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Economic evaluation of production capacity for natural gas hydrate industrial exploitation in the South China Sea

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Natural gas hydrate (NGH) is a worldwide strategic and prospecting commercial resource in the 21st century. The industrialization of NGH has great strategic significance for the achievement of peak carbon dioxide emissions and carbon neutrality. Prior to its industrialization, an economic evaluation of production capacity for each well per day should be conducted to determine whether it is profitable at different given gas prices. In this study, a new hybrid method based on the discounted cash flow (DCF) method and the energy return on investment (EROI) method is used to estimate the economic production rate of NGH exploitation at four different gas price scenarios. The results show that the lowest production rate to make NGH exploitation economic ranges from 1.96 to 29.60 × 10^4 m^3/d/well. With the change in the number of wells, gas–water ratio, gas price, decreasing rate in production cost, and sensitivity analysis are carried out. It shows that all these key factors have a significantly negative effect on the economic production rate initially, and then the sensitivity to the economic production rate will become lower and lower with the rising value of each key factor.

KEYWORDS

natural gas hydrate (NGH), economic evaluation, discounted cash flow (DCF), energy return on investment (EROI), economic production rate

1 Introduction

Over the past two centuries, industrial civilization has brought about substantial progress but also caused increasingly severe environmental and climate problems. A low carbon transformation of energy use is the key pillar to reducing CO_2 emissions toward a carbon neutral world. Renewable energy like solar and wind energy may dominate our energy mix completely in the future, but considering its tiny contribution to energy supply at present, the timing is still very uncertain (Michael and Arthur, 2019). According to the

BP Statistical Review of World Energy, renewable energy accounts for only about 18% of the world's total primary energy consumption in 2021 (BP, 2022). In the transition to a low-carbon energy future, natural gas is considered a clean, efficient energy source that will likely become an important alternative to coal and oil and a transitional fuel for renewable energy (Javed, 2016; Zheng et al., 2016). With rapid global industrialization, the world's demand for natural gas will grow sharply in the coming decades and will reach 4.9 trillion cubic meters (tcm) by 2040 (Sanja, 2021).

As conventional natural gas resources become depleted, exploration for unconventional gas resources is becoming increasingly important (Vedachalam et al., 2015; Kong et al., 2018). Natural gas hydrate (NGH), an ice-like carrier substance for natural gas formed by gas molecules and water molecules under high-pressure and low-temperature conditions (Sloan and Koh, 2007), is an unconventional gas resource and contains the largest gas resources remaining on the Earth. It is estimated that the gross carbon reserve of NGH is about twice as much as the total reserve of all the other fossil energy including oil, coal, and natural gas (Makogon, 1981; Kvenvolden, 1988; Englezos, 1993). NGH has been discovered worldwide in polar regions, normally associated with onshore and offshore permafrost, and in the sediment of outer continental and insular margins, with 90% of the ocean serving as potential areas for NGH deposits (Kvenvolden, 1993). In theory, when appropriate hydrate expansion factors are considered, 1 m^3 of NGH contains up to 164 m^3 of natural gas at standard conditions (Kvenvolden, 1993). According to preliminary estimates, the total global NGH reserve is approximately 1.5×10^4 tcm (Makogon et al., 2005), which is large enough to replace the increasingly depleted traditional oil and gas resources. As a result, NGH is a worldwide strategic and prospecting commercial resource concerned by many countries in the 21st century (Makogon et al., 2005), and its industrialization has great significance for the world's energy mix optimization, green development, and the achievement of peak carbon dioxide emissions and carbon neutrality.

Natural gas from NGH deposits can be theoretically produced by one or a combination of three main methods (Moridis and Sloan, 2007): 1. depressurization, in which the pressure is reduced below the equilibrium value at the system temperature; 2. thermal stimulation, in which the temperature is raised above the equilibrium value at the system pressure; and 3. injection of inhibitors such as salt and/or alcohol, by which the thermodynamic hydrate stability boundary is shifted to lower temperatures and higher pressures, thus inducing dissociation and gas release. Depressurization is thought to be the most technically efficient means of production from NGH deposits (Walsh et al., 2009; Michael and Arthur, 2019).

Over the last two decades, China has been attaching great importance to research on gas hydrate and has found a total amount of approximately 84 tcm of NGH reserves onshore and offshore, including the South China Sea, the East China Sea, and the Qinghai–Tibet Plateau, nearly 77% of which is distributed in the South China Sea (Tan et al., 2016). In 2013 and 2016, two NGH reserves with natural gas resources of more than 100 billion m^3 each were discovered in the eastern offshore area of the Perl River Mouth basin and Shenhu area in the South China Sea (Yang et al., 2017). The NGH industrialization consists of five general stages, namely, the theoretical research and simulation experiment, the exploratory production test, the experimental production test, the productive production test, and the commercial production stages (Hao, 2022). In 2017, China successfully conducted its first offshore exploratory production test from clayey silt reservoirs, the most widely distributed NGH reservoirs in the world. It lasted for 60 days continuously and stably, yielding cumulative gas production of 30.9×10^4 m^3 (Li et al., 2018). Three years later, the second major leap was evidenced by the experimental production test in 2020. This time it achieved 30 days of continuous gas production and set a new world record for cumulative gas production of 86.14×10^4 m^3 (Ye et al., 2020). Because of these great successes, China has now entered the stage of productive production test and is accelerating its steps to achieve commercial development of NGH by 2030.

