# Oil & Natural Gas Technology

## Detection and Production of Methane Hydrate

Technical Status Assessment Report

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# 1. TECHNICAL ASSESSMENT

## 1.1 Statement of Problem

Gas hydrates are ice-like substances composed of water and gas that precipitate from light hydrocarbon-charged water at moderately high pressure (P), low temperature (T), and low salinity (S). Enormous quantities of hydrate and associated free gas occur beneath the seafloor along continental margins. Hydrocarbons in these phases, principally $CH_4$, may constitute a future energy resource, a deep-water geohazard, and a large component of the carbon cycle, which could impact the environment if perturbed [e.g., *Kvenvolden* 1999].

In theory, gas hydrates can form in marine sediment wherever light hydrocarbons saturate pore waters between the seafloor and the base of gas hydrate stability (BGHS). This global hydrate stability zone (HSZ), which in places extends >500 m below seafloor (mbsf), is immense, costly to drill, and difficult to sample. The amount and distribution of hydrate in ocean sediments, therefore, is largely understood through a few near-seafloor observations, scientific boreholes in several locations, numerical models, and geophysical remote sensing.

Though limited and often qualitative, available data indicates heterogeneous but patterned gas hydrate distribution at multiple scales. Consider, for example, cores collected from the HSZ at Blake Ridge (offshore Georgia) and Hydrate Ridge (offshore Oregon) by Ocean Drilling Program (ODP) Legs 164 and 204 [*Paull et al.* 1996; *Tréhu et al.* 2003]. Hydrate abundance varies at cm- to m-scale down boreholes at both locations, probably because of differences in lithology and pore size [*Kraemer et al*. 2000; *Weinberger et al*. 2005]. At larger scale, however, hydrate appears dispersed over wide and thick regions of Blake Ridge, consistently increasing by a few percent of pore space down to 450 mbsf [*Paull & Matsumoto* 2000]. By contrast, hydrate is focused at Hydrate Ridge, ranging from <1% pore space on flanks above ~120 mbsf to dominating whole sediment core sections at 15-30 mbsf on the crest [e.g., *Tréhu et al.* 2004].

Heterogeneity in gas hydrate distribution impacts all key issues of gas hydrate research. *The challenge is to delineate, understand and appreciate these differences at the regional scale where masses relevant to resources, geohazards, and carbon cycling become important*. Why do regional heterogeneities occur? How can we detect them remotely? Where should concentrated gas hydrate accumulate? How will heterogeneities affect gas production strategies? How would different distributions respond to T perturbations? We address these issues as an integrated team targeting gas hydrates as a potential resource and geohazard.

## 1.2 Current State of the Art

***1.2.1 Marine gas hydrate systems***. Gas hydrates and free gas in marine sediment are components of dynamic systems where hydrocarbons, water, ions, and sediment move over space and time [e.g., *Egeberg & Dickens* 1999; *Xu & Ruppel* 1999; *Davie & Buffett* 2001; *Gering* 2003; **Fig. 1**]. Burial and degradation of organic carbon ($C_{org}$) generates $CH_4$ and other light hydrocarbons through microbial methanogenesis or thermal cracking. These hydrocarbons migrate laterally and vertically via diffusion or fluid flow. At sufficiently high hydrocarbon concentrations and appropriate environmental conditions, hydrate can precipitate in the pore space.

