

## Warm Water Flooding of Unconfined Gas Hydrate Reservoirs

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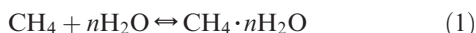
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Large quantities of natural gas hydrates are present in shallow marine sediments as well as in arctic regions. This research is aimed at assessing production of natural gas from unconfined marine hydrate deposits. A multiphase, multicomponent, thermal, 3D simulator is used to simulate production of hydrates in the equilibrium mode. Three components (hydrate, methane, and water) and four phases (hydrate, gas, aqueous-phase, and ice) are considered in the simulator. Depressurization and warm water flooding of unconfined, horizontal and dipping reservoirs have been simulated. Production of methane from gas hydrate reservoirs depends on reservoir confinement, injection temperature, injection pressure, and production pressure. For unconfined horizontal reservoirs, depressurization is ineffective; thermal stimulation is necessary for gas production. Even warm water (temperature  $\approx 30$  °C) injection improves the gas production from hydrate reservoirs. Lower vertical permeability helps the gas production by heating a larger area of the reservoir for hydrate dissociation. As the well spacing decreases, the gas production rate increases. Depressurization alone is effective in dipping unconfined reservoirs, but much slower than warm water injection. As the injection point of the warm water moves down the reservoir, the start of the high gas recovery phase gets delayed, but the time for completion of gas recovery becomes shorter.

### 1. Introduction

Gas hydrates are crystalline, ice-like compounds formed by gas (e.g., methane, ethane, and carbon dioxide) and water molecules at high pressures and low temperatures.<sup>1</sup> Hydrates of methane gas contain about 164 times the gas than the gas in the same volume at standard conditions. The storage capacity of hydrates makes them useful for storage and transportation of gases. The reaction of methane and water to form hydrates can be stated as



where  $n$  is the hydration number. Three types of crystal-line structure of gas hydrates have been found so far: structure I (SI), structure II (SII), and structure H (SH), in the order of increasing size. The thermodynamic properties of these structures are discussed in detail elsewhere.<sup>1</sup> SI methane hydrate is very common and will be the focus of the present study.

Hydrates are found in shallow sediments either in onshore arctic regions or in offshore coastline regions where the pressure is high and temperature is low.<sup>2</sup> Different estimates show different amounts of hydrates present in nature, but the amount is large. Three types of hydrate reservoirs have been

identified:<sup>3</sup> class 1 reservoirs are underlain by a free gas layer, class 2 reservoirs are underlain by a water-saturated layer, and class 3 reservoirs are a single layer of hydrates bounded by two impermeable shale layers. Unconfined class 2 reservoirs are the focus of the present work. Confined class 2 reservoirs have been studied in the past where the water layer below the hydrate layer is confined by an impermeable shale layer.<sup>4,5</sup> In the present study the water layer below the hydrate layer is considered to be a semi-infinite aquifer.

Depressurization, thermal stimulation, inhibitor injection, and CO<sub>2</sub> injection are methods proposed to produce gas from hydrate reservoirs.<sup>1,6</sup> Pressure is lowered below hydrate stability pressure at the production well for the depressurization method. The dissociated gas flows into the production well due to the pressure gradient.<sup>7–9</sup> The heat required for endo-thermic reaction of hydrate dissociation is obtained from the surrounding sediments (and fluids and hydrates), which is a

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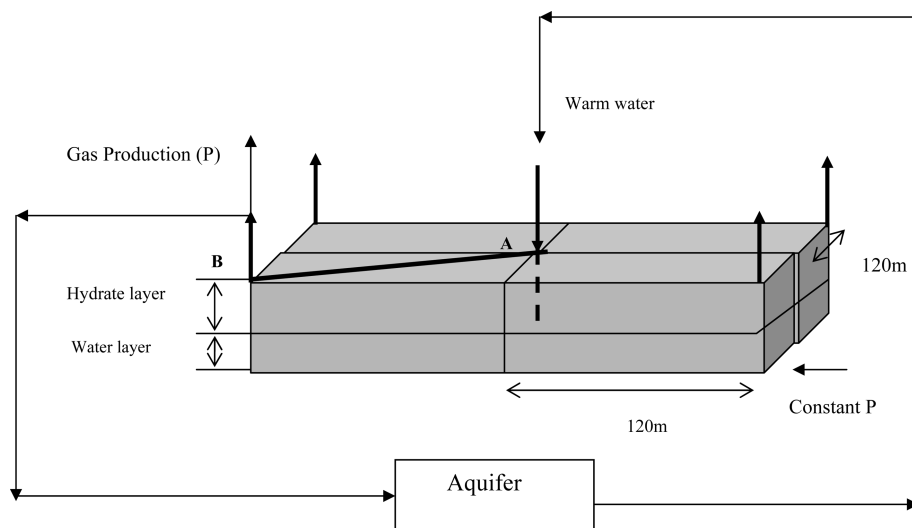
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**Figure 1.** Schematic of an unconfined horizontal reservoir.

slow process. In thermal stimulation, either wells are heated or warm water (or steam) is injected into the reservoir, raising the temperature above the hydrate stability temperature.<sup>10</sup> For thermal stimulation, the cost of heating is high if steam is used, but that can be lowered using warm water from aquifers at higher depths or nearby oil wells. The convection of warm water is necessary for the heating to be effective as conduction of heat is slow. In the inhibitor process, chemicals that inhibit hydrate formation are injected along with water in injection wells.<sup>5,11</sup> The use of inhibitors is often not recommended because the cost is high, formation water dilutes it, and salt-based inhibitors can precipitate. In the CO<sub>2</sub> process, injected CO<sub>2</sub> replaces methane in clathrate cages, resulting in methane production and simultaneous CO<sub>2</sub> sequestration. Thermodynamically, CO<sub>2</sub> hydrate formation is more favorable than methane hydrate formation. The heat needed for methane hydrate dissociation is supplied by the heat released during CO<sub>2</sub> hydrate formation. Methane can be released from hydrates spontaneously by exposing the hydrates to liquid CO<sub>2</sub>, which will form CO<sub>2</sub> hydrates;<sup>6</sup> mass transfer barriers can slow down this process.

