MECHANISMS OF GAS EVOLUTION AND TRANSPORT IN A PRODUCING GAS HYDRATE RESERVOIR: AN UNCONVENTIONAL BASIS FOR SUCCESSFUL HISTORY MATCHING OF OBSERVED PRODUCTION FLOW DATA

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ABSTRACT

The first sustained production of methane from hydrates was achieved at the Mallik site in March 2008, as part of a cooperative R&D effort by the Japan Oil, Gas, and Metals Corporation (JOGMEC: formerly JNOC - Japan National Oil Corporation) and the Geological Survey of Canada (GSC). Basic operational parameters such as gas/water flow rates, bottom hole flowing pressure and temperature, etc. were continuously recorded throughout the production period. These data have enabled subsequent history matching and interpretation of the Mallik test for the purpose of developing a geologically-grounded understanding of the intrinsic production behaviour of the Mallik gas hydrate reservoir. Importantly, our investigations reveal that the assumption of conventional gas flow behaviour in a producing gas hydrate reservoir is inadequate for explaining the pattern of gas production observed during the Mallik test. This should not be surprising when one considers that unlike conventional gas reservoirs, the Mallik reservoir contained no free gas initially, and therefore no established gas flow pathways from the interior of the reservoir to the producing well. As such, at every point within the reservoir, free gas must be generated in situ and subsequently must coalesce and connect across pore throats before a continuous gas flow pathway can be established. At the reservoir scale, this implies a systematic resistance or delay in moving gas from its generation point to the wellbore, and this phenomenon becomes more pronounced as the dissociation front penetrates deeper into the reservoir. We propose that this unconventional understanding of mechanisms for gas evolution and transport in gas hydrate reservoirs will be requisite for accurate numerical simulation of scenarios of long-term natural gas production from hydrates.

Keywords: gas hydrates, gas production, gas evolution, critical gas saturation, kinetics

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NOMENCLATURE

\( S_w \) fractional pore volume of water
\( S_h \) fractional pore volume of hydrate
\( k_v \) permeability (vertical)
\( k_h \) permeability (horizontal)
\( t \) time
\( ppt \) parts per thousand
\( \phi_v \) void porosity
\( \phi_f \) fluid porosity
\( \sigma^2 \) variance of log permeability

INTRODUCTION

The Mallik gas hydrate field is located in the Mackenzie Delta on the coast of the Beaufort Sea, Northwest Territories, Canada. Imperial Oil Limited’s (IOL) original Mallik L-38 discovery well was drilled in 1971-72, and subsequently the presence of significant gas hydrate accumulations at the Mallik site was inferred based on a number of operational and geophysical indicators [1]. In 1998, the JAPEX/JNOC/GSC Mallik 2L-38 gas hydrate research well was drilled as part of a Canada-Japan collaboration to characterize a concentrated gas hydrate deposit and to evaluate its energy potential. JAPEX Canada Ltd. served as the operator of the well. A compendium volume of scientific results and a comprehensive project data base were published as Geological Survey of Canada Bulletin 544 [2].

A second multidisciplinary research and development program was undertaken in the winter of 2001-02, and incorporated three new wells (JAPEX/JNOC/GSC 3L-38, 4L-38 and 5L-38) consisting of a production well (5L) and two monitoring wells (3L; 4L). The R&D studies were led by the GSC and JNOC with JAPEX again serving as operator. Additional participants included GeoForschungZentrum (Germany), the International Continental Scientific Drilling Program, the U.S. Geological Survey, the U.S. Department of Energy, the India National Gas Hydrate program, and BP/Chevron Joint Venture. In addition to state of the art geophysical and coring studies, the program included a series of controlled pressure drawdown experiments using Schlumberger Limited’s Modular Formation Dynamics Tester (MDT®), and a full-scale thermal production test which produced approx. 500 m³ of natural gas from hydrate over a 5 day period. More than 60 scientific and technical research papers documenting this work were published as Geological Survey of Canada Bulletin 585 [3].

Canada-Japan collaboration at Mallik culminated in March 2008 with the achievement of 6.75 days of continuous gas production from a 12 m perforated interval, at an average gas rate of about 2000 m³/d, and a total produced gas volume of approximately 13,000 m³ [4,5].

Figure 1: Map showing the regional gas hydrate stability field and well indications of \( \text{CH}_4 \) hydrate occurrence in the vicinity of the Mallik site in Canada’s Mackenzie Delta.

