Numerical simulation of Class 3 hydrate reservoirs exploiting using horizontal well by depressurization and thermal co-stimulation

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ABSTRACT

Class 3 hydrate reservoirs exploiting using horizontal well by depressurization and thermal co-stimulation was simulated using the HydarteResSim code. Results showed that more than 20% of hydrates in the reservoirs had been dissociated within 450 days at the well temperature of 42 °C and well pressure of 0.1P0, 0.2P0 (P0 is the initial pressure of the reservoirs, simplifying 42 °C & 0.1P0, 42 °C & 0.2P0). While the production behavior of 42 °C & 0.5P0, 42 °C & 0.8P0 were not so exciting. In order to understand the production character of the well in long term, the cross section of 1 m length reservoirs was simulated. Simulation results showed that 4.5 × 10^6 m^3 gas would be collected within 4500 days and 1.1 × 10^9 kg water could be produced within 1500 days in the well at 42 °C & 0.1P0. 3.5 × 10^7 m^3 gas would be collected within 8500 days and 1.1 × 10^9 kg water could be produced within 1500 days in the well at 42 °C & 0.2P0. The heat flow was 1620 W at the beginning and then decreased rapidly in the last about 1500 days in industry level[18]. Su et al.[20] and Myshakin et al.[21] employed the depressurization and thermal stimulation method to investigate vertical well hydrates dissociation, and simulations[15–17] have testified that these two kind of hydrates are worthy to extract methane. For Class 3 hydrate reservoirs, it is difficult to extract natural gas using single stimulation method through vertical well for their low permeability in the hydrate bearing internal, compared to Class 1, and Class 2 hydrates. It was controversial whether Class 3 hydrates are worthy to exploit considering low economy and energy efficiency [18,19]. Moridis studied the hydrates dissociation by step-by-step depressurization production method, and the results showed that the vertical well could be used for Class 3 hydrates exploitation if the correct strategy was taken. However, the production simulation carried out by Moridis and Reagan only lasted about 1500 days in industry level[18]. Su et al.[20] and Myshakin et al.[21] employed the depressurization and thermal stimulation method to investigate vertical well hydrates dissociation, and found that the gas released rate was too small to reach

1. Introduction

Natural gas hydrates are clathrate nonstoichiometric crystal compound. And hydrate reservoirs exist in the low temperature and high pressure geologic zone, such as the permafrost and marine sediments. It is believed that the amount of carbon in gas hydrate reservoirs on the earth is twice that in proven fossil fuels [1,2]. Many countries paid great attention to hydrates with the traditional fossil energy exhaustion and its wide range of applications developed in many field [3]. America had made all-round studies on hydrate dissociation in industry level [4–7]. Japan had made long-term strategies on the gas hydrates exploitation from Nankai Trough, and they hoped the hydrate reservoirs in Nankai Trough could be dissociated in the near future [8,9]. It is greatly expected that hydrate reservoirs in nature can be dissociated in the near future with the deep-going study of hydrate reservoirs around the world [10,11].

Moridis classified hydrate reservoirs into 4 types [6,11,12], according to reservoirs distributions, reservoir structures, hydrate components and bearing geophysical properties. Class 1 hydrates are composed of two layers. The underlying layer is two phases fluid zone with free gas and water, and the hydrates overlying layer is saturated with water and hydrates (Class 1W) or gas and hydrates (Class 1G) [13]. Class 2 deposits are also comprised of two zones, an overlying hydrates bearing and a mobile water zone. Class 3 deposits consist of three zones. The top and bottom are impermeability layers, and the middle layer is hydrate reservoirs layer. Class 4 deposits contain one zone, in which the hydrate saturation is very low (less than 0.1) and hydrates are dispersed in the deposits. Hence, it is worthless to exploit Class 4 deposits with the present technology for the small amount of hydrates in each unit volume of reservoirs [14]. The Class 1,2 hydrates with the mobile fluid in the under layers, the Class 1G hydrates can be produced by depressurization method[13], and Class 1W and Class 2 hydrates can be produced in depressurization method with the help of thermal stimulation, and simulations[15–17] have testified that these two kind of hydrates are worthy to extract methane.
industry-scale commercial production. Li et al. attempted to produce gas by depressurization and the pull and hull method in horizontal well, but the results were not as satisfactory as expected [19,22–24]. Bai et al. used the combination method of warm water flooding and depressurization to produce gas from Class 3 hydrate reservoirs by vertical well. Their research showed that the combination method contributed more to enhancing the stable period at high gas released rate than single stimulation method [25,26]. At the same time, Li et al. tried the lab experiment research in hot-brine injection and got the conclusion that the combine of thermal depressurization and thermal co-stimulation would be better for gas production from hydrate reservoirs [27]. A good introduction and summary in hydrate dissociation can be obtained from Ahmadi [28].

