Main Report

Asia has lagged behind other regions in utilizing natural gas despite its appeal as one of the cleaner readily available energy sources. Natural gas provided 10% of primary energy needs in Asia in 1999, which was substantially lower than the world average of 23%.

Key energy markets in Asia, such as Japan and South Korea, were isolated from major gas producing areas, requiring expensive conversion of natural gas into a liquid form, and regassification at the port of destination, so that it could be shipped in tankers as Liquefied Natural Gas (LNG). In the U.S. and, to a certain extent, Europe, plentiful regional natural gas supply can be transported more cost-effectively by pipeline. Liquefied natural gas (LNG) prices to Asian markets have generally averaged about 40% higher than Western prices where pipeline gas is sold under competitive terms.

In recent years, technical innovations have reduced the costs of LNG processing and shipping, allowing more LNG projects to achieve commercial viability. The result has been a proliferation of LNG sales in both Asian and Atlantic Basin markets.

LNG producers have captured substantial cost savings by using 3D seismic in exploration work and by deploying gas cleaning and gas liquids separation units on production platforms to enable the more efficient conversion of raw gas into suitable LNG feedstock. The development of down-hole separators in future wells will cut deepwater production costs and improve recovery rates.

In addition, there has been great progress in producing more economic LNG manufacturing, transportation and support infrastructure. Indeed, liquefaction and transportation costs have been reduced more than 30-40% over the last two decades, while regassification costs have fallen roughly 20%.

The main cost-cutting measures put into effect include improvements in the design efficiency of LNG plant, improvements in liquefaction technology, and improved economies of scale. Larger gas turbines have facilitated the improved scale economies. The improvements in liquefaction technology have included optimization of air and water-cooling, and a reduction in design redundancy. In addition, larger tankers and cargoes, coupled with expanded terminals to handle the bigger vessels, and enhanced tanker efficiencies have both lowered shipping costs substantially. Finally, new managerial practices have also played a role in reducing costs. The more significant changes have included changes in project management and contracting, new cost optimization strategies and innovative financing arrangements (see working paper by Troner).

The decline in costs for LNG and the general growth in LNG trade should allow natural gas to play an increasingly large role in meeting rising Asian energy demand. In addition, the end of the Cold War has created new natural gas pipeline opportunities in Northeast Asia. The higher priority many Asian governments now attach to environmental quality is likely to reinforce these developments. Several major natural gas pipeline projects have been proposed, and a series of large-scale LNG projects have been initiated. It is currently forecast that, despite the expected growth in end-user markets, the world's LNG supply capabilities will exceed demand until 2020 potentially stimulating lower prices.

Japan's IEEJ projects that LNG demand for Asia will rise by about 4 to 5% per annum to 105 to 112 MM tons/year by 2010 (see table). Industry estimates are higher at 108 to 138 MM tons/year (see working paper by Shook/Jaffe).

Already the largest importer of LNG in the world, accounting for 62% of global trade in LNG, Japan has targeted natural gas use to rise from roughly 13% of total energy supply currently to 20% by 2020. Japan's demand for natural gas for the power generation sector may rise further if the country cannot mobilize public support for the construction of 13 new nuclear energy plants. At present, there are no pipeline connections between Japan and gas producing areas, but a natural gas pipeline from Russia's Sakhalin Island fields is under consideration.

Asia Pacific LNG Demand in 2010
(MM tons/year)

Country	1999 (actual)	2010	Average Growth
Japan	51.30	64.00	2.0%
South Korea	12.97	22.00	4.9%
Taiwan	4.16	11.00	9.2%
India	0	5.00-10.00	
China	0	3.00-5.00	
Total	**68.43**	**105.00-112.00**	**4.0-4.6%**

Source: IEEJ

The Japanese government has long set a national priority of reducing dependence on foreign sources of crude oil while ensuring energy supplies remain stable and adequate to meet anticipated needs. Diversifying the country's energy sources was seen as a means to this end. In particular, nuclear energy has played a key role in providing Japan with a degree of energy security over the past four decades. It is the leading Asian country in nuclear capacity, operating 52 reactors that provide roughly 30% of the country's electricity needs.

Increased use of nuclear energy has allowed Japan to reduce oil use from 77% of its total primary energy mix to less than 55% in 2000. Nevertheless, Japan is now confronting an uncertain future in regard to expanding its nuclear energy capacity. A handful of accidents in the 1990s have undermined previously strong Japanese public confidence in nuclear power. Faced with mounting public opposition, the Japanese government in late 1999 reduced the number of new nuclear reactors expected to be built by 2010 from 20 to 13.

If the 13 additional nuclear facilities are not built, Japan could expect to face an annual shortfall of as much as 28 GWe of electricity, which will require turning to other energy sources. If the forgone capacity were replaced 100% by oil, the country would have to import as much as an extra 1.17 million b/d of crude. If the country resorted to 100% natural gas supplies to meet the shortfall in nuclear capacity, Japan would have to import an additional 186.648 million cubic meters a day (mcm/d). Replacing 30% of the planned nuclear capacity by oil and 70% by natural gas would require 350,000 b/d of imported crude oil and 130.653 mcm/d of natural gas.

Growth in town gas sales should also not be underestimated. The Japanese Gas Association notes that in 1999 while Japanese GNP rose only 0.5%, town gas rose 5.6% to 14 MM tons/year. The JGA projects that demand for town gas might rise to 22 to 24 MM tons/year by 2010.

