ANALYSIS OF 2007/2008 JOGMEC/NRCAN/AURORA MALLIK GAS HYDRATE PRODUCTION TEST THROUGH NUMERICAL SIMULATION

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ABSTRACT

Methane hydrate (MH) production tests were conducted using the depressurization method in the Mallik production program in April 2007 and in March 2008. In addition to attaining the first and the only successful methane gas production to the surface from a MH reservoir in the world, various data were obtained. The results of the production test were analyzed using a numerical simulator (MH21-HYDRES). This paper evaluates these test results through the analyses of production test data, numerical modeling and a series of history matching simulations.

In 2007, a certain amount of gas and water were produced from a 12 m perforation interval in one of the major MH reservoirs at the Mallik site in Canada, by reducing the bottomhole pressure down to about 7 MPa. However, because of the irregular pumping operations, the produced gas was not directly delivered to the surface via the tubing, but was accumulated at the top of the casing. In 2008, much larger and longer gas production was accomplished with a stepwise reduction of the bottomhole pressure down to about 4.5 MPa, resulting in the gas and water produced to the surface.

The flow rates of gas and water from the reservoir sand face in these tests were estimated by the comprehensive analysis of the continuously monitored data. The test results were then analyzed using MH21-HYDRES. The reservoir model was tuned through history matching so as to reproduce the flow rates of gas and water estimated in the above, not only by simply adjusting reservoir parameters, but by introducing the concept of the improvement/reduction of near-wellbore permeability reflecting the creation/deformation of high permeability zones associated
with the sand production. This series of history matching simulation studies clarified the mechanisms of MH dissociation and production during the tests.

**Keywords:** methane hydrates, production test, numerical simulation, history matching

**NOMENCLATURE**

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$A$</td>
<td>cross sectional area [L$^2$]</td>
</tr>
<tr>
<td>$D$</td>
<td>depth [L]</td>
</tr>
<tr>
<td>$g$</td>
<td>gravity acceleration [L/t$^2$]</td>
</tr>
<tr>
<td>$G$</td>
<td>accumulated gas volume [L$^3$]</td>
</tr>
<tr>
<td>$k$</td>
<td>absolute permeability [L$^2$]</td>
</tr>
<tr>
<td>$k^*$</td>
<td>effective permeability to single flowing phase in the presence of methane hydrate [L$^2$]</td>
</tr>
<tr>
<td>$k_e$</td>
<td>effective permeability [L$^2$]</td>
</tr>
<tr>
<td>$k_r$</td>
<td>relative permeability</td>
</tr>
<tr>
<td>$N$</td>
<td>permeability reduction exponent</td>
</tr>
<tr>
<td>$p$</td>
<td>pressure [M/Lt$^2$]</td>
</tr>
<tr>
<td>$q$</td>
<td>production rate [L$^3$/t]</td>
</tr>
<tr>
<td>$Q$</td>
<td>cumulative production [L$^3$]</td>
</tr>
<tr>
<td>$r$</td>
<td>radius [L]</td>
</tr>
<tr>
<td>$S$</td>
<td>phase saturation</td>
</tr>
<tr>
<td>$t$</td>
<td>time [t]</td>
</tr>
<tr>
<td>$T$</td>
<td>temperature [T]</td>
</tr>
<tr>
<td>$V$</td>
<td>volume content</td>
</tr>
<tr>
<td>$W$</td>
<td>water volume in annulus [L$^3$]</td>
</tr>
<tr>
<td>$x$</td>
<td>fraction of high permeability part</td>
</tr>
<tr>
<td>$z$</td>
<td>gas compressibility factor</td>
</tr>
<tr>
<td>$\gamma$</td>
<td>pressure gradient [M/L$^2$t$^2$]</td>
</tr>
<tr>
<td>$\rho$</td>
<td>phase density [M/L$^3$]</td>
</tr>
<tr>
<td>$\phi$</td>
<td>porosity</td>
</tr>
</tbody>
</table>

Superscript:

- $o$ original
- $ph$ phoenix gauge
- $s$ standard condition
- $sh$ shale
- $-surface$ measured at surface
- $t$ total
- $w$ water phase
- $wp$ pumped water