This paper presents an overview of the production characteristics of the Mallik gas hydrate reservoir, including production flow data, model parameterization, and history matching through numerical reservoir simulation. Problems encountered with the application of widely-accepted history matching techniques developed for conventional gas reservoirs are highlighted, and a new approach based on an unconventional understanding of gas evolution and transport in a producing gas hydrate reservoir (adapted from previous theoretical and laboratory work on gas exsolution from “foamy” oil reservoirs) is explored. In this work, the explicit numerical representation within CMG-STARS® [6] of newly proposed mechanisms for gas evolution and transport has enabled a relatively simple and internally consistent history match of the Mallik 2008 production data and subsequent production forecasting.
RESERVOIR FLOW RESPONSE TO DEPRESSURIZATION

Comparison of conventional vs. gas hydrate reservoirs
Gas hydrate dissociation is an effervescent process characterized by the in situ generation of gas and water from a solid hydrate phase. As such, there are important distinctions between a conventional natural gas reservoir and the Mallik gas hydrate reservoir as characterized in the three major Mallik production R&D programs conducted in 1998, 2002 and 2007-08. We define “conventional” as meaning a relatively porous and permeable reservoir containing free gas at or in excess of the critical gas saturation required to sustain bulk flow to the producing well [7,8]. Therefore, in this work we define a non-conventional gas reservoir as one in which the fractional free gas saturation is below the critical value necessary to establish effective flow pathways from the site of gas generation to the producing well.

In general, conventional gas reservoirs contain considerable amounts of free gas, such that gas flow pathways to the well already exist or can be readily established. In the case of the Mallik gas hydrate reservoir, a continuous water phase occupies the non-hydrate pore volume ($S_w=1-S_h$). This means that at $t = 0$ of a gas hydrate production operation, little or no free gas exists within the producing reservoir. This implies that few or no pathways exist for transporting gas from the interior of the reservoir to the wellbore.

Figure 2 presents a generalized representation of the classical flow response a conventional gas reservoir, in comparison to the general pattern of gas flow observed during Stage 2 and Stage 3 production at Mallik (based on the metered gas flow at the surface) as shown in Figure 4 and detailed in the following sections. In a conventional gas well, production rates tend to decline smoothly from an initial high production rate toward lower rates over time [9], as shown by the dashed red curve. In contrast to classical flow behaviour, Stage 2 and 3 gas production at Mallik was characterized by an initial gas surge of relatively short duration, followed by a rapid decline in rates to comparatively low values, and a subsequent gradual recovery to modest flow rates, apparently increasing with time. Analysis of the Mallik 2008 gas hydrate production data shows non-conventional gas production behaviour in response to reservoir depressurization. Initial efforts to history match the Mallik production data through numerical simulation using conventional parameter adjustment schemes were problematic [10,11] in that it was necessary to invoke multiple adjustments (in space and time) of key reservoir parameters (e.g. permeability and relative permeability) in order to obtain a reasonable fit to the field data.

Gas exsolution in a “foamy oil” sand pack
In order to overcome these difficulties, we have adopted a non-conventional model of gas evolution and transport in the Mallik gas hydrate reservoir, based on previous work describing patterns of gas exsolution in foamy oil (also known as live oil) reservoirs (Figure 3). Laboratory experiments and modeling suggest that significant amounts of exsolved gas can be trapped for some time in a foamy oil reservoir, depending on the role of several field mechanisms [12,13]. Gas bubble nucleation in foamy oil occurs when the flow system pressure is reduced below the equilibrium saturation pressure. The deviation of the system pressure from the equilibrium value can be considered as an excess energy density in the foamy heavy oil. This non-equilibrium pressure deviation was observed in constant rate gas exsolution tests in a foamy heavy oil sand pack. The pressure responses vs. time for two constant flow
rate experiments are shown in Figure 3. The steep pressure reduction (below the equilibrium value) created a supersaturated condition (ranging from 1500 to 4000 kPa) which resulted in vigorous bubble nucleation and growth and a corresponding rapid rebound in pressure. As this pressure rebound continued, the degree of supersaturation (pressure differential) decreased proportionally, reducing the driving force for bubble nucleation and growth, and slowing the rate of pressure increase until finally pressures began to drop again due to the depletion of gas in the sample.

As seen in Figure 4 (lower panel), the reservoir response (to depressurization) at Mallik 2L-38 displays characteristics similar to those observed in the foamy oil experiments, with initial high gas rates dropping to sharply lower values and subsequently rebounding gradually to near steady state production. Uddin et al. has thoroughly examined this similarity through extensive numerical sensitivity studies [11].

