

PUBLIC POLICY FOR THE

# Private sector

Note No. 182

April 1999

## Trends and Markets in Liquefied Natural Gas

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"It was the best of times, it was the worst of times, it was the age of wisdom, it was the age of foolishness, it was the epoch of belief, it was the epoch of incredulity, it was the season of Light, it was the season of Darkness, it was the spring of hope, it was the winter of despair, we had everything before us, we had nothing before us . . ." Quoting the opening of Charles Dickens's *Tale of Two Cities* in connection with the current state of the liquefied natural gas (LNG) industry may, if anything, be overly optimistic, beset as the industry is with low prices and stuttering demand in its Asian stronghold. But it is hard to resist calling on these contrasts to characterize the LNG industry, for despite its problems, there are glimmerings of change that could profoundly improve its lot.

LNG is essentially a niche fuel. Liquefying and shipping gas is expensive, so the LNG route is attractive for developers only where there is no local market or where capacity in the local market is insufficient to take all the available local supplies. LNG requires large investments by the buyers in terminal and regasification facilities, so it generally flourishes only where there is a shortage of indigenous gas supplies and where competition from pipeline gas is limited. In bulk, LNG is suitable for transport only by sea, so its use in landlocked areas is confined to small peak shaving plants or isolated locations such as central Australia.

Not surprisingly, there are only a handful of LNG projects, and most supply East Asia, which lacks indigenous resources (table 1). But the earliest LNG supplies went from Algeria to Europe and the United States. Europe still takes significant quantities (just under a quarter of world demand), and

the United States receives a trickle (soon to be augmented by the startup of the Trinidad project).

LNG commands a significantly higher price in Japan, the Republic of Korea, and Taiwan (China) than it does in Europe or the United States. So more supply has been economic to develop, and since the Pacific Rim has both ample gas reserves and limited local markets, that region dominates LNG trade, with more than three-quarters of total supply.

### In LNG, history matters

To find the roots of the current situation, it is necessary to go back to the 1980s. The 1970s had been years of expansion for LNG, and by the end of the decade Japan was receiving LNG from Alaska, Brunei, Abu Dhabi, and two Indonesian plants at Arun and Bontang, all under long-term take-or-pay contracts closely tied to crude oil prices. The first Malaysian plant was under construction and would start up in 1983. But the second oil shock of 1979 and the restructuring it engendered set back demand in Japan. The buyers—particularly the power companies—found out just how rigid those long-term take-or-pay contracts could be. They took the full volumes, but were not happy. New LNG became difficult to sell. The Australian project did not come on stream until 1989, after significant delays. By that time oil prices had dropped, Japan had recovered, and power demand in the country was growing so rapidly that it could be met only by building gas-fired power plant. Suddenly LNG was in demand again. Korea, in 1986, and Taiwan (China), in 1990, had begun to take LNG, having bought incremental capacity from the Indonesian



**TABLE 1 CURRENT AND POTENTIAL LNG SUPPLIES**

Current		Potential	
Country	Project	Country	Project
Algeria	Arzew	Pacific	
	Skikda	Australia	Darwin
Australia	North West Shelf		Gorgon
Brunei	Brunei		NWS Expansion
Indonesia	Arun	Indonesia	Bontang I
	Bontang		Natuna
Libya	Marsa el Brega		Tangguh
Malaysia	Malaysia I and II	Malaysia	MLNG Tiga
Nigeria	Nigeria LNG <sup>a</sup>	Oman	Oman Expansion
Oman	Oman LNG <sup>a</sup>	Qatar	RasGas Expansion
Qatar	Qatargas	Russian	Sakhalin 1
	Ras Laffan LNG <sup>a</sup>	Federation	Sakhalin 2
Trinidad and		United States	Alaska North Slope
Tobago	Atlantic LNG <sup>a</sup>	Yemen, Rep.	Yemen
United States	Kenai (Alaska)	Atlantic	
		Nigeria	Third Train
		Trinidad and Tobago	Atlantic Expansion

a. Expected to start production in 1999.

plants. The Korean market began growing at a phenomenal rate.

