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Transporting Natural Gas Around The Caribbean

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Many Caribbean islands have expanding tourist industries that will need increasing quantities of electricity. Gas is seen as the premium fuel particularly for electricity generation, but only if it can be delivered cheaper per energy unit (excluding environmental premium costs) rather than the conventional fuels. There are a number of possible methods of exporting gas from Trinidad's oil and gas fields for use as a fuel elsewhere - pipelines, LNG, gas to liquids (GtL) with a wide range of possible products including a clean fuel oil or methanol, gas to wire (GtW) i.e., electricity, compressed natural gas (CNG) and gas to solids (GtS), i.e., hydrates. However, an expanded Caribbean tourist industry would have only a 'small' energy demand that is not currently economically attractive to any major gas seller. Transportation of natural gas as hydrate, or CNG, is believed feasible at costs less than for LNG and where pipelines are not possible. The competitive advantage of the GtS or CNG processes over other non-pipeline gas technologies is that they are intrinsically simple processes and, as a concept, far easier to implement and feasible at lower capital costs. GtS and CNG technologies are options for handling niche markets for gas reserves which are stranded (no market), associated gas (on- or off-shore) which cannot be flared or re-injected, or small reservoirs which cannot otherwise be economically exploited. These options, particularly hydrates, are discussed in technical and economic terms.

Units

The petroleum industry uses a variety of units and conversion from one unit to another is often necessary. The major conversions for this paper are:

$1m^3 \equiv 6.29$bbl (barrels) $\equiv 35.3$cf.

1bbl = 5.615cf.

1 metric tonne oil ~ 7.5bbl.

Standard conditions represented as scf and sm^3 are 60^0F and 14.7 psi and 15^0C and 1bar.

Gas volumes are given as:

M = thousand (10^3). MM = million (10^6).

B = billion (10^9). T = trillion (10^{12}) scf.

M for other units is Mega-unit (10^6)

e.g., megawatt = 10^6W. 1000MM scf = 1B scf = 28.3MM sm^3. 1MM scf/day = 10MM sm^3/year $\cong$ 7500 metric tonnes LNG/year.

6000 scf gas contains approximately the same energy as 1bbl oil. Thus, if gas costs $1.00/Mscf, the oil energy equivalent is $6.00/bbl.

1 therm $\cong$100,000BTU $\cong$100scf of gas.

3412BTU = 1kWh = 10^3Wh.

1MM scf gas/day can supply ~10 megawatts electricity generating capacity continuously running.

$ = $US.

1. Introduction

Electricity generation is usually by the cheapest energy source available, which for the Caribbean islands is currently diesel, fuel oil or coal. These fuels are environmentally unfriendly, with emission of greenhouse gases, sulphur dioxide and dust, all of which are becoming increasingly unacceptable. Natural

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gas produces less than half the CO_2 emissions per unit of electricity generated compared to the conventional fuels, and is processed to be sulphur-fee so when burnt, there is no pollution or grit. Gas is also ideal for use in combined cycle power plants, (gas plus steam) whose efficiency is much greater than conventional steam-cycle plants. Because of its cleanliness, corrosion is less, so the boiler plant requires less maintenance. Gas is thus seen as the premium fuel for electricity generation, but only if it can be delivered cheaper per energy unit (excluding environmental compliance premium costs) rather than the conventional fuels. It also widens the fuel mix, which a number of islands wish, but getting natural gas to the Caribbean markets would be expensive by pipeline or Liquefied Natural Gas (LNG), so is not yet done [1,2].

1.1 Associated and Non-Associated Natural Gas

Sources of natural gas may be from non-associated reservoirs, where gas only is in the reservoir, or associated gas, which is the gas produced from an oil reservoir along with oil [3]. Crude oil cannot be produced without some associated gas also being produced. Non-associated natural gas is usually primarily methane with minor quantities of ethane, propane and butanes and may also include nitrogen, carbon dioxide, hydrogen sulphide, helium and water vapour. Associated gas usually has more percentage of the heavier hydrocarbons. Substantial volumes of both non-associated and associated gas are available in Trinidad as stranded gas, i.e., no current market, (e.g., the on- or off-shore fields where there is no pipeline).

Worldwide, governments are restricting the flaring of associated gas as their public perceives that it is a waste of a valuable non-renewable resource. Trinidad is no exception. There are often regulations that dictate when produced gas can be flared or not. When restrictions occur, associated gas must somehow be exported or reinjected, otherwise oil production must stop. The re-injection option can appear attractive at first sight, offering the added advantage of maintaining reservoir pressure, but the costs are high for the drilling and completion of the injection wells, the subsurface equipment, and the topsides equipment required to clean, pressurise and inject the gas. All of this is sunk cost, (perhaps \$0.25 - \$0.5/MMscf[4]), since no monetary value is gained from the gas until it is sold. It is essentially making an expensive round trip from the production well to the topsides and back down the injection well.

2. Trinidad's Gas Reserves

Trinidad has substantial reserves of natural gas, much of it non-associated gas, with the current estimate being over 30Tscf, $\approx$1Tsm^3 with potential for much more [1,2,5,6]. Because much of it is offshore, getting it to market has been problematical and has prevented reservoir development for many years.

2.1 Methods for Monetising Stranded Gas

There are a number of possible methods of monetising gas from Trinidad [6,7]. Firstly, for use as a fuel (gas) elsewhere and converting it to power at the buyer's country, although electricity generated locally and transmitted to the buyer (gas to wire (GtW)) is essentially doing the generating for the buyer. Methods include pipelines, liquefied natural gas (LNG), compressed natural gas (CNG), gas to solids (GtS) with natural gas hydrates and gas to liquids (GtL) (methanol, clean liquid fuel) (**Figure 1**) [3,6]. Gas energy itself can be transferred within commodities (GtC), e.g., aluminium, glass, bricks, cement and iron, all of which need large supplies of cheap energy in their production, so that their export is in reality export of energy [7]. If greater value is obtained to the producing country, then this is an option that must be considered. Likewise, export of gas molecules, which are used as plastic and chemical precursors at the destination market can also be considered, e.g., ethylene and polyethylene, polystyrene, acrylonitrile, methanol, ammonia, urea and other fertiliser products and dimethylether [1]. However, all require expensive and complex plants to carry out their manufacture.

