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

Masanori Kurihara*, Kunihiro Funatsu and Hisanao Ouchi
Japan Oil Engineering Company
1-7-3 Kachidoki, Chuo-ku, Tokyo, 104-0054, Japan

Yoshihiro Masuda
School of Engineering, The University of Tokyo

Masato Yasuda, Koji Yamamoto, Masaaki Numasawa and Tetsuya Fujii
Japan Oil, Gas and Metals National Corporation

Hideo Narita
National Institute of Advanced Industrial Science and Technology

Scott R. Dallimore and Fred Wright
Geological Survey of Canada, Natural Resources Canada

ABSTRACT
A gas hydrate production test using the depressurization method was conducted in early April 2007 as part of the JOGMEC/NRCan/Aurora Mallik production research program. The results of the production test were analyzed using a numerical simulator (MH21-HYDRES) coded especially for gas hydrate reservoirs. This paper evaluates the test results based on analyses of production test data, numerical modeling and a series of history matching simulations.

Methane gas and water was produced from a 12 m perforation interval within one of the major methane hydrate (MH) reservoirs at the Mallik MH field, by reducing the bottomhole pressure down to about 7 MPa. The measured gas production rate was far higher than that expected for a comparatively small pressure drawdown. However, irregular (on-off) pumping operations, probably related to excessive sand production, resulted in unstable fluid flow within the wellbore, which made the analysis of test performance extremely complicated.

A numerical reservoir model was constructed as a series of grid blocks, including those mimicking the wellbore, to enable rigorous simulation of fluid flow patterns in the vicinity of the wellbore. The model was then tuned through history matching, not by simply adjusting reservoir parameters, but by introducing the concept that sand production might have dramatically increased the near-wellbore permeability. The good agreement between observed and simulated performances suggests the mechanism of MH dissociation/production during the test. The history matched reservoir model was employed to predict the second-year production test performance, in order to examine the gas production potential of the Mallik MH reservoir, and to provide insight into future exploration and development planning for MH reservoirs.

Keywords: production test, numerical simulation, history matching, depressurization, sand production

* Corresponding author: Phone: +81 3 5548 1663 Fax: +81 3 5548 1673 Email: kurihara@joe.co.jp
NOMENCLATURE

\( A \) cross sectional area of annulus \([m^2]\)  
\( D \) depth \([m]\)  
\( G \) gas volume in annulus \([m^3]\)  
\( k \) absolute permeability \([m^2]\)  
\( k_e \) effective permeability \([m^2]\)  
\( k_r \) relative permeability  
\( p \) pressure \([Pa]\)  
\( q \) production rate \([m^3/s]\)  
\( S_h \) MH saturation  
\( t \) time \([s]\)  
\( T \) Temperature \([K]\)  
\( V_{sh} \) shale content  
\( W \) water volume in annulus \([m^3]\)  
\( z \) gas deviation (compressibility) factor  
\( \rho \) density \([kg/m^3]\)  
\( \phi_e \) effective porosity  

subscript  
\( ch \) casing head  
g gas  
i time level  
l liquid  
p phoenix gauge  
s standard condition  
w water  
wp pumping water

INTRODUCTION

The 2006-08 JOGMEC/NRCan/Aurora Mallik gas hydrate production research program is being conducted with a central goal to measure and monitor the production response of a terrestrial gas hydrate deposit to pressure draw down (depressurization). The Japan Oil, Gas and Metals National Corporation (JOGMEC) and Natural Resources Canada (NRCan) are funding the program and leading the research and development studies. Aurora College/Aurora Research Institute is acting as the operator for the field program.

This paper reviews observations (e.g. gas/water flows, pressure-temperature regimes, etc.) made during the 2007 production test, describes numerical modeling and analyses of production test performances through history matching simulation, and discusses probable mechanisms of MH dissociation and production during this test. Complimentary papers are also published in this volume describing operations [1], well log characteristics [2] and geophysical monitoring techniques employed [3].

The Research Consortium for Methane Hydrate Resources in Japan (MH21 Research Consortium), which was organized to realize the exploration and exploitation of methane hydrate (MH) offshore of Japan, has implemented a variety of research projects toward the assessment of MH resources, establishment of MH production methods, and examination of the impact of MH development on the environment. As part of this research, we have developed a state-of-the-art numerical simulator (MH21-HYDRES) for rigorous prediction of MH dissociation and production behaviors both at core and field scales. This simulator has a capability to deal with 3-D, 5-phase and 4-component problems associated with MH dissociation kinetics.

