

METHANE PRODUCTION STRATEGIES FOR OCEANIC GAS HYDRATE RESERVOIRS

Neelam Choudhary

Enhanced Oil Recovery Laboratory
Department of Chemical Engineering
Indian Institute of Technology Delhi
New Delhi 110016, INDIA
Email: Neelam.Choudhary@chemical.iitd.ac.in

Jyoti Phirani*

Enhanced Oil Recovery Laboratory
Department of Chemical Engineering
Indian Institute of Technology Delhi
New Delhi 110016, INDIA
Email: jphirani@chemical.iitd.ac.in

ABSTRACT

Gas hydrates can be an efficient replacement for the conventional fossil fuels, as the large amount of methane gas is trapped in the gas hydrate reservoirs that can be used as a potential source of energy. In this study, we investigate the impact of a combination of horizontal and vertical wells on the gas production from oceanic Class-2, unconfined gas hydrate reservoirs. An In-house multicomponent, multiphase, thermal, 3-D finite volume simulator is used. Different locations of horizontal and vertical wells as warm water injectors and methane gas producers are investigated. For unconfined reservoirs, depressurization is found to be ineffective with horizontal and vertical wells. Horizontal warm water injectors are more effective for gas production. The gas production increases from 22% of original gas in place (OGIP) when vertical injector is used to 48% of OGIP when horizontal injector is used.

NOMENCLATURE

VW Vertical wells
SVW Short Vertical wells
HBD Horizontal bottom depressurization
HTD Horizontal top depressurization
HIVP Horizontal injection Vertical production
HIBPT Horizontal injection bottom-production top
HM Horizontal mid

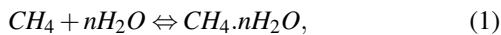
HT Horizontal top
HPVI Horizontal production vertical injection
 k permeability of the phase
 K absolute permeability
 k_r relative permeability of the phase
 μ viscosity of the fluid
 $\frac{\partial P}{\partial x}$ pressure gradient in x direction
 v superficial velocity
 K effective permeability
 K_o reference permeability
 ϕ_o reference porosity
 ϕ^e effective porosity of fluid phases
 ϕ absolute porosity
 S_G gas saturation
 S_A water saturation
 K_{rj}^o end point relative permeability
 n_j exponential parameter for the phase
 P_{ce} entry capillary pressure
 S_j^{e*} normalized saturation of the gas or aqueous phase
 S_j^e saturation of mobile phase
 S_{Ar}^e residual saturation for the aqueous phase
 S_{Gr}^e residual saturation for the gas phase
 M mass of component in the controlled volume
 F flux
 MW molecular weight of the component
 r reaction rate
 q source term
 U internal energy change

*corresponding author.

INTRODUCTION

Gas hydrates are ice like crystalline structures that are formed by water and gas molecules under high pressure and low temperature conditions. In past few decades, large reservoirs of methane gas hydrates have been found and studied [1, 2]. Gas hydrates can be a replacement for the conventional fossil fuels for an energy hungry country like India, where gas hydrate reservoirs have been found. A large amount of methane gas is trapped in the gas hydrates that can be used as a potential source of energy. They are usually found in two different geological settings; in the permafrost region where temperature is very low and in the oceanic sediments where pressure is very high. The current estimates of the worldwide quantity of methane gas present in the gas hydrates is around 10^{18} m^3 [1]. The sudden release of methane gas from gas hydrates can affect the global climate [3]. Thus, gas hydrates are important to global energy and environment.

Gas hydrates occur in three different crystalline structures in nature, which are SI, SII and SH in the order of increasing clathrate size. The properties of these clathrate structures of hydrates have been studied in past [4]. SI gas hydrates are the most abundant in nature and mainly contain methane gas. The conversion of gas hydrates into gas and water can be represented by the reaction



where, n is the hydration number that is the ratio between gas and water molecules. The hydration number of SI methane is approximately 6.

Hydrate reservoirs are classified into four types: (a) Class 1-hydrate layer is underlain by a gas layer. These reservoirs are found at Messoyakha Field in Russia [5]; (b) Class 2- hydrate layer is underlain by an aquifer layer that can either be a confined or an unconfined water layer. Class 2 reservoirs are found at Mallik site, Eastern Nankai trough and Gulf of Mexico [6, 7]; (c) Class 3-hydrate layer is confined by shale layers at overburden and underburden found at Qilian Mountain permafrost in China [8]; (d) Class 4-low saturation hydrate deposits that are usually found in oceanic sediments. Class 4 reservoirs are found at Krishna Godavari basin in India and Gulf of Mexico in the USA [9]. In the present study Class 2 unconfined reservoirs are considered.

Methane gas can be recovered from hydrate reservoirs by changing the pressure and temperature. A few methods and their combinations have been studied to produce methane gas from the reservoirs.