From the above analysis, gas production from Class 3 hydrate reservoirs by the vertical well is not suitable because of the single hydrate bearing internal and two impermeability layers structure of Class 3 hydrate reservoirs. So the horizontal well can be more favorable for gas extraction. At the same time, studies showed that depressurization can be particularly important for gas production from hydrate reservoirs for their hydrate dissociation and temperature infiltrating effect [29]. In this paper, we utilized the depressurization and thermal co-stimulation to exploit natural gas from Class 3 hydrate reservoirs using horizontal well, aiming to work out a feasible extraction strategy for Class 3 hydrates in industry level.

2. Physical model and gas production strategy

2.1. Reservoirs properties

![](image)

**Fig. 1.** Class 3 hydrate reservoirs structure characters sketch map defined by Moridis.

Fig. 1 shows the structure of Class 3 hydrate reservoirs with one impermeable top cover layer, one impermeable bottom layer, and one hydrate bearing layer. Many factors can affect the gas production from hydrate reservoirs [6]. In this paper, we just discuss those properties that greatly affect the economy and energy efficiency for gas production from hydrate reservoirs. The permeability of the top and bottom layers is impervious in Moridis’ definition. While the permeability of the top and bottom layer in this work is different from that of the hydrate bearing layer, and the Van Genuchten Capillary pressure model would be used [30].

A Class 3 hydrate reservoirs model was built based on the data of Shenhui site SH7 area hydrate reservoirs in China. The hydrate bearing layer exists 1108–1245 m under the water with thickness of 10–43 m (20 m of hydrate bearing layer, 30 m top and 30 m bottom layers were used in this work). The sediment porosity measured from pressure cores is 0.33–0.48 (0.4 was used in hydrate bearing layer, and 0.2 was used in top and bottom layers) and in situ salinity is 0.0290–0.0315 (0.0030 in this paper) in weight [22,23]. Wire-line logging features of site SH7 were described by Wu et al. [31]. Reservoir parameters used in this simulation were shown in Table 1, and the other parameters were set as default in HydrateResSim code [32].

2.2. Reservoirs discretization

The dimension of the studied hydrate reservoirs is 1495.2 × 400 × 80 m. The calculated thickness of the reservoirs in geophysical survey was 80 m. The horizontal dimensions in X, Y directions were 1495.2 m and 400 m respectively. The value of dimension width, 400 m, was set after referenced Grover’ physical model whose value was 350 m in diameter [7]. The horizontal length was set as 1495.2 m to ensure that the reservoirs contain large amount of hydrates, and if correct strategy were taken, large amount of natural gas would be produced. In X direction, the total length, 1495.2 m, was divided into 300 grids, where 299 grids are equal-length, i.e., 5 m intervals and 1 grid is 0.2 m which was used to locate the vertical part of well. In Y direction, the total width, 400 m, was divided into 3 intervals, i.e., 199.9 m for the two side grids, and 0.2 m for the well in the center. In Z direction, the total thickness, 80 m, was divided into 55 intervals and their length ranged from 0.2 m to 1 m for hydrate bearing layer, and 1–2 m for top and bottom layers. The total grids number was 49,500 (55 × 300 × 3), 3D model mesh of the reservoirs was shown in Fig. 2. The Dirichlet conditions of fixed pressure & temperature were applied for the most top-layer and most bottom-layer grids (300 × 3), and Neumann boundary conditions of no fluxes of mass & heat for the boundary grids of the other two directions [32]. The 2D model of a cross section slice with 165 (3 × 55) grids in 1 m length reservoirs is employed for gas collection, water production and heat flow study.

