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# India National Gas Hydrate Program Expedition 02 summary of scientific results: Numerical simulation of reservoir response to depressurization

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## Abstract

The India National Gas Hydrate Program Expedition 02 (NGHP-02) discovered gas hydrate at high saturation in sand reservoirs at several sites in the deepwater Bay of Bengal. To assess the potential response of those deposits to scientific depressurization experiments, comprehensive geologic models were constructed to enable numerical simulation for two sites. Both sites (NGHP-02-09 and NGHP-02-16) feature thick sequences of thinly-interbedded reservoir and non-reservoir facies at sub-seafloor depths less than 300 m and sub-sea depths of 2400 m or more. These settings pose significant challenges to current modeling capabilities. First, the thinly-interbedded reservoir architecture complicates the determination of basic reservoir parameters from both log and core data due to measurement resolution issues. Secondly, the fine scale variation in sediment properties imparts great contrasts in key parameters over very short distances, creating high gradients at multiple scales and varying orientations that necessitate careful design of high-definition simulation grids. Thirdly, the deposits include internal sources of water, as well as a range of complex boundary conditions, including variable permeability within the overlying mud-rich “seals,” that complicate reservoir depressurization. Lastly, because of the unique combination of great water depth and relatively shallow sub-seafloor depth: models designed to maximize the dissociation rate impose large pressure drawdowns on relatively low-strength sediments. This condition renders the proper evaluation and integration of the geomechanical response to hydrate dissociation critical. In this report, we review the history of gas hydrate reservoir simulation, discuss methods for creating geologic input models, and summarize the key findings and implications of the collaborative NGHP-02 numerical simulation effort. Together, the studies confirm the viability of the modeled accumulations for scientific testing and identify key challenges related to the selection of specific test sites and the design of test wells.

Keywords: Gas Hydrates, Geological Models, Numerical Simulation, Geomechanical Modeling

## 1. Introduction

Gas hydrate energy resource evaluation continues to accelerate world-wide. In recent years, major exploratory drilling and/or testing programs have been conducted onshore Alaska (Hunter et al., 2011; Boswell et al., 2016); Canada (Dallimore and Collett, 2005; Dallimore et al., 2012), and China (Li et al., 2017), as well as offshore Japan (Konno et al., 2017), Korea (Ryu et al.,

2013), India (Collett et al., 2014 and this issue; Kumar et al., 2014 and this issue), China (Li et al., 2018), and the United States (Flemings et al., 2017). Together, these programs confirm the widespread occurrence of gas hydrate resources and the technical viability of production via reservoir depressurization for gas hydrates housed at elevated saturations within relatively coarser-grained sediments. Further, these studies have identified the key challenges to designing the robust and stable well designs that are a necessary precursor to viable production over extended time frames (Hancock et al., 2010; Boswell et al., 2014).

Numerical simulation will continue to be a critical element in the evaluation of the energy resource potential of natural gas hydrates. In preparation for field programs, simulations provide information to design science testing protocols that maximize insight and minimize operational risks associated with well completions, well stability, flow assurance, sand control, artificial lift, and other systems (Beaudoin et al., 2014). Further, simulations that attempt to history-match field observations provide the primary means of interpreting the physical processes acting within the reservoir and allowing that behavior to be extrapolated throughout the potential life of production wells (Moridis et al., 2009; Anderson et al., 2011a; Kurihara et al., 2012; Udden et al., 2012; Konno et al., 2017). Given the high costs associated with reservoir response tests in deepwater or arctic settings, confidence in these simulations is imperative.

In 2015, India National Gas Hydrate Program Expedition 02 (NGHP-02) discovered gas hydrate at high saturation at multiple sites (Fig. 1) within deepwater channel-levee-fan systems known as “Area B” and “Area C” (Collett et al., this issue). These occurrences are in the deepest water yet explored for gas hydrate; however, the depth of the reservoirs below the seafloor is no greater than in other areas where sand-rich reservoirs have been studied (Fig. 2). For example, at Site NGHP-02-16 in Area B, the reservoirs occur at 272.8 m below seafloor in 2546.5 m of water: at Site NGHP-02-09 in Area C, the reservoirs lie at 214.9 m below seafloor in 2219.5 m of water. The two sites are both characterized by a thin-bedded internal architecture but differ in reservoir lithology: the Area B reservoir consists of finely-interbedded silty muds, sandy silts, and silty sands whereas the Area C reservoirs include a much broader range of lithologies, including very coarse-grained sands and localized gravels. Area C also features complex vertical interbedding of hydrate-bearing and hydrate-free (fully water-saturated) sand-rich units, whereas in Area B, the water-bearing sand units only occur directly below the hydrate-bearing units. In both areas, the intervening mud rich layers, as well as the bounding mud-rich “overburden” and “underburden” have relatively low, but non-zero, permeability. The overburden at Site NGHP-02-16 is particularly unique, as it is composed of a high porosity, diatomaceous sediment (Jang et al., this issue-a). Such complex systems represent a significant challenge to 1) the current capability of numerical models; 2) our ability to adequately characterize the

initial state of such systems; and 3) the applicability of available algorithms to describe the dynamic (and coupled) petrophysical and geomechanical processes that take place in such systems in response to depressurization.

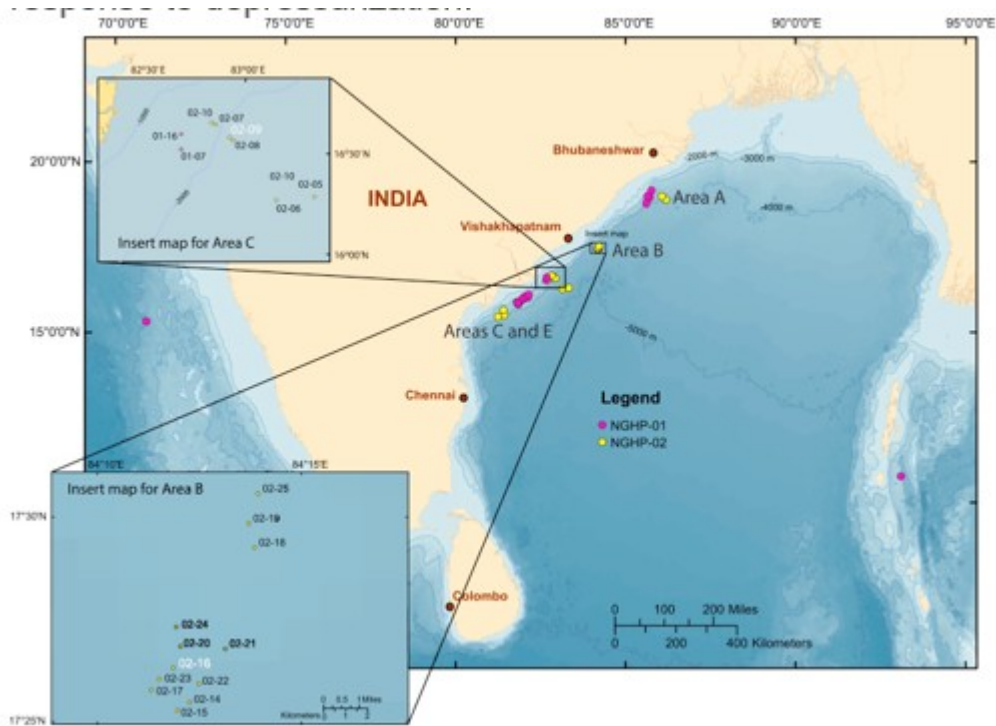


Fig. 1. Location of Sites NGHP-02-16 (Area B) and NGHP-02-09 (Area C), offshore India. The sites are the focus of numerical simulations studies conducted as part of NGHP-02. Pink dots indicate drill sites investigated during NGHP Expedition-01, conducted in 2006 (Collett et al., 2014). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

