GEOLOGIC AND POROUS MEDIA FACTORS AFFECTING THE 2007 PRODUCTION RESPONSE CHARACTERISTICS OF THE JOGMEC/NRCAN/AURORA MALLIK GAS HYDRATE PRODUCTION RESEARCH WELL

Scott R. Dallimore, J. Frederick Wright, F. Mark Nixon
Geological Survey of Canada,
P.O. Box 6000, Sidney, B.C., V8L 4B2
CANADA

Masanori Kurihara
Japan Oil Engineering, Tokyo, JAPAN

Koji Yamamoto, Tetsuya Fujii, Kasumi Fujii, Masaaki Numasawa, Masato Yasuda
Japan Oil, Gas, Metals National Corporation,
Technical Research Centre, Chiba, JAPAN

Yutaka Imasato,
Schlumberger K.K., Fuchinombe, JAPAN

ABSTRACT
A short-duration production test was undertaken at the Mallik site in Canada’s Mackenzie Delta in April 2007 as part of the JOGMEC/NRCan/Aurora Mallik 2007 Gas Hydrate Production Research Well Program. Reservoir stimulation was achieved by depressurization of a concentrated gas hydrate interval between 1093 and 1105m (RKB). Geologic and porous media conditions of the production interval have been quantified by geophysical studies undertaken in 2007 and geophysical and core studies undertaken by previous international partnerships in 1998 and 2002. These investigations have documented that the production interval consists of a sand-dominated succession with occasional silty sand interbeds. Gas hydrate occurs mainly within the sediment pore spaces, with concentrations ranging between 50-90%. Laboratory experiments conducted on reconstituted core samples have quantified the effects of pore water salinity and porous media conditions on pressure-temperature stability, suggesting that the partition between gas hydrate stability and instability should be considered as a phase boundary envelope or zone, rather than a discrete threshold. Strength testing on natural core samples has documented the dramatic changes in physical properties following gas hydrate dissociation, with sediments containing no hydrate behaving as unconsolidated sands. While operational problems limited the duration of the production test, a vigorous reservoir response to pressure draw down was observed with increasing gas flow during the testing period. We interpret that pressure temperature (P-T) conditions within the test zone were close to the gas hydrate phase equilibrium threshold, with dissociation initiated at 10 MPa bottomhole pressure (BHP), approximately 1 MPa below in situ conditions. The observation of an increase in production rates at approximately 8.2 MPa BHP may be consistent with the notion of an indistinct gas hydrate stability threshold, with rates increasing as P-T conditions traverse the phase boundary envelope. Significant sand inflow to the well during the test is interpreted to result from the loss of sediment strength during gas hydrate dissociation, with the sediment behaving as a gasified slurry. The increase in gas production rates during the final hours of the test may result from non-uniform gas hydrate dissociation and be affected by accelerated dissociation along water filled natural fractures or fine-scale geologic heterogeneities. These may initiate worm hole or high permeability conduits in association with sand production.

Keywords: gas hydrate production, pressure draw down, permafrost hydrates, porous media

* Corresponding author: Phone: +1 250 363-6423 Fax +1 250 363 6565 E-mail: sdallimo@nrcan.gc.ca
INTRODUCTION
The primary objectives of the 2006-08 JOGMEC/NRCan/Aurora Mallik gas hydrate production research program are to measure and monitor the production response of a terrestrial gas hydrate reservoir in response to pressure draw down. The Japan Oil, Gas and Metals National Corporation (JOGMEC), together with Natural Resources Canada (NRCan) provide program funding and lead the research and development studies. Aurora College/Aurora Research Institute is designated as the operator for the field program. This paper reviews the geologic setting and porous media conditions of the production interval chosen for testing, so as to provide a context for interpretation of the first year (2006-07) production test. Complimentary papers also published in this volume describe field operations and present production test results [1], well log characteristics [2], geophysical monitoring techniques employed [3], and numerical modeling scenarios [4].