2.3. Well design and production strategy

The cross section dimension of the well is 0.2 × 0.2 m. The well is in “L” form, whose horizontal and vertical length is 1495 m and 40 m, respectively. The vertical part of the well was located in a slice of 0–0.2 m in X direction. In Y direction, the coordinate was 199.9–200.1 m, and in Z direction, the coordinate was 0 to −40 m. The horizontal part of the well was located in the center of 80 m reservoirs in cross section of 0.2 × 0.2 m (also in the Hydrate bearing layer center), in X direction, the coordinate was 0.2–1495.2 m, in Y direction, the coordinate was 199.9–200.1 m, and in Z direction, the coordinate was −39.9 to −40.1 m. The well profile was shown in Fig. 3.

The simulations were conducted in two steps. Firstly, the 3D model of 80 × 400 × 1495.2 m hydrate reservoirs were studied. Secondly, the 2D cross section 80 × 400 × 1 m reservoirs were used to investigate the fluid behavior and heat flow in the well. Both in the 3D and 2D simulations, the well temperature was set as 42 °C for energy saving, second hydrates & ice formation proof. The well pressure were set as constant value every time. And then repeated simulation by changing pressure value to investigate pressure effect, i.e., 0.1P0, 0.2P0, 0.5P0, 0.8P0. So the cost effective production parameters were set as 42 °C & 0.1P0, 42 °C & 0.2P0, 42 °C & 0.5P0 and 42 °C & 0.8P0 respectively.

2.4. Numerical simulation code

HydrateResSim is an open source code, a member of TOUTH+ HYDRATE family from the National Energy Technology Laboratory (NETL) developed by Moridis et al. [32]. The code describes the gas-water system in mathematical models which governs the dissociation of methane hydrate reservoirs by depressurization, thermal stimulation, and inhibitor (like sodium chloride, methanol, etc.)
Table 1
Shenhua area hydrate reservoirs properties.

<table>
<thead>
<tr>
<th>Items</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrate bearing layer thickness</td>
<td>20 m</td>
</tr>
<tr>
<td>Top cover layer thickness</td>
<td>30 m</td>
</tr>
<tr>
<td>Bottom layer thickness</td>
<td>30 m</td>
</tr>
<tr>
<td>Initial pressure for reservoirs</td>
<td>$P_0 = 1.383 \times 10^7$ Pa</td>
</tr>
<tr>
<td>Pressure in the well</td>
<td>0.2$P_0$, 0.5$P_0$, 0.8$P_0$</td>
</tr>
<tr>
<td>Initial temperature</td>
<td>14.15 °C</td>
</tr>
<tr>
<td>Gas composition</td>
<td>100% of methane</td>
</tr>
<tr>
<td>Initial saturations for hydrate reservoirs</td>
<td>$S_{i,H} = 0.44:0.56$</td>
</tr>
<tr>
<td>Water salinity</td>
<td>3% by weight</td>
</tr>
<tr>
<td>Intrinsic permeability for hydrate-bearing layer</td>
<td>75 mD</td>
</tr>
<tr>
<td>Intrinsic permeability for top and bottom layer</td>
<td>45 mD</td>
</tr>
<tr>
<td>Geothermal gradient</td>
<td>0.0433 K/m</td>
</tr>
<tr>
<td>Grain density</td>
<td>2600 kg/m³</td>
</tr>
<tr>
<td>Porosity of hydrate reservoirs</td>
<td>0.41</td>
</tr>
<tr>
<td>Porosity of top and bottom layer</td>
<td>0.2</td>
</tr>
<tr>
<td>Dry thermal conductivity</td>
<td>3.1 W/(m/K)</td>
</tr>
<tr>
<td>Relative permeability model</td>
<td></td>
</tr>
<tr>
<td>Intrinsic permeability of aqueous</td>
<td></td>
</tr>
<tr>
<td>Intrinsic permeability of gas</td>
<td></td>
</tr>
<tr>
<td>Saturation of aqueous</td>
<td></td>
</tr>
<tr>
<td>Saturation of gas</td>
<td></td>
</tr>
<tr>
<td>Permeability reduction exponent</td>
<td>$n = 3.572$</td>
</tr>
<tr>
<td>Gas permeability reduction exponent</td>
<td>$n^f = 3.572$</td>
</tr>
<tr>
<td>Irreducible gas saturation</td>
<td>$S_{irr} = 0.05$</td>
</tr>
<tr>
<td>Irreducible aqueous saturation</td>
<td>$S_{irr} = 0.30$</td>
</tr>
<tr>
<td>Capillary pressure model</td>
<td>$P_{co} = P_{co}(S^n((1-i)/(1-i))-1(i))$, $i = 0.45$</td>
</tr>
<tr>
<td>Irreducible aqueous</td>
<td></td>
</tr>
<tr>
<td>Van Genuchten exponent</td>
<td>$S_{irr} = 0.29$</td>
</tr>
<tr>
<td></td>
<td>$P_{co} = 10^3$ Pa</td>
</tr>
</tbody>
</table>