1. Depressurization: Pressure is reduced below the hydrate stability pressure in the reservoir [5, 10–14]. In case of the confined reservoirs depressurization is sufficient, however ice may form during hydrate dissociation as it is an endothermic process

[15]. To avoid this generally pressure in the reservoir is maintained above 2.5 MPa .

2. Thermal stimulation: Temperature is increased in the reservoir by injecting steam or hot water [15–19]. In case of unconfined reservoirs thermal stimulation method becomes necessary [18].

3. Inhibitor injection: Chemicals like salt, alcohol are injected to inhibit the formation of hydrate. However, large amount of inhibitors are needed which makes this process expensive [20–23].

4. CO_2 injection: High pressure CO_2 is injected to replace the methane gas with CO_2 [24–26]. Depressurization method is considered to be the most effective method out of the above methods.

A few short term field tests have been conducted to produce methane from the natural gas hydrate reservoirs using depressurization method, such as at Mallik Site, Canada (2008) [27] and Nankai Trough, Japan in 2013 [28]. These production tests lasted only for a few days mostly due to sand production. Once these kind of difficulties are controlled, an economic method for gas production from these reservoirs is required. To this end, in this work we explore different well locations in an unconfined class-2 reservoir for efficient production of methane gas. The effect of horizontal wells in combination with vertical wells is also explored. A combination of depressurization and thermal stimulation methods are used.

Hydrate formation and dissociation dynamics model

Fig.1 shows the hydrate equilibrium curve (Pe-T curve), that represents the hydrate stability conditions [4]. The region above the equilibrium curve is hydrate stable zone and the region below is the gas stable zone. At T greater than 273.15 K , water is present and below 273.15 K water is present in the form of Ice. At quadruple point all four phases can exist. All the phases in a grid block are assumed to be in equilibrium at a particular pressure and temperature as kinetics are relatively fast for field scale [29].

Reservoir Description

A 1200 m long and 500 m wide reservoir block at a depth of 3210 m from sea surface and about 460 m below the seafloor as shown in Fig.2 is considered. It is considered to have 18 m thick hydrate layer underlain by an infinite aquifer layer simulated using 12 m thick aquifer. The reservoir is discretized into $25 \times 12 \times 10$ grid blocks. The bottom 3 m layer of the aquifer is assumed to have a permeability $1/10$ th of the initial permeability to simulate it as an unconfined aquifer. A constant pressure condition is considered at the bottom boundary to model the mass transfer and the water flow is maintained based on the pressure difference between the bottom grid layer and the bottom boundary. Homogeneous hydrate saturation of 0.75 and water

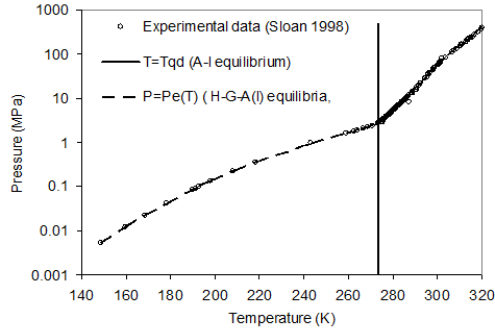


FIGURE 1: P-T DIAGRAM BY SLOAN [4]

saturation of 0.25 are assumed in the hydrate layer. The water saturation in aquifer zone is unity. The initial temperature of reservoir at the bottom is 294.88 K and initial pressure is 31.458 MPa. Both initial temperature and pressure vary with depth in the reservoir according to geothermal and hydrostatic gradients. The porosity is 0.42, initial permeability of the hydrate zone is 0.31 mD and the permeability of hydrate free sand is 1803 mD. At over-burden, mass transfer is not allowed. At over-burden and under-burden heat transfer is modeled with a specific heat transfer coefficient. At lateral boundary heat and mass transfer is not considered.

In this problem, using depressurization and warm water injection in different well locations are studied. For all the cases, the well temperature and pressure conditions are kept same. The injection well injects water at 50°C and pressure 50 MPa. The producer well pressure is maintained at 4 MPa.

Description of different well configurations

1. Horizontal producer using depressurization method: Previously, Phirani et al., (2009) [18] reported that the depressurization method is ineffective for unconfined permafrost reservoirs using vertical wells. Here, we evaluate horizontal wells for unconfined reservoirs using depressurization method. We considered two cases of horizontal wells based on the location of production well where in one case the horizontal producer is considered at the bottom of the hydrate bearing zone (HBD) as shown in Fig.3(a) and in second case the horizontal producer is considered at the top of the hydrate bearing zone (HTD) as shown in Fig.3(b).

2. Vertical wells: 5-spot pattern is considered for study where both the producer and injector wells are vertical, as shown in Fig.3(c) and a quarter of the 5-spot is simulated. Thus, in the simulation domain, we have diagonally opposite injection and production wells. Completion zone of these vertical wells is varied to assess production potential for wells completed in hydrate zone only represented by short vertical wells (SVW) and wells completed in hydrate and aquifer zone represented by vertical

wells (VW).

