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PRELIMINARY REPORT ON THE ECONOMICS OF GAS PRODUCTION FROM NATURAL GAS HYDRATES

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ABSTRACT

Economic studies on simulated natural gas hydrate reservoirs have been compiled to estimate the price of natural gas that may lead to economically viable production from the most promising gas hydrate accumulations. As a first estimate, large-scale production of natural gas from North American arctic region Class 1 and Class 2 hydrate deposits will be economically acceptable at gas prices over $\$CDN_{2005}$ 10/Mscf and $\$CDN_{2005}$ 17/Mscf, respectively, provided the cost of building a pipeline to the nearest distribution point is not prohibitively expensive. These estimates should be seen as rough lower bounds, with positive error bars of $5 and $10, respectively. While these prices represent the best available estimate, the economic evaluation of a specific project is highly dependent on the producibility of the target zone, the amount of gas in place, the associated geologic and depositional environment, existing pipeline infrastructure, and local tariffs and taxes. Class 1 hydrate deposits may be economically viable at a lower natural gas price due largely to the existing free gas, which can be produced early in project lifetimes. Of the deposit types for which hydrates are the sole source of hydrocarbons (i.e. Class 2, 3, and 4 deposits), theoretical simulation studies imply that Class 2 deposits may be the most likely to be economically viable (with all else equal) due to assistance that removal of the underlying free water will provide to depressurization; thus $\$CDN_{2005}$ 17/Mscf can be seen as a lower bound on the natural gas price that may render hydrate deposits economically acceptable in the absence of free gas. Results from a recent analysis of the production of gas from marine hydrate deposits are also considered in this report [6]. On a rate-or-return (ROR) basis, it is approximately $\$_{2008}$ 3/Mscf more expensive to produce from a Class 3 marine hydrates than a conventional marine gas reservoir of similar size.

Keywords: economics, gas hydrates, reservoir modeling, production testing

NOMENCLATURE

G Guest Molecule
N Hydration Number
ROR Rate or Return
NPV Net Present Value

INTRODUCTION

Background Gas Hydrates are solid crystalline compounds in which gas molecules reside inside cages formed by hydrogen-bonded water molecules in a crystal lattice [21]. At sufficiently low temperatures and high pressures, a guest molecule, G, will combine with water to form gas hydrates by equation 1, where N is the hydration number [21].

$$G + N\,H_2O \rightarrow G \cdot N\,H_2O \qquad (1)$$

For a thorough yet concise review of gas hydrates, the reader is referred to [12].

Of particular interest are hydrates formed from hydrocarbon gasses found in the earth. These natural gas hydrate deposits are found in two different settings in which the temperature and pressure conditions are suitable for their existence: in arctic regions (within and below permafrost) and below the seafloor [21]. The estimates of the natural gas present in hydrate accumulations vary between 10^{16} and 10^{19} SCF, and even the most conservative estimates double the energy content of currently recoverable worldwide fossil fuels [21]. Due to the size of this potential resource, if a fraction of the gas in hydrates can be proven economically recoverable, then production from gas hydrates could become a part of the world's energy portfolio as demand for natural gas increases along with the technology to compress and distribute natural gas to distant markets. A world map with known and inferred gas hydrates is given in Figure 1 [21].

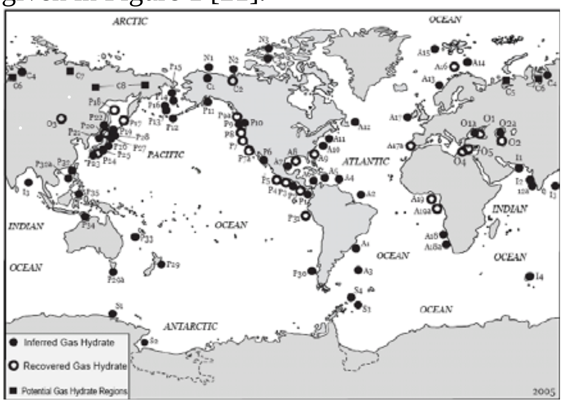

Figure 1. Map of known and inferred world-wide gas hydrate deposits [21].

