717/13/1/40> (accessed on 18 March 2025)) for further details.

Nevertheless, it remains necessary to provide further clarification on some of the basic simulation parameters within the scope of this study. To facilitate the initialization of hydrate saturation during the simulation, its distribution is fitted using the following piecewise function:

$$S_h = \begin{cases} -0.030h - 5.85 & -210m \leq h \leq -195m \\ 0.045h + 9.90 & -220m \leq h \leq -210m \end{cases} \quad (1)$$

where h is the depth below the seabed in m.

In addition, the temperature distribution at this site can be approximated by the following linear function:

$$T = -0.0456h + 5.6723 \quad (2)$$

Stress and pore pressure are assumed to vary linearly with depth, as approximately described by Equations (3) and (4), respectively [46–48].

$$\begin{cases} \sigma_V = \rho_s g h \\ \sigma_H = \sigma_h = \sigma_V \cdot \beta \end{cases} \quad (3)$$

$$P = \rho_w g (h + D) \quad (4)$$

where σ_V , σ_H , and σ_h are three components of the in situ stress in MPa, and β is the Boit coefficient.

In addition, other basic data used for the simulation are shown in Table 1. In Table 1, ϕ_0 and K_0 represent the porosity and permeability of hydrate-free sediments, respectively.

Table 1. Basic data for simulation (default case).

Parameter	Value	Unit
Water depth at site SH2	1230	m
Sediment porosity	$\phi = \phi_0(1 - S_h)$	
Sediment cohesion	$C = 0.5 + 1.50S_h$ (MPa)	
Sediment friction angle	34.6	Degree
Sediment Elastic modulus	$E = 125 + 1000S_h$ (MPa)	
Sediment Poisson's ratio	0.35	-
Sediment permeability	$K = K_0(1 - S_h)^{7.97}$ (mD)	
Specific heat	1900	J/(kg·K)
Total simulation time	10	Years
Borehole radius	0.22	m
Reservoir dry density	2500	g/cm ³
Density of sea water	1.03	g/cm ³

2.2. Model Geometry and Simulation Details

Figure 2 shows the simulation model used in the present work. As observed in Figure 2, there are two parts within this model, namely, the formation and the wellhead system. The total thickness of the model is 420 m, and the hydrate layer with a thickness of 25 m is located at a middle depth [49–52]. In this case, the thickness of the overlying and underlying strata in the model is 195 m. In addition, the wellbore extends to a depth of 220 m, with the

production interval located within the hydrate-bearing sediments. The model used herein is the same as that used in our previous paper <https://www.mdpi.com/2227-9717/13/1/40> (accessed on 18 March 2025) [38]. Therefore, for other details about the model, please refer to that paper.

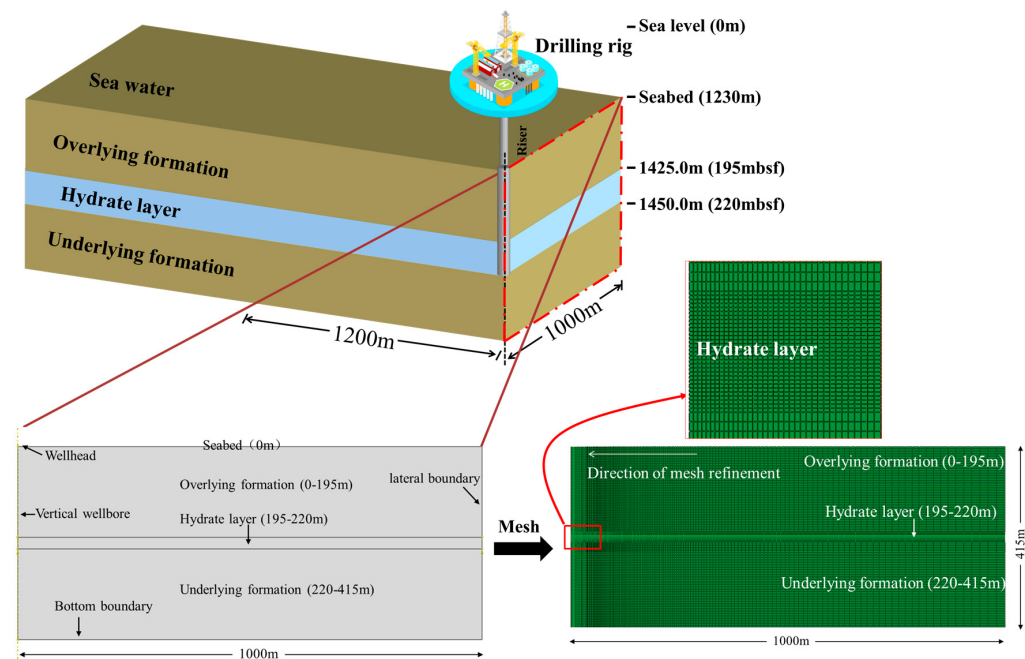


Figure 2. The geometric model used for wellhead instability simulation.

In this research, the analysis process was divided into three stages [38,53–55]. The three analytical steps and their corresponding primary tasks are illustrated in Figure 3. The first analytical step is employed to establish the initial state of the model [56]. The second step is designed to simulate the drilling process, while the third step is conducted to model the production of natural gas hydrates. In this study, the critical operation for simulating wellhead stability is utilizing the ‘Model Change’ function to deactivate and subsequently reactivate the wellhead system [57].

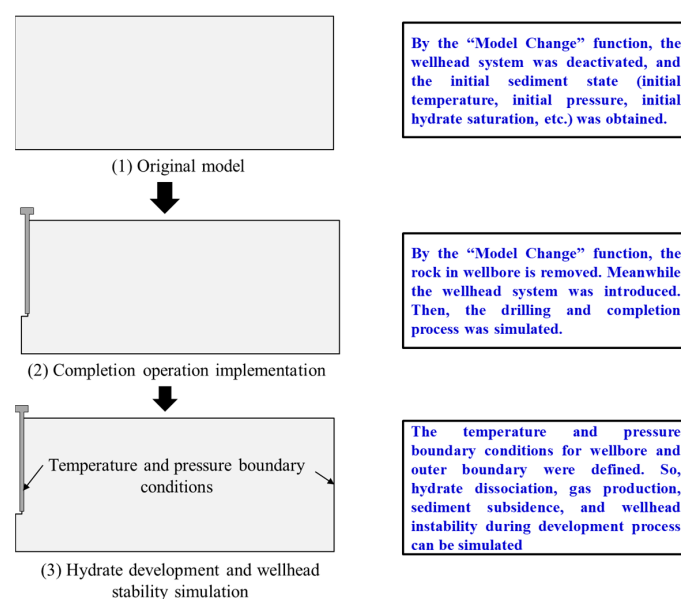


Figure 3. Implementation workflow of simulation by ABAQUS in the study.