For single driving force or co-stimulation. The code even can be applied to systems of laboratory scales hydrate dissociation [33]. It handles the transportation of multiple temperature-dependent components in multiple phases through a porous medium. The model equations are obtained by governing the multiphase Darcy’s law for natural gas and water system into both the mass component balances and the energy conservation equations for hydrate reservoirs. The code includes two sub models for hydrate dissociation. One is a kinetic model and the other is equilibrium model. The Newton–Raphson method was used to solve the linear equations after discretization of the reservoirs and construction of the Jacobin matrix. For the large number grids model of hydrate dissociation in industry level, there are no great differences between kinetic and equilibrium reaction models [34]. Equilibrium reaction models would be used in this paper for the less memory and computing requirement.

3. Results and discussion

3.1. Reservoirs dissociation in 3D model

The dissociation of the hydrates in the porous media can improve the fluid mobility and promote efficiency of depressurization and thermal stimulation, which would induce more hydrates to be dissociated. The effect of the depressurization and thermal driving force could continue a long time of 10–30 years, and the hydrates in several hundred meters reservoirs could be dissociated. The gas and water would be collected in the well smoothly if the correct strategies were taken.

Fig. 4 displays the gas released rate in the 3D model reservoirs simulation. The gas was released from the reservoirs at an average rate of 4–5 m³/s for 450 days in the cases of 42 °C & 0.1$P_0$ and 42 °C & 0.2$P_0$. For the case of 42 °C & 0.5$P_0$ and 42 °C & 0.8$P_0$, the gas released rate was about 3.0–3.5 m³/s, 0.5–1 m³/s in average respectively. Requirement of gas released rate in natural gas commercial production was about 3.0 × 10³ m³/day or about 10 Million Standard Cubic Feet per Day (MSCFD) [17]. The gas released rate in this simulation was large enough for gas production in industry level for 42 °C & 0.1$P_0$, 42 °C & 0.2$P_0$ and 42 °C & 0.5$P_0$ cases. And the gas released rate was larger than that of Mallick thermal stimulation field test for 468 m³ in several days production [10]. However, reservoirs were stable under production conditions of 42 °C & 0.8$P_0$ even at the beginning of depressurization and thermal co-stimulation process.

The dissociated hydrates would generate large amount of water and gas in the reservoirs. A large volume of gas would be cumulated in the reservoirs for a long time, and large amount would be collected in the well if the pressure differential was large enough between the well and the reservoirs. With the collection of the released fluid in the well, the depressurization effect could spread to a large area further, and more hydrates would be dissociated. Fig. 5 was the relationship between residual hydrates and time. About 25% or 1.1 × 10⁷ kg hydrates had been dissociated under the conditions of 42 °C & 0.1$P_0$, and about 25% or 9.2 × 10⁷ kg hydrates had been dissociated under the conditions of 42 °C & 0.2$P_0$ within 450 days. For the case of 42 °C & 0.5$P_0$, about 15% or 6.9 × 10⁷ kg of the hydrates had been dissociated, and for the case 42 °C & 0.8$P_0$ just about 4% or 2.2 × 10⁷ kg hydrates in the reservoirs had been dissociated within 450 days. The driving force of depressurization greatly affected the gas released rate under the same well temperature. This conclusion was consistent with the research from Ahmadi et al. in an analytical solution [28,35]. And the research of dimensionless parameters sensitivity analysis from Bai also showed that the depressurization was very important for the reason that pressure difference between the equilibrium pressure and the well pressure was the driving force of hydrate dissociation [29].