3. Horizontal wells: Horizontal injector and producer are considered along the length of reservoir 250 m apart from each other, shown in Fig. 3(d,e,f). Three different cases of horizontal wells are simulated: both the horizontal wells are at the top (HT), both at middle (HM) and producer at top and injector near the aquifer (HIBTP).

4. Horizontal injector and Vertical producer (HIVP): Horizontal injector at the top of the reservoir and vertical producer at one corner of the reservoir as shown in Fig. 3(g) is also considered.

5. Horizontal producer and Vertical injector (HPVI): Horizontal producer at the top of the hydrate layer and vertical injection at the one corner of the reservoir as shown in Fig. 3(h) is considered.

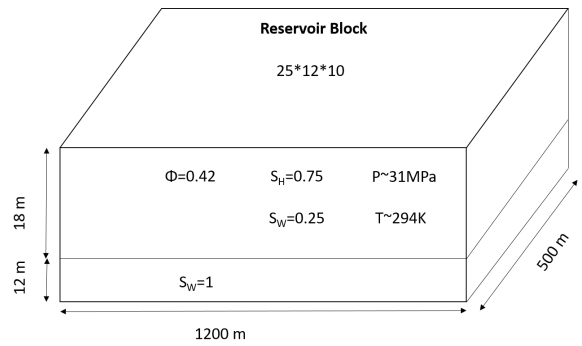


FIGURE 2: RESERVOIR DESCRIPTION

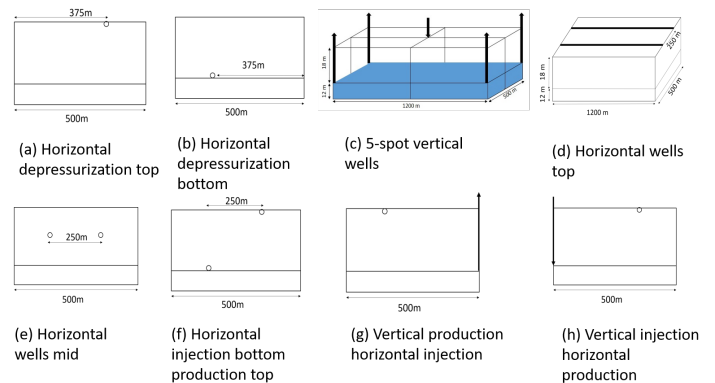


FIGURE 3: DIFFERENT WELL CONFIGURATIONS

Methods

The governing energy and mass balance equations are solved in space and time domain which are reported below,

Mass balance equations

$$\frac{\partial}{\partial t}(\phi M^m) + \nabla \cdot \bar{F}^m = q^m, \quad (2)$$

$$\frac{\partial}{\partial t}(\phi M^w) + \nabla \cdot \bar{F}^w = q^w, \quad (3)$$

Energy balance equation

$$\frac{\partial}{\partial t}(\phi U) + \nabla \cdot \bar{F}^e = -q^e, \quad (4)$$

The superscript in the above equations is the component where m is methane, w is water, hm is methane hydrate, and e is energy. In the above equations M is the mass of component in the controlled volume which changes with the time, F is the flux, MW shows the molecular weight of the component r is the reaction rate and q is the source term. The energy of formation and dissociation of the hydrates is taken in account by the internal energy change, U .

The two-phase flow in porous media is described by multi-phase Darcy's law that involves fluid mobility and driving force of each phase. Darcys law is only applicable for low Reynolds number generally observed in reservoirs. Fluid velocity is given by

$$v = \frac{k}{\mu} \left(\frac{\partial P}{\partial x} \right), \quad (5)$$

where, k is permeability of the phase given by $k = Kk_r$, K is absolute permeability, k_r is the relative permeability of the phase, μ is the viscosity of the fluid, $\frac{\partial P}{\partial x}$ is pressure gradient in x direction, v superficial velocity.

Effective Permeability K may change during the process of hydrate formation and dissociation due to the appearance and disappearance of solid phases such as hydrate and ice, that affects the effective pore volume. Effective permeability described by Power law model [30–32] has been used as given by,

$$\frac{K}{K_o} = \frac{\phi^e}{\phi_o} \left[\frac{\phi^e(1 - \phi_o)}{\phi_o(1 - \phi^e)} \right]^{2\beta} \quad (6)$$

where, K is the effective permeability, K_o reference permeability (assumed to be 100 md) at the reference porosity, ϕ_o reference porosity assumed to be 0.28, β assumed to be 2, ϕ^e effective porosity of fluid phases (gas and aqueous) expressed as

$$\phi^e = \phi(S_G + S_A), \quad (7)$$

where ϕ absolute porosity, S_G is gas saturation and S_A is water saturation.