Production from Natural Gas Hydrates Natural gas from hydrate deposits can be theoretically produced by one or a combination of three main methods [16]: 1. depressurization, in which the pressure is reduced below the equilibrium value at the system temperature; 2. thermal stimulation, in which the temperature is raised above the equilibrium value at the system pressure; and 3. injection of inhibitors such as salt and/or alcohol, by which the thermodynamic hydrate stability boundary is shifted to lower temperatures and higher pressures, thus inducing dissociation and gas release. Depressurization is thought to be the most technically efficient means of production from natural gas hydrate deposits [10].

The gas hydrate R&D programs in both the US and in Japan have targeted gas hydrates within coarse-grained (sand) reservoirs as the initial targets for potential gas production. Natural gas hydrate accumulations within coarse-grained reservoirs are divided into four main Classes [13,18]: Class 1 deposits are composed of a hydrate layer over a two-phase fluid zone containing mobile gas and water; Class 2 deposits involve a hydrate layer over a mobile water zone; Class 3 deposits are composed of a single hydrate zone without underlying mobile fluids; and Class 4 deposits are dispersed throughout the seafloor in low saturations. Class 4 deposits will likely not be economically producible in the foreseeable future [13]. Not all hydrate accumulations can be neatly catalogued in any of the above categories (e.g. clay-rich reservoirs with non-homogeneous hydrate distributions), and the generalizations about the four classes of hydrate accumulations should be seen as guides rather than strict rules.

Objective In this document we compile economic research conducted on the resource potential of gas hydrates, and report a preliminary estimate of the price of natural gas that may lead to economically-viable production from North American arctic region hydrates. We also discuss the implications of a recent study on the production of Class 3 marine hydrate deposits. An economic analysis is dependent on the type of deposits in question; the estimates presented in this paper were gleaned from reports on Class 1 and Class 2 arctic region deposits [7-9,20,22] and a recently described example of a Class 3 marine deposit from the Gulf of Mexico [6].

State of the Art in Hydrate Reservoir Modeling

Reservoir simulation currently plays an exclusive role and will continue to play an important role in estimating the potential production of gas from gas hydrate bearing reservoirs. To date, this has been the primary means to make decisions about potential production methods. A gas hydrate reservoir simulation program differs from a conventional oil and gas reservoir simulator in that the equations governing the flow of fluids in porous media must be coupled to the thermodynamic and kinetic equations governing the behavior of hydrates. The Department of Energy National Methane Hydrates R&D Program has compiled results from the major hydrate reservoir simulation programs to assemble a code comparison study and further information on the selected codes can be found on their website [5]. The code comparison study coordinated by the DOE tasked the users and developers of several sophisticated hydrate reservoir simulation programs to forecast the behavior of five model reservoirs of varying degrees of complexity, subject to the same reservoir parameters. The results of the code comparison indicate that the major hydrate reservoir simulation programs predict reservoir behavior within engineering accuracy of each other. [5] A further code comparison was performed with these major hydrate reservoir simulators on data obtained from the Mt. Elbert #1 well drilled in the winter of 2007 [1]. The Mt. Elbert #1 program included several dual-packer flow and pressure buildup tests, and participants in the code comparison successfully matched the dual-packer test data to within engineering accuracy.

