Advances in Geo-Energy Research

Vol. 7, No. 2, p. 90-98, 2023

Original article

Gas production from marine gas hydrate reservoirs using geothermal-assisted depressurization method

Md Nahin Mahmood*, Boyun Guo

Department of Petroleum Engineering, University of Louisiana, Lafayette, LA 70504, USA

Keywords:
Gas hydrate
dissociation temperature
production forecast
depressurization method
geothermal

Cited as:
Mahmood, M. N., Guo, B. Gas production from marine gas hydrate reservoirs using geothermal-assisted depressurization method. Advances in Geo-Energy Research, 2023, 7(2): 90-98.
https://doi.org/10.46690/ager.2023.02.03

Abstract:
Natural gas production from marine gas hydrate reservoirs has become attractive to the oil and gas industry in recent years. It is still a great challenge to recover natural gas from hydrate reservoirs efficiently mainly due to sand production and wellbore collapse problems associated with the production scheme of depressurization. The thermal recovery method has not been proven economical due to the high cost of energy consumption. This study focuses on using geothermal energy to assist the depressurization process so that well pressure drawdown can be reduced and thus sand production and wellbore collapse problems can be mitigated. The authors investigated the transfer of heat energy from a natural geothermal zone to a marine gas hydrate reservoir and its effect on gas well productivity using analytical models. The result of our investigation shows that the initial well productivity can be significantly improved using geothermal energy more than 10-fold. This work provides engineers with an analytical tool for the feasibility analysis of using geothermal energy to improve well performance in gas hydrate reservoirs.

1. Introduction

Methane gas hydrates are crystalline structures of ice and methane. The methane molecules are trapped inside cages of water molecules. When methane hydrate is depressurized and/or heated, it decomposes to give off water and natural gas. Methane hydrate reserves, also known as “fire ice”, exist around the globe offshore. In general, mud, sand, permafrost, and the seafloor are the common source of methane hydrates. The proportion of this resource is thought to be higher than the combined proportion of all other fossil fuels (Allison, 2008). Methane hydrate resources are considered as the major source of natural gas to support the future of world economic development (Dawe and Thomas, 2007).

High-pressure and low-temperature environments are most suitable for gas hydrate formation in the presence of sufficient gas and water such as that under permafrost and in oceanic sediment (Blunier, 2000). Researchers found different models to describe the gas hydrate formation mechanism, but the consensus states that the origin of the concentrated methane in naturally occurring hydrates is either microbial (generated by anaerobic decomposition of organic matter) or thermogenic (produced by thermal decomposition of organic matter) (Kvenvolden, 1993; Sloan and Kah, 2008). There are four important components associated with the formation of solid-gas hydrates (Nelson et al., 2000): hydrocarbon phase, water phase, low temperature, and high pressure. In high-pressure and low-temperature conditions, low-molecular-weight hydrocarbons, such as C1-C4, iC4-iC5, and nC5 along with CO_2 and H_2S are physically captured by water inside a hydrogen-bonded solid lattice (Moreno et al., 2009). These molecules, capable of existing both in vapor or liquid state and can be miscible or immiscible in water, are termed “hydrate formers”. Hydrate-formation tendencies of fluid are dictated by several factors namely, gas composition, produced fluid salinity, temperature, and pressure conditions (Nelson et al., 2000).

Recent investigation shows that the world’s oceanic surfaces contain an ample amount of gas hydrate reserve. The outcome of producing from gas hydrate is also significant. Research experience states that by melting one cubic meter of

Yandy Scientific Press

*Corresponding author.
E-mail address: nahin2582@gmail.com (M. N. Mahmood); boyun.guo@louisiana.edu (B. Guo).

Received September 27, 2022; revised October 27, 2022; accepted November 20, 2022; available online November 24, 2022.

hydrates 170 cubic meters of gas can be released. This justifies the rapidly growing interest in gas hydrate extraction by oil and gas companies (Stewart et al., 1995). The development of marine gas hydrate resources presents a huge challenge to the energy industry due to well production complications such as sand production, wellbore collapse, and low productivity (Mahmood et al., 2021).

The exploitation of natural gas from marine gas hydrate reservoirs is admired as a long-term solution to the upcoming energy scarcity due to the increased demand around the globe. Extensive research is ongoing worldwide to implement the most useful techniques for exploiting this huge natural source of energy. These researches include a broader area from investigations of petrophysical properties and geological characterization of reservoirs to the implementation in field pilot studies (Guo and Zhang, 2022). The field pilot projects are giving practical insights to the researchers regarding the critical issues and challenges that obstruct the commercial production of natural gas from gas hydrates. Out of various challenges relating to gas hydrates, one of the primary aspects that have been dragged the most attention is the method of production of this gas resource. Generally, to induce hydrate dissociation there are three main methods are in practice. They are the (1) depressurization method, (2) thermal stimulation method, (3) thermodynamic inhibitor injection method, and (4) a combination of some of these methods (Mahmood and Guo, 2021; Guo and Zhang, 2022).