To calculate the relative permeability and capillary pressure, Brooks-Corey model is used [33], as given below

$$K_{rG} = K_{rG}^o (S_G^{e*})^{n_G}, \quad (8)$$

$$K_{rA} = K_{rA}^o (S_A^{e*})^{n_A}, \quad (9)$$

$$P_c = P_{ce} (S_A^{e*})^{-nc}, \quad (10)$$

where, K_{rj}^o is the end point relative permeability and n_j is the exponential parameter for the phase j . P_{ce} is the entry capillary pressure that is related to the effective porosity expressed as

$$P_{ce} = P_{ce0} \sqrt{\frac{\phi^e k_0}{\phi_0 k}}, \quad (11)$$

S_j^{e*} is the normalized saturation of the gas or aqueous phase based on effective pore volume, given by the equation below,

$$S_j^{e*} = \frac{S_j^e - S_{jr}^e}{1 - S_{Gr}^e - S_{Ar}^e}, \quad (12)$$

where S_j^e is saturation of mobile phase j based on pore volume occupied by all mobile phases. The residual saturation for the aqueous phase S_{Ar}^e is considered to be 0.2 and for gas phase S_{Gr}^e it is 0.

Numerical Technique

A 3-D, finite-volume, in-house numerical simulator is used that takes into account heat transfer, multiphase fluid flow and equilibrium thermodynamics of hydrates formation and dissociation [34]. Energy and mass balance equations are solved in space and time. Three components (hydrate, methane, and water) and four phases (hydrate, gas, aqueous-phase, and ice) are considered in the simulator. Finite volume method is used to discretize equations in space and backward Euler method is used in time leading to fully implicit scheme of solution. The discretized non-linear equations are solved using the Newton-Raphson method [34]. Primary variable switch method (PVSM) is used to track the phase saturations [35]. This simulator has been validated against several other simulators for the problems in the code comparison study conducted by US DOE and history matched with hydrate formation and dissociation experiments [36].

Results and Discussion

We simulate a combination of depressurization and warm water injection using different well configurations as described

in Fig.3. For all the cases, injection well pressure is 50 MPa and injection water temperature is 50°C. The pressure at production well is maintained at 4 MPa. Fig.4 shows the cumulative gas production for all the cases in terms of percent of original gas in place (OGIP). Fig.5 shows the water production rate for different well configurations, respectively. Fig.6 shows the water injection rate. The acronyms in the legends in the figures are described in the nomenclature.

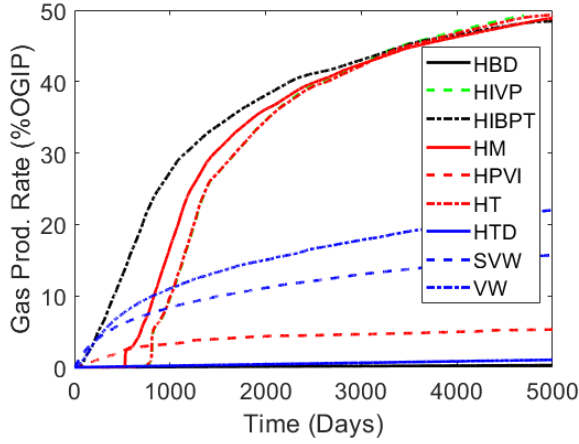


FIGURE 4: GAS PRODUCTION RATE IN % OGIP FOR DIFFERENT WELL CONFIGURATIONS

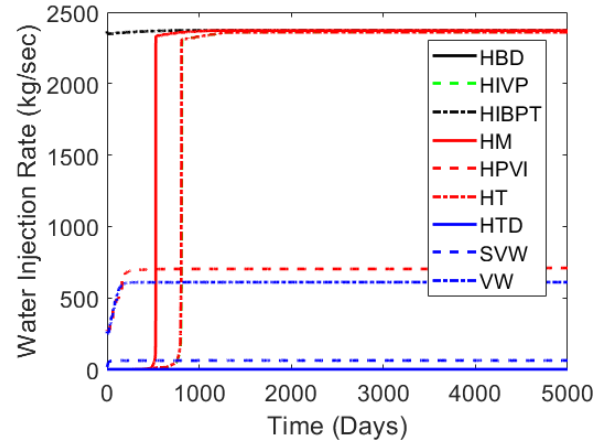
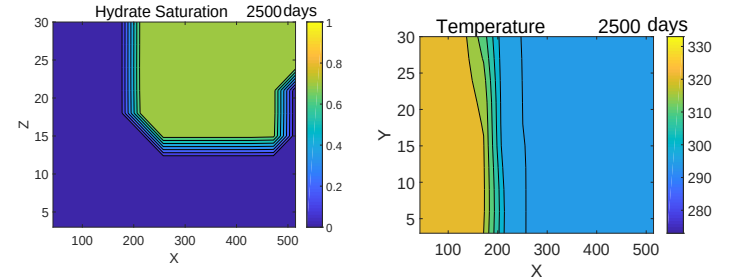


