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NATURAL GAS PRODUCTION FROM GAS HYDRATES – AN ECONOMIC PERSPECTIVE

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Abstract

Various methods of exploiting gas hydrates have been proposed so far, but each of them has some drawbacks. To overcome some of these drawbacks, we propose a new technology for producing methane from gas hydrates. The method uses *in situ* thermal stimulation by introducing a specially designed hydrate heating apparatus into a horizontal borehole drilled in gas hydrate zones (GHZ). An estimated energy gain efficiency of the proposed method shows that only about 1.1 to 1.7% of gas produced will have to be burned to decompose hydrates. An analysis of determinants of costs associated with production of natural gas from gas hydrates reveals the important role of the rates of production, proximity to large energy markets, pipeline networks, locations of gas hydrate deposits, etc. Finally, an economic modeling of gas production from hydrates emphasizes the importance of defining the baseline economics for gas production from various sources.

Key words: gas hydrates, gas production, energy efficiency, thermal stimulation

Introduction

Gas hydrates (clathrates) have been known for 200 years; for over 60 years they have been studied by the oil and gas industry. Recently, a flood of publications has covered in great detail many of the branches of the gas hydrates "knowledge tree".

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Suffice to point out that just the Annals of the New York Academy of Sciences since January 2000 list dozens of articles on gas hydrates dealing with hydrates from the point of view of resource characterization, carbon sequestration, geophysics, global climate change, etc[2]. Despite this progress, knowledge about gas hydrates remains patchy, particularly about their potential production.

The first public release of data from a comprehensive production test was just made during the International Symposium "From Mallik to the Future" (December 8-10, 2003) by the he partners of the Mallik 2002 Gas Hydrate Production Research Well Program[3], and may be followed by results from a test carried out by Anadarko Petroleum Corp., Maurer Technology Inc, and Noble Engineering & Development on Alaska's North Slope[4]. Beyond that, extensive national programs are underway in the U.S, Japan, India, and elsewhere. All of this is evidence that the focus of attention is gradually shifting from gas (methane) hydrates characterization to technology development and economic assessment of gas hydrates as a practical gas resource. Here, we attempt to make a modest contribution in the latter two aspects (technology and economics).

Methods of producing natural gas from gas hydrate deposits

To produce natural gas from hydrates, it is necessary to disassociate the gas from the ice. In short, this entails melting the hydrate. Three major potential methods for producing gas from hydrates have been previously identified (Makogon, 1997; Sloan, 1998). These include thermal stimulation, pressure reduction, and inhibitor injection (Figure 1).

Thermal stimulation involves heating the reservoir beyond hydrate formation. The usual scenario that is invoked is injection of steam or hot water from a surface-placed facility (fig. 1). More innovative ideas, such as using electromagnetic heating or microwave heating have also been discussed in the literature (Kamath, 1998). To decompose hydrates containing one mole of methane requires between 60 and 90 kJ (Holder et al., 1984). This represents a relatively large amount of heat. The primary difficulty in thermal stimulation consists in delivering heat efficiently to the hydrates which need to be dissociated. High energy losses occur during the injection of the hot water or steam from the surface to the non-hydrate portion of the reservoir and difficulties exist in establishing and maintaining high permeability flow paths between injection wells and production wells (Holder et al., 1982, 1984). Those energy losses from the source to the reservoir or through pipelines would significantly increase the production costs.

[2] http://www.annalsnyas.org/cgi/collection/gashydrates?page=1
[3] http://www.mh21japan.gr.jp/english/index.html
[4] Cf. Oil&Gas Journal, May 26 and July 21, 2003.

Pressure reduction (*depressurization*) was considered a more efficient method of extracting gas from gas hydrates (e.g., Makogon, 1997, Max and Dillon, 1998). It involves decreasing the reservoir pressure below hydrate equilibrium, thus allowing the gas to disassociate. However, depressurization process is self-limiting in that once the pressure of the formation drops below a certain level, the temperature of the formation will also be caused to drop, thereby resulting in the hydrates maintaining a solid state. We will try to demonstrate next what the main drawback of this method is.