The depressurization method reduces the pressure in the natural gas hydrates below the hydrate dissociation pressure and liberates the natural gases to be produced on the surface (Ahmadi et al., 2007; Li et al., 2016). On the other hand, in the thermal stimulation method, hot water or brine is injected into the gas hydrate deposit to raise the temperature of the hydrates above the hydrate dissociation temperature (Li et al., 2006; Kawamura et al., 2007; Li et al., 2008). The other method named the thermodynamic inhibitor injection method involves chemical injection (salts and alcohols), to change the equilibrium conditions of hydrate pressure-temperature (Kawamura et al., 2005; Najibi et al., 2009). Apart from these, some combinations of the methods were reported by some other researchers including Moridis and Reagan (2007a, 2007b). But unfortunately, none of these methods are proven perfect standalone due to unique limitations and extremely adverse challenges. For example, the thermal method is slow, costly, and requires a lot of energy input for hydrate dissociation. Besides, the inhibitor injection method is constrained by several factors notably, the concentration of injected chemical inhibitors, the rate of injection, and the hydrate-inhibitor interfacial tension (Mahmood and Guo, 2021). Inhibitors (salts and alcohols) can also shift the equilibrium of pressure-temperature (Makogon, 1997).

The depressurization technique is treated as the most familiar and cost-effective technique, but the gas production volume is usually low. Besides, as the dissociation of the natural gas hydrate is a highly endothermic process, the technique results in a Joule-Thompson cooling effect and reduction of the prevailing gas hydrate temperature condition (Mahmood and Guo, 2021). Kurihara et al. (2005) reported that the local temperature of the hydrate formation can drop steeply, and the well productivity is prone to be affected by the formation of secondary hydrate near the producing wellbore which facilitates flow restrictions or chocking. Researchers like Hong and Pooladi-Darvish (2005), Moridis and Reagan (2007a) suggested that the dissociation of natural gas hydrates is dominated mainly by heat transfer. This concept was verified by Qin et al. (2020) through field testing. Therefore, it is understood that a slow and graduate change of pressure and temperature is required to maintain stable and long-term productivity from gas hydrate reservoirs by the depressurization method. But the system will not act efficiently without an external heat source. Moridis et al. (2004) investigated the matter and confirmed that a longer production life span can be achieved by the replenishment of heat into an actively producing hydrate reservoirs (Guo and Zhang, 2022). Considering these issues, the use of geothermal energy is investigated in this study as a prospective solution to assist in the efficient use of the depressurization technique.

One of the notable features of a gas hydrate reservoir involves predicting the future reservoir temperature. It is challenging to directly extract the gas from the original hydrate form as the hydrate dissociation occurs and its surrounding pressure and temperature change out of the stability zone (Dickens and Quinby, 1994). Wang et al. (2015) reported their result of analytic modeling and large-scale experimental study of mass and heat transfer during hydrate dissociation with different dissociation methods. They discovered the synergistic effect of depressurization and heat stimulation. The contribution of heat stimulation to the hydrate dissociation is larger than that of depressurization. Wang et al. (2016) performed experimental and modeling analyses of scaling criteria for methane hydrate dissociation by depressurization. They concluded that the gas production rate in the depressurization stage of field scale hydrate reservoir is considerable but is too low to satisfy the commercial production level. Wang et al. (2016) show the temperature distributions during the hydrate dissociation process for the hydrate dissociation experiments within the reactors of the pilot-scale hydrate simulator, the cubic hydrate simulator, and the small cubic hydrate simulator. According to this research, there is very little difference recorded for the changes of the temperature distributions of the sediments during hydrate dissociation by depressurization. In the depressurization stages, the temperatures in all the simulators decrease from the initial reservoir temperatures (8.5 °C) to the hydrate equilibrium temperature (5.2 °C) due to the sensible heat consumption for hydrate dissociation. In the constant pressure stages, the temperatures for all three cases gradually increase from the boundaries to the center and finally recover to the initial reservoir temperatures. The difference in the temperature distributions that occur may be due to the different hydrate distributions. Wang et al. (2018) revealed fluid flow mechanisms and heat transfer characteristics of gas recovery from gas-saturated and water-saturated hydrate reservoirs. They concluded that depressurization-assisted thermal stimulation is the optimum method for hydrate dissociation in water-saturated hydrate reservoirs.