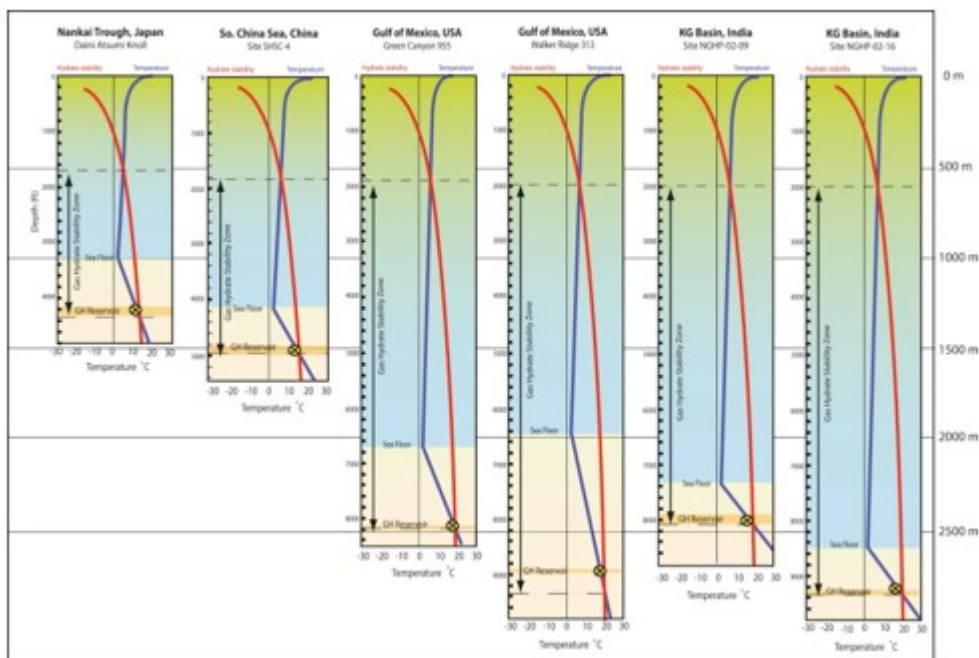


Fig. 2. Schematic depiction of select global occurrences of gas hydrate bearing sands, showing the deepwater, yet relatively shallow sub-seafloor context, of the NGHP-02 reservoirs discovered at Sites NGHP-02-09 (Area C) and NGHP-02-16 (Area B).

This paper summarizes the findings of the collaborative modeling studies conducted with respect to NGHP-02 sites and discusses the challenge of designing and executing numerical simulation studies for deposits such as those found offshore India. This paper does not present the specific details of model execution or results for the India deposits – for that information, the reader is referred to the specific reports included within the NGHP-02 Special Thematical Issue (Konno et al., this issue; Lin et al., this issue; Moridis et al., this issue; Myshakin et al., this issue; Uchida et al., this issue).

## 2. Summary of numerical simulation studies for NGHP-02 sites

To best inform the design of potential gas hydrate scientific production tests, the NGHP-02 modeling effort focused primarily on predicting the response of deepwater Krishna-Godavari basin gas hydrates to simple depressurization from a single vertical well. Geologic input models were constructed using well and core data from Site NGHP-02-09 to represent the accumulations in Area C and Site NGHP-02-16 to represent Area B. Neither site necessarily represents the most favorable location within the larger accumulations. At both sites, it was determined that gas production was technically feasible but that each site contains features that could add substantial risk to possible scientific production testing. In neither case is the projected reservoir performance likely to be compatible with current concepts of economically-viable deepwater production -- in virtually any circumstance or location, “commercial” rates will likely rely on further refinement of field development design (including multi-well configurations), well design (including non-vertical well bores), and well stimulation (including thermal, mechanical, and/or chemical methods focused on the near-wellbore environment) to augment production rates. The following summarizes key results of the modeling effort.

### 2.1. Production response - area C

As described in Moridis et al. (this issue), the production response for Area C was predicted using data obtained at Site NGHP-02-09. Unfortunately, NGHP-02 pressure-core recovery for Area C was limited, and therefore critical modeling input parameters are generally based on sparse data. To obtain reliable simulation results while honoring the unit's complex interbedded nature, a highly-discretized input design was generated that included 452 radial increments and 525 subdivisions of the domain's z-axis, the latter representing the 56 individual layers (Fig. 3). This design required very fine spatial discretization, so that even the thinnest geologic layer could be subdivided into a minimum of three sub-layers in order to accurately capture the curvature of the fluid and heat flow lines across strata with widely disparate properties. The very large resulting matrix and the steep flow and thermal gradients imposed very fine temporal discretization that was

necessary to achieve the linearization required by the Jacobian-based, fully-implicit simulator (Moridis, 2016; Moridis and Pruess, 2016). This in turn resulted in extreme computational loads requiring hundreds of thousands of super-computer hours per run. As a result, a single set of most likely input parameters were developed to investigate input parameter sensitivities and without imposing undocumented lateral heterogeneities; alternative cases were not investigated.

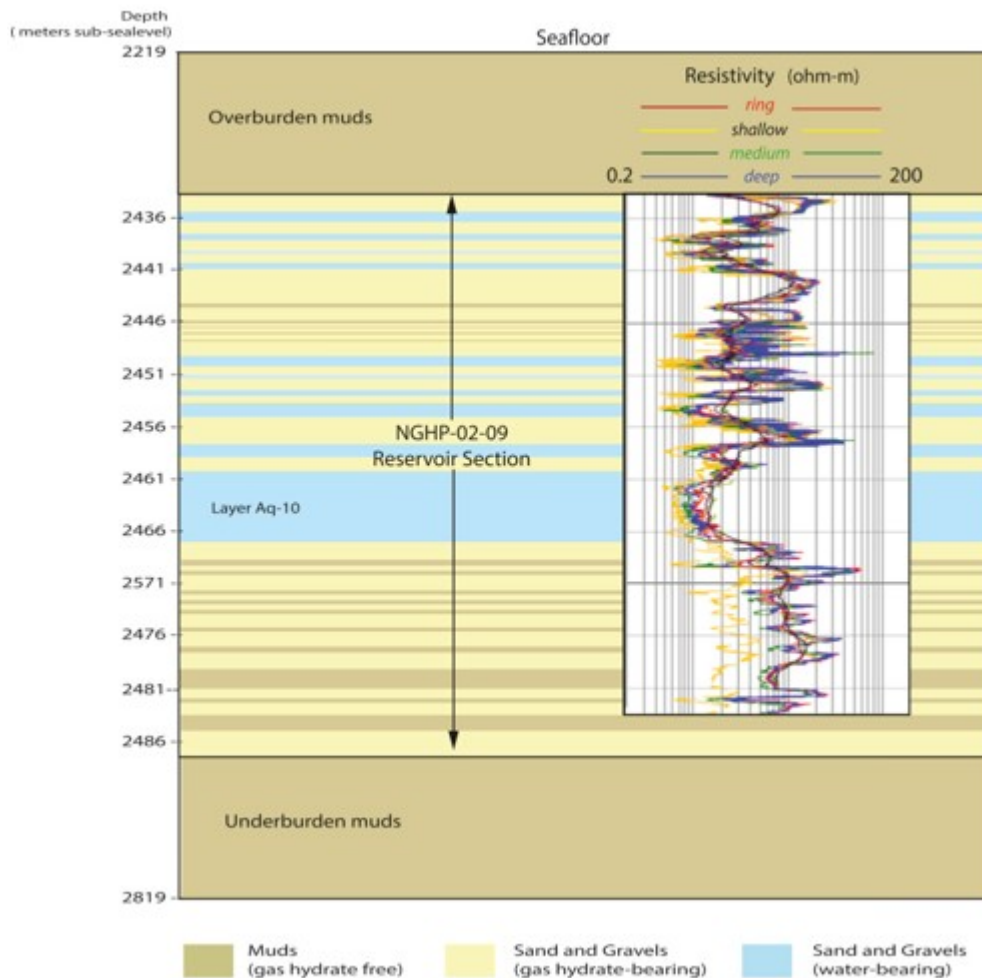


Fig. 3. Reservoir architecture for Site NGHP-02-09 (Area C). Insert is resistivity data from well NGHP-02-09A. Layer “Aq-10” is the water-bearing sand/gravel zone discussed in the text.