Like other conventional and unconventional resources, prior to NGH industrialization, it is necessary to conduct an economic evaluation to determine whether it is profitable or not (Chen et al., 2022a). There exist a lot of factors that can affect the economic feasibility of an NGH exploitation project. Meanwhile, economic production is rare and may be the most important one (Wu et al., 2020). Unfortunately, since now, only a few quantitative analyses of the economic production rate have been carried out. Based on previous studies on NGH industrialization (Yamamoto et al., 2014; Yang et al., 2014; Li et al., 2018; Ye et al., 2020), Wu et al. (2020) proposed that the economic production rate for terrestrial NGH industrial exploitation is 30×10^4 m^3/d/well, while for marine reservoirs, it should be no less than 50×10^4 m^3/d/well. Compared with several trial productions before, both capacities are still two or three orders of magnitude higher than those of pilot production tests (Figure 1). However, the economic production rate for profitable NGH industrial exploitation is not always fixed, and it may decrease with the development of low-cost exploitation technologies.

In recent years, some scholars have started to try to conduct economic evaluations of NGH exploitation, mostly with the method of energy return on investment (EROI) or the method of discounted cash flow (DCF). Kong et al. (2018) carried out an estimation of China's production efficiency of NGH in the South China Sea based on different production capacities. The results show if the production rate for a single well can reach 2.3×10^4 m^3/d with a 12-year production life, the standard energy return on investment is 1.25, indicating the net energy delivered to society by NGH production is positive. Chen et al. (2022b) calculated each EROI of four NGH exploitation

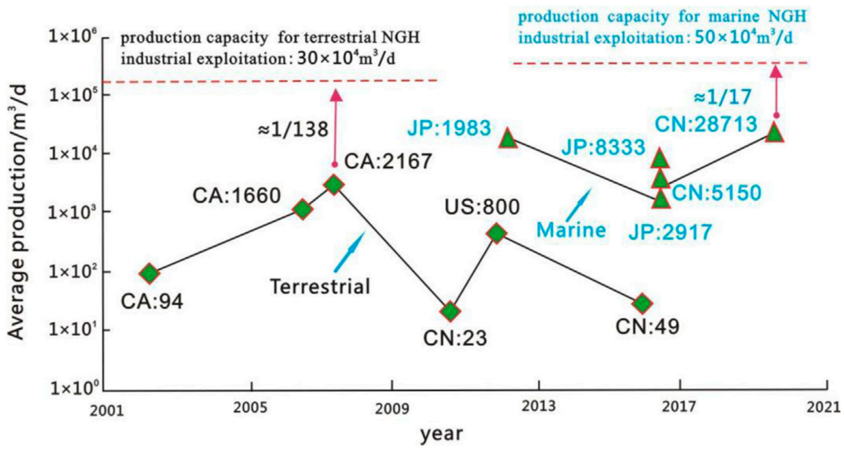

FIGURE 1
Average production capacity of NGH production tests in the world and the economic production rate for terrestrial and marine NGH industrial exploitation (Wu et al., 2020). CN means China, JP means Japan, CA means Canada, and US means the United States. The number after the country abbreviation represents the average daily production capacity of gas hydrates' production tests.

technologies to evaluate the economic potential. She illustrated that compared with thermal simulation, chemical injection, and CO_2 replacement, depressurization is the most economically feasible, with the lowest economic production rate of about 16–25 × 10^4 m^3/d per well. Walsh et al. (2009) presented a preliminary report on the economics of gas production from NGH with the method of discounted cash flow (DCF). According to the results, \$12/Mscf (about \$10.6/MMBtu) is the lowest gas price that would allow economically viable production from gas hydrates in the absence of associated free gas, while an underlying gas deposit will reduce the viability price estimate to \$7.50/Mscf (about \$6.62/MMBtu). The results also reported that the production cost for marine hydrate is \$3.5–4.00/Mscf (about \$3.1–3.5 MMBtu) more expensive than a conventional gas project given a 15% internal rate of return (IRR). Deepak et al. (2019) undertook a techno-economic study of a defined deepwater hypothetical gas hydrate accumulation in the Krishna–Godavari (KG) Basin located along the eastern margin of India. The economic evaluation suggested that when the predicted production rate reaches 600 × 10^4 m^3/d, the production cost will be \$9/MMBtu, which means economically viable. Based on the currently assumed production system and gas production behavior, the MH21-S R&D consortium (MH21-S, 2019) described the criteria for NGH commercial production after conducting the economic evaluation of hypothetical hydrate accumulations located in the Nankai Trough, Japan. The calculation results presented that when the LNG price is \$10/MMBtu, the production rate per well required for commercial production is about 15 × 10^4 m^3/d or more. Since the technology for commercial exploitation of NGH has not been established yet, exploring the economic production rate is critical to understanding the gap between pilot production tests and the final realization of commercialization. Notably, few studies focusing on the evaluation of the economic production rate for NGH industrial exploitation in the South China Sea have been conducted till now due to the lack of enough field data.