Moridis and Reagan<sup>8</sup> have studied the class 2 confined reservoirs for three different well designs, including warm water injection, and found depressurization to be the most efficient method. However, depressurization becomes difficult if the water zone is infinite. Moridis and Kolwalsky<sup>9</sup> have studied gas production from class 2 oceanic reservoirs with permeable overburden and underburden and found an impermeable barrier to be required for economical production of gas from hydrates. In this work, we explore the unconfined reservoirs that have an impermeable overburden layer but a permeable underburden. This requires the underneath water zone to be semi-infinite. The warm injection water can be obtained from a deeper aquifer below the reservoir or nearby oil wells to minimize the cost of warm water. The effects of temperature and pressure conditions in production and injection wells are studied.

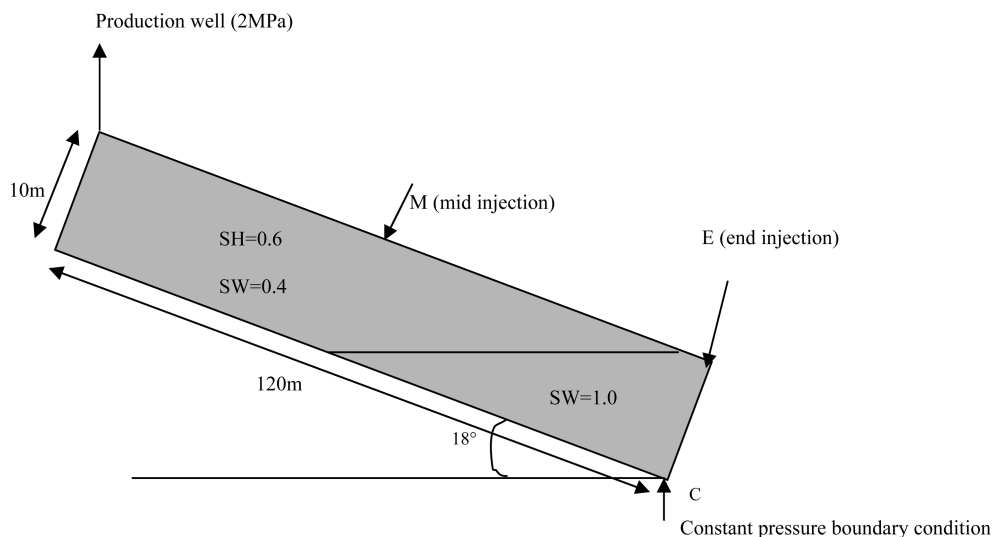
## 2. Methodology

This study includes horizontal as well as dipping unconfined hydrate reservoirs. Thickness is chosen to be 10 m for the horizontal reservoir and porosity to be 0.28. It is assumed that the horizontal reservoir would be developed in a five-spot pattern. Due to the symmetry of the five-spot pattern (Figure 1), a quarter of the five-spot pattern of area 120 × 120 m is studied. In Figure 1, the arrow pointing down at point A is an injection well, and arrows pointing up at the corners of the five-spot (for example at B) are production wells. The schematic shows the pumping of water from a warm aquifer (a deeper geological layer) to the injection well, separation of gas and water produced, and reinjection of produced water to the deeper layer. The top 8 m of the reservoir is considered to be the hydrate layer (hydrate saturation  $S_H = 0.6$ , aqueous saturation  $S_A = 0.4$ ). The bottom 2 m of the reservoir is considered to be the water layer ( $S_A = 1.0$ ). No gas is present in the reservoir initially. The initial temperature at the top of the reservoir is 7 °C, varying vertically with a geothermal gradient of 0.03 °C/m and the initial pressure is 9 MPa, varying with the hydrostatic gradient. No heat or mass flow is allowed through the lateral boundaries due to the symmetry of the five-spot pattern. No mass flow is allowed through the upper boundary, but heat flow is allowed with a specified heat transfer coefficient. To mimic the semi-infinite aquifer below the reservoir, a 1 m thick water layer is added at the bottom of the reservoir with a permeability of one tenth of the main reservoir permeability, and a constant pressure boundary condition is applied at the bottom of the extra water layer. Water can flow through this boundary depending on the local pressure gradient. The reservoir domain including the bottom 1 m layer with low permeability is discretized into 15 × 15 × 11 grid blocks. The production well is controlled by specifying a bottom hole pressure. In the case of warm water injection, injection pressure and injection water temperature are specified. Different production well pressures, injection well pressures, and injection water temperatures are assigned, and their impact on gas production is studied.