The economic analyses in this report were based on production forecasts from two of the codes used in the comparison study – CMG-STARS (Computer Modeling Group's Steam, Thermal and Advanced Processes Reservoir Simulator) and TOUGH+HYDRATE (Transport Of Unsaturated Groundwater and Heat). CMG-STARS is a commercial oil reservoir simulator that was adapted to describe hydrate reservoirs. In this adapted CMG-STARS reservoir simulator, hydrate is modeled as the oil phase, which can dissociate into methane and water when the local thermodynamic conditions move outside of the hydrate stability zone. The viscosity given to the oil (hydrate) phase is extremely high to represent hydrate as a solid; the hydrate thermodynamic stability relationship and heat of dissociation along with Kim-Bishnoi kinetic parameters are also input into the simulator. [7,9] TOUGH+HYDRATE, developed at the Lawrence Berkeley National Laboratory (LBNL) [17], was the first publicly available model to exclusively simulate hydrate reservoirs, and is a descendant of the TOUGH family of codes developed at LBNL to study multiphase flow in porous media. TOUGH+HYDRATE can model the non-isothermal dissociation of hydrates by fully coupling reservoir mass and energy balances and can accommodate up to four mass components (i.e. hydrate, water, methane, inhibitors) partitioned between four possible phases (hydrate, water, ice, and gas). The model can employ an equilibrium thermodynamic description of hydrate dissociation, in which a given amount of hydrate dissociates immediately when outside the thermodynamic stability zone, or it can use a kinetic model to describe the rapidity of hydrate dissociation. [17] TOUGH+HYDRATE has also been enhanced with the option of coupling the multiphase flow model to a commercial code, FLAC-3D [15] to assess the geomechanical consequences of hydrate dissociation and reservoir depressurization.

These models represent years of research, refinement, and collaboration to develop a dedicated hydrate reservoir simulator as well as industrial resourcefulness in the adaptation of an off-the-self commercial reservoir simulator. However, without long-term production tests to use as a benchmark, it is difficult to assess the accuracy of any hydrate reservoir simulator. Furthermore, because the economic results presented in this report rely directly on the predictions of these relatively untested codes, the results should be seen as preliminary, order-of-magnitude assessments until further production testing and code refinement are performed. Improvements to the hydrate reservoir models, in addition to possible modifications after longer-term production test data are available, will allow for a second generation of hydrate production economic feasibility studies, in which the uncertainty of the results should be markedly reduced.

State of the Art in Hydrate Reservoir Production and Petrophysical Testing

Small-scale gas hydrate production feasibility tests have been performed in the arctic region of Canada and the United States. The first hydrate reservoir petrophysical test occurred in the Mallik field in Canada in 1972 [2]. Drill stem tests on hydrate-containing sands indicated some methane recovery, but with a lower effective permeability when compared to the free gas zone in the same formation. [2] In 2002, dual-packer cased-hole formation testing as well as 6 days of experimental-scale petrophysical tests were performed in Canada's Mallik field. [4] In the case of the experimental-scale petrophysical test, hydrate dissociation was initiated by circulating water at ~ 60ºC to the testing interval. [4] This experimental test was seen as a proof of technical concept for producing gas from hydrates using conventional technology. Japan and Canada conducted a 60-hour flow test at Mallik in 2007 which served as another example of extracting gas natural hydrates. [23] A 6-day test was performed in the Mallik field in early 2008 with encouraging results. [19] For the first time, a sustained flow of gas was reported from a natural gas hydrate deposit. [19] Natural gas was produced for six days at a rate equivalent to a coal bed methane project. [19]

In the North Slope of Alaska, 2 days of experimental-scale wireline petrophysical tests were performed in 2007 on the Mt. Elbert prospect. [1] Hydrate dissociation was initiated by depressurization, and the flow and pressure build-up data suggest that gas was produced from hydrates. [1] This project represented another instance of the production of gas from hydrates using conventional technology. Plans are underway to design and seek industry approval for a potential long-term hydrate test well on the North Slope of Alaska. If approved by the resource owners, such a test would represent a very important step in the assessment of gas hydrates as a potential resource, since it would be the first time there would not be logistical or time constraints that limit the ability to fully evaluate production responses. [6]

It should be noted that most of the tests to date have reported production rates from hydrate deposits below economically feasible rates. However, scientific understanding and technical feasibility, rather than commercial viability, have been the goals of the gas hydrate production tests to date. The produced rates were the result of relatively short tests, and simulation results predict that hydrate reservoirs often display long lag times until peak production – a result of the necessity to unload the in-situ and dissociated water associated with any hydrate reservoir. The results of the latest test at Mallik [19] are cause for cautious optimism due to the production rates being comparable to coal bed methane. However, the need for long-tem production testing is apparent. Further hydrate production tests are being planned in India and Japan, Korea, China, and the U.S., while other countries are beginning to start field programs in gas hydrates, including Taiwan, New Zealand, and Colombia. [6,11]

Economics of Arctic Region Hydrates

Since 2004, several groups have reported preliminary economic analyses of arctic region hydrate accumulations [7,8,9,20, 22]. For the arctic region gas hydrate-bearing reservoir studies presented in this report, the commercial reservoir simulator CMG-STARS was utilized to model the hydrate system.