The Case for Gas Expansion in Asia

It is anticipated that governments will intervene to promote the widespread utilization of natural gas in Asia to meet both environmental needs and supply requirements. Even in Japan, where energy consumption is not expected to increase substantially, emphasis will be placed on expanding natural gas use beyond levels that would result from market forces alone. Such a policy furthers primary policy goals of energy security, increased competition in the energy sector and environmental protection. In China, where the national energy strategy is currently based on coal, the construction of natural gas pipelines running across the country from east to west has already begun. It is considered a high priority in China's energy and economic development strategy.

It is increasingly clear that natural gas must play a greater role in Japan's energy mix. Natural gas and products derived from it are being closely examined in the country for the best possible commercial applications. Of these various options, LNG and pipeline gas remain the most practical options in the context of the existing infrastructure and other considerations such as cost and safety. However, the expected surplus in Asian gas supplies is spurring an interest in development of other supplemental technologies for utilizing this gas.

In all markets, petroleum fuels such as gasoline and light oil have dominated as the primary transportation fuels because of their high ratio of energy content to weight and the convenience of handling, storing and transporting fuel that can be kept liquid at ordinary temperatures. A reduction in the costs of converting natural gas into a product that remains liquid at ordinary temperatures would substantially increase the use of gas in transportation. Since 70% of the increase in international oil use is expected to come from the transportation sector over the next decade, the ability to utilize plentiful natural gas supplies in transportation fuels would greatly contribute to enhanced energy security.

Moreover, regulations on automotive exhaust gas emissions are steadily being tightened, and costs on petroleum fuels for responding to this situation are steadily rising. Liquid fuels derived from natural gas have a competitive edge in this regard in so far as they do not contain sulfur or aromatic hydrocarbons. They are also a beneficial option for Asia's developing countries where environmental degradation is a concern as they prepare themselves for full-scale industrialization and motorization (see PEC working paper).

Governments have been exploring the use of natural gas as a raw material to produce liquid fuels. If liquid fuels derived from natural gas can become competitive, they would offer a promising option that could help curb the heavy dependency that Asian countries have on Middle East crude oil, providing both security of supply and a variety of energy sources.

In the Asian region, oil imports from the Middle East more than doubled from 1987 to 1999. Unless alternative energy sources are developed, oil demand in Asia is again expected to almost double from 17.58 million barrels a day (b/d) in 1996 to 34.99 million b/d in 2020. Of this, the increase in the middle distillates such as light oil is expected to be 6.26 million b/d. This boost is significantly larger than an expected increase in fuel oil of 2.41 million b/d. Although liquid fuels produced from natural gas could compete against oil imports in Asia, they require an enormous initial investment in facilities using large amounts of hydrogen (see PEC working paper).

Oil refineries in Asia's developing regions are mainly toppers, and such regions are lagging behind in introducing secondary devices such as hydro-cracking units that are used to maximize middle distillate production. Thus, additional investments will be required anyway to meet the rapid expansion of demand for middle distillates. This has raised the interest in developing middle distillate fuels or substitutes originating from natural gas.

Competing With LNG and Pipeline Gas: Other Gas Conversion Technologies

Several technologies could allow liquid fuels based on natural gas to substitute for oil-derived fuels. In addition, there are other means to utilize natural gas fuels beyond pipeline and LNG. They include GTL, Methanol, DME, LPG and Gas hydrates. Each is discussed briefly below.

GTL

The use of gas-to-liquids (GTL) technology has been dictated by severe necessity in the past, including in Nazi Germany at the end of World War II and in South Africa during the years of its economic embargo. GTL fuel is liquid hydrocarbon fuel at room temperature and can be used, in principle, to replace a variety of petroleum products. Natural gas with low sulfur content is used as the raw material for producing GTL fuel, allowing the final product to contain little or no sulfur, nitrogen, aromatic compounds or heavy metals.

Because of its properties, GTL fuel is best suited for substituting middle distillates such as diesel, oil kerosene and jet fuel. The most promising application of GTL is in automobiles, particularly in diesel-engine cars. The Fischer-Tropsch (FT) process, which is at the core of the technology for manufacture of GTL fuel, was commercialized by South Africa's Sasol in 1955. Royal Dutch/Shell and Exxon Mobil Corp. subsequently developed GTL fuel and most of the major oil companies are now moving into the GTL business with plans for commercial-sized projects (see working paper by Troner).

Tests on the use of GTL fuel in diesel engines have been conducted both inside and outside of Japan and show that there are few technological problems with using pure GTL or a GTL mix with diesel fuel. Because GTL fuel emits only a small amount of smoke, an engine's performance can be improved through a higher maximum load. The emission gas from a diesel engine powered by GTL fuel contains less hydrocarbons, CO2, NO_X and particulate matter compared with currently used diesel oil (see PEC working paper).

Because GTL fuel can be mixed with existing petroleum products, there is no need to build dedicated distribution infrastructure. For that reason, if the economic viability for developing

GTL fuel could be established, it could be introduced relatively quickly. The biggest incentive for pursuing GTL fuel is the need to reduce the sulfur content of diesel oil to meet U.S. and E.U. air quality regulations. The schedule for the reduction of sulfur in diesel oil is being accelerated, making the full-scale introduction of GTL likely to occur sooner than had been expected (see PEC working paper).