**Gas evolution and transport in the Mallik gas hydrate reservoir**

According to Lighthelm et al. [8], two conditions must be fulfilled to allow gas to be produced to a well: i) the fractional (pore) volume of the gas must exceed the critical gas saturation for the reservoir and; ii) during depressurization the gas phase must expand to a continuous network (i.e. establish a flow pathway to the well). Based on the gas exsolution studies described previously, we propose specific mechanisms for gas evolution and transport in the Mallik gas hydrate reservoir, as follows: generation of small bubbles entrained in pore water (mobile); coalescence of small bubbles to larger bubbles (immobile - trapped in individual pores) and; the connection of larger bubbles across pore throats (mobile). Only after sufficient connectivity between pores has been achieved will continuous gas flow pathways from the interior of the reservoir to the wellbore be established. The operation of these mechanisms implies a functional delay in the delivery of produced gas from its generation point in the reservoir to the wellbore, and this delay is additional to the intrinsic kinetics of gas hydrate dissociation as commonly implemented in numerical reservoir simulations. The time constant for these processes is thought to be dependent on the structure of the reservoir (grainsize/porosity distributions) and local driving forces (i.e. pressure fields and gradients). Quantification of these mechanisms is important for the reliable calibration of numerical reservoir simulators for gas hydrate production applications.

**OVERVIEW OF MALLIK 2008 FIELD PRODUCTION CHARACTERISTICS**

In March of 2008, 6.75 days of production testing was conducted at Mallik 2L-38, as represented schematically in Figure 4. Surface well testing consisted of 2 separate flow lines and metering instrumentation. Produced gas was flowed up the annulus to the well head and shunted to a surface metering shack, where the gas was flowed through a variable-orifice choke manifold (Train B designed to maintain stable well head pressures during production. After metering, the gas was passed to an external flare stack to be burned off. Produced water was flowed up the tubing to a separate surface flow line and metering/storage tank (Train A). The water was accumulated at the surface and was periodically delivered to a re-opened (Mallik 3L-38) for re-injection into a permeable sand formation located well below the 2L-38 production test interval.
An important consideration in the evaluation and understanding of the 2008 test is the recognition of the significant physical disturbance imparted to the near-wellbore region of Mallik 2L-38 as a result of operations conducted in the previous winter of 2007. These operations included reopening and completion of the Mallik 2L-38 well and a short (~1 day) production test, the results of which informed the final design of the extended production test scheduled for the following year. This short pre-test was conducted without screen protection across the perforated zone. As a consequence, significant sand production (approx. 5 m³ in total) caused an early termination of the test, in spite of substantial gas flow rates (exceeding 2000 m³/d) towards the end of the test period.

Furthermore, upon completion of 2007 operations the well was suspended pending the commencement of 2008 operations some 9 months later. This included the injection of saline fluid into the perforated production zone, which may have promoted instability of near-wellbore gas hydrate and the generation (or maintenance) of significant amounts of residual free gas in the near wellbore area.

The Mallik 2008 production test was conducted in three separate stages, with a total duration of 6.75 days. In light of the residual disturbances arising from 2007 operations, together with some initial operational problems encountered during the early hours of production testing in March 2008, we consider Stage 1 production to be generally unrepresentative of the intrinsic response of the Mallik reservoir to depressurization. A relatively simple (but rigorous) specification of a partially disturbed “dilation zone” in the vicinity of the perforations served as the initial condition from which the numerical simulation of 2008 production data was initiated. It was assumed that by the end of Stage 1 the residual gases and high-salinity well fluids had been flushed from the disturbed near-wellbore zone. By this means reasonable history matches for all 3 production stages were generated, however only Stage 2 & Stage 3 flow data were considered in the evaluation of the intrinsic production response of the Mallik gas hydrate reservoir.