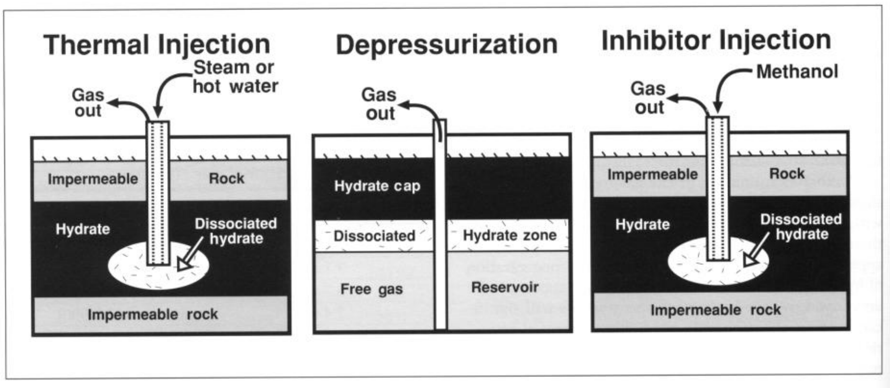

Fig. 1 Schematic of proposed gas-hydrate production methods (from Collett, 2001)

Hydrate stability depends upon both temperature and pressure, so it is possible to initiate dissociation by either raising the temperature or lowering the pressure. It is worth noting that many other factors also affect hydrate stability. Some influences, such as the proportion of propane to methane, are quite well understood. However, other factors, such as the influence of capillary forces, are poorly understood.

The amount of hydrates which can be dissociated by pressure reduction alone is limited by the amount of the available ambient heat. Dissociation by pressure reduction absorbs the same amount of heat (thermal energy) as dissociation by other means. Conservation of energy requires that the heat of fusion be supplied even though the dissociation takes place by pressure reduction instead of temperature increase. If the ambient environment contains insufficient heat to supply the heat of fusion, then dissociation by pressure reduction will stop after the initial thermal reservoir has been exhausted.

Finally, *inhibitor injection* involves injecting an inhibitor, such as methanol or glycol, into the reservoir to decrease hydrate stability (Kvenvolden, 1998). Production by inhibitor injection would be similar to thermal stimulation, the difference being the dissociation would be produced by chemical means rather than by heat melting. It is important to note that even if dissociation is by inhibitor injection, heat is nevertheless required. As the hydrate dissociates, it absorb heat from the ambient environment. The situation is analogous to melting ice by adding salt. If salt is added to an ice-water mixture, the ice melts. The heat necessary to melt the ice is provided by the heat content of the surrounding water, and the water temperature drops until a point is reached at which the ice will no longer melt. In a reservoir, the process may be similar. As inhibitor injection continues, the temperature will continue to drop until the hydrate is in equilibrium with the inhibitor and does no further dissociate. There appears to be no advantage to inhibitor injection over hot-water stimulation. Even if inhibitors are injected, the endothermic phase change is still present. Hydrate dissociation will be a self-limiting process unless external heat is provided. Both inhibitor injection and thermal stimulation have a similar problem of delivering efficiently the dissociating agent to the in situ hydrates.

While each of the above mentioned methods have been used to show that gas can theoretically be produced from hydrates at sufficient rates to make hydrates a technically recoverable resource, each method has drawbacks which at this point make gas hydrate production economically unfeasible.

