



Multi-gas co-production from deep-water shallow hydrates and underlying free gas: A numerical study of coupled production dynamics and secondary hydrate formation

Cong Li^{a, b, *}, Na Wei^{a, b, *}, Hai-tao Li^{a, b}, Shou-wei Zhou^{a, b}, Lie-hui Zhang^{a, b}, Jin-zhou Zhao^{a, b},
Bjørn Kvamme^{a, b}, Zhong-xia Wang^{a, b}, Di Nie^{a, b}, Qing He^{a, b}, Jun Wang^{a, b}, Zhi-hao Xia^{a, b}, Yu Qin^{a, b}

^a State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu 610500, China

^b State Key Laboratory of Natural Gas Hydrate, Beijing 100027, China

ARTICLE INFO

Article history:

Received 8 July 2025

Received in revised form 7 January 2026

Accepted 10 March 2026

Available online 10 April 2026

Keywords:

Natural gas hydrate

Combustible ice

Unconventional energy

Clean Energy

Underlying free gas

Deep-water shallow hydrate

Multi-gas joint-development

Deep oil and gas

Numerical simulation

ABSTRACT

The co-occurrence of marine gas hydrates, shallow gas, and deep oil and gas has been widely recognized, offering favorable conditions for integrated resource development. This study aims to explore the coupled production dynamics of shallow gas hydrates and underlying free gas to support the industrialization of marine natural gas hydrate resources. A productivity prediction model for the combined extraction of hydrate and underlying gas is developed, integrating multi-physics coupling mechanisms. Using logging data from two test wells in the Qiongdongnan Basin, a short-term physical model is constructed to simulate and predict production performance. Results show that: (1) The average wellhead gas production rate increases significantly with a linear relationship to the production pressure differential; (2) pressure propagation differs notably between hydrate and free gas layers, with a distinct low-temperature zone forming near the wellbore in the hydrate-bearing layer; (3) free gas migration results in a high-saturation gas zone near the hydrate-gas interface, and elevated pressure differentials can trigger secondary hydrate formation; and (4) during short-term testing, hydrate decomposition is limited, with most gas production sourced from the underlying gas layer. By adjusting production pressure or controlling wellbore temperature, hydrate decomposition and reformation can be balanced to optimize recovery efficiency. This study highlights a novel multi-gas co-production approach and provides a theoretical basis for sustainable deepwater hydrate development.

©2026 China Geology Editorial Office.

1. Introduction

Natural gas hydrate is a high-density, high-calorific-value unconventional natural gas resource primarily distributed in sediments of deepwater continental slopes at depths greater than 300 m and in terrestrial permafrost zones (Sloan ED and Koh CA, 2008; Sun WT et al., 2021). The in-place resource quantity of natural gas hydrates, converted to gas equivalent, is estimated to be $2.14 \times 10^{14} \text{ m}^3$, making it a highly promising successor energy resource after shale gas, coalbed methane, and tight gas (Su PB et al., 2024; Pang XQ et al., 2025). The

commercial development of natural gas hydrates in the future is expected to reduce China's dependence on foreign natural gas by 20%, playing a significant role in driving energy production and consumption revolutions and achieving the carbon peak and carbon neutrality goals (Wei N et al., 2021).

The exploitation of natural gas hydrates is complex, involving a variety of physical and chemical reactions such as hydrate formation, dissociation and migration. Key techniques currently deployed for hydrate recovery comprise depressurization (Wang DY et al., 2013; Zhao JF et al., 2015), inhibitor injection (Li G et al., 2007; Villano L et al., 2009), thermal stimulation (Cranganu C, 2009; Nair V et al., 2016), N_2/CO_2 replacement (Ohgaki K et al., 1996; Goel N, 2006). Among these options, depressurization and thermal stimulation offer relatively simpler technical implementation. Crucially, depressurization surpasses heating in both cost-effectiveness (economical advantage) and gas yield efficacy, establishing it as the predominant technique in recent field trials and the favored strategy for future hydrate development.

First author: E-mail address: 202114000002@stu.swpu.edu.cn (Cong Li).

* Corresponding author: E-mail address: 202114000002@stu.swpu.edu.cn (Cong Li);
weina8081@163.com (Na Wei).

Literary editor: Xi-jie Chen
doi:10.31035/cg2025157

2096-5192/© 2026 China Geology Editorial Office.

Successful production tests conducted across diverse locales, including Canada (Kurihara M et al., 2010), the United States (Schoderbek D et al., 2013), Japan (Konno Y et al., 2017; Yamamoto K et al., 2019) and China (Li JF et al., 2018; Ye J et al., 2020), have collectively validated natural gas hydrates as a viable clean energy resource (Li XS et al., 2016). Illustratively, Japan's inaugural offshore hydrate extraction in the eastern Nankai Trough employed depressurization, yielding a production rate of 20000 m³ per day (Konno Y et al., 2017; Yamamoto K et al., 2019). Similarly, China executed two production trials in the South China Sea's Shenhua area in 2017 and 2020. The initial trial utilized vertical wells for depressurization, achieving a modest average daily output of merely 5151 m³ (Li JF et al., 2018). In contrast, the subsequent trial leveraged horizontal well depressurization, markedly elevating the average daily production to 28700 m³ (Ye JL et al., 2020). Although the second trial production area is different from the first one (the extraction layer is particularly close to the shallow gas), due to immature exploitation technologies and sand production issues, there is still a long way to go before commercialization (Wu N et al., 2021; Chen XJ et al., 2022; Qin XW et al., 2022).

Extensive global research has demonstrated that marine hydrates, shallow gas, and deep oil and gas share interconnected accumulation mechanisms and often exhibit regional coexistence and spatial association, providing the foundational resource conditions for joint development (Sun QL et al., 2012; Wang HB et al., 2013; Wan ZF et al., 2017; Zhu WL et al., 2021; Cox D et al., 2021). As shown in Fig. 1, coexisting deposits of natural gas hydrates and shallow gas with development potential have been discovered in the Qiongdongnan Basin of China (Hui GG et al., 2016; Wei JG et al., 2019; He YL et al., 2022). Therefore, comprehensive exploration and integrated development of these resources via

the “three-gas co-production” (TGCP) pathway represent a strategic direction for the industrialization of marine natural gas hydrates and a core area of technological innovation (Wei N et al., 2021; Ye HY et al., 2025). In fact, the “Mechanisms and Key Engineering Technologies for Integrated Exploration and Development of Marine Natural Gas Hydrates and Oil and Gas” was listed as one of the 20 major scientific and engineering challenges announced by the China Association for Science and Technology in 2019.

The integrated production of marine natural gas hydrates and other gases (“multi-gas co-production”) is an extremely complex system engineering project involving cross-disciplinary scientific and engineering challenges. There is currently no mature theory, method, technology, or engineering precedent. Among these challenges are understanding the coexistence mechanisms and evaluation methods of hydrate-shallow gas accumulations, the coupling mechanism of inter-layer interference in multi-gas co-production, and the key engineering technologies and equipment for well construction in complex marine soft formations.

In the process of multi-gas co-production of deepwater shallow natural gas hydrates and underlying gas, pressure changes can induce phase transformation and dissociation of the overlying hydrate layer, resulting in changes in pore pressure, temperature, stress and chemical field distributions within the reservoir (Bian H et al., 2022; Lu C et al., 2023; Wei N et al., 2024; Yang L et al., 2024). These changes, in turn, affect the conditions and rate of hydrate phase transformations. Additionally, variations in hydrate saturation impact the reservoir's mechanical properties, thermal conductivity, and the flow capacity of gas and water phases within the reservoir pores (Li YL et al., 2021, 2022; Li P et al., 2024, 2025). Therefore, numerical simulations of multi-gas co-production of deepwater shallow natural gas hydrates

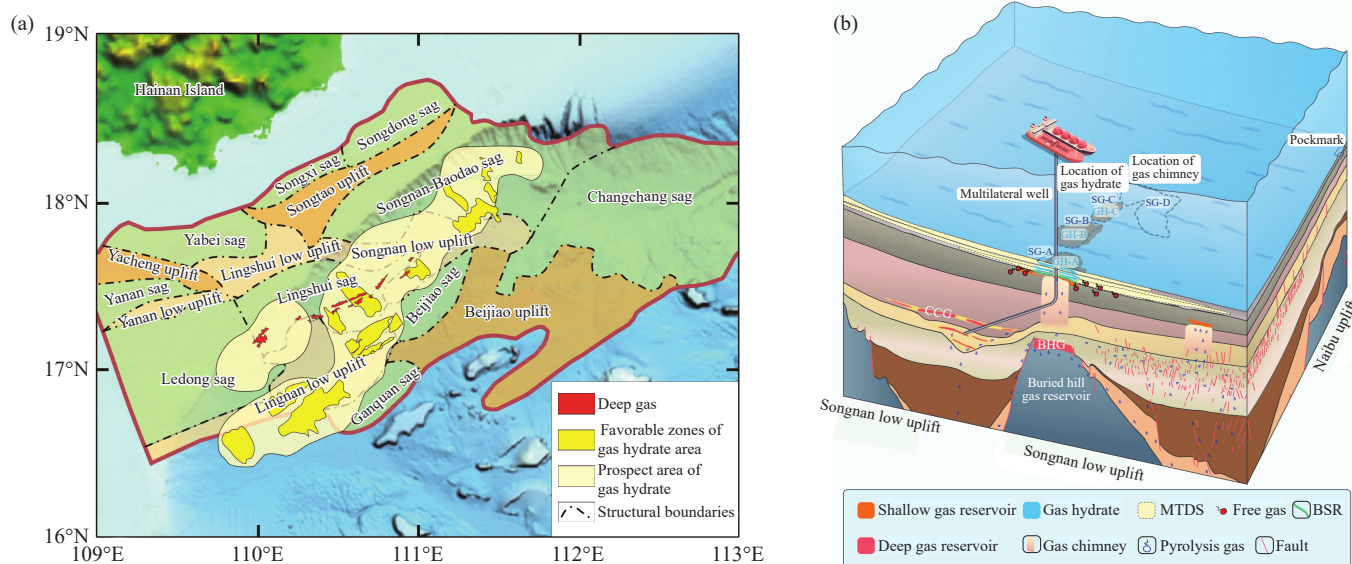


Fig. 1. Multi-gas system in the Qiongdongnan Basin, China. a–Tectonic units and geographical distribution; b–schematic of hydrate and underlying gas co-occurrence (after Wu SG et al., 2024). CCG–Central canyon reservoir; BHG–buried hill gas reservoir.

and underlying gas must comprehensively consider the interactions between temperature, fluid flow, and hydrate phase transformations.

To comprehensively understand the multi-physical field coupling characteristics involved in the multi-gas co-production of deepwater shallow natural gas hydrates and underlying gas, this study established a productivity prediction model. Using actual logging data from two test wells in the Qiongdongnan Basin, a short-term production physical model was developed to predict short-term productivity and analyze the spatiotemporal evolution of reservoir temperature and pressure, hydrate and gas phase saturation under multi-gas co-production conditions. The study also investigated the impact of different gas saturations in the underlying hydrate-bearing layer on production test results in a specific well. This research holds significant implications for the scaled production of deepwater shallow natural gas hydrates and underlying gas through multi-gas co-production.

2. Theoretical model

In the theoretical model for multi-gas co-production of deepwater shallow natural gas hydrates and underlying gas, the following assumptions are made: (1) The hydrate in the reservoir is a single methane hydrate with 100% methane content; (2) fluid flow complies with Darcy's law; (3) mechanical dispersion of dissolved gas and chemical agents during transport in the water phase is neglected, and molecular diffusion and hydrodynamic dispersion are not considered; (4) during the freezing of water, dissolved salts remain in solution without precipitating despite increasing concentrations; (5) the thermophysical behavior of the aqueous phase is unaffected by the dissolved inhibitors' concentration; (6) reservoir minerals exhibit no reactivity with the employed inhibitors; (7) reservoir pressure remains below 100 MPa.

2.1. Mass and energy balance equations

For multi-gas co-production of deepwater shallow natural gas hydrates and underlying gas, the integral finite difference method is used to discretize the simulation domain. The mass and energy conservation equations governing the hydrate and underlying gas layers are shown in Eq. 1.

$$\frac{d}{dt} \int_{V_n} M^{\kappa} dV = \int_{\Gamma_n} F^{\kappa} \cdot n d\Gamma + \int_{V_n} q^{\kappa} dV \quad (1)$$

where V_n is volume of the grid block (m^3); M^{κ} is mass accumulation term for component κ (kg/m^3 or J/m^3); κ is methane component (m), water component (w), hydrate (h), chemical agent component (i), or energy (θ); F^{κ} is darcy vector for component κ [$kg/(m^2 \cdot s)$ or $J/(m^2 \cdot s)$]; Γ_n is surface area of grid block n (m^2); n is unit normal vector of surface element $d\Gamma$; q^{κ} is source or sink term for component κ [$kg/(m^3 \cdot s)$ or $J/(m^3 \cdot s)$]; t is time (s).