Figure 4: Top - Generalized representation of the Mallik 2008 production test well configuration. Middle - Conceptual model of free gas evolution in a portion of the Mallik reservoir. Bottom - Stage 2 and Stage 3 gas flow response is consistent with the production response observed in the “foamy oil” sand pack experiments.
Stage 1 Although the initial pressure drawdown target for Stage 1 production was 8 MPa, the actual Stage 1 BHP (at the perforations) stabilized at about 7.3 MPa. Pressure at the perforations was calculated based on real-time pressure measurements at various locations (different depths) in the wellbore and estimates of fluid density (accounting for entrained gas). These estimates were later confirmed by downhole pressure data recorded in 3 memory gauges. Which were recovered at the end of the testing period. Unfortunately, early in Stage 1 a fluid line froze at surface and the casing had to be shut in to effect repairs. The resulting build-up of casing pressure led to an increase in the rate of liquid (water) removal from the annulus, as under this condition the pump required less lifting head to bring fluid to surface. When the casing was reopened it was found that the well was slow to recover, and the water flow rates were barely 4 to 5 m³/d. As shown in Figure 5, gas flow rates at the beginning of Stage 1 were in excess of 3500 m³/d but soon dropped steadily for the duration of the phase, finally reaching 2000 m³/d at the end of the test stage.

![Figure 5: Stage1 gas flow pattern assumed to be mainly a “clean-up of the disturbed near wellbore zone. Also includes well shut-in (no-flow) period, and gas surge upon re-opening of the well.](image)

Stage 2 BHP was reduced from about 7.3 MPa to approximately 5 MPa over the course of about seven hours. This pressure drawdown resulted in a large initial surge of gas that tapered off abruptly, finally stabilizing at a gas rate of about 1850 m³/d. Water flow rates for this time period were in the range of 10 to 15 m³/d. BHP was held steady at ~ 5 MPa for almost 60 hours until the next drawdown period commenced.

Stage 3 A final pressure drawdown to 4 MPa at the perforations was attempted to gather some final data before the conclusion of the production test. After about 2 hours of drawdown, gas pressure at wellhead increased dramatically and the Train B choke was opened to reduce the pressure buildup. As a result, gas rates increased dramatically at surface which in turn reduced the casing pressure and resulted in a further reduction in the annular pressure downhole. In fact for a period of 1.5 hours following this surge, intake pressure continued to drop even though casing pressure was stable and the pump was not moving fluid. This is believed to be due to the fact that the initial gas surge lifted the fluid column (essentially foaming it) and the dissipation of that surge led to the column collapsing on itself. The situation eventually stabilized (BHP ~4.3 MPa) at a pump-off condition in which the pump was running with very little or possibly no fluid above it. During this final stage, water rates were in the range of 20 m³/d with gas rates of approximately 2500 m³/d.

HISTORY MATCHING OF MALLIK PRODUCTION DATA

A numerical history match of the 2008 Mallik gas hydrate production test data has been conducted using best estimates of key geological parameters, and careful consideration of uncertainties in the initial state of the hydrate reservoir (related to disturbances imposed by field operations in the winter of 2007) and with regard to uncertainties in the gas hydrate dissociation process itself [11]. The work predicts the production responses of the Mallik reservoir to various levels of pressure drawdown (i.e. to successive stages of fixed bottom hole pressure). Initial efforts to history match the Mallik production data using conventional parameter adjustment schemes were unsatisfactory. Indeed our investigations lead us to suggest that successful characterization of the response of the Mallik gas hydrate reservoir to staged depressurization requires the consideration of non-equilibrium gas ex-solution behaviour. We present both some simple treatments to quantify such behaviour and some ideas for the development of a more complete model in the future.
Modeling parameters and assumptions
In our numerical history matching, model parameters were separated into two classes: the first consists of parameters which may be “tuned” as part of the history matching process, and the second consists of parameters whose values are “fixed” according to best estimates. The set of tuned parameters was selected as being strongly process-specific, and hence, highly uncertain with respect to their influence on the hydrate dissociation process. The set of fixed parameters featured a range of variability associated with geological uncertainty, but were not specific to gas hydrate dissolution itself, and hence model sensitivity to these parameters were assessed independently. A summary of values assigned to key modeling parameters is presented in Table 1.

Tuned parameters
In the present modeling, the tunable history matching parameters are: (1) hydrate dissociation or gas evolution rate coefficients, (2) variable gas bubbles transport or critical gas saturation endpoint. Both of these parameters can be considered as addressing non-equilibrium effects of gas hydrate dissolution and flow, and can be best interpreted in the context of a general model of gas ex-solution [11].

In this section we explore some of the critical steps towards the development of these concepts for gas hydrate applications. Our base case kinetic constant was set as kd = 9.405x10² (gmole/m³)²/day, a value which has been employed in our previous work [14], and by others [15]. Preliminary simulations with a constant critical gas saturation illustrated that no single constant value could produce a realistic representation of the time-dependent field evolution of free gas production from hydrate, especially with respect to the short term dynamic response to each pressure drawdown stage. The observation of non-conventional field behaviour forced us to the conclusion that accurate representation of short-time gas transport required the specification of a time-dependent critical gas response.