For dipping reservoirs, 2-dimensional simulations are performed. A reservoir of 120 m length, 10 m thickness, and 18° dipping angle is assumed. The third dimension is assumed to be 120 m to match the total volume to that of the horizontal

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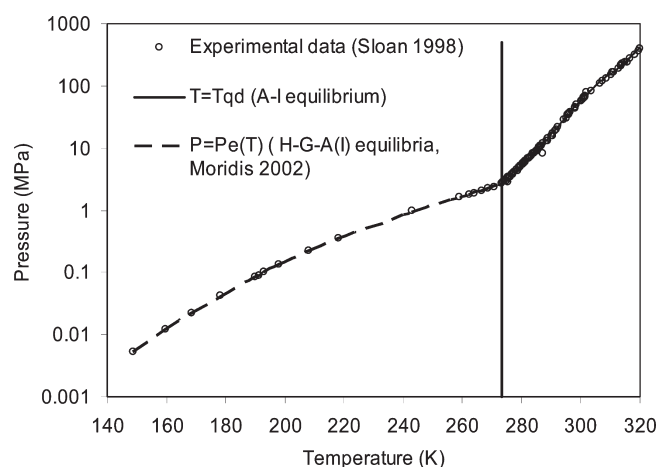
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**Figure 2.** Schematic of an unconfined dipping reservoir.

reservoir. The volumes of hydrate and water layers in the dipping reservoir are kept the same as those in the horizontal reservoir. Figure 2 shows the sketch of the dipping reservoir. The reservoir domain is discretized into  $120 \times 10$  grid-blocks. The gas is produced through a horizontal well at the top left corner. This well is placed in one grid block, but has a length of 120 m in the third dimension. Three different injection conditions are studied. In the first case (E, end injection), the warm water is injected through a horizontal well placed at the right top corner. In the second case (M, mid injection), the warm water is injected in the middle top grid block, as shown in Figure 2. In the third case, there is no injection well; only depressurization is applied. “No mass flow” boundary condition is applied to all boundaries except at the bottom right corner C, which is at a constant pressure; this boundary condition simulates the connection with an aquifer at the bottom all along the third dimension. A heat transfer coefficient is applied as the thermal boundary condition (to all the boundary grid blocks).

**2.1. Numerical Model.** The numerical model used is a 3D finite-volume simulator that takes into account heat transfer, multiphase fluid flow, and equilibrium thermodynamics of hydrates.<sup>12</sup> Energy and mass balance equations are solved in space and time domain. Three components (hydrate, methane, and water) and four phases (hydrate, gas, aqueous-phase, and ice) are considered in the simulator; the effect of salt concentration is not included. The simulator uses a fully implicit scheme to solve the discretized equations in space. The Newton–Raphson method is used to solve the nonlinear equations. 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 problems.<sup>13</sup> The primary variable switch method (PVSM) is used to track the phase saturations. This method has been proven to be a robust technique in dealing with phase transitions.<sup>14,15</sup> The simulator uses continuum-scale



**Figure 3.** Methane hydrate–gas equilibrium diagram.

modeling, hence, the coupling between thermodynamics, kinetics, and transport processes in the microscopic scale is neglected. This simulator has been validated against several other simulators for the problems in the code comparison study conducted by US DOE.<sup>16</sup>

**Thermal Properties.** Figure 3 shows the hydrate equilibrium curve ( $P_e$ – $T$  curve), where  $P_e$  is the equilibrium pressure of three phase equilibria  $H+G+A$  and  $H+G+I$  at temperature  $T$ . The curve is represented with empirical correlations obtained by Moridis.<sup>17</sup> The solid vertical line in the figure shows the water ice equilibrium curve. The region above the equilibrium curve is the hydrate-stable zone and below is the gas-stable zone. The region left of the solid vertical line is ice zone and the right is aqueous zone. Solubility of methane in aqueous phase and water in gas phase, specific internal energy, and specific enthalpy are taken from literature and are given in detail in Sun and Mohanty.<sup>18</sup>

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Table 1. Thermal and Flow Parameters

|                           |                         |                                            |          |
|---------------------------|-------------------------|--------------------------------------------|----------|
| hydrate density           | 910 kg/m <sup>3</sup>   | reference permeability ( $k_0$ )           | 100 md   |
| hydrate heat conductivity | 0.49 W/m/K              | reference porosity ( $\phi_0$ )            | 0.28     |
| hydrate heat capacity     | 1.62 kJ/kg/K            | permeability rock constant ( $\beta$ )     | 2        |
| ice density               | 917.1 kg/m <sup>3</sup> | gas rel. permeability constant ( $n_G$ )   | 2        |
| sand density              | 2670 kg/m <sup>3</sup>  | water rel. permeability constant ( $n_w$ ) | 4        |
| sand heat conductivity    | 5.57 W/m/K              | pore structure parameter ( $n_c$ )         | 5        |
| sand heat capacity        | 0.83 kJ/kg/K            | residual water, gas saturation             | 0.2, 0.0 |

**Transport Properties.** Power law model based on effective porosity, proposed by Civan<sup>19</sup> is used for absolute permeability correlation.

$$\frac{k}{k_0} = \frac{\phi}{\phi_0} \left( \frac{\phi^e (1 - \phi_0)}{\phi_0 (1 - \phi^e)} \right)^{2\beta} \quad (2)$$

$k$  is the scalar value of absolute permeability,  $k_0$  is reference permeability that is taken as 100 md for base case in the present study,  $\phi^e$  is the effective porosity for aqueous and gas phases, which can be related to absolute porosity as:

$$\phi^e = \phi(S_G + S_A) \quad (3)$$

where  $\phi_0$  is the reference porosity (0.28) at which the absolute permeability is  $k_0$ , and  $\beta$  is a parameter that can be determined from experimental data. For relative permeability the Brooks-Corey model is used.

$$k_{rG} = k_{rG}^0 (S_G^*)^{n_G} \quad (4)$$

$$k_{rA} = k_{rA}^0 (S_A^*)^{n_A} \quad (5)$$

$$P_c = P_{ce} (S_A^*)^{-n_c} \quad (6)$$

In eqs 4 and 5,  $k_{rj}^0$  and  $n_j$  are the end point and exponential parameter for phase  $j$ . In eq 6,  $n_c$  is a parameter for pore structure and  $P_{ce}$  is the entry capillary pressure, which is related to effective porosity as:

$$p_{ce} = p_{ce0} \sqrt{\frac{\phi^e k_0}{\phi_0 k}} \quad (7)$$

where  $p_{ce0}$  is the entry capillary pressure at the reference porosity  $\phi_0$ . The permeability  $k$  is calculated from eq 2.  $S_j^*$  is normalized saturation of gas or aqueous phase based on the effective pore volume occupied.