To overcome some of the above mentioned drawbacks, Cranganu (1999, 2005, 2009) has proposed a new method for producing methane from gas hydrates. In principle, the method uses *in situ* thermal stimulation by introducing a hydrate heating apparatus into a horizontal borehole drilled in Gas Hydrate Zone (GHZ) (fig. 2). Instead of using water or other hot fluid injected from the surface or another location away from the GHZ, an air/gas fuel mixture is introduced into a combustion vessel from the surface via a fuel injection tubing string directly in the GHZ. Burning the fuel mixture results in producing the heat necessary to dissociate hydrates in the GHZ itself. The freed natural gas is then conveyed to the surface via a casing that is lining the wellbore. This method has the advantage of permitting the dissociated gas to be produced via the same wellbore through which the air/gas fuel mixture is injected, thereby avoiding the need of using two wells (injection and exploitation). Furthermore, the gas used for the air/gas fuel mixture may be provided from the gas produced from GHZ. It is believed that the proposed process (Cranganu, 1999, 2005) overcomes the disadvantages associated with the "remote" injection of hot water, steam or another fluid into GHZ, since the heat which is delivered to GHZ is produced *in situ*, thereby avoiding the high energy losses occurring during injection of hot water or steam from the surface to the formation. An estimated energy gain efficiency of the proposed method (Cranganu, 1999, 2005) shows that only about 1.1 to 1.7% of gas produced would have to be burned to decompose the hydrates, i.e., an efficiency of ~6,000 – 8,900%. Previous estimates of other thermal decomposition methods, for example steam injection, show that about 8-10% of gas produced would have to be burned just to decompose the hydrates (Holder et al., 1982; Holder et al., 1984).

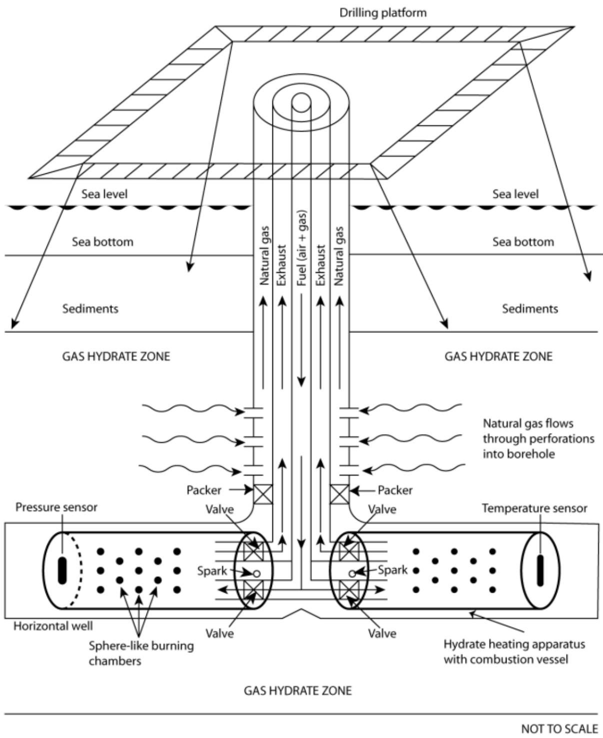

Fig. 2 Proposed technology for producing natural gas from gas hydrates

Gas hydrate exploitation – the determinants of costs

Using methane as a fuel is more environmentally benign than using more complex hydrocarbons or coal in conventional ways, such as power generation, industrial, residential and commercial heat applications, etc. Besides, emerging gas-to-liquids technologies may make it possible for gas hydrates to replace or at least complement conventional sources of liquid fuels in transportation (particularly middle distillates), or serve as a source of energy in fuel cells[5].

[5] Already in 1999, Syntroleum Corp., Tulsa, was awarded a patent of freeing, recovering and converting to liquids gas from hydrates trapped on the sea floor. Cf. OGJ, November 1, 1999.

Apart from higher energy efficiency, the proposed method of gas hydrate decomposition is more cost advantageous in comparison to previously considered methods as it involves traditional downhole technologies and surface facilities. Therefore, the cost of producing gas from conventional deposits with traditional technology can be used as the starting point for assessing the cost base of methane produced from gas hydrates by the proposed method.

Methane from gas hydrates is likely to be more expensive at the wellhead as compared to conventional natural gas. In the case of the proposed method, about 3% increase in unit cost will result from the need to burn some of the produced gas at the site. Other types of additional capital and operational expenditure are hard to judge at this point, as no tool development or field-testing of the proposed method has been done, but we expect these cost elements to be generally in line with traditional oilfield technology. Overall, unit production cost could be 5-10% higher than cost of conventional gas if the proposed method were to be used (other things assumed equal). If other gas hydrate decomposition methods were to be used, this production cost would be at least 15% and possibly much higher. It is assumed that the technology can achieve daily flow rates comparable to those at conventional gas fields – and admittedly, in the absence of field tests, this is just that: an assumption. Table 1 provides a wellhead cost comparison based on these assumptions.