As jet fuel produced from GTL contains practically no aromatic content, it is highly combustible, and can quickly start engines, with very little danger of blowout. GTL kerosene is paraffin-based and does not contain aromatic content, which produces a large amount of fumes, so incomplete combustion is unlikely (see PEC working paper).

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. Known projects are listed in the following table.

Proposed Commercial GTL Plants

Company	Site/Country	Capacity (MBD)	Startup	Notes
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 synfuel & 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 synfuel & Chevron proprietary isocracking technology.
Sasol/Chevron	Luanda/Angola	30-40	2008-10?	Parallel to Chevron (Texaco) grassroots LNG plant. Uses Sasol proprietary synfuel & 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 synfuel 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 synfuel 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 2nd phase at total cost of $1 billion.

Source: "Global LNG: New Models, New Options", to be published in November 2001, by Asia Pacific Consulting and the Institute of Gas Technology

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 (see working paper by Troner).

Despite the pitfalls, a wide number of companies, including most of the largest major companies, are now moving into the GTL business. The break-even point 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. If 8,500 CF of clean gas were 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. 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. Gas production can have a negative cost when companies pumping oil are forced to flare associated 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 (see working paper by Troner).

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 establish GTL projects. 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 expanded) glut of methanol, GTL technology can be used to retrofit working methanol production capacity (see working paper by Troner).

DME

Dimethyl ether (DME) is produced through oxygenation processes using a natural gas feedstock, whereby gas is first converted into methanol and then the methanol is converted into DME. DME and a similarly produced liquefied natural gas form, dimethoxymethane (DMM), are stable fluid products that do not need intense cold temperatures and can be transported in smaller volumes on LPG tankers. DME or DMM require less specialized infrastructure for transportation, handling and storage than LNG and the capital costs involved in building DME or DMM manufacturing plants are substantially less. Both are clean fuels that can be used in transport fuels and for power generation, with DME/DMM able to be blended into road diesel to generate a higher-quality, cleaner transport fuel. DME and DMM have properties similar to propane and butane and therefore can be used in existing infrastructure when mixed with these products.

DME is already commercially produced. Like other natural gas conversion technologies, start up costs for DME/DMM manufacturing are 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. A second drawback that is perhaps more difficult to overcome is that DME/DMM production involves a substantial loss of energy because of its two-part conversion of gas to methanol and methanol to DME/DMM. Up to 20% of the energy content of the gas is lost in processing. In contrast, GTL processes and even LNG transport are far more efficient (see working paper by Troner).

In Japan, several issues apart from costs have retarded the development of DME as a viable alternative to LPG for household or other uses. One involves the regulatory restrictions. The High Pressure Gas Safety Law and the General High Pressure Gas Safety Regulations currently govern the handling of DME in Japan. The Liquefied Petroleum Gas Law and the Liquefied Petroleum Gas Safety Regulations, which are less stringent than the laws governing DME usage, govern the use of LPG. DME regulations require greater distances between the surrounding buildings and the facilities for handling the fuel. For DME to make headway as an alternative energy source in Japan, the product will have to be regulated by the Liquefied Petroleum Gas Safety Regulations or new laws and regulations will have to be established separately for DME (see PEC working paper). In addition, the ability to use the existing infrastructure for distributing oil-based products makes GTL a favored alternative to LNG.

Methanol

Although technology for producing methanol from natural gas has been under study for some time, the prospects for its commercial viability are slim. The methanol-to-olefins (MTO) alternative converts natural gas to products such as ethylene and propylene. This technology already exists and has the advantage of low operating costs compared to a conventional ethylene cracker for olefins. High capital costs are likely, however, to prevent its commercial use in the near term.

Hydrogen can be extracted from methanol at a reforming temperature of around 300 degrees Celsius, making it usable in fuel-cell cars. Driving tests are being conducted for putting it into actual use. However, if direct synthesis of DME is developed, methanol is expected to be inferior to DME in terms of price as plant costs and energy conversion costs are 15% higher (see PEC working paper).

LPG

Liquefied petroleum gas (LPG) is a fuel that is indispensable for consumer use in rural areas of Asia and certain parts of Japan because the product can be supplied to areas with rudimentary infrastructure. LPG prices are, however, subject to large fluctuations because of the large share of production arising from Middle East suppliers. While LPG will remain an important import for the Asian market in coming years, circumstances are dictating that the region pursues alternatives. Asia accounts for about 60% of world LPG trade, with 82% of LPG supply from Middle East producers dedicated to Japan and other Asian countries. The growth rate in demand for LPG in Japan is only 0.5% per annum. Elsewhere in Asia, it averages 11.1% per annum. The future of LPG exports into the region is likely to be precarious, however, because certain Middle East producers such as Saudi Arabia are planning to use LPG at home as a raw material for petrochemical development, curbing volumes available for export to Asia (see PEC working paper).

Gas Hydrates

Gas hydrates are the result of the physical entrapment of gas in an ice-like structure, with the gas volumes reduced by 150 times compared to more than 1,600 times for LNG. A transportation system to move the gas while still in its ice form would allow this energy source to be exploited. This is likely to be practical only for markets located a short-distance from deposits. Giant gas hydrate deposits are said to exist offshore around the world and could represent a future avenue for unconventional gas reserves.

Natural Gas Supplies from the Sakhalin Islands: LNG, Pipeline or Both?

Regardless of any long term potential of new natural gas technologies, the primary focus of enhanced natural gas utilization in Japan in the coming years is likely to be either LNG or pipeline gas. Each offers certain advantages.