FIELD OPERATIONS OVERVIEW
Winter 2007
The primary objectives of the winter 2007 field activities were to undertake new geophysical and monitoring studies, install physical installations to establish a production and injection well, and to undertake a short term pressure draw down test to gain insights prior to undertaking a longer term testing planned for the winter of 2008. A drilling rig, a service rig and support facilities were mobilized by ice road from Inuvik to the Mallik site in January to allow re-entry and completion operations on two wells. Aurora/JOGMEC/NRCan Mallik 2L-38 was spud on February 23rd. This well was originally drilled to 1150m as a gas hydrate research and development well undertaken by Japan and Canada in 1998[5]. The open hole section of the wellbore was re-occupied and a 311.15mm (12 1/4") new hole section was advanced from 1150m to 1310m (RKB). To establish formation properties prior to testing, the open hole section (including the gas hydrate bearing intervals from 890-1100m) were logged with 5 separate logging runs [2]. A 244.5mm (9 5/8") production casing was installed to 1288m to enable production testing in this well and also re-injection of produced water into a lower injection zone. To monitor formation response to testing, 5 externally mounted geophysical sensors designed by JOGMEC were successfully installed outside of the casing and a cased hole logging program was conducted to allow repeat time series logging.

While operations were underway in Mallik 2L-38, re-entry operations on Aurora/JOGMEC/NRCan Mallik 3L-38 were undertaken. This well, which was originally drilled in 2002 as part of the Mallik 2002 Research Well Program[6], was deepened from 1188m to 1275m. Open and cased hole logging programs were carried out to characterize the geology below the gas hydrate bearing intervals and to establish candidate horizons for water injection planned during 2008 production testing. Mallik 3L-38 was cased with 73mm tubing and subsequently perforated and injection tested.

After completion of the physical installations at Mallik 2L-38 and Mallik 3L-38, a short pressure draw down production test was undertaken to evaluate equipment performance and the short term production response. Testing of a 12m gas hydrate interval from 1093-1005m was begun on April 2 and continued for approximately 60hrs.

Winter 2008
The goal of the winter 2008 field activities was to undertake longer term gas hydrate production testing. A service rig and support facilities were mobilized by ice road from Inuvik to the Mallik site in January. Re-entry and completion operations on the Mallik 2L-38 production well and the Mallik 3L-38 injection wells established in 2007, were carried out from February 15th to March 9th. Production testing was carried out from March 10 to 16th on the same interval from 1093-1005m that was perforated in 2007. Demobilization and abandonment operations were completed on April 1st.

1998 AND 2002 MALLIK RESEARCH STUDIES
The physical properties and setting of gas hydrate deposits occurring at the Mallik field have been well documented through two previous international research well programs. The 1998 Japex/JNOC/GSC Mallik 2L research well program collected the first permafrost gas hydrate core samples and provided much baseline engineering data [5]. The Japex/JNOC/NRCan et al. Mallik 2002 Gas Hydrate Production Research Well Program, conducted by a five-nation international
partnership, built on the achievements of the 1998 program to enable many new multidisciplinary investigations and provided a first opportunity to undertake well-constrained gas hydrate production testing [6]. Three research wells were completed in 2002 allowing advanced well logging and a carefully executed coring program was completed with comprehensive post field laboratory studies. A full-scale thermal production test was also undertaken as were small scale, short-term MDT (Modular Dynamic Formation Tester) pressure draw down tests. Advanced reservoir monitoring and measurement techniques included cross well geophysics and DTS (Distributed Temperature Sensing) fiber optic systems for obtaining high-resolution formation temperatures.

Figure 1: The Japex/JNOC/GSC Mallik 2L-38 research well was drilled in 1998 and re-occupied in 2007/08 as part of the Aurora/JOGMEC/NRCan gas hydrate production research program. This well log composite depicts the geology and permafrost conditions at the site and identifies the test interval located at the bottom of the gas hydrate stability field (pink depicts the gas hydrate horizons, yellow the interval of the section affected by casing effects.
POROUS MEDIA CONDITIONS
The physical properties of gas-hydrate-bearing sediments may differ substantially from those of a simple water-sediment system. Pore geometry, charged mineral surfaces, the phases and activity of the pore waters, and gas hydrate habit all exert significant influences on host sediment properties. Research and development studies carried out at Mallik in 2002 allowed for accurate determinations of sediment porosity and reasonable estimates of permeability as a function of gas hydrate content, the variability of sediment strength and elastic moduli, as well as non-uniform sediment properties such as natural fractures or lateral inhomogeneity. These properties were carefully assessed in the selection of the 2007-08 Mallik test horizon and are thought to influence the observed production behavior. The following discussion draws primarily on observations from Mallik 5L-38, at which continuous coring of the section was undertaken in 2002. As noted by Fujii et al [2], the reader should be advised that reservoir conditions vary somewhat between the 5L-38 and 2L-38 wells, given the ~100m separation between the well locations.