In April 2007, a field-scale production test was conducted at one of the major Mallik MH reservoirs (Zone A), attempting the dissociation and production of MH by reducing the bottomhole pressure. Because of the periodic shut-down of the downhole pump, due probably to problems related to sand production, essentially three consecutive pumping cycles (pumping followed by shut-in) were conducted during the production tests. Although the produced gas was not directly delivered to the surface via the tubing string, it was allowed to accumulate at the top of the casing, and the increase in the casing head pressure clearly indicated continuous MH dissociation and production during the test. Gas and water production rates were estimated based on continuously monitored parameters such as bottomhole pressure, casing head pressure, and pumping rate.

A series of numerical simulations were conducted to analyze the test performances through history matching. The gas production rate, which was considerably higher than expected given the bottomhole pressure reduction actually applied, was then successfully history matched based on an assumed improvement of reservoir permeability in the vicinity of the well casing perforations. Furthermore, the rate of the produced water, which was injected into a lower interval, was also estimated by rigorously matching the evolution of bottomhole temperatures. Using the reservoir model thus tuned through history matching, the performance of a subsequent planned production test, scheduled for March 2008, was predicted.
These numerical simulation studies show a promising potential for successful MH dissociation and production simply by controlled reduction of the bottomhole pressure.

NUMERICAL SIMULATOR

The simulator used in this study was originally developed by the University of Tokyo, and has since been modified and improved by Japan Oil Engineering Company, the University of Tokyo, Japan National Oil Corporation and National Institute of Advanced Industrial Science and Technology [4, 5, 6, 7]. This simulator is able to deal with three-dimensional, five-phase, four-component problems and has the following features:

- Three-dimensional Cartesian and two-dimensional radial co-ordinates can be applied with local grid refinement.
- Four-components (methane, water, methanol and salt) are available.
- Five phases (gas [V, mobile], water [L_m, mobile], ice [I, immobile], MH [H, immobile] and salt (deposit) [S, immobile]) are available.
- Darcy’s law and relative-permeability curves are applied to gas and water flows.
- Endothermic dissociation of methane hydrate and ice, and exothermic formation of MH and ice are accounted for.
- Kim-Bishnoi equation [8] is used for MH dissociation kinetics.
- V-H-L_m or V-H-I equilibrium pressure is estimated as a function of temperature and methanol/salt concentration.

Further details on this simulator are given in our previous papers [4, 5, 6, 7].

ESTIMATION OF GAS AND WATER PRODUCTION RATES

Data acquisition

Prior to the production test, a suite of well logging data was acquired [2] to enable characterization of important reservoir properties critical for reservoir modeling. During the production test, a variety of real-time data were acquired at various locations along the bottomhole assembly (Figure 1). Including:

- Pressure and temperature at the phoenix gauge
- Pressure and temperature at the memory gauge
- Casing head pressure
- Pumping rate (estimated based on intake-discharge pressure difference and number of revolutions).

Since neither gas nor water was essentially produced to the surface, the above data were used for estimating of gas and water production rates.

![Scheme of test well completion](image)

Figure 1: Scheme of test well completion

Calculation of gas and water production rates

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 ($D_p$) and the bottomhole pressure measured at this gauge ($p_b$).

$$D_l = D_p - \frac{p_b - p_{ch}}{\rho_l}, \quad (1)$$
where \( \rho_l \) denotes the liquid density, which is equivalent to the density of 5% KCl solution (1.035 g/cm\(^3\)=0.0101 MPa/m) in this test.

*Gas production:* Once the liquid level is estimated as describe in the above, the cumulative gas production \((G_i)\), which is accumulated at the upper part 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 \((A; 0.035 \text{ m}^2\) in this test).

\[
G_i = AD_p \frac{p_{li} T_s}{z p_s T_i},
\]

where \( p_s \) and \( T_s \) denote the pressure (0.1013 MPa) and temperature (288.8 K) at standard conditions, respectively. Gas production rate \((q_{gi})\) can be estimated by differentiating \(G_i\).

\[
q_{gi} = \frac{dG_i}{dt} \approx \frac{G_i - G_{i-1}}{t_i - t_{i-1}}
\]

The gas production thus estimated is shown in Figure 3. Total gas production during the test was estimated at about 830 m\(^3\).