FIGURE 6: WATER INJECTION RATE FOR DIFFERENT WELL CONFIGURATIONS



(a) HYDRATE SATURATION PROFILE AT 2500 DAYS FOR 5-SPOT PATTERN VERTICAL WELLS **(b) TEMPERATURE PROFILE AT 2500 DAYS FOR 5-SPOT PATTERN VERTICAL WELLS**

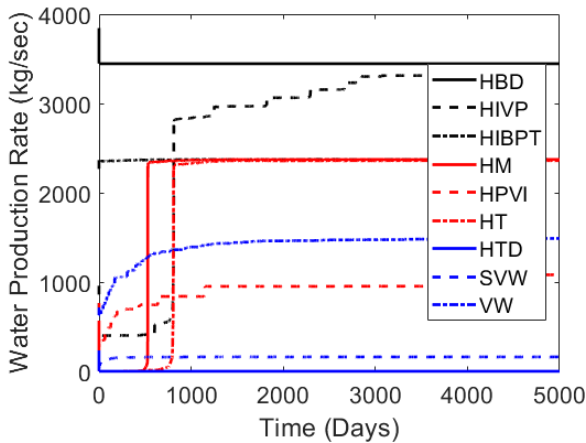


FIGURE 5: WATER PRODUCTION RATE FOR DIFFERENT WELL CONFIGURATION

We observe from Fig.4 that the gas production using depressurization in horizontal wells is only 0.3% OGIP irrespective of

the location. Therefore, depressurization in horizontal wells is also ineffective in an unconfined class 2 gas hydrate reservoir. In case of *HBD* Fig.3(a) water production is 3400 kg/s Fig.5 and *HTD* Fig.3(b) produces a small amount of water.

Now we explore a combination of depressurization and warm water injection. In the quarter of the 5-spot pattern simulated, if the vertical wells are completed in the hydrate as well as aquifer zone, we see from Fig.4 that 22% OGIP is produced in 5000 days. The water production rate in this case stabilizes around 1500 kg/sec Fig.5. To increase production using vertical wells and decrease water production, we explored well completion only in hydrate zone. Fig.4 shows using short vertical wells we are able to produce 16% OGIP. However, water production is less for short vertical wells Fig.5. This is because, the initial permeability near the wells is small which causes less warm water injection and depressurization in short vertical wells. In verti-