Furthermore, Table 2 presents the development operation-related parameters utilized for the wellhead stability simulation. During the trial production in the Nankai Trough conducted by Japan, the maximum depressurization amplitude reached as high as 10 MPa [58,59]. To mitigate the risk of uncontrollable sand production, the maximum depressurization amplitude was limited to 6.0 MPa in this study. The permeability in the Shenhu area of the South China Sea is typically less than 10 mD [60,61]. Accordingly, the maximum permeability of hydrate-bearing sediments is set to 5.0 mD in this study. Notably, to investigate the influence of permeability, the sediment permeability is assumed to be constant within each individual simulation.

Table 2. Development parameters in this study.

Parameter	Value	Unit
Depressurization amplitude	1.5, 3.0, 4.5, 6.0	MPa
Heating amplitude	25, 50, 75, 100	°C
Initial permeability	0.5, 1.0, 2.5, 5.0	mD
Total production cycle	10	Years

2.3. Boundary Conditions, Initial Conditions, and Loads

The normal displacements of the outer boundaries, particularly the bottom and side boundaries, must be fully constrained throughout the entire simulation. The top boundary represents the seabed, where the load (P_{seabed}), caused by the weight of the seawater, is applied. At the same time, the pore pressure at the top boundary should consistently match the pressure at the seafloor throughout the entire study, which can be calculated by [62–64]

$$P_{seabed} = \rho_{seawater}gh \quad (5)$$

Furthermore, the pore pressure at the bottom and side boundaries must stay constant during the entire simulation, with the values specified by Equation (4) [65,66].

As the method employed in this study combines depressurization with wellbore heating, it is necessary to apply both constant-temperature and constant-pressure boundary conditions to the wellbore at the same time. The wellbore temperature should remain constant at the heating temperature, while the pressure at the wellbore should be maintained as the production pressure [38,67–69]. The details of all the boundary and initial conditions are presented in Table 3.

Table 3. All boundary conditions and initial conditions.

	Boundary Condition Type	Notes
Wellbore	Temperature	Fixed
	Pore pressure	Fixed
Top boundary	Pore pressure	Fixed
	Load	Fixed
Bottom boundary	Normal displacement	0
	Pore pressure	Fixed
Side boundary	Normal displacement	0
	Pore pressure	Fixed

In addition, the initial conditions play a vital role in ensuring the successful completion of numerical simulations [38,67].

3. Applicability and Superiority Verification of the Investigation Methodology

To demonstrate the feasibility and effectiveness of the investigation methodology used in this study, its applicability was evaluated by comparing it with the results of Cheng et al. (2023) [70]. In Ref. [70], a mathematical model was developed and solved to investigate the instability behavior of the wellhead during the drilling operation. The verification model and the verification results are presented in Figure 4. As can be seen in Figure 4a, the verification model is similar to the one used in this study, except that the horizontal size of 1000 m is reduced to 200 m. In the verification model, the overlying and underlying formations, each measuring 195 m in thickness, are symmetrically distributed above and below the 25 m thick hydrate layer, respectively. In addition, other key simulation conditions are annotated in the verification model shown in Figure 4a.

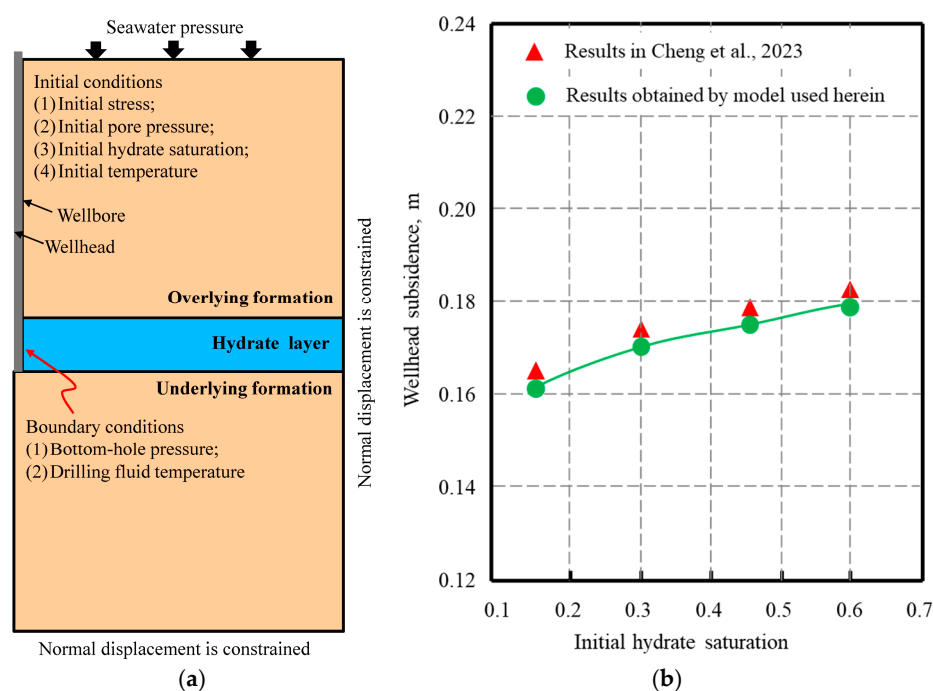


Figure 4. The verification model and verification results. (a) Verification model; (b) verification results [70].

From Figure 4b, it can be observed that for any initial hydrate saturation, the wellhead subsidence reported in Ref. [70] is slightly larger than that predicted by the investigation methodology in this study. The reason is that in the study conducted by Ref. [70], the physical properties of the sediments were considered to be functions affected only by hydrate saturation. In this study, these physical parameters are also considered to be influenced by stress or strain (see Table 1). In fact, the physical properties of hydrate-bearing sediment are inevitably influenced by multiple factors. In this respect, the model or investigation methodology employed in this study is superior. In addition, the difference between the two simulation results at different hydrate saturations in Figure 4b is minimal and can be considered negligible. Therefore, the investigation methodology can be used for investigation into wellhead instability during long-term hydrate development.

4. Results and Discussion

4.1. Evolution of Wellhead Instability During Hydrate Development

Exploring the evolution characteristics of hydrate dissociation, sediment stability, and wellhead subsidence is essential for understanding the mechanisms underlying wellhead

instability [71–75]. Figure 5 displays the evolution curves of the wellhead and seabed during the instability process. As illustrated in Figure 5, the instability observed at the wellhead is generally more pronounced than that at the seabed.