The substantial reserves of natural gas from the Sakhalin Islands provide a new, relatively close source of energy for Japan and for the first time, offer Japan the option to import natural gas by pipeline. The gas reserves of the Russian Far East are substantial. Proven and probable reserves (2P) are estimated at 50 to 65 trillion cubic feet and the proven, probable and possible reserves (3P) at as high as 847 trillion cubic feet.

The Sakhalin region is about 1,000 kilometers from Hokkaido in northern Japan and 2,200 kilometers from Tokyo. Rule of thumb analyses suggest that, given the distances involved, the costs of the two options for transporting Sakhalin natural gas to Japan are likely to be relatively similar. It may not be possible to resolve a substantial part of this uncertainty until construction (see working paper by Brito/Hartley). Given the possibility that the difference in cost between the two transport options might be small, the question of alternatives may not be one of pure economics, but rather one of political economy.

LNG supplies offer Japan certain advantages. One major advantage of the LNG alternative is that it may entail more supply flexibility and less risk of disruption.

Worldwide, a potential surplus of possible LNG projects currently exists. This means that a supply overhang could remain a typical feature of LNG markets in the coming years (see Appendix for the list of projects). Japan is unlikely to have to compete with U.S. buyers for limited LNG supplies. Rather, buyers could have many alternative exporters to choose from and will be able to maintain a diversified slate of suppliers. Only in the case of prolonged depressed prices might a widespread cancellation of projects limit new supply (see working paper by Shook/Jaffe).

U.S. demand, at 28 to 32 Tcf by 2010, is likely to exceed substantially domestic sources of natural gas of about 20-22 Tcf. Canada's shipments to the U.S. are expected to grow over the decade to 1.6 to 2 Tcf (4.5 to 5 Bcf/d), up from 3.5 Bcf/d currently while Alaska pipelines could provide as much as 1.5 Tcf (4 Bcf/d) and possibly an additional 0.75 Tcf (2 Bcf/d) from the Canadian Northwest. Thus, North American continental supply could be as high as 24.85 Tcf to 26.25 Tcf.

In a low demand/high supply growth scenario, where coal shaves close to 2 Tcf from natural gas demand growth and pipeline projects from Canada and Alaska proceed as planned, U.S. natural gas demand could almost be met without resorting to LNG supply. However, even in this most extreme scenario, it remains to be seen whether U.S. buyers would shun LNG as a marginal supply. Several short-haul LNG projects might have lower costs than some domestically drilled gas or Canadian supplies (see working paper by Shook/Jaffe).

If North American continental supplies attain the upper forecasts of 25 to 26 Tcf, even a robust growth in U.S. natural gas demand would require no more than around 120-140 millions tons a year (6-7 Tcf) of gas imports into the U.S. market. This would leave plenty of gas from the Middle East and elsewhere looking for a market in Europe or Asia-Pacific (see appendix for list of possible suppliers). The working paper by Shook/Jaffe contains a more detailed discussion of the U.S. natural gas supply demand balance.

PIRA Energy Group of New York projects in a new study on Atlantic Basin LNG markets that expanding LNG supplies to the Atlantic Basin could reach 90 MM tons/year in 2005, of which almost 80 MM tons/year is fairly committed under contract and 5 MM tons/year of capacity (about 6%) remains unsold. This compares with 60 MM tons/year in 2000 from Algeria, Libya, Trinidad, Nigeria, Abu Dhabi, Qatar, and Oman, of which 44 MM tons/year was committed under contract and 15 MM tons/year of export capacity unsold. By 2010, PIRA projects supply will expand to 132 MM tons/year with 20 MM tons/year still to be sold, or roughly 17%. PIRA estimates that 32 MM tons/year are still searching for buyers past 2015 or about 25% of potential supplies to the Atlantic Basin.

Interestingly, the possibility of a surplus of LNG in Asia as well as in the Atlantic Basin could leave Middle East producers as swing suppliers, delivering to East or West as demand trends require (see appendix for list of projects). CMS Energy, for example, has purchased short-term cargoes from Abu Dhabi, Oman, and Qatar for delivery to the U.S. market. Also, at the end of 2000, Enron signed a short-term contract with Oman LNG for 6 cargoes of 40,000 MTA each for 2001, most of which is expected to come to the Lake Charles, Louisiana, terminal. Some Pacific supplies could also serve to balance regional demand swings as several LNG projects are targeting both Asian buyers and the U.S. West coast. Shell, for example, is expected to market its contracted volumes from Australia's North West Shelf to the U.S. West Coast. Enron also asked for flexible terms in its now terminated contract with Malaysia LNG Tiga that would allow it to resell cargoes under special circumstances (see working paper by Shook/Jaffe).

Greater interactions between swing suppliers to both markets will likely cause prices to converge over time. This could be good news for Asian buyers who paid roughly $4.50–$5.00 per million Btu in July 2001 for LNG supplies from the Middle East, Malaysia, Indonesia and Australia compared to a U.S. Gulf coast natural gas price of $3.06 million Btu in July and $2.97 in August and a U.S. West Coast price of $4.61 in July and $3.26 in August (see appendix).

A global LNG market could use the New York Mercantile Exchange (NYMEX) as its primary pricing point, with other trading centers emerging at Zeebruge in Belgium, Tokyo, and other locations, all indexed off New York. This would operate in much the same way as oil markets, with West Texas Intermediate, Brent Blend, and Dubai serving as benchmarks. A linked price relationship with U.S. spot natural gas prices on the NYMEX would afford even small Japanese buyers a greater opportunity to hedge transactions through futures and derivatives markets, potentially promoting wider use of natural gas as energy market deregulation progresses (see working paper by Shook/Jaffe).