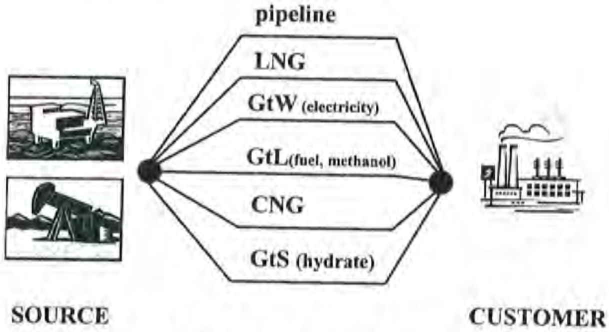

FIGURE 1: *Gas as Fuel Transport Options*

Most of these monetising routes are being considered, or have already been developed in Trinidad, to realise the commercial value of natural gas. The debate has often focussed on 'How can Trinidad best monitorise its gas?' and a Trinidad Gas Master plan has been delivered to the government [5].

2.2 Current Gas Exports of Trinidad

Export of gas from Trinidad to the United States by pipeline has always been regarded as uneconomic because of the difficult subsea terrain making pipeline installation and maintenance expensive, and the sea depths make any recompression along the route difficult. Export of gas by LNG to the United States and Europe has now become economic due to improvements in technology and thermodynamic efficiencies of LNG facilities, and in year 2001, some 450MMscf gas per day was exported as LNG produced in Point Fortin Atlantic LNG train 1 which commenced production in 1999. One tanker of LNG can carry 135,000m^3 LNG, equivalent to 3.2 Bscf of gas, enough to generate all the electricity used in Trinidad for 12 days. With the development of Atlantic LNG's trains 2 and 3, the export volume will soon triple to nearly 2 Bscf/day. In addition, Trinidad's GtL route via methanol and ammonia have capacities that make Trinidad a major world exporter (over 3 million tonnes each per year). Trinidad also uses gas locally to manufacture urea, iron, glass, bricks and cement for local consumption and export, as well as electricity [5].

2.3 Energy Needs of the Caribbean

Many Caribbean islands have expanding tourist industries that will need increasing quantities of electricity. However, even an expanded Caribbean tourist industry would only have a 'small' energy demand, which does not create much market attraction to major energy suppliers. Thus, for instance, a large 5-star hotel may use perhaps 11 million kilowatt-hours ($11*10^9$ Wh) of electricity per year. This is 30,000 kWh/day, which, if generated continuously, would need only a ~1.2 meagwatts generator. Because the demand is variable during the day, the generating capacity would have to be larger, perhaps 2 megawatts, but the generator would not always be on 100% output.

As 10 megawatts of electricity generating capacity continuously running requires ~1 MMscf/day of gas, thus to power our example hotel would consume only about 100 Mscf/day (100,000 scf) of natural gas. 100 Mscf/day is only 40MMscf/year, which is only 10% of intake to train 1 at AtlanticLNG for one day, i.e., a very small volume compared to the LNG requirements. Additionally, it would only generate an income of perhaps $0.1 million at $2.5/Mscf. However, such small quantities of power are all that some Caribbean islands currently need. (**Table 1**) [2]. For instance, 2 Mscf/day could power Saint Lucia and even Jamaica would increase its current electricity generating capacity by 22% in a power station of 240 megawatts with only 23 Mscf/day (costing ~$20 million/year). This is unlikely to be economically attractive to the major gas sellers/transporters, but it could be for an entrepreneur with gas in his portfolio, and linked with other products. Hence, developing new ways to transport gas at low cost in small volumes has many attractions for the islands until the 'ultimate solution' where an alternative energy of solar, wind or wave power conversion is used. This must surely happen one day, but in the meantime perhaps power via gas from Trinidad is the answer.

3. Methods for Transporting Gas To Market as Fuel from Trinidad

If transport of Trinidad's gas to the other Caribbean islands is to occur, a more flexible, less massive, less costly export method is needed. In this paper, we shall only consider transport of gas for fuel purposes; the other routes having been discussed elsewhere [1,4,5-7].

3.1 Pipelines

Pipelines are a very convenient method of transport but are not flexible as the gas will leave the source and arrive at its (one) destination [3]. The development of pipelines is an important factor in the expansion of gas-use in a country. Once the pipeline size is fixed, the quantities of gas that can be delivered is fixed by the pressures, although an increase can be achieved by adding compressors, extra pipe in the form of loops or increasing the pipeline pressure. Pipeline pressures are normally 700-1100 psig depending on the material of construction and the age of the pipe, and size can be up to 42" in diameter, although larger ones are in use. There is a 40" gas pipeline in Trinidad from the offshore East Coast gas fields to the onshore processing facilities at Point Lisas, and maybe soon a 52". Export by pipeline onland is extensive particularly throughout

3.2 Liquefied Natural Gas (LNG)

LNG is the liquid form of natural gas. Gas cooled to around -161°C liquefies and has a volume ~1/630 that of gas at room temperature. Export of LNG to Japan, the United States and Europe from distant production fields has now become economic due to improvements in technology and thermodynamic efficiencies of LNG facilities [3], but it is expensive to produce, often equivalent to oil costing $15 per bbl ($2.5/Mscf of natural gas) for its journey from the reservoir to being landed at the consumers' storage tanks.

The cost of producing LNG has fallen by about 40% since 1985 [3]. However, further cost reductions are likely to be limited. Generally, it is reckoned that LNG begins to gain the economic advantage over pipelines for distances over 700 miles [3]. Worldwide, 60 Bscf/day of natural gas is curently being processed for LNG export, and many more plants are being built around the world, e.g., Nigeria, Angola, Qatar, Egypt and Trinidad. Most require around 500 MMscf/day of gas per train [1].