The resurgent demand was met largely by expansion of existing plants. A second plant was constructed in Malaysia alongside the first, and Bontang continued to be expanded. All the other existing plants managed to squeeze out more LNG. Why were no new plants built? For three main reasons.

First, the cost of constructing LNG plants had risen sharply. Because few plants are built, there are few contractors and process licensors with a proven track record, and thus little competition. High LNG prices before 1986 and the emphasis on reliability of supply reinforced this tendency. Buyers and project sponsors insisted on proven technology and experienced contractors. Designs were lavishly gold-plated (an LNG plant can often produce at least 15 percent more than its nameplate capac-

ity, and Australian and Malaysian plants routinely produce 25 percent more). Greenfield plants also seemed uneconomic when compared with expansion, particularly after the fall in oil and LNG prices in 1986. While an expansion might need only marginal additional investment, a greenfield LNG plant involves not only a central gas processing unit, but also site preparation, harbor, marine, tankage, accommodation, utilities, and the general infrastructure to establish and support the operation in a remote location.

Second, an expansion does not have the same scale problems as a greenfield project. A typical liquefaction train by the late 1980s was about 2.5 million metric tons (3.5 billion cubic meters) a year—a volume that the market could easily digest. But the minimum scale for economic viability on a new site had come to be seen as 6 million metric tons a year—a much harder prospect to place even in quickly growing markets.

Third, speed was important, and it is quicker to expand existing plants than to build new ones. LNG projects are extremely complex, and it normally takes at least two or three years to set up the venture structure of a new one.

By the early 1990s all the expansion possibilities had been soaked up. By this time, encouraged by the buoyant demand if not by the prevailing prices, several new projects were emerging, mainly in the Middle East. Project sponsors were heard to say that the buyers needed the LNG and that prices would therefore have to rise to make new projects economic. Qatargas, based on the enormous reserves of Qatar's North Field, got in ahead of any real competition and sold 4 million metric tons a year to Chubu Electric in Japan, quickly followed by 2 million more to seven other Japanese buyers. It had started up in 1997, eight years after the last greenfield project in Australia, and was supported by a guaranteed minimum price (or so it appeared).

Not surprisingly, buyers were resistant to higher prices, and Japanese power companies shifted their preferences toward coal. Some of the project sponsors started to consider whether costs could be reduced to make greenfield plants economic without increasing prices.

Then demand growth started to ease, at least in the Japanese market, coming to a crashing halt in 1998. Yet gas continued to be found, and prospective projects to increase. By 1995 it had become apparent that there was more LNG than the traditional markets could absorb. Projects would have to become more competitive and find new markets. Nevertheless, on the strength of soaring Korean demand, two new projects, Oman LNG and Ras Laffan, will start up this year.

Meanwhile, there was at last some activity in the Atlantic basin. After some thirty years of trying, the Nigerian project finally began to supply LNG buyers in Europe. And a rejuvenated Trinidad project will supply the U.S. market as well as Spain. All four projects point in new directions,

and the rest of this Note focuses on where they might lead us.

### **Potential supply—and its implications**

More than 100 million metric tons a year of potential LNG is seeking a market. Given open markets and enough finance, the industry could more than double in size in half a dozen years.

The traditional markets in Asia will be unable to absorb the potential supply before 2015—or even 2020. The Pacific projects, all advertising startup dates between 2001 and 2005 (though with varying degrees of unreality), face an unpalatable prospect. The performance of an exploration company depends not only on its ability to find oil and gas but also on its ability to commercialize discoveries as rapidly as possible. In a highly capital-intensive industry the discount rate relentlessly ticks away value. Something must be done to rescue the projects. Three conclusions are emerging.

First, the projects must be made more competitive, not just with one another but now also against low oil prices. This conclusion is being accepted only reluctantly. LNG projects have scarcely had to compete with one another in the past and have generally had little problem competing with oil at US\$18 or more a barrel. For most of the life of the LNG industry the available gas barely sufficed to meet the needs of importers. Competition takes three main forms: competing on cost, offering more market-friendly terms, and calling on established buyer relationships.