Figure 2: The Japex/JNOC/GSC et al. Mallik 5L-38 was drilled and continuously cored through a partnership with NRCan, JNOC, GFZ, USGS, USDOE, Chevron BP Joint venture and the India gas hydrate program. This montage compiles core data and well log data and shows the location of small scale pressure draw down tests (MDT tests) completed in 2002 and the full scale pressure draw down testing completed in 2007 and 2008 in Mallik 2L-38. It should be noted that this well was approximately 100m away from Mallik 2L-38 and the reference depths are RKB which are about 5m shallower than those presented in Fujii et al [2].
**Geology and gas hydrate occurrence**

Figure 2 presents a composite of well log and core data from Mallik 5L-38, between 1040 and 1125m depth. Sediments within the interval are typical of a fluvio-deltaic depositional environment [7][8]. A fine-grained interbedded silt succession dominates above 1085m, interspersed with occasional thin coal and sand beds, and a thicker sand between 1070-1078m. Below 1085m a thick sand succession dominates, characterized by occasion thin silt interbeds. Core observations and well log estimates confirm that the gas hydrate occurs primarily as pore-filling material within the sands (50% to 90% pore saturation) with only rare visible gas hydrate observed as coatings on sand grains [8,9]. No gas hydrate was observed in the silt dominated intervals suggesting a strong lithologic control. However, the sharp basal contact (at 1107 m) of the lowermost gas hydrate zone occurs within a massive sand interval and is not lithologically controlled. This contact is interpreted as a salinity-conditioned, thermally-defined base of the gas hydrate stability field. [10,11].

When adjusted for reference depths, the base of the gas hydrate stability field at Mallik 2L-38 [2] is consistent with the basal depth at Mallik 5L-38 (Fig 3), as are the depths to the top of the lowermost gas hydrate interval (~1090 m). However the thickness, depths, and characteristics of the upper gas hydrate intervals vary somewhat between wells, most likely reflecting variations in the depositional environments between the two sites. Sediment porosities in both wells range from 30 to 40%.

Estimation of the permeability of gas-hydrate-bearing sediments is particularly challenging. A number of core and well log measurements were undertaken in the 2002 program in Mallik 5L-38 [12,13] and further well log investigations were undertaken as part of the 2007 well logging program in Mallik 2L-38 [2]. We estimate permeability’s in the production interval range from 0.1 to 1 mD, whereas the permeability in the gas-hydrate-bearing silt is generally less than 0.1 mD. In contrast permeability of the water saturated sands below the base of the gas hydrate stability field may be in the order of 100 to 1000 mD.

**Methane hydrate phase equilibrium conditions**

Laboratory experiments conducted on Mallik 5L-38 core samples have yielded detailed characterizations of the effects of pore-water salinity on in situ gas hydrate stability [10]. A GSC pressure-temperature cell was used to characterize the stability of methane hydrate under simulated in situ conditions and these data were subsequently compared to field data. As shown for a core sample recovered from the production interval at 1097 m (Specimen 3, Fig. 4), the partition between gas hydrate stability and instability was observed as a pressure-temperature phase boundary envelope or zone, rather than as a discrete threshold. These laboratory observations are of direct relevance to field operations, with respect to the confirmation of the depth of the base of the gas hydrate stability field, the expected production response to pressure or temperature stimulation, and ultimately to the design of the production test itself. As shown in Figure 5, undisturbed formation temperatures from DTS measurements by Henniges et al. [11] yield a temperature of 12.2°C at the base of the lowermost gas hydrate interval (at 1107 m). When plotted against salinity-shifted P-T phase equilibrium data, this implies an in situ pore water
salinity of ~45 ppt. This agrees favourably with the laboratory data for Specimen 3 which indicates a pore water salinity of about 48 ppt in the presence of hydrate and a background salinity of ~20 ppt for the same sample without gas hydrate.

An upward shift of the gas hydrate stability field of approximately 110 m is indicated, relative to the depth expected for methane hydrate in fresh water.

The laboratory data also provide insights into the possible formation response to a reduction in pressure during production testing. Gas hydrate dissociation would be expected almost immediately upon initiation of pressure drawdown, with gas rates likely to progressively increase as P-T conditions traverse the phase boundary envelope. The degree of endothermic cooling experienced can also be expected to influence the formation response (possible effects illustrated on figure 4 as points marked C and as left hand arrow on figure 5).