LNG plants are large scale, long contract (~20 years or more) and a committed chain which need extensive legal contract negotiations, and any link in the chain can suddenly become fragile. The LNG facilities require complex machinery with moving parts and special cryogenic ships for transporting the LNG to market [1]. They require large >3Tscf gas reserves and ~$1 billion investment for a train processing around 500 MMscf/day (3 million tons/year of LNG). Huge cryogenic tanks are needed to store the LNG; typically these may be 70m diameter, 45m high and hold 100,000 m^3. They have to have liner walls of cryogenic steel (9% nickel) as carbon steel shatters at temperatures below ~- 40°C. For transport, the current largest specially built refrigerated tankers can carry 135,000m^3 LNG, equivalent to 3.2 Bscf of gas (worth ~$10 million). These ships are huge, about 300m in length, expensive and require special harbours and stringent safety precautions [3]. At the consumer end, an infrastructure for handling the reprocessing of vast quantities of natural gas from LNG is required, which is also very expensive and vulnerable to sabotage and natural hazards, e.g., hurricanes. This makes it difficult for LNG to use smaller isolated (offshore) reserves and to serve small markets commercially, because it is this large capacity, continuous running that allows maximum thermodynamic efficiency and keeps costs to a minimum. However, small well-insulated LNG container trade is being investigated, and if successful, small quantities of LNG may be able to be delivered from the LNG storage, just like the gasoline tankers of today. Even so, the LNG must be stored for periods of time (months) without significant boil-off losses, which is difficult. Hub-concepts where one regassification plant can be used to supply a region are also being discussed but there must also be someone prepared to develop this market.

It must be remembered that 1bbl oil contains approximately the same amount of energy as 6000 scf (170 m^3) of gas, so that if the oil price is $15/bbl, then at equivalent energy prices, gas should sell at approximately $2.5 per Mscf. Transport and liquefaction costs for LNG account for 85% of the supply cost of delivered LNG to the customer's jetty. Thus, when the oil price is at $20/bbl, LNG is a cheaper energy source, but when it is at $10/bbl oil is cheaper. Total LNG costs from reservoir to the customers' jetty for the first train in the State of Qatar were estimated to be equivalent to $15.6/bbl oil, or $2.7/Mscf gas (and consisted of upstream costs $2.2/bbl, liquefaction costs, $7.7/bbl, transport costs $5.8/bbl) [8]. In Qatar's case, condensate sales (propane and butanes) from the gas lowered the overall train costs, but not all natural gas contains such significant quantities of condensates, e.g., North Coast Marine Trinidad gas. Additional costs occur to get the gas from the jetty via gassification to the burner tip [8,9]. Thus, small volumes of intermittent gas are not economically attractive to the major gas sellers via LNG facilities or pipelines.

3.3 Gas to Liquid (GtL)

Here, the natural gas is converted via syngas ($CO + H_2$) into liquid. The liquid is shipped in a suitable tanker. It can be methanol or in the future, a hydrocarbon fuel, possibly a clean-burning motor fuel (syncrude), using a Fischer Tropsch method, or some precursor for plastics manufacture (e.g., dimethylether (DME)) [1]. For this paper, only the gas to fuel liquids transport is considered. The production of chemicals is much discussed elsewhere [1,3].

Methanol is a gas-to-liquids option that has been in commission since the mid 1940's and Trinidad is a major world contributor, with some five plants, and three to come onstream, currently producing around 3 million tonnes/year of methanol and using 290 MMscf/

TABLE 1: *Electricity in the Caribbean 2000 [2]*

	Installed Capacity 1/1/2000 (megawatts)	Net Generation in Year 2000 (billion kWh)
Antigua and Barbuda	30	0.09
Aruba (NETH)	90	0.48
The Bahamas	400	1.34
Barbados	170	0.67
Cayman Islands (UK)	80	0.29
Cuba	4,330	15.27
Dominica	20	0.04
Dominican Republic	2,240	8.48
Grenada	30	0.11
Guadeloupe (FR)	390	1.22
Haiti	160	0.73
Jamaica	1,190	6.39
Martinique (FR)	120	1.08
Montserrat (UK)	4	0.01
Netherlands Antilles (NETH)	220	1.02
Puerto Rico (US)	4,580	17.77
St. Kitts and Nevis	20	0.09
Saint Lucia	20	0.11
St. Vincent/Grenadines	10	0.06
Trinidad and Tobago	1,250	4.76
US Virgin Islands	320	1.02
British Virgin Islands (UK)	10	0.04
Total	15,684	61.07

10 Megawatts of electricity ≈1MMscf/d of gas for electricity generation
MM = million standard cubic feet = 10^6scf.
Sources include: CIA World Factbook 2000; Latin America Monitor; Latin American Newsletters; Oil and Gas Journal; Petroleum Economist; International Market Insight Reports; US Energy Information Administration; EIA-www.eia.doe.govn [4]

Europe, USA and soon South America, but subsea lines over 2000 miles have, until recently, been regarded as uneconomic. This is because of the subsea terrain making pipeline installation and maintenance expensive and any recompression along the route, needed because of the friction causing pressure loss during gas transmission, difficult. However, plans have been proposed for lines from the Middle East to Pakistan and India and Venezuela to the United States.

Installation of a pipeline costs currently, on average, $1-2 million per mile depending on the terrain. Additionally, overland pipelines are vulnerable to sabotage in hostile countries, often have to cross several political boundaries, and are uneconomic for small volumes. Subsea lines over large marine distances and having difficult marine environments, such as deepwater (trenches) ice scouring or where fishermen are active, can be difficult to maintain and are also uneconomic for low throughputs. Safety has to be considered at all times particularly when trying to reduce costs. New corrosion resistant materials are being developed and novel construction methods including laser-welding techniques are at commercial status and should enable faster pipelaying. Drag reducing agents and treatments of the inner pipe surface are being introduced to increase flow throughputs [1].

day of natural gas. Optimised technology has improved the efficiency to 30 - 35 million-therms per tonne methanol (from over 50) so that there is now a larger output per unit of capital invested. Methanol can be used in internal combustion engines as a fuel, but the market for methanol as a fuel is limited, although the development of fuel cells for motor vehicles may change this. Methanol is best used as a basic chemical feedstock for the manufacture of plastics [1].

