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NEW ENERGY TECHNOLOGIES IN THE NATURAL GAS SECTORS:  
*A POLICY FRAMEWORK FOR JAPAN*

TECHNOLOGY AND LIQUEFIED NATURAL GAS: EVOLUTION OF MARKETS

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## Introduction

Hopes for the rapid expansion of natural gas use in Asia were deferred in 1997-1998 as economic recession tore asunder previous optimism about the expansion of LNG business in the region. From 1980 to 1990, world LNG trade rose 130% from 31.3 bcm to 72.14 bcm. By contrast, from 1990 to 1999, despite confident expectations of vast new sales prospects, LNG trade expanded by 72% to reach 124.2 bcm. In sum, Asia Pacific's woes slowed LNG growth across the board.

The nascent LNG market in the Atlantic Basin became the new focus for international LNG trade -- a market that promised new approaches in LNG development and commercialization as well as lower costs from new technologies. Highly flexible, trade-oriented and smaller sized projects have emerged. And as Asia Pacific recovers, unevenly, from the Asian recession, the new experiences of how LNG business is conceived, planned and executed in the Atlantic Basin is already reshaping the way LNG will proceed in the Asia Pacific.

This paper, excerpted from a longer study called *Global LNG: New Models, New Options*, to be published in November 2001, by Asia Pacific Consulting and the Institute of Gas Technology, investigates the technological innovations and improvements that are changing the LNG business today. By lowering costs and increasing flexibility, these changes will have dramatic impact on the development of the LNG business, with important consequences for Asia that will remain a key market. Rising environmental concerns, not only in OECD countries, but also in the developing world, are another powerful driver for change in LNG. In the Asia Pacific, the world's largest LNG consumption area, general environmental concerns are underpinning the region's structural shift to increased gas use.

Many of the parameters of traditional LNG development have changed minimally. The business remains a highly capital intensive, technologically sophisticated, costly, long-term business, needing long-term planning and continuing cooperation between the project host country, sellers and buyers. Yet we believe that new drivers have emerged in LNG that are rapidly reshaping the rules of the game. LNG companies still must be financially robust, able to forge immediate

profits for long-term returns and flexible enough to cooperate with a wide number of partners on a full range of issues – but now they must learn new rules of operations. The game itself has not so much changed as the assumptions and traditions, which colored LNG developments and outlook. We consider some of these changes below.

### **Cost Cutting Becomes Priority**

While security of supply was a major feature of early LNG market development, price has become a primary (though not always exclusive) consideration when LNG purchases are considered, whether in the traditional long-term contract market or for a *spot (that is single or short-term)* cargo. Many factors have contributed to a new awareness that the final delivered sales price for LNG is the major determinant in clinching new sales. They include: a) the opening of many domestic gas markets to foreign company participation, b) the deregulation and price decontrol of natural gas in a number of major consuming countries, c) the convergence of power and gas pricing and increased inter-sectoral competition, and d) the emergence of new LNG grassroots exporters. No realistic LNG promoter now can claim, as some did in the early 1990s, that a minimum base price averaging \$4/MM BTU or more is needed to get grassroots projects off the ground.

Korgas' Mideast contract rounds in Oman and Qatar showed that the long-assumed need for long-term sales contracts with pricing ceiling/floor was a chimera and that a minimum sales price was not a necessity to secure a commitment to LNG investment. More recent contracts, signed by the Trinidad and Nigerian LNG groups, have demonstrated that these ideas of minimum price and minimum base load are now guidelines rather than hard and fast absolute laws.

In this world of more flexible sales terms, LNG producers' efforts to cut cost remain the chief tool to increase project competitiveness. The chief areas of focus in cost cutting have been in technology, contracting/ project management and financing, including sponsorship and financial guarantees.

By the mid-1990s, it was clear that LNG costs had spiraled out of control. Some idea of LNG cost increases can be seen from a RD/Shell study. Capital costs for project-selling LNG to customers in a typical shipping distance of 6,000 nautical miles was examined. Overall costs were 60% for the LNG plant itself and 40% for LNG tankers. The survey of LNG plant costs from 1970 to 1995 concluded that specific plant capital costs rose from approximately \$50/MTA to \$400/MTA. The cost trend for actual projects, on a green field basis, approached \$600/MTA. In the same timeframe, general inflation accounted for only about 80-85% of increased cost. Something had gone very wrong.<sup>1</sup>

Trinidad LNG partners claim that they have been able to sharply cut capital costs in their project. With development costs averaging slightly over \$250/MTA compared to the latest Mideast LNG capacity expansions that topped \$400/MTA.<sup>2</sup> Promoters of new model LNG projects claim that such a sharp reduction in capital costs allows new LNG producers to compete strongly despite buyer price pressure. Exclusion of certain expenses associated with civil construction of community projects, such as hospitals, as well as other offsite costs, helped reduce overall capital costs considerably. Some cynics claimed that 'cost-cutting' was simply the result of creative accounting. Yet objectively costs did drop and pro-active steps taken by LNG planners played an important role.