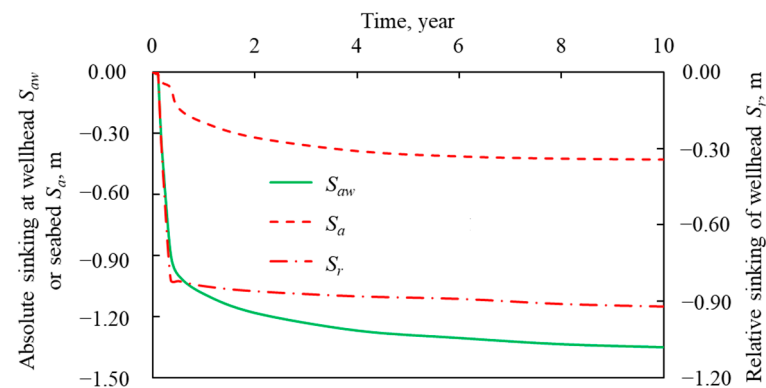


Figure 5. Subsidence evolution curves of the wellhead and seabed.

As shown in Figure 5, both the wellhead and the seabed exhibit high stability during the first 0.1 years of the simulation. This is because, in the initial stage of the simulation, the stability of the hydrates surrounding the well is less influenced by disturbances from development operations, and the cementation between the wellhead system and the sediments remains strong [76,77]. At this time, the sinking of the wellhead is predominantly affected by the subsidence of sediments, and its sinking law is analogous to that of sediment subsidence [78,79]. At the end of this stage, the instability of the wellhead system is only 1.25 cm. Within approximately 0.25 years thereafter, the subsidence of the wellhead increases by 88.27 cm. This is because, within the 0.25-year period, the support provided by the sediment to the wellhead system is compromised due to the extensive decomposition of hydrates. However, by the end of this stage, the subsidence of the seabed is limited to 7.91 cm, and the instability of the wellhead relative to the seabed reaches 81.24 cm. Subsequently, the instability of both the wellhead and the seabed becomes increasingly pronounced. By the end of the simulation, the absolute and relative settlements of the wellhead reach 1.340 m and 0.914 m, respectively.

4.2. Impact of Depressurization Amplitude

Depressurization affects the stability of gas hydrates, which in turn affects the stability of the sediments and ultimately the stability of the wellhead [80–83]. In this section, an investigation is conducted to analyze the instability of the wellhead, as well as gas production, under four specified depressurization amplitudes: 1.5 MPa, 3.0 MPa, 4.5 MPa, and 6.0 MPa. During the analysis, the heating amplitude was kept at 100 °C, and the reservoir permeability was fixed at 5.0 mD.

Figure 6a presents the evolution curves depicting gas production from hydrate decomposition. As demonstrated in Figure 6a, the impact of the depressurization amplitude on gas production is concentrated during the early stage of the development operation, approximately within the first 0.5 years. The maximum production rates under depressurization amplitudes of 6.0 MPa, 4.5 MPa, 3.0 MPa, and 1.5 MPa are 4.85×10^4 m³/day, 4.05×10^4 m³/day, 3.30×10^4 m³/day, and 1.97×10^4 m³/day, respectively. After approximately 0.5 years, the difference in gas production rates from hydrate decomposition under different depressurization amplitudes becomes minimal, and the gas production rate curves nearly overlap. The final cumulative gas production for depressurization amplitudes of 6.0 MPa, 4.5 MPa, 3.0 MPa, and 1.5 MPa is 1.85×10^7 m³, 1.82×10^7 m³, 1.78×10^7 m³, and 1.73×10^7 m³, respectively. All these cumulative productions are significantly lower than

those achieved using a 1200 m long horizontal well for development [84]. Moreover, the impact of the depressurization amplitude on the gas production behavior is significantly weaker than that of horizontal wells. The main reason is that when a vertical wellbore is used for hydrate development, the dissociation range around the wellbore is relatively limited [85–87]. Moreover, in the later stage of development, the equilibrium pressure at various locations around the wellbore becomes significantly lower than the actual pore pressure at various depressurization amplitudes [88]. The differences in hydrate dissociation at varying depressurization amplitudes affect the stability of both the sediment and the wellhead in the investigation model.