The objective of this article is to estimate the economic production rate required for the industrialization of gas hydrate at different gas prices from an economic point of view and to figure out the key factors affecting production capacity. For evaluation of the economics, calculating capital expenditure (CAPEX) and operating expenditure (OPEX) data are the two fundamental prerequisites. Although the exploitation of marine NGH is similar in many respects to that of offshore conventional gas, there are still some differences in a number of ways, some of which will have a significant effect on the overall economics (Walsh et al., 2009). Unlike conventional gas that can be produced by natural flow, NGH should be first dissociated into a fluid phase (gas and water) that can consume energy (Yamamoto and Nagakubo, 2021). In addition, because the water production from a gas hydrate reservoir could be highly variable, a gas hydrate development will require artificial lift such as electric submersible pumps (ESPs) or gas lift, which will also increase front-end costs in most cases, as well as operating costs over the life of the field (Walsh et al., 2009). On this basis, when the method of discounted cash flow (DCF) is applied, OPEX fully refers to an offshore gas project just as many of the evaluations reviewed previously may cause a large deviation. As for the energy return on investment (EROI) method, it is pretty hard to reasonably calculate CAPEX and OPEX data in energy terms due to the lack of enough available data for trial production tests. As an alternative solution, the authors use a hybrid model, which is widely used in the energy sector (Li and Zhang, 2018, Li and

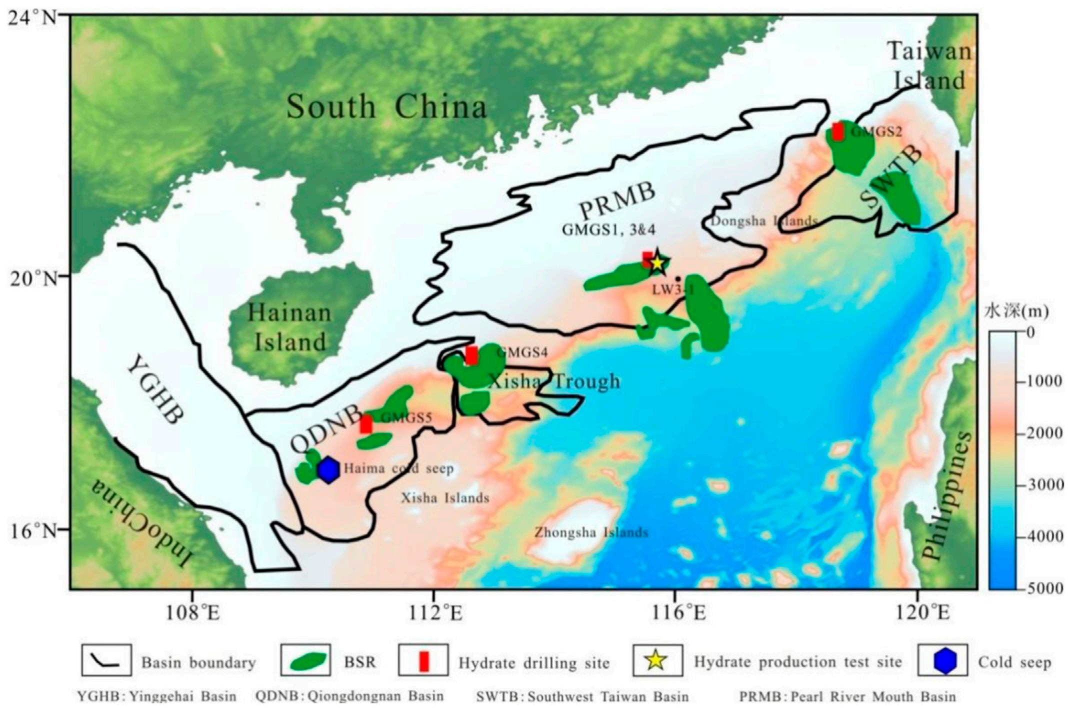

FIGURE 2
Depositional basins and gas hydrate surveying in the northern South China Sea. BSR, bottom simulating reflector (modified from Wu and Wang (2018) and Liang et al. (2019))

Zhang, 2019) and which combines both discounted cash flow (DCF) and energy return on investment (EROI) to estimate the economic production rate required for NGH industrial exploitation at different gas prices. Section 2 describes the method of discounted cash flow (DCF) and energy return on investment (EROI) and proposes a novel DCF-EROI hybrid model. Section 3 makes a range of assumptions for economic evaluation and gives data estimation of key parameters used in the model. Based on Section 3, Section 4 presents the study results and discussion in four different gas price scenarios. Section 5 carries out sensitivity analyses to reduce the uncertainty resulting from the limited data, and Section 6 states the conclusion.

2 Methodology

2.1 Discounted cash flow method

Discounted cash flow (DCF) analysis values of cash flows by bringing them to the present, and its result is known as the net present value (NPV), which is probably the most popular and most sophisticated economic valuation technique to determine whether a project yields a return in excess of the alternative equal risk investment in trade securities (Žižlavský, 2014; Hou, 2016). NPV compares the value of net cash flows today to the value of the same net cash flows in the future, taking inflation and returns into account (Donald, 2012; Bosri, 2019). Here, in this research, expenditure and sales revenue were estimated for hypothetical NGH reservoirs in Shenhu area of the northern South China Sea (Figure 2).

The equation of NPV can be expressed as follows:

$$NPV = \sum_{t=1}^{n} (CI - CO)_t (1 + r)^{-t},$$

where NPV = net present value; CI = cash inflow; CO = cash outflow; $(CI - CO)_t$ = net cash flow generated by innovation project in year t; r = discount rate.