**INTRODUCTION**

At Mallik site located in Mackenzie Delta, Northwest Territories of Canada, the 1998 JAPEX/JNOC/GSC Mallik 2L research well program was conducted in 1998, in which the research well 2L-38 was drilled through MH reservoirs and a variety of engineering data including the well log data and the first permafrost MH core samples were collected [1]. In 2002, JAPEX/JNOC/GSC et al. Mallik 5L-38 gas hydrate production research well program was conducted. In this program, the 124 hour thermal stimulation test was performed at another research well 5L-38 along with 2 monitoring wells of 3L-38 and 4L-38, accomplishing the production of 468 m$^3$ of total gas from one of the MH reservoirs by hot water circulation for the first time in the world [2]. Furthermore, 6 pressure drawdown tests were conducted using Schlumberger’s Modular Formation Dynamics Tester™ (MDT) wireline tool at this well [3], the results of which showed the promise of much more gas production from MH reservoirs at this site by the depressurization method [4, 5, 6].

In response to the results of the above tests at the 5L-38 well, the 2006-08 JOGMEC/NRCan/Aurora Mallik gas hydrate production research program was conducted with a central goal to measure and monitor the production response of a terrestrial gas hydrate deposit to pressure drawdown (depressurization). The Japan Oil, Gas and Metals National Corporation (JOGMEC) and Natural Resources Canada (NRCan) funded the program and lead the research and development studies. Aurora College/Aurora Research Institute was acting as the operator for the field program. Since this site was accessed by ice roads that are
available only in the winter season, the production test was conducted in two winter seasons of the years 2007 and 2008. In 2007, the production well was completed in the Zone A MH reservoir by re-entry of the 2L-38 well followed by the short term production test only for about 1.5 days. On the other hand in 2008, the longer term production test was attained for about 6 days, resulting in the world first sustainable gas production to the surface from the MH reservoir by depressurization [7].

The gas and water production from the reservoir during the 2007/2008 production test is estimated in this paper. This paper, then, describes the details of the history matching simulation studies conducted to reproduce the test performances and infers the reservoir behaviors during the test from results of these studies. Complimentary papers are also published describing operations [8], well log characteristics [9], geophysical monitoring techniques employed [10] and production behavior [11, 12, 13].

**OVERVIEW OF THE PRODUCTION TESTS**

**2007 winter test**

After the re-entry and the re-completion of the Mallik 2L-38 well with the 12 m perforation interval (1,093-1,105 m RKB), the pumping test was commenced at about 16:00 (local time) on April 2nd in 2007. This test, however, could last only for about 60 hours (about 30 hours for main production with 3 times attempts (Stages-1 through -3) to reduce the bottomhole pressure), because of the irregular (on-off) pumping operations due probably to the excessive sand production. The produced gas was not directly delivered to the surface via the tubing, but was accumulated at the top of the casing, while the produced water was injected into the aquifer located below the MH reservoir. Hence, neither the gas production rate nor the water production rate could be directly measured at the surface.

During the production (pumping) operation, the bottomhole pressure and temperature were measured at the phoenix gauge (1,124 m: adjacent to the pump intake) and 4 memory gauges (1,091 m) as illustrated in Figure 1. In addition, the pressure at the outlet of the pump (discharged pressure), the temperature of the motor of the pump and the casing head pressure (i.e., pressure of the annulus between casing and tubing) were measured as depicted in Figure 2, the details of which are presented in our previous papers [11, 12, 13].

The well was then suspended installing cement and bridge plugs toward the field activities in the winter of 2008.