$$S_j^* = \frac{S_j - S_{jr}}{1 - S_{Gr} - S_{Ar}} \quad (8)$$

where  $S_j^e$  is saturation of mobile phase  $j$  based on pore volume occupied by all mobile phases and is related to total pore volume by

$$S_j^e = \frac{S_j}{\sum_{j=G,A} S_j} \quad (9)$$

The residual saturation in eq 8 is also based on effective pore volume. For the present case, the residual saturation of the aqueous phase is assumed to be 0.2, and for gas phase it is 0. Some of the important parameters are listed in Table 1. Other details can be found in Sun and Mohanty.<sup>11</sup>

### 3. Results and Discussions

**3.1. Horizontal Reservoirs.** The total thickness simulated for the unconfined reservoir is 11 m. The top 8 m is the

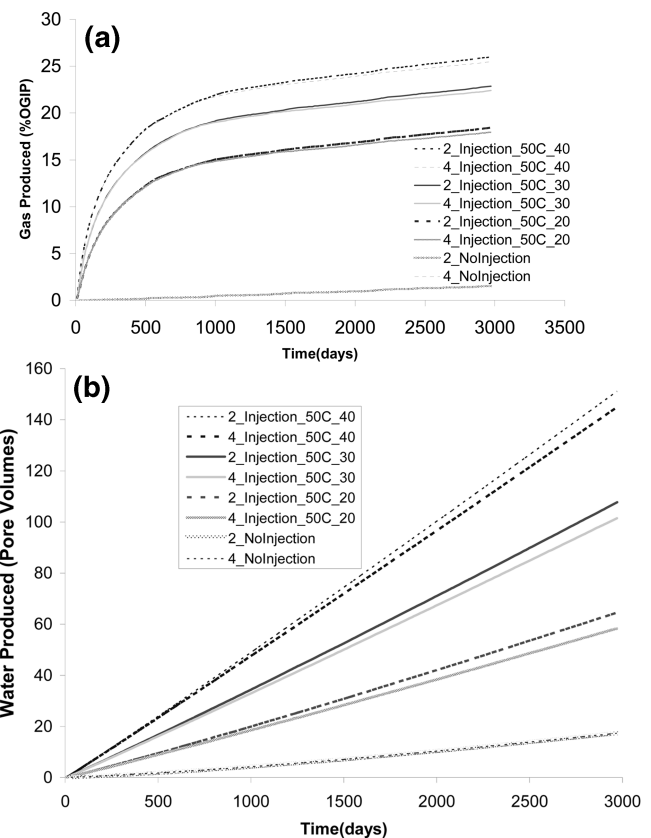
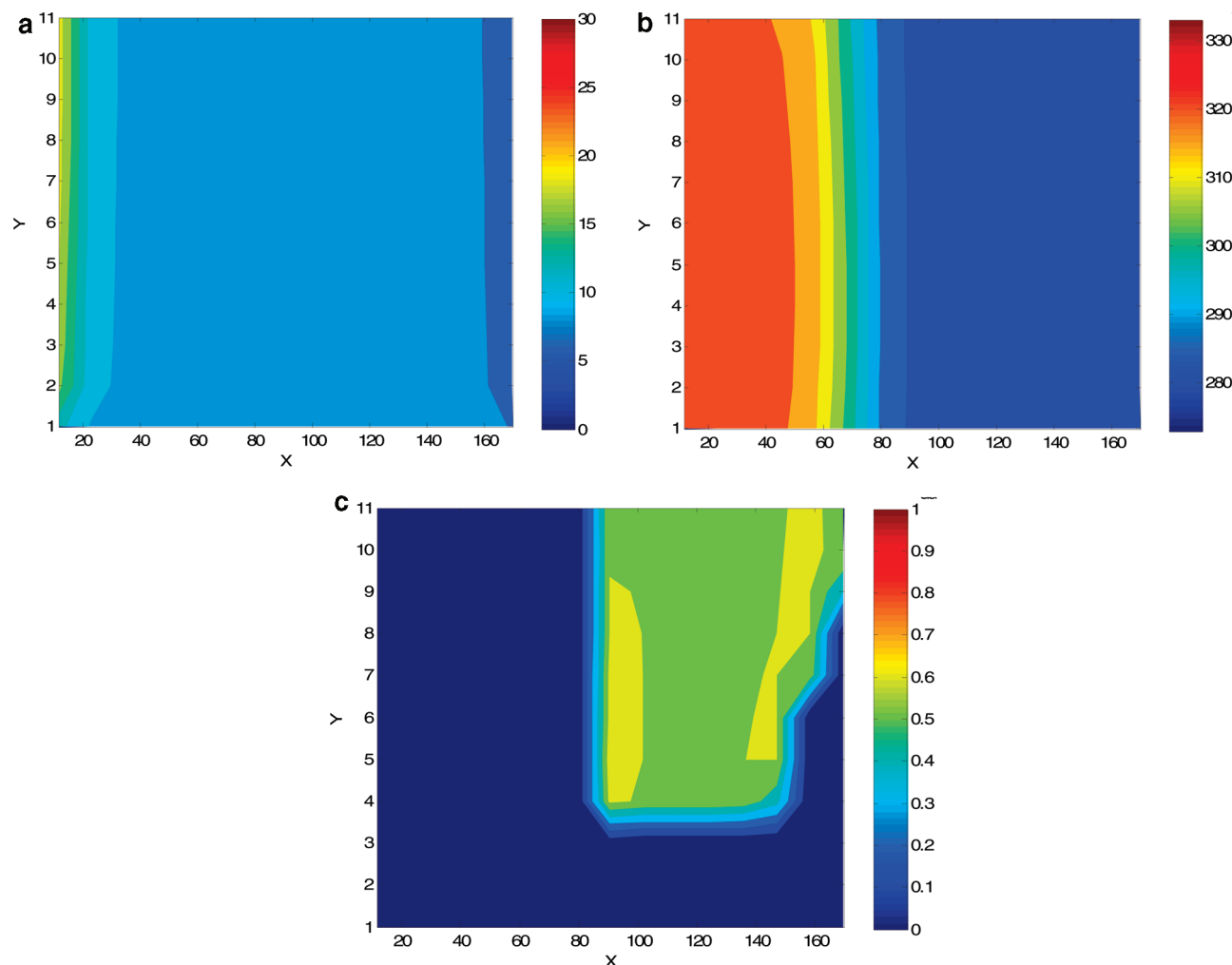