Tab.1 Economic study of gas hydrates production (from Collett and Kuuskraa, 1989)

Economic study of gas hydrate production*			
	Thermal injection	Depressurization	Conventional gas
Investment, million $	5,084	3,320	3,150
Annual cost, incl. capital + O&M, million $	3,200	2,510	2,000
Total production, MMcf/year†	900	1,100	1,100
Production cost, $/Mcf	3.60	2.28	1.82
Break-even wellhead price, incl. royalties and fees, $/Mcf	4.50	2.85	2.25

* Assumed reservoir properties: h = 25 ft; φ = 40%; k = 600 md. †Assumed process: injection of 30,000 b/d of water at 300^0 F

Due to this higher cost, it becomes very important to either prove that *higher* rates of production are economically favorable from GHZ as compared to conventional gas fields, which is probably impossible, or to locate GHZ in proximity to large energy markets that cannot be supplied by gas in the required volume from other sources, e.g. by importing LNG. Such markets may be supplied with gas from great distance, and may also have gas sector infrastructure already in place. In such cases, economies of scale or lower gas transportation cost could be a factor that would balance the higher wellhead cost. Methane from gas hydrates may also be viable in cases where power is generated from highly polluting coal.

Gas transportation technologies have been steadily advancing and it is possible now to economically deliver gas over vast distances, either via pipelines or in liquefied state (LNG). The transportation cost of gas via pipeline is a function of its throughput (i.e. diameter and pressure), length, and other factors. At a particular pressure, the larger the diameter of the pipe or the shorter the distance, the cheaper it is to move gas via pipelines. However, supply (gas reserves) at one end of the pipe must be sufficient to meet demand at the other end for a long period of time. The larger the diameter of the pipe, the bigger reserves and demand loads must be. Reserves at one end of the pipeline must be sufficient to balance demand at the other end for at least 20 years, and the pipe itself must be of such "thickness" (length and diameter) as to carry the required quantities at an acceptable cost. The following table (tab. 2), adapted from Jensen (1997), illustrates the basic economic parameters of medium-high pressure pipelines at a transportation cost level of $1 per 1000 cubic feet (about $35 per 1000 cubic meters). It is unlikely that a high capacity, large diameter pipeline to deliver methane from GHZ would be considered for construction before first proving the technology on a smaller scale. If pilot projects are successful, the likely size of the first pipelines would be small. Therefore, with higher wellhead cost, methane from GHZ would initially be competitive only if produced within a short distance from well-established gas markets currently supplied from high-cost distant gas fields, or if co-produced and piped with conventional gas. Around the world, there are only two regions where both GHZs and mature gas markets with branched pipeline systems supplied over great distances exist: the United States and Europe. In the United States, the GHZs are in the area of Blake Ridge in the Atlantic Ocean, in the Gulf of Mexico and off the West Coast (California), and in Europe they are in the Black Sea. Finally, in the case of North Slope and Mackenzie Delta, methane from gas hydrates will have to be pumped together with conventional gas to justify the construction of a 1,200 km pipeline, at least initially.

Tab. 2 Basic pipeline parameter interdependencies for a cost of $1/1000 cubic foot

Pipe size, inch/mm	Throughput, CMY	Reserves, 20 years, BCM	Demand load, MW electric equivalent	Distance, km
20/508	3.2	91	1550	1360
30/762	7.2	201	3500	2000
36/914	10.2	290	5000	2500
42/1067	13.9	394	6800	2800
56/1422	24.6	700	12000	4400

With decreasing landed cost of LNG (generally less than $4 per 1000 cubic feet) and offers to supply some markets with LNG at $3 per 1,000 cubic feet over a distance of 5,000 km or more, the reasoning is analogous to the case of piped gas and has the same implications: methane from GHZ must originate in locations close to the market if it were to compete with LNG from conventional resources. There are two cases, where GHZs are known in proximity to large LNG markets: Japan (existing) and India (possible).