**2008 winter test**

After re-opening and re-completing the 2L-38 well, including the installation of the sand screen at the perforation interval as illustrated in Figure 3, and heating the bottomhole for about 10 hours, the pumping test was commenced at about 18:00 (Greenwich Mean Time) on March 10th in 2008.
First, the bottomhole pressure was reduced from the initial pressure of about 11 MPa to about 7.4 MPa taking about 12 hours. The bottomhole pressure was kept to be almost constant for 39 hours (Stage-1). Spending another 6 hours, the bottomhole pressure was lowered down to about 5.2 MPa, which was maintained for 59 hours (Stage-2). In the last stage (Stage-3), the bottomhole pressure was reduced down to about 4.5 MPa spending 4 hours and was kept at this level for 24 hours. Much larger and longer gas production was accomplished with this stepwise reduction of the bottomhole pressure, preventing sands from flowing into the wellbore by the screen. In this test, both the gas and water were delivered to the surface. The gas and water flow rates were metered at the surface, mainly at 2,000-3,000 m$^3$/d and at 10-20 m$^3$/d, respectively. In addition, the bottomhole pressure and temperature were monitored at the phoenix gauge (822 m: adjacent to the pump intake), CTS gauge (798 m) and 4 memory gauges (1,083 m), and the casing head pressure was also measured (Figure 4).

![Figure 3 Downhole assemblies for 2008 winter test](image)

**Figure 3** Downhole assemblies for 2008 winter test

**ESTIMATION OF GAS AND WATER PRODUCTION FROM RESERVOIR**

Since neither gas production rate nor water production rate was directly measured at the surface in the 2007 winter test, there is no direct information available about how much gas and water flowed from the reservoir. On the other hand in the 2008 winter test, although both gas and water production rates were directly measured at the surface, these rates must be different from those flowing from the reservoir because of the accumulation of gas and water in the wellbore.

Analyzing the data acquired, the volumes of gas and water produced from the reservoir were estimated taking account of the change in the pressure and of the gas-water mass balance in the wellbore. Since the detailed calculation for these production volumes are introduced in our previous paper [11, 12, 13], only the calculation procedure and the results are presented below.

**2007 winter test**

*Estimation of liquid level* The depth of the interface between the liquid and the gas accumulated at the top of the casing ($D_l$) was estimated based on the casing head pressure ($P_{ch}$), the depth of the phoenix gauge ($D_{ph}$) and the bottomhole pressure measured at this gauge ($P_{ph}$) as

$$D_l = D_{ph} - \frac{P_{ph} - P_{ch}}{\rho_l g}.$$  

(1)
Note that this liquid level was calculated to check the gas volume existing in the annulus above the phoenix gauge.

**Estimation of gas production** Once the liquid level is estimated as described in the above, the cumulative gas production \( (Q_{g(i)}) \), which is accumulated at the top of the casing, can be calculated at each time \( (t_{(i)}) \) in accordance with the gas deviation factor \( (z) \), the temperature of the upper part of the casing \( (T : 273.15 \text{ K in this test}) \) and the cross sectional area of the annulus between casing and tubing \( (A_w : 0.035 \text{ m}^2 \text{ in this test}) \) as

\[
Q_{g(i)} = A_w D_p \frac{P_{ch}}{z} \frac{T_s}{T}.
\]

Then the gas production rate at each time \( (q_{g(i)}) \) can be estimated by differentiating \( Q_{g(i)} \) as

\[
q_{g(i)} = \frac{dQ_{g(i)}}{dt} = \frac{Q_{g(i)} - Q_{g(i-1)}}{t_i - t_{i-1}}.
\]

The gas production rate and the cumulative gas production thus estimated are shown in Figure 5. When the bottomhole pressure was reduced from 11 MPa to 7.2-7.5 MPa, 1,000-2,000 m³/d of sustainable gas production was achieved. Furthermore, the instantaneous gas production of about 8,000 m³/d was observed when the bottomhole pressure was decreased to 6.9 MPa. Total gas production throughout the 2007 winter test period is estimated at about 830 m³.

**Estimation of water production** First, the water production volume was estimated based on the pumping rate simply calculated from the number of revolution and inlet-outlet pressure difference of the pump, assuming the 100% of pumping efficiency. In this case, the volume of the liquid \( (W(i)) \) existing above the phoenix gauge at each time can be calculated as

\[
W(i) = A_w (D_{ph} - D_i).
\]

The rate of the water produced from the reservoir \( (q_{w(i)}) \) can be estimated as the summation of the pumping rate \( (q_{wp(i)}) \) and the rate of increase in \( W(i) \).

\[
q_{w(i)} = q_{wp(i)} + \frac{W(i) - W(i-1)}{t_i - t_{i-1}}.
\]