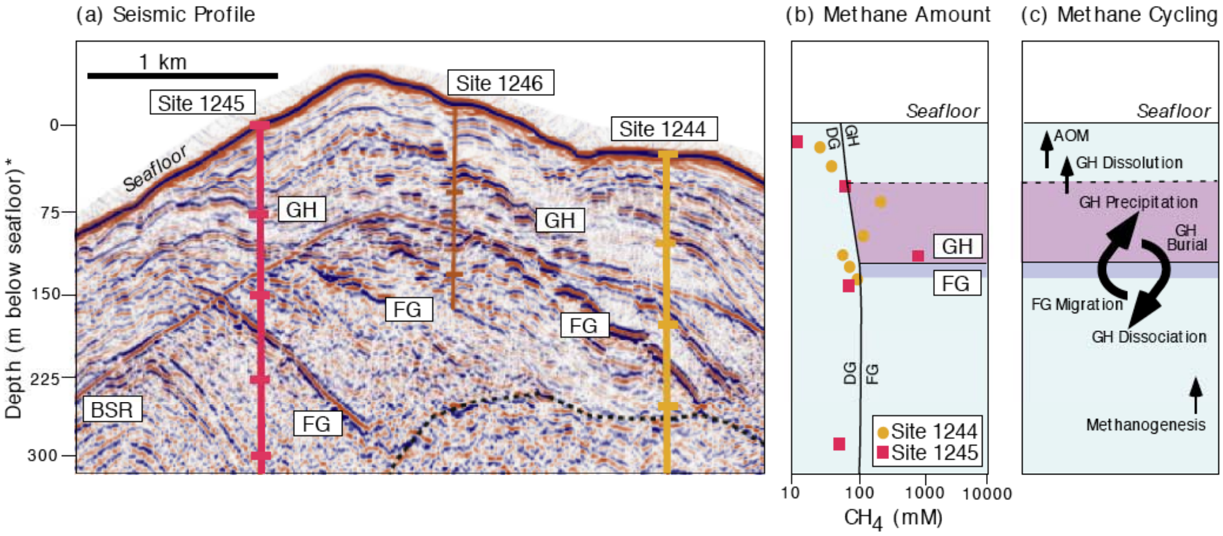

***Figure 1**. Seismic reflection profile across northern flank of southern Hydrate Ridge showing bottom simulating reflector (BSR) and drill site locations [Tréhu et al, 2003]. Also shown are in situ $CH_4$ concentrations, depth zone of gas hydrate (GH), and inferred dynamic $CH_4$ cycling.*

Sediment burial slowly brings hydrate to the BGHS, where it dissociates to hydrocarbon-saturated water and free gas. Some fraction of hydrocarbons released at depth moves upward, perhaps along faults driven by free gas [e.g., *Gorman et al.* 2002], to recycle through the above processes; the remainder escapes through two pathways. Above most, if not all, gas hydrate systems, $CH_4$ encounters $SO_4^{2-}$ diffusing down from the seafloor, which drives anaerobic oxidation of methane (AOM) [e.g., *Borowski et al.* 1999]. In some places, notably where faults extend from the seafloor to depths below hydrate, high flow rates along conduits discharge hydrocarbons into the water column [e.g., *Tréhu et al.* 2003].

Grounded with a dynamic perspective (**Fig. 1c**), models have been constructed to predict the location and abundance of marine gas hydrate [e.g., *Buffett & Archer* 2004; *Klauda & Sandler*, 2005]. Results from these models disagree at a basic level. For example, Klauda and Sandler estimate ~75,000 Gt (1 Gt = $10^{15}$ g) of carbon stored in global gas hydrate, whereas Archer and Buffett suggest ~3000 Gt. *The discrepancies result from assumptions that grossly simplify heterogeneities of gas hydrate systems* (e.g., S = 35 g/kg, modern seafloor fluxes of $C_{org}$; uniform lithology; diffusion only, etc.). Such heterogeneity also precludes meaningful extrapolations of gas hydrate information from the limited boreholes [cf. *Milkov*, 2004; *Buffett & Archer* 2004; *Klauda & Sandler*, 2005].

By June 2006, five marine gas hydrate systems will have been drilled and extensively investigated and reported. Work in these areas shows considerable variability of gas hydrate distribution and challenges common assumptions. For example, the contrast between Blake Ridge and Hydrate Ridge generalized above suggests that, per area of seafloor, passive margins can contain far more gas hydrate and free gas than active margins [*Milkov et al*. 2003], perhaps because generally greater fluid advection in the latter removes more hydrocarbons over time. The two other locations, Gulf of Mexico (GOM) and Peru Margin further amplify potential differences and issues. Focused flux of thermogenic hydrocarbons in GOM has led to seeps where gas hydrate can be found at or near the seafloor. Although ample hydrocarbon supply could produce thick zones of massive gas hydrate [*Milkov & Sassen* 2003], advection of high salinity (S) fluids may severely curtail this distribution [*Ruppel et al*. 2005]. Slopes of Peru Margin (ODP Legs 112 and 201) receive extreme $C_{org}$ input. However, amounts of gas hydrate and free gas seem small, perhaps because high $C_{org}$ burial has only occurred for a few million years and these systems are still growing [*Dickens & Snyder* 2003]. *Such regional heterogeneity needs to be appreciated and understood for economical and safe production of gas hydrate systems*.