Currently, it is still a great challenge to recover natural gas

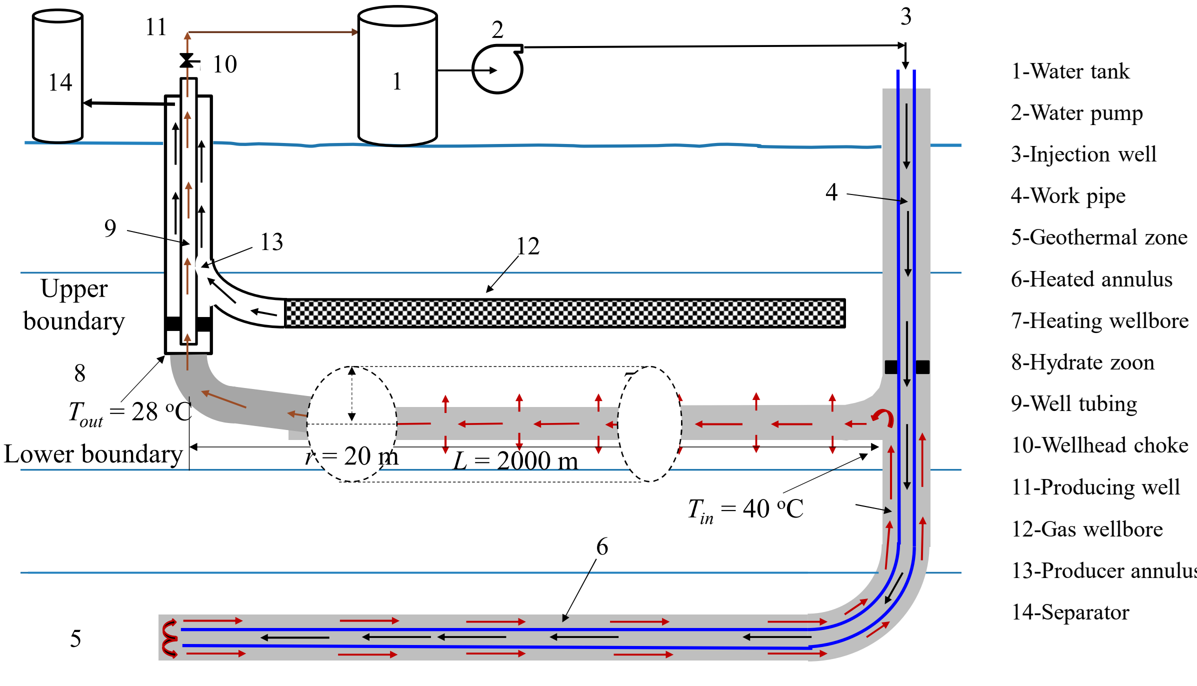

Fig. 1. Wellbore configuration for heat transfer from geothermal zone to gas hydrate reservoir (Modified from Fu et al. (2021))

from gas hydrate efficiently mainly due to sand production and wellbore collapse associated with the production scheme of depressurization. The thermal recovery method has not been proven economical due to the high cost of energy consumption. Recently, Fu et al. (2021) presented a y-shaped well couple and mathematical modeling of heat transfer for developing gas hydrate reservoirs using geothermal energy. The technique was proposed to extract gas from gas hydrate formation by transporting the natural geothermal energy from a geothermal zone to a gas hydrate zone. This technique may provide an economical energy source to dissociate the gas hydrate continuously for steady gas production. This proposed method involves the injection of a working fluid (mostly water) through an injection well inside the reservoir. This fluid is heated up by geothermal energy. This geothermally heated fluid heats the hydrate-bearing zone and causes hydrate dissociation to occur. The dissociated gas is collected through another production well. The working fluid carries the heat from the geothermal zone to the gas hydrate zone for facilitating the dissociation of methane. After heating the gas hydrates, the working fluid with a lower temperature can be recovered to the surface which can be used for re-injection. In this way, the maximum use of the remaining geothermal energy can be assured. Following Fu et al.'s (2021) work, Guo and Zhang (2022) formulated a mathematical model to predict gas hydrate reservoir temperature because of heat transfer from the geothermal fluid to the reservoir.

This study follows the work of Guo and Zhang (2022) to investigate the effect of geothermal stimulation of gas hydrate reservoirs on gas well productivity. The result of our investigation shows that the initial gas productivity of the well can be increased by over 10-fold.

2. Mathematical models

This section describes mathematical models for predicting reservoir temperature and well productivity. The former was recently presented by Guo and Zhang (2022). The latter is the model originally proposed by Joshi (1988) and modified by the latter researchers (Guo, 2019).

2.1 Heat transfer model

For predicting the future reservoir temperature inside the reservoir this work follows Guo and Zhang's (2022) work which contains the following assumptions:

1) A homogeneous and isotropic reservoir is assumed with constant density, specific heat, and thermal conductivity.
2) The reservoir is considered infinitely large as compared to the wellbore size.

Besides, as the reservoir is homogeneous, the system is assumed to have uniform permeability and the impact of varied saturations has not been considered in the model. Generally, in the depressurization method, hydrate dissociation occurs when the pressure of the formation drops to the hydrate dissociation pressure. As the pressure drops the temperature of the formation is supposed to be increased and reach a certain temperature which is usually addressed as dissociation temperature.

Fig. 1 depicts a sketch of the y-shaped wellbore couple for heat transfer from a geothermal zone to a gas reservoir zone. Assuming heat conduction only, Guo and Zhang's (2022) developed an analytical model for heat transfer from the heating wellbore to the hydrate reservoir. The resultant equations are summarized as follows.

The governing diffusivity equation for temperature is commonly expressed as:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial T}{\partial r}\right)=\frac{1}{\beta}\frac{\partial T}{\partial t} \tag{1}$$

where T is the temperature in °C, r is the distance from the wellbore center line in m, t is time in s, and β is the thermal diffusivity constant defined by:

$$\beta=\frac{K}{\rho c} \tag{2}$$

where K is thermal conductivity in W/(m·°C), ρ is density in kg/m^3, and c is specific heat in J/(kg·°C).

The solution of Eq. (1) is sought by Boltzmann's transformation constant S:

$$S=\frac{r^2}{4\beta t} \tag{3}$$

The initial condition is expressed as:

$$T=T_i \text{ at } t=0 \text{ for all } r \tag{4}$$

where T_i is the initial reservoir temperature in °C. The boundary condition at the wellbore is expressed as:

$$q_{r_w}=-K\left[\frac{dT}{dr}\right]_{r=r_w} \quad \text{for all } t \tag{5}$$

where q_{rw} is the rate of flow of heat per unit time per unit area of the wellbore in J/(s·m^2). For a circular wellbore with radius r_w and length L, the following relation holds:

$$q_{rw}=\frac{Q_{rw}}{2\pi r_w L} \tag{6}$$

where Q_{rw} is the rate of flow of heat per unit time in J/s. Substituting Eq. (6) into Eq. (5) and rearranging the latter gives:

$$\frac{Q_{rw}}{2\pi LK}=-r_w\left[\frac{dT}{dr}\right]_{r=r_w} \quad \text{for all } t \tag{7}$$

By solving the diffusivity Eq. (1), the final equation for predicting future reservoir temperature can be presented as:

$$T=T_i+\frac{Q_{r_w}}{4\pi LK}E_i(S) \tag{8}$$

Here, the exponential integral function (E_i) function is incorporated to predict the future reservoir temperature. In mathematics, the exponential integral E_i is a function specified on the complex plane. It is defined as a definite integral of the ratio between an exponential function and its argument. Generally, it can be expressed as $E_i(x)=-\int_{-x}^{\infty}(e^{-t}dt/t)$.