The results presented in this section relate specifically to North American Class 1 and 2 hydrate deposits. However, because it is understood that quantitative findings from these studies are estimates, in the absence of other economic studies, we assert that they represent the "best-available guess" for arctic region Class 1 and 2 deposits in general; they should at least be interpreted as a useful reference for entities considering arctic region hydrate resource exploitation elsewhere in the world. Clearly, the natural gas market price that may enable production from hydrates to be economically viable would vary from field to field, and the results presented here should be seen as the establishment of a preliminary estimate based on assumptions of producibility yet to be validated with field production testing.

Steve Hancock et al. A Preliminary Investigation of the Economics of Onshore Gas Hydrate Production, November, 2005 [7]. <u>All prices in this investigation refer to 2005 Canadian dollars</u>. In this investigation, CMG-STARS is used to model free-gas and gas-from-hydrate production from a reservoir modeled after the Mallik field. Both Class 1 ("case 1" in the presentation) and Class 2 ("case 2") environments are modeled. In the Class 1 reservoir, a 50 meter gas hydrate zone is underlain by a 10 meter free-gas zone (which does not exist in the Mallik field). The hydrate saturation in the hydrate zone is 75%, while the aqueous saturation is 25%. The hydrate zone contains 1.07 TCF of gas-in-place and the free-gas zone contains 232 BCF of gas-in-place. The Class 2 reservoir is identical except for the lack of an underlying free-gas zone. The formation intrinsic (non-hydrate-bearing) permeability averages 1000mD is reduced to 0.05mD when hydrate-filled. Two relative permeability curves are used, as shown in Figure 2.

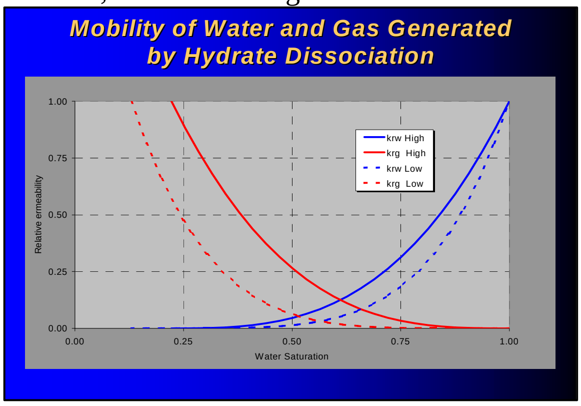

Figure 2: High and low relative permeability curves to gas (red) and water (blue) as a function of water saturation from [7]. The high relative permeability curves are represented by the solid lines, while the low relative permeability curves are represented by the dashed lines.

The modeled field consists of 5 production wells and 2 disposal wells. Production is initiated via depressurization in both cases. Figures 3, 4, and 5 represent the results of gas production rates, cumulative gas production, and water production for the simulations.

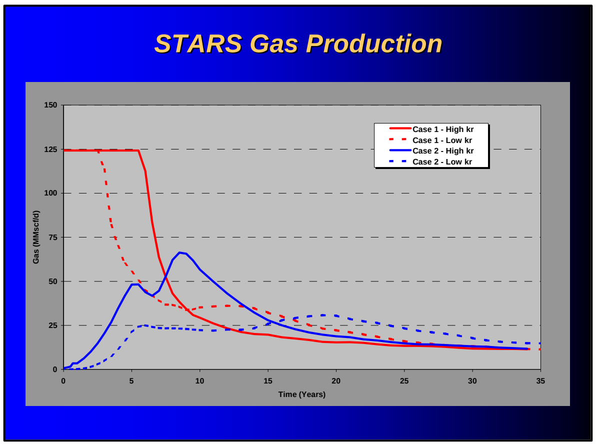

Figure 3: Field gas production rate (MMscf/d) for Case 1 (red) and Case 2(blue) from [7]. In both cases, the high k_r case is represented by the solid line, while the low k_r case is represented by the dashed line.