*Water production:* The volume of the liquid \((W_l)\) existing above the phoenix gauge at each time can be calculated as

\[
W_i = A(D_p - D_l).
\]

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

\[
q_{wi} \approx q_{wp,i} + \frac{W_j - W_{j-1}}{t_j - t_{j-1}}
\]

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

\[
Q_{wi} \approx Q_{wi-1} + q_{wi}(t_i - t_{i-1})
\]

Approximately 40 m\(^3\) of water was estimated to have been produced from the reservoir, as depicted in Figure 4. Note that water production may be overestimated because the pumping efficiency was assumed to be 100% in this calculation, even during the period of suspected plugging of the pump.
**RESERVOIR MODELING**

**Estimation of reservoir properties**

*Initial pressure and temperature:* The initial reservoir pressure was estimated based on the results of the Modular Dynamic Formation Tester (MDT) tests conducted at 5L-38 wells in 2002 [9] and was calibrated with the memory gauge data acquired during this test. On the other hand, the initial reservoir temperature was estimated from the Distributed Temperature Sensing (DTS) data measured at 4L-38 well after the MH production test conducted in April 2002 [10] and was adjusted according to the DTS data measured during this test. The initial pressure and temperature traverses are expressed by the equations below and are shown in Figure 5, which indicates that the initial pressure (11 MPa) and temperature (286 K) 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.

\[ p \text{ (MPa)} = 0.01051D \text{ (m)} - 0.39375 \]  
(7)

\[ T \text{ (K)} = \begin{cases} 
0.0379D \text{ (m)} + 244.12, & \text{for } D \leq 1085 \text{ m} \\
0.0267D \text{ (m)} + 256.32, & \text{for } D > 1085 \text{ m} 
\end{cases} \]  
(8)

Figure 5: Initial reservoir pressure and temperature traverses

**Reservoir properties:** Initial reservoir properties such as effective porosity, shale content, MH saturation and effective permeability were estimated based on interpretation of open hole well logging data acquired prior to the production test [2].

**Absolute permeability:** Because of the excessive scatter apparent in the simple porosity-absolute permeability relationship derived from the core analysis data of 5L-38 well, as shown in 6a, absolute permeability was estimated by multiregression analysis as a function of porosity, shale content and MH saturation as presented in Equation (9) and in Figures 6a through 6c. The absolute permeability values thus estimated are shown in Figures 7a and 7b, indicating a remarkable reduction of estimation error by the multivariate analysis as compared to that of the porosity-permeability relationship.

\[
\log(k) = \begin{cases} 
7.220\phi - 2.436V_{sh} + 1.123S_h - 0.0106 & \text{for MH interval} \\
6.855\phi - 3.33V_{sh} + 0.6613 & \text{for non - MH interval} 
\end{cases} \]  
(9)

Figure 6: Relation between absolute permeability and other reservoir parameters

(a) \( \phi \text{ vs. } k \)
(b) \( V_{sh} \text{ vs. } k \)
(c) \( S_h \text{ vs. } k \)

Figure 7: Relation between estimated permeability and measured permeability

(a) MH interval
(b) Non-MH interval
Construction of reservoir model

We have constructed a two-dimensional radial reservoir model which reflects the initial reservoir properties estimated above. Ninety-nine grid blocks with a minimum grid size (Ar) 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 8.