Fig. 6 shows the cumulative gas from hydrates in the production of natural gas. More than 1.9 × 10⁶ m³ natural gas was released from the reservoirs in 42 °C & 0.1$P_0$ case, and about 1.6 × 10⁶ m³ natural gas was released from the reservoirs in 42 °C & 0.2$P_0$ case. 1.3 × 10⁷ m³, and 3.0 × 10⁷ m³ natural gas was released from 42 °C & 0.5$P_0$, 42 °C & 0.8$P_0$ cases respectively. Based on the 3D model simulation results, the natural gas released rate from Class 3 hydrate reservoirs was about 230–280 m³/(m day) in average under condition of 42 °C & 0.1$P_0$ and 42 °C & 0.2$P_0$, much larger than the simulation result from Li et al. in 10 m³/(m day) in average [22] and consistent with the simulation result from Moridis about 200 m³/(m day) [11]. Their simulation results were gotten from ten days trial production simulation. The simulation results of this model were gotten from 450 days production based on the 3D model simulation. From the 3D model simulation work in this paper, Class 3 hydrate reservoirs could be exploited in industry level with depressurization and thermal co-stimulation using horizontal well under the conditions of 42 °C & 0.1$P_0$, 42 °C & 0.2$P_0$, 42 °C & 0.5$P_0$. As to 42 °C & 0.8$P_0$ case, gas released rate was not large enough for industry level production, at the same time, most of released gas would stay in the reservoirs for the small depressurization driving force between reservoirs and well in this case according to the Darcy law. And the fluid flow behaviors in the well would be studied further in the 2D 1 m length reservoirs model.

3.2. 2D reservoirs simulation

To evaluate the energy efficiency, and to study the fluid behavior in the well and check the potential of Class 3 hydrate
exploitation in long term in industry level, the cross section 1 m length reservoirs (80 x 400 x 1 m) 2D model was built in this work. The 2D mesh was shown in Fig. 7.

3.2.1. Reservoirs dissociation in 2D model

Fig. 8 was the gas released rate of 1 m 2D reservoir dissociation. The gas production continued for about 4500 days (13 years) under the conditions of 42 °C & 0.1P0 and about 8500 days (about 23 years) under the conditions of 42 °C & 0.2P0, 42 °C & 0.5P0, 42 °C & 0.8P0. For 42 °C & 0.1P0 case, the gas release rate was about $2.5 \times 10^{-3}$ m³/s (or 215 m³/day) in average for the total 4500 days production. For 42 °C & 0.2P0 case, at the beginning, the gas release rate was $5.5 \times 10^{-3}$ m³/s (or 475 m³/day) and then decreased to $1.0 \times 10^{-3}$ to $5.0 \times 10^{-4}$ m³/s level and lasted about 4000 days at this level. The gas release rate for remaining 4500 days was about $5 \times 10^{-4}$ m³/s. For cases of 42 °C & 0.5P0 and 42 °C & 0.8P0, the production lasted about 8300 days and 8200 days respectively. For case of 42 °C & 0.5P0, the gas released rate was $1.0 \times 10^{-3}$ to $5.0 \times 10^{-4}$ m³/s for the beginning 2000 days and smaller than $5 \times 10^{-4}$ m³/s for the left 6300 days. For the case of 42 °C & 0.8P0, the gas released rate was less than $2 \times 10^{-4}$ m³/s even at the beginning of the production. The gas released rate in the 2D model was consistent with the gas released rate in 3D model, also in the level of 40–500 m³/(m day) in 42 °C & 0.1P0, 42 °C & 0.2P0, 42 °C & 0.5P0 cases and less than 40 m³/(m day) in 42 °C & 0.8P0 case.