The predicted production response at Site NGHP-02-09 Area C is dominated by the occurrence of multiple high-permeability water-bearing (and hydrate-free) sands throughout much of the unit. Simulations of a proposed long-term, single well test in which the full reservoir is modeled as open to the wellbore show substantial gas production (up to 5 MMCF/D within the first month), but that the bulk of the gas has exsolved from the tremendous volume of produced water with limited contribution from the dissociation of gas hydrate.

Production rates rapidly plateau, which can be attributed to the large influx of water from highly-permeable, hydrate-free interlayers (such as “Layer Aq-10”; Fig. 3). This water influx substantially hinders further reservoir depressurization. Given this production response, Moridis et al. (this issue) investigate alternative well completion designs that attempt to isolate the water-bearing sand, but these are only moderately successful, as communication with the water-bearing sands is established relatively quickly under any long-term, single-well test scenario. Moridis et al., (this issue) also investigate a second full-production scenario involving multiple wells on a regular pattern. This second scenario suggests that the difficulties with depressurization in such a setting can be mitigated via coordinated multi-well development strategies that compartmentalize the water-bearing zone and allow more effective reservoir-scale depressurization that can begin after dewatering the thick, highly permeable and hydrate-free interlayers. While per-well production rates are much higher in these broader field-development scenarios, the authors report that such a production system may be prone to substantial geomechanical effects as discussed below. The results suggest that further exploration within the large Area C accumulations is warranted, with the goal of identifying and avoiding locations with large internal water-bearing zones.

## 2.2. Production response – area B

Myshakin et al. (this issue) leverage extensive NGHP-02 well log and core data obtained in Area B to support a range of numerical simulations of potential production response (Fig. 4). Those data indicate that the gas hydrate-bearing units occur within an interval of poorly consolidated silts and fine sands interbedded with mud-rich layers. Geological and geophysical evaluation of the Area B accumulation (Collett et al., this issue; Shukla et al., this issue) indicate the presence of hydraulically-isolated fault blocks, allowing the introduction of lateral-no flow boundaries at the inferred fault locations. Similar to the work conducted for Site NGHP-02-09 Area C described above, the numerical simulations conducted by Myshakin et al. (this issue) for Site NGHP-02-16 Area B use highly-detailed input geologic characterizations. Two alternative depictions were created to explore the sensitivity of modeling results to increasingly fine resolution of bed thickness and small-scale variation in select petrophysical parameters.

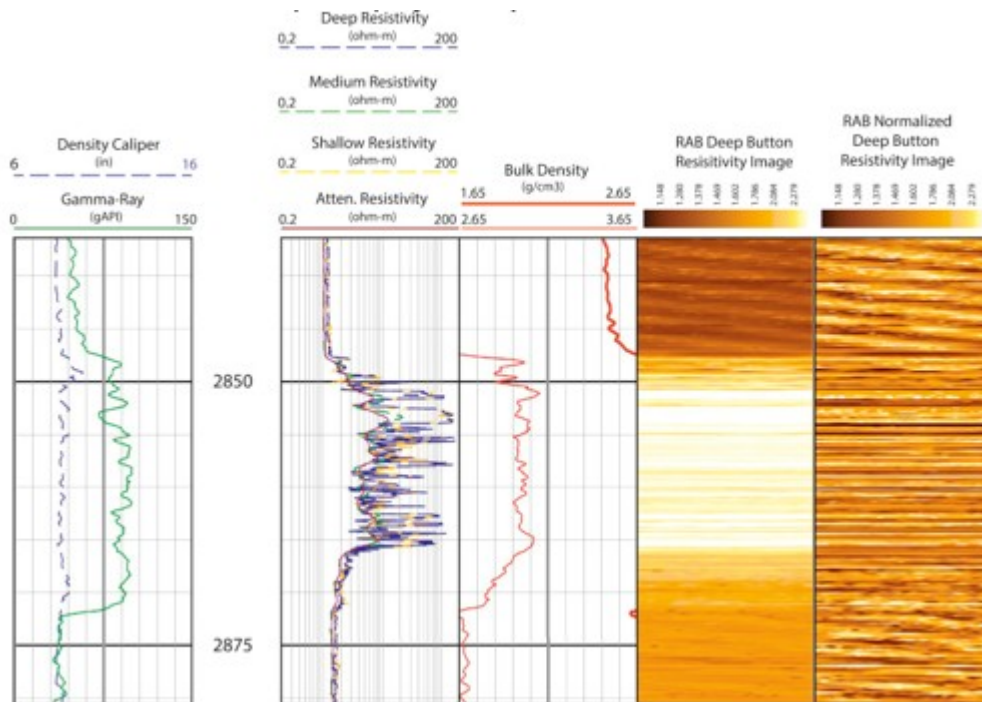


Fig. 4. Log data from well NGHP-02-16A showing the thin-bedded architecture of the primary reservoir section. This architecture is best revealed in the resistivity images at right, which provided the greatest vertical resolution.

Further, for each case, alternative geologic models were created to reflect uncertainties in two key input parameters: initial effective permeability and permeability reduction due to pore compressibility. Jang et al., (this issue-a) report on the unique characteristics of the “seal” units overlying Site NGHP-02-16, which include a diatomaceous lithology with porosity as high as 70%. Permeability of the “seal” is assessed as low (0.05 millidarcies, mD) but subject to significant uncertainty. Konno et al., (this issue) explore the production response at Site NGHP-02-16 through alternative cases that set seal permeability at 0.01 mD and 0.1 mD, and document excessive water influx from the bounding units at the higher permeability.

The numerical simulations for Site NGHP-02-16, Area B, reveal the great sensitivity of modeling results to input model design, initial reservoir permeability, permeability reduction due to pore compressibility, and seal integrity. For example, in Case H of Myshakin et al. (this issue), gas production rates on the order of 1 MMCF/D are sustained throughout a potential 90-day production period using the 10 mD initial effective permeability and most-likely values for compressibility. However, reducing initial permeability to 0.1 mD cuts those rates roughly in half; and setting higher sensitivity for permeability due to pore compressibility further degrades production potential to a level of ~0.1 MMCF/D. These findings are consistent with those of Konno et al., (this issue) who report ~0.33 MMCF/D rates over a 180-day simulation period given favorably low (0.01 mD) seal permeability and initial reservoir permeabilities that vary vertically from 0.01



to 1 mD. Konno et al. (this issue) further discuss the complex interaction of seal permeability on production, particularly the increased water production that would attend more aggressive pressure drawdowns in the presence of relatively high-permeability seals.