Geomechanics

The variability of in situ properties and changes in geomechanical properties due to gas hydrate dissociation can be expected to significantly influence the physical response of sediments influenced by production testing, particularly in the vicinity of the near wellbore. Research undertaken as part of the Mallik 5L-38 program reviewed the stress state [14], strength properties, and occurrence of natural fractures [15]. The vertical-stress gradient (defined as the depth-normalized vertical stress) was found to range from 18.8 to 19.6 kPa/m in the shallow part of the section (upper 700 m), and from 19.2 to 19.8 kPa/m in the depth interval of the gas hydrate occurrences at Mallik 5L-38. The presence of gas hydrate appears to contribute substantively to the strength of the sediment matrix, with core samples showing rapid and dramatic reduction in strength following hydrate dissociation [16, 17], such that the sands subsequently behave as unconsolidated sediment. In simple terms, gas hydrate serves as the cement binding the individual sand grains, thereby providing the bulk of the material strength.

Field data suggest that natural fractures are ubiquitous to the gas-hydrate-bearing interval at Mallik, and that indeed they may behave essentially as open fractures in terms of flow response [18]. Small-scale pressure drawdown tests (MDT tests) conducted in 2002 support
estimation of the in situ stress state and provide insights into the formation (sediment) response to pressure change. These tests reveal that pore pressure regime at Mallik 5L-38 is very near to, but slightly above, hydrostatic.

**DISCUSSION**

As reviewed in several papers in this volume, a short pressure drawdown production test was completed at Mallik 2L-38 during April, 2007 [1]. As shown in Figure 6, a total of approximately 830m$^3$ of methane gas was measured at surface, with significantly higher production rates observed in the latter portions of the test period. This paper considers the influence of critical geologic and porous media conditions in modulating the production response of the reservoir to stimulation by depressurization.

**Evidence for gas hydrate dissociation as a phase boundary envelope rather than a discrete P-T threshold**

Unfortunately, flow data during the first 12 hrs of the 2007 production test was limited due to an operator error. However, approximately 100m$^3$ of gas was produced during this period, as bottom hole pressure was reduced from 11MPa to about 8MPa. Extension of the linear flow trend observed between hr 12 and hr 14, backward to the start of the test, suggests that an early phase of gas hydrate dissociation may have been initiated at a BHP of 10MPa (dashed horizontal line on Fig. 6). Consistent with this interpretation, a coincident reduction in the rate of pressure drawdown under a constant pump rate (see intersection of the vertical dashed line) may be indicative of an inflow of formation water (and gas) released during this initial phase of gas hydrate dissociation. As reviewed previously, laboratory studies using Mallik core samples suggest that in saline sediments, gas hydrate dissociates across a pressure-temperature phase boundary envelope or zone, rather than according to a discrete P-T threshold defining gas hydrate stability-instability. In terms of the reservoir response to pressure drawdown, this implies a relatively early (albeit weak) initial production response, with subsequent increasing gas yields as the pressure drawdown continues and P-T conditions traverse the phase boundary envelope. Indeed a very marked increase in production was observed during this period.

---

*Figure 6.* Cumulative production (red line) and derived bottom hole flowing pressure (black line) from pressure drawdown test completed on Mallik production interval April 2-3, 2007. As described by Numasaki et al [1], operational problems during the test caused intermittent pump operations (light shaded times) and periods where the pump did not operate (dark shaded times) and unfortunately no flow data was recorded during the early stage of the test.
in flow rate was observed during the 2007 test as the BHP was further reduced from 8MPa to about 7.3MPa (Fig. 6). We interpret the significant but relatively small gas and water production during the early stages of the test to result from a combination of gas hydrate reaction inside of the phase boundary envelop and small relative permeability during the initial stages of the test.