The E_i in Eq. (4) is evaluated according to polynomial approximations given by Abramowitz and Stegun (1965).

The heat flow rate from the wellbore to the reservoir can be calculated by:

$$Q_{rw}=C_p\dot{m}_p(T_{in}-T_{out}) \tag{9}$$

where C_p is the heat capacity of the fluid inside the wellbore in J/(kg·°C), $\dot{m}_p$ is the mass flow rate inside the wellbore in kg/s, and T_{in} and T_{out} are fluid temperatures in °C at the inlet and outlet of the wellbore, respectively.

The model is only valid within some time limit. The maximum possible temperature is the inlet temperature. It should take an infinitely long time to approach this temperature inside the reservoir.

2.2 Well productivity model

Joshi's (1988) inflow performance relationship model for horizontal wells was modified by the latter researchers to include the effects of non-Darcy flow and pseudo-pressure (Guo, 2019). It takes the following form:

$$q_g=\frac{1}{1424T_i}\frac{k_h h[m(p_e)-m(p_{wf})]}{\ln\frac{2a+2\sqrt{a^2-(0.5L)^2}}{L}+\frac{I_i h}{L}\ln\frac{I_i h}{r_w(I_i+1)}+s+Dq_g} \tag{10}$$

where

$$a=0.5L\sqrt{0.5}+\sqrt{0.25+\left(\frac{2r_{eh}}{L}\right)^4} \tag{11}$$

$$I_i=\sqrt{\frac{k_h}{k_v}} \tag{12}$$

where q_g is gas well production rate in Mscf/day, k_h and k_v are the average horizontal and vertical permeabilities in mD, respectively, h is pay zone thickness in ft, p_e and p_{wf} are reservoir and wellbore pressures in psi respectively, m(p_e) and $m(p_w f)$ are real gas pseudo-pressures at p_e and p_{wf} respectively, L is the length of the horizontal wellbore in ft, s is Darcy skin factor, D is the non-Darcy coefficient in day/Mscf, and r_{eh} is the radius of the drainage area of the horizontal well in ft.

Pseudo-pressure is generally used for normalizing the pressure for gas viscosity and compressibility due to the variation of gas viscosity (μ_g) and compressibility (z) at different pressures in an unconventional reservoir (Guo and Ghalambor, 2012). Gas pseudo-pressure is defined as:

$$m(p)=2\int_{p_b}^{p}\frac{p}{\mu_g z}dp \tag{13}$$

The pseudo-pressure values used in this analysis are generated from the spreadsheet program PseudoPressure.xls provided by Guo and Ghalambor (2012).

It is understood that heating the gas hydrate reservoir will increase real gas pseudo-pressure proportionally. Therefore, its effect should not be considered Eq. (10). Applying (10) to both non-heated and heated reservoir conditions give:

$$q_{gnh}=\frac{1}{1424T_i}\frac{k_h h[m(p_{enh})-m(p_{wf})]}{\ln\frac{2a+2\sqrt{a^2-(0.5L)^2}}{L}+\frac{I_i h}{L}\ln\frac{I_i h}{r_w(I_i+1)}+s+Dq_g} \tag{14}$$

and

$$q_{gh}=\frac{1}{1424T_i}\frac{k_h h[m(p_{eh})-m(p_{wf})]}{\ln\frac{2a+2\sqrt{a^2-(0.5L)^2}}{L}+\frac{I_i h}{L}\ln\frac{I_i h}{r_w(I_i+1)}+s+Dq_g} \tag{15}$$

where q_{gnh} and q_{eh} are gas production rates of wells in non-heated and heated reservoirs, respectively and p_{enh} and p_{eh} are pressures of the non-heated and heated reservoirs respectively. Dividing Eq. (15) by Eq. (14) yields:

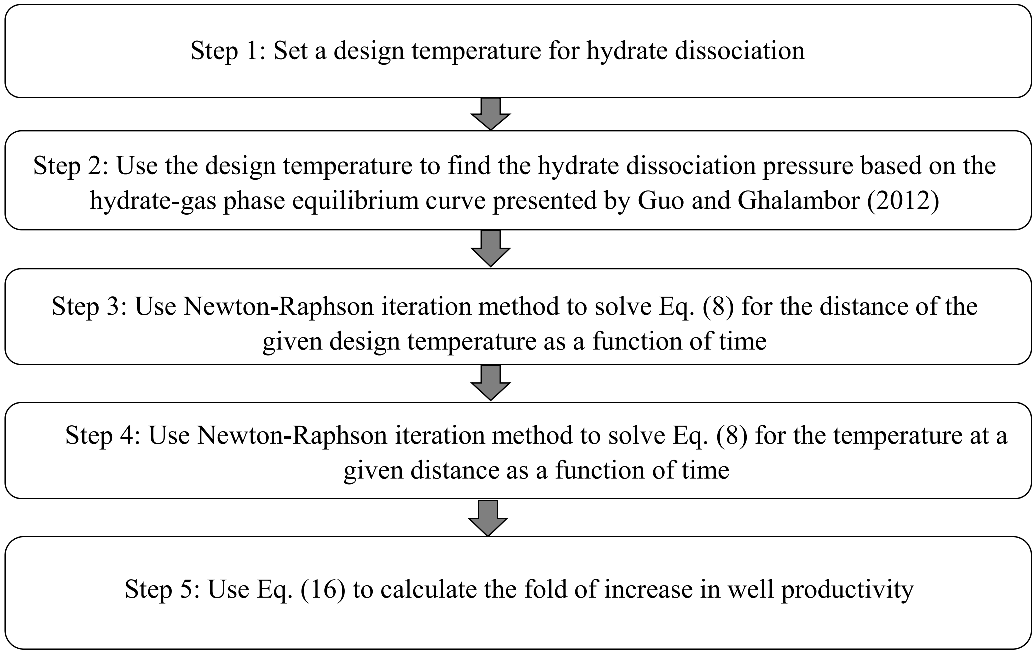

Fig. 2. Steps followed in this research.

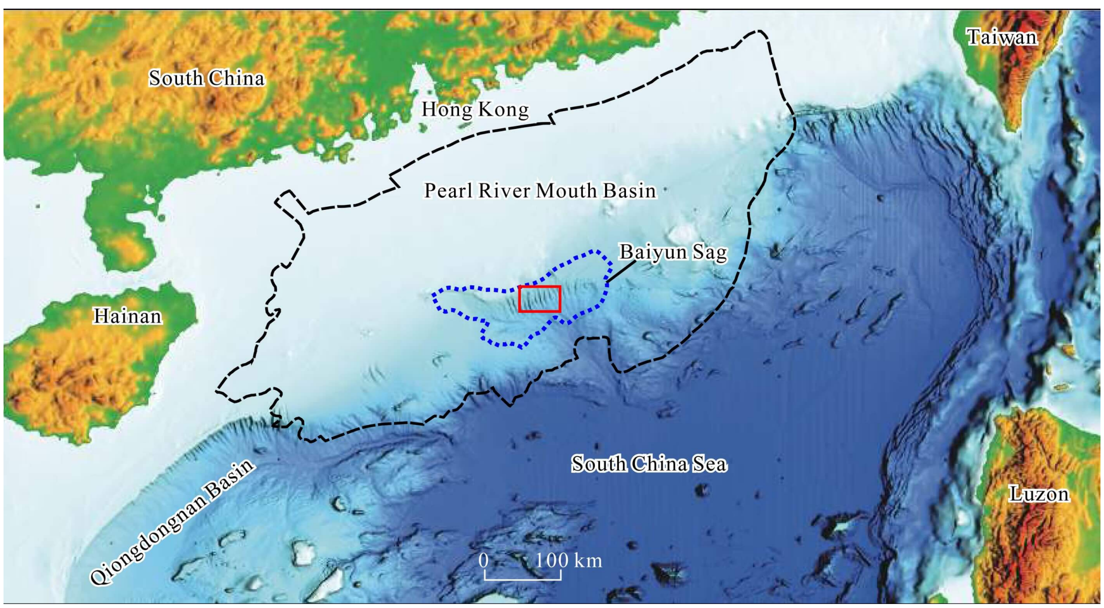

Fig. 3. Location of the gas hydrate reservoir in the Shenhu area, Northern South China Sea (Modified from Ye et al. (2020)).

$$\mathrm{FOI} = \frac{q_{gh}}{q_{gnh}} = \frac{m(p_{eh}) - m(p_{wf})}{m(p_{enh}) - m(p_{wf})} \tag{16}$$

where FOI is the fold of increase in well productivity because of reservoir heating.

For gas hydrate reservoirs containing no free gas in the initial conditions (Class 1W), no gas is expected to be produced before the reservoir pressure drops below the hydrate dissociation pressure. Therefore, the p_{enh} and p_{eh} should be determined based on the gas hydrate phase equilibrium curve using reservoir temperature as the entry parameter.

The flow chart shown in Fig. 2 were used in the Case Study presented in the next section.

3. Field case study

This section describes the FOI by geothermal stimulation using the data from the Shenhu natural gas hydrate reservoir in the middle of the North Continental Slope of the South China Sea (Liu et al., 2012). The location of the Shen hu area is shown in the red box in Fig. 3. The gas hydrate reservoir is composed of clayey silt with extremely low permeabilities ranging from 1.5 to 7.4 mD and low hydrate saturations between 11.7% and 34% (Yu et al., 2021). Table 1 provides basic data relevant to the model analysis of well productivity

Table 1. Basic data for a Shenhu well relevant to model analysis.

Parameters	Value
Hydrate reservoir depth (ft)	4,415
Pay zone thickness (ft)	78
Reservoir pressure (psia)	2,053
Initial reservoir temperature (°F)	43
Design gas wellbore depth (ft)	4,450
Design heating wellbore depth (ft)	4,448
Design gas wellbore pressure (psia)	500

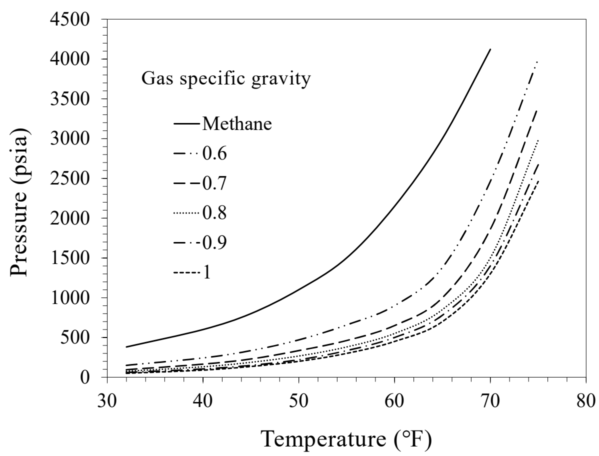

Fig. 4. Hydrate-gas phase equilibrium curves (Guo and Ghalambor, 2012).