On the exploration side, increased use of 3-D seismic, which provides a better understanding of field size and physical features, has allowed for less expensive and quicker development of natural gas finds. Slim-hole drilling technology has reduced appraisal well costs sharply, while deviated well technology and horizontal drilling allow for gas production from fields previously considered non-commercial. Unocal's drilling program offshore Kalimantan (Borneo) in Indonesia, reduced per well costs to \$7-8 million, while allowing wells to be drilled one after another, in rapid succession. Drill ships now can drill and produce gas from depths of 2,500 meters, but new technology in the experimental stage could extend that to depths of more than 3,000 meters in the near future.

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<sup>1</sup> From: Peter Tijm, Ed Stanton and Robert Klein Nagelvoort, "Liquefied natural gas: reducing costs", Shell Selected Paper, June 1995.

<sup>2</sup> Geoffrey Bothamley: "BG's LNG Portfolio", Speech delivered at LNG in the Atlantic Basin Conference, Savannah, Ga., USA, April, 2000.

The use of *downhole separators* in future wells, which separate water from gas or oil in the well bore and re-inject the water into the production reservoir, will cut deepwater production costs and improve recovery rates, in some cases by as much as 50%. Gas cleaning and natural gas liquids separation units are now often located on production platforms, allowing more efficient conversion of raw gas into suitable LNG feedstock.

Pioneering work in the North Sea and offshore Western Australia has reduced the cost of linking gas finds to a central gathering/processing point sharply in the past five years, in some case by up to 40%. Statoil, BP Amoco, Woodside and BHP have demonstrated the utility of subsea completions in varied developments around the world. Reduced development costs already have had a substantial impact in lowering the costs for new LNG projects.

A substantial number of innovations in building LNG manufacture, transportation and support infrastructure over recent years have cut costs significantly. Costs for liquefaction and transportation have declined more than 30 to 40% over the last two decades. The real price of a new LNG ship has fallen nearly 50% over the last decade, from \$300 to \$170 million. Regassification costs have dropped by about 20% and are expected to fall further. Among the more interesting developments have been:

- **Design Efficiency Improvements:** Substantial cost cutting has occurred in LNG plant capital and operating costs, with substantial savings seen in most areas of LNG plant design. Design efforts to move towards standardization of *boilerplate* parts, such as heat exchangers, has also reduced costs (see table below). Building LNG complexes in large and self-supported modules (known as *modularization*) in areas with low labor costs and high productivity and shipping these models to remote sites where LNG complexes are often located (i.e. Irian Jaya, Eastern Indonesia; Western Australia; Alaska North Slope, U.S.) could also reduce total construction costs.
  
- **Economies of Scale:** LNG liquefaction units have been growing steadily and facilities of 4 MM MTA are now in the planning stage. Increased efficiency in gas turbines, combined

with larger sized units, is reducing the number of gas turbines needed in plants by half. Operating costs are also less for a larger train size in terms of total production capacity, and using less trains to produce more LNG output significantly cuts the time needed for Engineering, Procurement and Construction (EPC) completion. According to a study by Merlin Associates, "...a two train 8.0 MM MTA plant can be built for about 10-15% more than the cost of a two-train 6.6 MM MTA plant. Unit costs per (metric) ton basis for the larger plant are nearly 15% less than that for the smaller capacity project."<sup>3</sup> Other studies show notable reductions for both, in capital and operating costs in the operation of a 2-train complex using 4.5 MM MTA liquefaction units versus a complex with two trains of 3.5 MM MTA capacity each.<sup>4</sup> With each successive announcement of new train construction, train capacity has increased -- the latest nameplate size 3.8 MM MTA in Qatar's Ras Laffan-II project.

- **Improvements in Liquefaction Technology:** Since the early 1980s the Propane/Mixed Refrigerant process (P-MR) was used for all new liquefaction trains. Some process technology developers, such as Phillips with its *Cascade* process, are claiming significant efficiency gains and the Cascade process was chosen for the recently commissioned Trinidad project and for expansion now underway. If more LNG is produced for less operating cost per unit, sizable savings could be made. Competitor studies claimed Cascade capital costs considerably higher than P-MR technology, but even critics did note that Cascade technology operates at near parity with P-MR, despite operation in rugged arctic conditions for any length of time (Alaska). Competing technologies are more or less equal in thermodynamic efficiency, but the major savings are in the number and design of compressors needed. In certain circumstances (such as projects with limited reserves or in floating LNG proposals (detailed below), this could make a difference. Or, as one LNG designer concludes, "Although all liquefaction cycles can approach the same efficiency by modifying cycle configuration and equipment design, each (liquefaction) cycle will have its own optimum,

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<sup>3</sup> DiNapoli, Robert N. and Yost III, Charles C., "LNG Plant Costs: Present and Future Trends"; Paper presented at LNG 12, Perth, Australia, May, 1998.

