Methane hydrate is an icelike form of concentrated methane and water found in the sediments of permafrost regions and marine continental margins at depths far shallower than conventional oil and gas. Despite their relative accessibility and widespread occurrence, methane hydrates have never been tapped to meet increasing global energy demands. With rising natural gas prices, production from these unconventional gas deposits is becoming economically viable, particularly in permafrost areas already being exploited for conventional oil and gas. This article provides an overview of gas hydrate occurrence, resource assessment, exploration, production technologies, renewability, and future challenges.

KEYWORDS: methane hydrate, energy, natural gas

INTRODUCTION

When various low molecular weight gases (e.g. methane, ethane, carbon dioxide, hydrogen sulfide) combine with water at the pressures and temperatures common in the sediments of continental margins and permafrost regions, the resulting compound is gas hydrate, an icelike substance consisting of water cages surrounding guest gas molecules in a clathrate structure. Structure I clathrates (Fig. 1), the most widespread type, have cubic symmetry (space group Pm3n; lattice parameter ~12 Å) with 46 water molecules and 8 potential gas guest sites. The gas sites are two smaller (average radius \( r = 3.95 \) Å) pentagonal dodecahedral cavities and six larger cavities ( \( r = 4.33 \) Å) with 12 pentagonal and 2 hexagonal faces (Sloan 2003). If gas molecules fill all the cages, as they rarely do in nature, Structure I clathrates can concentrate methane by ~160 times compared to gas at standard pressure and temperature. Methane hydrate deposits and the often-proximal gas-charged sediments thus constitute a potentially large, but currently untapped, hydrocarbon reserve within porous sediments.

Methane hydrate is a conventional hydrocarbon resource (natural gas) that is found in an unconventional form (frozen), at shallower (tens to hundreds of meters), more readily accessible depths than conventional oil and gas, and in locations both within and outside some of the permafrost and marine areas that supply conventional fuels (Fig. 2). The methane contained in gas hydrate deposits can originate through the same, deep-seated thermal cracking (thermogenic) processes that produce oil and conventional natural gas from sedimentary organic carbon. More often, though, the carbon isotope signature (\( \delta^{13}C \)) of the hydrated methane indicates a biogenic source, namely microbial degradation of sedimentary organic matter. Even within a major petroleum basin like the Gulf of Mexico, the volumetrically most extensive gas hydrate deposits (e.g. those located in pore space in regional strata, not concentrated in discrete faults and seeps) may be dominated by biogenic (\( \delta^{13}C \) values between ~110‰ and ~50‰), not thermogenic (\( \delta^{13}C \) values between ~50‰ and ~20‰), methane. Prior to the last decade, gas hydrates were studied primarily to enhance safety and productivity in the petroleum industry. Without thermodynamic or kinetic inhibitors or measures to closely control pressure and temperature (see Sloan 1998), conventional wells and pipelines can clog with artificial gas hydrates that damage equipment, halt production, and endanger workers. If natural gas is not carefully dried, even some consumer gas lines can be subject to gas hydrate formation. Within the past few years, naturally occurring gas hydrates have also become an important focus for the private sector. As conventional offshore hydrocarbon exploration has shifted to progressively deeper waters (greater than 300 to 500 m), there has been increased awareness of potential hydrate-associated geohazards (e.g. Howland and Gudmestad 2001), such as uncontrolled degassing from shallow sediments, seafloor collapse, and sediment fluidization.

Since the mid-1990s, the academic research community has undertaken numerous studies of geochemical, geophysical, and microbiological processes in marine gas hydrate reservoirs (Tréhu et al. 2006). Although locating economically important gas hydrate deposits is not a priority for this community, the Integrated Ocean Drilling Program (IODP) and its predecessor, the Ocean Drilling Program (ODP), have directly sampled gas hydrates (Fig. 2) during clathrate-focused expeditions on the Cascadia active margin (Tréhu et al. 2003; Expedition 311 Scientists 2005) and on the Blake Ridge and Carolina Rise passive margin (Paull et al. 1996).