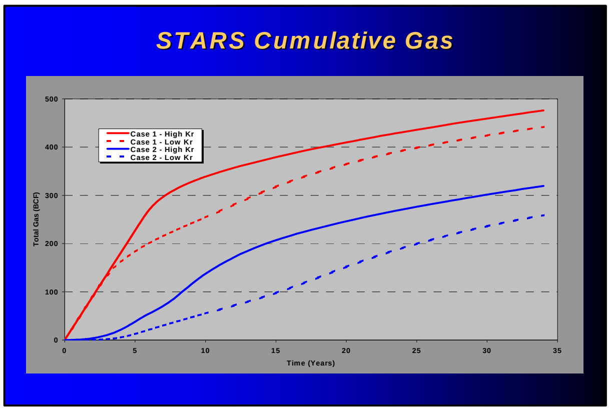

Figure 4: Cumulative gas production for Case 1 (red) and Case 2 (blue) from [7]. In both cases, the high k_r case is represented by the solid line, while the low k_r case is represented by the dashed line.

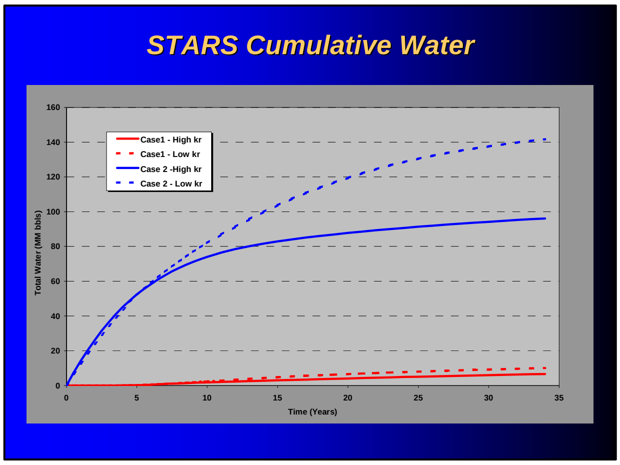

Figure 5: Cumulative water production for Case 1 (red) and Case 2 (blue) from [7]. In both cases, the high k_r case is represented by the solid line, while the low k_r case is represented by the dashed line.

The production results and associated costs, such as compression and separation facilities, water disposal wells, 20 kilometers of gas pipeline, and pipeline tariffs are analyzed with Que$tor costing database program to yield the economic results. Two main economic parameters are provided for both Class 1 and Class 2 cases: 1. unit technical cost and 2. internal rate of return as a function of market gas price. The reservoir behavior at the higher relative permeabilities (solid lines in Figure 2) is used for the economic analysis.

The unit technical cost is the price at which a resource owner would have to sell produced natural gas in order to redeem the capital and operating costs of the project; this number does not include royalties and taxes. Neglecting the time-value of money (that is, at a 0% discount rate), those prices are $CDN 5.74 and $CDN 6.54 for Cases 1 and 2, respectively, as seen from Table 1.

			Case 1	Case 2
Total Cap and Operating Cost ($MM CDN)			2,618	2,089
Sales Gas, High Case, BCF			456	319
Unit Technical Cost	$CDN/Mscf	0% discount	5.74	6.54
		10% discount	5.09	7.38
		20% discount	4.88	9.60

Table 1 – Unit technical cost results from [5].

The origin of these values can be seen from Table 1. Dividing the total operating and capital cost by the sales volume yields the 0%-discount unit technical cost. Table 1 also indicates that as the discount rate increases and costs and revenues are brought back to an equivalent starting point in time, the unit technical cost decreases in case 1 and increases in case 2. These opposite trends are a product of the fact that the maximum gas production rate from the Class 2 reservoir occurs at least 8 years after beginning production (Figure 3), whereas the maximum gas production rate for the Class 1 reservoir occurs immediately due to the presence of the free gas. With each passing year before the majority of the reservoir's gas is produced, the Class 2 project becomes more "expensive" on a time-valued basis when compared with other investment scenarios that can achieve a ROR of 10%; thus, the unit technical cost increases with increasing discount rate for the Class 2 reservoir.