Changes in the way LNG markets will develop over time could reduce the attractiveness to Japan of firmly committing to buy pipeline gas from Sakhalin. In the future, the LNG market may become more like the oil market of today, in which substantial sales and purchases are made on the spot market, and firms invest in infrastructure without first arranging long-term contracts with specific trading partners.

The recent drop in the cost of transporting LNG makes it easier for LNG suppliers to find a suitable trading partner. As the expected time required finding a good trading partner decreases, the present value cost of delaying the receipt of revenue until a match is found declines. This tends to favor the option of investing in infrastructure before searching for, and arranging a long-term contract with, a committed buyer or seller (see working paper by Brito/Hartley).

Other recent changes have reduced the disadvantages of investing before searching by lowering infrastructure investment costs. Moreover, the market for natural gas is expanding rapidly, not least because more stringent air pollution requirements have favored natural gas, as it is a relatively clean fuel. The increased natural gas demand has expanded the depth and geographical extent of the market for LNG producers. Expanded market alternatives reduce the risk to any one producer or customer of investing in infrastructure without having secured long-term contracts for selling or buying LNG.

A tendency for firms to invest in infrastructure before arranging long-term bilateral contracts could feed on itself. If some new firms begin to invest before searching for partners, other entrants also find it beneficial to invest first too, so they can take advantage of searching in a more liquid market. Over time, then, entrants will abandon the relatively illiquid long-term bilateral contract market as happened in oil markets in the 1980s (for a formal model showing how such a change in market structure might evolve, see the working paper by Brito/Hartley). This possibility of radical change in the LNG market favors exploiting the Sakhalin gas deposits in the form of LNG to optimize Japan's flexibility to take advantage of new market opportunities in global LNG trade.

The appeal of LNG notwithstanding, pipeline supply also has certain advantages. Pipelines can be installed under land, limiting environmental objections. Pipelines also are less vulnerable to attack or sabotage since the infrastructure is spread over a large area and only a small portion can be destroyed at a time. By contrast, an LNG terminal concentrates the infrastructure in one place where the damage would be much more extensive and more costly to repair. The likely greater extent of the damage would also mean that repairs would take longer for an LNG terminal. Repair of pipeline sections can often be organized in a matter of weeks or months while reconstruction of an LNG receiving terminal, depending on the level of damage, might take more than a year (see working paper by Soligo).

The second issue concerns insurance against price increases in the event of a sudden supply interruption. A reliance upon LNG purchased on a spot market implies that Japanese consumers would have to outbid rival buyers for remaining uncommitted LNG supplies during such an event. A pipeline from Sakhalin, by contrast, would be dedicated to the Japanese market and the gas it carries could not be bid away by other consumers. Of course, the opposite also applies in the case of a sudden supply surplus. While consumers buying on a spot market could take advantage of the resulting price declines, consumers tied to a long-term contract would end up paying more for their gas. In addition, if options and futures markets for natural gas expand, and LNG and pipeline gas prices become better linked, financial contracts are likely to provide a better hedge against unanticipated price fluctuations than could be obtained with long-term bilateral contracts.

Of course, a pipeline tying Japan to Russia may give the latter country undue leverage over Japan in the event of a dispute between the two countries. A diverse range of LNG suppliers reduces the political leeway for the Russian government as gas could be obtained from many other sources in such an eventuality. On the other hand, a cut-off of pipeline gas deliveries would hurt Russia as well as Japan, lowering the chances of such an eventuality. The existence of a pipeline also ties Russia's interests more closely to those of Japan. This in itself is of some value from a political and strategic point of view (see working paper by Soligo).

The significance of the debate over pipeline gas versus LNG might be overstated, however, given the volumes involved relative to total Japanese gas use and overall energy supply. Exxon Neftegas, operator of the consortium developing the pipeline proposal, estimates that the pipeline would deliver about 6 million tons of natural gas per year, beginning at the earliest in 2006, out of a total forecast level of Japanese gas imports of 75 million tons per year by 2010. Currently, gas accounts for roughly 13% of total energy supply in Japan. Even if plans to raise that share to 20% by 2020 materialize, it is clear that Sakhalin pipeline gas will account for less than 2% of Japan's energy use by 2020.

In addition, the "security" dimension of the LNG versus pipeline debate should involve a determination of where the most likely risks are. A disruption in the Middle East is a much more likely event than a Russian cut-off of gas deliveries. Indeed, Western Europe has been importing large quantities of gas from Russia for some time without interruption. A pipeline from Sakhalin ties that gas to Japan, regardless of events in the Middle East. Security of supply, therefore, might be best achieved by using both pipeline and LNG technologies.

Finally, as a spot market in LNG develops, the prices of spot LNG delivered to Japan will depend on tanker rates that have exhibited considerable volatility. Currently, LNG is typically delivered in vessels owned by either producers or buyers, and transport prices are determined as part of a long-term contract. Unlike fluctuations in natural gas prices, variations in shipping costs are much more difficult to hedge in organized financial markets. An advantage of pipelines is that the transport costs are determined once the line is built and are unlikely to vary much over the life on the pipeline (see working paper by Soligo). This advantage need not, however, accrue to consumers. If pipeline gas is not under long-term contract, the price of pipeline gas would likely be set equal to the cost of imported LNG implying that the pipeline owner would capture any rents associated with an increase in the costs of shipping LNG. Furthermore, third parties are increasingly buying transport vessels to be used in the growing spot market. A greater market depth would tend to reduce volatility in shipping rates.