### 2.3. NGHP-02 geomechanical modeling

The simulations of Moridis et al. (this issue) and Myshakin et al. (this issue) incorporate geomechanical compression and attendant porosity/permeability reduction into their predictions of flow response associated with depressurization-driven dissociation. Moridis et al., (this issue) also evaluate the large-scale geomechanical response (well-bore stability and potential subsidence at the production zone and at the seafloor) of Site NGHP-02-09 Area C reservoirs. In the single-well case (Case R) where produced fluid volumes are relatively modest, estimated seafloor subsidence is negligible because of the inability to affect substantial depressurization (a direct consequence of the thick, highly permeable, hydrate-free interlayers, which quickly replenish the produced water). However, the more aggressive full-field development (Case C2) involves significant depressurization that follows dewatering of the water-bearing interlayers, which is made possible by isolating the main body of the hydrate from external water intrusion by installing a set of wells along perimeter of the hydrate accumulation. . These producing wells are expected to have limited gas production, and their main function is to prevent water from the boundaries to entering the formation and hampering the gas-production performance of the main producing wells in the interior of the hydrate accumulation. In this case, seafloor subsidence in the vicinity of the interior wells is predicted to reach up to 9 m, driven by the significant depressurization that is affected by enormous volumes of withdrawn water and the prevention of its replacement from the boundaries. For Site NGHP-02-16 Area B, which contains no significant internal sources of water and for which fault compartmentalization provides lateral no-flow boundaries, Lin et al. (this issue) report minimal seafloor subsidence and minimal potential for imposition of strains that might degrade wellbore stability, despite aggressive pressure drawdowns. Uchida et al., (this issue) conducted focused simulations to address the implication of interbedded sand-mud reservoir architecture on geomechanical stability, in particular, the potential for sand detachment and mobilization within the reservoir. The study concludes that the degree of sand mobilization increases directly with the number of sand-mud interfaces within the reservoir, further confirming the need for detailed geologic models to fully capture the likely nature of gas hydrate reservoir response.

### 3. Discussion

The effort to model the response of NGHP-02 sites has revealed a number of critical issues that relate directly to the continued advance of gas hydrate numerical simulation capability. These issues include the generation and design of geologic input models, the evaluation of existing

algorithms designed to relate various parameters, and implications for gas hydrate production strategies.

### 3.1. Geologic input models

*History:* In the early stages of gas hydrate simulation, geologic input models were necessarily simple, featuring homogeneous, highly-saturated, and highly porous and permeable reservoirs bounded by impermeable “seals”. A three-fold class system (Moridis and Collett, 2004) was devised that recognized gas hydrate reservoirs as either 1) having a basal zone of free gas (“Class 1”); 2) having a basal zone of mobile water (“Class 2”), or 3) fully-saturated with gas hydrate (“Class 3”). Class 1 and Class 2 were assessed as having the greater production potential under select conditions, (ex. Moridis and Reagan, 2007); however, as it became clear that Class 1 systems are likely rare in nature (Collett et al., 2009), and that Class 2 systems would be challenged by the typically unconfined nature of the water zone (Moridis and Kowlasky, 2006; Boswell et al., 2009), simulation efforts began to focus on Class 3 systems. In the initial Class 3 studies, the bounding muds were depicted as impermeable and therefore the gas hydrate reservoir was isolated within no-flow boundaries (ex. Reagan and Moridis, 2009). Simulations indicated technical recoverability of substantial gas volumes in Class 3 settings, but typically at low to moderate flow rates over long durations (Wilson et al., 2011) and often include long “lag” times (delays in the production of gas) that would pose a serious barrier to potential commercial viability (Anderson et al., 2011b).

The development of geologic input models entered a second phase with the acquisition of extensive well log and geophysical data that enabled more comprehensive reservoir depictions. Combined with increasing capability of computer codes, studies of reservoirs in the Nankai trough (Kurihara et al., 2009), the Gulf of Mexico (Myshakin et al., 2012), and Alaska (Anderson et al., 2011b), increasingly captured the vertical lithologic heterogeneity within the reservoirs. These studies generally resulted in higher and earlier peak production rates, and also predicted that the production lag period could be eliminated in accord with emerging field data that suggested immediate gas production upon depressurization. However, field production test data remained of insufficient quantity or duration to provide meaningful opportunities to calibrate long-term production projections. More recent work has continued to increase the sophistication of modeling approaches, including massive 3-D simulations (ex. Reagan et al., 2015) and further incorporation of structural and lithological heterogeneity (ex. Ajayi et al., 2018).

The unique and challenging nature of the Krishna-Godavari hydrate reservoirs discovered during NGHP-02 have provided a significant test of gas hydrate numerical simulation approaches and capabilities. While the reliability of numerical simulations is highly dependent on the optimal depiction of both the initial reservoir properties and the dynamic

hydraulic, thermodynamic, and geomechanical phenomena; the results of numerical simulations are also highly dependent on decisions made in the set-up and execution of the model. The following discusses select data input and model design issues.

*Dimensionality of the Input Models:* Reservoir production simulation requires a 3-D reservoir depiction if heterogeneity is to be captured and described, and this is necessary even in single-well simulations. In general, a geologic input model that captures natural reservoir variation in all three dimensions is required, particularly for any location in which the reservoirs are highly-dipping (where gravity variations play a major role), in areas of pervasive faulting or other structural deformation, for reservoirs with a high degree of potential stratigraphic compartmentalization, for locations in which predictions are desired for multi-year time frames, or where modeling will consider multiple wells within a large area. In the case of the NGHP-02 modeling effort, which was generally focused on estimating short-term well response related to areas of ~500 m radius around single well locations in generally flat-lying strata, none of these conditions apply. Consequently, the geologic modeling effort focused on the generation of detailed 1-D vertical models based on the available well data. These models were then extended radially to a distance of 500 m around the well locations to generate the 3-D realization. Although it is well established that incorporation of reasonable lateral petrophysical heterogeneity can have profound implications for predicted reservoir response (Reagan et al., 2010; Ajayi et al., 2018), the NGHP-02 models are characterized as laterally homogeneous for two reasons 1) the modeling was designed to incorporate the vertical heterogeneity to an unprecedented degree, which imposed severe computational burdens on the simulations; and 2) there was little to no data to document lateral heterogeneity at the NGHP-02 Sites. Nonetheless, the incorporation of informed lateral heterogeneity (full 3-D modeling) is warranted wherever it can be accommodated. Notably, Myshakin et al. (this issue) conclude that lateral homogeneity (in particular radial homogeneity) creates conditions by which evolving flow paths to the well are much more easily blocked through phenomena such as secondary hydrate formation, which once it occurs, is simultaneously radiated 360° around the well – a situation that could be mitigated by incorporating natural 3D heterogeneity.