2.1.1. Mass accumulation terms

Under kinetic conditions, the calculation formula for the mass accumulation term M^{κ} of component κ is described by Eq. 2.

$$M^{\kappa} = \sum_{\beta=A,G,I,H} \phi S_{\beta} \rho_{\beta} X_{\beta}^{\kappa}, \kappa \equiv w, m, h, i \quad (2)$$

where ϕ is porosity; ρ_{β} is density of phase β ($kg \cdot m^{-3}$); S_{β} is saturation of phase β ; X_{β}^{κ} is mass fraction of component (kg/kg), $\kappa \equiv w, m, h, i$ in phase β .

The equations describing the hydrate mass components and phase behavior are shown in Eq. 3.

$$Q_H = \frac{\partial M}{\partial t} = -K_0 \exp\left(\frac{\Delta E_a}{RT}\right) F_A A (f_{eq} - f_v) \quad (3)$$

where K_0 is intrinsic hydrate reaction constant [$kg/(m^2 \cdot Pa \cdot s)$]; ΔE_a is hydration activation energy (J/mol); R is universal gas constant [$8.314 J/(mol \cdot K)$]; T is temperature (K); F_A is area adjustment factor; A is Surface area involved in the reaction (m^2); f_{eq} is equilibrium fugacity at temperature T (Pa); f_v is vapor-phase fugacity at temperature T (Pa).

(i) Mass accumulation term for methane component ($\kappa \equiv m$) is shown by Eqs. 4–6.

$$M^m = \phi S_A \rho_A X_A^m + \phi S_G \rho_G X_G^m + \phi S_H \rho_H X_H^m \quad (4)$$

$$F^m = X_A^m F_A + X_G^m F_G \quad (5)$$

$$q^m = X_{q,A}^m q_A + X_{q,G}^m q_G \quad (6)$$

where M^m is mass accumulation of methane component (kg/m^3); ϕ is reservoir porosity; S_A is water-phase saturation; S_G is gas-phase saturation; S_H is hydrate-phase saturation; ρ_A is water-phase density (kg/m^3); ρ_G is gas-phase density (kg/m^3); ρ_H is hydrate-phase density (kg/m^3); X_A^m is mass fraction of methane in the water phase; X_G^m is mass fraction of methane in the gas phase; X_H^m is mass fraction of methane in the hydrate phase; F^m is mass flux of methane component [$kg/(m^2 \cdot s)$]; F_A is mass flux of water phase [$kg/(m^2 \cdot s)$]; F_G is mass flux of gas phase [$kg/(m^2 \cdot s)$]; q^m is source or sink of methane component [$kg/(m^3 \cdot s)$]; q_A is source or sink of water phase [$kg/(m^3 \cdot s)$]; q_G is source or sink of gas phase [$kg/(m^3 \cdot s)$]; $X_{q,A}^m$ is mass fraction of methane in the source or sink of the water phase; $X_{q,G}^m$ is mass fraction of methane in the source or sink of the gas phase.

(ii) Mass accumulation term for water component ($\kappa \equiv w$) is shown by Eqs. 7–9.

$$M^w = \phi S_A \rho_A X_A^w + \phi S_G \rho_G X_G^w + \phi S_H \rho_H X_H^w + \phi S_I \rho_I X_I^w \quad (7)$$

$$F^w = X_A^w F_A + X_G^w F_G \quad (8)$$

$$q^w = X_{q,A}^w q_A + X_{q,G}^w q_G \quad (9)$$

where M^w is mass accumulation of water component (kg/m^3);

S_1 is ice-phase saturation; ρ_1 is ice-phase density (kg/m^3); X_A^w is mass fraction of water in the aqueous phase; X_G^w is mass fraction of water in the gas phase; X_H^w is mass fraction of water in the hydrate phase; X_1^w is mass fraction of water in the ice phase; F^w is mass flux of water component [$\text{kg}/(\text{m}^2 \cdot \text{s})$]; q^w is source or sink of water component [$\text{kg}/(\text{m}^3 \cdot \text{s})$]; $X_{q,A}^w$ is mass fraction of water in the source or sink of the aqueous phase; $X_{q,G}^w$ is mass fraction of water in the source or sink of the gas phase.

(iii) Mass accumulation term for chemical agent component ($\kappa \equiv i$) is shown by Eqs. 10–12.

$$M^i = \varphi S_A \rho_A X_A^i \quad (10)$$

$$F^i = X_A^i F_A \quad (11)$$

$$q^i = X_{q,A}^i q_A \quad (12)$$

where M^i is mass accumulation of the chemical agent component (g/m^3); X_A^i is mass fraction of the chemical agent in the aqueous phase; F^i is mass flux of the chemical agent component [$\text{g}/(\text{m}^2 \cdot \text{s})$]; F^i is source or sink of the chemical agent component [$\text{kg}/(\text{m}^3 \cdot \text{s})$]; $X_{q,A}^i$ is mass fraction of the chemical agent in the source or sink of the aqueous phase.

2.1.2. Energy accumulation terms

When $\kappa \equiv \theta$, the energy accumulation terms include contributions from the rock matrix and all phases. In the dynamic model, they are given by Eqs. 13–15.

$$M^\theta = (1 - \varphi) \rho_R H_R + \sum_{\beta=A,G,H,I} \varphi S_\beta \rho_\beta H_\beta + \varphi \rho_H \Delta S_H \Delta H_0 \quad (13)$$

$$F^\theta = -K_c \nabla T + \sum_{\beta=A,G} H_\beta F_\beta \quad (14)$$

$$q^\theta = \sum_{\beta=A,G} H_\beta q_\beta \quad (15)$$

where M^θ is energy accumulation (J/m^3); ρ_R is rock density (kg/m^3); H_R is enthalpy of rock (J/kg); S_β is saturation of phase β ; H_β is enthalpy of phase β (J/kg); ΔS_H is change in hydrate saturation during the current time step; ΔH_0 is enthalpy of hydrate decomposition/formation (J/kg); F^θ is energy flux [$\text{J}/(\text{m}^2 \cdot \text{s})$]; K_c is effective thermal conductivity of the system [$\text{W}/(\text{m} \cdot \text{K})$]; F_β is mass flux of phase β [$\text{kg}/(\text{m}^2 \cdot \text{s})$]; q^θ is source or sink of energy [$\text{J}/(\text{m}^3 \cdot \text{s})$]; K_R is thermal conductivity of the rock matrix [$\text{W}/(\text{m} \cdot \text{K})$]; K_β is thermal conductivity of phase $\beta \equiv A, G, H, I$ [$\text{W}/(\text{m} \cdot \text{K})$].

2.1.3. Flux terms

The mass flux of water, methane, and inhibitor components originates from contributions in the water and gas phases, while the contributions from the ice phase and hydrate phase to mass flux are zero. The calculation formula is described by Eq. 16.

$$F^\kappa = \sum_{\beta=A,G} F_\beta^\kappa, \quad \kappa \equiv w, m, i \quad (16)$$

The energy flux includes contributions from thermal conduction, thermal convection, and thermal radiation, calculated by the following Eq. 17.

$$F^\theta = -\bar{k}_\theta \nabla T + f_\sigma \sigma_0 \nabla T^4 + \sum_{\beta=A,G} h_\beta F_\beta \quad (17)$$

where $\bar{k}_\theta$ is composite thermal conductivity of the medium/fluid ensemble [$\text{W}/(\text{m} \cdot \text{K})$]; h_β is specific enthalpy of phase β (J/kg); f_σ is emission coefficient for radiation; σ_0 is Stefan-Boltzmann constant [$5.6687 \times 10^{-8} \text{ J}/(\text{m}^2 \cdot \text{K}^4)$].

2.2. Hydrate phase equilibrium model

Based on the thermodynamic state of the system, the amount of CH_4 hydrate formed or CH_4 gas released depends on the hydrate dissociation kinetics (Eq. 18).



where N_H is the hydration number. The regression relationship for the phase equilibrium of hydrate dissociation and Eq. 19 was established using Sloan's experimental data (Sloan ED and Koh KA, 2008):

$$\ln(p_e) = \begin{cases} -1.94138504464560 \times 10^5 + \\ 3.31018213397926 \times 10^3 T \\ -2.255402644493806 \times 10^1 T^2 + \\ 7.67559117787059 \times 10^{-2} T^3 \\ -1.30465829788791 \times 10^{-4} T^4 + \\ 8.86065316687571 \times 10^{-8} T^5 \\ (T \geq 273.2\text{K}) \\ -4.38921173434628 \times 10^1 + \\ 7.76302133739303 \times 10^{-1} T \\ -7.27291427030502 \times 10^{-3} T^2 + \\ 3.85413985900724 \times 10^{-5} T^3 \\ -1.03669656828834 \times 10^{-7} T^4 + \\ 1.09882180475307 \times 10^{-10} T^5 \\ (T < 273.2\text{K}) \end{cases} \quad (19)$$

where T is temperature (K); p_e is equilibrium pressure at temperature T (Pa). The effect of chemical agents on the phase equilibrium curve is described by Eq. 20.

$$T_e = T + \Delta T_D \quad (20)$$

where T_e is the equivalent equilibrium temperature in the presence of a chemical agent (K); ΔT_D is the equilibrium temperature and temperature change caused by the chemical agent (K). The calculation of ΔT_D is shown in Eq. 21.

$$\Delta T_D = \Delta T_{D,r} \frac{\ln(1 - X_{\text{mol},A}^c)}{\ln(1 - X_{\text{mol},A,r}^c)} \quad (21)$$

where $\Delta T_{D,r}$ is drop in equilibrium temperature for mole fraction $X_{\text{mol},A}^c$ (K); $X_{\text{mol},A}^c$ is mole fraction of chemical agent in the aqueous phase; $X_{\text{mol},A,r}^c$ is reference mole fraction of

chemical agent in the aqueous phase.

2.3. Auxiliary equations

2.3.1. Saturation constraint

The sum of the saturations of the aqueous phase, gas phase, hydrate phase, and ice phase equals 1, as shown in Eq. 22.

$$\sum_{\beta=A,G,H,I} S_{\beta} = 1 \quad (22)$$

2.3.2. Mass fraction constraint

The sum of mass fractions of components in the water, gas, hydrate, and ice phases equals 1, as shown in Eqs. 23–26.

$$X_G^m + X_G^w = 1 \quad (23)$$

$$X_A^m + X_A^w + X_A^c = 1 \quad (24)$$

$$X_H^m + X_H^w = 1 \quad (25)$$

$$X_I^w = 1 \quad (26)$$

where,

$$X_G^w = \frac{p_G^w}{p_G} \quad (27)$$

$$X_A^m = \begin{cases} \frac{p_G^m}{H_m} p_G \leq p_{eH} \\ \frac{p_{eH}}{H_m} p_G > p_{eH} \end{cases} \quad (28)$$

$$X_H^m = \frac{M_{CH_4}}{M_{CH_4} + N_H \cdot M_{H_2O}} \quad (29)$$

where p_G is pressure of the gas phase (Pa); p_G^w is partial pressure of water in the gas phase (Pa); p_G^m is partial pressure of methane in the gas phase (Pa); N_H is hydration number of methane hydrate, value taken as 6 in this study; M_{CH_4} is molar mass of CH_4 (0.016 kg/mol); M_{H_2O} is molar mass of H_2O (0.018 kg/mol); H_m is Henry's constant for methane dissolution in water at temperature T (Pa).

2.3.3. Relative permeability model

During multi-gas co-production of deepwater shallow natural gas hydrates and underlying gas, the relative permeabilities of the water and gas phases are calculated using the modified Stone's model (Moridis G, 2003), as shown in Eqs. 30, 31.

$$k_{rA} = \max \left\{ 0, \min \left\{ \left[\frac{S_A - S_{irA}}{1 - S_{irA}} \right]^{n_A}, 1 \right\} \right\} \quad (30)$$

$$k_{rG} = \max \left\{ 0, \min \left\{ \left[\frac{S_G - S_{irG}}{1 - S_{irG}} \right]^{n_G}, 1 \right\} \right\} \quad (31)$$

where k_{rA} is relative permeability of the aqueous phase; S_{irA} is irreducible water saturation; n_A is exponent for relative permeability reduction in the aqueous phase; k_{rG} is relative permeability of the gas phase; S_{irG} is irreducible gas saturation; n_G is exponent for relative permeability reduction in the gas phase.

2.3.4. Effective porosity and permeability variation equations

The effective porosity and permeability of the reservoir are influenced by two main factors. When differences exist between local pressure, temperature, and initial pressure and temperature, porosity and permeability are affected by formation compressibility and thermal expansion. When the hydrate saturation in pore spaces changes during production, causing continuous changes in effective porosity and permeability, the expressions are Eqs. 32, 33.

$$\varphi_e = \varphi_0 (1 + \alpha_p \Delta P + \alpha_T \Delta T) (1 - S_H) \quad (32)$$

$$k_e = k_0 \exp [\gamma (\alpha_p \Delta p + \alpha_T \Delta T)] \left[\frac{\varphi_0 (1 - S_H) - \varphi_c}{\varphi_0 - \varphi_c} \right]^n \quad (33)$$

where φ_e is effective porosity of the reservoir; k_e is effective permeability of the reservoir; α_p is rock compressibility coefficient (1/Pa); α_T is rock thermal expansion coefficient (1/K); φ_0 is permeability variation index related to temperature and pressure; φ_c is critical porosity; S_H is hydrate saturation; n is permeability variation index related to solid-phase saturation.