There are several arguments for developing a pipeline network within Japan. First, a domestic pipeline network will provide flexibility, which is of some benefit in the event that a terminal is suddenly shut down. Thus, a domestic pipeline network could provide an opportunity for gas providers to hedge against different risks. Second, developing domestic transportation pipelines will create a unified natural gas market (including pipeline gas and LNG) and would become a factor in increasing competition. Whereas pipelines create a unified market, LNG terminals tend to create a fragmented market. The greater competition in a unified national market is likely to produce lower prices on average. Furthermore, pipeline gas can be quickly delivered in continuous increments from one geographical market to another, balancing short-term gaps between supply and demand. The ability to arbitrage price differentials implies that price fluctuations also will tend to be smaller in a pipeline network (see PEC summary paper). De Vany and Walls (1995) point out that an important factor in the development of a well-functioning gas market in the U.S. was:

> The wide participation of buyers and sellers in many markets that are interlinked throughout the pipeline network (that) gives the market a high degree of liquidity and graceful adaptability to shocks (De Vany and Walls p. 4).

In addition, they point out that:

> One important factor in this evolution was the emergence of "market centers" for gas and transportation trading at places where pipelines intersect or pass so close to one another that a short link is all that is needed to connect them. These centers connect the network and make possible the flexible routing of gas that allows shippers to contest many markets from any supply point. Another crucial factor was the attainment of a connection structure that opened enough paths in the network to arbitrage to force a transition of the segmented special markets to an integrated natural gas market (De Vany and Walls, p. 10).

Pipelines also can economize on storage since no one market needs to maintain as much storage. Deliveries by tanker are large discrete events whereas pipeline gas is continuous. Each LNG terminal must have enough storage to meet demand until the next LNG tanker arrives. A tanker will not be diverted from one terminal to another unless the new market can absorb the whole load since it is costly for a tanker to make several stops. Finally, a domestic gas grid will provide wider access to potential users and hence, a more diversified customer base. It will expand the use of gas in the overall energy mix within Japan (see working paper by Soligo).

The construction of a trunk pipeline for imported natural gas could facilitate the development of a domestic gas pipeline network. Along a trunk pipeline, large-volume end-users could purchase gas directly at lower wholesale prices. In addition, areas where city gas networks are not currently available (areas using LPG) could see an increase in businesses using natural gas as a raw material. With a reduction in retail prices, distributed power sources such as gas cogeneration may spread, promoting competition with petroleum products in producing electric power. The resulting increase in natural gas demand will promote competition with other fuels (see PEC summary paper).

Japan has a long way to go before it has a pipeline network that compares to the U.S. market. Therefore, it also has a long way to go before its energy markets will be as competitive or sophisticated as those of the U.S. Still, some of the advantages of pipelines can be gained while Japan continues to maintain substantial LNG supplies and their relative advantages, arguing for a diversified policy that makes room for both alternatives.

Electricity Trade: A Third Alternative For Sakhalin Gas

Instead of transporting gas from Sakhalin to Honshu, Sakhalin gas could be used in Hokkaido to generate electricity, which could then be transported south by wire to the main demand centers. Such a plan would obviate the expense of constructing liquefaction and gasification plants for LNG or extended long distance gas pipelines.

To allow the existing transmission system to carry additional power from the north, the capacity of the AC electricity lines in Hokkaido and northern Honshu would need to be upgraded as well as the existing undersea DC line link between the two islands. An alternative would be to build an HVDC line from northern Hokkaido to the vicinity of the pumped storage facilities and the Shin-Shinano link between the Tokyo and Chubu utility areas. The investment costs for the second option are likely to be lower while operating costs, in the form of transmission losses, would also be lower on optimized DC lines than on optimized AC lines of the same power capacity. The tradeoffs between losses and capital costs will ultimately depend on factors specific to individual project specifications, including the cost of right of ways. For systems designed to transfer 2,000 MW of power, however, the losses in the HVDC system will be lower for distances above 200 kilometers (see working paper by Brito/Hartley).

An added advantage to an HVDC scheme to carry electricity from the north is that a parallel HVDC north-south link from Hokkaido to Tokyo would improve stability and controllability of the existing Japanese AC system. The line could also be constructed in a fashion that enhances the transfer capability between Japan's 50Hz and 60Hz power regions. An increased ability to trade electricity will yield substantial cost savings and enhance competition in Japan's electricity sector. An HVDC link from Hokkaido could dramatically expand the amount of power exchanged between the two frequency regions, allowing greater market competition across the country (see working paper by Brito/Hartley).

Besides cost issues, reduced air pollution near population centers may be another substantial benefit of generating electricity in a relatively unpopulated region and transporting the electricity to the major population centers via HVDC. Establishing a new HVDC link could, however, be more disruptive to existing power generation businesses than increased shipments of natural gas. Moreover, electricity shipments would not allow as diverse a use of the Sakhalin natural gas, which if shipped directly to mainland Japan could be used for fueling industry and households as well as electricity generation.