*Gridding:* Gridding, or “mesh resolution,” relates to the spatial dimensions of the reservoir discretization in the input model. In numerical modeling, a reservoir is modeled as an array of individual cells of finite dimension: the coarser the grid, the greater the difference in conditions any grid cell “sees” between one edge and another. For example: a gas hydrate bearing sand may have a permeability of 0.1 mD but be in close contact both laterally and vertically with non-hydrate bearing sediments with permeability four orders of magnitude higher. Erroneous and erratic results can occur where mesh discretization is too coarse (Ajayi et al., 2018). A coarse discretization (larger grid cells), attenuate the thermal, pressure and flow gradients by averaging

the phenomena over larger volumes. As a result, processes such as depressurization more slowly. Ultimately, production behavior in any system described using finer grids is inherently more reliable, although grids that are too fine may introduce additional modeling inefficiencies. To illustrate the effects of lateral grid size selection, we have conducted simple sensitivity analyses for a generic gas hydrate reservoir (Fig. 5). In this example, based on the Alaska North Slope accumulations modeled by Ajayi et al. (2018), a massively-bedded gas-hydrate-bearing sand reservoir of 500 m lateral extent is alternatively segmented into 80, 120, 200, 250, 300, 400 and 500 cells. In each case, the grid cell size increases logarithmically with distance from the wellbore. The results of these simulations reveal significant differences in the predictions of reservoir behavior. Notably, the model with fewer larger cells features a production “lag” (time to onset of first gas production) of about four years. As grid resolution increases, this period of water production diminishes until the “lag” disappears completely at 200 cells. Similarly, with decreasing grid cell size, the peak in gas production occurs sooner, and the maximum rate is larger. For example, the 500-cell case produces gas at year 2 at a rate that is double that of either the 300-cell or 400-cell case. Total cumulative production of the 500-cell case is also substantially greater than any other cases. Such differences, which are driven solely by grid cell size selection, profoundly impact the potential economics of production. Which projection is “most correct” is difficult to determine. There is no existing body of production data that can be used to calibrate results, therefore it is necessary to execute multiple simulations with increasing grid resolution until simulation results converge. In this instance, the 300-cell and 400 cell cases are very similar and suggest some convergence; however, the 500-cell case returns “well behaved” results for the initial 8 years of the simulation before displaying a more variable character. Due to severe computational issues, we do not know how additional cases (for example, a 1000-cell case) might perform.

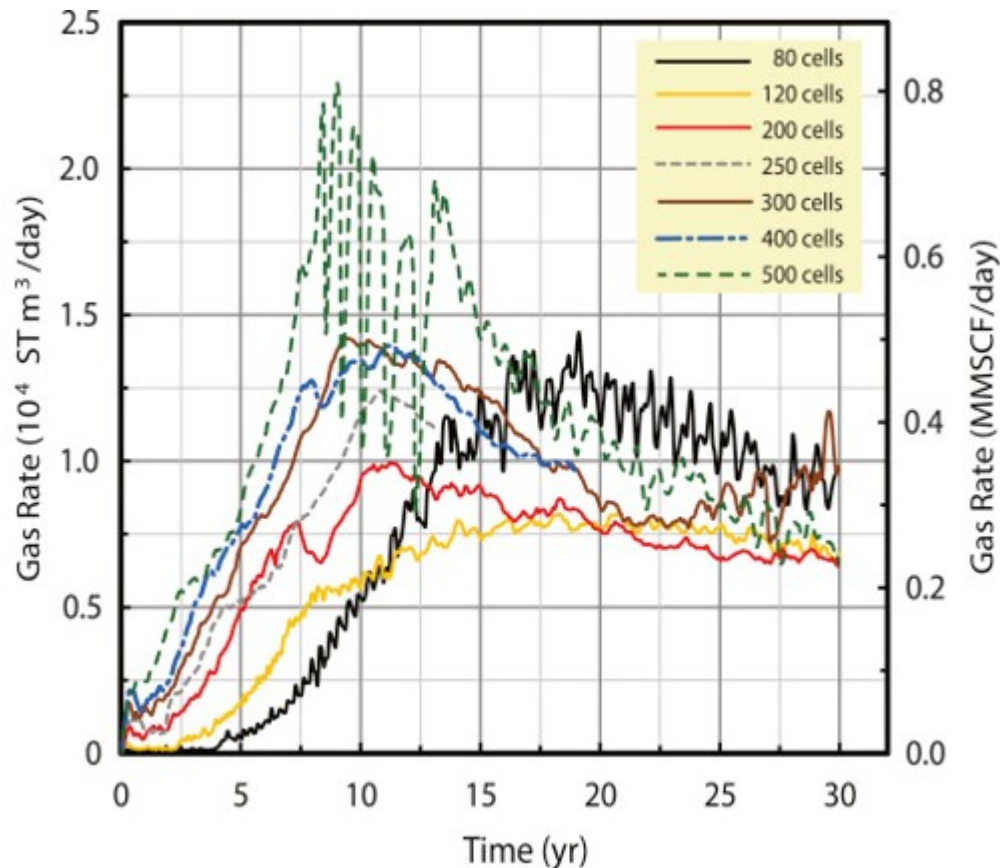


Fig. 5. Investigation of the sensitivity of numerical simulation results to gridding convention for a simple case of 13-m thick gas hydrate bearing sand in northern Alaska. The reservoir is bound by silty shale above (at 30% porosity and 1- mD effective permeability) and 35% porosity/50 mD sandy silt (at 35% porosity and 50 mD effective permeability) below. The reservoir consists of three layers of 40%, 32% and 37% porosity, gas saturation of 75%, 65%, and 75% respectively, and effective permeability of 0.07 mD, 0.001 mD, and 0.07 mD respectively.

In addition to lateral grid dimension sensitivity, the thinly-bedded character of many gas hydrate reservoirs suggest that attention must also be paid to the setting of vertical grid dimensions. This issue is heightened by the observation (discussed further below) that dissociation fronts are not only vertical features that progress laterally away from the wellbore but are also horizontal features that shift vertically from both the lower and upper unit contacts (Fig. 6). To address this issue, Moridis et al., (this issue) recommend that no fewer than three vertical cells are required for each individual reservoir unit. These findings indicate that selection of appropriate grid parameters is critical to reliable numerical simulation. The effects of variable spatial discretization in the description of hydrate system has yet to be fully investigated, and the approaches followed until now have been ad-hoc: discretization has been determined quite often through the intuition of the researcher, with the availability of substantial computing resources or time limitations as the main criteria, instead of through adherence to as yet undetermined scientific principles.