For these reasons, the likely locations where commercial production of methane from gas hydrates could eventually begin are only five: offshore Japan, offshore the United States, Mackenzie Delta (possibly along with North Slope gas), offshore India, and (possibly) in the Black Sea (Cranganu and Downey, 1998; Cranganu and Nitzov, 2005).

Basic economics of gas production from hydrates

To be competitive, gas from hydrates must generally have a wellhead cost comparable to that of the alternatives, i.e. to gas produced from conventional fields onshore and offshore, and at the same time provide comparable returns on the investment.

To get some insights into what costs and returns for gas from competitive sources are, data for largest U.S. producing regions (Texas onshore and Gulf of Mexico offshore) was run on popular industry models of gas well economics[6]. The following is a discussion of the input to the models, the results of the runs, and some conclusions about the prospects of natural gas production from hydrates.

Onshore Texas, the assumed values of various parameters needed as input to the model of a "typical" well are generally those available for new wells, with most recent data from 1997-8 (Swindell, 1999). Initial production rate is typically 41.2 million cubic feet (MMcf) per month, first year decline rate is 56%, and ultimate projected recovery is 1,019 MMcf per well, and the cost of a well in 1997 U.S. Dollars is around $770,000. On the other hand, depending on the well design options, the cost of a well (including completion) in 2002-2003 would be in the range of $770,000-$1,610,000, with the high estimate applicable to a "designer" 3,000' lateral well. The same source indicates operational costs (opex) for 2002-2003 of around 40¢ per thousand cubic feet (Mcf) + 20¢ per barrel (b) of water disposal cost (Pearson, 2005). As baseline input to the models, we used $1 million drilling and completion cost per well and $1/Mcf + $5,000 per well p.a. opex. The decline rate is hyperbolic with an exponent of 0.5. The model uses escalation of 2% p.a., and assumes 100% working and net revenue interest, abandonment cost of $100,000, net gas loss of 2%, and a discount rate of 10%. Finally, representative *ad valorem* added and severance taxes for Texas are used (4% each).

The runs of the models with these inputs held constant and the wellhead price as the variable indicates that an acceptable internal rate of return (IRR) is reached for a

[6] M.A. Mian's model as available in "Project Economics and Decision Analysis", CD courtesy of Palisade Corp., and Ryder Scott's "Quick Look Economics", available from http://www.ryderscott.com.

"typical" onshore gas well at a minimum wellhead price of around $2.75-2.80 per Mcf. The lifetime of the well would be around 4.15 years at an ultimate recovery of 1,015 MMcf. While higher wellhead price radically improves economics, with IRR exceeding 100% when price is over $3.75 per Mcf, the model does not indicate longer life or greater same-well ultimate recovery at higher prices; any increase in production would be primarily from a greater number of wells – if the resource were to be there in the first instance.

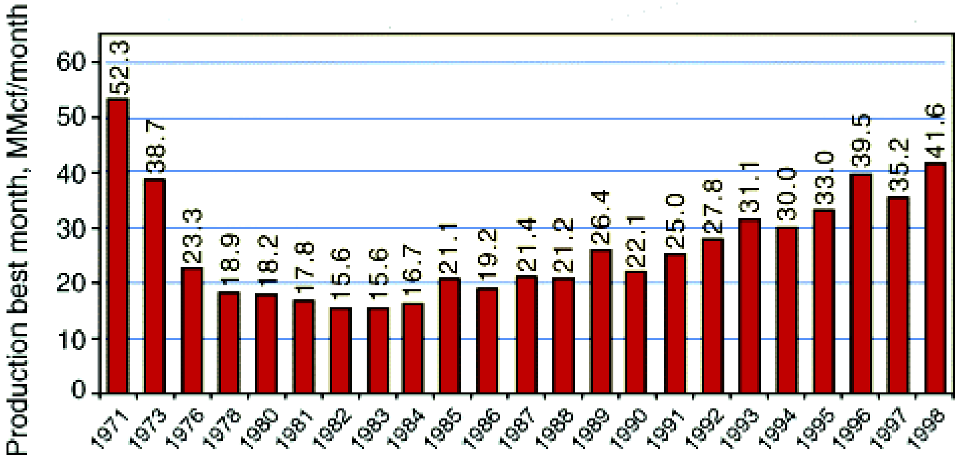

Fig. 3 Texas gas well average initial flow rate (from Swindell, 1999)