There were $3.6 \times 10^6$ kg hydrates in total in the 2D model in 1 m length reservoirs. Fig. 9 describes the residual hydrates in the reservoirs with the natural gas production from. Under the condition of 42 °C & 0.1P0, all the hydrates were dissociated within 4500 days, and there were also no residual hydrates in the reservoirs after 8500 days production for 42 °C & 0.2P0 case. For case of 42 °C & 0.5P0, about $1.5 \times 10^6$ kg hydrates were left after 8300 days production, for case of 42 °C & 0.8P0, more than $2.5 \times 10^6$ kg hydrates were left in the end. In all the cases, the hydrate dissociation rate could be indicated in the gas released rate figure in Fig. 8. Fig. 10 shows the cumulative gas in the reservoirs. Under the condition of 42 °C & 0.1P0, 42 °C & 0.2P0 cases, in the end, the cumulative gas peaked for 6.8 × 10¹⁰ m³ in the two cases, which meant $1.0 \times 10^3$ m³ gas could be produced in 1495.2 m reservoirs. For the case of 42 °C & 0.5P0, cumulative gas was about $4.0 \times 10^9$ m³ within 8300 days for 1 m reservoirs and $6.0 \times 10^8$ m³ for 1495.2 m reservoirs. For case of 42 °C & 0.8P0, the cumulative gas was about $2.9 \times 10^9$ m³ for 8200 days for the 1495.2 m reservoirs. The cumulative gas in this study was consistent with the simulation result from Moridis in Class 2 hydrates production simulation in Ulleung basin in Korea, in thousands million cubic meter level [36].

Driving force of hydrate dissociation came from the depressurization and thermal co-stimulation. At constant temperature in the well, the lower the well pressure, the larger the gas released rate could be obtained. From the data in Figs. 4 and 8, a larger gas released rate was got from the larger depressurization driving force.
in 42 °C & 0.1P₀ and 42 °C & 0.2P₀, 42 °C & 0.5P₀ cases. On the contrary, the smaller gas released rate in 42 °C & 0.8P₀ case contributed to the small depressurization driving force. In the cases of 42 °C & 0.1P₀ and 42 °C & 0.2P₀, hydrate dissociation in large gas released rate could consume large amount of sensible heat of the reservoirs. Heating strategy was taken proof the second hydrates and ice formation which would be induced by the rapid dissociation of hydrates by the big depressurization driving force [37,38]. To ensure the successful production in long term, heating strategy also would be taken in dissociating of hydrates in permafrost sediments [19].

3.2.2. Fluid flow in the well in 2D model

Hydrate dissociation could generate large amount of water and gas in the reservoirs, and the fluid could be collected in the well. Due to the permeability of hydrate reservoirs, the gas collected in the well was less than the gas released from the reservoirs for Class 3 hydrates dissociation, Kurihara pointed out, in the favorable case, more than 60% of the released natural gas could be collected in the well. And if the correct strategy was taken, all the natural gas released from the hydrates could be collected in the well [8]. Gas collecting rate was determined by the cumulative gas in the reservoirs, permeability of the reservoirs and the pressure differential between reservoirs and well.