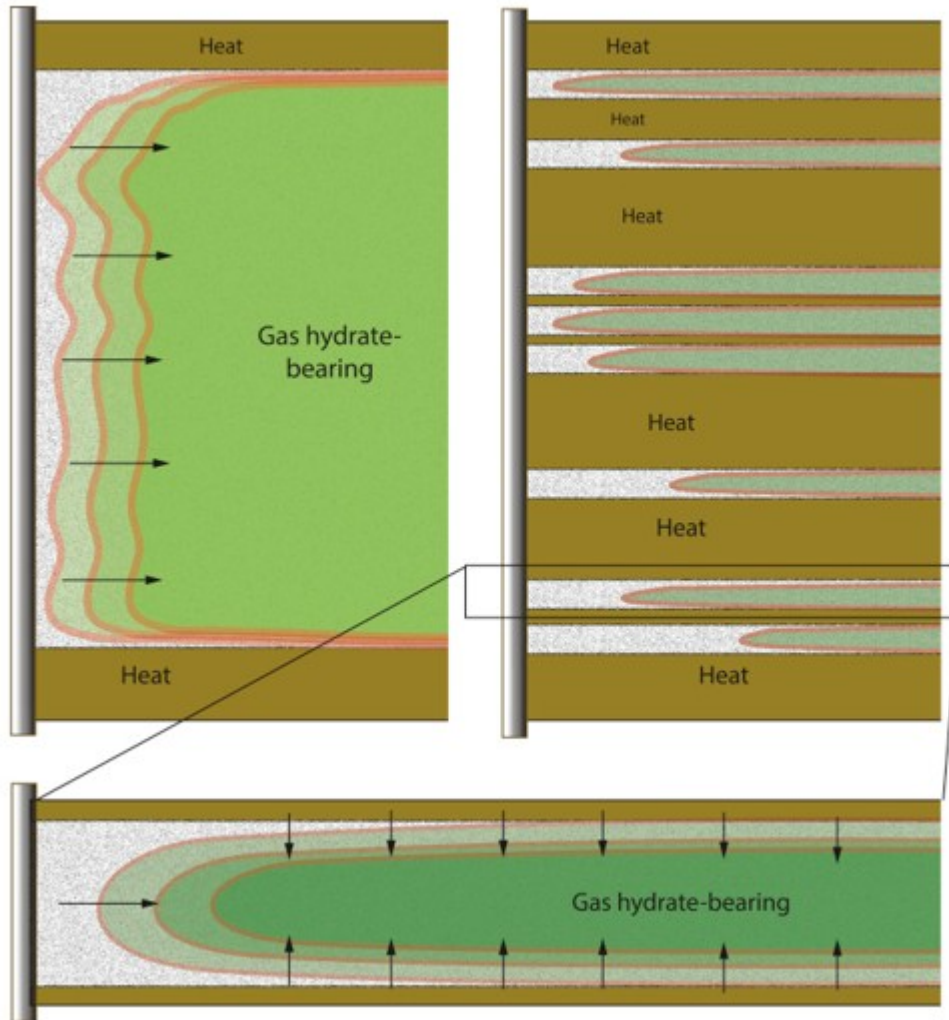


Fig. 6. Cartoon showing the orientation of the gas hydrate dissociation front (red) and the shifting of that front with time (arrows). Dissociation front may be primarily vertical in massive reservoirs (upper left) but largely horizontal in thin-bedded reservoir (upper right): Bottom: a depiction of a single thin interbed shows that the propagation of the dissociation front is largely in the vertical dimension. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

**Reliability of Input Data:** For each grid cell in the input model, a range of petrophysical and geomechanical parameters, such as porosity, saturation of various pore-filling materials, permeability, strength, and others, are required. This information is commonly based on well log data supplemented by evaluation of core samples. The reliability of these data sources is generally quite good, particularly in massively-bedded, homogeneous units. However, the NGHP-02- log data (Fig. 3) indicate the gas hydrate-bearing units are exceedingly thin, which is an architecture that has been observed in many gas hydrate occurrences. When bed thickness is below the vertical resolution of the logging tools, one cannot assume that key reservoir properties are accurately recorded in the log data. Instead, the log reading, particularly for the lowest-resolution data (such as gamma ray and density

porosity), represent a composite, bulk average, response of both gas hydrate-saturated units and the interbedded water-saturated muds. This uncertainty extends to any parameters that are calculated using the log data; for example, gas hydrate saturation will be characteristically underestimated (and free water saturation overestimated) in thinly-bedded gas-hydrate-bearing sands. Because previous modeling work has indicated a high sensitivity of reservoir response to the phase saturations, care is required in setting these values for input models. The issue with resolution and the attendant bulk averaging of parameters is not just limited to log data: core samples can be impacted by this issue as well depending on the nature of the sample and the design of measurements being taken.

The use of core data is further complicated by several factors. Core recovery is often limited, and it can be a complex endeavor to precisely tie the depth of any specific core sample to the measured log depth. Furthermore, it is necessary to critically assess the relevance of any core-derived measurement for application to geologic units in a simulation model. For example, core measurements must consider the potential for core disturbance and whether the measurements are taken in the direction of primary bedding or across the bedding. Therefore, all field data must be evaluated to determine whether those data are likely to represent the natural in-situ conditions at the bed scale for the lithology to which they are applied in the generalized geologic input model.

*Heterogeneity:* Proper representation of any reservoir's inherent heterogeneity is vital to the prediction of reservoir behavior. In the context of gas hydrates, the issue of heterogeneity is complex and somewhat counter-intuitive. At the reservoir scale, a key aspect of heterogeneity is the detailed bedding structure, including the presence of non-reservoir (mud-rich) interbeds. In conventional reservoirs, this form of heterogeneity translates into degradation of production potential. However, in a hydrate reservoir, it is likely that the presence of additional internal or bounding sources of sensible heat support the dissociation reaction (Anderson et al., 2011a; Myshakin et al., 2012). Structural and stratigraphic heterogeneity can also reduce reservoir productivity, for example by augmenting compartmentalization (Kurihara et al., 2009), undermining geomechanical stability, complicating flow paths, or generally degrading intrinsic reservoir quality (ex. Reagan et al., 2010). Therefore, a proper incorporation of heterogeneity is a complex but critical goal of gas hydrate simulation. Myshakin et al., (this issue) use two alternative input models that incorporate the interpreted bedding heterogeneity for Site NGHP-02-16 with increasing detail, and, reveal very different production profiles over a time frame of five years. Therefore, the incorporation of vertical heterogeneity is recommended to the extent viable given the very real impact that it may have on computational complexity. As noted above, lateral heterogeneity may also be an important issue in three-dimensional hydrate simulations, although information to support such heterogeneity requires a very well

characterized reservoir. The introduction of lateral heterogeneity should respect the insights on lateral stratigraphic and structural heterogeneity provided by regional geophysical interpretations (ex. Noguchi et al., 2011; Tamaki et al., 2016). One final important consideration in the introduction of heterogeneity in hydrate reservoir models is that it should not be imposed in an unrealistically random fashion - the known or expected linkages between the different parameters (ex., reservoir quality and the saturation of various fluid phases - an issue for which data are only now emerging through the acquisition and evaluation of pressure core samples; see Boswell et al., this issue) should be respected.

### 3.2. Physical processes

*Permeability:* Gas hydrate numerical simulation studies quickly established that reservoir permeabilities both with gas hydrate (*initial effective permeability*:  $K_{i\text{-eff}}$ ) and without gas hydrate (*intrinsic permeability*:  $K_{\text{int}}$ ), are key determinants of reservoir response to depressurization. Where samples can be collected without significant disturbance,  $K_{\text{int}}$  values ranging from 100s of mD to 1 Darcy (Yoneda et al., this issue-a; Jang et al., this issue-a; Konno et al., 2017; Boswell et al., 2009) have been obtained. Historically,  $K_{i\text{-eff}}$  has remained difficult to constrain (Dai et al., 2017) and inferred primarily from either laboratory evaluation of synthetic and/or “reconstituted” cores (ex. Kneafsey et al., 2011; Miyazaki et al., 2011), from nuclear-resonance logging (Kleinberg et al., 2005; Fujii et al., 2015) or the complex evaluation of short duration reservoir tests (Hancock et al., 2005; Anderson et al., 2011a; Kurihara et al., 2009, 2011; Udden et al., 2012) which generally suggest relatively low values on the order of 0.1 mD. However, recent evaluation of pressure cores acquired in Japan (Yamamoto, 2015; Konno et al., 2015; Santamarina et al., 2015; Yoneda et al., 2017) and India (Yoneda et al., this issue-a), as well as from production and thermal observations of a short-duration depressurization test conducted offshore Japan in 2013 (Yamamoto et al., 2017; Konno et al., 2017) suggest values for  $K_{i\text{-eff}}$ , ranging from 0.1 to 10 mD or more. Notably, the evaluation of NGHP-02 cores has further underscored the need to closely examine the dynamic evolution of permeability within reservoirs undergoing gas hydrate dissociation. The reservoir does not simply progress from  $K_{i\text{-eff}}$  to  $K_{\text{int}}$  with hydrate removal. Instead, the reservoir progresses to a final effective permeability (or post-consolidation permeability:  $K_{f\text{-eff}}$ ; see Fig. 7) as the reservoir consolidates in response to increasing effective stress (Yoneda et al., this issue-b).  $K_{f\text{-eff}}$  is a parameter that has not yet been measured in nature. Further understanding the nature and controls on both  $K_{i\text{-eff}}$  and  $K_{f\text{-eff}}$  and the transition from one to another is a key goal of ongoing research (Boswell et al., this issue).