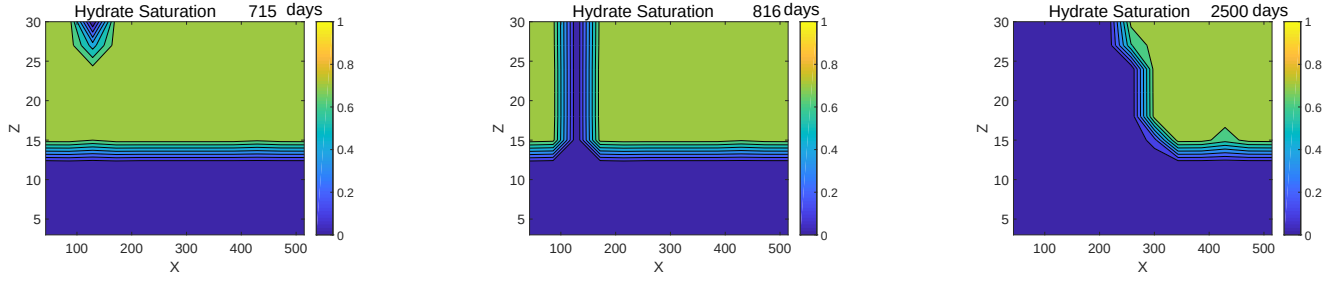


FIGURE 8: HYDRATE SATURATION PROFILES FOR HORIZONTAL WELLS AT TOP

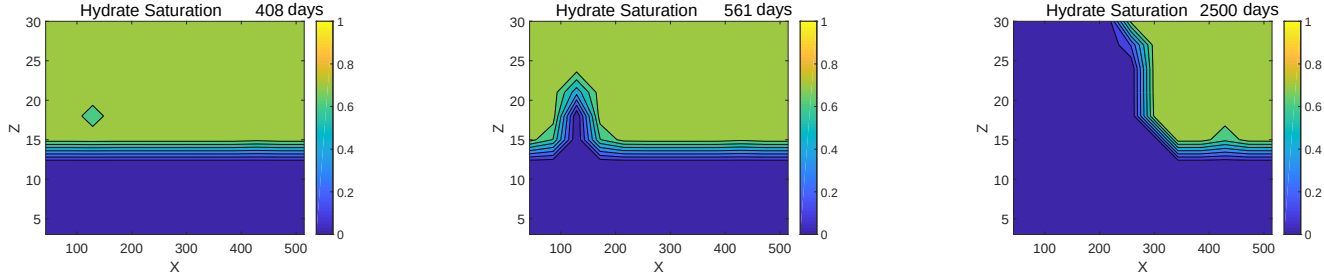


FIGURE 9: HYDRATE SATURATION PROFILES FOR HORIZONTAL WELLS AT MIDDLE

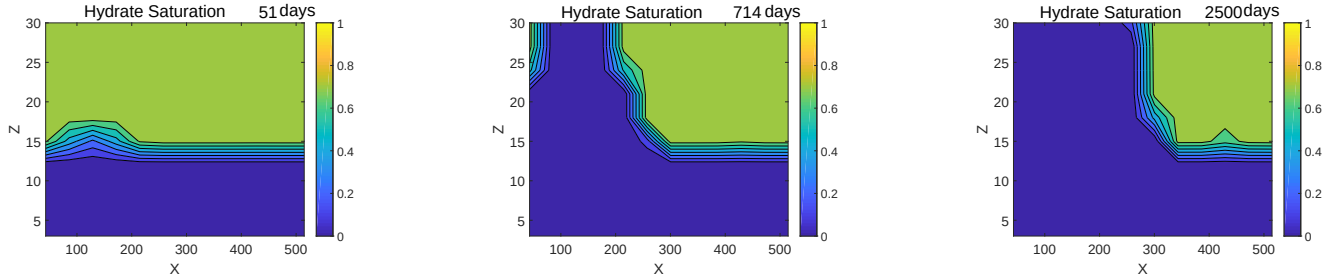


FIGURE 10: HYDRATE SATURATION PROFILES FOR HORIZONTAL INJECTION AT BOTTOM AND PRODUCER AT TOP

cal wells completed in aquifer zone, the aquifer zone gives the higher water injectivity due to high permeability initially. This is evident from Fig.6 that the water injection rate in short vertical wells is much lower than the vertical wells. Fig.7 shows the hydrate saturation and the temperature profiles at 2500 days for the VW case. The horizontal axis is the diagonal connecting the injection well at the left to the production well at the right and the z axis is the depth of the reservoir. The profiles shows that the hydrate dissociation near the injection well is due to the temperature increase and near the production well is due to depressurization. The enthalpy of dissociation (for depressurization) near the production well comes from reservoir heat capacity, as shown by the decrease in temperature in the hydrate zone near the overburden.

We now study horizontal wells to see their effect on gas production. The production from three cases shown in Fig.3(d,e,f) is plotted in Fig.4. The ultimate gas recovery from the three cases is approximately $\sim 47\%$ OGIP in 5000 days. Fig.4 shows that

when the injection well is located near the aquifer (HIBPT) the gas production starts immediately. However, when the horizontal wells are located in the middle of the hydrate layer (HM) the production starts at 500 days and when the wells are located at the top of the hydrate layer (HT) the gas production starts at 700 days. This is because, the low permeability hydrate zone decreases the water injectivity initially and the heat transfer is dominated by the heat conduction for cases HM and HT. The hydrate saturation profiles for HT and HM shown in Fig.8 and Fig.9, shows that when the injection well is located in low permeability hydrate layer, hydrate dissociation near the injection well is initially slow. When the dissociation front reaches aquifer, the production rate increases for the two cases. Fig.10 shows the hydrate saturation profile when the injection well is near the aquifer (HIBPT). In this case, the hydrate dissociation from the beginning is fast. Therefore, the initial gas production is controlled by the vertical distance between the injector well and the aquifer

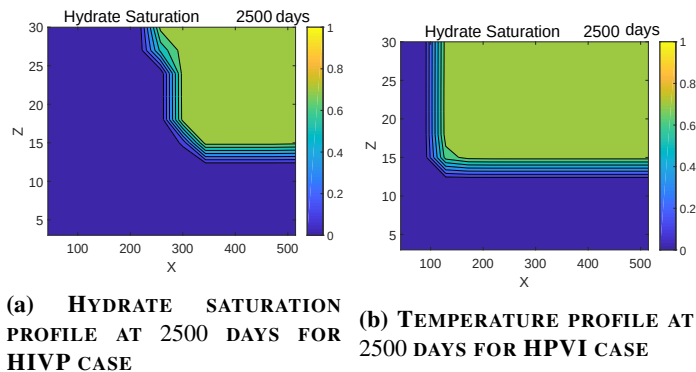


FIGURE 11: HYDRATE SATURATION PROFILES AT 2500 DAYS FOR HIVP AND HPVI CASE

layer. The water production rate and injection rate is also similar for the three horizontal well cases after the hydrate dissociation front reaches the aquifer as shown in Fig.5 and Fig.6

Further, to increase the productivity we study two cases of the combination of vertical and horizontal wells; horizontal injector vertical producer (HIVP) and horizontal producer vertical injector (HPVI). In the first case where injector is horizontal and producer is vertical (HIVP) shown in Fig.3(g), the final gas production is similar to the horizontal well cases (47%OGIP) as shown in Fig.4. It can be seen in the hydrate saturation profile in Fig.11(a) that warm water injection is responsible for most of the hydrate dissociation seen. However, when the producer is horizontal and injector is vertical as shown in Fig.3(h), the gas production in 5000 days is the smallest of all the warm water injection cases (6%OGIP) as shown in Fig.4. This is because, the pressure near the injection well does not decrease when vertical injector is used leading to the less hydrate dissociation as it can be seen in the Fig.11(b).