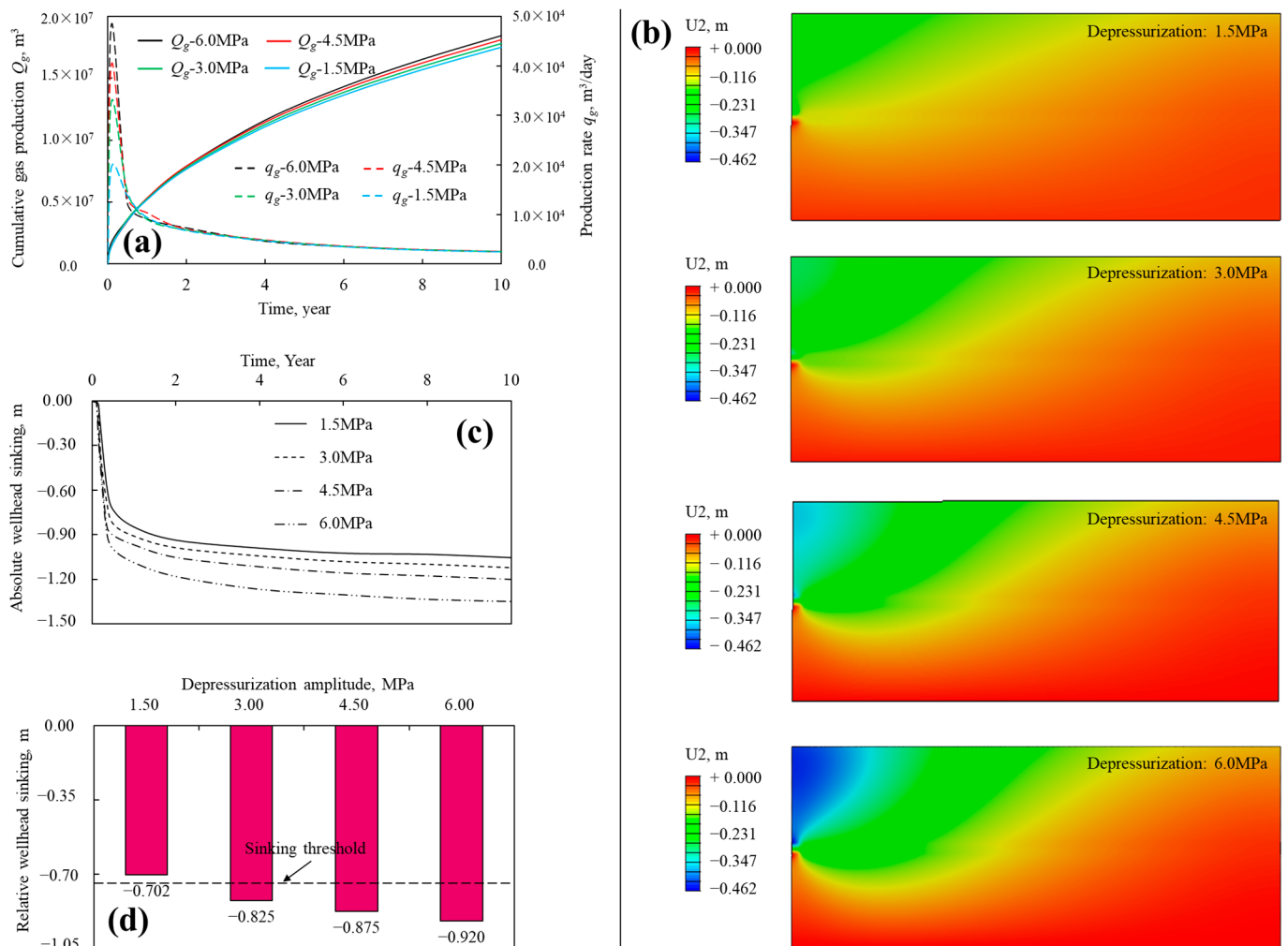


Figure 6. (a) Evolution of gas production; (b) final sediment subsidence; (c) evolution of wellhead sinking; and (d) relative wellhead sinking with vertical well for different depressurization amplitudes.

Figure 6b shows the subsidence nephogram of sediment for different depressurization amplitudes. From Figure 6b, it can be seen that although there is little difference in hydrate dissociation under different depressurization amplitudes, the blue area (significant subsidence area) shows a significant variation. This indicates that the subsidence of sediments still exhibits significant differences in the development of gas hydrates under different depressurization amplitudes. The maximum subsidence under depressurization amplitudes of 1.5 MPa, 3.0 MPa, 4.5 MPa, and 6.0 MPa is 19.29 cm, 27.18 cm, 35.07 cm, and 46.21 cm, respectively. The main reason for this is that the pore pressure is affected to varying extents by different depressurization amplitudes. For a large depressurization

amplitude, the pore pressure is significantly influenced, the skeleton stress is elevated, and substantial formation deformation occurs [89].

Figure 6c shows the evolution curve of the absolute wellhead sinking when the depressurization amplitude is different. As illustrated in Figure 6c, the evolution curve of wellhead sinking for varying depressurization amplitudes exhibits an intense trend in the initial stage, subsequently transitioning to a more gradual trend in the subsequent stages. Secondly, as the depressurization amplitude increases, the dissociation of hydrates around the well accelerates, leading to a faster attenuation of the wellbore system's support by the surrounding sediments. This causes the wellhead to start sinking rapidly earlier, and the duration of the rapid sinking phase is also shortened. For the four depressurization amplitudes of 1.5 MPa, 3.0 MPa, 4.5 MPa, and 6.0 MPa, the wellhead begins to experience rapid sinking at 0.25, 0.20, 0.13, and 0.10 years, respectively. Furthermore, the time at which the wellhead begins to sink sharply at the depressurization amplitude of 6.0 MPa is 0.15 years earlier than that when the depressurization amplitude is 1.5 MPa. Finally, when the depressurization amplitude is high, hydrate dissociation around the wellbore is intense, and the decrease in pore pressure is also severe [90]. This causes both sediment settlement and wellhead subsidence to be pronounced. The final absolute wellhead sinking at depressurization amplitude of 1.5 MPa is 1.05 m. However, when the depressurization amplitude increases to 3.0 MPa, 4.5 MPa, and 6.0 MPa, the final absolute wellhead sinking reaches 1.12 m, 1.20 m, and 1.35 m, respectively.

However, the parameter of the wellhead's sinking relative to the seabed is a better indicator of the stability of underwater equipment, such as the wellhead. Therefore, Figure 6d shows the final sinking of the wellhead relative to the seabed under different depressurization amplitudes. As illustrated in Figure 6d, the development operation of hydrates, regardless of the depressurization amplitude, results in a relative sinking of the wellhead with respect to the seabed. However, the four instances of relative sinking show minimal difference. The relative wellhead sinking with the depressurization amplitude of 1.5 MPa is 0.702 m. The relative wellhead sinking increases slightly with the depressurization amplitude. When the depressurization amplitude increases to 6.0 MPa, the wellhead experiences a relative sinking of 0.920 m relative to the seabed. This is attributed to the fact that as the depressurization amplitude increases, both the seabed subsidence and the wellhead sinking gradually increase [91]. However, the increase rate of wellhead sinking with the rising depressurization amplitude is greater than that of seabed subsidence. Unfortunately, there are currently no relevant agreements or industry standards specifying the sinking threshold for subsea wellheads [92]. This study tentatively stipulates a relative subsidence threshold of 0.75 m for the wellhead during hydrate development, as indicated by the dashed line in Figure 6d. Based on this, it can be observed from Figure 6d that to maintain wellhead stability during the hydrate development process, the depressurization amplitude needs to be lower than 3.0 MPa. It can be inferred that if this sinking threshold decreases, the available depressurization amplitude for hydrate development operations will also decrease.

4.3. Impact of Heating Amplitude

In this section, the stability of the wellhead is studied when the heating amplitude of the wellbore is 25 °C, 50 °C, 75 °C, and 100 °C, respectively. Notably, the heating amplitude here is defined relative to the formation temperature, meaning it is the value above the formation temperature. In the ABAQUS 2016 software, this is achieved by defining an amplitude function. During the simulation, the depressurization amplitude was fixed at 6.0 MPa, and the initial permeability of the hydrate reservoir was assumed to be 5.0 mD.