***1.2.2 System characterization***. Certain basic parameters have been (or will be) measured in boreholes at the four well-studied marine gas hydrate systems. Among these are T, S, and amounts of hydrocarbons and gas hydrate. These parameters constrain the abundance and overall distribution of gas hydrate in boreholes at each location [e.g., *Paull & Matsumoto* 2000; *Tréhu et al.* 2004]. However, they offer limited insight for why gas hydrate varies down boreholes, between boreholes or regionally. Two crucial elements generally missing from these studies are the carbon/$CH_4$ inputs and outputs over time. Certain physical properties of hydrate/sediment mixtures are not available, as discussed later.

Microbial methanogenesis of $C_{org}$ supplies most hydrocarbons in most gas hydrate systems. This can be deduced from molecular and isotopic compositions of hydrocarbons [e.g., *Kvenvolden* 1999; *Paull & Matsumoto* 2000], as well as dissolved species in pore water, particularly those released during $C_{org}$ degradation (alkalinity, $PO_4^{3-}$, $Br^-$ and $I^-$) in the upper 200-400 mbsf [*Dickens & Snyder* 2003]. Numerical models for gas hydrate systems, however, typically invoke a free parameter for hydrocarbon production without consideration of solid and fluid compositions, or variations in the $C_{org}$ flux over time. In part, this is because links between methanogenesis and solid and fluid compositions (e.g., how much iodine transfers from $C_{org}$ to fluids during methanogenesis) remain uncertain. Fluid composition and gradients can also constrain fluxes at locations where advection brings significant amounts of thermogenic gas. These have often been ignored, the extreme case being GOM seep sites [*Ruppel et al.* 2005].

Present-day $CH_4$ outputs through AOM can be constrained locally and regionally using pore water $SO_4^{2-}$ gradients [e.g., *Borowski et al.* 1999]. The problem with this approach in regards to understanding the mass and evolution of gas hydrate systems, however, is that it assumes steady-state conditions [*Dickens* 2001]. Losses through venting are more difficult to measure, especially because these can vary over short time-scales [e.g., *Tryon et al.* 2002].

***1.2.3 Accumulation and distribution of methane hydrate in sediments.*** The presence and distribution of gas hydrates in marine sediment have been modeled in 1-D using a dynamic framework [e.g., *Egeberg & Dickens* 1999; *Xu & Ruppel* 1999; *Davie & Buffett* 2001; *Gering* 2003]. These models (schematically shown in **Fig. 1c**), which include thermodynamic equilibrium conditions for gas hydrate (e.g., pressure, temperature salinity; P, T, S), inputs of biogenic or thermogenic hydrocarbons, advection or diffusion of solutes, and loss of hydrocarbons, provide insight into how specific gas hydrate systems can evolve over time. They also demonstrate, to some degree, the sensitivity of a system to changes in various parameters. These models, however, generally have over a dozen parameters, many either assumed or poorly constrained. For example, the model by *Gering* [2003] – arguably the current state-of-the-art – assumes constant S during hydrate formation and dissociation, homogenous sediment composition, no advection beyond compaction, and methanogenesis dependent on P and T but independent of $C_{org}$ burial. The first three assumptions are reasonably justified for Blake Ridge [*Egeberg & Dickens* 1999]; but obviously incorrect for the crest of Hydrate Ridge [*Tréhu et al.* 2003]. The latter assumption is not valid, as evidenced by comparisons of pore water data from Blake Ridge and Peru Margin [*Paull et al. 1996*; *D'Hondt et al.* 2003].