(Su et al., 2014; Ekhator and Guo, 2021).

Fig. 4 also shows that the reservoir pressure of 2,023 psia corresponds to the gas hydrate dissociation pressure at 59 °F (15 °C). If the gas hydrate reservoir is heated to this level, the initial reservoir pressure can be taken as the driving pressure for gas flow, i.e., p_{eh} = 2,023 psia.

Table 2 provides basic data relevant to heat transfer analysis. Most parameter values are from the work of Fu et al. (2021). Fig. 5 presents a model-calculated front of the temperature 15 °C as a function of fluid circulation time. It shows that the rate of front propagation decreases with time, which is expected for a radial heat-transfer system. The curve implies that the front will propagate to the upper and lower boundaries of the gas hydrate reservoir (39 ft, or 12 m) in 0.35 years (4.26 months). This means that all gas hydrates within 39 ft from the heating wellbore will be dissociated in 4.26 months. Beyond this time of fluid circulation, the front will propagate across the upper and lower boundaries and laterally as well.

Fig. 6 illustrates temperature change over time at 20 meters from the heating wellbore. It reads that the temperature at 20 m from the heating wellbore will rise to the hydrate dissociation temperature of 15 °C in about 11 months of fluid circulation. The plot shows a plateaued trend nearly for the first 6 months as the dissociation has not been started and the temperature

Table 2. Basic data for heat transfer analysis.

Parameters	Value
Initial reservoir temperature (°C)	6
Heating horizontal wellbore radius (m)	0.1
Heating horizontal wellbore length (m)	2,000
Thermal conductivity of hydrate reservoir (W/(m·°C))	3.06
Maximum heat transfer time (days)	365
Circulation fluid density (kg/m^3)	1,030
Circulation fluid flow rate (m^3/s)	0.2
Maximum distance from heating wellbore (m)	20
Density of reservoir rock (kg/m^3)	2,600
Specific heat of reservoir rock (J/(kg·°C))	878
Fluid heat capacity inside heating wellbore (J/(kg·°C))	4,184
Fluid temperatures at the inlet/ outlet of heating wellbore (°C)	40/28

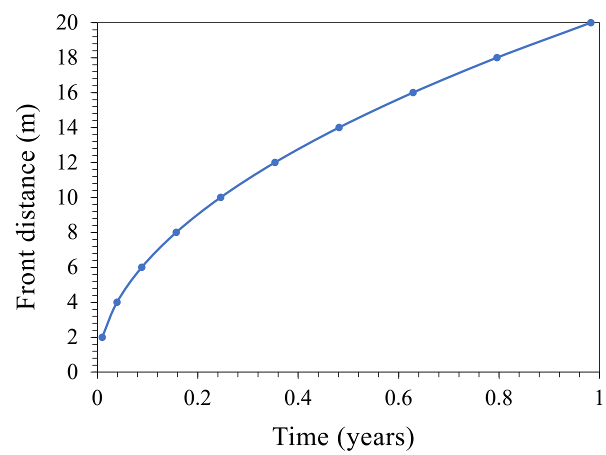

Fig. 5. Front advancement plot overtime for dissociation temperature 15 °C.

remains unchanged to the initial reservoir temperature of 6 °C or 43 °F.

The spreadsheet program PseudoPressure.xls provided by Guo and Ghalambor (2012) gives respectively:

$$\begin{aligned} m(2023) &= 369977516 \\ m(700) &= 51837405 \\ m(500) &= 27159242 \end{aligned} \tag{17}$$

Inserting these numbers into Eq. (16) gives:

$$\mathrm{FOI} = \frac{q_{gh}}{q_{gnh}} = \frac{369977516 - 27159242}{51837405 - 27159242} = 13.89 \tag{18}$$

Following the same procedure, the FOI data were obtained in the range of heated reservoir temperature between 6 °C (43 °F) and 15 °C (59 °F). The data are plotted in Fig. 7, which shows a non-linear relationship between the two variables. The rate of FOI increases sharply with the heated level of the gas hydrate reservoir.

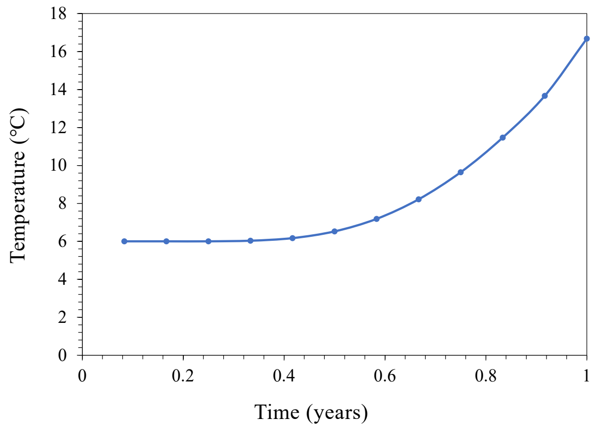

Fig. 6. Temperature change over time at 20 meters from the heating wellbore.