Regulatory Issues

Japan's current Gas Law has been designed effectively to cover the conditions of the present domestic market. Recent regulatory changes have introduced some element of competition. For example, the introduction of a revised Gas Utility Industry Law in 1995 allowed new entrants to be guaranteed third party access to pipelines owned by gas majors Tokyo Gas, Osaka Gas and Toho Gas. However, government advocacy has not succeeded in producing new linkages between the Tokyo gas areas and Osaka gas areas to create a master system. A 1999 gas marketing law allowed non-gas utilities to sell to the largest retail consumers buying a minimum of 1 million cubic meters a year. Moreover, the major gas pipeline holders were required to establish non-discriminatory carrying rates.

Japan’s Ministry of Economics, Trade and Industry (METI) is considering open gas sales to any company, in any volume, by 2003. In addition, regulations are still needed to enforce third party access to LNG receiving terminals. An omnibus deregulation bill that would require oil, gas and power companies to open their storage, pipeline and other infrastructure to third party access has been discussed. At present, Japan’s Gas Law does not address key issues such as access to infrastructure, that would need to be addressed should an import pipeline and transnational transportation system be constructed. Therefore, with respect to establishing a more comprehensive gas market policy for the future, laws and enabling legislation must be implemented to facilitate the evolution of competitive gas markets (see working paper by Soligo).

The Challenge of Existing Natural Gas Contract Terms

Japan's existing natural gas business is based mainly on traditional take or pay, high priced contracts that were negotiated many years ago when LNG markets were less flexible than they are today. These contracts could be an impediment to rapid price decontrol since new entrants will be able to obtain supplies (as have the Koreans) on much better terms than the established firms. The established firms may thus become a vested interest opposing reform. We can think of these contracts as equivalent to the stranded costs that have been an important factor in determining the pace of electricity deregulation in the United States. Alternatively, if new entrants retain a relatively small market share, they are likely to obtain profits far above their fixed costs, reducing the benefits of competition for consumers (see working paper by Soligo).

Since existing LNG contracts will continue to serve as the foundations for Japan's gas supply, even with the introduction of pipeline gas, open access to gas terminals may have to be phased in to allow gas and power companies to recover the costs of these contracts. Alternatively, access to terminals can be made available to new entrants immediately, but at rates which allow terminal owners to recover sunk costs. If excess capacity at gas receiving terminals remains limited, then the process of moving to a deregulated regime would have to await investments in further terminal capacity. A national pipeline network can serve to alleviate any shortage of excess terminal capacity that might exist in a particular region.

Companies may be averse to spending several billion dollars to construct a pipeline if they can be forced to turn over its capacity to competitors under open access rules. At times when the producer could expect to make higher returns, it may be forced to carry gas at regulated prices. In order to reduce risks and facilitate the financing of a pipeline, therefore, Sakhalin pipeline gas will most likely have to be given preferential access to any new pipeline grid (Troner, 2001). An open access rule can be introduced gradually as the domestic pipeline network matures. Where spare capacity is available, it should be offered to third parties on a non-discriminatory, first-come, first-serve basis, subject to issues of credit-worthiness, timing of commercial operations and other genuine commercial and/or operational considerations (see working paper by Soligo).

An active secondary market for surplus capacity, gas trading and other "energy services" will naturally develop if enabling legislation clearly supports the basic principles of commercial negotiations. If there is demand for short-term or seasonal sales and services, then competition can ensure that market demand is met without legislation mandating a certain percentage of sales and/or capacity be reserved for short-term commerce.

Policy Recommendations and Conclusions

Japan's energy security and environmental goals can be enhanced through greater utilization of natural gas in Japan's energy mix. At present, LNG and pipeline gas remain the most practical options to utilize more natural gas inside Japan given the advantages of existing infrastructure and other considerations such as cost and safety. A combination of LNG and pipeline gas imports would allow Japan certain advantages. Such a combination would enhance natural gas trade in smaller volume increments, increasing the number of sectors that might use natural gas. It would also increase competition and likely lower costs without jeopardizing supply stability and security. In addition, in so far as the resulting technologies provide non-appropriable benefits, government should increase support for research in emerging natural gas technologies. In any event, it should consider regulatory changes that could accelerate the development of other supplemental technologies for utilizing gas such as GTL technology and DME. More generally, energy-related laws should be reviewed and adjusted to allow for the flexibility to easily adapt to technological advances and changes in international standards.

In order to facilitate the augmentation of gas markets, changes to Japan's existing Gas Law are needed. The preparation of new laws, regulations, and procedures should not be allowed to impede the efficient introduction of new fuels and the expansion of natural gas pipelines.

In order to prevent unreasonable construction costs, obstacles to the development of high-pressure pipelines need to be removed from the existing laws and regulations. Industry regulations need to be adjusted to allow electric power and oil companies, through increased price competition, to select natural gas as a fuel and develop a comprehensive energy business.

The introduction of new fuels such as GTL and DME, and the construction of international pipelines were not considered in the formation of existing laws, regulations, and procedures. An effort to adapt these products and the building of pipelines to existing laws, regulations, and procedures, will likely result in a good deal of confusion and many delays. Thus, adjustments to these laws, regulations, and procedures should be made quickly to enhance the introduction of new fuels and facilities. The introduction of new fuels and facilities will increase the options for utilizing natural gas in Japan, contribute to establishing competitive natural gas prices and enhance the goal of environmental conservation. Obstacles to the introduction of new fuels and facilities resulting from excessive and outdated regulation should thus be eliminated. Promotion of a competitive market structure through regulatory and legal reform could stimulate private investors to create new opportunities for natural gas supply.