<sup>4</sup> Perez, Victor; Hauhe, William E.; Freels, Jay A.; Davis, Keenis; and Durr, Charles A., "The 4.5 MMPTA LNG Train – A Cost Effective Design"; Paper presented at LNG 12, Perth, Australia, May, 1998.

which is driven by project specific factors,”<sup>5</sup> i.e. different liquefaction processes must be used in varied LNG projects. With Cascade process now operating for the Trinidad LNG complex, its true capital and operating costs can be better gauged over the next few years. Other alternative liquefaction techniques, notably the Dual Mixed Refrigerant (DMR) process and the Single Mixed Refrigerant (SMR) are also being revamped and possibly revived.

- **Larger Gas Turbines:** The replacement of steam turbines by gas represented a leap in operational efficiency for LNG trains. Over recent years, gas-driven turbine sizes have risen, increasing the mechanical drive they provide for plants. Larger turbines often mean that fewer units are needed, and this reduces capital cost for liquefaction considerably. Shell estimates that 2-turbine plants reduce capital costs by more than 20% through the mid-1990s.<sup>6</sup> Advances since then have further improved efficiency and have allowed for the design of LNG trains with a nameplate capacity “in excess of 4 MM MTA.”<sup>7</sup>
- **Optimization of Air and Water Cooling:** More efficient cooling techniques are improving plant efficiencies significantly. Air-cooling, rather than water cooling, projects are now the norm for new LNG complexes. Combined with improved turbines, significant savings can be made in LNG manufacturing costs. In addition liquefaction trains are increasingly using differences in temperature in zones surrounding the LNG plant, according to time of day/night to boost conversion efficiency.
- **Less Design Redundancy:** Until the completion of grassroots projects in the late 1990s LNG complexes were planned under a basis of very conservative design, emphasizing ample capacity margins, proven technologies and unit redundancy, in order to give the highest assurance of security of supply, reliability and the ability to meet offtake supply obligations. Nearly two generations of operation for LNG plants have proven technology and showed that

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<sup>5</sup> Vink, K.J. and Nagelvoort, R. Klein, “Comparison of Baseload Liquefaction Processes”; Paper presented at LNG 12 Conference, Perth, Australia, May, 1998. Liu, Yu Nan; Daugherty, Tamara L.; Bronfenbrenner, James C., “LNG Liquefier Cycle Efficiency”, paper presented at LNG 12 Conference, Perth, Australia, May, 1998.

<sup>6</sup> Peter Tijm, Ed Stanton and Robert Klein Nagelvoort, “Liquefied natural gas: reducing costs”, Shell Selected Paper, June 1995.

there is less need for conservative complex design and overuse of design redundancy in planning operating units. Operational experience and the introduction of equipment and performance guarantees have reduced design margins substantially in the past half-decade. Assuming gas feed was available, almost all LNG trains operating before 1995 could regularly manufacture 20% more LNG than their stated capacity for sustained periods, and up to 40% over nameplate capacity for short periods. Many liquefaction trains have been retrofitted and their true working capacity is far higher than their original nameplate design.

- **Transportation:** Economies of scale have also impacted LNG shipping, which has moved to larger tankers and cargoes, decreasing transport costs per unit, while receiving terminals have grown both in their ability to handle larger tankers as well as adding substantial tank storage. These changes will reduce landed LNG prices by some 10% plus over the next 2-5 years. It is likely that the industry will move soon to a new standard long-haul tanker size of at least 160,000 CM carrying capacity, though naval architects have proposed tankers of up to 250,000 CM. The move to increase tankers from the currently largest class of 135,000-137,500 CM to 165,000-200,000 CM is under study by a number of companies. While buyers are reluctant to have to refurbish their receiving terminals, operational cost savings of 10-15% (and 5% in capital costs) are believed possible if 165,000 CM class tankers are put into service. With a 144,000 Cm vessel under construction for a Japanese utility, the day of the 160,000 CM LNG carrier is not far away.
  
- **Receiving Terminals also are Getting Larger:** Tokyo Gas's Ohgishima LNG receiving terminal was completed in the late 1990s with 200,000 CM tanks and even larger facilities are planned in new terminals. It is interesting to note that many of the newer LNG projects have buyers assuming shipping costs in order to retain any value added in the transport segment of the LNG chain, most notably South Korea (Oman) and India (Qatar.) In other new LNG projects, such as Trinidad, shipping is dominated by a single member of the sellers' consortium.