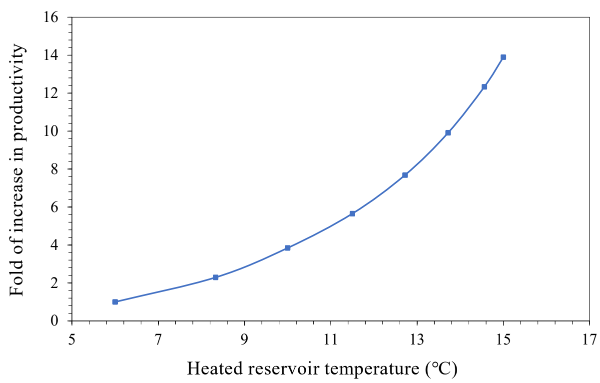

Fig. 7. Calculated fold of increase in well productivity as a function of heated reservoir temperature.

4. Discussion

The mathematical models presented in this work are subjected to errors due to the assumptions made in mathematical modeling. First, the heat transfer model was derived for a simplified process. The heat transfer model considers heat conduction only, not heat convection which can occur if the gas production has been initiated during the heating period. Due to the loss of heat to the produced gas, the model should overestimate the heat transfer efficiency. The reservoir temperature drops due to depressurization (Wang et al. 2016) were not considered in heat transfer modeling. This should also lead to over-estimated heat transfer efficiency. Heating of the dissociated gas will cause the gas pressure to increase, which should slow down the hydrate dissociation process. Second, the well productivity model assumes a Class 1W hydrate reservoir where there is no free gas in the reservoir in the initial condition. This should result in under-estimated well productivity by the model if it is applied to other types of gas hydrate reservoirs where free gas exists in the initial condition. It is understood that the well productivity model assumes that the driving pressure is the hydrate dissociation pressure at the external flow boundary of the dissociated region of the reservoir. Because the boundary distance is time-dependent and controlled by heat transfer efficiency, the well productivity should also be fluid-circulation time-dependent.

5. Conclusions

The study employed heat transfer and well productivity models to investigate the productivity of gas wells in geothermal-stimulated gas hydrate reservoirs. A case study was carried out using data from a gas hydrate reservoir in the Shenhu area, Northern South China Sea. The following conclusions are drawn:

1) The heat conduction model dictates that the rate of heat-front propagation inside a gas hydrate reservoir decreases with time, which is expected for a radial heat-transfer system. The model result indicates that, in the studied gas hydrate reservoir, the heat front will propagate to the upper and lower boundaries of the gas hydrate reservoir (39 ft, or 12 m) in 0.35 years (4.26 months). This means that all gas hydrates within 39 ft from the heating wellbore will be dissociated to release gas in 4.26 months.
2) Compared to the well in a non-heated gas hydrate reservoir, geothermal heating can increase initial well productivity by more than 10 times. The FOI in well productivity grows non-linearly with heated reservoir temperature. The rate of FOI increases sharply with the heated level of the gas hydrate reservoir.
3) The mathematical models presented in this work may over-predict well productivity in geothermal-stimulated reservoirs due to the assumptions made in the deviation of mathematical models. Further studies are needed to consider the effects of heat convection, temperature drop due to depressurization, gas pressure increase due to heating, and the existence of free gas in the hydrate reservoir.

Acknowledgements

The authors are grateful to the Chittagong University of Engineering & Technology and the University of Louisiana at Lafayette for their cordial support to this research work.

Conflict of interest

The authors declare no competing interest.

References

Abramowitz, M., Stegun, I. A. Handbook of Mathematical Functions with Formulas, Graphs, and Mathematical Tables. Washington DC, USA, US Department of Commerce, 1965.

Ahmadi, G., Ji, C., Smith, D. H. Production of natural gas from methane hydrate by a constant downhole pressure well. Energy Conversion and Management, 2007, 48: 2053-2068.

Allison, E. Methane hydrates, in Future Energy: Improved, Sustainable and Clean Options for Our Planet, 1st Edition, edited by T. M. Letcher, Elsevier, Amsterdam, pp. 277-290, 2008.

Blunier, T. Paleoclimate: "Frozen" methane escapes from the Sea Floor. Science, 2000, 288(5463): 68-69.

Dawe, R. A., Thomas, S. A large potential methane source-Natural gas hydrates. Energy Sources, Part A-Recovery, Utilization and Environmental Effects, 2007, 29: 217-229.

Dickens, G. R., Quinby-Hunt, M. S. Methane hydrate stability in seawater. Geophysical Research Letters, 1994, 21(19): 2115-2118.

Ekhator, E., Guo, B. Assessing the effect of well completion types on productivity in a class 1G gas hydrate reservoir under pseudo steady state. Petroleum, 2021, 7: 414-426.

Fu, C., Guo, B., Shan, L., et al. Mathematical modeling of heat transfer in y-shaped well couples for developing gas hydrate reservoirs using geothermal energy. Journal of Natural Gas Science and Engineering, 2021, 96: 104325.

Guo, B. Well Productivity Handbook, 2nd Edition. Cambridge, UK, Elsevier, 2019.

Guo, B., Ghalambor, A. Natural Gas Engineering Handbook, 2nd Edition. Houston, USA, Gulf Publishing Company, 2012.

Guo, B., Zhang, H. Mathematical modeling of the dynamic temperature profile in geothermal-energy-heated natural gas hydrate reservoirs. Sustainability, 2022, 14(5): 2767.

Hong, H., Pooladi-Darvish, M. Simulation of depressurization for gas production from gas hydrate reservoirs. Journal of Canadian Petroleum Technology, 2005, 44: 39-46.

Joshi, S. D. Augmentation of well productivity with slant and horizontal wells. Journal of Petroleum Technology, 1988, 40(6): 729-739.