Figure 4. (a) Cumulative gas production, (b) cumulative water production for different injection and production well pressures.

hydrate zone with a hydrate saturation of 0.6. The bottom 3 m is the aquifer region, of which the last meter is of low permeability (1/10 of the base permeability) and communicates with the bottom aquifer with the boundary condition of constant pressure (same as the initial reservoir pressure). As the warm water is injected into the reservoir, the reservoir temperature increases, which dissociates hydrates. The gas tends to flow out of the production well along with water. Gas does not flow out from the bottom boundary because water is heavier than gas. Water flows between the bottom aquifer and the hydrate reservoir.

**3.1.1. Effect of Injection and Production Pressures.** Figure 4a shows the cumulative gas production as a percentage of the original gas in place (OGIP) for different injection and production pressures. For the water injection cases shown, the temperature of the injection water is kept constant at 50 °C. The following nomenclature is used: “2\_injection\_50C\_40” indicates that the production well pressure is 2 MPa, the injection water temperature is 50 °C, and the injection well pressure is maintained at 40 MPa. The lowest production (about 2% OGIP in 8 years) is in the case of no injection, only depressurization. The infinite aquifer does not allow the pressure to go below the initial pressure in the

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**Figure 5.** (a) Gas pressure profile, (b) temperature profile, and (c) hydrate saturation profile after 3000 days for 2 MPa production pressure, 30 MPa injection pressure, and 50 °C injection temperature.

reservoir except in the near-production-well region. The cumulative gas production increases with increasing injection pressure. About 15–25% of the methane can be produced in about 8 years for these warm water injection cases. Production well pressure (4 or 2 MPa) does not affect the gas production significantly. The 2 MPa case has a slightly higher production than the 4 MPa case. Dissociation due to depressurization is only in the region near the depressurization well. The saturation profiles below explain the production mechanisms.

Figure 4b shows the water produced during hydrate production for the different scenarios considered above. Many pore volumes (PV) of water are produced during this process. For example, in 1000 days, for the case with 2 MPa production pressure, 20 MPa injection pressure, and 50 °C injection temperature, about 20 PV of water is produced. Water-to-gas ratio is about 1.8 at 1000 days. It increases to 4.7 in 3000 days. This water includes water dissociated from hydrates, injected water, and some water from the aquifer. As the injection pressure increases, the water production increases, as shown in Figure 4b. Water production is the least for the pure depressurization (no injection) case. The handling of water adds cost to the process and affects the economics (which is not evaluated in this paper).

Figure 5a shows the pressure profile for the horizontal unconfined reservoir studied after 3000 days along the diagonal joining the injection and the production wells. The production well pressure is 2 MPa and injection well pressure is 30 MPa for this case. The injection temperature is 50 °C. The initial reservoir pressure is 9 MPa; initial temperature is 7 °C. The *X*-axis is the diagonal connecting the injection well and the production well (A-B in Figure 1). The *Y*-axis is the vertical position. In unconfined reservoirs, the pressure drop is limited to the region near the wells because the water from the aquifer does not allow the pressure to decrease elsewhere. The injected water goes to the aquifer near the injection well, and the aquifer water comes up to the reservoir near the production well where the reservoir is depressurized. Figure 5b shows the temperature profile for this case. The thermal stimulation has propagated only about half the interwell distance in 3000 days. Figure 5c shows the hydrate saturation after 3000 days. About half of the hydrate dissociates in 3000 days because of the increase in temperature. Only a small amount of hydrate dissociates near the production well (at the bottom half of the well) due to depressurization. The inflow of warm water in horizontal direction to the hydrate layer is very slow due to the low permeability of the hydrate layer. Some amount of hydrate is still present after 3000 days.

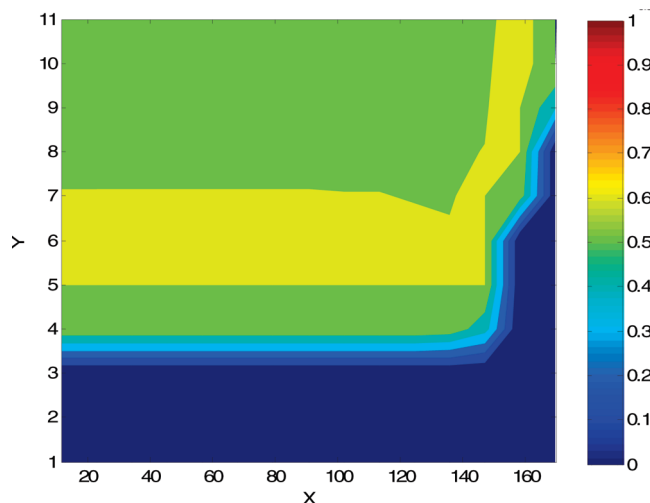


Figure 6. Hydrate saturation after 3000 days for only depressurization.