Fig. 11 describes the gas collecting rate with time under different conditions. The change of gas collecting rate was consistent with that of the gas released rate showed in Fig. 8. In Fig. 8, the gas released rate from the reservoirs decreased rapidly in all the four cases. Gas released rates were the largest at the beginning period. However, the gas collection situation was different. In the case of 42 °C & 0.1P₀, the gas collecting rate increased dramatically after a period of about 100 days lagging behind and then kept relatively stable in $1.2 \times 10^{-3}$ m³/s (about 100 m³/(m day)) level within 4000 days, and then decreased rapidly to $2 \times 10^{-4}$ m³/s within about 1000 days in the end. In the case of 42 °C & 0.2P₀, the gas collecting rate increased dramatically after a period of about 200 days lagging behind and then kept relatively stable in $6 \times 10^{-4}$ m³/s level within 4000 days, and then decreased slowly to $2 \times 10^{-4}$ m³/s within the later 4000 days. While in 42 °C & 0.5P₀ case, the gas collecting rate lagged behind about 300 days and then increased from 0 to $5.6 \times 10^{-4}$ m³/s within 2000 days. Then decreased to $1 \times 10^{-4}$ m³/s within about 1000 days, and lasted about 3000 days in this level. The character of the gas collecting rate was different from that of the lab level experiment. In lab experiment, gas collecting rate can be identified to several stages in Li et al. [39]. However, the gas released rate and the gas collecting rate cannot be divided to several stages clearly in Figs. 8 and 11. In 42 °C & 0.8P₀ case, the gas collecting rate kept nearly $0 \times 10^{-4}$ m³/s in long time production. However, from Fig. 8, the gas released rate from the reservoirs was at a small rate in the case 42 °C & 0.8P₀, but it was not 0 m³/s. This indicated that all the released gas stayed in the reservoirs under this condition. The
cumulative gas in the well was about $4.5 \times 10^5$ m$^3$ under 42 °C & 0.1$P_0$ condition in 1 m reservoirs, and for length of 1495.2 m reservoirs, $6.7 \times 10^5$ m$^3$ (about 100 m$^3$/(m day)) natural gas could be collected in 4500 days production. The cumulative gas in the well was about $3.5 \times 10^5$ m$^3$ under 42 °C & 0.2$P_0$ condition in 1 m reservoirs, and for length of 1495.2 m reservoirs, $5.3 \times 10^5$ m$^3$ (about 41 m$^3$/(m day)) natural gas could be collected in 8500 days. Under 42 °C & 0.5$P_0$ condition, $2.3 \times 10^5$ m$^3$ could be collected. There was no gas collected in the well under 42 °C & 0.8$P_0$ conditions, as shown in Fig. 12.

Fig. 13 describes the variation of cumulative water with time. In the cases of 42 °C & 0.1$P_0$, 42 °C & 0.2$P_0$, the cumulative water weight was $1.1 \times 10^6$ kg and hardly increased after 1500 days. This indicated that water did not flow into the well after 1500 days exploiting. In 42 °C & 0.5$P_0$ case, the water collection lasted about 5000 days, and the total weight of the water was about $1.1 \times 10^6$ kg. For case of 42 °C & 0.8$P_0$, $7.1 \times 10^5$ kg water could be collected within 8200 days production. From Fig. 11, the gas collecting rate was kept in a large value after 15000 days production under the 42 °C & 0.1$P_0$, 42 °C & 0.2$P_0$, 42 °C & 0.5$P_0$ condition. However, the water collecting rate was very small at this time, which indicated that more gas and less water would be collected in the well for long term production, and the gas collection was lagged behind the collection of water. Comparing Figs. 8 and 13, the gas released rate synchronized with water collecting rate under the condition 42 °C & 0.1$P_0$, 42 °C & 0.2$P_0$ and 42 °C & 0.5$P_0$.

3.2.2.3. Heat flow and depressurization to hydrate dissociation in 2D model

From Fig. 13, the water production in the well increased rapidly at the beginning, which was consistent with the high heat flow at the beginning of the dissociation showed in Fig. 14. From Fig. 14, heat flow was 1620 W at the beginning in the cases 42 °C & 0.1$P_0$, 42 °C & 0.2$P_0$, 800 W for the case of 42 °C & 0.5$P_0$, and 400 W for the case of 42 °C & 0.8$P_0$. After about 2000 days production, the system did not consume energy any more in all the four cases. In Fig. 8, the gas released rates were in a large value at time point of 1500 days in 42 °C & 0.1$P_0$, 42 °C & 0.2$P_0$ cases. However, at this time, the reservoirs system did not consume large amount of energy (less than 50 W), which indicated that hydrates dissociation was contributed mainly by driving force of depressurization.