The advances in technology for the last 15 years or so seem to have little impact on the cost of a well, but very significant two-fold impact on flow rates: first, initial flow rates tend to be much higher than 20-30 years ago, and second, decline rates are much steeper (fig. 3 and 4). What this means is that, while ultimate recovery may not be very different, much greater production is available in the early life of a well, but its lifetime is much shorter. What can also be inferred from short-lived high flow rates is that technology has made possible the tapping of a great number of small reservoirs that would have been uneconomic otherwise, but not really expanded the resource base by much. In the times of yore, high flow rates were also associated with long well life, i.e. large reservoirs. Returns today are consequently much more dependent on short-term variations of price: with the bulk of production extracted in less than two years, a well only has two winter seasons to make it or break it if operated continuously. Consequences would include *inter alia* the increase of the share of production from new wells in overall production, which has actually been observed. New gas well production share in total productions has increased between 1971 and 1998 from around 7% to some 17% (Swindell, 1999).

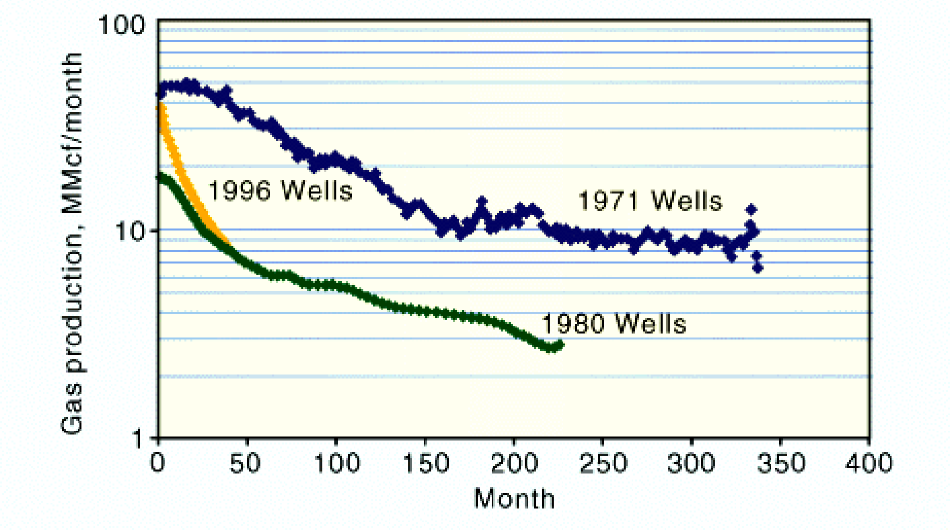

Fig. 4 Texas gas well decline profiles (from Swindell, 1999)

Offshore, the picture is a bit more diverse due to advances in deepwater technology that continue to open new acreage. Besides, there are considerable gas resources that are unreported as either proven or unproven, as they occur on leases that have not yet qualified (and therefore have not been placed in a field) or they occur as unproved reserves and/or known resources in proved fields, or as known resources in unproved fields. As further drilling and development occur, additional hydrocarbon volumes will become reportable. Mineral Management Service believes such resources to be around 10.8 trillion cubic feet (Tcf), in addition to 24.6 Tcf of proven and 2.3 Tcf of unproven reserves (Crawford et al., 2002).

The same source indicates the median of proven reserves in gas fields varies between 7.3 million barrels of oil equivalent (MMboe) (about 41,000 MMcf) in the Western Gulf to 9.4 MMboe (about 53,000 MMcf) in the Central and Eastern Gulf, with mean between 20.4 and 30.2 MMboe (~115,000 to 170,000 MMcf). For unproved fields, however, the median is ~11,500 MMcf and the mean ~36,000 MMcf. One large unproven field (>720,000 MMcf) contains some 48% of total unproven reserves (Crawford et al., 2002).