The internal rate of return versus the market gas price is shown in Figure 6 and is used for our price estimation purposes as follows: say that an operator would be satisfied, all else equal, with a rate of return of 15%*. For case 1, which includes original free gas in place, a market gas price of about $CDN 7/Mscf would yield the acceptable rate of return. However, for the same reservoir but without the free gas (the Class 2 hydrate system), the gas price would have to be slightly more than $12CDN /Mscf to make the investment acceptable due to factors such as lower gas production rates, higher water production rates, and longer payout times. Multiplying these prices by 1.4* to account for taxes and unforeseen costs yields values of $CDN 10 and $CDN 17 per Mscf as the market prices necessary for economical production from land-based Class 1 and Class 2 gas hydrate-bearing reservoirs, respectively. These estimates should be seen as rough lower bounds, with positive error bars of $5 and $10, respectively. The positive error bars stem from the choice of the higher of the two estimated relative permeability curves and from the simplistic geometry of the production simulations from which the economic analysis was performed. A more realistic geologic environment may reduce the well performance, which would raise the price of natural gas that would render production from hydrates a viable scenario. Additionally, the unpredictable costs of production operations including but not limited to sand control, flow assurance, and artificial lift contribute to the positive error bars.

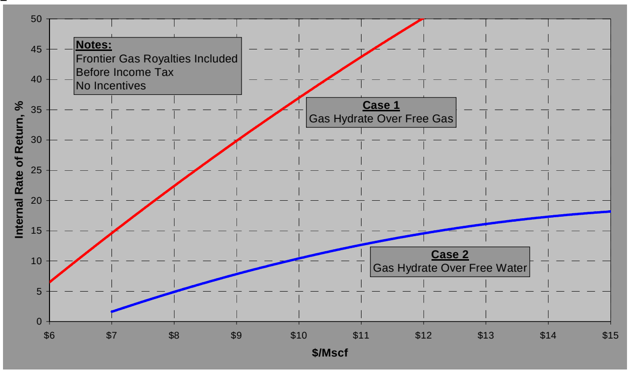

Figure 6: Internal Rate of Return as a function as market gas price ($/Mscf) for case 1 (red) and case 2 (blue) from [7].

*We believe our choices of 15% as a benchmark and 1.4 as a multiplier for taxes and unforeseen costs are reasonable values and representative (given the approximate nature of this report) of current oilfield projects. The reader is encouraged to use Figure 6 with his or her benchmark rate of return and tax/miscellaneous multiplier to generate acceptable prices, using the method outlined above.

Scott Wilson et al.: Economic Analysis and Feasibility Study of Gas Production from Alaska North Slope Gas Hydrate Resources, September, 2004 [20, 22] In his 2004 thesis, Stephen Howe used STARS to model production from a hydrate-bearing reservoir [9] and Scott Wilson and Stephen Howe extended this work thereafter [20, 22].

At the 2004 AAPG Hedberg conference, Scott Wilson and Robert Hunter teamed with Stephen Howe, Shirish Patil and members of the University of Alaska Fairbanks to present an economic analysis of arctic region hydrate deposits. In the study presented, CMG-STARS was used to construct a reservoir representative of a typical hydrate bearing area of the Alaska North Slope [20, 22]. The thicknesses and saturations of the respective zones are constrained by a USGS description of the area [3]. Production is initiated by depressurization, and Figure 7 shows a graph of total gas and incremental-hydrate gas production (gas produced from the hydrates) over time. Note that the total and incremental gas production from hydrate curves are qualitatively similar to the production vs. time graphs of Hancock et al. for the Case 1 and Case 2 studies (Figures 3 and 4), respectively.