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<sup>7</sup> DiNapoli, Robert N. and Yost III, Charles C., "LNG Plant Costs: Present and Future Trends," paper presented at LNG 12 Conference, Perth, Australia, May, 1998



- **Improved Tanker Efficiencies:** LNG loaded onto tankers slowly regassifies as the ship travels. The liquid reconverted to gas is used (in some carriers) in part as ship's fuel, but boil-off is a loss of fuel that can impact profitability considerably. In the first generation LNG carriers, boil-off of up to 3% was common on a 10-14 day journey. Latest generation tankers have operational boil-off rates of less than 1% though a boil rate maximum of 1.5% is the lowest guaranteed. This can represent a significant distance in loss over long-haul voyages, such as Qatar to Japan. Continued technical innovations are expected in the next generation of LNG tankers to cut boil-off losses further.
  
- **Using Heat/Cold:** LNG terminal planners have been attempting to use the tremendous variations in temperature inherent in LNG regassification either in power generation or refrigeration. When LNG is allowed to warm to ambient temperatures, a considerable amount of *cold* is lost. Power companies such as Tractebel calculate that if a LNG terminal is developed with an adjacent power plant, heat/cold recovery could allow for large-scale electric generation and reduced regassification costs. "Optimization of those synergies may conduct to a cost savings of around 10% for capital cost and of 15-20% for the operating costs of the LNG terminal."<sup>8</sup>
  
- **Project Management/Contracting:** There have been considerable changes in how projects are managed with substantial gains claimed for new techniques in contracting in newer LNG grassroots projects. In recent Mideast Gulf projects, such as Ras Laffan, ExxonMobil and QGPC, prepared their in-house Front End Engineering and Design (FEED) plans and then accepted bids for the entire project, on a turn-key basis, with bidders then submitting their Engineering, Procurement and Construction (EPC) bids for consideration. The LNG promoters in this approach set the parameters for the overall project as a whole, and anticipate lower costs through careful design of the initial FEED document for bidders.

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<sup>8</sup> Pairon, Jean L., "Potential Synergies Between an LNG Receiving Terminal and An Adjacent Power Plant – Impact on Efficiency and Investment/Operating Costs"; Paper presented at LNG 12 Conference, Perth, Australia, May, 1998.

A second approach taken in new, particularly Atlantic Basin projects is to establish competitive bidding at every stage, with design, management and construction awards made as piece-work, with substantial subcontracting allowed. This approach emphasizes competition at every stage, and for each separate piece of work, in hopes that competition will drive down average cost.

- **Cost Optimization:** In order to manage costs better, engineering firms have identified certain areas of design and engineering specifications where substantial savings could be made. High cost impact savings in downstream design/engineering specifications are summarized in the table below.

**Areas For Cost Optimization**

<b>Process</b>	<b>Concept</b>
<b>General</b>	Take advantage of economies of scale by building larger and fewer LNG trains; promote competition in the manufacture of specialized equipment; promote development/use of innovative design concepts for plant, equipment & materials.
<b>Acid Gas Removal</b>	Combining acid gas removal and dehydration into a single absorbent bed to remove waste gas and water, usable for gas with low acid content.
<b>Liquefaction</b>	Choosing liquefaction processes that are simpler or have less moving parts, even if less efficient in gas conversion. Use gas turbines and optimize their use.
<b>Storage/Loading</b>	Use larger and fewer tanks; avoid excess LNG storage; pick the right tank type (single vs. full containment) for the complex.
<b>Project Execution</b>	Improve project execution techniques; relax design standards & specifications, within safety limits; adopt modular engineering & construction; invest heavily in the FEED phase of design to make major technically and unit decisions early in the project.

Source: Coyle, David A.; Durr, Charles A. and Hill, Don K., “ ‘Cost Optimization.’ The Contractor’s Approach ”, chart adapted from paper presented at LNG 12 Conference, Perth, Australia, May, 1998.

The cumulative impact of reductions in capital costs downstream has been substantial, as illustrated by calculations from Poten & Partners/Merlin Associates. Forecasts of further cost reductions in the near to medium future (3-5 years) foresee further capital cost cuts of 5-8%.

**Reduction in LNG Complex Costs (1980s Design = 100)**

	<i>Variation in Design Basis</i>		
	<b>Typical 1980s LNG Design</b>	<b>Typical 1990s LNG Design</b>	
# Trains	3.0	2.0	
Train Capacity (Nameplate MM MTA)	2.2	3.3	
Plant Capacity (Nameplate MM MTA)	6.6	6.6	
<b><u>UNITS</u></b>			<b>1990s Cost as % of 1980s Cost</b>
Liquefaction	33.2	20.9	63%
Utilities	12.0	10.3	86%
LNG Storage/Loading	5.8	4.9	84%
Buildings/Misc.	6.9	4.3	62%
EPC	21.7	9.0	41%
<b>Subtotal</b>	<b>79.6</b>	<b>49.4</b>	<b>62%</b>
Marine	3.7	2.5	68%
Infrastructure	4.1	4.1	100%
<b>Subtotal</b>	<b>7.8</b>	<b>6.6</b>	<b>85%</b>
Owner	12.5	9.8	78%
<b>Total</b>	<b>100.0</b>	<b>65.8</b>	<b>66%</b>

Adapted from: David Nissan, Robert DiNapoli, “Atlantic Basin LNG: Cost and Competition.”  
Presentation delivered at the LNG in the Atlantic Basin Conference, Savannah, GA, USA, April 2000.