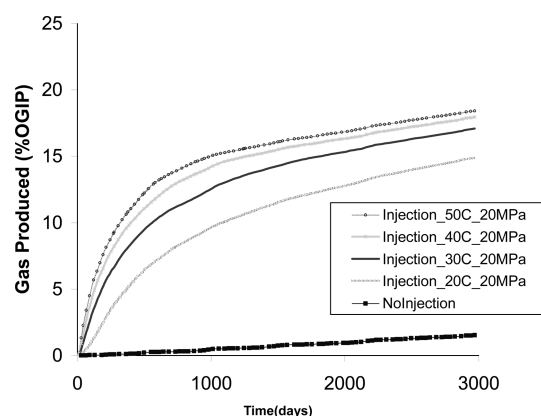


Figure 7. Cumulative gas production for different injection temperatures.

Figure 6 shows the hydrate saturation profile for only depressurization after 3000 days. The dissociation takes place only near the production well and near the aquifer region. The pressure gradient pulls water up from the semi-infinite aquifer. A lot of water is produced. Gas production is less than 2% of OGIP in 3000 days. The depressurization in unconfined reservoir is ineffective.

**3.1.2. Effect of Injection Temperature.** Figure 7 shows the cumulative gas production as a percentage of OGIP for different injection temperatures. The production pressure for these cases is 2 MPa; the injection pressure is fixed at 20 MPa. Increasing injection temperature increases the heat input to the reservoir, and hence, increases the cumulative gas production. However, the incremental difference in the gas production is not high if the temperature is raised beyond 30 °C. As the reservoir temperature increases, the heat loss from the reservoir also increases. At the injection pressure of 30 MPa, warm water is able to sweep only about 50% of the hydrate volume in 3000 days (Figure 5b).

**3.1.3. Effect of Vertical Permeability.** In all the cases discussed above, the vertical permeability was assumed to be identical to the horizontal permeability. The vertical permeability is often much less than the horizontal permeability. Figure 8 shows the effect of vertical to horizontal permeability ratio ( $k_v/k_h$ ) for the case with 2 MPa production pressure, 20 MPa injection pressure, and 30 °C injection

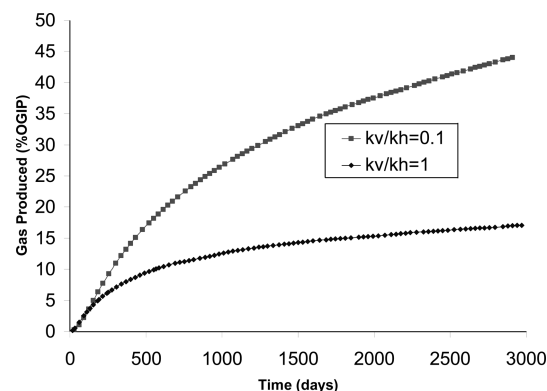


Figure 8. Effect of vertical permeability on cumulative gas production for 2 MPa production pressure, 20 MPa injection pressure, and 30 °C injection temperature.

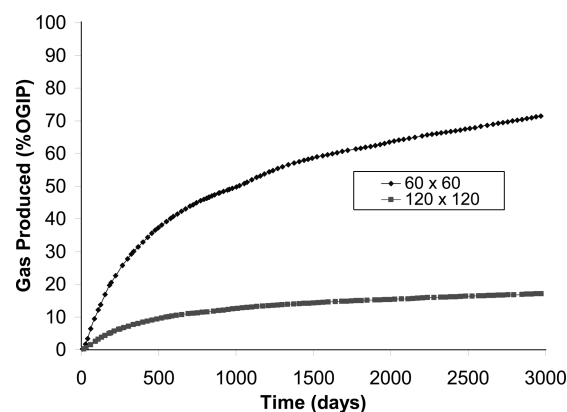
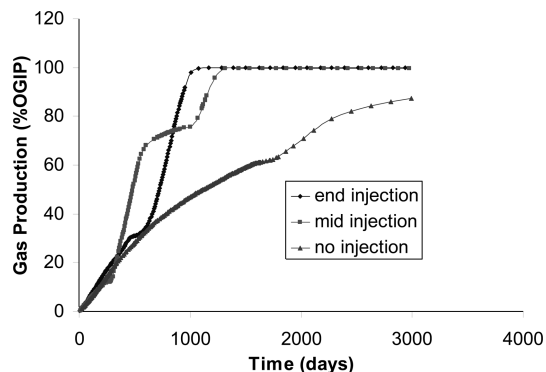


Figure 9. Effect of pattern size on cumulative gas production for injection pressure 20 MPa, injection temperature 30 °C, and production pressure 2 MPa.