Conclusion

Gas production by depressurization is ineffective in unconfined hydrate reservoirs with horizontal wells. Warm water injection is necessary for gas production from unconfined hydrate reservoirs. Vertical injectors are less efficient than horizontal injectors. The horizontal producers have less significant impact on the gas production. The cumulative gas production is similar for all the cases of horizontal injection wells. However, If the horizontal injection wells are located in the hydrate bearing zone, the low permeability of the hydrate zone leads to negligible gas production in the initial periods. If the injection well is near the aquifer layer, the convection of the water is faster and the gas production starts earlier.

REFERENCES

- [1] Kvenvolden, K. A., 1999. "Potential effects of gas hydrate on human welfare". *Proceedings of the National Academy of Sciences*, **96**(7), pp. 3420–3426.
- [2] Milkov, A. V., and Sassen, R., 2002. "Economic geology of offshore gas hydrate accumulations and provinces". *Marine and Petroleum Geology*, **19**(1), pp. 1–11.
- [3] Matsumoto, R., 2002. "Comparison of marine and permafrost gas hydrates: Examples from nankai trough and mackenzie delta". *Proc. 4th ICGH*, 2002, pp. 1–6.
- [4] Sloan Jr, E. D., 1998. *Clathrate Hydrates of Natural Gases, revised and expanded*. CRC press.
- [5] Bhade, P., and Phirani, J., 2015. "Gas production from layered methane hydrate reservoirs". *Energy*, **82**, pp. 686–696.
- [6] Milkov, A. V., and Sassen, R., 2001. "Estimate of gas hydrate resource, northwestern gulf of mexico continental slope". *Marine Geology*, **179**(1-2), pp. 71–83.
- [7] Boswell, R., Shelander, D., Lee, M., Latham, T., Collett, T., Guerin, G., Moridis, G., Reagan, M., and Goldberg, D., 2009. "Occurrence of gas hydrate in oligocene frio sand: Alaminos canyon block 818: Northern gulf of mexico". *Marine and Petroleum Geology*, **26**(8), pp. 1499–1512.
- [8] ZHU, Y., ZHANG, Y., WEN, H., LU, Z., JIA, Z., LI, Y., LI, Q., LIU, C., WANG, P., and GUO, X., 2010. "Gas hydrates in the qilian mountain permafrost, qinghai, north-west china". *Acta Geologica Sinica-English Edition*, **84**(1), pp. 1–10.
- [9] Moridis, G. J., and Sloan, E. D., 2007. "Gas production potential of disperse low-saturation hydrate accumulations in oceanic sediments". *Energy conversion and management*, **48**(6), pp. 1834–1849.
- [10] Cheng, Y., Li, L., Yuan, Z., Wu, L., and Mahmood, S., 2013. "Finite element simulation for fluid–solid coupling effect on depressurization-induced gas production from gas hydrate reservoirs". *Journal of Natural Gas Science and Engineering*, **10**, pp. 1–7.
- [11] Li, G., Li, B., Li, X.-S., Zhang, Y., and Wang, Y., 2012. "Experimental and numerical studies on gas production from methane hydrate in porous media by depressurization in pilot-scale hydrate simulator". *Energy & Fuels*, **26**(10), pp. 6300–6310.
- [12] Uddin, M., Wright, F., Dallimore, S., and Coombe, D., 2014. "Gas hydrate dissociations in mallik hydrate bearing zones a, b, and c by depressurization: Effect of salinity and hydration number in hydrate dissociation". *Journal of Natural Gas Science and Engineering*, **21**, pp. 40–63.
- [13] Makogon, Y., and Omelchenko, R., 2013. "Commercial gas production from messoyakha deposit in hydrate conditions". *Journal of Natural Gas Science and Engineering*, **11**, pp. 1–6.
- [14] Bhade, P., and Phirani, J., 2015. "Effect of geological lay-