**Innovations in Financing Arrangements**

Another major area of reduced capital cost is simply new and different ways to finance multi-billion dollar LNG projects. Traditionally, LNG projects were self-financed. Project promoters depended heavily on soft loans and credits from the buyers, who were bound to commit to long-

term, fixed price purchase agreements. Yet current and future LNG projects are not all being financed by purchasers at this juncture. LNG promoters are going directly to global capital markets now, most notably through bond issues, with or without, host country sovereign guarantees. The wholly commercial Ras Laffan \$1.3 billion bond issue in the mid-1990s was a historic first, and though the issue went through a period of financial shakiness, due to the recession that first hit Asia Pacific in 1997, moves by Mobil (and now ExxonMobil) to back bonds with further company financial support, if necessary, have restored investor confidence and regained assessment as a low risk bond offering. Further bond issues are likely to be floated to pay for LNG receiving infrastructure in developing countries, notably India, while both, LNG project developers and potential LNG buyers are exploring other financing alternatives for raising capital.

### **New Technologies That May Lower Costs and Change LNG Markets Further**

#### ***Floating LNG Production***

While floating LNG operations have been studied by many companies, only ExxonMobil has made a concrete and detailed exposition of their plans for this novel system, though more recently, RD/Shell has begun to reveal its plans for a floating LNG production system. ExxonMobil had hoped to bring the Gorgon gas reserves online as a floating LNG project by early this decade, though the project since has been sidetracked. Mobil, at that time, had estimated that use of its floating system could reduce operating costs for Gorgon LNG by \$1/MM BTU, cut capital spending to as little as \$4 billion (a more than 20% reduction) and could offer an internal rate of return on capital of about 15% - with a total project lead-time of only 3 years. While little progress has been made on the Gorgon project specifically, floating LNG production systems are still being explored, notably in Australia, where RD/Shell designed an LNG-ship production system, for development of the deep offshore North Australian Gas Venture. Partners Woodside and Phillips have yet to give this development approach their approval.

Two basic types of floating systems have been mooted, the first based on a true ship and the second mounted on a large barge. Ship-mounted LNG systems are designed for a capacity of 1.5-3.0 MM MTA output, as well as up to 25 MBD in condensate production. Barges, particularly the giant barge concept developed by Mobil (before its merger with Exxon) is believed to be able to be designed with a capacity of up to 6 MM MTA of LNG output and up to 55 MBD of associated condensate. The Gorgon LNG project design allowed for production in water depths of up to 200 meters and it was claimed that such a barge could operate 95% of the time and is designed to withstand once-in-a-century waves.

There are substantial advantages in the idea of floating LNG production facilities. Distant and isolated gas finds could be developed without having to create an entire infrastructure support network, reducing the minimum size of a discovery necessary to underpin a LNG project. Also, since production equipment can be moved, costly gas gathering systems can be avoided, or minimized.

However, safety concerns have not been fully resolved for the innovative technology. Since floating production systems are often proposed for areas with seasonally violent weather (i.e. typhoons for the Gorgon project), the system must be able to resist vertical and lateral movements of the floating system that could destabilize the transfer of LNG and LPG. Moreover, floating systems as proposed do not appear to have sufficient ability to deal with gas that contains substantial percentages of inert gas (such as CO<sub>2</sub>) or corrosives (such as SO<sub>2</sub>), possibly requiring costly gas reinjection. If flaring is prohibited, operational flexibility of floating systems is further limited.

Finally, substantial doubts still exist about the viability, and safety margin provided, in loading LNG at sea. Some offshore systems, such as a proposal by BHP, suggest mooring a floating production platform by anchoring it to an artificial mound built from seabed to create additional stability, however, doubts about operational efficiency and safety still have yet to be overcome. Shell has claimed that its marine system is significantly different, as it is designed as a ship, rather than barge, but detailed design plans have yet to be released.