GtL processes other than methanol are in the process of being developed to produce clean fuels from gas but require complex (expensive) chemical plant with novel catalyst technology, and are currently only in their pilot stage [1], although Malaysia has had a commercial plant producing clean middle distillate fuel since 1996. The State of Qatar is likely to be the next country to produce clean fuels commercially this way [9]. Such premium fuels are expensive compared to normal fuel oil, but are environmentally much cleaner because of the absence of sulphur components, as these are removed at the initial recovery stage of the natural gas from the reservoir. These fuels may become mandatory in some downtown parts of cities to reduce poisonous pollution problems.

3.4 Gas-to-Wire (GtW)

Much of the transported gas is used as fuel for electricity generation, so why not generate the electricity near the reservoir source and transport the power by cable (gas-to-wire – GtW)? For instance, offshore gas could be used to fuel an offshore power plant (maybe sited in less hostile waters), which would generate electricity for sale onshore or to other offshore customers. Unfortunately, installing high-power lines to reach the shoreline is almost as expensive as pipelines, so GtW could be viewed as defeating the purpose of an alternative solution of gas export. Some consider having the energy as gas at the consumers' end gives greater flexibility and better thermal efficiencies by using the waste heat for local heating and desalination. This view is strengthened because even large generation capacity does not consume much of the gas from the larger fields, as power generation uses approximately 1MMscf/day for every 10 megawatts of power generated, and thus would not generate large revenues. There is also significant energy loss from the cables along the long distance transmission lines, moreso if the power is AC rather than DC. Losses also occur when the power is converted to DC from AC and when converted from high voltage used in the transmission to the lower values needed by the consumers.

If the gas powering the generators is associated gas, and if there is a generator shutdown and no other gas outlet, and if the gas cannot be released to flare, the whole oil production facility might also have to be shut down causing further revenue loss.

There are the usual considerations of safety to examine. For instance, if there are operational problems within the generation plant, it must be able to shut down quickly (in around 60 seconds) to keep a small incident from escalating. Any plant that has complicated processes that require a purge cycle or a cool-down cycle before it can shut down is clearly unsuitable. GtW has been an option much considered in the United States for getting energy from the Alaskan gas and oil fields to the populated areas, particularly California. There is a powerline from Trinidad to Tobago.

3.5 Compressed Natural Gas (CNG)

Gas can be transported in containers at high pressures, typically 1800 psi (rich gas) to roughly 3600 psi (lean gas) i.e., as CNG. Originally, these containers were heavy-walled (and hence heavy in weight) pressure vessels, but recently new designs have been proposed and are being actively pursued. For instance, relatively long lengths of thin-walled tubing (6.25in outside diameter with a wall thickness of 0.25in) can be coiled into large diameter reels [10]. A tube 9.6 miles long would become a helix (termed by the inventors as a Coselle) 'a coil in a carousel' - the carousel structure is important since it not only controls the pipe, even against total break, but it permits stacking 6ft to 8ft high. A Coselle is typically some 11ft high with a 50ft outside diameter and 10ft inside diameter and containing approximately 3MMscf of gas at 3000 psig. There could be many vertical girders around the outside so that a Coselle would be a large and safe pressurised gas containment system, which should not lead to a catastrophic chain reaction such as when one bursting linear pressure vessel causes a neighbour to burst. The behaviour and long-term viability of the coiled storage vessel under repeated loading/unloading is being tested but no serious difficulties are anticipated. The total weight of pipe and associated structures has to be transported along with the gas, but the inventors claim that the lower fabrication costs for the gas containers make this design attractive.

An alternative approach, Votrans™, has been defined as 'a total marine gas transport system (not just another gas container concept)' [11]. Here, a 'volume-optimised' gas delivery process includes dedicated transport ships carrying straight, long, large diameter pipes in an insulated cold storage cargo package. The volume optimised characteristics suggest that the resulting gas-filled containers may allow more gas to be transported in any ship of a given payload capacity. Suitable compressors and chillers, which would be much cheaper than an LNG liquefier, would be standard, so that costs could be further minimised. The system also has an offloading process that simplifies the delivery of product to low-cost receiver facilities. Terminal facilities (which are part of both the Votrans and the Coselle system) are of a lower cost than the LNG equivalent.

These total systems development could make transport possible for stranded gas (i.e., gas in places where there is no current market or no export pipeline) and for smaller, variable or intermittent quantities of associated gas which cannot be flared or reinjected. Suitably-sized ships or trucks would carry the gas to its destination. The number and size of Coselles or Votrans ships could be scaled to fit demand (possibly down to quite small volumes) and would depend on daily production rates from the reservoirs (whether variable or not), and weight restrictions of transporters. Case studies have shown that huge quantities of natural gas can be transported to markets at costs substantially below LNG costs over short distances and probably over longer distances when the largest ships are employed. Coselles capable of carrying up to 1Bscf each and Votrans up to 2Bscf each have been proposed. A potential problem would be that ships are required to be fully safety-inspected every five years and these carriers may be too heavy to dry dock. Smaller, but more ships delivering gas directly into the distribution pipeline with some backup storage in case a ship is delayed in transit, are possible, so creating greater flexibility. These would be able to cope with variable gas supplies such as often occurs with associated gas.

In some countries, CNG is used for vehicular transport as an alternative to conventional fuels (gasoline or diesel). Trinidad is an example, however, the time to fill a tank with 3000 psig gas can be slow and frustrating. The filling stations can be supplied by pipeline gas but the compressors needed to get the gas to 3000 psig can be large, multistage and expensive to purchase and operate. The thermodynamics of gas compression (heat generation), and gas expansion (significant cooling) have to be considered in any gas-processing operation and appropriate heat exchangers used, which add to the costs significantly. A gas network is also needed for the filling stations. Nevertheless, vehicular fuelling using CNG may become more common in the future.

3.6 Gas to Solids (GtS)

The final gas transport route that is considered for development in this paper is gas-to-solids, with the solid being gas hydrate. Natural gas hydrate (NGH) is the product of mixing liquid water with natural gas to form a stable snow-like substance. One research group has described the production process simply as 'just add water and stir' [13].