<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-z radial coordinate</td>
</tr>
<tr>
<td>Number of grid blocks</td>
<td>796 (r direction) 55 (z direction)</td>
</tr>
<tr>
<td>Initial pressure (MPa)</td>
<td>10.9-11.3 (11.1 @ center of MH zone)</td>
</tr>
<tr>
<td>Initial temperature (K)</td>
<td>284.8-286.0 (285.6 @ center of MH zone)</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>MH zone: 5.0-33.8 water zone: 10.3-29.9</td>
</tr>
<tr>
<td>Absolute permeability (mD)</td>
<td>MH zone: 0.01-1,615.8 water zone: 20.5-1,538.6</td>
</tr>
<tr>
<td>Initial effective permeability to water (mD)</td>
<td>MH zone: 0.006-63.8 water zone: 20.5-1,538.6</td>
</tr>
<tr>
<td>Initial MH saturation (%)</td>
<td>MH zone: 0-83.0 water zone: 0</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

RESERVOIR SIMULATION

Conventional runs

Using the reservoir model constructed above, gas and water production rates were simulated, with the observed bottomhole pressure profile specified as a boundary condition. As shown in Figure 9, predicted gas production volumes are far lower than the estimated actual volume of gas produced during the test. Several simulation runs attempted to history match the gas production rate by increasing the absolute permeability, initial water effective permeability, and/or relative permeability to gas. Even by increasing these permeabilities, however, the simulated gas production rate was still much lower than the estimated actual rate as shown in Figure 10.

Figure 9: Simulated and estimated gas production

History matching with enhanced permeability

Since the conventional simulation runs revealed the difficulty in reproducing the observed gas production by simply adjusting the bulk reservoir permeability and/or other parameters, it was considered that the high gas production rate might have been caused by a drastic improvement of
permeability in the vicinity of the wellbore. It was speculated that high permeability conduits (such as wormholes or other open pathways) may have been generated in the near-wellbore sediments as a consequence of sand production associated with the dissociation of MH during the test. To express this phenomenon in the numerical simulation, the simulator was modified so that the absolute permeability of any grid block for which more than 3% (this figure was estimated through trial and error history matching) of MH had been dissociated could be increased by the factor specified (Figure 11).

Figure 11: Concept of permeability increase along with MH dissociation

Additional history matching simulation was then attempted by employing this adjustment factor for absolute permeability. Figure 12 shows the simulated gas and water production for the history matched run in which absolute permeability was increased by a factor of 45. Given that the simulated water production volume is much lower than the estimated actual water production, we acknowledge that Equations (5) and (6) may overestimate water production rates as discussed above. The predicted two-dimensional spatial distribution of effective gas and water permeabilities at the end of the test are depicted in Figure 13. History matching simulation suggests that the improvement of near-wellbore permeability may increase the gas production significantly, even though the area of improvement is very limited.

Figure 12: Gas and water production predicted by the history matched model

(a) Gas production

(b) Water production

Figure 13: Distribution of effective permeabilities to gas and water predicted by the history matched model

(a) Effective permeability to gas

(b) Effective permeability to water
SIMULATION OF FLUID MOVEMENT IN WELLBORE

Temperature matching
As discussed above, the estimation of actual water production rates is very challenging because of the difficulty in specifying the actual pumping rate. Fortunately, downhole temperatures were measured at the Phoenix and memory gauges (Figure 1), providing reasonable estimates of bottomhole temperature. The initial temperature profile of the liquid in the wellbore as well as that of the surrounding formation was inferred from DTS data. In addition, the temperature of the water produced from the MH reservoir is roughly deduced from the above history matched simulation results and three-phase equilibrium temperature. Hence, it may be possible to estimate the actual rate of water production from the reservoir, as well as the actual pumping rate, by matching both the bottomhole pressure and temperature through simultaneous adjustment of these rates.

A radial numerical model with 3x129 grid blocks replicating the wellbore was constructed as illustrated in Figure 14. The heat transfer coefficient between the fluid inside the wellbore and the surrounding formation was estimated based on the thermal conductivity of fluid, casing, cement, and the formation. The shape of the protective pump shroud was also incorporated in this numerical model.

Estimation of water production rates
The results of the first trial, in which the water rates and the pumping rates estimated above were simply applied as calculation constraints, are shown in Figure 15. In this case, calculated bottomhole temperatures agree poorly with those actually observed. After several trial and error simulation runs, a successful match between predicted and observed temperatures and pressures was attained, yielding adjusted estimates of water production rates and pumping rates as shown in Figure 16. This history matched model suggests that total water production throughout the test period was approximately 20 m$^3$ instead of the 40 m$^3$ initially estimated, as shown in Figure 17. The results also support the notion that significant reverse flow (from injection zone towards wellhead) occurred during periods when the pump was idle, and that during some pumping periods pump efficiency was considerably lower than previously estimated (Figure 18).