Figure 7a shows the evolution of gas production from hydrate dissociation under various wellbore heating amplitudes. As demonstrated in Figure 7a, an increase in the heating temperature results in elevated production rates and gas production. This finding suggests that an appropriate increase in wellbore heating temperature using vertical wells is conducive to the development of natural gas hydrate reservoirs. After a decade of development, the final cumulative gas production reaches $1.85 \times 10^7 \text{ m}^3$ at the heating amplitude of 100°C . However, the final cumulative gas production decreases to $1.69 \times 10^7 \text{ m}^3$, $1.47 \times 10^7 \text{ m}^3$, and $1.11 \times 10^7 \text{ m}^3$, respectively, when the heating amplitude is reduced to 75°C , 50°C , and 25°C . These three gas production values are 91.35%, 79.46%, and 60.00% of the gas production at the heating amplitude of 100°C . This is significantly different from the situation when using horizontal wells for development, where the heating temperature has almost no effect on hydrate dissociation and gas production [93].

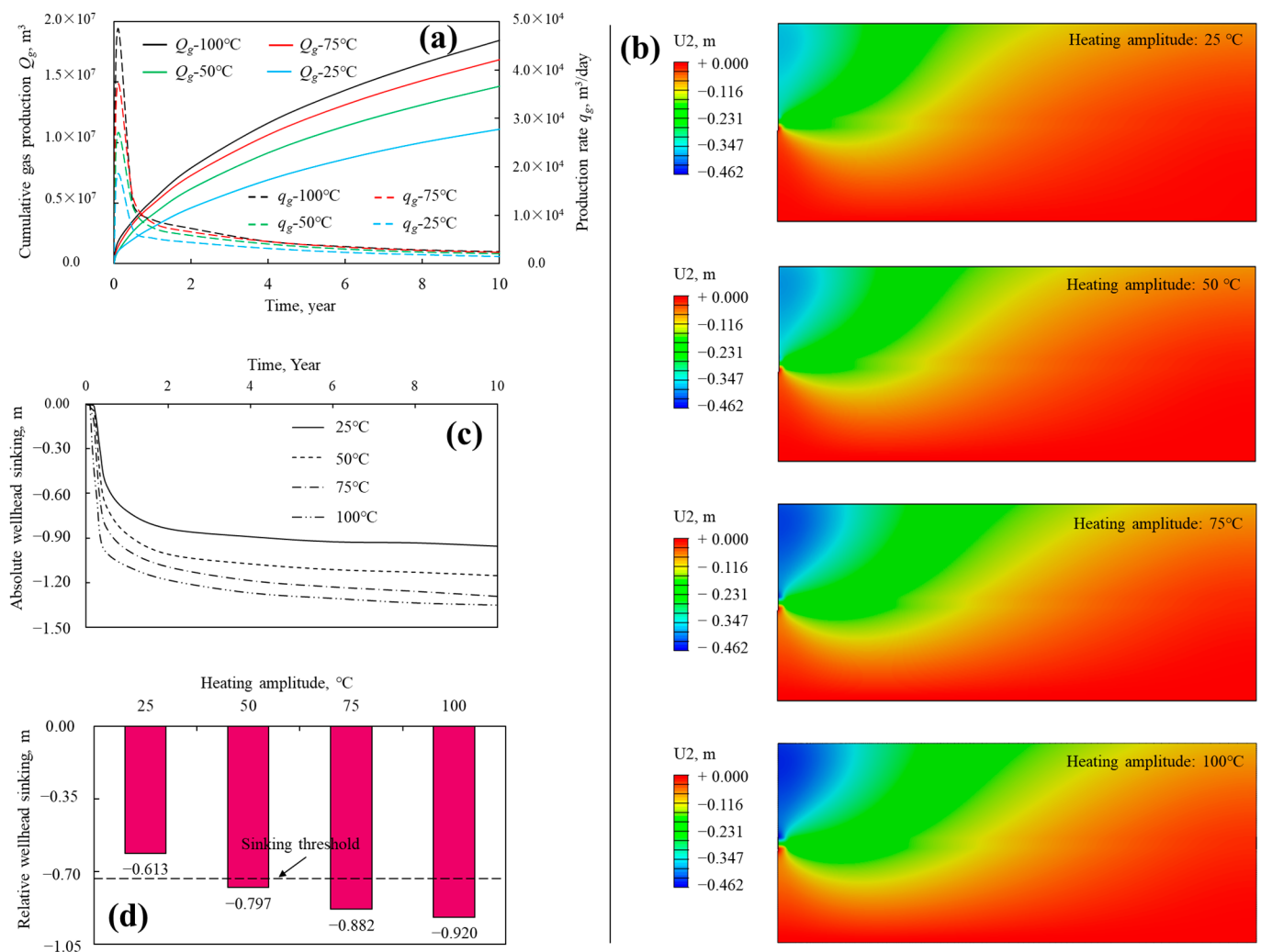


Figure 7. (a) Evolution of gas production; (b) final sediment subsidence; (c) evolution of wellhead sinking; and (d) relative wellhead sinking with vertical well for different heating amplitudes.

Figure 7b displays the final subsidence distribution of the formation in the model for different heating amplitudes. As demonstrated in Figure 7b, an increase in heating temperature results in an expansion of the dissociation range of gas hydrates, thereby gradually intensifying the subsidence of the formation in the model. When the amplitude of the wellbore heating is 25°C , the maximum seabed subsidence is only 34.17 cm. However, when the heating amplitude is increased to 50°C , 75°C , and 100°C , the maximum seabed subsidence is observed to change to 37.45 cm, 40.89 cm, and 43.20 cm, respectively.

Furthermore, it can be seen from Figure 7b that the formation subsidence is pronounced under varying heating temperatures. The primary reasons can be analyzed from the following two perspectives. On the one hand, a large drawdown pressure will itself cause a significant change in pore pressure, leading to severe formation subsidence [94–96]. On the other hand, a high wellbore heating temperature will cause hydrate dissociation over a larger area around the wellbore and exacerbate formation subsidence.

In order to apply the research to engineering design and optimization, Figure 7c illustrates the evolution curve of the wellhead's absolute subsidence under different wellbore heating amplitudes. From Figure 7c, it can be seen that the heating amplitude exerts differential effects on the stability of the wellhead. As shown in Figure 7c, the absolute sinking of the wellhead increases with heating temperature, and this trend is more pronounced at lower heating amplitudes. Moreover, the time for the wellhead to sink rapidly decreases significantly as the heating amplitude increases. This is attributable to the fact that an increase in heating temperature results in accelerated hydrate dissociation in the near-wellbore region, thereby resulting in earlier support for the wellhead system being lost.