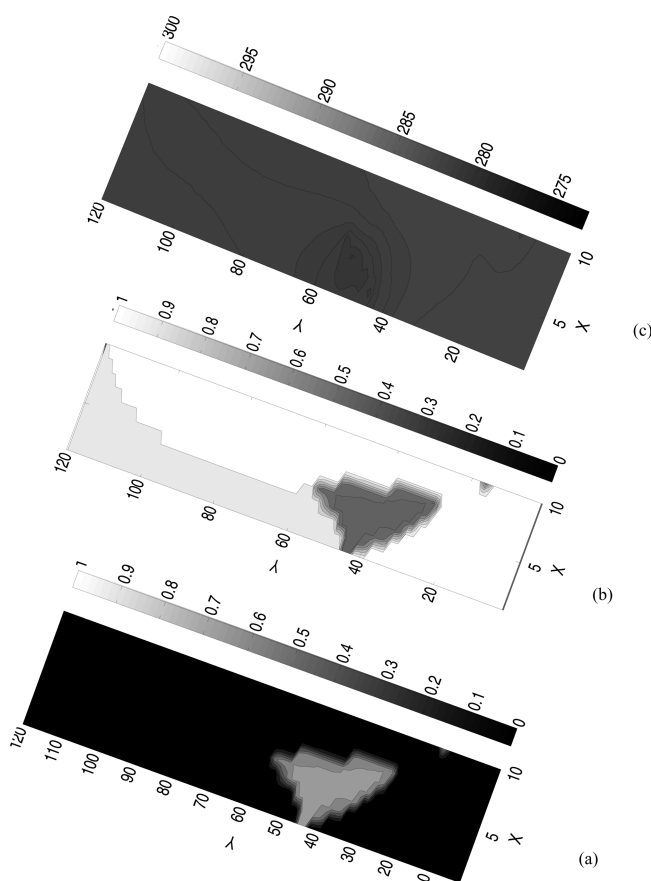
temperature. As the ( $k_v/k_h$ ) decreases, gas production rate increases. When the vertical permeability decreases, flow to aquifer decreases and more warm water reaches the hydrate layer. The gas production is about 45% of OGIP in 3000 days for a  $k_v/k_h$  of 0.1.

**3.1.4. Effect of Five-spot Pattern Size.** The base case pattern assumed for the horizontal reservoir has been a quarter of five-spot of  $120 \times 120$  m. As shown in Figure 5b, the warm water injection increases the temperature only in about half of the reservoir in 3000 days. The pattern size is decreased to see the effect on the cumulative production of gas. Figure 9 shows the effect of pattern size on cumulative gas production for the injection pressure of 20 MPa, the injection temperature of 30 °C, and the production pressure of 2 MPa. As the pattern size is decreased from  $120 \times 120$  m to  $60 \times 60$  m, the gas production in 3000 days increases from 17% OGIP to 71%. Of course, the number of wells per unit area also increases. An optimum can be calculated for a field after accounting for all the costs.

**3.2. Dipping Reservoir.** Hydrate reservoirs may not be horizontal. An unconfined dipping reservoir (Figure 2) with a dip angle of 18° is studied. The reservoir is  $120 \times 10$  m in cross-section. The third dimension is assumed to be 120 m to match its volume with that of the horizontal unconfined reservoir studied above. The initial hydrate and water saturations in this reservoir is assumed to be the same as those in the horizontal reservoir case. Initial pressure is

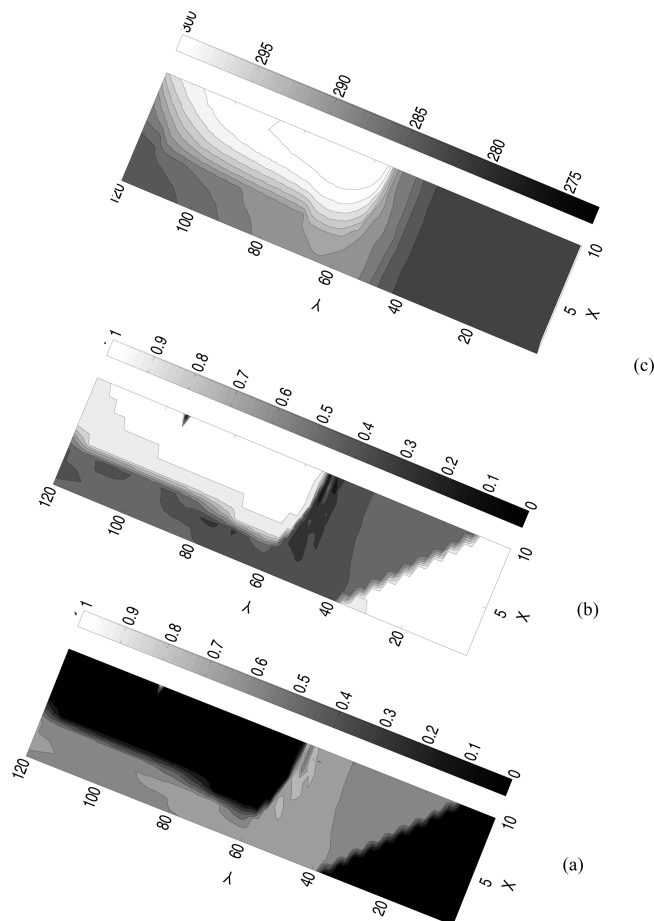


**Figure 10.** Gas production for the dipping reservoir for 2 MPa production pressure, 20 MPa injection pressure, and 30 °C injection temperature.



**Figure 11.** (a) Hydrate saturation profile, (b) aqueous saturation profile, and (c) temperature profile for no injection case after 3000 days.

9 MPa and temperature is 7 °C (same as horizontal reservoir). The reservoir is discretized by  $120 \times 10$  grid-blocks; two-dimensional simulation is conducted. Gas is lighter than the water; so the production well is placed at the top left corner. The depressurization pressure is 2 MPa. Different positions of the injection well are considered, that is, the middle of the reservoir (M) or the end of the reservoir (E). The injection pressure is 20 MPa and the injection temperature is 30 °C. To represent the semi-infinite aquifer at the bottom, the right-most grid-block denoted by point “C” in Figure 2 is given a constant pressure. The water can flow through this boundary depending on the local pressure