The basic problem with current models (except for *He, et al.*, 2006) is that they are geared toward specific locations in 1-D so cannot be used to understand fundamental differences in gas hydrate distribution within and between regions. Existing gas hydrate reservoir simulators (below) are not adequate because they lack long-term natural processes (e.g., methanogenesis, sedimentation with compaction) and hydrocarbon fractionation. Moreover, models for gas hydrate formation have been designed without applicability to remote geophysical approaches. For example, "blanking" (a dampening of seismic reflections) commonly occurs where hydrate is present, and may represent reduced impedance contrasts between relatively coarse-grained, high porosity sediment with hydrate and surrounding sediment without hydrate [*Lee et al.* 1996; *Pecher & Holbrook*, 2000]. But existing models can neither predict nor utilize the degree of observed blanking. Chaotic zones often exist where there is an upwelling of fluids, possibly including free gas. There no satisfactory model to explain how these chaotic zones develop or how to relate hydrate and free gas presence to the seismic observations.

***1.2.4 Production strategy.*** Reservoir simulation is a critical tool to evaluate production strategies for any hydrocarbon resource, and several models have been developed to assess natural gas production from hydrate systems. In general, these models track the evolution and composition of hydrate, gas and water in a perturbed system (e.g. a drop in P) as a function of position and time. Early work constructed 1-D models with various assumptions [*Yousif et al.* 1991; *Ji et al*. 2001; *Tsypkin et al*. 2001]. More recently, *Sun et al.* [2005] have developed a 1-D numerical model for gas hydrate dissociation and production that considers kinetics, multiphase flow and heat transfer. 3-D reservoir simulation tools have also been developed recently [*Swinkels & Drenth* 2000; *Moridis* 2003; *Sun & Mohanty* 2005]. These models divide a gas hydrate system into finite difference grid cells, and conduct material balance, energy balance, flow and hydrate dissociation in each grid cell. *Moridis* [2003, 2005] developed a comprehensive model (TOUGH2/EOSHYDR), which simulates equilibrium and kinetic conditions for permafrost and marine hydrate accumulations. *Sun & Mohanty* [2005,2006] have also developed a hydrate simulator, which accounts for kinetics, heat transfer, multiphase flow, and phase behavior including local ice formation. Primary variable switch method (PVSM) is incorporated into the Newton-Raphson iteration to track phase transitions during gas production. This method gives us the capability to model depressurization and hot water flooding in heterogeneous marine hydrate reservoirs. **Figure 2** shows the in situ saturation distribution in a hydrate reservoir produced by depressurization. The hydrate zone is underlain by a free gas zone. As the hydrate decomposes, the reservoir temperature falls and in part of the reservoir, ice forms.

*Moridis* [1993, 1995] have classified hydrate reservoirs into three classes. Class 1 reservoirs have a free gas zone underneath the hydrate zone. Class 2 reservoirs have a water zone beneath the hydrate zone. Class 3 reservoirs have impermeable zones both above and below the hydrate zone. Various production strategies (depressurization, steam injection, hot water flooding) have been employed in reservoir simulators for gas hydrate systems. Results generally show that the strategy affects rates (and thus economics) of gas production. Importantly, results also strongly depend on initial distribution of gas hydrate, and physical properties of surrounding sediment. Most published results derive from fairly homogeneous reservoirs with uniform gas hydrate distribution and simple correlations for physical properties. It is not clear how various production strategies would generate natural gas in complex, heterogeneous gas hydrate systems with appropriate physical property information. Moreover, the impact of various production strategies upon sediment properties (and potential sediment failure) has generally been ignored.

***1.2.5 Seafloor and borehole stability***. Sediment instability associated with gas hydrate systems has been cited as a regional problem driving large seafloor failures and a local problem yielding failures around boreholes. In theory, sustained decreases in P or increases in T could dissociate large amounts of gas hydrate to free gas, alter the stress field, and cause sediment failure. Several lines of evidence suggest this mechanism operates naturally [summarized by *Kennett et al.* 2003]. Much of the literature focuses on large-scale geologic failures such as those inferred to result from hydrate dissociation and subsequent instability. *Bugge et al.* [1987] suggest that the Storegga Slide (5600 km$^3$) is a hydrate-related failure, and more recent studies [e.g. *Bouriak et al*. 2000] have continued to investigate the role that