Second, new markets must be opened up. Oman LNG tried to open a new market in Thailand but ultimately failed against competition from pipeline gas imports and the contracting economy. The emphasis is now on India and China.

Third, producers can get out while the going is good. BP is the only producer to have done this, selling its gas resources in Papua New Guinea. Two other projects, Pac Rim in Canada and Cristóbal Colón in Venezuela, have stopped trying to market LNG, having failed to put

economic schemes together. In all these cases there are possible alternative uses for the gas.

### **Finding ways to compete on cost**

LNG is forced to be more competitive in the Atlantic trade than in the Pacific. There is competition from pipeline gas in the target markets in Europe and the United States, and prices are lower than in East Asia. Not surprisingly, the Nigerian and Trinidad projects lead the way in the pursuit of low cost.

#### **Shipping**

Nigeria's main innovation was to use idle ships. For many years there has been a pool of unemployed ships, built speculatively on the assumption that a spot trade in LNG would develop, or freed up by the failed Algeria-U.S. project or the failed Indonesia-California project. Because buyers in Japan insisted on new ships for new trades, the ships languished except for occasional short-term charters.

Shell acquired some of these ships cheaply for Nigeria LNG at the end of the 1980s—well before the project needed them, as it turned out. It was a brave move that paid off handsomely in the end. Nigeria LNG earned enough from short-term charters to cover the cost of the ships before they reached Nigeria. And high demand for LNG in Japan and Korea that could be supplied from spare capacity in existing LNG plants created a need for ships that Shell was only too pleased to fill.

The Trinidad project has also benefited from the use of secondhand ships, two retired from the Phillips Marathon Alaska-Tokyo route, one from the Abu Dhabi project, and one of the U.S. Marad ships, now owned by Trinidad partner Cabot. But under normal conditions, cheap secondhand ships are not necessarily the bargain they appear to be. Usually they have to be acquired well before they are needed, and they need upgrading to ensure that they last for the life of the new project, or at least for much of it. If they then must be laid up for a year or two, the initial cost advan-

tage can be eroded. Moreover, the number of used ships available has declined, while the demand has increased to the point where the benefits of used ships have virtually disappeared.

#### **Plant cost**

Although BP was probably the first to call attention to the need for improving the cost and economic performance of new LNG schemes, Trinidad made the real breakthrough. Although new to LNG exports, the Trinidad partners were determined not to build a high-cost plant. They applied the cost savings lessons that low oil prices had forced on offshore developments in such high-cost areas as the North Sea. At the same time Phillips, with Bechtel, was attempting to market an updated version of the cascade liquefaction technology developed for the early Alaskan plant and not used since. The Trinidad team not only produced a design suited for the purpose, it sought bids for two front-end engineering design contracts, one for the Phillips technology and the other for the APCI process that has been used for all other recent plants. This strategy enabled it to obtain truly competitive bids for the main contract for plant construction.

The results were startling. All the bids came in at less than US\$250 per metric ton a year of installed capacity—30 to 40 percent less than the costs in the late 1980s. The Phillips cascade technology probably had little to do with the low bids. The real breakthroughs were in design philosophy and, perhaps most important, in engendering real competition among the contractors. In most LNG projects the construction contract goes to the contractor that carries out the front-end engineering design because of its significant information advantage. And since there are few contractors, the advantages of bidding have been limited.

The producers in the Pacific basin do not seem to have fully absorbed the lessons of Trinidad, although both RasGas and Oman LNG benefited from relatively low bid prices, possibly from contractors trying to avoid losing out again. Shell, probably the leading LNG supply com-

pany, is pursuing its own route to cost reduction, largely through scale economies. It is talking of single liquefaction trains approaching capacity of 4 million metric tons a year. Not only is this an unwieldy scale for a project, Shell also appears to be struggling to get costs down to US\$250 per metric ton a year.