Based on the investigation results, Figure 7b–d presents a statistical bar chart showing the final sinking of the wellhead relative to the seabed under different heating amplitudes. From Figure 7d, it can be seen that the sinking of wellhead relative to the seabed during hydrate development increases as the heating temperature rises. The difference in value between the maximum and minimum wellhead sinking is nearly 30 cm. In general, when using vertical wells to develop natural gas hydrates, high heating temperatures can increase the gas production of a single well to some extent. However, the rapid and intense dissociation of gas hydrates around the wellbore under high heating amplitudes can also threaten the stability of the formation and subsea equipment. Based on the threshold for wellhead sinking during hydrate development in this study, it is not recommended that the wellbore heating amplitude exceed 50 °C.

4.4. Impact of Reservoir Permeability

The difference in permeability of hydrate-bearing sediments can also affect the dissociation of gas hydrates and the deformation of hydrate-bearing sediments around wellbore, thereby influencing the wellhead stability [97,98]. In this section, the stability of wellhead when the reservoir permeability is 0.5 mD, 1.0 mD, 2.5 mD, and 5.0 mD is numerically investigated. It should be noted that during the investigation, the depressurization amplitude was 6.0 MPa, the heating amplitude was 100 °C, and the total development time was 10 years.

Figure 8a shows the evolution of gas production from hydrate dissociation and the production rate when the permeability of hydrate-bearing sediments is different. As shown in Figure 8a, there is little difference in both the gas production and production rate for varying reservoir permeability. The final cumulative gas production corresponding to the four reservoir permeabilities of 0.5 mD, 1.0 mD, 2.5 mD, and 5.0 mD is $1.834 \times 10^7 \text{ m}^3$, $1.839 \times 10^7 \text{ m}^3$, $1.843 \times 10^7 \text{ m}^3$, and $1.850 \times 10^7 \text{ m}^3$, respectively. From Figure 8a, it can also be observed that there is a slight difference in the gas production rate during the initial stage of the development operation, after which the production rate curves begin to overlap [99]. This is mainly due to the fact that when using vertical wells to develop natural gas hydrates, hydrate dissociation mainly occurs in the near-wellbore region. In this case, the pore pressure in the near-wellbore region will stabilize within a very short period, regardless of the reservoir permeability [100]. This results in highly similar hydrate dissociation under different reservoir permeabilities.

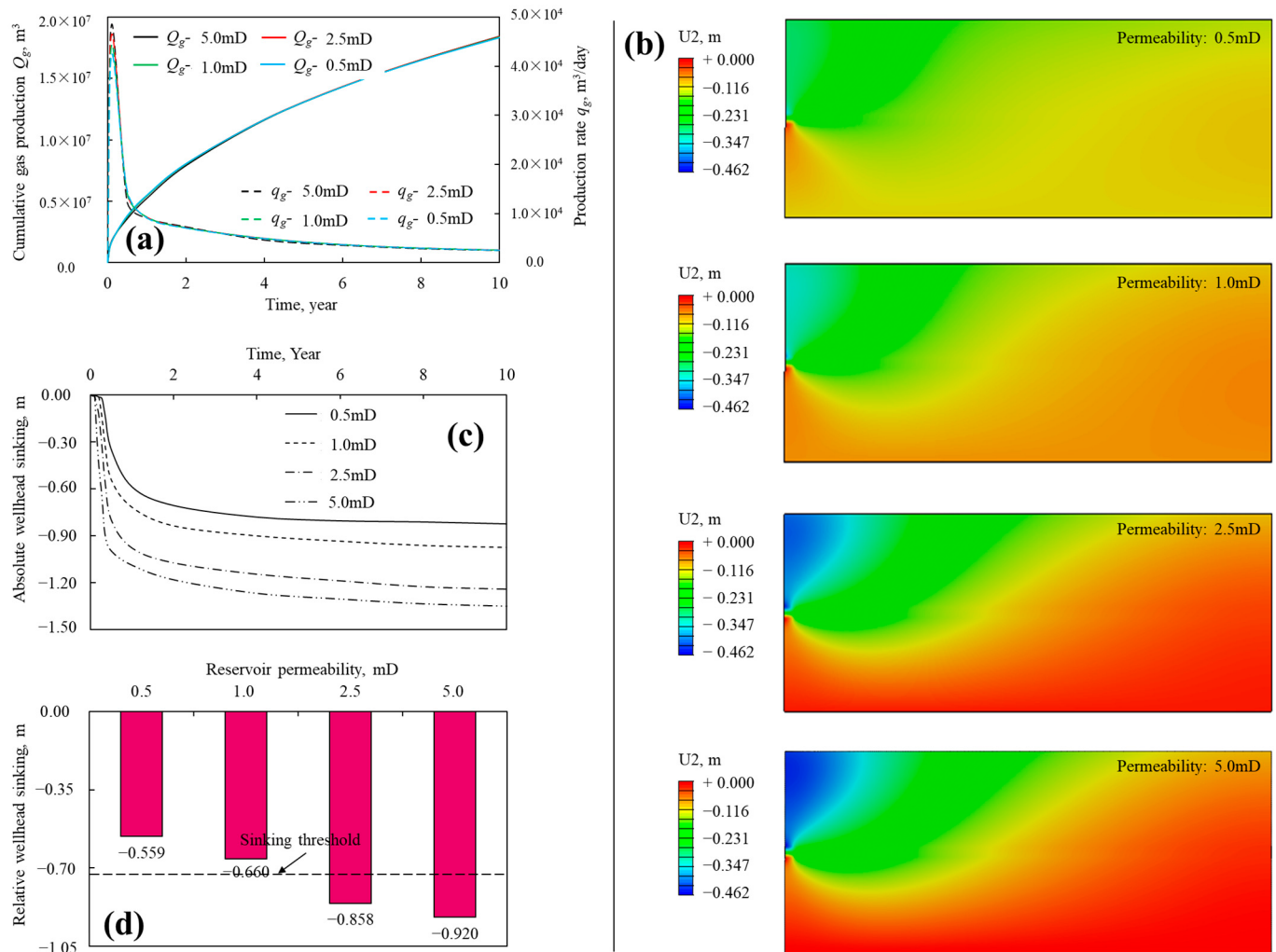


Figure 8. (a) Evolution of gas production; (b) final sediment subsidence; (c) evolution of wellhead sinking; and (d) relative wellhead sinking with a vertical well when reservoir permeability is different.