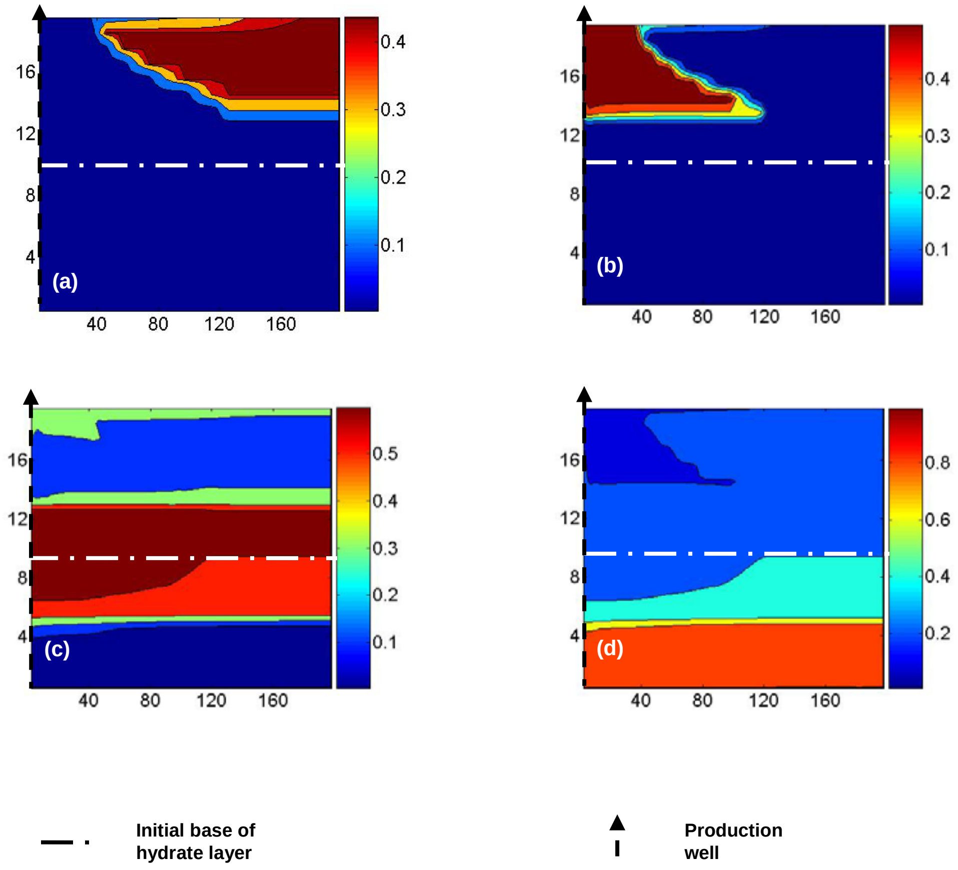

***Figure 2.*** *Contour plots of phase saturations at 1010 days after depressurization of a hydrate reservoir. The x-axis represents the horizontal distance from the production well, and the y-axis marks the vertical distance from the bottom of the reservoir. The scales of the coordinates are in meters: (a) Hydrate; (b) Ice; (c) Gas; (d) Aqueous phase [Sun & Mohanty, 2005].*

hydrates had in this large failure. Similarly *Dillon et al.* [1998] presented a conceptual model for how gas hydrate and accumulating free gas generated sediment failure and collapse at the Blake Ridge offshore southeastern United States. These studies however do not incorporate sediment properties or transients in pressure and temperature and have not evaluated how hydrate saturation may impact the failures. Destabilization of hydrate can also lead to instability, deformation, and failure of boreholes during drilling or potentially in wells during production. This raises some pressing issues. What happens to sediment properties during various hydrate production strategies? And can production lead to sediment failure?

Beyond reservoir simulations noted above, *Xu et al.* [2003] have developed 1-D models pertinent to marine gas hydrate systems that address the propagation of heat and conversion of gas hydrate to free gas, although from an environmental perspective where heat is supplied from the seafloor via changing bottom water temperature. Simple approaches have also been employed to understand how much free gas can accumulate before sediment fracturing occurs [*Flemings et al.* 2003; *Hornbach et al.* 2004]. Crucially, however, the two issues have not been collectively tackled, and the latter study neglects changes in sediment properties that occur from effective stress decreases and free gas accumulation and flow. To address the potential for seafloor or borehole failure, we propose to characterize properties of hydrate-bearing and non-hydrate bearing sediments and to implement these properties in stability models that are coupled with flow models (geologic or production scale).