### ***Floating LNG Regassification Terminals***

The flip side of floating production systems has been floating LNG receiving terminals. Mobil has been a leader here as well, but competition includes detailed proposals from BHP, BP Amoco, ExxonMobil, Gaz de France, Kvaerner (now Moss Maritime), Shell, TotalFina Elf, as well as Mitsubishi, Mitsui and Itochu. While floating or at least offshore-based terminals have been proposed for Italy, Taiwan, Turkey, Greece and India, it would appear that Italy's Edison is on the way to commissioning the first offshore LNG receiving terminal near the head of the Adriatic Sea, 15 km offshore the Rovigo. Edison has opted for a large complex, ranging from 5.5-8.3 MM MTA (4-6 BCM/Year). Construction of the gravity-based structure, which will be sited in water depth of about 28 meters, will begin by the end of 2001, with completion targeted for end-2004.

Turkey, which appeared poised to complete the first floating LNG regassification terminal located at Izmit, near Istanbul, has been sidelined by the financial crisis of early 2001 and the project is at least temporarily suspended.

Offshore terminals consist of either Shipboard Regassification Technology (SRT) or Gravity Base Structure (GBS) LNG terminals. SRT facilities allow buyers to advance the schedule of LNG deliveries by allowing for completion of receiving facilities in as little as 2 years, compared to a conventional terminal's average construction time of 4 years; to purchase smaller volumes of LNG initially, and to take advantage of potential *spot* sales offers. Both SRT and GBS systems are of utility in environmentally sensitive areas, or where land costs and availability is limited. Both offshore terminals avoid harbor construction, dredging and berthing costs, and while the risk of LNG exploding is minimal, offshore terminals pose even less safety risk as they are several kilometers from populated areas onshore.

GBS facilities, while limited to shallow water of 30 meters depth or less, have the additional advantages of being able to handle larger volumes of LNG, as it uses conventional LNG receiving technology, and in some rough weather conditions, allow for greater access by LNG tankers than conventional harbors.

Still no GBS, let alone SRT facility, has yet to been built, though Italy's Rovigo project would break ground in this area. Taiwan appeared to be leaning towards an ExxonMobil sponsored SRT project, when a barrage of rockets from Mainland China showed how potentially vulnerable such a complex would be in times of war.

### ***Regassification Tankers***

A further innovation being pursued by major LNG operators is the development of transport vessels that can regassify on ship and then deliver gas directly into coastal grid networks. The introduction of such onboard gasification technology would have dramatic impact on the way LNG is traded worldwide and would allow LNG to be sold into markets where expensive receiving terminals do not exist, potentially broadening the market dramatically for LNG and enhancing a global spot market for natural gas. This revolutionary technology has tremendous potential but is still many years away from actual utilization.

A key problem that must be solved for such technology to proliferate is that LNG discharge is limited to markets that are large enough to take substantial volumes of gas in a short period of time, either shipping it through national gas pipeline systems or storing it temporarily, until gas be shipped out through the transmission grid. Since demurrage charges for LNG carriers can easily average \$70,000 or more a day, timely dispatch of regassified LNG is vital. Such liquid markets exist in the Atlantic Basin, but at present only Korea could possibly utilize such a system in Asia.

### **Other Gas Conversion Technologies: Competition for LNG?**

#### ***Gas-To-Liquids Facilities***

The conversion of gas, whether natural or synthetic, into artificial liquid petroleum products has been around since the 1920s, when the Fischer-Tropsch process was patented. But, such synfuels have had a long and somewhat spotted history. In the past, the use of GTL technology

always has been dictated by severe necessity, as in the case of Nazi Germany during the waning years of World War II or in South Africa during the economic embargo.

However, in recent years, costs of gas conversion have been lowered to the point where commercial plant operations now seem feasible. GTL offers a chance to meet both volume and quality demands for ultra-clean liquid fuel in line with growing diesel fuel demand in the developing world. By converting natural gas into synthetic petroleum fuels, GTL diesel can penetrate world transport fuel markets very quickly and may well account for a substantial proportion of diesel supply by the next decade. Nor is GTL output limited solely to diesel. GTL processes can also produce aviation fuel (Jet A-1 kerosene) as well as gasoline.

In the next few years, the primary focus of GTL technology is likely to be the production of low sulfur diesel fuel that can meet pending fuel quality regulations in both the European Union (EU) and the U.S. market. Moreover, about a third of Asia Pacific's oil product consumption is gas oil, mainly road diesel. But exploration has proved up far more gas than oil in the region. Since the Asia Pacific region is second only to North America in total oil product consumption, the sheer size of its diesel needs has peaked interest in GTL.

Though still not yet at the point of commercial breakthrough for large-scale plants, a number of companies are planning commercial-sized GTL projects, including Shell, ExxonMobil, Sasol, Sasol/Chevron and small U.S. independent Syntroleum. It should be noted that both Shell and Sasol have extensive experience in operating smaller GTL plants, the former with the Malaysian Synthetic Middle Distillate (MSMD) project in Sarawak, Borneo and the latter with the Mossel Bay complex in South Africa, while others have operated much smaller GTL pilot plants. Skeptics have noted that the Malaysian plant has not been able to recover a regular profit on operations and was closed for two years due to a plant explosion and that the Moss Bay project has only survived because of substantial direct and indirect government subsidies.