2.3.5. Capillary pressure model

The capillary pressure model is described by Eq. 34.

$$P_{cap} = -P_0 \left[(S^*)^{-\frac{1}{\lambda}} - 1 \right]^{1-\lambda}, \quad S^* = \frac{(S_A - S_{irA})}{(S_{mxA} - S_{irA})} \quad (34)$$

where P_0 and λ are both model parameters; S_{mxA} is the maximum limiting aqueous saturation, which represents the maximum water saturation that the pore space can be fully saturated with water under a system free of gas phase, ice and hydrate.

2.3.6. Momentum equations

The flow of the gas and water phases follows Darcy's law. The momentum equation is described by Eq. 35.

$$F_{\beta} = -k_0 \frac{k_{r\beta} \rho_{\beta}}{\mu_{\beta}} (\nabla p_{\beta} - \rho_{\beta} g), \quad \beta \equiv A, G \quad (35)$$

where k_0 is absolute permeability of the reservoir (mD); $k_{r\beta}$ is relative permeability of phase β ; μ_{β} is viscosity of phase β (Pa·s); p_{β} is pressure of phase β (Pa); g is gravitational acceleration (9.8 m/s²).

2.4. Boundary conditions

The outer boundary is a closed boundary. The inner boundary conditions refer to wellbore control conditions, including constant flow rate and constant pressure conditions.

2.4.1. Constant bottom-hole pressure

For production or injection wells, the gas and water phase production or injection rates within a grid are calculated as Eqs. 36, 37.

$$q_{\beta} = \frac{k_{r\beta}}{\mu_{\beta}} \rho_{\beta} PI (p_{\beta} - p_{wf}), \beta \equiv A, G \quad (36)$$

$$PI = \frac{2\pi k_a h}{\ln\left(\frac{r_e}{r_w}\right) + s - \frac{1}{2}} \quad (37)$$

where p_{wf} is bottom-hole flowing pressure (Pa); PI is productivity index of the well; h is thickness of the grid block containing the well (m); r_e is radius of the well (m); s is skin factor, taken as 0 in this study.

2.4.2. Constant flow rate

For wells penetrating multiple grids, production rates are distributed among grids based on transmissibility. For production wells, only cases with specified total production rates for all phases are studied. The gas and water production rates are distributed based on the flow capacity of the gas and water phases as a percentage of the total flow capacity, calculated as Eqs. 38, 39.

$$q_{A,p,i} = \frac{\sum_{i=1}^N \left(PI \frac{k_{rA}}{\mu_A} \right) Q_p}{\sum_{i=1}^N \left(PI \frac{k_{rA}}{\mu_A} \right) + \sum_{i=1}^N \left(PI \frac{k_{rG}}{\mu_G} \right)} \quad (38)$$

$$q_{G,p,i} = \frac{\sum_{i=1}^N \left(PI \frac{k_{rG}}{\mu_G} \right) Q_p}{\sum_{i=1}^N \left(PI \frac{k_{rA}}{\mu_A} \right) + \sum_{i=1}^N \left(PI \frac{k_{rG}}{\mu_G} \right)} \quad (39)$$

where N is number of grid blocks containing the well; $q_{A,p,i}$ is production rate of the aqueous phase in grid block i [$\text{kg}/(\text{m}^3 \cdot \text{s})$]; $q_{G,p,i}$ is production rate of the gas phase in grid block i [$\text{kg}/(\text{m}^3 \cdot \text{s})$]; Q_p is total production rate [$\text{kg}/(\text{m}^3 \cdot \text{s})$].

Although geomechanical deformation is a significant factor in long-term reservoir stability, this study focuses on the thermal-hydraulic-chemical (THC) coupling mechanisms during the initial 5-day production test. Given the short duration and the high-permeability nature of the underlying gas zones, fluid phase transitions and pressure propagation are considered the primary drivers of productivity. Therefore, reservoir geomechanics are simplified in the current model to isolate the complex flow dynamics and gas-source interactions between the HBGL and underlying free gas layers. The numerical solution of the proposed model is obtained through a fully implicit finite-difference scheme, ensuring temporal and spatial stability during the coupled simulation of thermal, hydraulic, and chemical processes. To manage the strong non-linearity arising from hydrate phase transitions and the associated thermo-pressure variations, the Newton-Raphson iteration method is employed to solve the system of governing equations simultaneously. Convergence

is strictly enforced by setting a relative residual tolerance of 1×10^{-6} for all primary variables, including pressure, temperature, and phase saturations. This computational framework ensures the robustness of the transient response analysis during the initial production phase.

3. Numerical model

3.1. Geological background

This study focuses on predicting the production capacity under pressure reduction for co-production of shallow gas hydrates and underlying gas in two test wells of a gas field located in the offshore area of the Qiongdongnan Basin, China. The gas field is situated on the Lingnan Low Uplift of the Qiongdongnan Basin, at a water depth of 1508–1639 m, as shown in Fig. 1a. It features a structural-lithologic trap group formed by a large Quaternary submarine fan sourced from the western provenance of the Ledong Formation. The discovered gas reservoirs are mainly located in the higher parts of the central-eastern block, which aligns with the migration and accumulation direction. The traps are well-defined, and the reservoir-forming conditions are favorable. The target layer in simulation well A consists of two sections: (1) The gas hydrate-bearing layer lies within the depth range of 1763.1–1765.5 m, with a total thickness of 2.4 m; (2) the underlying gas layer is located between 1765.5–1778.5 m, with a total thickness of 13 m. Similarly, the target layer in simulation well B also consists of two sections: (1) The hydrate-bearing layer is found within the depth range of 1856–1863.4 m, with a total thickness of 7.4 m; (2) the hydrate-bearing gas layer is located at a depth of 1868.9–1875.5 m, with a total thickness of 6 m (Pei JX et al., 2024).

3.2. Model construction

Based on field logging and test production data, physical models for co-production of shallow gas hydrates and underlying gas were established for simulation wells A and B, as shown in Fig. 2. For simulation well A, the overlying layer has a thickness of 5 m (depth 1758.1–1763.1 m), the gas hydrate-bearing layer has a thickness of 2.4 m (depth 1763.1–1765.5 m), the underlying gas layer is 13 m thick (depth 1765.5–1778.5 m), and the underlying layer has a thickness of 5 m (depth 1778.5–1783.5 m). The porosity of the overlying layer, hydrate-bearing layer, free gas layer, and underlying layer is 30.0%, 46.8%, 43.6%, and 30.0%, respectively, while their permeability values are 10 mD, 25 mD, 50 mD, and 10 mD. For simulation well B, the overlying layer is 5 m thick (depth 1851–1856 m), the hydrate layer has a thickness of 7.4 m (depth 1856–1863.4 m), the interlayer is 5.5 m thick (depth 1863.4–1868.9 m), the hydrate-bearing gas layer is 6 m thick (depth 1868.9–1875.5 m), and the underlying layer is 5 m thick (depth 1875.5–1879.5 m). The porosity of the overlying layer, hydrate-bearing layer, interlayer, hydrate-bearing gas layer, and underlying layer is 30.0%, 44.4%, 30.0%, 37.8%, and 30.0%, respectively, while their permeability values are 10 mD, 40 mD, 10 mD, 50 mD,

and 10 mD. These parameters are representative values derived from integrated logging interpretations and regional geological characteristics of the Qiongdongnan Basin (Pei JX et al., 2024; Wu SG et al., 2024). To ensure numerical stability and computational efficiency, these values are idealized as uniform within each layer, while remaining consistent with the permeability ranges typical of unconsolidated shallow marine sediments in the South China Sea. The specific formation conditions are detailed in Table 1.

For the target hydrate reservoir characteristics of simulation well A, a cylindrical hydrate reservoir model was used to simulate the co-production of hydrates and underlying free gas with a single vertical well. The radial and vertical depths of the model are 500 m and 26.6 m, respectively. The radial direction around the wellbore is divided into 30 grids, with the first production well grid set at 0.1 m. The vertical direction is divided into 31 grids, resulting in a cylindrical system discretized into $30 \times 31 = 930$ grid blocks.

For the target reservoir characteristics of simulation well B, a cylindrical reservoir model was used to simulate the exploitation of the hydrate layer and hydrate-bearing gas layer

with a single vertical well. The radial and vertical depths of the model are 500 m and 29 m, respectively. The radial direction around the wellbore is divided into 29 grids, with the first production well grid set at 0.1 m. The vertical direction is divided into 33 grids, resulting in a cylindrical system discretized into $29 \times 33 = 957$ grid blocks.

A cylindrical grid system is established with a vertical production well ($r_w = 0.1$ m) positioned at the center of the hydrate model. To capture the significant gas-water flow and rapid thermo-pressure variations, a refined grid layout is employed in the near-wellbore region. The boundary conditions are implemented by setting the uppermost units of the overburden, the lowermost units of the underlying layer, and the outermost radial units as inactive cells. This configuration ensures that their temperature and pressure remain constant throughout the simulation, effectively acting as constant-state boundaries for the reservoir.

The initial hydrate and gas saturations are distributed uniformly within each respective layer according to the site-specific data provided in Table 1, with the reservoir assumed to be in a state of initial thermodynamic equilibrium. The

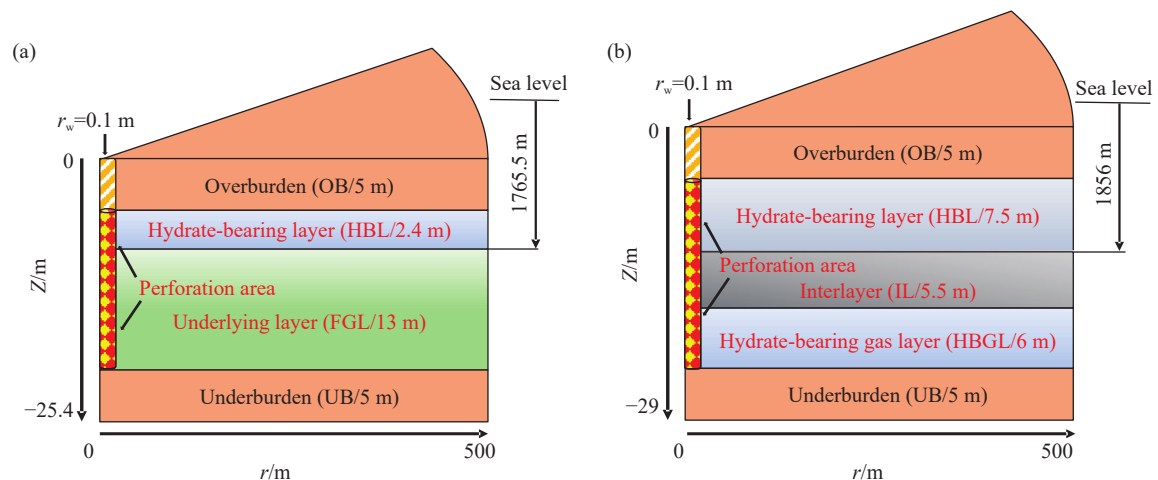


Fig. 2. Physical models for multi-gas co-production. a–Simulated Well A with a direct hydrate-bearing layer (HBL) and underlying gas layer (FGL) interface; b–simulated well B featuring an interlayer (IL) separating the hydrate-bearing layer (HBL) and the hydrate-bearing gas layer (HBGL).

Table 1. Formation conditions of the model wells.

Parameters	Simulated well A	Simulated well B
Water depth/m	1548.45	1600.13
Initial temperature at the bottom of the HBL/°C	16.35	16.68
Initial pressure at the bottom of the HBL/MPa	17.98	18.98
Porosity/%	30.0 (OB & UB) 46.8 (HBL) 43.6 (FGL)	30.0 (OB & UB) 44.4 (HBL) 37.8 (HBGL)
Permeability/mD	10 (OB & UB) 25 (HBL) 50 (FGL)	10 (OB & UB) 40 (HBL) 50 (HBGL)
Saturation/%	$S_A = 100$ (OB & UB), $S_A = 20.3$, $S_H = 56.7$, $S_G = 23.0$ (HBL) $S_G = 87.7$, $S_A = 12.3$ (FGL)	$S_A = 100$ (OB & UB) $S_A = 20.1$, $S_H = 75.3$, $S_G = 4.6$ (HBL) See the following section for the saturation of the HBGL
Geothermal gradient/(°C/m)	0.0475	0.04
Pressure coefficient	1.04	1.041

dissociation front of the natural gas hydrate is modeled to expand horizontally from the wellbore along the upper and lower edges of the reservoir. Fluid flow within the production well is governed by Darcy's law as a gas-liquid multiphase process. To represent the wellbore hydraulics under specified pressure drawdowns (BHP constraints), the porosity is set to 1.0, the vertical permeability of the wellbore is 5000 D, the radial permeability in the perforated zone is 10 D, and the capillary pressure is assumed to be zero.