National governments and some industry interests have also invested substantially to investigate natural gas hydrates (Fig. 2). Since 1998, permafrost gas hydrates, which will undoubtedly be the first exploited commercially, have been explored at the edge of Canada’s Mackenzie Delta during drilling and prototype production testing in the Mallik well (e.g. Dallimore and Collett 2005). Japan, motivated by a lack of domestic hydrocarbon reserves and the government’s strong commitment to gas hydrates research, cosponsored the Mallik drilling and also undertook ocean drilling in the Nankai Trough gas hydrate province beginning in 1999. Recently major gas hydrate drilling campaigns have also been conducted in offshore India and China. In the U.S., the
Natural Gas in the 21st Century

Methane hydrates and associated free gas deposits have relevance as an unconventional energy resource only insofar as natural gas is a viable fuel to power the world’s economies. Natural gas is typically made up of methane, ethane, butane, and propane, but the focus here is on methane, which constitutes 70% to over 90% of most conventional natural gas. Although methane has ~80% of the heat content [4.62 million BTU or 4840 megajoules (MJ) per barrel] of crude oil (5.85 million BTU or 6120 MJ per barrel), natural gas remains impractical for applications that rely on a liquid fuel stable at ambient pressure and temperature. Nonetheless, the U.S. Energy Information Administration projects an increase of more than 90% in annual, absolute global consumption of natural gas between 2003 and 2030, corresponding to a ~2% increase (from 24% to 26%) in natural gas use relative to other energy sources.

The world’s largest-known reserves of conventional natural gas lie in Iran, Qatar, and western Siberia. Compared to liquid fuels that need intense refining, raw natural gas has a much shorter path from extraction to reaching a usable form, as it requires only separation of the different gases. The critical challenge is transportation of the gas, which requires either specialized pipelines or extreme cooling to form liquid natural gas (LNG). At present, less than 10% of global natural gas production is transported as LNG, and a significant increase in LNG capacity will be necessary to accommodate rising global natural gas consumption in areas that cannot be served by direct pipelines. Due in part to transportation issues, the small amounts of natural gas produced from methane hydrates in the initial commercial projects might be used to power infrastructure on site instead of being transported to markets.

Natural gas is regarded as a relatively clean hydrocarbon-based fuel because methane combustion yields fewer pollutants than either oil or typical coal, with markedly lower emissions of CO₂, nitrogen oxides, SO₂, and particulates. Methane is ~20 times more potent than CO₂ as a greenhouse gas and is typically oxidized in the atmosphere in less than 10 years. Natural outgassing of methane hydrates is estimated to account for ~1–2% of present-day atmospheric methane. Conventional fossil fuel production and use accounts for 15% to 18%, and rice production, wetlands, ruminants, and landfills for up to ~75%. Methane emissions will certainly increase if methane hydrate reservoirs are exploited for natural gas, but a more critical concern is possible catastrophic release of methane to the atmosphere or ocean from shallow gas hydrate deposits as a result of extraction activities or even climate change. For marine gas hydrates, the potential for direct outgassing of methane to the atmosphere is considerably greater.

THE IN SITU METHANE HYDRATE RESOURCE

An understanding of the conditions under which methane hydrates form and remain stable in natural systems is necessary for assessing the extent of the resource. On present-day Earth, the suitable pressure and temperature conditions occur at depths shallower than ~1 to 2 km in permafrost regions and in the uppermost tens to several hundreds of meters of marine sediments on continental margins lying at water depths greater than ~300 m (FIG. 3). Gas hydrates have also been discovered beneath large lakes and inland seas (e.g. Lake Baikal, Black Sea).

Production of natural gas (see box) from methane hydrate deposits could become economically viable in conventional hydrocarbon reservoirs in permafrost regions (e.g. Hancock et al. 2004; Howe 2004) if existing infrastructure is used and if natural gas is priced at US$4 to $6 per thousand cubic feet (approximately US$141 to $211 per thousand cubic meters). This price was consistently attained at the wellhead starting in 2003, underscoring the potential viability of production from accessible, land-based, methane hydrate/shallow free gas deposits located close to conventional reservoirs. Clearly, the era in which natural gas in unconventional reservoirs can be viewed as a worthwhile target for exploration, and perhaps production, may be dawning.