The future net cash flows are computed by subtracting the capital expenditure (CAPEX), operating expenditure (OPEX), and taxes (Tax) from the gas sales revenue (R_gP_g), a product of gas production (R_g) and gas price (P_g). The field tests in China and Japan have demonstrated that conventional offshore gas production facilities can be used for gas hydrate exploitation (Yamamoto et al., 2014; Li et al., 2018; Ye et al., 2020). Therefore, it is reasonable to refer CAPEX, including the cost of production platforms ($C_{platform}$), well drilling and completions (C_{well}), subsea system (C_{subsea}), pipeline construction ($C_{pipeline}$), and field abandonment ($C_{abandonment}$), to those of offshore gas. As mentioned earlier, OPEX can't be fully referred to the cost of offshore gas. It should constitute $OPEX_1$, referring to the operating cost of offshore gas ($C_{operation}$) and $OPEX_2$, including dissociation costs ($C_{dissociation}$) and artificial lift costs (C_{lift}).

Then, the NPV becomes

$$NPV = \sum_{t=1}^{n} \frac{R_g P_g - \left(C_{platform} + C_{well} + C_{subsea} + C_{pipline} + C_{abandonment} + C_{operation} + C_{dissociation} + C_{lift} + Tax\right)}{(1+r)^t}.$$

Here, the economic production rate, which means the minimum production that is needed to make NGH exploitation financially profitable, is calculated when the final net present value can then be estimated either as zero given a certain discount rate. Then, the economic production rate equals R_g when

$$NPV = \frac{R_g P_g - \left(C_{platform} + C_{well} + C_{subsea} + C_{pipline} + C_{abandonment} + C_{operation} + C_{dissociation} + C_{lift} + Tax\right)}{(1+r)^t}.$$

2.2 Energy return on investment method

The concept of energy return on investment (EROI) was first proposed by Hall and Cleveland (1981). Rather than purely monetarily, the EROI is a useful measure to examine the energetic efficiency of energy processes and systems (Cleveland et al., 1984; Cleveland, 1992).

The equation of EROI can be expressed as follows:

$$EROI = \frac{Energy\ outputs\ (return)}{Energy\ inputs\ (invested)}.$$

Since energy costs (energy outputs and energy inputs) can be converted into currency costs (cash inflow and cash outflow) by dividing the energy intensity, the energy consumed for NGH dissociation ($E_{dissociation}$) and artificial lift (E_{lift}) can be obtained by theoretical estimation.

$E_{dissociation}$ resulted from NGH dissociation is described by energy consumption for each cubic meter of gas produced, which differs for different production methods. For the depressurization method, the energy input is caused by an electric submersible pump (ESP) to lower the pressure during gas production, which can be estimated by Chen et al. (2022b):

$$E_{dissociation} = T_p * P_{ESP} * H_{elec},$$

where T_p = total production time; P_{ESP} = ESP power; H_{elec} = heating value per KWh of electricity.

E_{lift} is lifting energy input for produced fluid. It is a product of the drainage discharge, vertical depth, and corresponding consumption factor (Zeng et al., 2015), as expressed by Kong et al. (2018):

$$E_{lifting} = M_{water} * D_{well} * I_{ESP} * H_{elec},$$

where M_{water} = the amount of water; D_{well} = lifting height, which equals water depth plus well depth; H_{elec} = heating value per KWh of electricity; I_{ESP} = effective power of the electrical submersible pump.

Therefore, according to all the previous equations, $OPEX_2$ can be estimated by

$$OPEX_2 = \left(T_p * P_{ESP} * H_{elec} + M_{water} * D_{well} * I_{ESP} * H_{elec}\right) / * EI,$$

where EI = energy intensity.

3 Assumptions and data estimation

3.1 Assumptions of the model

As the longest gas production period of a marine NGH production test was approximately 2 months in the world (Ye et al., 2020), the long-term gas production behavior is still uncertain, which means there remain various levels of uncertainties such as the number of production wells and the capacity of production facilities for future commercial production. Therefore, for economic evaluation, it is necessary to make a range of assumptions to supplement such uncertain parameters (Table 1).

3.2 Data estimation

As discussed previously, CAPEX and operating expenditure $OPEX_1$ can be referred to an offshore gas project, and they are generated using IHS Energy Que$tor™ planning software and costing database. For $OPEX_2$, it can be estimated by converting energy consumed for NGH decomposition and water lifting into currency. All the key parameters used in this study are referred to simulation and experimental results in the literature (Table 2, 3).

4 Results and discussion

For economic evaluation of gas hydrate exploitation, the economic production rate for each well is one of the most important factors, and it is obviously affected by the market gas price, which has a significant impact on total sales revenue (cash inflows). Due to the variability, it is pretty difficult to predict future gas prices. In this study, four gas price scenarios are assumed with the gas–water ratio set at 100, which is close to the data observed in the first offshore production test of methane hydrates in the eastern Nankai Trough (Yamamoto et al., 2014). The first scenario is at the gas price of $6.15/MMBtu, the average price of China's imported pipeline gas in

TABLE 1 Conditions/assumptions for economic evaluation.

Items	Condition/assumption
Reservoir	Assumed the research is based on hypothetical NGH reservoirs at scientific drilling expedition sites GMGS1, GMGS2, GMGS3, GMGS4, and GMGS 5 conducted by Guangzhou Marine Geological Survey (Figure 2)
	Specific geological conditions, such as porosity and permeability, and production potential are not taken into consideration
Production methods (including production behavior)	Depressurization method is used
	No exchange of heat or fluid between the inside and outside areas
	During the production period, the gas production rate is constant
	Almost has the same production profile as an offshore gas field
Capital expenditure	All the capital investments including drilling wells are completed in the first year
Operating expenditure	Affected by offshore gas technology and the energy consumed for NGH dissociation and gas-water lift
Tax	Tax exemptions due to NGH exploitation are a new industry need of support
Cash inflow	Revenue all comes from gas produced and sold on the domestic market at a given price

TABLE 2 Key parameters used in DCF-EROI analysis.