The size of reserves increases with the depth of water, especially beyond 2,600 ft. The mean proved reserves per proved field in the Gulf of Mexico is 45.2 MMboe. For water depths less than 651 ft, it is 40.1 MMBOE; for 651-1,300 ft, it is 40.3 MMBOE; for 1,301-2,600 ft, it is 51.1 MMboe; and greater than 2,600 ft, it is 143.8 MMboe.

Production rates are also significantly higher than onshore, with mean production from gas completions in 2002 of 106 MMcf per month (3.8 MMcf per day). However, the mean number of gas completions producing more than 10 MMcf per day was 233 (Crawford et al., 2002).

The major difference that defines baseline economics between shelf and deepwater can be summed up in two points:

- Deepwater development well cost is some $25-$40 million as opposed to average development well cost on the shelf of $5-$10 million (Bradberry, 2003);
- Deepwater reservoirs are much larger[7].

However, the greatest distinction in terms of future supply of gas lies not between onshore and offshore, but between mature, declining areas and new, growing ones. From this point of view, gas hydrates would have to compete not with onshore or shallow water fields, but with deep, ultra deep and currently closed areas, such as the Eastern Gulf. It will also have to be compared to emerging global alternatives, i.e. LNG, as well as emerging natural gas technologies, such as shale gas.

A run of the model with deepwater data - well cost in the range of $30 million, ultimate recovery per well in the range of 10-40 MMboe (we assume 25 MMboe ~140,000 MMcf) and flow rate around 10-50 Mboe/day (we assume 25 Mboe/day ~4,200 MMcf/month), at a wellhead price of $2.70 per Mcf and other parameters mutatis mutandis, indicates higher IRR as compared to onshore Texas, in the range of 35-40%. This should actually be the case, given the higher risks that a deep offshore operator has to face.

On the other hand, LNG is becoming available from many sources at a landed cost of around $4.00-4.50 per Mcf, while prices are spiking to much higher levels. At the same time, constraints to LNG imports related to sitting, permitting and other factors are becoming relaxed. A recent assessment by DOE puts LNG imports at more then 6 Tcf/year by 2025.

If supply of natural gas from hydrates were to ever materialize in North America setting, it has thus to compete with deepwater gas and LNG imports. While supply from both of these sources may be constrained in the short run, resulting in spikes of gas prices in North America as supply from mature areas declines, there seems to exist few constraints for LNG in the long run, at a landed cost of $4.50 per Mcf or less. Also in the long run, alternatives such as shale gas may materialize, at an indicated wellhead cost of $5.40 per Mcf. Figure 5 illustrates a projected path of gas prices until 2030.

Another factor that puts gas hydrates in some perspective is the cost/resource ratio. Gas hydrate projects – if they ever materialize – are likely to be in the same basket as

[7] This is natural distinction, as deepwater development is generally much younger than shelf or onshore: large fields tend to be discovered and developed first.

deepwater and LNG projects, i.e. high capital/high volume projects. It is difficult to expect that such projects would go ahead on the assumption that prices would stick at high levels for a very long period of time. An onshore well may cost about $1 million and have a lifetime of 4 years or so, but deep offshore and LNG undertakings require billions and are expected to last decades. Therefore any decision about such large scale projects would tend to be based on a time-tested price floor, unless the argument about security of supply prevails. In the latter case, however, a clear understanding of the associated cost must also be provided.