TABLE 1

| Methane Hydrates Research and Development Act of 2000, which was reauthorized by the U.S. Congress in 2005 through the Energy Policy Act, has been a primary driver for investment and innovation that may lead to eventual production of methane from natural gas hydrate deposits and has been instrumental in gas hydrates exploration in the northern Gulf of Mexico and the Alaskan North Slope.

[FIGURE 1 (A) A snapshot of M. Chaplin’s three-dimensional rendering of Structure I clathrate (www.lsbu.ac.uk/water/clathr.html), showing twelve 14-sided water cages surrounding a single pentagonal dodecahedral cage outlined in orange. Only the oxygen atoms from the water molecules are shown, with blue oxygens at the vertices of the outer cages and the red oxygens indicating the contained dodecahedron. Guest gas molecules such as methane can fit in either type of cage. Not shown are Structure II (136 water molecules and 24 gas sites) and Structure H (34 water molecules and 6 gas sites) clathrates, which occur far less frequently in nature, but which can accommodate higher-order hydrocarbons such as propane, isobutene, and neohexane (Sloan 2003) in larger gas sites. (B) Scanning electron microscope image of synthetic methane hydrate crystals in sediments. Courtesy of L. Stern. (C) Gas hydrate chunks acquired less than 10 m below the seafloor in the Cascadia accretionary wedge (Expedition 311 Scientists 2005). Photo from IODP/Texas A&M University. (D) Porous methane hydrate (inverted snowcone) formed around methane bubbles beneath a carbonate ledge (top) overhanging a seafloor cold seep on the Blake Ridge Diapir. Image is ~85 cm across and was taken from DSV Alvin in 2001. Photo from Woods Hole Oceanographic Institution.}
Temperature, which is largely governed by the background, conductive geothermal gradient and superposed perturbations associated with fluid advection, primarily controls the thickness of the gas hydrate stability zone. Typical geothermal gradients in the shallow sediments of permafrost and marine settings range from 15°C km\(^{-1}\) to 50°C km\(^{-1}\), while the temperature of the phase transformation from methane hydrate to gas increases by only a few degrees per kilometer for pressures greater than ~6 MPa (equivalent to ~600 m water depth). Hydrostatic, not lithostatic, pressure is often used to determine the phase transformation for methane hydrate: Saturated, near-seafloor or near-surface sediments have high porosity (usually 50–75%), meaning that they are mostly water by volume and have water-supported grains. Increasingly, though, studies of gas hydrate reservoir dynamics include more sophisticated pressure formulations (e.g. Flemings et al. 2003).

The pressure and temperature controls on gas hydrate stability lead to predictable vertical zonation of reservoirs (Fig. 3). In marine settings conducive to gas hydrate formation, methane hydrate is stable in the sediments closest to the seafloor but often does not form in this portion of the stability zone due to the consumption of methane in oxidation reactions. Below this zone, gas hydrates may occur as disseminated deposits in fine-grained sediments, as vein or fracture fill deposits, as nodules, or as cementing material in higher permeability sediments (e.g. sand, volcanic ash). Beneath the base of the gas hydrate stability zone, sediment pores may be charged with free gas. In places, a negative impedance seismic reflector—the bottom-simulating reflector or BSR—marks the phase boundary between higher-velocity, gas hydrate-bearing sediments above and lower-velocity sediments charged with free gas below (e.g. Hyndman and Davis 1992; Minshull et al. 1994). The BSR cuts across stratigraphic layers and can be dramatically deflected by thermal perturbations associated with fluid flow or salt diapirs.

In many locations in the world’s oceans, gas hydrate is stable (but relatively rare) not only in the sediments, but also in the deeper part of the water column and at the seafloor. Gas hydrate (density of 910 kg m\(^{-3}\)) that detaches from seafloor outcrops or that forms around methane bubbles is buoyant relative to ocean water (nominal density of 1024 kg m\(^{-3}\)) and eventually dissociates (outside its stability field) or dissolves in ocean waters undersaturated in methane as it ascends. In a global inventory, seafloor gas hydrates (e.g. in the northern Gulf of Mexico) are not volumetrically important. Such deposits occur primarily at sites of enhanced advective flux (e.g. seeps), where the gas hydrates are sustained from below even as they dissolve in the overlying water; they also occur where physical barriers (e.g. petroleum or biofilm coatings on gas hydrate mounds) prevent wholesale dissolution of exposed seafloor hydrates in ocean water.