![Figure 14: Grid model representation of the wellbore](image)

![Figure 15: Bottomhole pressure and temperature predicted by the model (first trial)](image)

![Figure 16: Bottomhole pressure and temperature predicted by the history matched model](image)
Since water production predicted in Figure 12b is higher than that estimated through matching of downhole P-T conditions (as above), the reservoir simulation was again performed with the goal of reconciling these predictions. Successful history matching was attained both for water production and gas production as shown in Figure 19. The distribution of reservoir properties such as pressure, temperature, MH saturation and gas saturation predicted at the end of the test are presented in Figure 20, which indicates that penetration of the pressure disturbance due to pressure drawdown (and hence of partial or complete MH dissociation) was approximately 7-10 m from the wellbore in the lateral direction and about 4 m above and below the perforation interval in the vertical direction.
Another production test at Mallik was planned for March 2008, to be conducted within the same gas hydrate interval. Using the final history matched reservoir model, the performances of this test were predicted assuming that

- the bottomhole pressure would be gradually decreased to achieve the bottomhole pressure of 8, 6 and 5 MPa with the reduction rate of about 0.42 MPa/h,
- after the bottomhole pressure reached the
target level, it would be kept at constant at 8, 6 and 5 MPa for 12-24 hours, and
• the area and the intensity of the permeability improvement induced in the 2007 test would not extend further into the formation due to the application of a sand control system.

Figure 21 shows the predicted gas and water production rates for the 2008 test, along with the scheduled bottomhole pressure. The modeling results suggest that relatively high gas and water production rates are expected reflecting the effect of improved formation permeability in the near-wellbore area soon after lowering the bottomhole pressure. The model also predicts that gas and water production rates become stable at about 2,000 m$^3$/d and 40 m$^3$/d respectively, after 1-2 days following stabilization of the bottomhole pressure.

![Figure 21: Predicted 2008 test performances](image)

CONCLUSIONS
Numerical reservoir modeling was conducted for estimating gas and water production rates during the 2007 JOGMEC/NRCan/Aurora Mallik production research program. Reservoir and wellbore history matching simulations reveal the following:

- Gas and water production rates during the first few hours of testing were negligibly small.
- When the bottomhole pressure was reduced from `11 MPa to 7.2-7.5 MPa, 1,000-2,000 m$^3$/d of sustainable gas production and 10-70 m$^3$/d of continuous water production were achieved.
- Instantaneous gas production of about 8,000 m$^3$/d was observed when the bottomhole pressure was decreased to 6.9 MPa.
- Total gas and water production throughout the test period are estimated at about 830 m$^3$ and 20 m$^3$, respectively.
- During periods of pump shutdown, some of the water injected into the lower water disposal zone reversed-flowed upwards towards the test interval (presumably due to failure of a check valve) increasing the wellbore temperature.
- Sand production during testing may have created relatively high permeability conduits (e.g. wormholes) resulting in significantly enhanced formation permeability near the wellbore, promoting higher than expected rates of gas production.
- The area of MH dissociation is estimated at about 7-10 m from the well in the lateral direction and at about 4 m above and below the perforation interval in the vertical direction.

Furthermore, subsequent numerical simulation using the history matched reservoir model predicted the performances of the planned 2008 production test as follows:

- Upon achieving the initial scheduled reduction in bottomhole pressure, generally high rates of gas and water production are expected to persist for about one day, reflecting the effect of enhanced near-wellbore permeability.
- Gas and water production rates become stable at about 2,000 m$^3$/d and 40 m$^3$/d respectively, after 1-2 days following stabilization of the bottomhole pressure.

ACKNOWLEDGMENTS
This work was financially supported by the Research Consortium for Methane Hydrate Resources in Japan (MH21 Research Consortium) on the National Methane Hydrate Exploitation Program by the Ministry of Economy, Trade and Industry (METI). The authors gratefully acknowledge these agencies for their financial support and permission to present this paper. The authors wish to thank the Japan Oil Engineering Company, the University of Tokyo, Japan Oil, Gas and Metals National Corporation, the National Institute of Advanced Industrial Science and Technology, the Geological Survey of Canada and Natural Resources Canada for their technical support.
REFERENCES