3.3. Production strategy

For simulation well A, a constant-pressure depressurization method was applied using a single vertical well. The vertical well penetrated both the hydrate layer and the FGL, enabling co-production, with perforations set at the locations of the hydrate layer and the free gas layer. The production pressure differentials were set at 0.7 MPa, 0.8 MPa, 0.9 MPa, 1.0 MPa, 2.0 MPa, 3.0 MPa, and 4.0 MPa, with a short-term production test of 5 days.

For simulation well B, the same constant-pressure depressurization method was applied with a single vertical well. The vertical well penetrated both the hydrate layer and the hydrate-bearing gas layer, enabling co-production, with perforations set at the locations of the hydrate layer and the hydrate-bearing gas layer. The production pressure differentials were set at 0.5 MPa, 1.0 MPa, 2.0 MPa, 3.0 MPa, 4.0 MPa and 5.0 MPa, with a short-term production test of 5 days. To explore the effects of different gas saturations in the hydrate-bearing gas layer on productivity testing, the original water saturation of the hydrate-bearing gas layer was kept constant, and six simulation scenarios were designed, as shown in Table 2.

4. Results and analysis

4.1. Simulation well A

4.1.1. Productivity analysis

Fig. 3 shows the changes in wellhead gas production rate

and cumulative gas production over time under different production pressure differentials. Taking the production pressure differential of 1 MPa as an example, during the initial testing phase, the pressure differential between the wellbore and the surrounding reservoir is at its maximum, resulting in the highest gas production rate of $281.87 \times 10^4 \text{ m}^3/\text{d}$. Subsequently, the gas production rate decreases rapidly. After one day, the decline slows down, and the production rate gradually stabilizes. It should be noted that the predicted peak rate of $281.87 \times 10^4 \text{ m}^3/\text{d}$ represents the total deliverability of the multi-gas system under idealized conditions. The vast majority of this flow is attributed to the high-permeability underlying gas zone. In real-world operations, this rate would be constrained by wellbore hydraulics, downhole equipment, and sand control measures, which are not explicitly accounted for in this reservoir-scale simulation. The larger the production pressure differential, the higher the gas production rate. After five days of testing, the wellhead gas production rate under a 1 MPa pressure differential is $110.98 \times 10^4 \text{ m}^3/\text{d}$, while under a 0.1 MPa pressure differential, it is $12.93 \times 10^4 \text{ m}^3/\text{d}$, meaning the former is 8.58 times higher than the latter. As shown in Fig. 3b, after five days, the cumulative gas production under a 1 MPa pressure differential is $716.19 \times 10^4 \text{ m}^3$, whereas under a 0.1 MPa pressure differential, it is $86.19 \times 10^4 \text{ m}^3$, meaning the former is 8.31 times higher. Fig. 4 shows the relationship between production pressure differential and average wellhead gas production rate during the test period. As the

Table 2. Simulation scenarios and initial phase saturations of the hydrate-bearing gas layer for well B.

Case	Saturation of hydrate-bearing gas layer/%		
	S_A (Water)	S_H (Hydrate)	S_G (Gas)
Case 1	9.8	75.2	15
Case 2	9.8	70.2	20
Case 3	9.8	65.2	25
Case 4	9.8	60.2	30
Case 5	9.8	55.2	35
Case 6	9.8	50.2	40

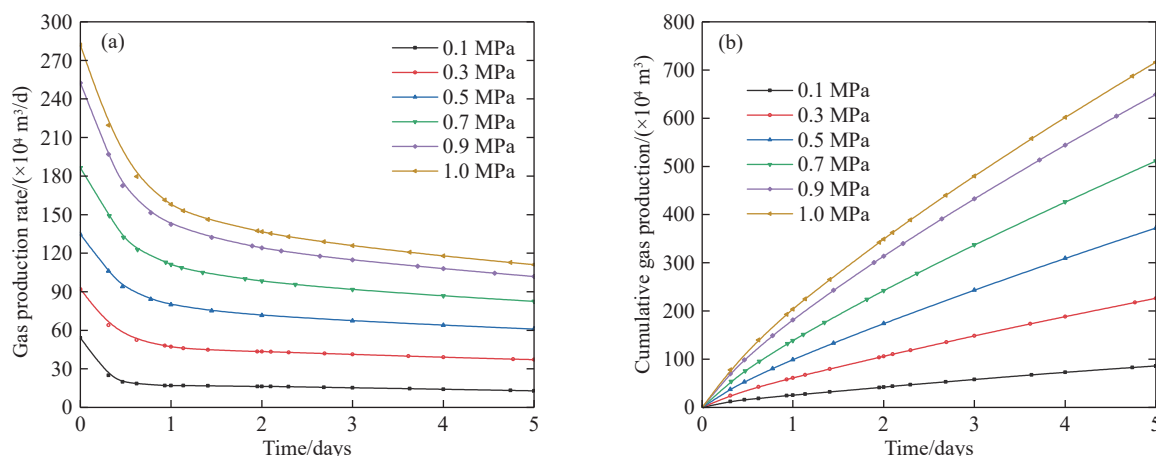


Fig. 3. Changes in wellhead gas production rate (a) and cumulative gas production (b) over time under different production pressure differentials.

production pressure differential increases from 0.1 MPa to 1.0 MPa, the average gas production rate increases significantly, showing a linear relationship between the production pressure differential and the average gas production rate.

4.1.2. Hydrate dissociation patterns

Fig. 5 illustrates the variations in hydrate dissociation rate and cumulative gas production from hydrate dissociation under different production pressure differences over time. Positive values in the figure indicate gas production from hydrate dissociation, while negative values indicate secondary hydrate formation consuming gas. As shown in Fig. 5a, hydrate dissociation occurs rapidly after being disturbed by pressure at the start of testing. Following heat absorption and cooling of the reservoir, secondary hydrate formation occurs briefly, with the formation rate dropping rapidly to zero, after which dissociation and gas production resume. The greater the production pressure difference, the quicker the dissociation and gas production resume. At production pressure differences of 0.5–1.0 MPa, gas production resumes within 0.5 days, while at pressure differences below 0.3 MPa, it takes approximately 2 days. After resuming gas production, the dissociation rate gradually decreases, stabilizing after 3 days, with minimal differences across the pressure differences. Fig. 5b shows that cumulative gas production from hydrate

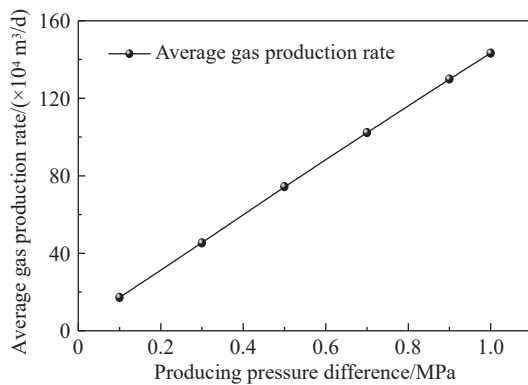
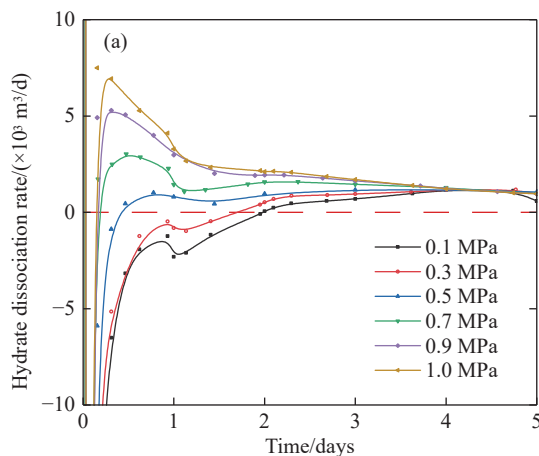


Fig. 4. Relationship between production pressure differential and average wellhead gas production rate.



dissociation increases with production pressure difference over the 5-day testing period. Under low-pressure conditions (less than 0.3 MPa), longer recovery times for gas production and extended secondary hydrate formation result in negative cumulative gas production from hydrates. This dissociation pattern is primarily due to the reservoir's thin hydrate layer, thicker underlying gas layer, and higher permeability. These conditions facilitate the upward migration of free gas from the underlying layer, which partially impedes contact between the hydrate dissociation front and nearby thermal fluids, weakening heat conduction and hindering effective dissociation within the hydrate reservoir.

Fig. 6 shows the daily contribution rate of the hydrate layer to gas production under different production pressure differences for simulation well A during testing. At a 1 MPa production pressure difference, the hydrate layer contributes most significantly on the first day, reaching 3.47%, but gradually decreases to around 1.95% as production continues. Under a 0.9 MPa pressure difference, the trend is similar, decreasing from 2.93% to 1.83%. At a 0.7 MPa pressure difference, the contribution rate decreases slightly from about 1.5% on the first day to approximately 1.333% on the fifth day. For a 0.5 MPa pressure difference, the rate increases from 0 to 0.67%. However, under pressure differences of 0.1 MPa and 0.3 MPa, the contribution rate of the hydrate layer remains zero. Overall, the contribution of the hydrate layer to gas production is minimal, with the majority of wellhead gas production during testing supplied by the underlying free gas.

4.1.3. Evolution of reservoir physical properties

Fig. 7 shows the spatial distribution of pressure, temperature, hydrate saturation, and gas saturation during production under a 1 MPa pressure differential at the start, and after 1, 2, 3, 4, and 5 days. From the pressure distribution cloud map in Fig. 7a, it can be seen that during production, the constant wellbore pressure creates a significant pressure gradient around the well. However, there is a notable difference in the pressure propagation distance between the hydrate layer and the underlying free gas layer. Over the 5-day test period, the difference in pressure propagation distance between the two layers becomes more pronounced,

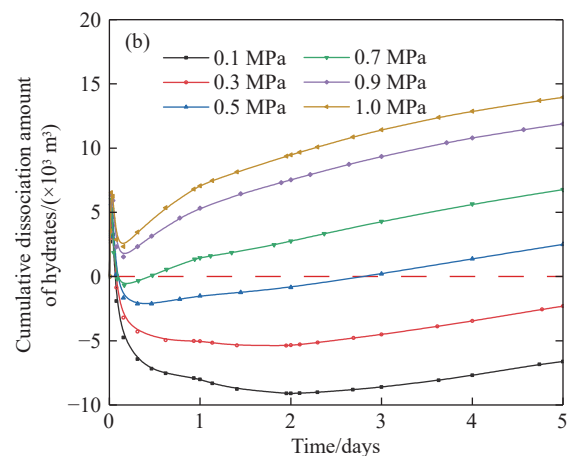


Fig. 5. Changes in hydrate dissociation rate (a) and cumulative dissociation gas volume (b) over time under different pressure differentials.

as shown under a 1 MPa pressure differential. This indicates that the presence of free gas hinders pressure propagation in the hydrate layer, reducing the pressure propagation distance in the hydrate layer over time. From the temperature distribution cloud map in Fig. 7b, it can be seen that temperature changes occur primarily near the interface between the hydrate layer and the underlying free gas layer and propagate radially along this interface. This is due to the rapid dissociation of hydrates, which absorbs heat, and the influx of free gas into the wellbore, causing a “Joule-Thomson effect”. Since the gas production from hydrate dissociation is minimal, the low-temperature zone is mainly concentrated in the underlying free gas layer. From the hydrate saturation cloud map in Fig. 7c, it can be seen that the total dissociation of hydrates is extremely small over the 5-day test, with almost no visible changes in the cloud map. However, small amounts of dissociation can still be observed,

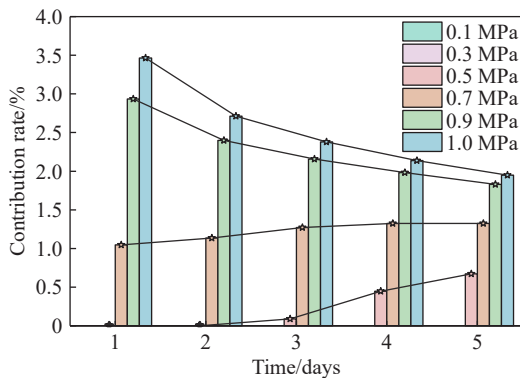


Fig. 6. Changes in daily contribution rate of hydrate layer to gas production under different pressure differentials.

primarily near the interface between the hydrate layer and the underlying free gas layer. This dissociation is facilitated by the disturbance caused by the free gas at this interface. From the gas saturation cloud map in Fig. 7d, it can be seen that free gas migration occurs not only radially toward the wellbore but also upward due to its low density. However, the amount of upward migration is minimal, resulting in a slightly lower gas saturation in the lower-left part of the underlying free gas layer compared to the upper-right part in the cloud map.