Compared to marine methane hydrate reservoirs, permafrost reservoirs have more complex zonation (Fig. 3b). Typically, free gas is the stable methane phase nearest the surface, with a zone of coexisting water ice and methane hydrate in the underlying sediments. Because some of the geophysically detectable properties of water ice are similar to those of methane hydrate (e.g. shear wave velocity, electrical properties), assessment of gas hydrate concentration and distribution is particularly difficult within this zone. At greater depth, the system resembles marine reservoirs, although BSRs are typically lacking. Another key difference between gas hydrate reservoirs in marine and permafrost regions is the direct impact of terrestrial hydrologic processes (e.g. unsaturated flow, aquifer recharge) in the latter setting.

Within its stability field, methane hydrate only forms if the constituent water and methane are available. While some gas hydrate may contain biogenic methane produced in situ within the stability zone, rates of microbial methane generation and/or the concentrations of methanogenic microbes are probably too low for this to be the most important mechanism. More likely, fossil biogenic methane that has been transported into the stability zone by hydrologic processes (e.g. Hyndman and Davis 1992; Minshull et al. 1994; Nimblett and Ruppel 2003) constitutes a significant portion of the gas trapped in global gas hydrate deposits. In this scenario, much of the gas hydrate forms
from ascending fluids that contain aqueous phase methane (Hyndman and Davis 1992). The solubility of methane gas in water actually increases with temperature (and therefore depth) in the presence of gas hydrate (e.g. Buffett and Zatsepina 2000), so ascending fluids encounter decreasing methane solubility, which may result in exsolved methane combining with water to form gas hydrate. Such a formation mechanism is consistent with observations of sediments younger than the included pore waters (e.g. Fehn et al. 2000) or methane in some provinces. Another gas hydrate formation mechanism—formation around gas bubbles (Minshull et al. 1994)—is energetically favorable and relatively rapid and may produce massive deposits near the base of the gas hydrate stability zone, in permeable conduits that have enhanced fluid flow (e.g. faults that tap free gas zones) and near the seafloor.

The composition of fluids (pore waters and gases) and host sediment characteristics affect the formation and stability of gas hydrates in natural systems. Increasing pore water salinity inhibits gas hydrate stability. A 3.3% by weight increase in salinity (difference between freshwater and typical seawater) produces a ~1.1°C reduction in the phase transformation temperature for pure methane hydrate for pressures up to ~10 MPa. Pore water salinity changes can be caused by dissolution of salt diapirs, deep-seated brine formation, or the exclusion of salts from the gas hydrate lattice upon hydrate formation (e.g. Torres et al. 2004). The pressure–temperature conditions for methane hydrate phase transformation can also be affected by the presence of gases like ethane and carbon dioxide, whose molecules are small enough to fit in the guest sites in Structure I clathrates, or by fine-grained sediments, which generate increased capillary pressures (Clennell et al. 1999).

**RESOURCE ASSESSMENT**

In the past 25 years, numerous estimates have been made of the amount of methane contained in global gas hydrate deposits (the resource) and the amount that can be economically extracted (the reserve). Published estimates of total methane in marine gas hydrates range from ~3100 Tm$^3$ to ~7,650,000 Tm$^3$, while the range for the smaller permafrost reservoirs is 14 Tm$^3$ to 34,000 Tm$^3$ (see Collett 2002). Global estimates for methane contained in both permafrost and oceanic reservoirs have now converged on ~150 Tm$^3$ (10 terratonnes) but range from 0.5 to 24 terratonnes (Kvenvolden and Lorenson 2001). For the U.S. Exclusive Economic Zone offshore and North Slope permafrost region combined, Collett (1995) estimated ~9000 Tm$^3$ of methane in gas hydrates, an estimate now lowered to ~5700 Tm$^3$ based on observations during drilling (Collett pers. comm.). Even this latter figure, which represents more than one-third of the nominal global estimate given by Kvenvolden and Lorenson (2001), is ~150 times the 95%-confidence-level estimate of the U.S. conventional natural gas reserve (Collett 2002) and ~900 times the current annual natural gas consumption in the U.S.