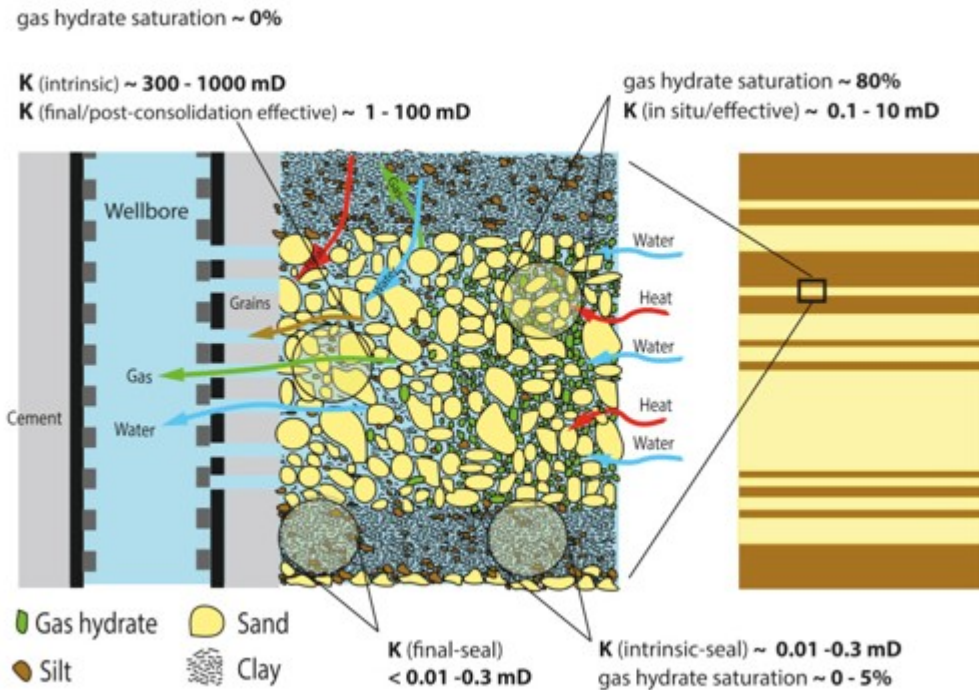


Fig. 7. Stylized reservoir showing various geologic contexts for which permeability (K) must be estimated in order to conduct numerical simulations in gas hydrate reservoirs. The general range of reported values for each variety of permeability are noted as discussed in the text.

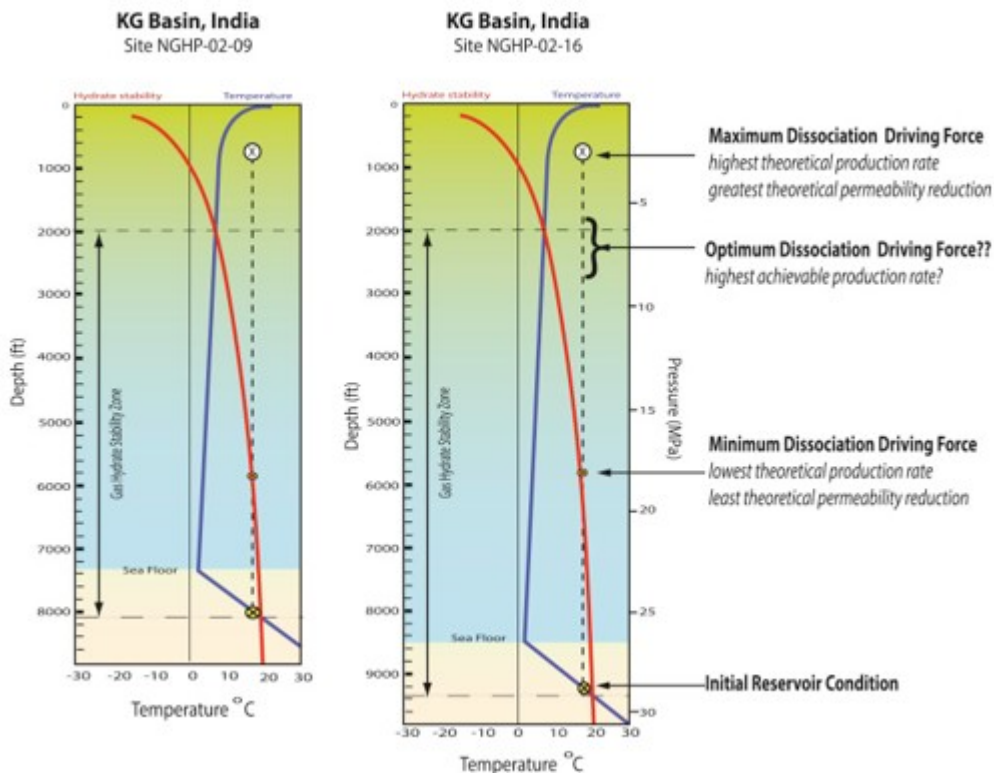


Fig. 8. Schematics of the general geologic setting of Site NGHP-02-09 and Site NGHP-02-16. With respect to depressurization-based production, drawdowns that are intended to maximize dissociation driving force can be very large, and exceed the minimal drawdown needed to initiate dissociation.

Optimal drawdowns may maximize production rate and/or overall well economics as a balance between dissociation driving force and reservoir response, such as reservoir consolidation and water production.

*Geomechanics:* The initial stages of gas hydrate simulation focused exclusively on capturing the thermodynamic and hydraulic phenomena encompassing interactions between gas, water, and hydrate (in all possible phases) within a static porous medium. In these initial studies, the only things physically moving in the reservoir were heat, liquid, and gas – the grain matrix was held stable. Geomechanical complications were suspected to exist but were not yet accommodated in numerical simulation (Yamamoto, 2008). The magnitude of the issue was unclear and assumed to be driven largely by the unsettled issue of gas hydrates' role in the pore space (as pore filling, grain supporting, or cementing).

However, recent field experiments have indicated that grain mobilization and resulting reservoir instability are likely critical phenomena (Dallimore et al., 2012; Boswell et al., 2016; Konno et al., 2017). Efforts to extend gas hydrate modeling capability to allow the movement of sediment grains remains in the early stages. Initial studies (ex. Rutqvist and Moridis, 2009; Kim et al., 2012) generally utilized geomechanical parameters derived from laboratory study of reconstituted Nankai Trough cores (ex. Miyazaki et al., 2011) and handled the issue through iterative porosity reduction. Geomechanical data obtained from pressure-cores are now emerging (ex., Lee et al., 2013; Priest et al., this issue; Yoneda et al., 2015; Yoneda et al., this issue-c), which enable assessment of grain detachment and mobilization (Uchida et al., this issue). Beyond the indication of profound implications for reservoir consolidation discussed above, work is ongoing to assess the larger-scale impact on wellbore stability and subsidence, both at the reservoir level and at the land surface/seafloor (ex. Lin et al., this issue). Other physical processes that are currently under investigation include those common to many productive reservoir systems, such as clogging due to the migration of fines (Cao et al., this issue), and the impact of geochemical changes (local water freshening) during production (Jang et al., this issue-a; this issue-b). The outcome of this work may have profound implications for the design of well completions and production technologies.