For gas transport, it has been found that if the hydrate slurry is refrigerated to around -15°C, it is stable at atmospheric pressure and decomposes very slowly, so that the hydrate can be stored and transported by ship to market in simple insulated (inexpensive compared to LNG carriers) bulk carriers, i.e., a large 'thermos flask' under near adiabatic conditions. Natural gas hydrate (NGH) can be deliberately formed by mixing natural gas and water at pressures >50 bar perhaps 80-100 bar and -2°C to 10°C (depending on the gas composition), the richer (more ethane) the 'easier' the formation conditions [12-14]. At the market, the slurry is melted back to gas and water by controlled warming using water for use in electricity power generation stations or, after appropriate drying, other requirements. The hydrate yields ~160sm^3 of natural gas per cubic metre of hydrate. The hydrate can be processed to a dry state, or into a pumpable slurry. The transport therefore involves the stages: production, shipping and re-gassification, along with storage (**Figure 2**). The manufacture of the hydrate could be carried out onshore using mobile equipment and ship for offshore (FPSO - floating production, storage and off-loading vessel) with minimal gas processing prior to hydrate formation. This is attractive commercially [12,13,15]. The water can be used at the destination or returned as ballast to the hydrate generator, and since it is saturated with gas would not take more gas into solution.

Continuous production of hydrate in a large-scale reactor, long-term hydrate storage and controlled regeneration of gas from storage have all been

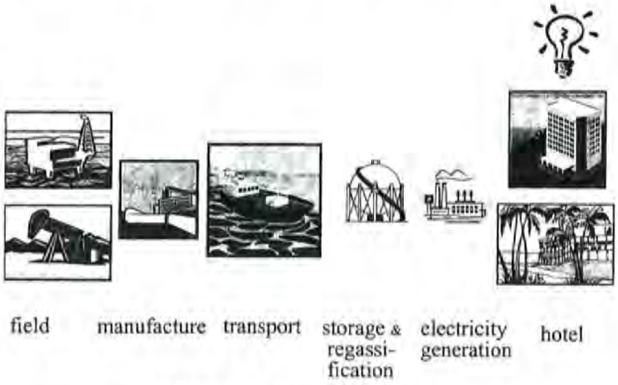

FIGURE 2: *The Hydrate Chain*

demonstrated. Reactor and process data have been obtained and equipment design for full-scale process development outlined. Pilot plant feasibility has been recently demonstrated by Adventica Technical Ltd for British Gas for dry and slurry processes, as discussed in the next section [12,13]. When compared to the transportation of natural gas by pipeline or LNG, the hydrate concept has significant lower capital and operating costs for the movement of quantities of natural gas over adverse conditions. The simplicity and flexibility of the process could make the GtS worth the development required.

The remainder of this paper will concentrate on the GtS route, the general process of hydrate manufacture and wider considerations.

4. Natural Gas Hydrate

NGH is a snow-like substance formed from natural gas in the presence of liquid water. The conditions have to be in the high pressure/low temperature side of the equilibrium curve of the phase diagram of hydrate forming gas and liquid water [13,17-20] (**Figure 3**). The thermodynamic and phase diagrams of water,

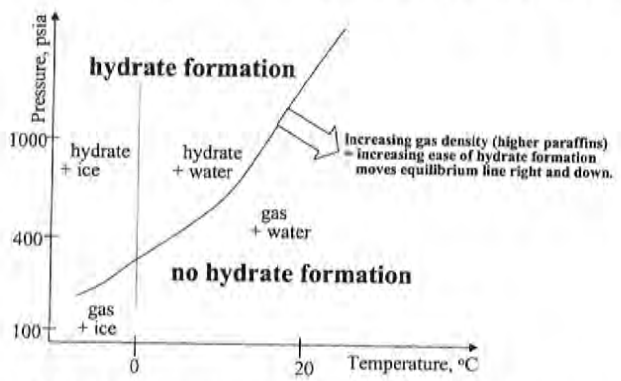

FIGURE 3: *Schematic P-T Diagram for NGH Formation*

hydrate and various gases have all been well-researched and documented [21]. NGH has a density of around 950 kg/m^3 and contains about 0.85 m^3/m^3 of water. The heat of formation is 410kJ/kg i.e., exothermic, so heat must be removed to maintain constant temperature conditions in the reactor or added to regassify.

Hydrates occur because certain small molecules, particularly methane, ethane and propane, stabilise the hydrogen bonds within water to form a 3-dimensional cage-like structure with the gas molecule trapped within the cages [14,16] (**Figure 4**). A cage is made up of several water molecules held together by hydrogen bonds. These types of structures, known as clathrates, have been well-studied and are complex. Water has three different cages within its lattice which can hold different sizes of molecules; sI containing 46 water molecules per 8 gas molecules (**Figure 4**), sII containing 136 water molecules per 24 gas molecules and sH containing 34 water molecules per 6 gas molecules. The main natural gas hydrate formers are methane and ethane into sI, and propane and isobutane into sII. Structure sH has only recently been fully identified and is a larger cage and hence can accommodate larger molecules including benzene but a mixture of gases are needed, particularly methane, to make the structure thermodynamically stable [14].

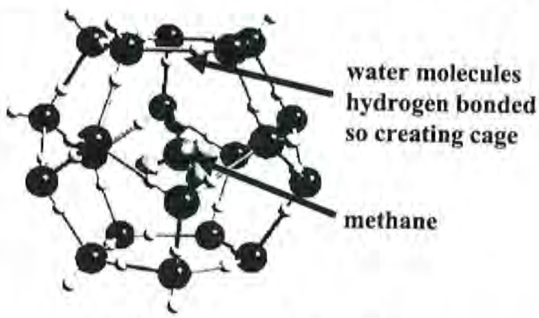

FIGURE 4: *The Hydrate Cage*

In theory, water can absorb 180sm^3 of gas if all the sites are used, but so far only about 160sm^3 have been recovered from 1m^3 of hydrate. This is because natural hydrate is non-stoichiometric, so has variation in its composition. The method of formation, gas composition, pressure and temperature all contribute to the 'degree of filling'. Thus 1m^3 of hydrate will contain about 160sm^3 gas per m^3 of water which makes the 'concentration' of gas very attractive compared to the 200 sm^3 from 1m^3 of compressed gas

>200bar) or the $637sm^3$ liquid from $1m^3$ of LNG (low temperature of -161°C) because the hydrate can readily be stored at normal temperatures (0 to -10°C) and pressures (10 to 1bar) which are easier, safer and cheaper. The advantage of storing gas in the hydrate state is due to the molar ratio of gas to water and to the exceptionally high density of gas in the hydrate state. Gas storage in hydrate form becomes especially efficient at relatively low pressures where substantially more gas per unit volume is contained in the hydrate than in the free state.