Parameter	Value	Unit	References
Production life	30	Year	Estimated
Energy intensity	5.994	MJ/$2011	World (2012)
ESP power	50	KW	Wang (2015)
IESP	0.01	kWh/m^3•m	Zeng et al. (2015)
H_{elec}	3.6	MJ/kWh	Kong et al. (2018)

December 2021. The second scenario is assumed at the price of $10/MMBtu, the LNG price used by the MH21-S R&D consortium for economic evaluation. The third one is at $18.93/MMBtu, representing the average price of China's imported LNG in December 2021. The last scenario is at the price of $35.4/MMBtu, the CIF price of China's imported spot LNG in August 2022. Table 4 summarizes the economic production rates at sites GMGS1, GMGS2, GMGS3, GMGS4, and GMGS5 in the South China Sea, changing with the number of production wells in these four scenarios. Compared with the previous economic evaluations resulting from the literature reviewed earlier (Deepak et al., 2019; MH-21S, 2019; Wu et al., 2020), the calculation results are nearly within the same order of magnitude, which implies the economic production rates estimated could be regarded reasonable.

As shown in Table 4, under the same conditions of production life and gas–water ratio, economic production rates in the South China Sea are highly dependent on the gas price, ranging from 1.96 to 29.60 × 10^4 m^3/d/well. Given a certain gas price, the economic production rate needed differs at different sites but not very significantly. This is because the eight NGH sites are located in the similar geological condition with near water depth, costing similar capital expenditure and operating expenditure. In addition, all economic production rates at these sites will decrease with the increase of production wells, which may be resulted from the lower marginal costs for each well. Additionally, Table 4 also shows the effect of gas price and the number of wells on the economic production rate vary from site to site. Here, the GMGS4-SC1 site and GMGS5-W9 are taken for example. In most cases, the economic production rate at the GMGS4-SC1 site is a little lower than that at the GMGS5-W9 site with the same gas price and the number of wells, but this situation will reverse when the LNG price is $35.4/MMBtu, and the number of wells is more than 30. The reason causing such an interesting phenomenon is maybe the sensitivity of gas price and well number on economic production rate changes when these two key factors change by themselves, which will be analyzed in Section 5.

In the case of an actual pipeline gas price of $6.15/MMBtu in late 2021, the gas produced from NGH is certainly not competitive against imported pipeline gas at the current stage. In this scenario, the average economic production rate per well should be about 12.96–29.6 × 10^4 m^3/d, almost 4–10 times higher than the rate recorded in the second production test in Shenhu area, South China Sea (Ye et al., 2020). In other words, there is still a big gap between the gas production efficiency of actual production tests and that required for commercial production.

Based on the LNG price of $10/MMBtu, the economic production rates range from 7.45 to 13.26 × 10^4 m^3/d/well, lower than 15 × 10^4 m^3/d/well estimated by the MH21-S R&D consortium (MH-21S, 2019). This may be caused by the different expected well production life in the two models. In this study, the production life for each well is 30 years, while the parameter used by the MH21-S R&D consortium is 8 years. Considering that most of the life span investigated for simulation of gas hydrate exploitation is about 20–30 years or even longer (Cleveland, 1992; Walsh et al., 2009; Yamamoto and Nagakubo, 2021; Chen et al., 2022a; Chen et al., 2022b), it is more reasonable

TABLE 3 Key parameters for hypothetical NGH reservoirs.

Expedition	Site	Water depth (m)	Mbsf	Expedition time	References
GMGS1	SH2	1,230	200	2007	Yang (2013) and Zhang et al. (2018)
	SH7	1,108	160	2007	Li and Li (2011) and Zhang et al. (2018)
GMGS2	G8	798	80	2013	Wang et al. (2016)
	G16	896	218	2013	Feng et al. (2015)
GMGS3	W19	1,274	156	2015	Sun et al. (2017) and Liang et al. (2022)
	W11	1,274	206	2015	Zhang et al. (2019)
GMGS4	SC1	1,286	150	2016	Wei et al. (2018), Zhang et al. (2019)
GMGS5	W9	1722	168	2018	Liang et al. (2019)

TABLE 4 Economic production rates for NGH industrial exploitation at different natural gas prices, changed with the number of production wells.

Gas price		Pipeline gas $6.15/MMBtu					LNG $10/MMBtu				
Site	Well	20	30	40	50	60	20	30	40	50	60
Economic production rate threshold (10^4 m^3/day/well)											
GMGS1	SH2	22.74	17.98	16.66	16.97	15.87	11.59	9.53	8.61	8.65	8.20
	SH7	21.27	16.90	15.64	15.92	14.90	11.24	9.26	8.37	8.41	7.97
GMGS2	G8	18.38	14.73	13.58	13.77	12.96	10.43	8.63	7.80	7.81	7.45
	G16	19.55	15.51	14.26	14.54	13.58	10.65	8.73	7.87	7.92	7.49
GMGS3	W19	22.99	18.24	16.93	17.24	16.14	11.72	9.67	8.74	8.79	8.34
	W11	23.28	18.39	17.05	17.37	16.24	11.72	9.64	8.71	8.75	8.29
GMGS4	SC1	23.85	19.06	17.78	18.10	17.00	12.14	10.09	9.18	9.21	8.77
GMGS5	W9	29.60	23.26	21.83	22.23	20.78	13.26	10.95	9.93	9.96	9.45