Initially, the “Variable Permeability Parameter” (or Carmen-Kozeny exponent “ck”) was also considered as a “tuning” parameter, as it is sensitive to changes in effective permeability as hydrate dissociates. However, the excellent fit of the field log data of effective permeability (due to vertical variation of initial hydrate saturation) to a Carmen-Kozeny parameter of 6.0 led us to exclude this as a tunable parameter, and all simulations were conducted with this parameter fixed. The Carmen-Kozeny function, together with the vertical well log data describing gas hydrate saturation, porosity and permeability at Mallik 21-38 can be found in our recent paper [11].

<table>
<thead>
<tr>
<th>Model Properties</th>
<th>Values</th>
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<td>Field log data - Well 21L-38</td>
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<tr>
<td>Perforation (1093-1105 m)</td>
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<td>Effective permeability for GH layers (mD)</td>
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<td>Absolute permeability - bottom aquifer (mD)</td>
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<td>Void porosity for bottom aquifer (%)</td>
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<tr>
<td>Salinity (ppt)</td>
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Radial grid model
Figure 6 shows the radial grid configuration utilized in the long-term (502 m radius) numerical simulations. Smaller grid sizes were employed in the vicinity of the well bore in order to capture a very steep transient pressure, temperature and gas hydrate concentration fronts. The numerical domain was discretized into 287 cells in the R-direction and 57 layers in Z-direction (the top 52 layers at 1 m thickness and the bottom 5 layers at 2 m thickness) with an angular θ-direction of 1 (θ = 360). The total number of grid cells for the 502 m radius grid was 16,359. It is emphasized that such a grid discretization maintains a horizontal/vertical aspect ratio close to 1. A grid sensitivity study was
performed to ensure that this grid choice eliminates discretization effects.

Figure 6: General configuration of the radial grid model. A 102 m grid radius was used for history matching of the short-term (6.75 days) Mallik production data. A grid radius of 502 m was employed for predictive modeling of long-term production trends.

RESULTS

History Matching
Figure 7 shows the numerical history match of gas production rate for Stage 2 & Stage 3 of the field test, for which bottom hole pressures were reduced to approx. 5000 kPa and 4350 kPa respectively. Based on the metered production data measured at the surface, a nearly steady state gas production rate of approx. 1900 m³/day was achieved at the end of Stage 2, while the gas rate at end of Stage 3 was nearly 2500 m³/day and appeared to be following an increasing trend.

Figure 7: Numerical history match of Mallik 2008 gas production from APEX/NOC/GSC Mallik 2L-38 [16]

History matching of Stage 2 and 3 production closely matches the metered rates, and also reproduces the essential pattern of the gas surge and subsequent steep drop in gas rates in response to the pressure drawdown at the beginning of each production stage. The history matching results are also generally consistent with a separate estimate of gas inflow at the perforations (purple plot in Fig. 7) based on P-V-T (pressure-volume-temperature) calculations.

Figure 8: Numerical history match of Stages 2 and 3 cumulative gas and water production from Mallik 2L-38 [16]

The history matches for cumulative gas and water productions are shown in Figure 8. At the end of 6.75 days production test, total measured cumulative gas and water productions are 12,278 and 67 m³ (STD), respectively and total simulated cumulative gas and water productions are 12,596 and 73 m³ (STD), respectively.

Prediction of long-term production trends
Figure 9 shows predicted gas production rates and cumulative gas production for a period of 2800 days (~7.7 years), based on forward execution of the tuned (history matched) model. Here it is seen that the gas rate continues to rise and accelerate throughout the production period. The fact that gas hydrate dissociation results in a 1000-fold increase in effective permeability implies that there is little resistance to gas flow in the dissociated zone, and that the observed gas production can be interpreted as production from an ever-increasing well radius. This interpretation is somewhat dependent on the vertical permeability and initial gas saturation distributions, but at least in the Mallik case, there is vertical permeability sufficient to permit an
uninhibited flow of gas to the well through the dissociated zone.

Figure 9: Numerical forecasting of gas production from JAPEX/JNOC/GSC Mallik 2L-38 [16]

Figure 11: Predicted overall field water-gas-ratio (WGR) and change in solid (gas hydrate) volume, based on 502 m radius single well radial grid model [16]

Uddin et al. [16] estimate that approximately 31% of the hydrate volume within the 500 m radius simulation zone had dissociated by the end of the 2800 day simulation period. This represents approximately $1.3 \times 10^8$ m$^3$ of hydrate dissociated, generating a total of about $2.1 \times 10^8$ m$^3$ of methane gas, of which $1.5 \times 10^8$ m$^3$ (or ~70%) was delivered to the well. This suggests that about 30% of the gas produced remained in the reservoir at the end of the simulation period.