*Heat Transfer:* The ability to supply heat to fuel the dissociation reaction is a key limiting factor in gas hydrate dissociation. Even in relatively warm reservoirs, aggressive dissociation can reduce local reservoir temperatures to the point that hydrate (or even ice if the temperature drops below the quadruple point) will form (Moridis et al., 2009). An early key finding in this regard was the modeling of Anderson et al. (2011a) that showed that the presence of gas-hydrate-barren, mud-rich interbeds within the general reservoir unit are a primary source of local heat and are a favorable component of gas hydrate reservoir systems. More recently, convective heat transfer through the movement of formation fluids in response to production

has also been found to be a significant heat source in certain geologic settings (Yamamoto et al., 2017).

### 3.3. Implications for production strategies

*Managing Pressure Drawdown:* At the depths present at many marine gas hydrate sites, reservoirs will require large pressure drawdowns to initiate and sustain dissociation. This drawdown will expose the reservoir to large increases in effective confining stresses that require a detailed evaluation of the reservoir's potential geomechanical response (Moridis et al., this issue; Myshakin et al., this issue; Lin et al., this issue; Uchida et al., this issue). The extent of sediment compaction and permeability reduction may be managed through the imposition pressure drawdowns that are less than that which generates the maximum dissociation driving force (Fig. 8). Konno et al. (this issue) similarly recommend reduced pressure drawdown in reservoirs with high seal permeability as a means to balance high rates of water production that would accompany aggressive pressure drawdown. Consideration of heat transfer will also impact the selection of optimal pressure drawdown (in association with other means to add heat to the near-wellbore environment).

*Managing Hydraulic Isolation:* Hydraulic isolation refers to the potential for a producing reservoir to access an unconfined water zone (Moridis et al., 2011). Common practice among early gas hydrate simulation efforts was to assume that no flow of heat or mass could cross the contacts between gas hydrate and the bounding non-hydrate-bearing units. Such conditions are clearly favorable for effective depressurization, but are not expected to occur in shallow, under-consolidated sediments typical of gas hydrate systems (ex. Waite et al., this issue). Therefore, most recent simulation studies recognize this lack of hydraulic isolation from the bounding units and account for both heat and mass transfer between the reservoirs and the “seals” (Ajayi et al., 2018; Konno et al., this issue).

A second component of hydraulic isolation that is illustrated by Site NGHP-02-16, is the presence within the reservoir facies of a basal water-bearing unit (likely associated with the base of gas hydrate stability). Where this occurs, reservoir depressurization may be severely hindered if that unit is unconfined (for example, see Boswell et al., 2009). At Site NGHP-02-16, this complication is mitigated by reference to regional geophysical data that indicate the reservoir and the subjacent water zone are confined on all sides by faults that are interpreted as “sealing” (no-flow boundaries around individual fault blocks (ex. Collett et al., this issue).

An emerging issue with respect to hydraulic isolation is the presence of “internal” aquifers – water-bearing reservoir facies interbedded within the gas hydrate reservoirs. It is currently not well understood just how common this situation may be; examples of interlayered gas hydrate and water-bearing reservoir sands include the Mallik Site in Canada (Dallimore and Collett, 2005), the Gulf of Mexico Green Canyon 955 deposit (Boswell et al.,

2012), the eastern Nankai Trough (Konno et al., 2017), and Site NGHP-02-09 in the offshore of India (Collett et al., this issue). In the case of the Nankai accumulation, extensive drilling and seismic data collection have indicated that individual reservoir sand layers can be tracked laterally from hydrate-rich to water-rich and back into hydrate-rich with no obvious correlation to reservoir stratigraphic or structural compartmentalization (Tamaki et al., 2017). As with “bottom water”, the occurrence of such “internal water” hinders depressurization and degrades reservoir productivity (Moridis et al., this issue) and is likely an even greater operational challenge to mitigate.

*Managing the Advance of the Dissociation Front:* To effectively develop a reservoir requires the proper spacing of multiple individual wells. In gas hydrate applications, the nature of the progression of the dissociation front is key to assessing the nature of reservoir drainage. The ideal case would be where the gas hydrate dissociation front is a vertical feature that advances laterally in a uniform and predictable fashion with time. Wells could then be spaced at optimal distances related to the declining flow rate with dissociation front advance. However, simple dissociation front geometry may only be realistic in the most massive, homogeneous reservoirs. Konno et al. (2017) used information from monitoring wells proximal to the 2013 offshore production test in the Nankai Trough to assess the dissociation front as an increasingly broad zone of partial dissociation with progression from the wellbore, rather than as a sharp front. Further, in the case of thinly-interbedded reservoirs, the presence of shale interbeds and the heat they provide will likely focus dissociation along those horizontal interfaces (Fig. 6), creating a potentially complex geometry of dissociation fronts. Within individual units, the rate of dissociation front advance may be highly sensitive to the amount of available heat – with a slower advance rate in intervals of higher sand to mud ratio. Further, the rate of advance may also vary with the effective permeability of different units; zones with higher permeability and/or low saturation may possess greater mobile water content that can enable more effective depressurization. Alternatively, these zones may result in higher water production rates and a greater proclivity toward hydrate reformation. Given these complexities, the nature of dissociation within complex reservoir architectures remains poorly known.

#### 4. Summary

The numerical simulation of gas hydrate reservoirs has now fully transitioned from the first-order evaluation of poorly-constrained hypothetical situations to the detailed evaluation of reservoir response in complex and increasingly well-characterized reservoirs. The ability to simulate the behavior of these systems with confidence is critical to both the safe and successful operations of complex and costly field experiments and the effective evaluation of field program results. A joint effort conducted in partnership with the India NGHP has provided extensive data with which to test current numerical simulation capabilities and approaches in complex gas hydrate reservoirs. Insights from this work include the following, which are likely applicable to many situations

world-wide: 1) to be most successful, modeling activities must incorporate comprehensive geologic information on reservoir heterogeneity, structural and lithologic complexity; and hydraulic isolation; 2) the construction of geologic input models should fully account for the limitations of field data (such as vertical resolution), and carefully translate data obtained from cores, logs, and test monitoring into the most optimal modeling input sets; 3) uncertainties in key data elements must be accommodated in the models, and carefully communicated to scientists working to gather measurements from field data and samples; 4) known or suspected linkages between parameters (such as reservoir quality and various phase saturations) should be respected when estimating poorly known parameters; 5) simulations must address all relevant phenomena, particularly geomechanical effects; and 6) simulations must be careful to not oversimplify modeling approaches (including dimensionality and grid discretization) in the effort to avoid long and costly computational times.

The NGHP-02 modeling effort confirms that substantial volumes of gas are available for production; however, obtaining production in a manner consistent with economic deepwater production will require the selection of sites that optimize reservoir conditions. With respect to Site NGHP-02-09 within Area C, the reservoirs are of extremely high quality and the associated resource volumes are likely very large (Collett et al., this issue). The primary challenge to reservoir performance at Site 9 is hydraulic isolation. While some degree of hydraulic connection with nearby hydrate-free units can provide sources of heat to fuel the dissociation reaction, the influx of large volumes of fluids into the reservoir system can dramatically reduce the ability to depressurize the reservoir. Further, the handling and disposal of large water volumes will impose significant operational and economic challenges; therefore, further exploration should prioritize identification of prospective locations that minimize the impact of free water zones. With respect to Site NGHP-02-16, the reservoir is of moderate quality with a high degree of fine grains. The reservoir (and the overburden) are also poorly consolidated, and the extraction of gas hydrate from the reservoir could result in reservoir consolidation, mobilization of fine-grained sediments, as well as fluid production from the overburden, all of which would negatively impact gas production rate. As such, production approaches that optimize pressure drawdown to manage these geomechanical complications would be warranted.

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