Gas price		LNG $18.93/MMBtu					LNG $35.4/MMBtu				
Site	Well	20	30	40	50	60	20	30	40	50	60
Economic production rate threshold (10^4 m^3/day/well)											
GMGS1	SH2	5.26	4.33	3.85	3.93	3.67	2.67	2.20	1.96	1.99	1.86
	SH7	5.21	4.29	3.83	3.90	3.65	2.67	2.20	1.96	2.00	1.87
GMGS2	G8	5.06	4.19	3.74	3.79	3.57	2.64	2.19	1.95	1.98	1.86
	G16	5.03	4.13	3.67	3.74	3.49	2.59	2.13	1.89	1.93	1.80
GMGS3	W19	5.32	4.39	3.92	3.99	3.73	2.70	2.23	1.99	2.02	1.89
	W11	5.29	4.35	3.87	3.94	3.69	2.68	2.20	1.96	2.00	1.87
GMGS4	SC1	5.51	4.57	4.11	4.18	3.92	2.79	2.32	2.08	2.12	1.99
GMGS5	W9	5.63	4.65	4.15	4.23	3.95	2.79	2.30	2.05	2.09	1.96

to assume a longer production life span of about 30 years for economic evaluation.

In the scenario of the LNG price of $18.93/MMBtu, it may look pretty promising to exploit gas hydrate with the economic production rate per well 3.67–5.63× 10^4 m^3/d, which can be achieved by some enhancement recovery methods like dual horizontal wells, etc. (MH-21S, 2019; Wu et al., 2020). In addition, when the LNG price is as high as $35.4/MMBtu, it means gas hydrate could be commercially developed with the lowest production rate needed of only 1.86 × 10^4 m^3/d. However, considering the longest production life in trial tests to now is just about 60 days (Li et al., 2018), and the maximum gas produced from production tests over the last two decades is only a total of 8.6 × 10^5 m^3 (Ye et al., 2020), there is still a long way to extract natural gas from NGH at a production rate of 1.86 × 10^4 m^3/d

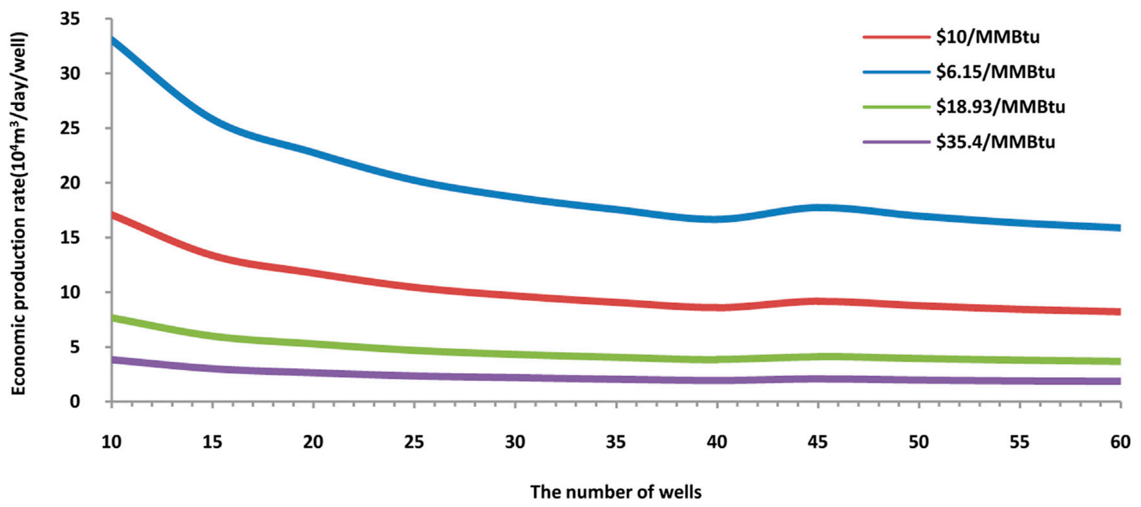

FIGURE 3
Sensitivity analysis of the number of wells on economic production rates at different gas prices with the gas–water ratio set at 100.

for nearly 30 years, which will have a cumulative gas production of about 122.2×10^8 m^3.

5 Sensitivity analysis

High economic production rate results from high cash inflows and low cash outflows over the production life span. As discussed earlier, a lot of factors can affect cash flows, such as the number of wells, gas price, production life, gas-water ratio, etc. In this section, taking the GMGS1-SH2 site as an example for the discussion, a sensitivity analysis is conducted to better understand the effect of four key factors on economic production rate.

As shown in Figure 3, when the number of wells increases, all economic production rates would generally decrease. However, the degree of decline is quite different for different gas prices. The lower the gas price, the faster the economic production rate drops with the rising number of wells. This may be explained by the fact that lower gas price causes lower cash inflows, making the economic production rate more sensitive to cash outflows resulting from drilling more wells. Meanwhile, even at the same gas price, the economic production rate also varies at different levels. Initially, when the number of producing wells increases, the curve of the economic production rate will decline and become more and more flat. While, when the well number reaches about 40, the economic production rate suddenly goes up and then goes down again when the well number arrives at about 47. After that, the curve will become nearly horizontal very slowly. A reasonable interpretation for the variation is that if the number of production wells is less than 40, wells may share the same facilities such as platforms or FPSO (floating production storage and offloading), resulting in the marginal cost for drilling a new well becomes less. Once the well number hits the threshold, another new platform may be needed, and more expenditure will cost.