### Financing

Financing has seen some innovation, although not all the developments have been positive. Even with highly creditworthy buyers, most of the early LNG projects were equity (or at least shareholder) financed, and it was generally large oil companies that developed LNG schemes. More recently project financing has increased, presumably because companies with smaller balance sheets are becoming involved. Project financing is not a cost savings route and is also time consuming. Nigeria LNG gave up its attempts to raise project finance and reverted to equity financing. RasGas moved to bond financing, raising US\$1.2 billion on the U.S. bond market at remarkably good rates. But Korea's economic problems and the decline in its debt rating have led to a downgrading of the bonds' rating (although not below investment grade), with a corresponding impact on their price. The bond route has probably closed for LNG finance, at least temporarily. Oman LNG had intended to go that route but changed course after the East Asian financial crisis.

### Opening new markets

With demand low in the main East Asian markets, the industry has tried to open up new markets in Asia. India and China have always been seen as the main prizes, though the first progress was in Thailand, where Oman LNG and RasGas tried to sell LNG. Price was a sticking point: pipeline gas set a marker, and Thailand wanted indexation linked to coal for power generation. Oman LNG proved more flexible on this point and a deal was concluded in principle, only to be overturned as more pipeline imports appeared and Thai demand collapsed.

Attention shifted to India and China, but both present formidable obstacles to establishing a market for LNG. In traditional markets LNG can rely on powerful, creditworthy buyers that can underwrite a twenty-five-year take-or-pay contract. No such buyers exist in the new markets. Neither country has a fully convertible currency. There is virtually no gas infrastructure, particularly in the target areas for LNG. But there is huge potential demand, particularly in power generation, a sector in crisis in both countries. With the traditional route to developing LNG trades closed, a new way of conducting business had to be found.

Initially, supply to independent power producers (IPPs) in India was expected to be an easy market to develop. But finance proved to be an obstacle. IPPs are generally project financed and rely on long-term electricity sales contracts. In India most state electricity companies supply electricity below cost to the rural sector and are loss making. The federal government is unwilling to issue sovereign guarantees. And the complexities of dual project financing—with an IPP at one end of the chain and a new LNG development at the other, and with different borrowers—are probably insurmountable.

A second obstacle was the lack of gas infrastructure in all but a limited area. There was no obvious strong utility company to buy LNG and develop the nonpower market. LNG sellers would probably have to get into local marketing, but while they were prepared to invest in receiving terminals, few were willing to go much further. Yet LNG imports were unlikely to be limited to power demand: even with a serious shortage of electricity, demand at any one location would not grow fast enough to fully load an LNG terminal (or a large LNG plant) quickly enough.

Complicating the situation in India, the host governments have tended to put the cart before the horse, calling for tenders for LNG supply before tackling the market absorption and finance questions. Because of the complexities of LNG development, no tender can be unconditional on either

side; usually there are major reservations by both parties over financing, timing, and commitment by the other side. So the process has been of dubious value, at best only an invitation to negotiate.

Enron's scheme to supply Dabhol Power Company, in India, will probably be the first LNG supply in either India or China. It appears that this scheme will be able to use the tested method for opening new Asian LNG markets—taking spare capacity from existing projects, in this case Oman and Abu Dhabi. The suppliers will probably have to take more risk and provide more contract flexibility than in traditional contracts. The saving graces: the demand is apparent, and the state is prepared to give some support to the state electricity board.

Enron will have a major stake in the receiving terminal and power plant, but not in LNG supply. The company also plans to market gas to other industries in the region. Financial closure, the key step, is reported to be imminent.

Elsewhere in India, a different approach is being tried by the Petronet group, which includes most of the largest oil and gas companies in India, presumably in an attempt to assemble stronger creditworthiness. This group called for tenders to supply 7.5 million metric tons a year and to be involved in the receiving terminals at several locations. RasGas won the bid and is reported to be moving toward a sales contract. But the scheme raises all sorts of questions and there is a long way to go. A major expansion for RasGas, it will have to be financed, and the two sides will have to work out an acceptable way of distributing the risks. Even so, with Qatar boasting in December of 4 million metric tons a year of spare capacity, even the Petronet project will not rely entirely on new LNG. RasGas also won a bid for the Tamil Nadu state project planned for Ennore (this time as the fuel source for a group interested in investing in the terminal and associated power plant).