4.2. Simulation well B

4.2.1. Productivity analysis

Fig. 8 and Fig. 9 show the changes in gas production rates and cumulative gas production over a 5-day test under different conditions, respectively. When the gas saturation of the hydrate-bearing gas layer is 15%, the gas production rate during the test is relatively low, stabilizing below 20×10^4 m³/d after one day. At 20% gas saturation, the gas production rate improves, stabilizing in the range 10×10^4 – 50×10^4 m³/d after one day. At 25% gas saturation, the gas production rate also stabilizes in the range 10×10^4 – 50×10^4 m³/d after one day, with all gas production contributed by free gas. At 30% gas saturation, the gas production rate stabilizes in the range 20×10^4 – 70×10^4 m³/d after one day. At 35% gas saturation, the gas production rate stabilizes in the range 30×10^4 – 80×10^4 m³/d after one day. At 40% gas saturation, the gas production rate remains primarily in the range 40×10^4 – 120×10^4 m³/d during the test.

Fig. 10 shows the relationship between average daily gas production, production pressure differentials, and gas saturations under various conditions. Fig. 10a indicates that

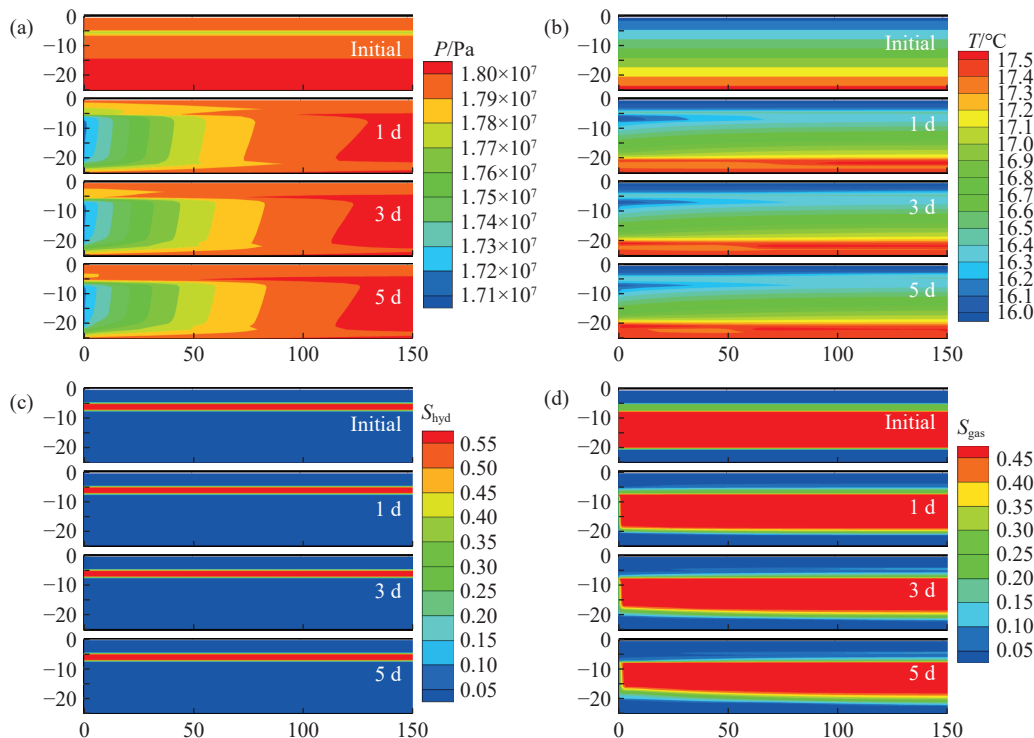


Fig. 7. Evolution of reservoir physical parameters during production over time.

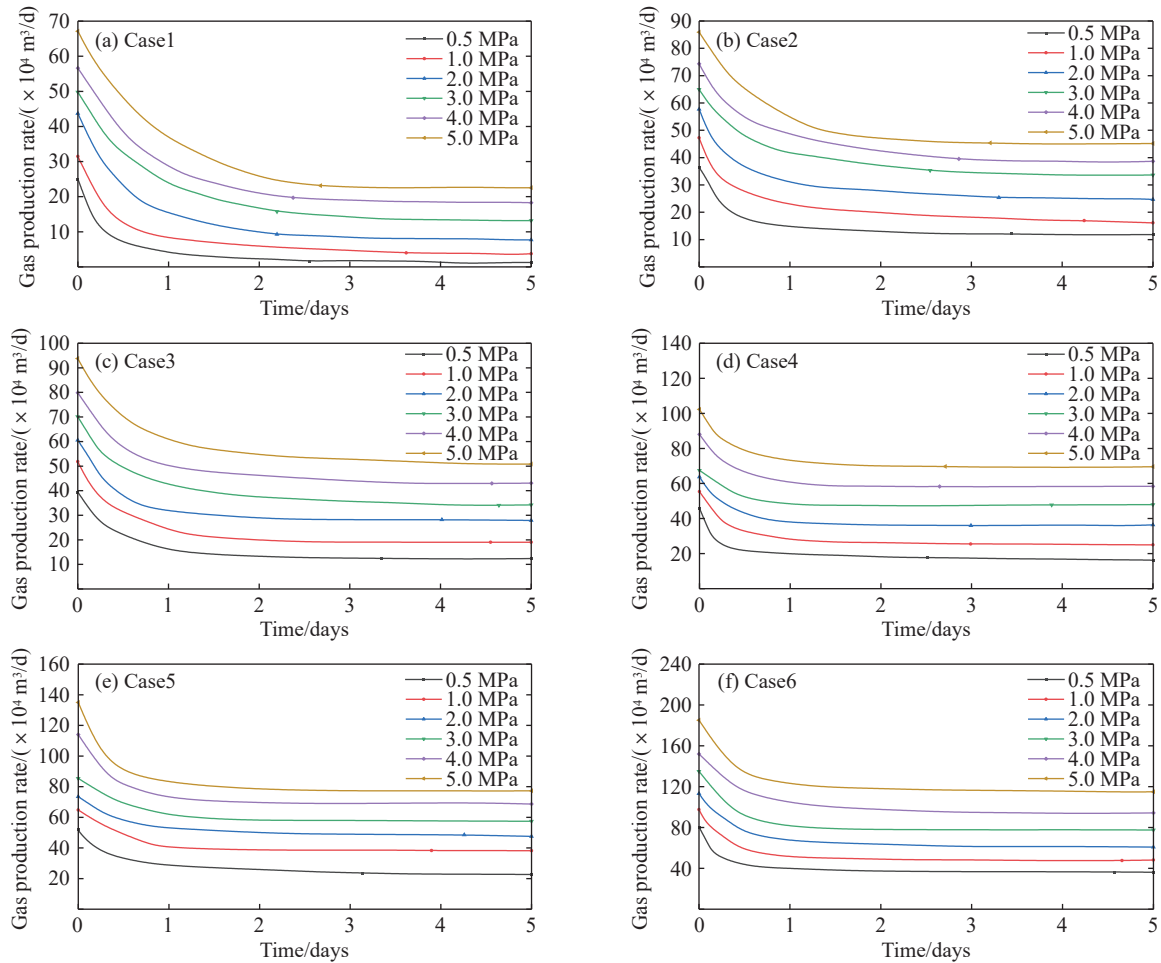


Fig. 8. Changes in gas production rate over 5 days under different conditions.

under the same gas saturation (same condition), the average daily gas production increases with higher production pressure differentials. Fig. 10b shows that under the same production pressure differential, the average daily gas production increases with higher gas saturations. The growth rate is slow when gas saturation increases from 15% to 30% but accelerates significantly as saturation increases from 30% to 40%. This non-linear production response is primarily attributed to the evolution of effective permeability within the HBGL. At low gas saturations (15%–30%) and high hydrate saturations (75.2%–60.2%), the solid hydrate phase occupies the majority of pore throats, creating high-tortuosity paths that severely restrict gas mobility. In this state, the HBGL effectively acts as a flow barrier, suppressing the upward migration of underlying gas. However, as S_G reaches the 30%–40% range and S_H drops accordingly, the connectivity of the gas phase improves significantly, and the “blocking effect” of the solid hydrates is markedly weakened. This transition allows the HBGL to shift from a flow-restricting layer to a high-conductivity conduit, facilitating a substantial influx of gas from both the HBGL itself and the high-pressure underlying reservoir.

4.2.2. Hydrate dissociation patterns

Fig. 11 and Fig. 12 illustrate the trends in hydrate

decomposition rates and cumulative hydrate quantities over 5 days under various conditions. In Fig. 11, the red dashed line indicates a hydrate decomposition rate of 0; values above it represent decomposition rates, while values below represent secondary formation rates. In Fig. 12, the red dashed line denotes a cumulative hydrate decomposition amount of 0; values above it indicate positive decomposition, while those below signify negative decomposition, indicating secondary hydrate formation in the reservoir. When the gas saturation in the hydrate-bearing gas layer is 15%, hydrate decomposition occurs within a very short time after testing begins. Following reservoir cooling from heat absorption, secondary hydrate formation accelerates but slows within 2 days and approaches zero afterward. Greater production pressure differences reduce total secondary hydrate formation. At 20% gas saturation in the hydrate-bearing gas layer, hydrate decomposition occurs rapidly at the start. Cooling from heat absorption triggers secondary formation, which decelerates and nears zero by 1.5 days. Increasing production pressure differences reduce cumulative secondary hydrate formation. For a 25% gas saturation, hydrate decomposes quickly at testing onset, followed by rapid secondary formation after cooling. The secondary formation process decays continuously over 3 days and terminates entirely by the third day. Higher production pressure differences reduce total

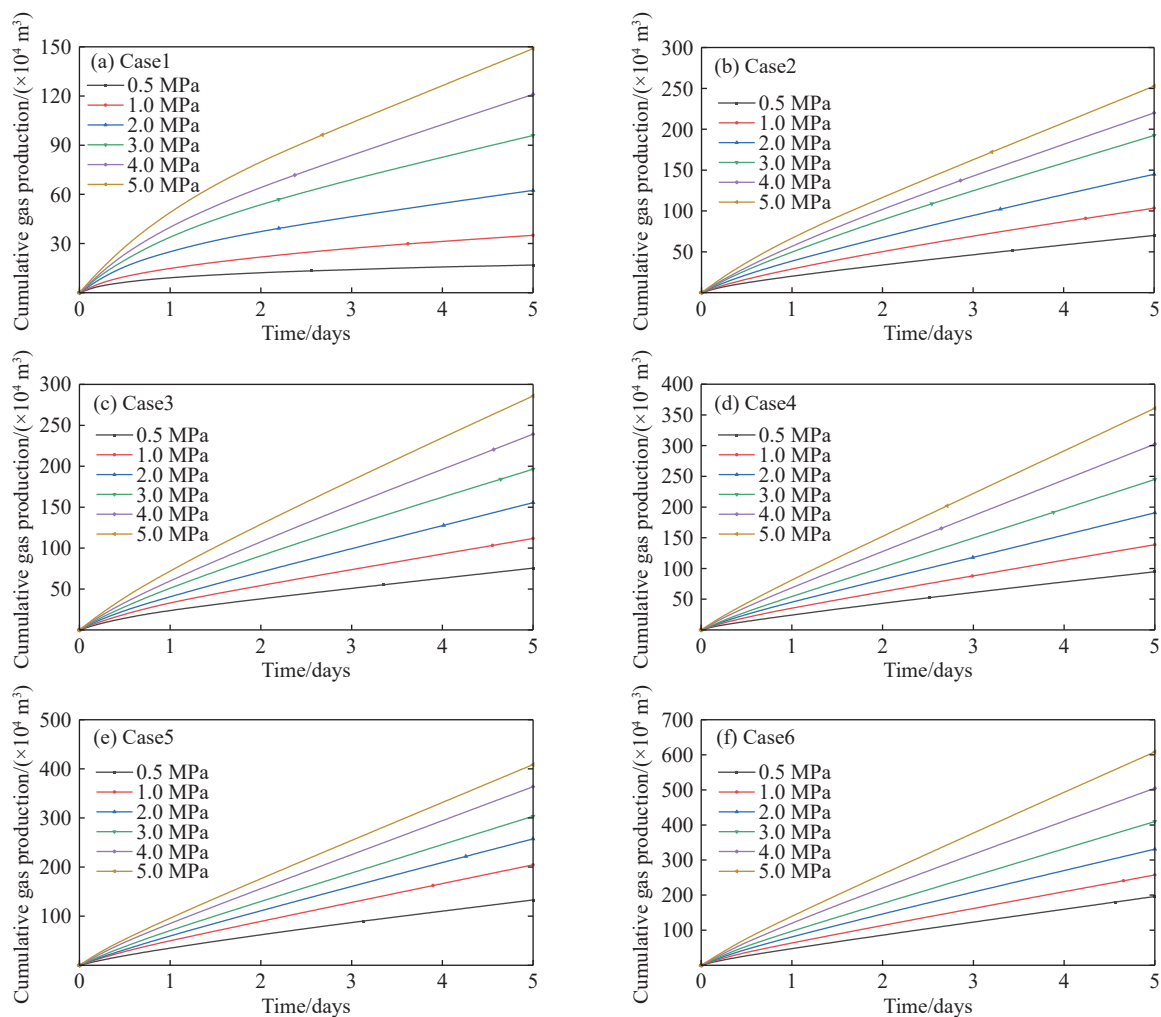


Fig. 9. Changes in cumulative gas production over 5 days under different conditions.