When the gas-water ratio changes, the energy input for the artificial lift will be different, causing the gas production cost to fluctuate. Similar to the sensitivity analysis on the number of wells, we refine the gas–water ratio to analyze its sensitivity to economic production rate. Figure 4 shows that with the rise of the gas–water ratio, the economic production rate will rapidly drop down from a very high peak and, then the magnitude of the decline becomes smaller and smaller. This is because when the assumed gas price is lower than the cost of lifting produced water, it is impossible to compensate the production cost by sales revenue, no matter how much natural gas is produced. On the other hand, if the gas price is higher than the unit production cost, the higher the gas–water ratio, the less impact it will have on the economic production rate. When the gas–water ratio is higher than 200, the impact is very low; if it is as high as 1,000 or more, the effect of the gas–water ratio can be negligible.

As discussed previously, gas price will directly determine cash inflows. A high gas price means a low economic production rate needed based on the same conditions. Figure 5 illustrates the negative correlation between the economic production rate and natural gas price. Apparently, with a lower number of wells, the gas price has a higher sensitivity to the economic production rate. However, when the number of production wells is more than 40, the gas

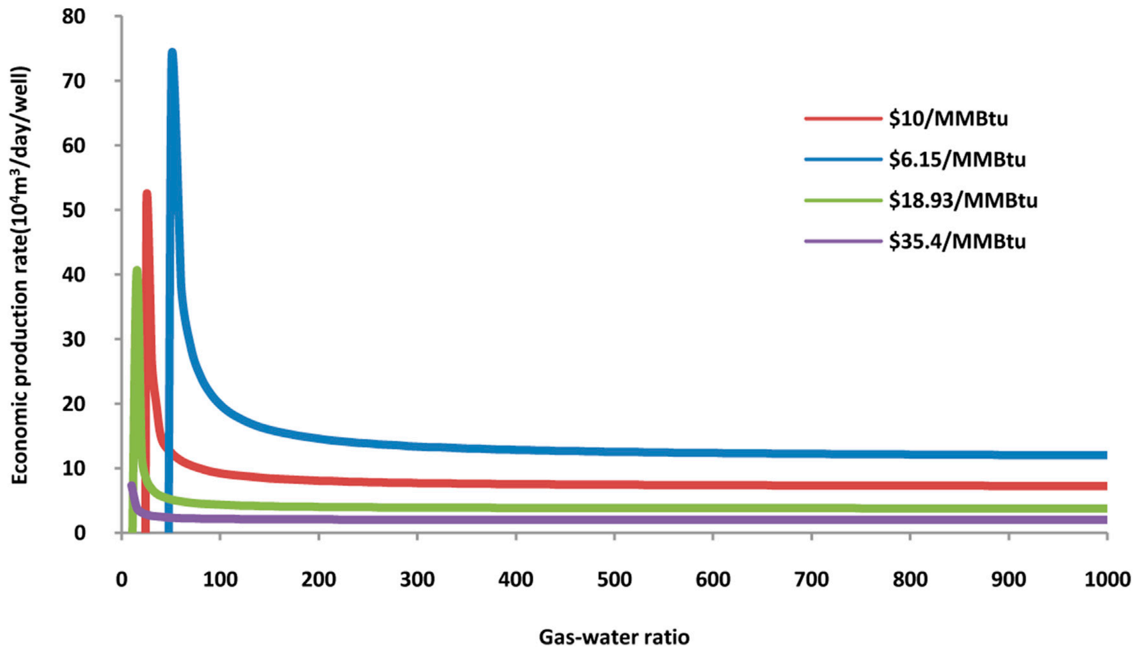

FIGURE 4
Sensitivity analysis of the gas–water ratio on economic production rate at different gas prices with the number of wells set at 30.