The cumulative water production is then calculated integrating \( q_{w(i)} \).

\[
Q_{w(i)} = Q_{w(i-1)} + q_{w(i)} (t_i - t_{i-1}).
\]

The water production volume calculated in the above must be overestimated because the pumping efficiency was assumed to be 100%, even during the period of suspected plugging of the pump. Hence, the water production volume and pumping rate thus calculated were tuned through history matching simulation using the radial numerical model replicating the wellbore, in order to estimate the actual water production volume and the actual pumping rate more accurately [11, 12, 13]. The adjusted estimate of water production
rate was then yielded as shown in Figure 6. The water production rate from the reservoir ranged from 0 to 80 m³/d and that the total water production throughout the test period was approximately 20 m³.

2008 winter test

Estimation of liquid level The liquid level \( D_l \) was simply calculated from the depth of the phoenix gauge \( D_{ph} \), casing head pressure \( P_{ch} \), phoenix gauge pressure \( P_{ph} \) and the liquid density \( \rho_l \) as

\[
D_l = D_{ph} - \frac{P_{ph} - P_{ch}}{\rho_l g}.
\] (7)

Estimation of bottomhole pressure The bottomhole pressure \( P_B \) was estimated assuming that the pressure gradient of the fluid \( \gamma_f \) located between the memory gauge depth \( D_m \) and the mid-perforation depth \( D_B \) was identical to that between the phoenix gauge and the memory gauge. 

\[
P_B = P_m + \gamma_f (D_B - D_m),
\] (8)

where

\[
\gamma_f = \frac{P_m - P_{ch}}{D_m - D_{ph}}.
\] (9)

The fluid level for calculating the amount of gas and water volumes above mid-perforation in the wellbore was estimated as

\[
D_{l-fv} = D_B - \frac{P_B - P_{ch}}{\rho_l g}.
\] (10)

Estimation of gas production The rate of the gas produced from the reservoir can be estimated as a combination of the gas produced to the surface and that accumulated at the top of the annulus.

\[
q_{g(i)} = q_{g-surface(i)} + A_{an} \frac{D_{l-fv(i)} - D_{l-fv(i-1)}}{\bar{z}_l(i)} \frac{T_s}{\bar{T}(i)} (t_i - t_{i-1}) P_{ch(i)}.
\] (11)

\[
Q_{g(i)} = Q_{g(i-1)} + q_{g(i)}(t_i - t_{i-1}).
\] (12)

where \( \bar{T} \) and \( \bar{z} \) denote the average temperature and z-factor over the interval between the liquid level and the surface.

Estimation of water production The water production from the reservoir was estimated at each time level, based on the rate of the liquid produced to the surface and the change in the liquid level, as

\[
q_{w(i)} = q_{w-surface(i)} - A_{an} \frac{D_{l-fv(i)} - D_{l-fv(i-1)}}{t_i - t_{i-1}}.
\] (13)

\[
Q_{w(i)} = Q_{w(i-1)} + q_{w(i)}(t_i - t_{i-1}).
\] (14)
produced continuously from the reservoir throughout the test period. The gas production rate ranged from 2,000 to 3,000 m$^3$/d and the water production rate was 10-20 m$^3$/d, while the bottomhole pressure was rather stable. The total gas and water production throughout the test period are estimated at about 13,000 m$^3$ and 70 m$^3$, respectively.

NUMERICAL SIMULATOR
The simulator used in this study (MH21-HYDRES) was originally developed by the University of Tokyo and has since been modified and improved by Japan Oil Engineering Co., Ltd., the University of Tokyo, Japan National Oil Corporation and National Institute of Advanced Industrial Science and Technology [4, 14, 15].

This simulator is able to deal with three-dimensional, five-phase (gas, water, ice, MH and salt) and six-component (methane, carbon dioxide, nitrogen, water, methanol and salt) problems.

Further details on this simulator are given in our previous papers [4, 14, 15].