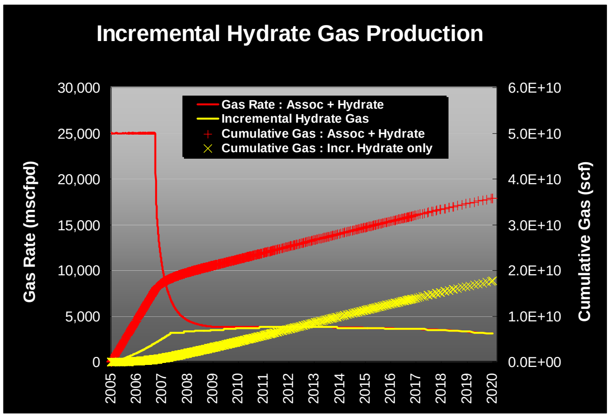

Figure 7: Total (red) and incremental hydrate (yellow) cumulative gas (thick) and production rates (thin) from [20, 22].

The results of this study can be qualitatively compared to the results of the work done by Hancock. Figure 8 illustrates that a flat production rate of 2.5 MMscfd would yield a

ROR in the low-teens and a NPV with a 10% discount rate (PV10) near zero within the given assumptions. Furthermore, Figure 7 shows that the contribution to the gas flow rate from the hydrate portion of the reservoir would average about 2.5MMscfd over the life of the project based on the preliminary simulation results. This would indicate that while the overall economics of the project could be favorable, the economics from the hydrate contribution alone would be much less favorable. This reinforces the results assembled from Hancock's presentation that hydrate zones associated with free gas would be more likely to be economical at a lower market gas price than hydrate zones lacking a free-gas base.

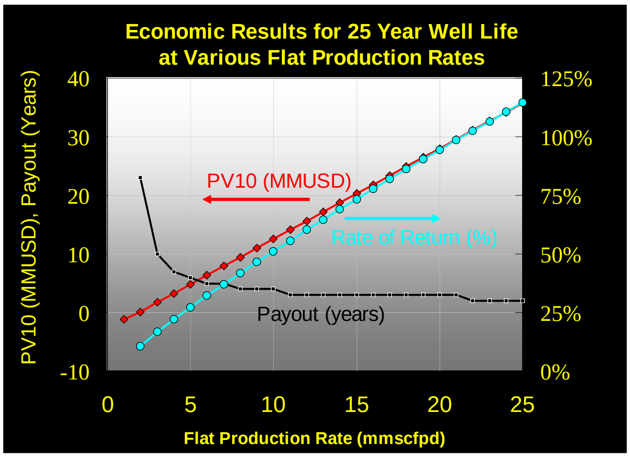

Figure 8: PV10, rate of return and payback from [20, 22].

Economics of Marine Hydrates

At the 2008 CERI 2008 Natural Gas Conference in Calgary, Steve Hancock presented results on the economics of hydrate production from Class 3 marine deposits. [6] In this study, the hydrate gas production economics are forecasted using production estimates from [14], in which TOUGH+HYDRATE is used to predict the gas production from a typical Class 3 hydrate accumulation. The economics of the potential project are calculated assuming that no previous energy infrastructure existed in the area prior to drilling. Therefore, the costs of a new production facility, subsea development, and a 120 kilometer pipeline are added to standard costs such as compression, dehydration, and separation. Extra costs associated with hydrate gas production, such as artificial lift, reduced platform pressure, and flow assurance are also considered, in addition to sand control, which could be especially troubling in the unconsolidated shallow sediments characteristic of marine hydrate reservoirs, were also considered in the analysis. A summary of the project costs is given in Table 2. [6]

(All prices MUSD)	Conventional Gas	Gas Hydrate Base Case	Gas Hydrate + 50%	Gas Hydrate - 25%
FPO and Topsides	356.1	419.8	419.8	419.8
Pipeline	332.4	332.4	332.4	332.4
Subsea	299.6	572.5	511.2	572.5
Drilling and Completion	682.5	1948	1301.1	1948
Subtotal Capital Costs	1670.6	3272.7	2564.5	3272.7
Operating Cost	1994.8	3232.6	2996.2	3232.5
Total Cost	3665.4	6505.3	5560.7	6505.2
Well Count	18	48	32	48

Table 2 – Costing information from [6]

The nominal field capacity is taken to be 500 MMscfd, and the required number of hydrate wells to reach this capacity, based on a one-well simulation in [14] is considered in the cost of the project. The conventional gas and hydrate field production profiles for this study are given in Figure 9.