In hydrate dissociating process, the depressurization was very important in two aspects. The first was to dissociate hydrates efficiently, and the second was to help gas and water collection in the well. From the hydrate residual profile shown in Fig. 9, all the hydrates had been dissociated in cases of 42 °C & 0.1$P_0$, 42 °C & 0.2$P_0$. In 42 °C & 0.5$P_0$ and 42 °C & 0.8$P_0$ cases about 65% and 50% of the hydrate had been dissociated respectively. According to Darcy’s law, if the pressure differential between well and reservoirs was not large enough, the fluids could not go into the well smoothly, and would greatly hinder the hydrate dissociation and the fluid flowing to the well. From Fig. 10, Fig. 12 more than 65% of the released gas had been collected in the well in 42 °C & 0.1$P_0$ case, and about 50% of the released gas had been collected in the well in 42 °C & 0.2$P_0$ case, 35% for the 42 °C & 0.5$P_0$ case, while no natural gas had been collected in 42 °C & 0.8$P_0$ case. From Fig. 10, large amount of released natural gas stayed in the reservoirs in 42 °C & 0.8$P_0$ case, while there was no gas collected in the well. This indicated that the released gas stayed at the reservoirs for long time for the small pressure difference between well and the reservoirs in 42 °C & 0.8$P_0$ case. The gas stayed in the reservoirs would hinder hydrate dissociation further.

The depressurization was the critical factor to hydrate dissociation for Class 3 hydrate dissociation, and the larger the differential pressure between the well and the reservoirs, the more gas could be collected. While, from the traditional oil production engineering, the pressure in the well was a key operation parameter, and the lowering well pressure can be very expensive. The role of a petroleum production engineer is to maximize the well deliverability in an energy-saving and cost-effective manner. From this perspective, the operation parameters of 42 °C & 0.1$P_0$ would not be taken. And the parameters between 42 °C & 0.2$P_0$ and 42 °C & 0.5$P_0$ could be feasible in engineering.

![Fig. 9. Hydrates residual under different pressure for 2D simulation.](image1)

![Fig. 10. Cumulative gas under different pressure for 2D simulation.](image2)

![Fig. 11. Gas collecting rates in the well under different pressure for 2D simulation.](image3)
be dissociated to recover natural gas in the industry level and good economic and social effect would be got. The gas released rate could reach to $4.2 \times 10^3$ m$^3$ per day in 42°C & 0.1P$_0$ and 3.5 $\times 10^5$ m$^3$ per day 42°C & 0.2P$_0$ cases in the 3D model simulation, and could satisfy the industry production requirement of 3.0 $\times 10^5$ m$^3$ per day. In the 2D 1 m reservoirs simulation, all the hydrates had been dissociated within 4500 days under the condition of 42°C & 0.1P$_0$ and all the hydrates had been dissociated within 8500 days under the condition of 42°C & 0.2P$_0$. The gas released rate peaked for 40–500 m$^3$ (m day) level. The cumulative gas in the well was 4.5 $\times 10^5$ m$^3$ under 42°C & 0.1P$_0$ condition and 3.5 $\times 10^5$ m$^3$ under 42°C & 0.2P$_0$ condition. About 1.1 $\times 10^6$ kg water was collected in the well within 1500 days, and the heat flow was 1620 W at beginning and then decreased rapidly in the two cases. Considering the production should be energy-saving and cost-effective, the operation parameters between 42°C & 0.2P$_0$ and 42°C & 0.2P$_0$ could be feasible in engineering. However, the production situation in 42°C & 0.8P$_0$ was not so positive. These indicated that the Class 3 hydrate reservoirs could be exploited in the industry level by large depressurization and thermal co-stimulation driving force using horizontal well.

4. Conclusions

The simulation results of Class 3 hydrates reservoirs dissociation in 3D and 2D models using HydrateResSim code were exciting. The Class 3 hydrate reservoirs of Shenhu area in South China could

**Fig. 12.** Cumulative gases in the well under different pressure for 2D simulation.

**Fig. 13.** Cumulative water under different pressure for 2D simulation.

**Fig. 14.** Heat flow to the reservoirs under different pressure for 2D simulation.

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