RESERVOIR MODELING

Estimation of reservoir properties

Petrophysical properties As stated in the above, the 2007 and 2008 production tests were conducted in the reservoir called “Zone A”. The petrophysical properties of the Zone A reservoir, such as porosity, MH saturation and permeability, were estimated mainly by interpreting the open hole well log data measured while the Mallik 2L-38 well was deepened in 2007 and the core data acquired during the JAPEX/JNOC/GSC et al., Mallik 5L-38 gas hydrate production research well program [6, 9, 11].

The shale content was estimated based on the gamma ray (GR) log data assuming the responses of GR to clean sand and to shale. The effective porosity was calculated correcting the total porosity (estimated from the density log results) by the shale content. The MH saturation was estimated by the following equation, combining the total porosity estimated by the density log results and that by the NMR log results applying the Density-Magnetic Resonance (DMR) method.

\[ S_h = \frac{\phi_t - \phi_t\text{-NMR}}{\phi_i} \]  

(15)

The initial effective permeability to water in the presence of MH was estimated by the Schlumberger-Doll Research (SDR) method.

The absolute permeability (in the condition without MH) was estimated based on the core analysis data by multi-regression analysis as a function of porosity, shale content and MH saturation as presented in Eq. (16).

\[
\log(k) = \begin{cases} 
7.220\phi_t - 2.436 V_{sh} + 1.123 S_h - 0.0106 & \text{for MH interval} \\
6.855\phi_t - 3.331 V_{sh} + 0.6613 & \text{for non-MH interval}
\end{cases}
\]  

(16)

As depicted in Figure 9, Zone A reservoir is composed of 3 major parts in the vicinity of the Mallik 2L-38 well. The upper part is located at the interval of 1,078-1,082 m, where the effective porosity, shale content, MH saturation, absolute permeability and initial effective permeability to water range from 10 to 30%, from 20 to 50%, from 30 to 80%, from 10 to 1,000 mD and from 0.01 to 1 mD, respectively. The middle part, extending from 1,082 m to 1,093 m, is a silty/shaly interbed with relatively low porosity, MH saturation and absolute permeability. In the lower part, extending from 1,093 m to 1,113 m, MH is accumulated most intensively with MH saturation of 70-90%. In this interval, the effective porosity, shale content, absolute permeability and initial effective permeability to water range from 30 to
35%, from 10 to 20%, from 100 to 1,000 mD and from 0.01 to 1 mD, respectively. The lower part is underlain by the layer filled with free water with the effective porosity of 30%, shale content of about 25% and absolute permeability greater than 100 mD.

The 12 m interval of 1,093-1,105 m was selected as a perforation interval, since the numerical simulation suggested that this interval was optimal to produce a certain amount of gas and to prevent the bottom water from breaking through during the production test [9].

Initial pressure and temperature The initial reservoir pressure was estimated based on the results of the MDT tests conducted at the Mallik 5L-38 well in 2002 [3] and was calibrated with the memory gauge data acquired during the 2007 winter test. On the other hand, the initial reservoir temperature was estimated from the Distributed Temperature Sensing (DTS) data measured at the Mallik 4L-38 well after the MH production test conducted in April 2002 [15] and was adjusted according to the DTS data measured during the 2007 winter test. The initial pressure and temperature traverses are expressed by the equations below, which indicates that the initial pressure (approx. 11.3 MPa) and temperature (approx. 285.7) at the MH-water contact level (1,113 m) is almost equivalent to the equilibrium condition for MH, methane and water of 50,000 ppm salinity.

\[
\begin{align*}
    p (\text{MPa}) &= 0.01051 D (\text{m}) - 0.39375 \\
    T (\text{K}) &= \begin{cases} 
    0.0379 D (\text{m}) + 244.12 & \text{for } D \leq 1085 \text{ m} \\
    0.0267 D (\text{m}) + 256.32 & \text{for } D > 1085 \text{ m}
    \end{cases}
\]

(17) (18)

Construction of reservoir model

A two-dimensional radial reservoir model was constructed reflecting the initial reservoir properties estimated above. 796 grid blocks with a minimum grid size (\(\Delta r\)) of 2 cm were allocated in the radial direction, while in the vertical direction, 42 and 13 grid layers were assigned for the interval above the MH-water contact and for the free water interval, respectively. The initial reservoir properties such as effective porosity, shale content, MH saturation, effective permeability to water and absolute permeability were defined for each grid layer as shown in Table 1 and Figure 9 [10, 17].