Mostly in the industry, natural gas hydrates are a pipeline nuisance and safety hazard, and require considerable vigilance by the operators to ensure that they do not form [16]. Hydrates block gas pipelines if stringent precautions, such as methanol injection, are not taken. Millions of dollars are spent annually in their prevention. For example, in year 2001, 1.4 million tons of methanol were used by the industry to prevent hydrate formation at a total cost of over $500 million. On the other hand, vast quantities of gas hydrate have been found in permafrost and at the seabed in depths below 500m (1500ft), and if properly exploited could become a major energy source in the next 30 years [14,17,18]. Estimates have been made that the volume of methane in these hydrates is two, or maybe as much as 10,000 times as much as current conventional gas reserves, leading to considerable worldwide interest in finding methods to extract them to solve the likely energy shortage by 2030. Commercial extraction at the moment is only at an early research stage. The stability of gas hydrates, particularly when extracting them, is an issue of concern, in the face of global warming and the potential environmental consequences of significant accidental methane release.

5. The Hydrate Process

GtS is believed to be a viable alternative to LNG or pipelines for the transportation of natural gas from source to demand. The process involves the manufacture of NGH from natural gas and water, the transportation of the hydrate by ship and the re-gassification of the hydrate to natural gas and water (**Figure 2**). The reservoir gas, whether associated or non-associated, would be produced to surface from the reservoir by normal petroleum engineering practice [3] and then transported to the hydrate manufacturing facility by pipeline. For offshore stranded gas, the hydrate facility would probably be on a floating platform within the field, or at some more sheltered place, depending on the water depth. The stages are:-

- Gas production from field and transport to hydrate facility, with cleaning if necessary (removal of heavier hydrocarbons, CO_2 and sulphur compounds)

- Hydrate facility (temperature: -10°C and pressure 50 - 90bar) located on-land, platform or floater. The natural gas and water are combined under pressure at temperatures below ambient with the pressure and temperature chosen from considerations of the equilibrium curve for the system (**Figure 3**). The reactor temperature is dropped a few degrees below the equilibrium temperature to increase the reaction rate for the formation of natural gas hydrate. Typically, the process would consist of (**Figure 5**):-

  - Cooling and compression of gas to 10°C and 50-100bar (pressure depending on temperature and gas composition (phase diagram).

  - Mixing with cool water in a series of stirred reactors. As the process is exo-thermic, cooling is necessary to keep the reaction at constant temperature.

  - Hydrate separation from the water and uncombined gas to prepare 'dry' hydrate or pumpable slurry. For this, the hydrate must be cooled and decompressed, but remaining in the thermodynamically stable region (**Figure 3**).

  - Excess gas and water are separated from the hydrate and recycled (**Figure 5**). The hydrate is conditioned either to a 'dry' form or a pumpable slurry for storage and transport.

- Transport by moderately insulated bulk carrier.

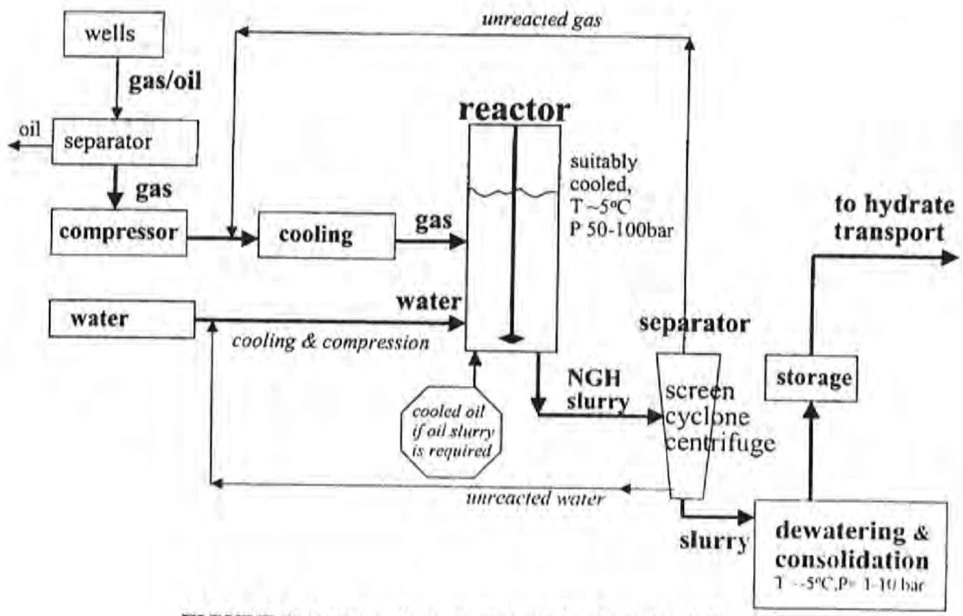

FIGURE 5: *Possible Hydrate Process for Associated Gas*

- Then, at the customers' end, discharge from carrier, store, regassify for use for power generation or other use.

5.1 Design Considerations

General:- There are a number of design criteria which have to be considered when producing the hydrate at pressures of 50-90bar and temperatures of 1 - 10°C in a series of reactors and then stabilising it for transport [12,13,18-23]. The entering natural gas must first be compressed to 50-90bar depending on composition, and cooled to 10°C in a heat exchanger before entering the reactor. Water enters the plant at atmospheric pressure and is cooled to ~2°C in a heat exchanger and pumped at 50bar to the reactors. The compression and cooling costs to get the gas to the required pressures and temperatures have to be minimised along the whole process. However, the real problem is the separation of the hydrate from the water, otherwise there is a 'freezing' of the hydrate making it difficult to move to storage, to ship, from ship to customer storage and to the regassification plant.