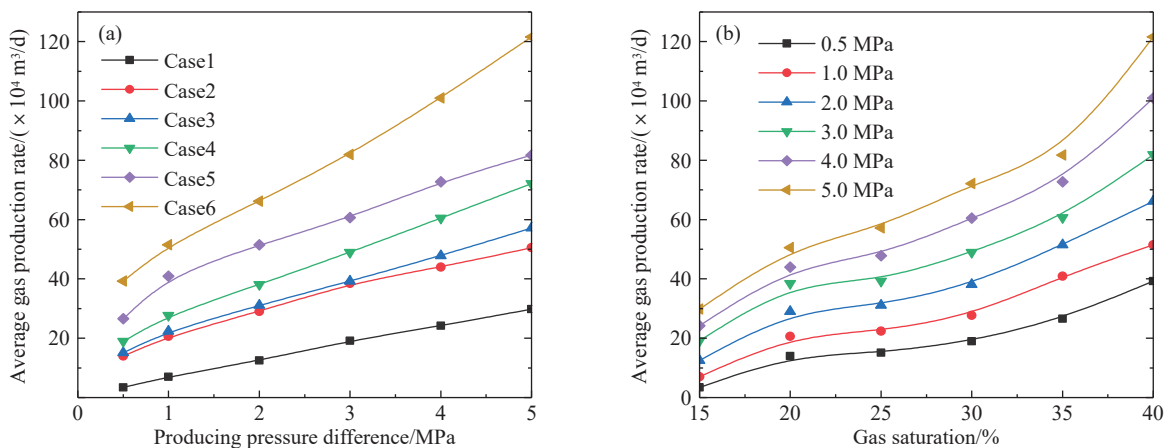


Fig. 10. Changes in average daily gas production under different production pressure differentials and gas saturations.

secondary hydrate formation. At 30% gas saturation, rapid initial hydrate decomposition is followed by secondary formation as the reservoir cools. The secondary formation diminishes by the third day, after which low-rate hydrate decomposition recovers. Secondary formation totals decline under increasing production pressure differences over 5 days. For 35% gas saturation, initial rapid hydrate decomposition leads to fluctuating secondary formation in the first day. By

the third day, the secondary formation rate approaches zero. Cumulative secondary hydrate formation decreases with higher production pressure differences over 5 days. At 40% gas saturation, rapid hydrate decomposition initiates secondary formation, showing significant fluctuations during the first day. By the third day, the secondary formation rate falls close to zero. Total secondary hydrate formation declines with increased production pressure differences over 5 days.

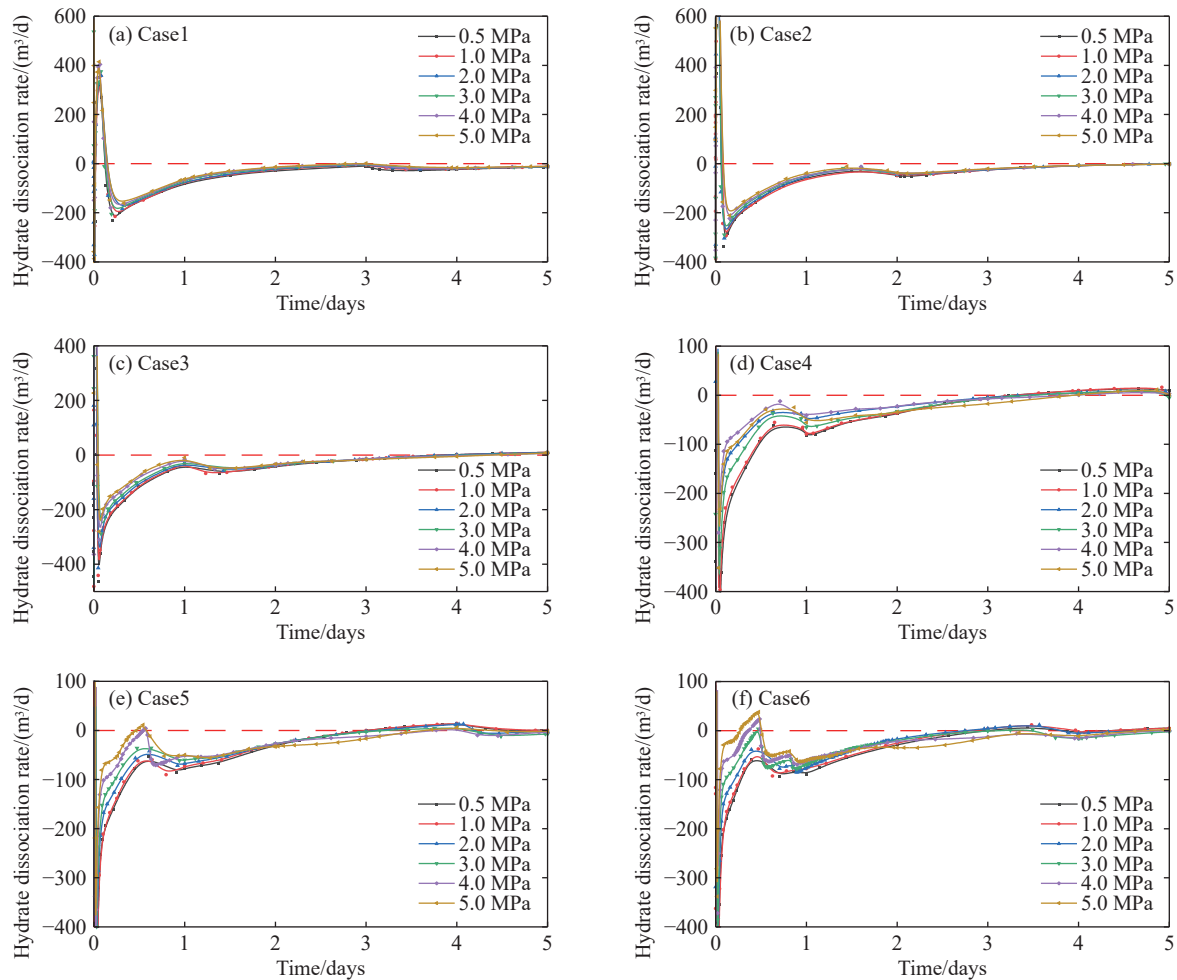


Fig. 11. Changes in hydrate dissociation rates over 5 days under different conditions.

Fig. 13 compares the cumulative hydrate dissociation amounts under various conditions (gas saturation) and production pressure differentials over 5 days. For all conditions and pressure differentials, the cumulative dissociation amount is negative. This indicates that secondary hydrate formation occurred in the reservoir during the five-day tests under all tested conditions. The occurrence of this phenomenon is closely related to the reservoir's pressure-temperature state. Specifically, when the pressure-temperature state of the hydrate-bearing layer is near the hydrate phase equilibrium curve, even minor pressure disturbances or the influence of free gas can trigger secondary hydrate formation. With increasing gas saturation and higher production pressure differences, the wellbore gas production increases correspondingly. This increase promotes hydrate dissociation within the reservoir, as greater pressure differences enable faster pressure drops to propagate, providing more kinetic driving force for hydrate dissociation. However, the total amount of secondary hydrate formation observed during the tests remains relatively small, and its impact on shallow gas production tests is not significant. In summary, by adjusting production pressure differences or controlling wellbore temperature, it is possible to balance hydrate dissociation and secondary formation, thereby achieving efficient and

sustainable reservoir exploitation.

4.2.3. Evolution of reservoir physical properties

Fig. 14 illustrates the spatial distribution of pressure, temperature, hydrate saturation, and gas saturation under condition Case 3 (initial gas saturation of 25%) with a production pressure difference of 3 MPa, covering the initial production state and the states after 1, 3 and 5 days of production. Over the 5-day test period, it can be observed that, due to the absence of hydrate and gas in the intermediate barrier layer, the pressure drop propagates relatively far through the barrier, forming a “cone-shaped” spread pattern in the reservoir along the wellbore, reaching approximately 60 m. This propagation pattern may be associated with the heterogeneity of the reservoir, and the propagation path and speed of the pressure drop directly affect reservoir production efficiency. The dissociation of hydrate and the release of gas is a complex physico-chemical process. When the reservoir pressure drops below the hydrate stability zone, the hydrate structure begins to dissociate, releasing methane gas. This process involves not only a physical phase change but also thermodynamic variations. The gas release rate is influenced by multiple factors, including reservoir temperature, pressure, hydrate composition, and pore structure. Crucially, this

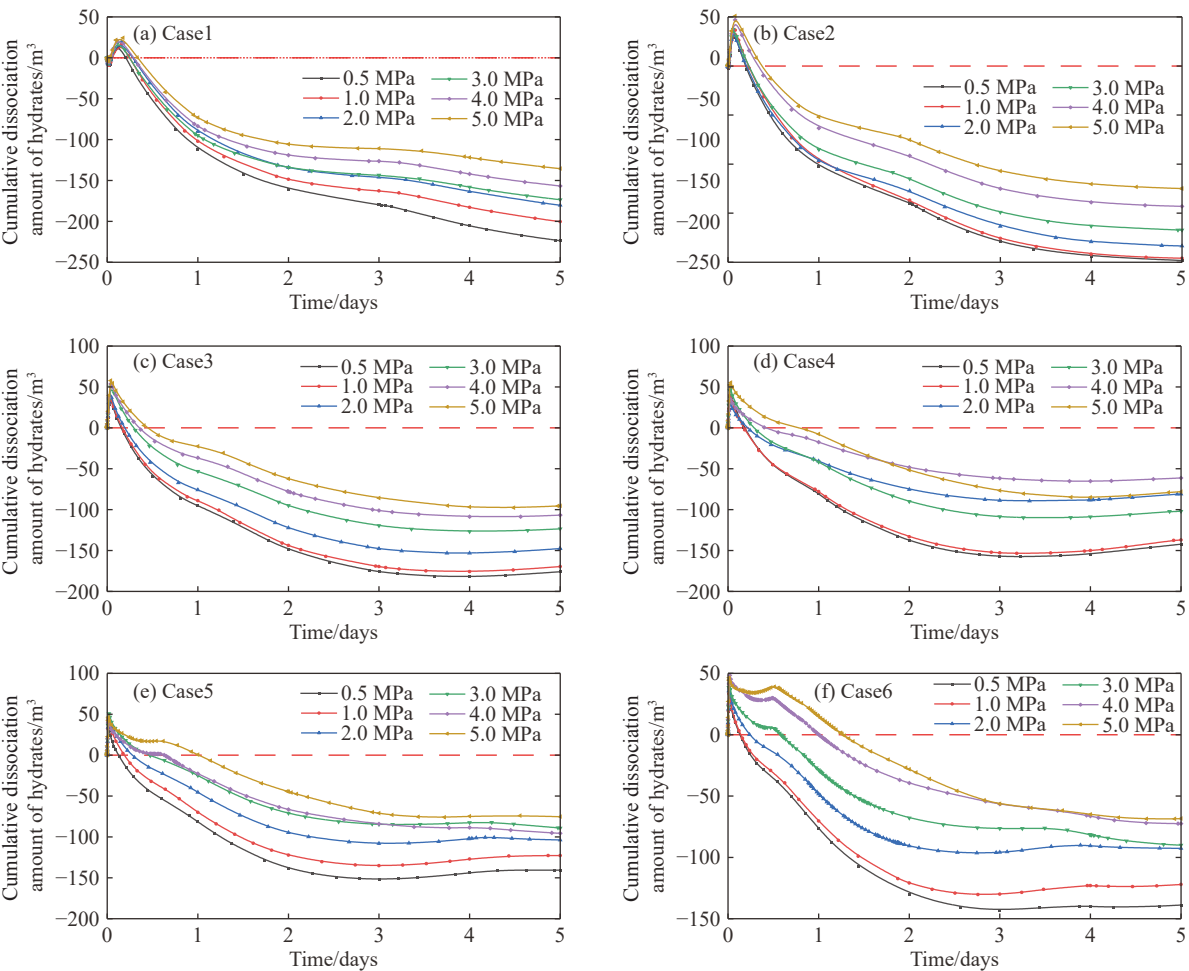


Fig. 12. Changes in cumulative hydrate dissociation over 5 days under different conditions.