<table>
<thead>
<tr>
<th>Model properties</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Modeling area</td>
<td>5,000 m around the well</td>
</tr>
<tr>
<td>Thickness (m)</td>
<td>72.4 (MH zone: 39.4; water zone: 33.0)</td>
</tr>
<tr>
<td>Grid system</td>
<td>r radial coordinate</td>
</tr>
<tr>
<td>Number of grid blocks</td>
<td>796 (42 layers)</td>
</tr>
<tr>
<td>Initial pressure (MPa)</td>
<td>10.8-11.3 (11.1 (water of MH zone)</td>
</tr>
<tr>
<td>Initial temperature (K)</td>
<td>284.8-286.0 (285.6 (water of MH zone)</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>MH zone: 5-0.35; water zone: 10.3-29.9</td>
</tr>
<tr>
<td>Absolute permeability (mD)</td>
<td>MH zone: 0.01-1.615; water zone: 20.3-1.538</td>
</tr>
<tr>
<td>Initial effective permeability to water (mD)</td>
<td>MH zone: 0.006-0.3; water zone: 20.5-1.538</td>
</tr>
<tr>
<td>Initial MH saturation (%)</td>
<td>MH zone: 0; water zone: 0.6</td>
</tr>
<tr>
<td>Initial water saturation (%)</td>
<td>MH zone: 17-100; water zone: 100-100</td>
</tr>
</tbody>
</table>

Table 1. Reservoir model parameters.

HISTORY MATCHING SIMULATION

Procedure of history matching simulation

Figure 10 illustrates the overall procedure of the history matching simulation. As introduced in the above, the gas and water volumes produced from the reservoir sand face were rigorously estimated based on a variety of data measured during the tests. On the other hand, as mentioned in the above, the numerical model for the tested reservoir was constructed based mainly on the results of the interpretation of the well log and core data acquired in the course of the 2007 winter test and/or during the past production tests.

First of all, the 2007 winter test performances were simulated specifying the observed bottomhole pressure profile as a boundary condition. The simulated gas and water production volumes showed a significant difference from those estimated based on the observed data. Hence, in the second step, the reservoir model parameters

Figure 10 Overall study flow.
were adjusted so as to reproduce the observed/estimated gas and water production performances by numerical simulation. Although the simple modification of the reservoir model parameters could not provide good history matching results, the 2007 winter test performances were successfully reproduced through numerical simulation by modifying the model parameters with a new concept that the sand production might have dramatically increased the near wellbore permeability [10, 17].

In the third step, the reservoir performances during the shut-in from the end of the 2007 winters test to the beginning of the 2008 winter test as well as those during the 2008 winter test were simulated using the reservoir model tuned through the history matching simulation for the 2007 winter test. Unfortunately, the simulated 2008 winter test performances did not satisfactorily agree with the observed/estimated test performances. Then, in the fourth step, taking various phenomena that had possibly occurred during the tests into consideration, the reservoir model parameters were adjusted again and again until the reservoir performances for the entire test period (i.e., during the 2007 winter test, shut-in period and the 2008 winter test) could be reproduced by numerical simulation.

**Final history matching simulation**

A large number of trial simulation runs were attempted for obtaining good matching between simulated and observed/estimated production performances for both the 2007 winter and the 2008 winter tests. In the course of these history matching simulation runs, the model parameters were adjusted as described below, to attain the final good matching [17].