Exothermicity:- Hydrate creation is an exothermic process and releases energy (410kJ/kg) as heat which has to be removed. This can be achieved in the reactor via a jacket through which a cooling fluid removes this heat. The cooling fluid may be any available and economical coolant such as cold gas, water or a fluid from a neighbouring plant that needs to be heated.

Mixing:- As the reaction is combining a liquid and a gas to form a solid, good mixing is important. The best type of impeller in the reactor should maximise the interfacial contact between the water and gas. Perhaps a series of reactors might be necessary. Another method could be spraying in cold water as fine jets into high pressure cool gas. The residence time of the reactor should be around 10 mins. In one concept process [12], a ~7% by mass hydrate slurry is initially created and any unconverted gas and water are separated and recycled.

Hydrate-processing:- The hydrate needs further processing before the finished hydrate product can be shipped. The selection and specification of equipment to separate the hydrate and remove the unconverted gas and water depends on the extent of dewatering required. This water and gas are recycled after compression and cooling. Cyclone, screens or centrifuges, or a combination could carry out the separation.

The dry process:- The hydrate can be dewatered to a dry solid containing in excess of 150 volumes of gas per volume of hydrate, with virtually all of the free water removed. This would require two stages of water removal: a primary stage to achieve bulk separation, followed by a secondary unit to complete the dewatering. This has been successfully demonstrated in laboratory testing (at kg scale) [13], using cyclones, screens and centrifuge. This dry hydrate is fully stable at atmospheric pressure at around -40°C; the exact temperature depending on the composition of the hydrate. It is a white snow-like, dry solid. In fact, hydrate has been stored in the laboratory at -5°C and atmospheric pressure for periods of several months, with no loss of gas. The dry solid could be conveyed pneumatically, stored and readily transported at sub-zero temperatures by insulated ships without problems of freezing.

The water slurry process:- A partial dewatering can be carried out to produce a concentrated, but pumpable, hydrate slurry containing at least 75 volumes of gas per volume of hydrate [12]. However, water freezing out as ice can cause problems. To create stability, the hydrate would need to be cooled to -10°C through a heat exchanger. This cooling would solidify the free water around the hydrate particles and this ice shield would make the hydrate less susceptible to melting. A pressure drop would facilitate the flow of hydrate from the separator to a hydraulic press which should increase the hydrate particle size from 1-10mm to 5-15mm. The hydrate, after agglomeration, would be further cooled to -15°C through another heat exchanger and then sent to storage via conveyors if solid, or pumped if still a slurry. Laboratory experiments suggest that the concentrated hydrate slurry at ~ 2°C would need pressure containers at around 10 bar on a vessel similar to an LPG ship, which is extra cost.

Oil Slurry Route:- An alternative proposed method to enable easier hydrate transfer from the generator to storage or transporter involves the mixing of hydrate with refrigerated hydrocarbon liquids (e.g., light crude oil) for easy pumpability at ~ -10°C [15,22-25]. Clearly additional processing to remove the oil (hydrate contaminant) at the delivery stage would be required. In addition, the hydrocarbon liquid requires refrigeration to maintain hydrate stability and this is additional (energy) cost at each of the manufacturing, transport and regassification stages.

Storage:- After production, the NGH is stored in bulk, in an insulated container at a temperature between -5 to -15°C and atmospheric pressure if it is a dry product or perhaps at 10 bar if a slurry.

Transport:- The best means of transporting the hydrate to the customer is via insulated bulk carriers, barges or floating containers towed by tugboats, depending on the distance. The holds of the carriers could receive the hydrate as dry product, or a water-based or oil-based slurry. The dry solid can be transported at atmospheric pressure and -40°C, whereas the slurry at around 10 bar and 2°C. The bulk carriers for the dry hydrate have sufficient insulation not to need refrigeration. The slurry carriers would need to be insulated, pressurised vessels contained in bulk transporters. Any gas released during the voyage could be used as fuel for the vessel. The main difficulty with the use of the bulk carrier would be the unloading process. It is likely that during the voyage, the hydrate could solidify to some extent into a large mass. This mass would be impossible to remove from the vessel without adding some heat via a fluid (natural gas, oil or water) so that it can be pumped. An alternative, but less attrative method could be the storing of the product in large plastic containers which are then lifted by crane into the carrier's hold. At the plant, the plastic containers could be emptied into the storage tanks for melting.

Regassification:- The regassification process is a simple addition of heat to provide the energy of dissociation of the hydrate (410 kJ/kg). The design of the regassification plant would depend on the detailed engineering and local requirements, and distance to the power generator. One method could be that the hydrate enters the regassification plant from a storage vessel and warm water is added, probably as a spray, to the hydrate to supply the heat to melt the hydrate to natural gas and water.

Use:- The produced gas would need to be dried (perhaps in a recycle ethylene glycol absorption unit, or some other appropriate solvent with an affinity for water but not for the components of natural gas), collected off the top of the drying vessel via a gas vent and be available for use. It may need to be recompressed to the design pressure of the power generator. The water melted from the hydrate, and any water used in the melting process would be collected from the bottom of the vessel, now at around 5°C, to be used as a cooling fluid for, perhaps, cold storage or air-conditioning, or further purified for local use. Probably, the regassification plant would be located near to the power generation plant and the water for the melting of the hydrate warmed using waste heat from the power generation plant.

Pilot Studies:- Further pilot studies of the complete hydrate manufacturing routine would be needed when a specific project has been identified [12,13].

6. Discussion

Detailed economic calculations have been carried out for the entire hydrate supply chain for both onshore and offshore production facilities and comparisons made with LNG, GtL and CNG gas transport for bulk gas transportation [4,15,25,26]. Comparisons of which is the better (cheaper and cost effective) transport scheme are fraught with danger of not always comparing like with like. Some may quote the capital cost of the whole plant but ignore the risks of higher capital borrowing for a more complicated process; there are differences in technical difficulty, the risks of exposure to the investors or payback time. Sometimes, there is not much mention of operating costs, maintenance costs, particularly plant upgrades during the lifetime of the project, general mechanical complications of ageing plant or perhaps the local political difficulties requiring security against terrorist attacks or natural hazards. Thus, negotiators have to be very wary when preparing the long-term contracts.