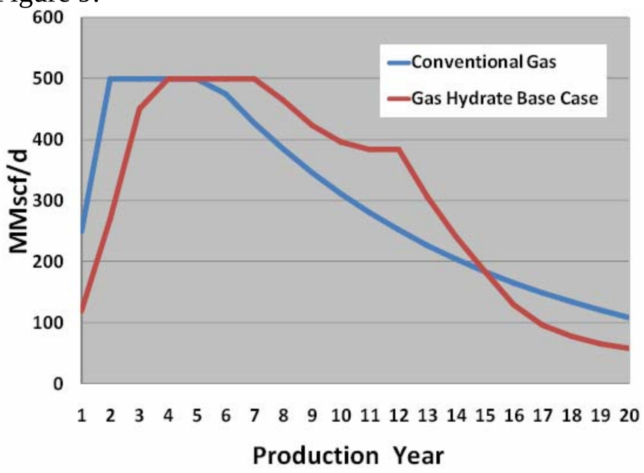

Figure 9: Field production vs. time for the gas hydrate reservoir vs. a conventional gas well development, from Hancock, 2008.

The production profiles and associated costs for the hydrate the conventional projects are input into the Que$tor cost database software. A pre-tax, pre-royalty plot of IROR vs. market gas price for all cases considered is shown in figure 10. [6] The '+50%' and '-25%' production profiles are calculated by multiplying the production forecast by 1.5 and 0.75, respectively, as a sensitivity analysis on the results of the economic evaluation.

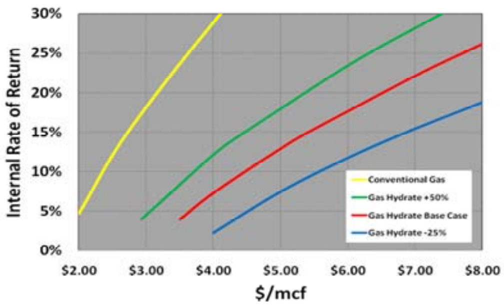

Figure 10: Internal Rate of Return as a function as market gas price ($/Mscf) for Class 3 marine hydrates (Hancock)

It is difficult to make direct comparisons between this NPV plot and the plot given for arctic region hydrates because the production profiles are calculated using different reservoir descriptions and development scenarios; furthermore, the production estimates for the case of marine hydrates are generated by replicating the behavior of one simulated type well by as many as 48 scheduled wells, instead of performing rigorous field-wide simulation. However, within the analysis itself, it is possible to compare the hydrate reservoir to the conventional gas reservoir, and it is encouraging to note that for a 15% IROR, the viability price increment for hydrate reservoirs is only ~3_{2008}$/Mscf over conventional gas.

Conclusions

As a rough estimate, the requisite natural-gas market prices for economically viable onshore gas-hydrate production from Class 1 and Class 2 deposits are approximately CDN_{2005}$ 10 / Mscf and $ CDN$_{2005}$ 17 / Mscf, respectively. These prices were determined mainly from the 2005 presentation given by Steve Hancock, et al., and corroborated with the 2004 reports of Scott Wilson and Stephen Howe [7,8,9,20, 22]. These estimates should be seen as lower bounds, with positive error bars of $5 and $10, respectively. Clearly, the presence of underlying free gas aids the economics of developing a hydrate reservoir, both in terms of promoting higher production rates and achieving earlier maximum production rates. Additionally, on a ROR basis, it is approximately $$_{2008}$ 3 / Mscf more expensive to produce Class 3 marine hydrates than conventional gas. [6] A critical need remains the validation of these reservoir and economic predictions through extended field testing that actually demonstrates a technical ability to produce significant hydrate gas with current technology. It should also be stressed that there is not one price that would render all hydrate reservoirs economically viable due to differences such as well performance, sediment type, gas-in-place, thermodynamic conditions of a reservoir, and the access to existing infrastructure. While the somewhat optimistic results presented in this report should be interpreted with caution, the economically-viable gas production from hydrates is not an unreasonable scenario.

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