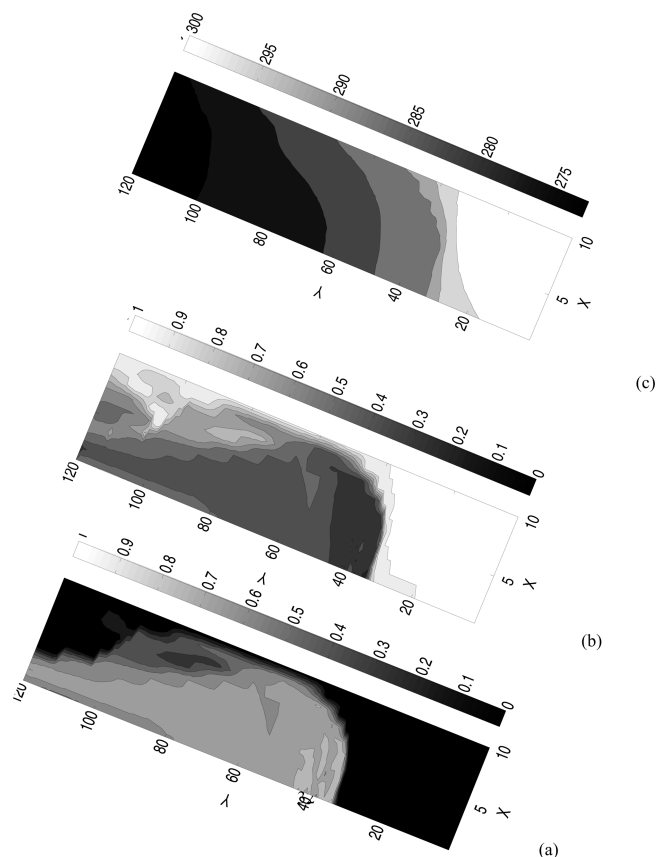


**Figure 12.** (a) Hydrate saturation profile, (b) aqueous saturation profile, and (c) temperature profile for mid injection case after 428 days.

gradient. The other boundaries are considered to be impermeable for mass flow, and heat flow is represented with a heat transfer coefficient.

Figure 10 shows the cumulative gas production as a percentage of original gas in place for three different cases. The “no injection” case stands for only depressurization. In the “end injection” case warm water is injected at point E (in Figure 2) in the water layer. In the “mid injection” case, warm water is injected at the point M (in Figure 2) in the middle of hydrate layer. The gas production is about the same for all the three cases in the 300 days, since the production is mainly due to depressurization at the production well. After that the mid injection gas production rate increases significantly, due to breakthrough of the warm water at the top part of the reservoir. The breakthrough of warm water in the end injection case happens a little later around 600 days, and the gas production rate also increases sharply over that of the no injection case. All the hydrate is dissociated in 1000–1200 days for the warm water injection cases. It takes about 3000 days to produce 87% of the gas in the no injection case.

Gas production is slower, but effective in the no injection unconfined dipping reservoirs. This is because the semi-infinite aquifer is not very close to the production well, unlike that in the horizontal reservoir case. Figure 11 shows the hydrate saturation, aqueous saturation and the temperature profiles at 3000 days for the no injection case. Hydrate saturation profile shows that all the hydrates are not



**Figure 13.** (a) Hydrate saturation profile, (b) aqueous saturation profile, and (c) temperature profile for end injection case after 581 days.

completely dissociated at 3000 days. Dissociation is slow because the latent heat comes from the surrounding medium, primarily through conduction. Temperatures are relatively low.

Figure 12 shows the saturation and temperature profiles at 428 days for the mid injection case. Initially the production is due to depressurization near the production well. The warm water that is injected into the hydrate zone (point M in Figure 2) dissociates the hydrates nearby, and the gas and water move up toward the production well. When the dissociation front originating at the production well due to depressurization and the dissociation front originating at injection well due to thermal stimulation meet, the production rate increases. Figure 12 shows the profiles when the fronts have met each other. The production rate increases because gas can flow easily and more energy is injected in to

the reservoir through increased injection of warm water. The dissociation rate again decreases at about 600 days. This happens when all the hydrates above the injection well have dissociated, but there is hydrate below the injection well. Warm water takes about 1000 days to warm up the bottom region and then gas production rate increases again, as shown in Figure 10.

In the end injection case the warm water is injected in the water layer at point E in Figure 2. In the first 500 days, hydrates dissociate near the production well due to depressurization without being affected by the injection warm water. The water flowing up the structure is very small due to the low water permeability in the hydrate region. When the depressurization front meets the warm water front, the warm water flow up structure increases, which increases the rate of gas production (at about 580 days, as shown in Figure 10). Figure 13 shows the saturation and temperature profiles at 581 days. Hydrates have dissociated from the top part of the reservoir at this time. The injected warm water moves up toward the production well because of the dissociation of the hydrate on the top side of the reservoir. The warm water heats up the middle part of the reservoir which helps in hydrate dissociation. As the injection point of the warm water moves down the reservoir, the start of the high gas recovery phase gets delayed, but the time for completion of gas recovery becomes shorter.

#### 4. Conclusion

Production of methane from gas hydrate reservoirs depends on reservoir confinement, injection temperature, injection pressure, and production pressure. For unconfined horizontal reservoirs, depressurization is ineffective; thermal stimulation is necessary for gas production. Even warm water (temperature  $\approx 30\text{ }^{\circ}\text{C}$ ) injection improves the gas production from hydrate reservoirs. Lower vertical permeability helps the gas production by heating a larger area of the reservoir for hydrate dissociation. As the well spacing decreases, the gas production rate increases. Depressurization alone is effective in dipping unconfined reservoirs, but much slower than warm water injection. As the injection point of the warm water moves down the reservoir, the start of the high gas recovery phase gets delayed, but the time for completion of gas recovery becomes shorter. The cost of wells and warm water must be optimized along with the gas production to determine the optimal strategy for producing hydrate reservoirs.

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