The lack of consensus about methane hydrate resource estimates frustrates policy makers, the energy sector, and scientists, but major improvements in the assessments will require intense data collection and far more complete understanding of gas hydrate reservoir dynamics. Part of the disparity among resource estimates can be attributed to markedly different assumptions about gas hydrate concentrations. In some assessments, gas hydrate concentrations are assumed to be several tens of percent of pore space. Yet field-based studies have rarely found in situ gas hydrate concentrations in excess of a few percent to perhaps 10% of pore space outside of highly permeable lithologies or conduits (e.g. faults and fractures) or localized features characterized by rapid flux (e.g. cold seeps, mud volcano flanks).

Further complicating resource assessments is the poor state of knowledge about gas hydrate distribution. Researchers routinely overestimate the resource by assuming that methane hydrate is distributed throughout the entire stability zone. In fact, the distribution of gas hydrate in natural systems is fundamentally inseparable from the hydrodynamics...
(permeabilities combined with flow dynamics) of shallow sedimentary reservoirs (e.g. Nimblett and Ruppel 2003) that display heterogeneity at every hydrologic scale (pore scale to regional scale). Therefore, nearly site-specific information about sediment type and sedimentation rate, availability of organic carbon, shallow fluid-flow patterns, and structural features can be required to assess distributions.

One of the most sophisticated approaches to gas hydrate assessment has been adopted by the U.S. Minerals Management Service. Focusing on marine sediments in the U.S. waters of the Gulf of Mexico and the Atlantic, Pacific, and Arctic oceans (Ray et al. 2006), researchers have scrutinized seismic records and borehole logs to identify lithologies and geologic features conducive to hosting concentrated deposits. This massive data mining effort is coupled with statistical parameterizations to account for heterogeneity in lithologies and permeabilities, structures (e.g. faults), and other factors (e.g. distribution of brines) that control gas hydrate distribution patterns.

**EXPLORATION CHALLENGES**

If natural hydrate is to become an exploitable resource, success in the exploration phase will be required to propel the field toward large-scale production. A critical challenge remains locating concentrated methane hydrate deposits, preferably using geophysical methods (e.g. seismic, geoelectrical, electromagnetic) that can be rapidly applied over large areas. For many years, seismic surveys appeared to hold promise for finding production-grade gas hydrate deposits, particularly in marine settings. The presence of a BSR, which can be easily detected with even rudimentary seismic reflection surveys, almost certainly indicates the occurrence of gas hydrates in the overlying sediments, but gas hydrate has also been found in areas lacking BSRs (e.g. Site 994 of Pauli et al. 1996). The absence of BSRs has proved a particular challenge in permafrost regions and in the northern Gulf of Mexico, where existing infrastructure might be readily adapted to exploit these deposits.

Once gas hydrates are found, estimating concentrations is critical to assessing their economic viability. Seismic velocities, seismic velocity ratios, and attenuation can probably not be reliably and routinely used for such assessments. Attribute analysis of high-resolution two- and three-dimensional seismic data is independent of seismic velocities (e.g. Hato et al. 2000) and may eventually prove critical to routine quantification efforts. Attribute analysis of high-resolution two- and three-dimensional seismic data is independent of seismic velocities (e.g. Hato et al. 2006) and may eventually prove critical to routine quantification efforts. Controlled-source electromagnetic surveying (Weitemeyer et al. 2006) has shown promise for mapping concentrations of gas hydrate in marine settings. As a survey strategy, drilling discrete boreholes is prohibitively expensive. Yet once boreholes exist, downhole logging, particularly with tools that record the enhanced electrical resistivity of gas hydrate–bearing sediments, is highly effective as a detection and evaluation tool.