Some basic principles around which new legislation should be centered are as follows:

1. Stability of fiscal and legal frameworks: Major capital and ongoing investments will be based on the fiscal regimes in force and the expectations of the investors that existing contracts will be honored and remain in effect for their full life. Continued stability of fiscal and legal frameworks, clarity and consistency of interpretation and avoiding retroactive changes, are important to develop investor confidence. Such confidence is built up over time and is necessary to ensure that the large, up-front capital investments required for new gas infrastructure projects will be made.

2. Administration of laws and regulations in a non-discriminatory manner: All market players, including new entrants into a liberalized market, should compete under impartial and predictable rules. If not, incentives to make future investments may be adversely affected. For example, if existing firms are forced to give new entrants access to infrastructure at a price that does not yield a competitive rate of return, there will be little incentive to make

further investment in infrastructure. Market transparency and agreed network codes can facilitate competition.

3. Reducing obstacles to building, owning and operating gas infrastructure: Low barriers to entry by new firms are essential to maintaining competition. Any companies wishing to build, own and/or operate gas infrastructure should be allowed to do so provided safety and environmental safeguards are satisfied. Regulations regarding such safeguards, and processes for granting building permits and so forth, should be implemented and maintained in a non-discriminatory manner. Eminent domain laws are needed to facilitate pipeline investments. Environmental protection regarding new pipeline right-of-ways needs to be balanced with national security of supply considerations. There is a need to consolidate, or at least co-ordinate, the permitting process to reduce the delays and obstacles imposed by separate administrative departments.

4. Sanctity of contracts: Contracts have traditionally been designed to cover market needs over a period and therefore reflect a balance of risk and reward. These contracts must be respected.

5. Freedom to negotiate commercial arrangements and structures: Negotiations between producers, transporters and consumers should be conducted on a commercial basis.

6. Market based, non-subsidized commodity pricing: All prices, both natural gas as well as its competitive fuel alternatives, need to be market based and transparent such that inter-fuel and gas-to-gas competition will establish the most competitive delivered price to the end-user.

7. Regulatory oversight: While a general regulatory policy of minimal oversight is desirable, it is recognized that there may be a need for regulatory intervention in certain instances. In markets where competition is absent or inadequate, regulation may be needed to protect consumers from price gauging, speculative gaming of the system that results in unnecessary rate hikes, or to ensure reliability of supply etc (World Bank, 2001). Investors will prefer that laws be enforced by a clearly autonomous entity that is free of government influence or

intimidation. This does not necessarily imply the establishment of an independent regulator. Indeed, Japan has rejected the idea of setting up an independent regulatory body such as the Federal Energy Regulatory Commission (FERC) as in the U.S. Other countries have used a Competition Authority rather than a Gas Regulatory Agency to oversee the operation of their gas systems. In either case, it is essential that the regulatory process be transparent to all industry players. Rate methodologies for services like terminal charges, transportation and storage, need to be published in order to ensure non-discriminatory practices. Lastly, consistent oversight needs to be given to the entire gas value chain by a single authority, which has jurisdiction over the Upstream (production), Midstream (transportation and storage) and Downstream (end use). This authority needs to be at the National (Federal) level whose decisions supersede those of regional agencies.

APPENDIX

NEW LNG TRAINS

Project	Size (MM tons/year)	Startup
Abu Dhabi	2.0-3.8	2010 or beyond
Alaska LNG	7.7	2010
Angola	4.3	2005-06
Australia - Gorgon	8.0	2005-06
Australia - Greater Sunrise	4.8	2005-06
Australian – North West Shelf	4.2	2004-2005
Bolivia	7.7	2006
Brunei	3.0-4.0	2008
Egypt – BG	3.0	2004
Egypt - BP	7.7	2005
Egypt – Shell	4.0	2004
Egypt - Union Fenosa	3.0	2005
Equatorial Guinea	4.0	2008
Indonesia Tangguh	8.0	2005-2006
Iran (BP)	10.0	2008-2009
Iran (Shell)	7.0-8.0	Under study
Iran (TotalFinaElf)	7.0-8.0	Under study
Nigeria - Bonny 3	3.0	2005
Nigeria - Bonny 4&5	8.5	2007-08
Nigeria II	4.7	2007-08
Nigeria III	5.0	2008
Norway - Snohvit	4.0	2006
Oman	3.3	2004-2005
Peru - Camisea	4.3	2005-06
Qatar –Qatargas	3.1-4.0	2004
Qatar. - RasGas	5	2004
Sakhalin II	9.6	2006
Timor Sea – Bayu Undan	5.8	2005-06
Trinidad 2&3	6.0	2004-05
Trinidad 4	5.5	2006-07
Venezuela Jose	2.0	2005
Venezuela Paria	4.3	2006
Yemen	6.2	2004-2005
TOTAL	**175.7-181.4**	

(Source: Industry, EIG World Gas Intelligence, Asia Pacific Consulting

COMPARATIVE LNG PRICES

(JULY 2001)

Buyer	Seller	Price
Japan	Abu Dhabi	$2.50
Japan	Australia	$4.51
Japan	Indonesia	$5.05
Japan	Malaysia	$4.45
Japan	Oman	$4.57
Japan	Qatar	$4.52
Japan	Average	$4.66
South Korea	Various	$4.81 (June)
U.S. Spot Market Trunkline Louisiana	Various	$3.06
California	Pipeline	$4.61

Source: EIG's World Gas Intelligence