**Sand inflow into the production well**

As reviewed previously, the substantive loss of sediment strength following dissociation of pore-space gas hydrate has been observed in a number of laboratory investigations conducted on Mallik cores. A conscious decision was made to undertake the 2007 Mallik production test without the implementation of sand control measures. The rationale behind this decision was the perceived need to assess whether this reduction in sediment strength would result in sediment inflow into the well, or conversely whether any mobile sediment would simply reconsolidate in the near wellbore area, and pack around the casing perforations. The 2007 test results showed conclusively that the dissociated sands were highly mobile, and indeed many of the operational problems encountered during the test were caused or exacerbated by sand flow into the well. It is estimated that at least 2.5m$^3$ of sand flowed into the well, accumulating in the well sump, within the production tubing, and around the check valve [1]. Additional sand may have been emplaced within the water injection intervals located below the production test zone. Based on sediment characteristics and gas hydrate saturation levels within the production zone, we estimate that more than 20% of the dissociated sediment may have moved into the well. As observed in some field and laboratory samples, depressurization of pore-space gas hydrate can yield a highly energetic dissociation reaction. It is reasonable to consider that the vigorous released of gas from a dissociating sediment face may literally drive a slurry of gasified sediment and water towards the well bore. Clearly, the simulation of this environment in a laboratory experiment or in a numerical modeling scenario would be very challenging.

**Non-uniform dissociation response**

As reviewed in a paper by Kurihara et al. [4] in this volume, numerical simulation of the 2007 Mallik production test proved problematic, as the high flow rates observed could not be matched using estimates of in situ reservoir properties from geophysical logs and core data. Given the sand inflow to the well, it was postulated that the development of “worm holes” in the near-wellbore portion of the formation might account for this discrepancy. Modeling trials using simple worm hole geometry and substantially modified permeability assignments were conducted with some success, in some cases achieving a near match between estimated and observed flow data. In essence the difficulty in matching the modeled vs. observed flow rates reveals that the pressure disturbance induced by the production test must have affected a larger portion of the reservoir than can be explained by the steady propagation of a simple radial dissociation front away from the wellbore. This raises the question of non-uniform formation conditions that might facilitate localized penetration of the pressure disturbance further into the reservoir, effectively increasing the total area of the dissociating “surface”, thereby increasing dissociation rates and ultimately, gas yields. The most obvious factor to be considered in this regard is geological heterogeneity and the associated variability in local sediment permeability and gas hydrate saturation. As shown in Figures 2 and 3, at coarse scales no striking discontinuities in the geology of the production interval are apparent (i.e. a thick uniform sand sequence with relatively high gas hydrate saturations is interpreted). However, as shown on Figure 7, high-resolution FMI (Formation Micro-Imager) logs indicate cm-scale variations in geology, as well as the presence of natural fractures within the production test interval. Both of these conditions could promote non-uniform gas hydrate dissociation. In our view, the occurrence of open or water-filled natural fractures would be a strong facilitator of non-uniform dissociation and may influence possible worm hole development or the formation of high-permeability conduits in association with sand production. We note that FMI interpretations from Mallik 5L-38 [15] identifies a number of open fractures within the gas hydrate intervals, the presence of which may also explain the pressure response observed for MDT test #2 [18] conducted within the production test zone. Recent interpretation of new well log data from Mallik 2L-38 also suggests the presence of a conductive or water-filled fracture at 1096.5m, and three fractures in the interval from 1103 to 1104. We anticipate that new numerical simulations conducted in the near future will attempt to model
the influence of open fractures on gas hydrate production by depressurization.

CONCLUSIONS
This paper concludes that the gas flow response observed during the 2007 production test at Mallik was influenced significantly by porous media properties and various geological heterogeneities inherent to sediments within the production interval of the Mallik gas hydrate reservoir. Preliminary interpretations suggest:
1) the tracking of reservoir P-T conditions across a theoretical phase boundary envelope explains an early low-flow response to a limited pressure drawdown, with progressively increasing gas yields as drawdown continues.
2) the transport of sediment into the well bore is consistent with a reduction in the strength of hydrate-bonded sands, and the energetic and possibly effervescent release of gas at the dissociation face.
3) geological heterogeneity and the presence of natural fractures may promote non-uniform gas hydrate dissociation, thereby yielding gas production rates greater than those predictions using simple radial geometry.

The 2007 test program was followed by a longer duration testing program in March, 2008. Based on observations from the 2007 program measures were taken to control sand production and therefore allow more uniform operating conditions. These results will be reviewed in future publications.

ACKNOWLEDGEMENTS
The authors of this paper would like to express their appreciation to those field workers who participated in the 2007 Mallik field program. Andrew Applejohn and Alan Taylor of Aurora College contributed substantially in their role as operator. Much credit is also due to D. Ashford, L. Hernandez Johnson and G. Serrano and well site supervisors who undertook the technical program as well as the more than 250 field participants who worked on site over the winter.

REFERENCES