**Proposed Commercial GTL Plants**

<b>Company</b>	<b>Site/Country</b>	<b>Capacity (MBD)</b>	<b>Startup</b>	<b>Notes</b>
Shell	Sabah, Kota Kinabalu/Malaysia	70-75	2005-2006	Prelim EPC to be awarded by end-year; All use Shell's proprietary technology.
Shell	Egypt	70-75	2006-2007	Will be side-by-side with grassroots LNG plant.
Shell	Tierra del Fuego/Argentina	70-75	2006-2007	Alternative plant to Bolivia.
Shell	Iran	70-75	By 2009	Will be side-by-side with grassroots LNG plant.
Shell	Bangladesh	70-75	By 2009-10?	With Petronas possible partner.
Shell	Indonesia	70-75	Post 2009-10?	Gas supply unclear
Shell	Trinidad	70-75	By 2010?	Few details released.
Sasol/Chevron	Escarvos/Nigeria (EGTL)	33	2005	JV firms formed; Uses flare gas. GTL plant based on extension of Escarvos gas gathering. Focus on diesel. Use Sasol proprietary syngas & Chevron proprietary isocracking technology.
Sasol/Chevron	W. Australia	30	2006-7	Site still to be set; Multiple choices on gas supply. Focus on diesel. Use Sasol proprietary syngas & Chevron proprietary isocracking technology.
Sasol/Chevron	Luanda/Angola	30-40	2008-10?	Parallel to Chevron (Texaco) grassroots LNG plant. Uses Sasol proprietary syngas & Chevron proprietary isocracking technology.
Sasol/Chevron	Point Fortin? /Trinidad	30-40	By 2010?	Based on Chevron (Texaco) gas holdings, preliminary study.
Sasol/Chevron	Mozambique	30-40	N/A	Proposal only.
Sasol/Chevron	Venezuela	30-40	N/A	Proposal only.
Sasol/Chevron	M. Saied/Qatar	34	2005	With QP, Phillips withdrew from project. Focus on diesel output. Uses Sasol proprietary syngas technology.
ExxonMobil	M. Saied/Qatar	80	By 2007?	Uses ExxonMobil's AGC-21 proprietary technology; Detailed feasibility study underway.
ExxonMobil/BP/Phillips	Alaska North Slope/USA	50	By 2007-8?	Uses ExxonMobil's AGC-21 proprietary technology; Syncrude will move via TAPS oil pipeline and syngas manufacture at Valdez.
Syntroleum/Enron	Burrup Peninsula/W. Australia	10	2003-4	Targets specialty output, mainly lubricants and paraffinic wax. FEED completed; gas supply contract signed. Major may enter project. BP, Enron, Kerr-McKee, Marathon, Texaco, Repsol, Ivanhoe Energy, Australian government also Syntroleum licensed.
Rentech/Total	Bolivia	20	2005-6	Total is touted as most likely gas partner, but others include BG, BP, and Repsol. Will use Rentech proprietary technology, also licensed to Pertamina. Will rise to 50 MBD in 2 <sup>nd</sup> phase at total cost of \$1 billion.

Despite the pitfalls, a wide number of companies, including most of the largest major companies, are now moving into the GTL business. The *breakpoint* for profitability for GTL investments is generally considered to be in the \$15-20/BBL oil price range, though Shell has claimed it could run a GTL plant on a crude price as low as \$14/BBL average. BP says it believes a minimum profitability threshold of \$20/BBL average is more realistic.

It should be noted that all GTL projects are also very sensitive to both the base cost of gas and the tax regime for capital costs. Many prospective host countries for GTL projects – such as Qatar – have been willing to ask a moderate price on gas feedstock for either LNG or GTL projects. If 8,500 CF of clean gas is needed for 1 barrel of product, the price of feedstock gas alone for GTLs would cost \$4.25/BBL at \$0.50/MM Btu and \$6.0/BLL at \$0.70/MM Btu. It should be noted that associated gas production could have a negative value, when companies pumping oil are forced to flare gas. The primary push behind GTL in Nigeria, for example, is the need to end gas flaring by 2007-2008. Chevron's Escravos gas development devotes phases 1& 2 (the latter only completed in 2001) to domestic and export gas pipeline sales, while a third development phase will supply a GTL plant and allow the major to boost crude production, without flaring gas.

Increasingly, in order to encourage GTL as an alternative to LNG exports, many host countries – and their state oil companies – are willing to give substantial tax breaks to get GTL projects up and running. For host countries, GTL has many advantages. GTL output reduces oil product import dependency in countries currently buying oil product from abroad; for oil exporters, it reserves crude oil and oil products for export sales. GTL plants will not only monetize stranded gas, but also produce large volumes of potable water, an attractive byproduct in the parched Mideast Gulf, but also in such places as Western Australia and Egypt. And heat from the GTL process can be used in power generation, with a number of projects planning power co-generation units within the GTL complex. Finally, in face of the current (and likely to expand) glut of methanol, GTL technology can be used to retrofit working methanol production capacity.