**Modification of effective permeability with high permeability conduits**

The concept that each grid block consisted of the two parts (i.e., one with the original absolute permeability and the other representing the high permeability conduits) was introduced to reproduce the increase/decrease in the effective permeability of each grid block more flexibly. As shown in Figure 11, each grid block was assumed to be composed of the parts with and without high permeability conduits. It was also assumed that the effective permeability to gas and water in each grid block could be expressed by the following equations.

\[
k^* = x k_{hp} (1 - S_h)^2 + (1 - x) k_o (1 - S_h)^2
\]

(5)

\[
k_{eg} = k^* k_{eg}
\]

(6)

\[
k_{ew} = k^* k_{ew}
\]

(7)

where \(x\) denotes the fraction of the part with high permeability conduits in each grid block and \(k_{hp}\) stands for the absolute permeability of a high permeability conduit, which was assumed to be 15 D based on the Hagen-Poiseuille law. Since none of the grid blocks have the part of high permeability conduits before the 2007 winter test, the value of \(x\) should be zero throughout the reservoir model in the initial stage. The value of \(x\) for each grid block, which represents the intensity and the extent of high permeability conduits associated with the sand production during the 2007 winter test, was then appropriately adjusted with time so that the simulated production performances could agree with the observed/estimated performances for the 2007 winter test. In the simulation for the shut-in period and for the 2008 winter test, the value of \(x\) for each grid block was assumed to be constant at the value of \(x\) estimated for the end of the 2007 winter test, considering that no more growth of high permeability conduits were expected after the 2007 winter test because of the sand control by the screen.

![Figure 11](image-url) Concept expressing overall grid block permeability as a function of MH saturation with growth of high permeability conduits

**Modification of transmissibility**

To reproduce the observed/estimated gas production smaller than simulated for the period after the middle of the Stage-1 of the 2008 winter test, the transmissibility of the grid blocks located in the vicinity of the well was decreased at the timing of the reduction of the bottomhole pressure (Figure 12). This decrease in the near wellbore transmissibility must
quantitatively reflect the effects of collapse/deformation of high permeability conduits and/or accumulation of fine sand grains in the vicinity of the well.

Modification of vertical permeability To suppress the simulated water production caused by the cross flow from the water bearing layers overlying the perforation interval, the absolute permeability in the vertical direction was reduced by the factor of 1/5. This may be reasonable taking account of the presence of interbedded silty sand and/or sandy silt.

Modification of relative permeability After the major modifications of the reservoir model parameters for the large-scale history matching, the relative permeability curves were slightly modified. Note that the alteration of relative permeability curves was kept to the minimal, only for the fine tuning of simulated gas and water production.

The gas and water production performances simulated for the 2007 winter test and for the 2008 winter test using the final history matched model are depicted with the observed/estimated values in Figures 13 and 14, respectively. In addition, Figures 15 and 16 shows the distributions of the reservoir properties such as pressure, temperature, MH saturation and gas saturation simulated using the final history matched model for the ends of the 2007 winter test and the 2008 winter test. Note that the estimated gas production volumes before the shut-in of the casing head valve in the 2007 winter test and the estimated water production volumes measured by the surface flow meter before the tank gauge measurement in the 2008 winter test are unreliable. Hence, the final history matching was attained concentrating on the matching for the test period with the reliable data.

DISCUSSION
Judging from the results of the history matching simulation, the following are inferred as the overall MH dissociation and production behaviors
During the 2007/2008 winter tests, which are schematically illustrated in Figure 17.

- In the 2007 winter test, sand production must have created relatively high permeability conduits (e.g., wormholes) resulting in significantly enhanced reservoir permeability near the wellbore, promoting higher than expected rates of gas production (Figures 17a through 17d). The extent of the area with high permeability conduits was simulated to be about 10 m from the well (Figure 12). On the other hand, the major area of MH dissociation is simulated to be about 7-10 m from the well in the lateral direction and about 1-2 m above and below the perforation interval (Figure 15), which is almost identical to that with high permeability conduits.

- During the shut-in period from the end of the 2007 winter test to the beginning of the 2008 winter test, all the free gas associated with the dissociation of MH during the 2007 winter test was absorbed to re-form MH (Figure 17e) increasing the MH saturation in the vicinity of the well by about 1-5%.

- In the Stage-1 of the 2008 winter test, the gas production increased and decreased rapidly followed by the stable and then gradually decreasing gas production. It is inferred that the rapid increase and decrease in the gas production early in this stage was induced reflecting the rapid MH dissociation in the regions with high permeability conduits. The subsequent stable and then gradually decreasing gas production should reflect the dissociation of MH located out of the high permeability regions (Figure 17f). During this stage, the transmissibility in the vicinity of the well decreased down to about 70% of the original value (Figure 12), due probably to the collapse/deformation of high permeability conduits and/or to the migration of fine sand grains.