- ers on hydrate dissociation in natural gas hydrate reservoirs". *Journal of Natural Gas Science and Engineering*, **26**, pp. 1549–1560.
- [15] Phirani, J., and Mohanty, K., 2009. "Warm water flooding of confined gas hydrate reservoirs". *Chemical Engineering Science*, **64**(10), pp. 2361–2369.
- [16] Castaldi, M. J., Zhou, Y., and Yegulalp, T. M., 2007. "Down-hole combustion method for gas production from methane hydrates". *Journal of petroleum Science and Engineering*, **56**(1-3), pp. 176–185.
- [17] Kamath, V. A., Godbole, S. P., et al., 1987. "Evaluation of hot-brine stimulation technique for gas production from natural gas hydrates". *Journal of petroleum technology*, **39**(11), pp. 1–379.
- [18] Phirani, J., Mohanty, K. K., and Hirasaki, G. J., 2009. "Warm water flooding of unconfined gas hydrate reservoirs". *Energy & Fuels*, **23**(9), pp. 4507–4514.
- [19] Phirani, J., Mohanty, K. K., and Hirasaki, G. J., 2009. "Warm water flooding of unconfined gas hydrate reservoirs". *Energy & Fuels*, **23**(9), pp. 4507–4514.
- [20] Dong, F., Zang, X., Li, D., Fan, S., and Liang, D., 2009. "Experimental investigation on propane hydrate dissociation by high concentration methanol and ethylene glycol solution injection". *Energy & Fuels*, **23**(3), pp. 1563–1567.
- [21] Li, G., Li, X.-S., Tang, L.-G., and Zhang, Y., 2007. "Experimental investigation of production behavior of methane hydrate under ethylene glycol injection in unconsolidated sediment". *Energy & fuels*, **21**(6), pp. 3388–3393.
- [22] Sira, J., Patil, S., Kamath, V., et al., 1990. "Study of hydrate dissociation by methanol and glycol injection". In SPE Annual technical conference and exhibition, Society of Petroleum Engineers.
- [23] Makogon, I. F., Makogon, I. F., and Makogon, Y. F., 1997. *Hydrates of hydrocarbons*. Pennwell Books.
- [24] Graue, A., Kvamme, B., Baldwin, B. A., Stevens, J., Howard, J. J., Ersland, G., Husebo, J., Zornes, D. R., et al., 2006. "Magnetic resonance imaging of methane-carbon dioxide hydrate reactions in sandstone pores". In SPE Annual Technical Conference and Exhibition, Society of Petroleum Engineers.
- [25] Mohebbi, V., and Behbahani, R., 2014. "Experimental study on gas hydrate formation from natural gas mixture". *Journal of Natural Gas Science and Engineering*, **18**, pp. 47–52.
- [26] Phirani, J., Mohanty, K. K., et al., 2010. "Kinetic simulation of co2 flooding of methane hydrates". In SPE Annual Technical Conference and Exhibition, Society of Petroleum Engineers.
- [27] Kurihara, M., Sato, A., Funatsu, K., Ouchi, H., Yamamoto, K., Numasawa, M., Ebinuma, T., Narita, H., Masuda, Y., Dallimore, S. R., et al., 2010. "Analysis of production data for 2007/2008 mallik gas hydrate production tests in canada". In International Oil and Gas Conference and Exhibition in China, Society of Petroleum Engineers.
- [28] Konno, Y., Fujii, T., Sato, A., Akamine, K., Naiki, M., Masuda, Y., Yamamoto, K., and Nagao, J., 2017. "Key findings of the worlds first offshore methane hydrate production test off the coast of japan: Toward future commercial production". *Energy & Fuels*, **31**(3), pp. 2607–2616.
- [29] Kim, H., Bishnoi, P. R., Heidemann, R. A., and Rizvi, S. S., 1987. "Kinetics of methane hydrate decomposition". *Chemical engineering science*, **42**(7), pp. 1645–1653.
- [30] Civan, F., 2001. "Scale effect on porosity and permeability: Kinetics, model, and correlation". *AIChE journal*, **47**(2), pp. 271–287.
- [31] Civan, F., et al., 2002. "Relating permeability to pore connectivity using a power-law flow unit equation". *Petrophysics*, **43**(06).
- [32] Civan, F., et al., 2002. "Fractal formulation of the porosity and permeability relationship resulting in a power-law flow units equation-a leaky-tube model". In International Symposium and Exhibition on Formation Damage Control, Society of Petroleum Engineers.
- [33] Brooks, R., and Corey, T., 1964. "Hydrauc properties of porous media". *Hydrology Papers, Colorado State University*, **24**, p. 37.
- [34] Sun, X., and Mohanty, K. K., 2006. "Kinetic simulation of methane hydrate formation and dissociation in porous media". *Chemical Engineering Science*, **61**(11), pp. 3476–3495.
- [35] Falta, R. W., Pruess, K., Javandel, I., and Witherspoon, P. A., 1992. "Numerical modeling of steam injection for the removal of nonaqueous phase liquids from the subsurface: 1. numerical formulation". *Water Resources Research*, **28**(2), pp. 433–449.
- [36] Phirani, J., Pitchumani, R., Mohanty, K. K., et al., 2009. "History matching of hydrate formation and dissociation experiments in porous media". In SPE Reservoir Simulation Symposium, Society of Petroleum Engineers.