GTL profitability may get a boost when the E.C. and the U.S. move to an allowable sulfur percentage for diesel of less than 0.05%S, probably around 2006. Under present market

conditions, it seems unlikely that ultra-low sulfur GTL-based synthetic fuel products will be able to carry the 30-40% premium to regular refined product that promoters are counting on.

### ***Methanol***

Technology for conversion of natural gas into methanol has long been known, but few planners would consider this option commercially viable for the development of lonely gas. The world market is already suffering from a supply overhang that is likely to worsen as the U.S. and other countries begin to phase out of gasoline octane additive MTBE, a major market for methanol output.

An alternative conversion for natural gas is that of Methanol-to-Olefins (MTO), which would produce base chemical intermediates, such as ethylene and propylene. The technology already exists, though no commercial plant yet built is using it. The process has the advantage of low operating cost compared to a conventional ethylene cracker for olefins, but capital costs are high, probably discouraging commercial use of this technology in the near term. Mideast gas producers may be among those to first venture into MTO conversion. ExxonMobil, Lurgi and UOP/Norsk Hydro offer process technologies for MTO.

### ***Dimethyl Ether (DME) or Dimethoxymethane (DMM)***

While the Fischer-Tropsch process produces synthetic crude, which is then refined into synthetic oil products, oxygenate processes, using a natural gas feedstock, produce methanol, DME or DMM.

DME currently is produced in two steps – first gas is converted into methanol; then methanol is converted to DME. A similar process is used to create a similar product DMM. DME/DMM have certain advantages over LNG. They are stable fluid products, do not need intense cold, and can be transported, in smaller volumes, in LPG tankers. DME/DMM needs less specialized infrastructure for transportation, handling and storage than LNG and capital costs in building a DME/DMM plant are substantially less than LNG. DME/DMM is a very clean fuel and can be

used both in transport fuels and for power generation. DME/DMM can be blended into road diesel to produce a better quality, cleaner transport fuel. In power generation DME is as clean as regassified LNG and on a volume basis has a higher calorific value.

Then why hasn't DME/DMM supplemented LNG, if not replaced it? These liquefied forms of natural gas have two substantial drawbacks. Firstly, DME/DMM is expected to be fairly capital intensive. BP has been considering a \$350 million, 20-30 MBD plant, based on Mideast gas production, for exports to India as part of a \$1 billion JV with ONGC. That is a cost nearly on par with current GTL oil product technology. A second drawback, and perhaps more difficult to overcome, is that DME/DMM production involves a substantial loss of energy in its two-part conversion, of gas to methanol and methanol to DME/DMM, with up to 20% of gas loss in processing. In contrast, oil product GTL processes are far more efficient, and even with boil-off losses, LNG remains a more efficient gas transport option.

### ***Gas Hydrates***

Gas hydrates result from the physical entrapment of natural gas in an ice-like structure, with gas volumes reduced by 150 times (compared to more than 1,600 times for LNG). If a transportation system can be found to move this gas while still in the form of ice, it could be used in small markets and for short distance transport. Also, massive gas hydrate deposits are known to exist offshore across the globe and would represent a future source of unconventional gas reserves. BG is operating a pilot plant for gas hydrates with a capacity of 365 MT/year and sees hydrates as a complementary form of transport to LNG for distances of 2,000-3,000 KM.

### **Conclusion**

LNG facilities and transport costs have fallen dramatically as technology has improved. These lower costs have allowed LNG projects to lower costs and be competitive in a wider number of markets. As a result, the number of LNG players has grown exponentially and is likely to continue doing so. Contracts are becoming more flexible and duration is shortening.

LNG promoters hope to broaden the appeal of gas transport by ship from a relatively specialized trade that focused heavily on Asia Pacific's energy import-dependent economies such as Japan, South Korea and Taiwan to a global industry, balanced among a wide range of potential buyers located in South America, Europe, Asia and the U.S. New business models and marketing trends made possible by new technologies and falling costs will revolutionize the way LNG business is done in Asia and will have significant bearing on how natural gas is deployed in the region in the coming decade. Japanese buyers will increasingly re-examine how they do business in light of lowering costs and new financing methods while deregulation and sector liberalization will encourage players to seek to lower costs and shorten the span of contracts. Further development of LNG markets also allows countries to diversify the amount and types of energy they use and the geographic areas that they import from.

In the coming years, new natural gas technologies will emerge that may compete with LNG. But for the time being, cost factors will limit the role for these technologies, leaving a huge market growth potential for LNG.