- When the bottomhole pressure was further decreased early in the Stages-2 and -3, the gas production rapidly increased reflecting the dissociation of MH in the high permeability regions. This increase, however, was not remarkable, affected by the further reduction of the transmissibility in the vicinity of the well down to about 30% of the original value (Figure 12). Since the gas production late in each stage must have been induced by the dissociation of MH located out of the high permeability regions (Figures 17g and 17h), this gas production must suggest the intrinsic (i.e., undisturbed by high permeability conduits) potential of the tested MH reservoir (Zone A).

CONCLUSIONS
The MH production tests were conducted using the depressurization methods in the JOGMEC/NRCan/Aurora Mallik production program in April 2007 and in March 2008. By analyzing various data such as wellhead/bottomhole pressure, temperature, and gas/water flow rates acquired during these tests, the gas and water production volumes from the reservoir were estimated. Based on the production thus estimated, the overall performances of the production test were successfully history matched by a series of numerical simulation. Through this history matching simulation, the test performances were quantitatively examined.
1. In the 2007 winter test, a certain amount of gas and water were produced from a 12 m perforation interval in the Zone A MH reservoir at the Mallik site in Canada, by reducing the bottomhole pressure down to about 7 MPa. The produced gas, however, was not directly delivered to the surface via the tubing, but was accumulated at the top of the casing because of the irregular (on-off) pumping operations due probably to the excessive sand production. Hence, the test performances, including the gas and water production rates, were examined based on the monitored data. For example, it was inferred that 1,000-2,000 m$^3$/d of sustainable gas production and 10-70 m$^3$/d of continuous water production were achieved when the bottomhole pressure was reduced from 11 MPa to 7.2-7.5 MPa.

2. In the 2008 winter test targeting the same reservoir interval, much larger and longer gas production was attained with a stepwise reduction of the bottomhole pressure down to about 4.5 MPa, preventing sands from flowing into the wellbore by the screen. Since both the gas and water could be delivered to the surface, the test performances were analyzed mainly on the measured gas and water production rates and on the bottomhole data as follows. As a result of these analyses, it was estimated that the sustainable gas production had been accomplished for about 6 days with the stable gas production of 2,000-3,000 m$^3$/d and water production of 10-20 m$^3$/d and that the total gas and water production throughout the test period were about 13,000 m$^3$ and 70 m$^3$, respectively.

3. The performances of both the 2007 winter test and 2008 winter test were successfully reproduced through history matching simulation, by appropriately adjusting the reservoir parameters introducing the hypotheses of the generation and growth of high permeability conduits and the collapse/compaction of these conduits.

4. In accordance with the results of the above history matching simulation, the test performances are examined qualitatively as follows.

   • In the 2007 winter test, sand production must have created relatively high permeability conduits (e.g., wormholes) resulting in significantly enhanced reservoir permeability near the wellbore, promoting higher than expected rates of gas production. The extent of the area with high permeability conduits was simulated to be about 10 m from the well. The major area of MH dissociation is simulated to be about 7-10 m from the well in the lateral direction and about 1-2 m above and below the perforation interval.
   • During the shut-in period from the end of the 2007 winter test to the beginning of the 2008 winter test, all the free gas associated with the dissociation of MH during the 2007 winter test was absorbed to re-form MH increasing the MH saturation in the vicinity of the well by 1-5%.
   • It is inferred that the rapid increase and decrease in the gas production early in the Stage-1 of the 2008 winter test was induced reflecting the rapid MH dissociation in the regions with high permeability conduits. The subsequent stable and then gradually decreasing gas production should reflect the dissociation of MH located out of the high permeability regions.
   • During the 2008 winter test, the gas producibility gradually decreased down to about 30% of the original value, due probably to the collapse/deformation of high permeability conduits and/or to the migration of fine sand grains.
   • The gas production late in each stage was induced by the dissociation of MH located out of the high permeability regions, which must suggest the intrinsic (i.e., undisturbed by high permeability conduits) potential of the tested MH reservoir.

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