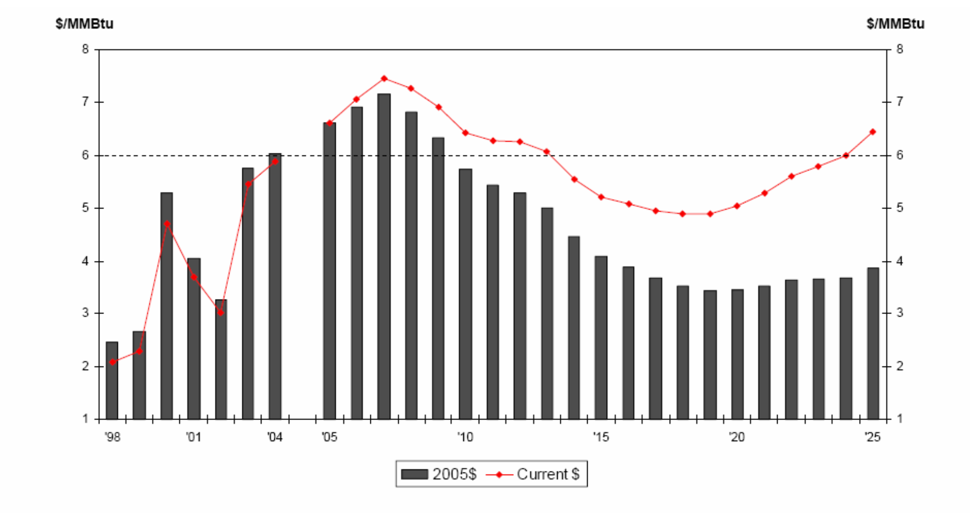

Fig. 5 Long-term natural gas price outlook (from Piper, 2005)

All of this simply makes us believe it would be prudent in any discussion about gas hydrate economics to always keep in sight the baseline, i.e. the price at which alternatives are available or may realistically be expected to appear in the long run. Right now in North America, this baseline seems to be in the range of $4.00-4.50 per Mcf. Flow, decline, recovery rates, capital expenditures and opex, etc. of gas hydrate projects would have to be tested against this benchmark.

Conclusions

Producing natural gas from gas hydrates by thermal stimulation, depressurization, or inhibitor injection) involves some drawbacks (lower energy efficiency, possible re-formation of hydrates, high costs, etc). To overcome some of those drawbacks, we propose using a novel technology for producing natural gas from gas hydrates. The method uses *in situ* thermal stimulation by introducing a specially designed hydrate heating apparatus into a horizontal borehole drilled in gas hydrate zones (GHZ). An estimated energy gain efficiency of the proposed method shows that only about 1.1 to 1.7% of gas produced will have to be burned to decompose hydrates. Previous estimates of other thermal decomposition methods, for example steam injection, show that about 8-10% of gas produced will have to be burned just to decompose hydrates. It is considered that the proposed technology overcomes the main difficulties of the thermal stimulation procedure and has some advantages over the other methods proposed to produce natural gas from gas hydrate deposits. Its estimated efficiency is between ~6000% and ~8900%. In order to maximize the benefits, the method needs to be applied using a specialized gas extraction strategy (controlled, slow draw-down).

An analysis of determinants of costs associated with production of natural gas from gas hydrates reveals the important aspects:

- It is important to either prove that higher rates of production are economically feasible from GHZs as compared to conventional gas fields or to locate GHZs in proximity to large energy markets that cannot be supplied by gas in the required volume from other sources, e.g., by importing LNG;

- It is unlikely that a large diameter pipeline to deliver natural gas from GHZs would be unlikely to be built before first proving a technology. Therefore, one should consider using smaller diameter pipelines from an existing network. Consequently, with higher wellhead costs, natural gas from GHZs would initially be competitive only of produced within a short distance form well-established gas markets currently supplied from high-cost distant gas fields;

- With decreasing landed cost of LNG and offers to supply some markets with LNG at $3 per 1,000 cubic feet over a distance of 5,000 km or more, natural gas from GHZS must originate in locations close to the market if it were to compete with LNG form conventional sources.

To get the basic economics of gas production from gas hydrates as compared to production from conventional sources (onshore, offshore, LNG imports), we run an economic model using available production data from Texas onshore and Gulf of Mexico offshore. The analysis shows that, if supply of natural gas from hydrates were to ever materialize in North America setting, it has to compete with deepwater gas and LNG imports. While supply from both of these sources may be constrained in the sort run, producing spikes of gas prices in North America as supply form mature areas decline, it appears that in the long run there are few constraints for LNG, if the landed cost is less than $4.50/Mcf.

In conclusion, we believe it is advisable in any discussion about gas hydrate economics to always keep in sight the baseline, i.e., the price at which alternatives are available or may realistically be expected to appear in the long run.

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