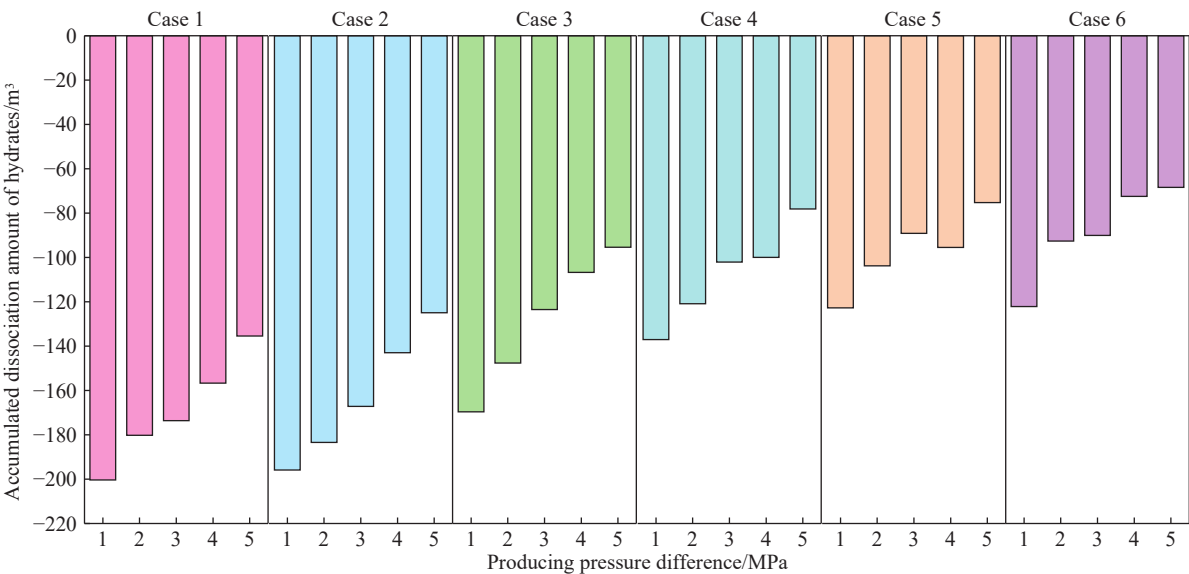


Fig. 13. Comparison of cumulative hydrate dissociation over 5 days under various conditions.

behavior is highly sensitive to the coupled hydro-thermal properties of the sediment. For instance, higher intrinsic permeability can accelerate pressure drawdown but also intensify the gas flow velocity, thereby magnifying the cooling effect. Near the wellbore, rapid hydrate dissociation

absorbs heat (governed by the dissociation enthalpy), and the influx of free gas into the wellbore triggers the “Joule-Thomson effect”, creating a significant low-temperature zone in the HBGL. The extent of this cooling is further moderated by the thermal conductivity of the formation, which

determines the rate of heat recharge from the surrounding strata. This low-temperature zone significantly impacts secondary hydrate formation, as it alters the thermodynamic conditions of the reservoir. Due to the presence of the barrier layer, similar phenomena are observed in the hydrate layer and the HBGL. During the 5-day test, some hydrates in the HBGL dissociated at approximately 20 m from the wellbore after 1 day. However, over the following days, secondary hydrate formation gradually began within the 20 m range. Quantitative results from Fig. 12 and Fig. 13 confirm that cumulative gas production from hydrate dissociation is negative by the end of the test. Consequently, gas production from the wellbore is primarily supplied by free gas in the HBGL. This finding specifically characterizes the response of the modeled reservoir under the defined extraction parameters. Given that hydrate dissociation is highly sensitive to both sediment properties and operational constraints, these results reflect the performance of this specific multi-gas system during short-term testing rather than establishing a universal constant.

Based on the simulation results, several field-scale optimization strategies are suggested for the co-production of hydrates and underlying free gas. First, a dual-layer completion strategy is recommended to leverage the high-pressure energy of the underlying gas layer, which can provide continuous pressure support to the HBGL. Second, the production pressure differential should be maintained above the identified threshold to ensure that the gas influx from the underlying reservoir remains sufficient to counteract the flow resistance caused by secondary hydrate formation. Furthermore, to mitigate the risk of near-wellbore blockage,

localized thermal stimulation or the injection of kinetic inhibitors could be integrated into the production control system. These measures would maintain high-conductivity pathways for gas migration, thereby achieving a balance between maximizing gas recovery from the HBGL and sustaining the long-term productivity of the multi-gas system.

It should be noted that the reservoir model employed in this study adopts a simplified and geometrically regular configuration to isolate the fundamental thermohydrodynamic interactions between the HBGL and underlying gas layers. In reality, hydrate-bearing sediments often exhibit significant heterogeneity in terms of lithology, pore structure, and spatial distribution. Such complexities, including irregular stratigraphic boundaries and varying hydrate morphology, could introduce preferential flow paths and more complex pressure propagation patterns than those observed in an idealized model. Therefore, while the current simulation effectively identifies the primary mechanisms of secondary hydrate formation and gas-source synergy, the results should be interpreted as a mechanistic baseline. Future studies incorporating more complex geological heterogeneities and stochastic parameter distributions are necessary to further refine these field-scale predictions.

5. Conclusions

(i) During co-production, the gas production rate transitions from an initial rapid decline, driven by pressure depletion in the high-permeability underlying gas layer, to a stable phase within 1–2 days due to the synergistic support of the underlying free gas and the HBGL. The average daily production exhibits a dual sensitivity to reservoir and

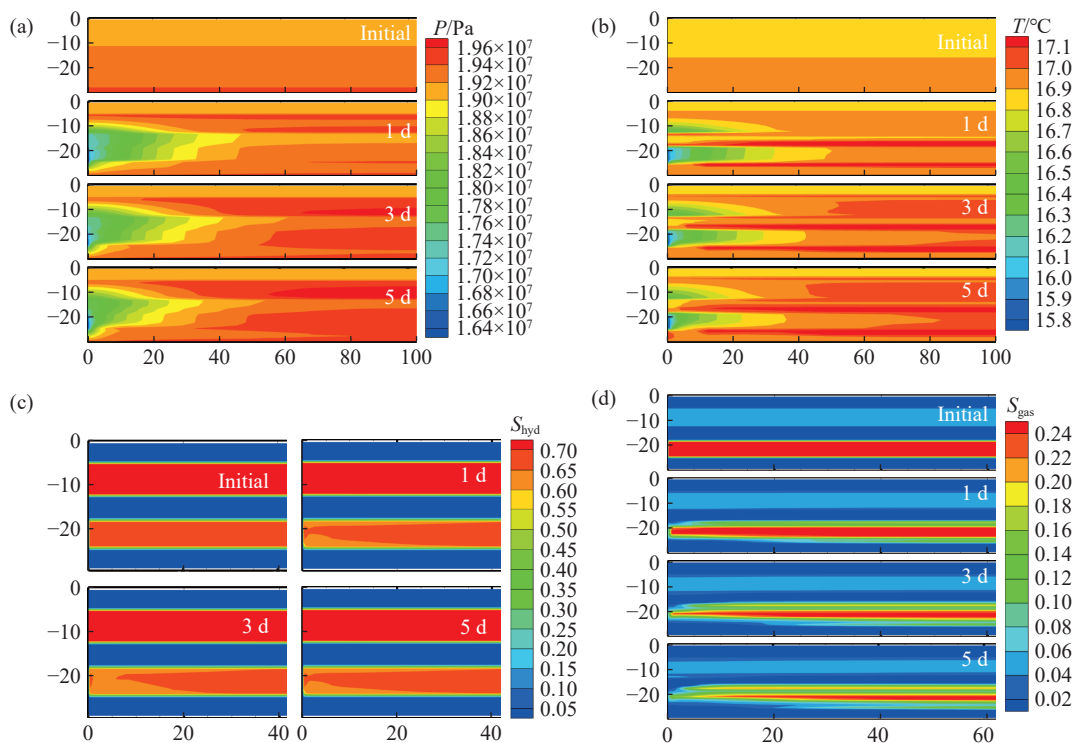


Fig. 14. Evolution of reservoir physical properties during production (Case 3, 3 MPa).

operational parameters: It increases linearly with the production pressure differential, reflecting the dominance of pressure-driven Darcy flow, and rises non-linearly with higher initial gas saturations under constant pressure drawdown.

(ii) Significant differences in pressure propagation exist between layers, where the underlying free gas facilitates propagation while hindering it within the hydrate layer; this imbalance, coupled with upward gas migration, forms a high-saturation gas band at the interface that triggers secondary hydrate formation. Because the reservoir state is near the phase equilibrium curve, these disturbances easily shift the thermodynamic balance. Near the wellbore, the endothermic dissociation of hydrates combined with the Joule-Thomson effect from gas inflow creates a distinct low-temperature zone, a phenomenon observed in both the hydrate layer and the hydrate-bearing gas layer due to the sealing effect of the interlayer.

(iii) During the short-term testing period, the phase transition within the overlying hydrate layer remains minimal and exerts negligible influence on the productivity of the shallow gas zones. The wellbore output is predominantly sustained by the underlying free gas, which serves as the primary energy and gas source.

(iv) To achieve efficient exploitation, the balance between hydrate dissociation and secondary formation must be managed through precise operational control. Additionally, integrating thermal stimulation, such as circulating heated fluids, can shift the localized thermodynamic state outside the hydrate stability zone, effectively inhibiting secondary formation and maintaining high-conductivity pathways for the underlying gas influx.

CRediT authorship contribution statement

Cong Li conceived of the study, prepared the original draft, and contributed to formal analysis, data curation, and manuscript revision. Na Wei contributed to methodology development, investigation, resource coordination, funding acquisition, and manuscript editing. Hai-tao Li was responsible for visualization, data curation, and conceptualization. Shou-wei Zhou, Lie-hui Zhang, Jin-zhou Zhao, and Bjørn Kvamme contributed to conceptualization, project administration, and critical revision of the manuscript. Zhong-xia Wang, Di Nie, Qing He, Jun Wang, Zhi-hao Xia, and Yu Qin participated in visualization, formal analysis, and data curation. All authors reviewed and approved the final manuscript.

Declaration of competing interest

The authors declare no conflicts of interest.

Acknowledgment

This work was financially supported by the National Key Research and Development Program (2023YFC2811002, 2021YFC2800903), National Natural Science Foundation of

China (U2444216), 111 Project (D21025), and High-end Foreign Expert Introduction Program (G2021036005L).

References

- Bian H, Qin XW, Luo WJ, Ma C, Zhu J, Lu C, Zhou YF. 2022. Evolution of hydrate habit and formation properties evolution during hydrate phase transition in fractured-porous medium. *Fuel*, 324, 124436. doi: [10.1016/j.fuel.2022.124436](https://doi.org/10.1016/j.fuel.2022.124436).
- Chen XJ, Lu HL, Gu LJ, Shang SL, Zhang Y, Huang X, Zhang L. 2022. Preliminary evaluation of the economic potential of the technologies for gas hydrate exploitation. *Energy*, 243, 123007. doi: [10.1016/j.energy.2021.123007](https://doi.org/10.1016/j.energy.2021.123007).
- Cox D, Huuse M, Newton A, Sarkar A, Knutz P. 2021. Shallow gas and gas hydrate occurrences on the northwest Greenland shelf margin. *Marine Geology*, 432, 106382. doi: [10.1016/j.margeo.2020.106382](https://doi.org/10.1016/j.margeo.2020.106382).
- Cranganu C. 2009. In-situ thermal stimulation of gas hydrates. *Journal of Petroleum Science and Engineering*, 65(1–2), 76–80. doi: [10.1016/j.petrol.2008.12.028](https://doi.org/10.1016/j.petrol.2008.12.028).
- Goel N. 2006. In situ methane hydrate dissociation with carbon dioxide sequestration: Current knowledge and issues. *Journal of Petroleum Science and Engineering*, 51(3–4), 169–184. doi: [10.1016/j.petrol.2006.01.005](https://doi.org/10.1016/j.petrol.2006.01.005).
- He YL, Liang JQ, Kuang ZG, Deng W, Ren JF, Lai HF, Meng MM, Zhang W. 2022. Migration and accumulation characteristics of natural gas hydrates in the uplifts and their slope zones in the Qiongdongnan Basin, China. *China Geology*, 5(2), 234–250. doi: [10.31035/cg2022004](https://doi.org/10.31035/cg2022004).
- Hui GG, Li SZ, Guo LL, Zhang GX, Gong YH, Somerville I, Zhang Y, Zheng QL, Zang YB. 2016. Source and accumulation of gas hydrate in the northern margin of the South China Sea. *Marine and Petroleum Geology*, 69, 127–145. doi: [10.1016/j.marpetgeo.2015.10.009](https://doi.org/10.1016/j.marpetgeo.2015.10.009).
- Konno Y, Fujii T, Sato A, Akamine K, Naiki M, Masuda Y, Yamamoto K, Nagao J. 2017. Key findings of the world's first offshore methane hydrate production test off the coast of Japan: Toward future commercial production. *Energy and Fuels*, 31(3), 2607–2616. doi: [10.1021/acs.energyfuels.6b03143](https://doi.org/10.1021/acs.energyfuels.6b03143).
- Kurihara M, Sato A, Funatsu K, Ouchi H, Yamamoto K, Numasawa M, Narita H, Masuda Y, Dallimore S, Wright F, Ashford D. 2010. Analysis of Production Data for 2007/2008 Mallik Gas Hydrate Production Tests in Canada. *International Oil and Gas Conference and Exhibition in China*, Beijing, China, June 2010. doi: [10.2118/132155-MS](https://doi.org/10.2118/132155-MS).
- Li G, Li XS, Tang LG, Zhang Y. 2007. Experimental investigation of production behavior of methane hydrate under ethylene glycol injection in unconsolidated sediment. *Energy and Fuels*, 21(6), 3388–3393. doi: [10.1021/ef060644d](https://doi.org/10.1021/ef060644d).
- Li JF, Ye JL, Qin XW, Qiu HJ, Wu NY, Lu HL, Xie WW, Lu JA, Peng F, Xu ZQ, Lu C, Kuang ZG, Wei JG, Liang QY, Lu HF, Kou BB. 2018. The first offshore natural gas hydrate production test in South China Sea. *China Geology*, 1(1), 5–16. doi: [10.31035/cg2018003](https://doi.org/10.31035/cg2018003).
- Li P, Fan ZQ, Zhao L., Li MX, Yang CL, He K, Wang DY. 2024. Mechanistic understanding of sand production in marine hydrate exploitation: Insights from field tests and THMC simulations. *Energy and Fuels*, 38(14), 12730–12740. doi: [10.1021/acs.energyfuels.4c01227](https://doi.org/10.1021/acs.energyfuels.4c01227).
- Li P, Fan ZQ, Zhao L, Yang CL, He K, Wang DY. 2025. Underestimated risks for application of hydraulic fracturing into hydrate exploitation: In the perspective of formation deformation and sand production. *Marine and Petroleum Geology*, 177, 107393. doi: [10.1016/j.marpetgeo.2025.107393](https://doi.org/10.1016/j.marpetgeo.2025.107393).
- Li XS, Xu CG, Zhang Y, Ruan XK, Li G, Wang Y. 2016. Investigation