The deformation of sediments is unavoidable due to the changes in pore pressure and the dissociation of gas hydrates [101]. Therefore, Figure 8b presents the distribution nephogram of sediment subsidence or deformation for different reservoir permeabilities. As shown in Figure 8b, there is a clear correlation between the increase in reservoir permeability and the subsequent gradual rise in sediment subsidence. Furthermore, this correlation is more significant within the range of lower reservoir permeability. When the reservoir permeability is 0.5 mD, 1.0 mD, 2.5 mD, and 5.0 mD, the maximum seabed subsidence is 22.55 cm, 29.41 cm, 40.28 cm, and 43.00 cm, respectively. The seabed subsidence varies significantly with changes in reservoir permeability. This is because, although the hydrate dissociation is generally similar across different permeabilities, the formations are affected differently by the depressurization due to the variations in permeability [102,103]. When the permeability is within the higher range, the difference in the final pore pressure distribution across varying permeabilities is small, leading to more significant sediment subsidence. However, when the permeability is in the lower range, the difference in pore pressure distribution is significant, resulting in a large difference in sediment deformation.

Figure 8c illustrates the evolution curve of the absolute wellhead sinking for different reservoir permeabilities. From Figure 8c, it can be observed that reservoir permeability has a significant impact on wellhead stability. The higher the reservoir permeability, the more pronounced the subsidence of the wellhead. When using vertical wells for development, the impact of permeability on wellhead stability is more closely related to its effect on

pore pressure and skeleton stress, rather than its influence on hydrate dissociation. When the permeability is high, the pore pressure is more quickly affected by depressurization, causing the wellhead to begin sinking rapidly at an earlier stage. When the permeability is 0.5 mD, the wellhead begins to sink sharply at 0.35 years. However, when the permeability increases to 5.0 mD, this time is advanced to 0.10 years.

In addition, Figure 8d shows a bar chart of the final sinking of the wellhead relative to the seabed for different reservoir permeabilities. It can be observed from Figure 8d that the reservoir permeability has a significant impact on the instability and sinking of the wellhead relative to the seabed. In addition, the instability and sinking of the wellhead relative to the seabed becomes pronounced with the increasing permeability. When the permeability is only 0.5 mD, the final relative wellhead sinking is 0.559 m. However, when the permeability increases to 1.0 mD, 2.5 mD, and 5.0 mD, the final relative wellhead sinking increases to 0.660 m, 0.858 m, and 0.920 m, respectively. Moreover, it can be observed from Figure 8d that when the permeability exceeds 2.5 mD, the sinking of the wellhead exceeds the threshold. Therefore, when the reservoir permeability is high, using a low depressurization amplitude or a low heating temperature can help maintain effective hydrate development while also ensuring the stability of the wellhead.

4.5. Impact of Model Type

An appropriate model and investigation methodology are crucial for ensuring an effective analysis of wellhead stability [101]. In this section, the wellhead stability during hydrate development was studied using the hydraulic–mechanics–thermal–chemical (HMTC) coupling model, the hydraulic–mechanics–chemical (HMC) coupling model, and the mechanics (M) model. In addition, the pressure reduction amplitude in the study was 6.0 MPa, the heating amplitude was 100 °C, and the initial permeability was 5.0 mD.

Figure 9a shows the evolution curve of gas production from hydrate dissociation during hydrate development using the different investigation models. It can be seen from Figure 9a that when only the mechanics field is considered, gas production from hydrate dissociation reaches $1.850 \times 10^7 \text{ m}^3$, which is clearly inconsistent with the actual situation. Meanwhile, the final cumulative gas production when using the HMC model is only $0.499 \times 10^7 \text{ m}^3$. When the temperature field is also taken into account, i.e., when using the HMTC coupling model, the cumulative gas production is significantly higher than this value. By comparison, the HMTC coupling model, which considers more physical fields, can predict gas production more accurately.

Figure 9b shows the subsidence distribution nephogram of sediments in the hydrate development process using the different research models. From Figure 9b, it can be observed that when the model only considers force and deformation, the sediment experiences a subsidence and uplift of 26.61 cm near the upper and lower boundaries of the reservoir decomposition area. In this case, there is no significant deformation or subsidence at the seabed. In addition, by comparing the results of the other two models, it can be found that although the maximum seabed subsidence under the two models is slightly different, the compaction of the reservoir is significantly different. The phenomenon of reservoir compaction can be more readily observed when the HMTC coupling model is utilized in research endeavors. This is primarily due to the reduced gas production associated with hydrate dissociation when using the HMC coupling model for simulation, compared to the HMTC model.