That all the supplies for India originate in the Middle East is not insignificant. The shipping distance to India is considerably shorter from the

Gulf than from any of the Pacific Rim projects (except Arun to Ennore). Competition among Gulf producers should keep their f.o.b. (free on board) prices close to the equivalent netback from traditional buyers, making it unattractive for Pacific-based projects to compete in the Indian market. But the Gulf-based projects suffer a freight disadvantage in supplying Japan and Korea.

Less progress has been made in China, despite intensive study of the market by several potential suppliers, including Shell and Mobil. Most attractive is the fast-growing coastal strip between Guangdong and Shanghai. With Shanghai now appearing to be within economic reach of pipeline gas from Siberia, the focus has shifted to the Guangdong area. The government has said that it favors LNG imports and has called for a major feasibility study, but nothing will happen until this study has been completed. The stronger central control in China lends a different flavor than in India, but many of the same issues will have to be faced and there seems to be no prospect of central government guarantees to support imports.

### **Weathering liberalization in established markets**

In the Japanese market the effects of the economic downturn on energy demand and LNG prices may be short term and coped with fairly easily, but the effects of liberalization in the gas and, particularly, the power sectors are essentially unpredictable. Power buyers in particular cannot be sure of their future market share, which makes it distinctly risky for them to make long-term take-or-pay commitments and favors fuels that can be purchased as and when needed. Small wonder that Japanese buyers have apparently decided to take on minimal new long-term LNG commitments. But this is largely a problem of transition. In the long run a liquid spot market should remove the volume risk even for gas, as it has in the United States. Even so, it takes years for such a market to develop, and LNG sellers could face a decade of uncertainty. The future is further clouded by the emissions reduction obligations Japan accepted at Kyoto, which



tend to put fuel choices in conflict with those that follow from liberalization.

The Korean LNG market—highly seasonal and bedeviled by conflict between the two users of LNG, KEPCO (Korea Power) and KOGAS (Korea Gas)—has suffered a decline that has been exacerbated by the conflict. This decline led to rephasing of some contracted purchases and to concern about Korea's capacity to absorb contract volumes from Rasgas and Oman LNG that start this year. But Korea, which has done more to put its economic house in order than most countries in the region, should be able to meet its contractual obligations.

In Korea too liberalization is in the air, but the timing and extent are uncertain. POSCO, a major steel maker, will be allowed to build a terminal and import LNG for use in electricity generation, mainly for its own use. Whether POSCO will cooperate with KOGAS to avoid worsening the problems of temporary oversupply and seasonal storage remains to be seen. KOGAS has been planning a third terminal of its own, and there seems no need for both this and a POSCO terminal. Nor does there appear to be any immediate need for newly contracted supply to meet POSCO's requirements. The problems of seasonal supply and demand could be addressed in several ways, including introducing interruptible industrial tariffs that would reduce summer valleys and thus increase total supply. And there is inherent unsatisfied demand that new initiatives could uncover.

Taiwan (China) has suffered little from the economic disturbances in the region. Here too there are thoughts of energy liberalization. There are also new IPPs, and severe strains in the relationship between CPC, the government-owned monopoly operator for both oil and gas, and Taipower, the government-owned power utility. Political positions will take time to unravel, and as the future growth of LNG supply depends largely on the timing, cost, and ownership of the proposed second LNG terminal, the watchword is "wait and see."

European gas markets are also under pressure to liberalize—pressure that is being strongly resisted in some quarters. Liberalization does not sit easily with the traditional way of trading LNG, which relies heavily on long-term contracts and take-or-pay. In the longer run, with liquid trading systems removing volume risk, long-term contracts and take-or-pay can be combined with a floating gas market price, but the uncertainties of the transition are unsettling. Moreover, liberalization usually pushes prices down—an uneasy prospect for a high-cost source of supply.

### Price wars?

LNG pricing is an area where novelty and tradition are likely to come into conflict—with unpredictable results.