Kawamura, T., Ohtake, M., Sakamoto, Y., et al. Experimental study on steam injection method using methane hydrate core samples. Paper ISOPE-M-07-024 Presented at the 7th ISOPE Ocean Mining Symposium, Lisbon, Portugal, 1-6 July, 2007.

Kawamura, T., Yamamoto, Y., Ohtake, M., et al. Experimental study on dissociation of hydrate core sample accelerated by thermodynamic inhibitors for gas recovery from natural gas hydrate. Paper Presented at the 5th International Conference on Gas Hydrates, Trondheim, Norway, 13-16 June, 2005.

Kurihara, M., Funatsu, K., Ouchi, H., et al. Investigation on applicability of methane hydrate production methods to reservoirs with diverse characteristics. Paper Presented at the 5th International Conference on Gas Hydrates, Trondheim, Norway, 13-16 June, 2005.

Kvenvolden, K. A. Gas hydrates-geological perspective and global change. Reviews of Geophysics, 1993, 31: 173-187.

Li, G., Li, X. S., Tang, L. G., et al. Control mechanisms for methane hydrate production by thermal stimulation. Paper Presented at the 6th International Conference on Gas Hydrates, Vancouver, BC, Canada, 6-10 July, 2008.

Li, G., Tang, L. G., Huang, C., et al. Thermodynamic evaluation of hot brine stimulation for natural gas hydrate dissociation. Journal of Chemical Industry and Engineering-China, 2006, 57: 2033-2038.

Li, X., Xu, C. G., Zhang, Y., et al. Investigation into gas production from natural gas hydrate: A review. Applied Energy, 2016, 172: 286-322.

Liu, C. L., Ye, Y., Meng, Q. The characteristics of gas hydrates recovered from Shenhu area in the South China Sea. Marine Geology, 2012, 307-310: 22-27.

Mahmood, M. N., Guo, B. Productivity comparison of radial lateral wells and horizontal snake wells applied to marine gas hydrate reservoir development. Petroleum, 2021, 7(4): 407-413.

Makogon, Y. F. Hydrates of Hydrocarbons. Tulsa, USA, Penn Well Publishing Co., 1997.

Moreno, B., Haydell, G., Landry, L. Critical data needs for design of frac-pack completions in today's oilfield environment. Paper SPE 124389 Presented at the Offshore Europe Meeting, Aberdeen, UK, 8-11 September, 2009.

Moridis, G. J., Collett, T. S., Dallimore, S. R., et al. Numerical studies of gas production from several methane hydrate zones at the Mallik site, Mackenzie Delta, Canada. Journal of Petroleum Science and Engineering, 2004, 43(3-4): 219-238.

Moridis, G. J., Reagan, M. T. Strategies for gas production from oceanic Class 3 hydrate accumulations. Paper OTC-18865-MS Presented at the Offshore Technology Conference, Houston, USA, 30 April-3 May, 2007a.

Moridis, G. J., Reagan, M. T. Gas production from oceanic Class 2 hydrate accumulations. Paper LBNL-62757 Presented at the Offshore Technology Conference, Houston, USA, 30 April-3 May, 2007b.

Najibi, H., Chapoy, A., Haghighi, H., et al. Experimental determination and prediction of methane hydrate stability in alcohols and electrolyte solutions. Fluid Phase Equilibria, 2009, 275: 127-131.

Nelson, R. D., Fleyfall, F., Dubois, R., et al. A novel gas-hydrate inhibitor for deepwater frac-pack and subsea environments. Paper SPE 58764 Presented at the SPE International Symposium on Formation Damage Control held in Lafayette, Louisiana, 23-24 February, 2000.

Qin, X., Liang, Q., Ye, J., et al. The response of temperature and pressure of hydrate reservoirs in the first gas hydrate production test in South China Sea. Applied Energy, 2020, 278: 115649.

Sloan Jr, E. D., Koh, C. A. Clathrate Hydrates of Natural Gases, 3rd Edition. Boca Raton, USA, CRC Press, 2008.

Stewart, B. R., Mullen, M. E., Ellis, R. C., et al. Economic justification for fracturing moderate to high permeability formations in sand control environments. Paper SPE 30470 Presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas, 22-25 October, 1995.

Su, M., Yang, R., Wu, N. Y. Structural characteristics in the Shenhu Area, northern continental slope of South China Sea, and their influence on gas hydrate. Acta Geologica Sinica, 2014, 88: 318-326.

Wang, Y., Feng, J., Li, X., et al. Analytic modeling and large-scale experimental study of mass and heat transfer during hydrate dissociation in sediment with different dissociation methods. Energy, 2015, 90: 1931-1948.

Wang, Y., Feng, J., Li, X., et al. Experimental and modeling analyses of scaling criteria for methane hydrate dissociation in sediment by depressurization. Applied Energy, 2016, 181: 299-309.

Wang, Y., Feng, J., Li, X., et al. Fluid flow mechanisms and heat transfer characteristics of gas recovery from gas-saturated and water-saturated hydrate reservoirs. International Journal of Heat and Mass Transfer, 2018, 118: 1115-1127.

Ye, J., Qin, X., Xie, W., et al. The second natural gas hydrate production test in the South China Sea. China Geology, 2020, 2: 197-209.

Yu, T., Guan, G., Wang, D., et al. Numerical evaluation on the effect of horizontal-well systems on the long-term gas hydrate production behavior at the second Shenhu test site. Journal of Natural Gas Science and Engineering, 2021, 95: 104200.