SUMMARY

This paper has presented an overview of the production characteristics of the Mallik gas hydrate reservoir, including production flow data, model parameterization, and history matching through numerical reservoir simulation. Problems encountered with the application of widely-accepted history matching techniques developed for conventional gas reservoirs are highlighted, and new approach based on an unconventional understanding of gas evolution and transport in a producing gas hydrate reservoir has been explored.

Gas hydrate reservoirs are unique in that they generally contain no initial free gas. Therefore free gas must be generated in situ at every location within the producing reservoir. Specific mechanisms for gas evolution and transport in a
gas hydrate reservoir have been proposed, as follows: generation of small bubbles entrained in pore water (mobile); coalescence of small bubbles to larger bubbles (immobile - trapped in individual pores); connection of larger bubbles across pore throats (mobile). Only after sufficient connectivity between pores has been achieved will continuous gas flow pathways from the interior of the reservoir to the wellbore be established. The operation of these mechanisms implies a functional delay in the delivery of produced gas from its generation point in the reservoir to the wellbore, and this delay is additional to the intrinsic kinetics of gas hydrate dissociation. The explicit numerical representation of the proposed mechanisms of gas evolution and transport has enabled a relatively simple and internally consistent history match of the Mallik 2008 production data.

In this work, the explicit numerical representation (within CMG-STARS) of the proposed mechanisms of gas evolution and transport has enabled an internally consistent history match of the Mallik 2008 production data, without the need to impose arbitrary variation (in space and time) of key reservoir properties such as permeability and relative permeability [16]. In particular, we have demonstrated high vertical well productivity for a well completion intersecting multiple geological layers, while ancillary work suggests that horizontal well productivity may be limited due to upward gas migration blocked by geological layering [17].

CONCLUSIONS

The implementation of a new concept of gas evolution and transport in numerical reservoir simulation of methane production from gas hydrate has enabled a comparatively simple and internally-consistent history matching of the Mallik 2008 production data.

The short-time Mallik field test result provides a useful basis for predicting longer term primary gas exsolution from hydrate reservoirs, and additionally motivates the investigation of potentially attractive enhanced recovery schemes. However, such extended studies are currently limited by uncertainties regarding geological heterogeneities (especially laterally away from the well) and would benefit from additional multi-well well performance information and higher resolution seismic mapping. Throughout, the kinetics of gas hydrate dissociation have been shown to dominate the field response to production stimulation (i.e. depressurization), even at the field scale.

It is recognized that the gas production behavior predicted (i.e. progressively increasing gas rates) is an idealized result and that some limit to gas production may eventually be encountered. Sensitivity studies have demonstrated that the predicted results are not an artifact of numerical boundaries or other gridding choices of the radial model. Rather, we believe that the physically limiting issue is the three dimensional spatial distribution of properties (porosity, permeability, and initial hydrate distribution) and that areal regions of lower porosity, permeability, and hydrate saturation may act as effective areal “boundaries” to gas production from individual vertical wells. Therefore, depending on the actual areal distribution of these properties within the reservoir, each individual hydrate well will have its own effective drainage area.

FUTURE WORK

More fundamental experimental (and theoretical) work is required to quantify a kinetic gas hydrate model at various scales. Of paramount importance is the integration of kinetic processes operating at different scales - specifically, from microscopic analysis [18] through pore and core scales [10] up to the field scale. We hope to employ our flexible kinetic modeling approach to unify these representation of these process various scales.

Because future reservoir simulations may involve larger areas of investigation and possible repeating patterns of well development, we propose to incorporate the available seismic gas hydrate accumulation information from the Mallik field [19] in future modeling. Additionally, well logs from nearby hydrate wells (L-38, 3L-38, 4L-38) could be employed to generate a more complete statistical representation of the interwell stratigraphic variation in reservoir properties. This should facilitate improved quantification of gas hydrate accumulations and porosity variations, both vertical and horizontal). This could also lead to the development of protocols for applying 4D seismic methods to spatial monitoring of gas
hydrate dissociation during long term production, analogous to those used to quantify steam zone evolution in heavy oil reservoirs [20].

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