Natural gas production from gas hydrate and the associated free gas reservoirs will commence with regions for which exhaustive site survey data already exist. In some cases, industry seismic data acquired for conventional resource exploration can be reprocessed to focus on the shallower, gas hydrate–bearing sediments, and geotechnical surveys conducted for the siting of petroleum infrastructure (e.g. drill rigs, pipelines) can be re-assessed for evidence of gas hydrates. As more data are acquired, calibrations that quantitatively link detectable changes in geophysical properties to direct measurements of gas hydrate concentrations will become more refined. At the same time, more robust predictive models and imaging techniques will be developed to enhance discovery and production of methane deposits associated with gas hydrates.

**EXTRACTION TECHNOLOGIES**

Commercial-scale production of methane from gas hydrate or the proximal free gas deposits will require safe, efficient, cost-effective, and environmentally sound extraction technologies. Some experience garnered from producing natural gas in conventional reservoirs can be readily applied to gas hydrate reservoirs. For example, extracting free gas from beneath capping, gas hydrate–bearing sediments is similar to production of natural gas from beneath much deeper structural traps in conventional reservoirs.

Direct mining of solid methane hydrate will probably remain economically and logistically impractical due to the relatively low concentrations of gas hydrate per unit volume of sediment in most places and the difficulty of maintaining gas hydrate within its stability field. Instead, exploitation of the solid hydrate will involve controlled dissociation (Fig. 4) of the gas hydrate through perturbations to pressure, temperature, and/or chemical conditions in the reservoir (Holder et al. 1984; Sloan 1998; Collett 2002). Dissociation increases pressure in the reservoir, meaning that the free gas released from the gas hydrate should in some cases flow freely to the wellhead (Max et al. 2006). In contrast, energy must often be expended to drive natural gas to the wellhead for extraction in conventional reservoirs. Owing to the relatively shallow nature of gas hydrate deposits, preventing blowouts, borehole collapse, and the release of methane—a potent greenhouse gas (see Box)—is critical. Measures must also be adopted to avoid new gas hydrate formation in sediments or in wells as the liberated gas expands and cools. The strongly endothermic nature of gas hydrate dissociation (~55 kJ mol⁻¹ at 273 K for pure methane hydrate) means that ice formation could also pose a production challenge.

Injection of heated fluids (liquids or steam), possibly enhanced by hydraulic fracturing of the formation, is the simplest technique for driving dissociation of methane hydrate to liberate gas for extraction (Fig. 4a). While conductive heating of the sediments is limited by the low thermal diffusivity of saturated sediments (nominally 3 to 7 × 10⁻⁷ m² s⁻¹), forced injection of hot fluids or steam could expose larger amounts of gas hydrate to destabilizing temperatures. Because dissociation is largely a surface phenomenon (Max et al. 2006), more energy must be expended to extract methane from the interior of deposits than from those close to the injection well. The thermal stimulation method has several disadvantages. Heating and pumping large quantities of fluids in places with cold ambient temperatures (permafrost or deep sea) would be expensive. There would also be the potential for permeable zones other than the target area to capture significant fluid flow and heat from the injection event and, conversely, it might be difficult to penetrate massive, low-permeability gas hydrate deposits (if they exist) with the fluids. Last, there would be the possibility of unintended gas hydrate dissociation and mechanical weakening of the sediments adjacent to the thermal stimulation borehole.

For more than two decades it has been known that depressurization (Fig. 4b) requires less energy input, yields more gas, and has lower overall production costs than thermal stimulation alone (e.g. Holder et al. 1984). Initially, the free gas that often underlies gas hydrate deposits would be extracted, thereby lowering the pressure in the overlying sediments and leading to dissociation, gas expansion, and then a drop in formation temperature. In an ideal reservoir, such depressurization should cause relatively uniform dissociation progressing upward from the base of the gas hydrate stability zone. Dissociation would continue until the reservoir pressure drops to the equilibrium pressure.
corresponding to the now-reduced formation temperature (Sloan 1998). Continued production would require heating of the reservoir to prevent gas hydrate from forming again and to drive new dissociation.

Methods developed to prevent the formation of gas hydrate plugs in hydrocarbon pipelines may also be applied to produce methane from gas hydrates (e.g. Sloan 1998). Injection of inhibitors like methanol, glycol, or brine could drive dissociation (Fig. 4C) but carries unknown environmental risks. Brines, which also occur naturally, might be the obvious choice to enhance production where depressurization combined with limited thermal injection is the primary production technique.