- into gas production from natural gas hydrate: A review. *Applied Energy*, 172, 286–322. doi: [10.1016/j.apenergy.2016.03.101](https://doi.org/10.1016/j.apenergy.2016.03.101).
- Li YL, Dong L, Wu NY, Nouri A, Liao HL, Chen Q, Sun JY, Liu CL. 2021. Influences of hydrate layered distribution patterns on triaxial shearing characteristics of hydrate-bearing sediments. *Engineering Geology*, 294, 106375. doi: [10.1016/j.enggeo.2021.106375](https://doi.org/10.1016/j.enggeo.2021.106375).
- Li YL, Yu GQ, Xu M, Ou WJ, Niu CC, Jiang HY, Zhang YJ, Wu NY, Sun JS. 2022. Interfacial strength between ice and sediment: A solution towards fracture-filling hydrate system. *Fuel*, 330, 125553. doi: [10.1016/j.fuel.2022.125553](https://doi.org/10.1016/j.fuel.2022.125553).
- Lu C, Qin XW, Sun JS, Wang R, Cai JC. 2023. Research progress and scientific challenges in the depressurization exploitation mechanism of clayey-silt natural gas hydrates in the northern South China Sea. *Advances in Geo-Energy Research*, 10(1), 14–20. doi: [10.46690/ager.2023.10.03](https://doi.org/10.46690/ager.2023.10.03).
- Moridis G. 2003. Numerical studies of gas production from methane hydrates. *SPE Journal*, 8(4), 359–370. doi: [10.2118/87330-PA](https://doi.org/10.2118/87330-PA).
- Nair V, Ramesh S, Ramadass G, Sangwai J. 2016. Influence of thermal stimulation on the methane hydrate dissociation in porous media under confined reservoir. *Journal of Petroleum Science and Engineering*, 147, 547–559. doi: [10.1016/j.petrol.2016.09.017](https://doi.org/10.1016/j.petrol.2016.09.017).
- Ohgaki K, Takano K, Sangawa H, Matsubara T, Nakano S. 1996. Methane exploitation by carbon dioxide from gas hydrates—phase equilibria for CO₂-CH₄ mixed hydrate system. *Journal of Chemical Engineering of Japan*, 29(3), 478–483. doi: [10.1252/jcej.29.478](https://doi.org/10.1252/jcej.29.478).
- Pang XQ, Jia CZ, Xu Z, Hu T, Bao LY, Pu TY. 2025. Application of the whole petroleum system in the evaluation of the global natural gas hydrate resource. *Petroleum Exploration and Development*, 52(2), 301–315. doi: [10.1016/S1876-3804\(25\)60568-4](https://doi.org/10.1016/S1876-3804(25)60568-4).
- Pei JX, Liu ET, Song P, Yan DT, Luo W, Zhan JM, Wang ZZ, Li GP, Uysal I, Yang PF. 2024. Influencing factors and model of shallow gas enrichment in the Quaternary sediments of the Qiongdongnan Basin, South China Sea. *Journal of Marine Science and Engineering*, 12(11), 1928. doi: [10.3390/jmse12111928](https://doi.org/10.3390/jmse12111928).
- Qin XW, Lu C, Wang PK, Liang QY. 2022. Hydrate phase transition and seepage mechanism during natural gas hydrates production tests in the South China Sea: A review and prospect. *China Geology*, 5(2), 201–217. doi: [10.31035/cg2022029](https://doi.org/10.31035/cg2022029).
- Schoderbek D, Farrell H, Howard J, Rateman K, Silpngrarnlert S, Martin K, Smith B, Klein P. 2013. ConocoPhillips Gas Hydrate Production Test. Technical Report, U.S. Department of Energy. <https://www.osti.gov/biblio/1123878>.
- Sloan ED, Koh CA. 2008. *Clathrate Hydrate of Natural Gases*: 3rd Edition. Boca Raton, CRC Press, 1–752. doi: [10.1201/9781420008494](https://doi.org/10.1201/9781420008494).
- Su PB, Wei WW, Sun YB, Lü YY, Cheng H, Han WF, Zhang W, Liang JP. 2024. Geological reservoir and resource potential (10¹³ m³) of gas hydrates in the South China Sea. *China Geology*, 7(3), 422–444. doi: [10.31035/cg2024069](https://doi.org/10.31035/cg2024069).
- Sun QL, Wu SG, Cartwright J, Dong DD. 2012. Shallow gas and focused fluid flow systems in the Pearl River Mouth Basin, northern South China Sea. *Marine Geology*, 315–318, 1–14. doi: [10.1016/j.margeo.2012.05.003](https://doi.org/10.1016/j.margeo.2012.05.003).
- Sun WT, Pei J, Wei N, Zhao JZ, Xue J, Zhou SW, Zhang LH, Kvamme B, Li QP, Li HT, Jiang L, Zhang C, Li C. 2021. Sensitivity analysis of reservoir risk in marine gas hydrate drilling. *Petroleum*, 7(4), 427–438. doi: [10.1016/j.petlm.2021.10.013](https://doi.org/10.1016/j.petlm.2021.10.013).
- Villano L, Kommedal R, Fijten M, Schubert U, Hoogenboom R, Kelland M. 2009. A study of the kinetic hydrate inhibitor performance and seawater biodegradability of a series of poly (2-alkyl-2-oxazoline)s. *Energy and Fuels*, 23(7), 3665–3673. doi: [10.1021/ef900172f](https://doi.org/10.1021/ef900172f).
- Wan ZF, Xu X, Wang XQ, Xia B, Sun YF. 2017. Geothermal analysis of boreholes in the Shenhu gas hydrate drilling area, northern South China Sea: Influence of mud diapirs on hydrate occurrence. *Journal of Petroleum Science and Engineering*, 158, 424–432. doi: [10.1016/j.petrol.2017.08.053](https://doi.org/10.1016/j.petrol.2017.08.053).
- Wang DY, Ma XJ, Qiao J. 2013. Impact factors of natural gas hydrate dissociation by depressurization: A review. *Advanced Materials Research*, 868, 564–567. doi: [10.4028/www.scientific.net/AMR.868.564](https://doi.org/10.4028/www.scientific.net/AMR.868.564).
- Wang HB, Yang SX, Wu NY, Zhang GX, Liang JQ, Chen DF. 2013. Controlling factors for gas hydrate occurrence in Shenhu area on the northern slope of the South China Sea. *Science China Earth Sciences*, 56(4), 513–520. doi: [10.1007/s11430-013-4596-3](https://doi.org/10.1007/s11430-013-4596-3).
- Wei JG, Liang JQ, Lu JG, Zhang W, He YL. 2019. Characteristics and dynamics of gas hydrate systems in the northwestern South China Sea—Results of the fifth gas hydrate drilling expedition. *Marine and Petroleum Geology*, 110, 287–298. doi: [10.1016/j.marpetgeo.2019.07.028](https://doi.org/10.1016/j.marpetgeo.2019.07.028).
- Wei N, Bai R, Zhao JZ, Zhang Y, Xue J. 2021. The prospect of natural gas hydrate (NGH) under the vision of Peak Carbon Dioxide Emissions in China. *Petroleum*, 7(4), 357–363. doi: [10.1016/j.petlm.2021.11.001](https://doi.org/10.1016/j.petlm.2021.11.001).
- Wei N, Li C, Zhao XX, Li HT, Zhang LH, Zhao JZ, Kvamme B, Coffin R. 2024. Numerical simulation of depressurization exploitation in class 1 hydrate reservoirs under different development factors in Shenhu area, South China sea. *Frontiers in Earth Science*, 12, 20–24. doi: [10.3389/feart.2024.1444690](https://doi.org/10.3389/feart.2024.1444690).
- Wu NY, Li YL, Wan YZ, Sun JY, Huang L, Mao PX. 2021. Prospect of marine natural gas hydrate stimulation theory and technology system. *Natural Gas Industry B*, 8(2), 173–187. doi: [10.1016/j.ngib.2020.08.003](https://doi.org/10.1016/j.ngib.2020.08.003).
- Wu SG, Sun J, Li QP, Ma YS, Lüdmann T. 2024. Potential on joint development of three-gas reservoirs in the Qiongdongnan Basin. *The Innovation Geoscience*, 2, 100065. doi: [10.59717/j.xinngeo.2024.100065](https://doi.org/10.59717/j.xinngeo.2024.100065).
- Yamamoto K, Wang, XX, Tamaki M, Suzuki K. 2019. The second offshore production of methane hydrate in the Nankai Trough and gas production behavior from a heterogeneous methane hydrate reservoir. *RSC Advances*, 9(45), 25987–26013. doi: [10.1039/C9RA00755E](https://doi.org/10.1039/C9RA00755E).
- Yang L, Wang ZF, Shi KJ, Ge Y, Li QP, Leng SY, Zhou Y, Zhang LX, Zhao JF, Song YC. 2024. Upward migration of the shallow gas enhances the production behavior from the vertical heterogeneous hydrate-bearing marine sediments. *Energy*, 307, 132612. doi: [10.1016/j.energy.2024.132612](https://doi.org/10.1016/j.energy.2024.132612).
- Ye HY, Zhang Q, Yao YX, Duan J, Chen DY, Lu HL, Wu XZ, Li DY, Jiang YJ, Zi MC. 2025. Co-production of gas hydrates, shallow gas, and deep gas in the Qiongdongnan Basin: A pathway to commercial production. *Applied Energy*, 384, 125482. doi: [10.1016/j.apenergy.2025.125482](https://doi.org/10.1016/j.apenergy.2025.125482).
- Ye JL, Qin XW, Xie WW, Lu HL, Ma BJ, Qiu HJ, Liang JQ, Lu JA, Kuang ZG, Lu C, Liang QY, Wei SP, Yu YJ, Liu CS, Li B, Shen KX, Shi HX, Lu QP, Li J, Kou BB, Song G, Li B, Zhang HE, Lu HF, Ma C, Dong YF, Bian H. 2020. The second natural gas hydrate production test in the South China Sea. *China Geology*, 3(2), 197–209. doi: [10.31035/cg2020043](https://doi.org/10.31035/cg2020043).
- Zhao JF, Zhu ZH, Song YC, Liu WG, Zhang Y, Wang DY. 2015. Analyzing the process of gas production for natural gas hydrate using depressurization. *Applied Energy*, 142, 125–134. doi: [10.1016/j.apenergy.2014.12.071](https://doi.org/10.1016/j.apenergy.2014.12.071).
- Zhu WL, Shi HS, Huang BJ, Zhong K, Huang YW. 2021. Geology and geochemistry of large gas fields in the deepwater areas, continental margin basins of northern South China Sea. *Marine and Petroleum Geology*, 126, 104901. doi: [10.1016/j.marpetgeo.2021.104901](https://doi.org/10.1016/j.marpetgeo.2021.104901).