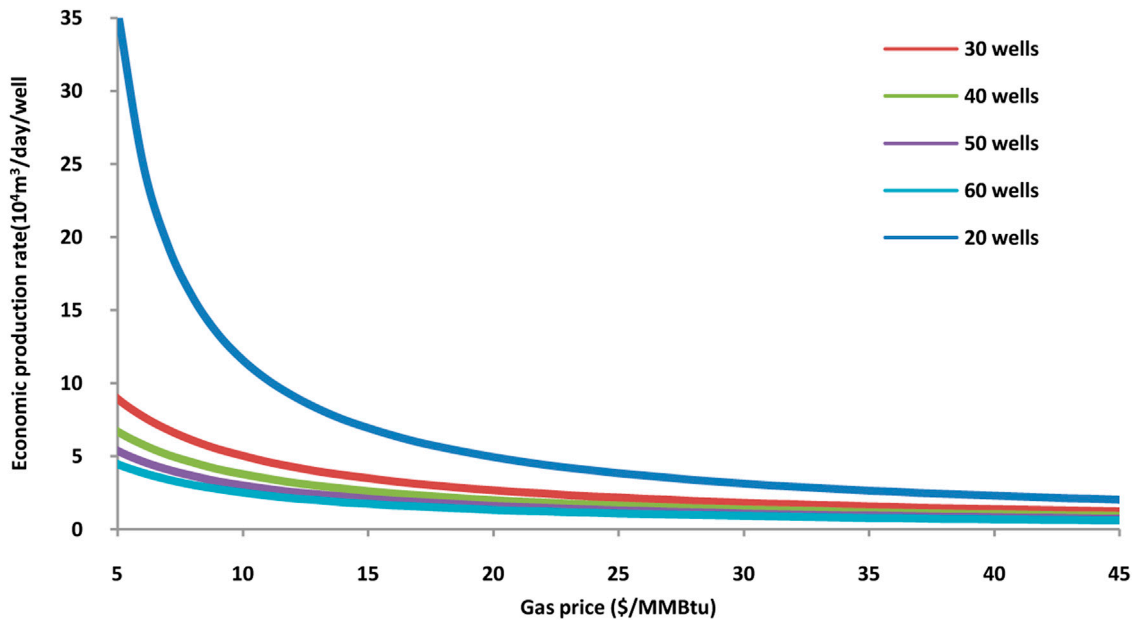

FIGURE 5
Sensitivity analysis of the gas price on economic production rate with the different number of wells with the gas–water ratio set at 100.

price has no obvious effect on the economic production rate.

To accelerate the pace of hydrate industrialization, promoting production capacity and reducing the production cost through technological progress are the two main ways. Figure 6 describes the impact of different rates of decreasing production costs on the economic production rate. Gas price

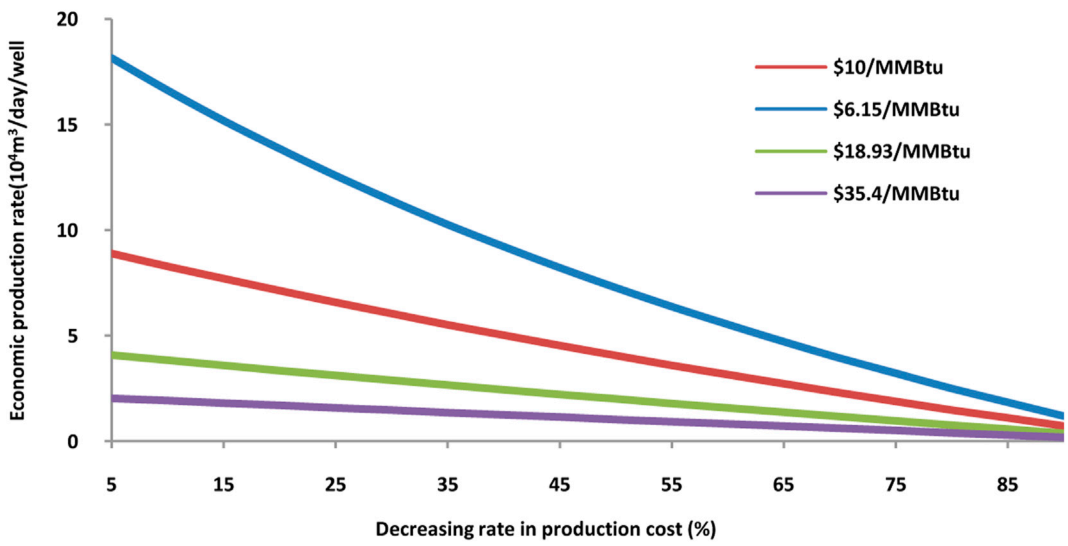

FIGURE 6
Sensitivity analysis of the decreasing rate on economic production rate at different gas prices with the gas–water ratio and the number of wells set at 100 and 30, respectively.

fluctuations make the economic production rate go down at different rates. Similar to the gas–water ratio and the number of wells, the lower gas price has stronger negative correlations with the economic production rate. Based on the previous analysis, it is reasonable to conclude that at a lower natural gas price, it is more necessary to develop gas hydrate exploitation technology to reduce production costs.

6 Conclusion

NGH is a strategic resource with a huge natural gas production potential. The industrialization of NGH has great significance for the achievement of peak carbon dioxide emissions and carbon neutrality. Economic evaluation is a prerequisite for NGH industrial exploitation. In this study, the economic production rate for industrial exploitation of NGH in different parameter scenarios, such as gas price, the number of wells, gas–water ratio, and decreasing rate in production cost, is estimated with a new hybrid method based on the discounted cash flow (DCF) method and the energy return on investment (EROI) method, and the following results are obtained:

1) The economic production rate of natural gas hydrate at sites GMGS1, GMGS2, GMGS3, GMGS4, and GMGS5 in the South China Sea is quantified in four scenarios with different gas prices. Changing the number of wells from 20 to 60, the economic production rate ranges from 1.96 to 29.60 × 10^4 m^3/d/well.
2) In a low gas price market, drilling more wells can decrease the economic production rate quickly at first, but when the number of wells reaches a certain number, it has little effect on the economic production rate.
3) Gas–water ratio has a limited impact on economic production when it is higher than 200. To make gas hydrate exploitation profitable, the lowest gas price must be higher than the cost for lifting produced water.
4) Gas price has a strong negative correlation with the economic production rate. Higher gas prices usually mean more cash inflows and lower economic production rate needed.
5) Reducing gas production costs is necessary to make gas hydrate exploitation competitive against other kinds of natural gas, especially at a low gas price.

Data availability statement

The original contributions presented in the study are included in the article/Supplementary Material; further inquiries can be directed to the corresponding author.

Author contributions

LW: methodology, formal analysis, and writing—original draft. TZ: review and editing. HZ: supervision. YS: figure drawing. XY: editing and supervision. MM: figure drawing.

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Conflict of interest

Authors LW, TZ, YS, and MM were employed by the Development and Research Center, China Geological Survey, China Geological Survey, and Oil and Gas Survey, China Geological Survey.

The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

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