A more exotic mechanism for production of methane from gas hydrates is substitution of CO$_2$ for methane in the gas hydrate molecule. Natural gas hydrate reservoirs could thus be used for simultaneous energy extraction and sequestration of waste CO$_2$ generated by burning fossil fuels. The thermodynamics and kinetics are favorable for the exchange of methane for CO$_2$, but the process occurs rapidly only near the surface of the gas hydrate masses, leaving the deeper crystals untouched. Thermal perturbations and the processing of CO$_2$ to form emulsions of very fine droplets prior to injection (McGrail et al. 2004) might allow more methane to be released from natural deposits.

Since the 1980s, there have been claims of natural gas production from gas hydrate in the Messoyakha field in Russia, but subsequent analyses indicate that gas hydrates may not have contributed to recovered gas at the site (Collett and Ginsburg 1998). The first verifiable production of natural gas from gas hydrate probably occurred during depressurization and thermal injection tests conducted at the Mallik permafrost well in 2002 (Dallimore and Collett 2005). This test was promising not for the amount of gas produced, but rather for information it provided about extraction techniques, production rates, well control, and the capacity of models to predict the rate and pattern of gas extraction.

**RENEWABILITY**

Compared to conventional oil, which develops at depths of kilometers over millions of years, the largely biogenic methane contained within most natural gas hydrates accumulates at far shallower depths, from lower concentrations of buried organic matter, and possibly more rapidly. These factors might make gas hydrate seem potentially more renewable than conventional hydrocarbon resources, although certainly not renewable in the sense that biofuels are. Because gas hydrate formation from aqueous-phase methane is so slow even at high rates of advection (e.g. Nimblett and Ruppel 2003), artificial stimulation to enhance the flow of existing free gas into the hydrate stability zone is probably the best prospect for catalyzing regeneration of methane hydrate. Still, this simply enhances the formation of new methane hydrate without actually replenishing the methane itself. Biogenic methane production is limited by the availability of organic carbon, the population of methanogens, and the rates of methanogenesis and related biochemical processes. Without artificial manipulation of the microbial consortium or the environmental factors that affect the rates of microbial methanogenesis, it is difficult to envision a means for actually renewing the biogenic methane supply on short timescales.

**THE FUTURE**

Coal and conventional oil and gas have largely powered the industrialized world for decades. Petroleum production may peak by the middle of the 21st century, while coal use is increasingly criticized for its contribution to air pollution and greenhouse gas accumulation. Methane hydrates could provide a cleaner hydrocarbon fuel accessible at shallower depths than conventional oil and gas, but major advances in exploration, extraction, and distribution techniques will be necessary to achieve routine production of natural gas from these deposits. The recent U.S. government proposal to temporarily suspend natural gas royalties for production of gas from gas hydrates in Alaska or on the U.S. outer continental shelf may stimulate commercial interest in unconventional gas from gas hydrates. Nonetheless, the National Petroleum Council recently predicted that methane hydrate is unlikely to contribute significantly to natural gas production before ~2025. According to Kumar, as summarized by Doyle et al. (2004), milestones in the projected development and production timeline include production of natural gas from the free gas near methane hydrate deposits within 5
years, enhanced recovery owing to technology developments in the next 10 years, extraction from permafrost gas hydrate deposits starting more than a decade from now, and deep-water production in perhaps 20 years.

**ACKNOWLEDGMENTS**

This article was largely completed while the author was on assignment at and wholly supported by the National Science Foundation (NSF), but the views expressed here are the author’s, not NSF’s. This paper benefited from exposure to interactions with T. Collett, E.D. Sloan, P. Ray, J.C. Santamarina, D. Hutchinson, B. Buffett, and G. Dickens, and from more than a decade of participation in ODP, IODP, NSF, NOAA, and DOE-sponsored activities related to gas hydrates. I thank M. Chaplin for use of his Structure I model, L. Stern for the SEM photomicrograph of methane hydrate, N. Toksöz for logistical support at MIT, and T. Collett, D. Hutchinson, and other reviewers for comments about the manuscript.

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