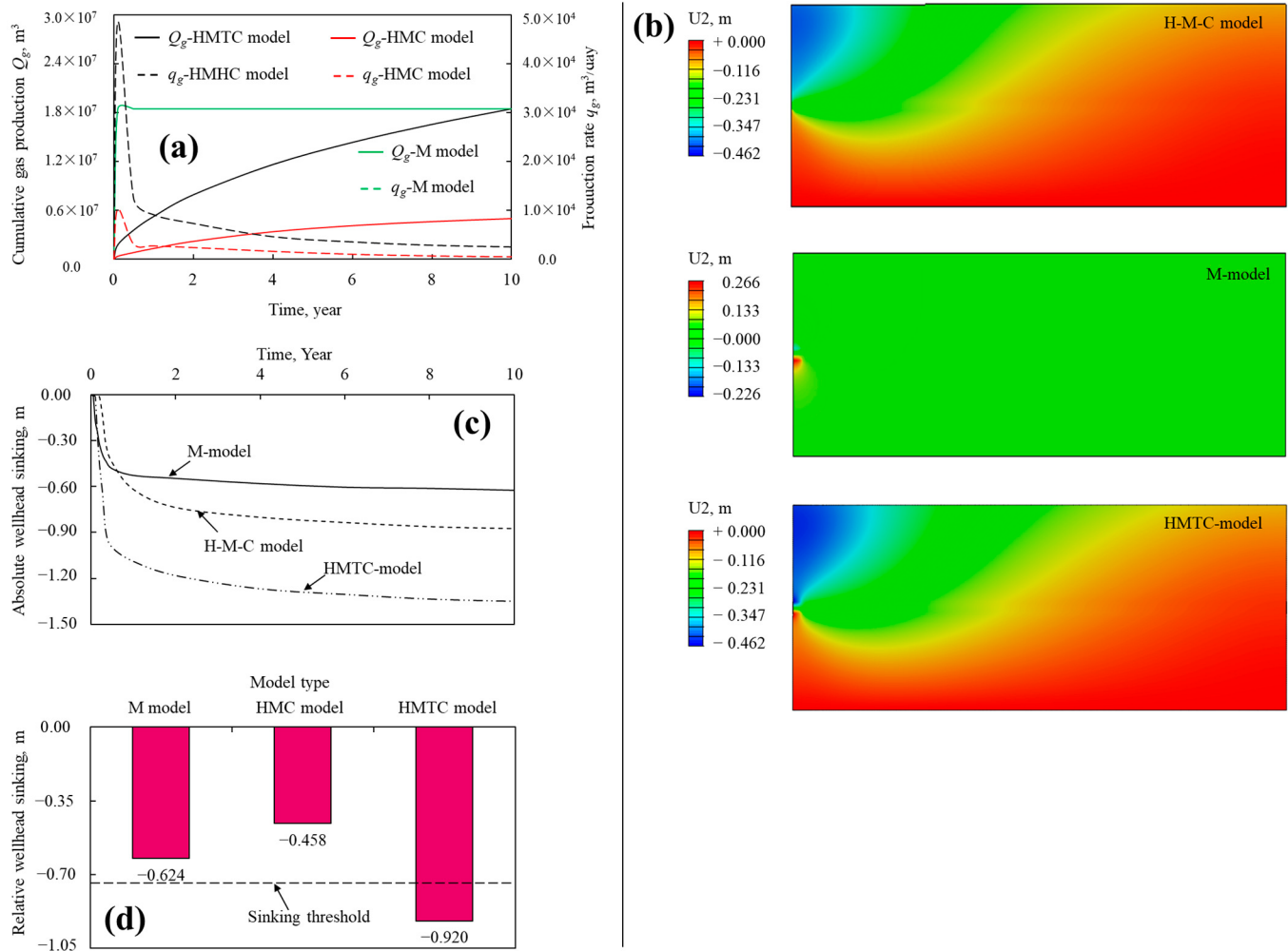


Figure 9. (a) Evolution of gas production; (b) final sediment subsidence; (c) evolution of wellhead sinking; and (d) relative wellhead sinking with a vertical well when simulation model is different.

Figure 9c shows the evolution curve of absolute wellhead subsidence for the different investigation models. From Figure 9c, it can be observed that the wellhead begins to sink most rapidly when the M model is used, followed by the HMTc coupling model, with the HMC model exhibiting the slowest rate. Additionally, the final absolute sinking of the wellhead differs depending on the model type used in the investigation. When the M model is used, the final absolute wellhead sinking is the smallest, measuring 0.624 m, while the HMC model corresponds to a moderate absolute sinking of 0.874 m. When the HMTc model is employed to study the stability of wellhead, the final absolute wellhead sinking is found to be the largest, at 1.350 m. Figure 9d presents a bar chart depicting the final wellhead sinking relative to the seabed for the different investigation models. As shown in Figure 9d, although the absolute wellhead sinking is smallest with the M model, the relative sinking remains significant at 0.624 m. This is because subsidence of the seabed does not occur in this case (see Figure 9b). Meanwhile, although the absolute wellhead sinking is large when using the HMC model, the relative sinking is smaller, at 0.458 m. This is because the seabed also experiences significant subsidence in this case. When the HMTc coupling model is used, both the absolute and relative sinking of the wellhead are the largest among these three cases. It is evident that neglecting any physical field leads to deviations in the simulation results.

5. Conclusions and Future Work

The main conclusions are as follows:

(1) When the depressurization amplitude is small, the wellhead sinks slowly, and the final wellhead sinking is low. Nevertheless, the depressurization amplitude has little effect on the stability of the wellhead system. This is because any depressurization amplitude causes the pressure in the sediment around the wellbore to drop below the equilibrium value, prompting it to rapidly reach a new equilibrium state. In this way, the dissociation range around the wellbore is not significantly affected by the depressurization amplitude. Taking into account both wellhead stability and gas production, if the wellhead is to remain stable during the development process, the depressurization amplitude should not exceed 3.0 MPa.

(2) The instability of the wellhead is significantly exacerbated by an increase in the heating amplitude of the wellbore. The reason is that an increase in wellbore heating temperature can cause the dissociation of hydrates over a larger area around the wellbore. This leads to a significant reduction in sediment strength within a wider dissociation area. Based on the investigation results, it can be concluded that the heating temperature should not be too high when using the strategy of wellbore heating combined with depressurization. Under the research conditions, the wellbore heating amplitude should not exceed 50 °C.

(3) Although the gas production under different sediment permeability is not significantly different, the wellhead stability varies greatly. The stability of the sediment and wellhead is enhanced with decreasing reservoir permeability. This is because the stability of the sediment and the wellhead system is governed by the synergistic effects of pore pressure distribution and hydrate dissociation around the wellbore. Therefore, it is essential to fully understand the reservoir characteristics before the development operation to provide the prerequisite conditions for the design of the development operation. During the development of reservoirs with permeability greater than 2.5 mD, wellhead stability can be maintained by using a small depressurization amplitude or low heating temperature.

(4) When the pure mechanical model (i.e., the M model) is employed to analyze wellhead stability, although the wellhead sinks earliest, the sinking value is smallest. Therefore, when conducting numerical analysis of engineering geological hazards related to hydrate development, it is essential to comprehensively consider the interactions between various physical fields. To ensure the accuracy of the research, it is recommended to employ the HMTC model, which accounts for a broader range of factors in the multi-field coupling analysis.

In this study, the failure behavior of the first and second interfaces under the disturbance of development operations was not analyzed. It should be noted that such failure is a key factor contributing to the relative sinking of the wellhead system and compromising the integrity of the wellbore. Therefore, future research will focus on the effects of hydrate dissociation on the failure of the first and second interfaces, to better reveal the mechanisms of wellbore integrity and wellhead stability.

Author Contributions: Conceptualization, J.W. and Q.L. (Qingchao Li); methodology, Q.L. (Qiang Li); formal analysis, Q.L. (Qingchao Li); investigation, K.H. and Y.X.; resources, Q.L. (Qingchao Li); writing—original draft preparation, J.L. and Q.L. (Qingchao Li); writing—review and editing, J.W. and Y.X.; visualization, F.W.; supervision, Y.C. and F.W.; project administration, Q.L. (Qingchao Li) and J.W.; funding acquisition, Y.C. All authors have read and agreed to the published version of the manuscript.

Funding: This research was funded by the Fundamental Research Funds for the Universities of Henan Province (NSFRF240616), Henan Provincial Science and Technology Research Project (232102321128, 242102320342) and the Postdoctoral Program of Henan Polytechnic University (Grant No. 712108/210).

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Data Availability Statement: No new data were created or analyzed in this study. Data sharing is not applicable to this article.

Acknowledgments: The conception and launch of this work are also supported by the Rock Mechanics Laboratory (RML) of China University of Petroleum (East China).

Conflicts of Interest: The authors declare no conflicts of interest.

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