Sediment properties (e.g., strength, porosity, permeability) have been measured for cores from marine gas hydrate systems as well as in a few laboratory experiments using sediment-gas mixtures at high pressure [e.g., *Winters*, 2004]. This work provides a snapshot for physical properties of hydrate-bearing sediment at ambient conditions or hydrate-sediment mixtures at near-*in situ* conditions. Recent laboratory studies have focused on acoustic properties and shear strength of pure hydrate or sand containing hydrate *[Durham et al.*, 2003; *Waite, et al.*, 2004]. We lack, however, observations, experiments, and models that define how properties of hydrate-bearing sediment change with variations in pore pressure, gas saturation, and stress. By understanding how these properties vary with P and T, we can effectively model the stability of systems that undergo P/T changes from environmental or anthropogenic forces.

***1.2.6 Geophysical imaging.*** Gas hydrates and free gas affect acoustic and elastic properties of host sediment in ways that can be detected by seismic imaging [e.g. *Lee et al.* 1996; *Jakobsen et al.* 2000; *Lee & Collett* 2001; *Chand & Mishull* 2004]. One well-known expression is the bottom-simulating reflector (BSR), which can mark an abrupt drop in seismic velocity across the BGHS (**Fig. 1a**). However, local variations in T and S (and perhaps hydrocarbon composition) can greatly complicate the shape of the BGHS [*Wood et al.*, 2002; *Ruppel et al*., 2005], and hydrates can occur without a BSR or with multiple BSRs [*Xu and Ruppel* 1999; *Bangs et al.*, 2005]. Unlike the BSR, velocity models of the HSZ may provide a reliable indicator of hydrate presence [e.g. *Zillmer et al*. 2005]. The velocity structure can be complex, however, because of heterogeneities in sediment and hydrate [e.g. *Gorman et al.* 2002; *Lu & McMechan* 2004].

Much of our understanding of gas hydrate distribution has come from seismic techniques [e.g., *Dai et al.* 2004; *Xu et al. 2004*]. Likely, this will continue given the cost of drilling wells. A major problem with current seismic approaches, however, is that they cannot accurately quantify the amount of hydrate and free gas (or localized structure such as pathways connecting free gas and hydrate zones) at high spatial resolution; this applies to both conventional reflection processing, and modeling/inversion methods that attempt to estimate physical properties from seismic data. Conventional seismic methods can provide high-resolution (wavelength-scale) images, including the BSR, but a high-resolution seismic section, as obtained by single- or multi-channel reflection processing, represents a structural image, not a direct estimate of any physical property (e.g. seismic velocity), which holds the key to quantifying gas hydrate and free gas. On the other hand, current remote techniques to estimate physical properties typically assume a 1-D earth [e.g. *Singh et al.* 1993; *Xu et al.* 2004].

Various rock physics models have been used to derive estimates of hydrate saturation and gas content from physical properties (e.g., compressional and shear velocity, density, attenuation) constrained by seismic data [e.g., *Chand et al. 2004; Xu et al. 2004; Kumar et al. 2006*]. To best constrain the physical properties, a wide range of source-to-receiver offsets is needed. Conventional reflection processing, amplitude versus offset (AVO) analysis, and 1-D waveform inversion methods, however, assume lateral homogeneity over the range of offsets in a single multi-offset data gather, perhaps as much as several km. Lateral variations within the study area can be approximated by combining results of many 1-D analyses, but this results in smoothing, which underestimates the heterogeneity of the gas hydrate system. In theory, a properly migrated reflection section possesses lateral resolution on the order of the seismic wavelength, but only in terms of the structural image not physical parameters. Traveltime methods, such as tomography, are routinely applied using a 2-D or 3-D earth model, but the high-frequency approximation of these techniques limits their resolution to a size on the order of the Fresnel zone, typically much larger than the seismic wavelength [e.g. *Jaiswal et al.* 2006].

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