In Europe LNG needs to compete with pipeline gas at the point of entry, and current prices are low enough to frighten all but the very brave or foolhardy. The big questions for the future are how long gas prices will be coupled to oil prices in continental Europe and what will happen to gas prices when there is a decoupling. In North America and Britain decoupling has tended to reduce prices.

In Asia the pricing signals also point to innovation, and perhaps confusion. After nearly three decades in which prices in Japan, Korea, and Taiwan (China) moved in parallel (under the general control of Japanese buyers), there are now seeds of real competition among suppliers. The "floor price" that was essentially agreed for Qatargas supplies has already been dropped (RasGas dropped a parallel provision for Korea in order to enlarge the supply contract), and the recent results of price renegotiation with existing suppliers suggest that the apparently inexorable upward creep of prices has been halted and probably reversed.

The traditional pricing formulas ensure that LNG becomes less competitive with oil at low oil prices, causing gas companies to suffer and discouraging power companies from using any more LNG than their contracts call for. If low oil

prices persist, there may be pressures for price changes that are difficult to resist. And if East Asian buyers overcome their reluctance to buy new LNG, competition could result in a new, more buyer-friendly deal, giving established buyers a new yardstick and a reason to renegotiate across the board.

East Asian pricing structures may also come under strain as a result of deals in India, where novel pricing structures and levels are being proposed. For example, the winning bid for Ennore is reported to offer LNG at a fixed price, a rather eccentric choice. Indexation, which is more closely tied to real competition in the end use market, must be a real possibility. The ultimate end is a price linked to gas prices in a liberalized and liquid gas market (as in the United States). But this is a long way off, and how the industry gets there will be interesting to watch.

### Will spot trading develop?

So far there has been no real spot trading in LNG, although there have been many short-term deals between established buyers and sellers based on spare plant and shipping capacity. Nevertheless, several forces could lead to more extensive trading that might just result in a spot market.

The first is the Korean seasonality problem. Gas demand in Korea has a strong winter peak, but LNG contracts require even deliveries through the year. This can be handled in part (though expensively) by storage. But the growth of the Korean market has threatened to exceed the storage capacity and the country has run perilously close to stock-outs in winter. Much of the Korean supply has been based on short-term supplies, and these can be biased toward winter, although not without diverting some cargoes originally intended for Japan. Japanese buyers have been reluctant to participate in swaps, but in the current market stress Osaka Gas has provided Korea with a winter cargo this year. There is an obvious synergy with Taiwan (China), where the load peaks in summer, but the buyers have not organized to take advantage of it yet. There is also much poten-

tial for freight saving deals (although the benefit is not easy to capture). Clearly, a more flexible trading pattern would benefit both buyers and sellers, but extreme caution, particularly among the Japanese buyers, has inhibited its development.

The opening of new markets such as India could also lead to a more flexible trade. The players in the chain have to accept more risk that the market will not perform as expected. To deal more flexibly with the Indian market, they may look at alternative ways of disposing of surplus LNG or acquiring LNG on short notice. But for this to be a real option requires a market of last resort. In winter there is generally a market in Europe that could absorb some surplus LNG at a reasonable price, as long as there is shipping capacity to get it there. The only truly liquid gas market, however, is in the United States. It is probably too far and its price too low to support an Indian or Pacific traded market, but it could provide the Atlantic trade with yet another opportunity to innovate. There are signs that this opportunity is being exploited. Cabot, one of the Trinidad partners and also the U.S. buyer of Trinidad gas, has on-sold part of its supply to an IPP in Puerto Rico promoted by Enron. Thus a new market has been opened using LNG whose development was underwritten by a sale into the United States. This might eventually evolve into a much more flexible trade, although there are still many obstacles to overcome, not least the availability of adequate shipping capacity.

### Conclusion

These are obviously difficult times for LNG. But they are also exciting times. Difficulties lead to new ideas and to attempts to rewrite the rules. Not all these efforts will succeed, of course, but there is certainly plenty to maintain the interest in the LNG business today.

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