6.1 LNG vs. GtS vs. CNG vs. GtL

The current large LNG projects have contracts typically for up to 20 years initially, and once the plants have been carefully planned, marketed and built, they are expected to provide stable revenues over this time period or longer, and so can cushion shorter term fluctuations (e.g., oil price variations) in other parts of an oilfield development.

The GtS hydrate plant should have capital costs much lower than for LNG, perhaps by half [4,15,25,26], and CNG maybe even less [4,10]. Consequently, the payback period will be shorter for the same gas throughput. However, competition with LNG for expansion of these large-sized gas transport projects is unlikely, as too much has already been invested in LNG. GtS or CNG are contenders for gas transport for green site developments and smaller niche markets, e.g., Caribbean islands, or where portable process equipment can be brought onto site, e.g., for associated gas, such facilities can then be used until either pipeline facilities are built, or other infrastructure developed, or the variable gas production rate drops to below the economic value.

GtL technology is currently under rapid development, but likely to be as costly as LNG, although the true costs will depend on the volumes of gas being processed and the premium value of the product.

Clearly, if hostile government or terrorist activity could occur, a project that is less costly would be favoured from an insurance point of view, particularly in terms of equipment loss.

6.2 Small Volume Applications

Much of the analysis found in the current literature [4,25,26], is for large volume markets and comparisons made with the large LNG plants, however, there is still the small volume needs of, for instance, the Caribbean, Black Sea and Mediterranean island tourist industries.

Stranded gas i.e., no current market, can supply these types of small volumes of gas, and they are available in Trinidad in fields not connected or contracted to the Atlantic LNG plant, or maybe even from flaring prohibition of associated gas. Transporting such small quantities should not need the huge costs associated with the large LNG trains and expensive specially-built refrigerated LNG ships, but there will be significant development initialising.

The manufacturing of hydrate could be carried out using mobile equipment for onshore and ship for offshore or for CNG with a mobile compressor with a suitably-sized, truck-mounted Corselle. The equipment can be removed if the field ceases production. If standard equipment and procedures could be developed worldwide, then a profitable and successful small volume gas transport route could be developed, particularly if the development costs have been absorbed in the initial projects.

The five-star large modern hotel mentioned earlier may need only 2 megawatts electricity output, which, as mentioned in Section 2.3, would need some 200 Mscf/day of gas, (70MMscf/year) or, equivalently, 40 tons of hydrate per day (13,000 tons per year), or about 11,000 bbl fuel oil/year. While remembering that 100 Mscf/day (45 MMscf/year) would generate an income of only \$0.1 million at \$2.5/Mscf, the market to give the hotels a 'green' image would not give much margin to the gas transporters for investment, unless a consortium could be developed, with probably interconnected oilfield development. However, the stranded gas is available and the novel GtS transport might appeal to the entrepreneur.

6.3 Environmental Considerations

The island hotels currently use the 'environmentally unfriendly' fuel oil. They could clean up the exhaust gases of the sulphur dioxide and soot and so claim that they are being 'clean'. However, fuel oil produces more CO_2 for the same energy output than gas so the environmental costs would be higher per tonne of CO_2 emitted. Thus, from an environmental point of view, electricity generated by gas transported by CNG, hydrate or even LNG in small containers, could possibly be cheaper than fuel oil at say, \$30/bbl (i.e., \$5/Mscf) gas if environmental compliance (exhaust clean-up, increased boiler corrosion and carbon tax, etc.) is included.

7. Conclusions

- Gas needs to be sold to monetorise it. Currently pipelines and LNG are the only fuel transport routes.

- LNG production is expensive (around US\$15/bbl oil equivalent - \$2.5/Mscf) and many Caribbean islands do not have the need nor the capital to build the storage and regeneration facilities. Small volumes of intermittent gas are not economically attractive to the major gas sellers for LNG facilities or pipelines. Transportation of natural gas as hydrate or CNG is feasible at costs believed to be less than for LNG where pipelines are not possible, because the manufacturing plant and ships for hydrate/ CNG transport would be cheaper.

- Hydrate yields about 160 (ideally 180m^3) of gas at standard conditions from 1m^3 of NGH and is very effective for gas storage by eliminating low temperatures, and the necessity of compressing the gas to high pressures. The competitive advantage of the GtS and CNG processes over other non-pipeline gas technologies is that they are intrinsically simpler processes and, as concepts, far easier to implement. The hydrate process does not involve extreme temperature, either high (GtL) or low (LNG), the pressure disadvantages are not as high as for CNG, does not require an oxidant or a catalyst, nor does it feature any complex unit operations only standard process equipment. In addition, the technology is able to cope with an intermittent and variable profile of gas production with time, as is usually the case with associated gas, and the quantities far better regulated and designed for the needs of a particular power station.

- The major parts of the GtS manufacturing process have been tested up to pilot plant level. These processes are feasible at lower capital costs, and hence require smaller investments and payback times for equivalent gas sales. Another commercial advantage of GtS or CNG over LNG is that to implement a project, a much smaller lead-time is needed, which means that GtS or CNG are producing revenue while the LNG is needing more years of investing (larger) capital before any return.

- Although economic analysis shows that the delivered cost of gas by hydrate or CNG can compete in the energy market at any scale compared to LNG, by concentrating on a niche, for instance offshore associated gas or stranded onshore gas, the actual economics of gas transportation can become one element of a much bigger scenario. If an oil development does not proceed if there are no means to dispose the associated gas (flaring prohibited or conditions are not suitable for reinjection (reservoir properties) or the gas-handling equipment is too expensive), then exporting the gas by GtS or CNG may ensure that the oil project can be successful commercially.

- Further detailed analysis to find the economic energy windows of opportunity for the best option for gas transport must always occur on a site specific basis.

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