The Prospects for LNG in Asia in the 21st Century

The scene is set in Asia for rapid growth in the production of LNG. New reception terminals planned and underway in China, Japan, South Korea, Taiwan, Indonesia, and the Philippines will underpin the regional demand curve for LNG, which, together with the prospect of exporting LNG from Asia into markets further afield, provides fresh encouragement for sellers to debottleneck and expand existing production facilities and to undertake greenfield developments.

The future of LNG in Asia will not however simply be a larger-scale version of the historic development of the market. Asia’s LNG industry is in the throes of significant evolution, and it will be necessary for sellers, buyers, and project lenders to examine how the development and financing of LNG projects in Asia can be successfully undertaken in light of changing market conditions.
THE CURRENT ASIA ENERGY PICTURE

The consumption of primary energy (oil, gas, coal, hydro, and nuclear) in Asia (including India, Australia, China, and Japan) during 2002 stood at 2,717.8 MTOE. This figure represents an almost 8 percent growth in demand year-on-year from 2001. What is most significant about this statistic, however, is that for the first time Asia has overhauled the equivalent figure for primary energy consumption in North America. Asia is the region experiencing by far the quickest growth in primary energy consumption and, with per capita energy consumption levels still low compared to North America and Europe, it is well positioned to be the most dynamic region for energy sector growth in the near future.

In terms of individual fuels, 2002 saw a modest (4.7 percent) growth in the consumption of gas in Asia from 2001. The greatest individual fuel growth by consumption was coal (up by 16 percent from 2001), but these statistics belie the trend towards a growth in gas consumption; in just 10 years, the consumption of gas within Asia has almost doubled and the dash for gas is set to continue, particularly through the advent of a dramatic shift towards promoting LNG across the region.

Asia LNG Supply and Demand

Current LNG production capacity in Asia resides in Indonesia, Malaysia, Australia, and Brunei. Present and prospective LNG production capacity from the region is as follows:

<table>
<thead>
<tr>
<th>Australia</th>
<th>MLN 3</th>
<th>6.8 MTPA</th>
<th>Commenced production in 2003</th>
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<tbody>
<tr>
<td>NWS T1 – T3</td>
<td>7.5 MTPA</td>
<td>First production scheduled for 2004</td>
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<tr>
<td>NWS T4</td>
<td>4.2 MTPA</td>
<td>First production scheduled for 2006</td>
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<tr>
<td>Bayu-Undan</td>
<td>3.0 MTPA</td>
<td>First production scheduled for 2007</td>
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<tr>
<td>NWS T5</td>
<td>4.2 MTPA</td>
<td>First production scheduled for 2007</td>
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<tr>
<td>Gorgon</td>
<td>10.0 MTPA</td>
<td>First production scheduled for 2008</td>
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<tr>
<td>Greater Sunrise</td>
<td>5.0 MTPA</td>
<td>First production scheduled for 2009</td>
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<tr>
<td>Brunei</td>
<td>7.2 MTPA</td>
<td>Commenced production in 1972</td>
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<tr>
<td>Lumut 1</td>
<td>4.0 MTPA</td>
<td>First production scheduled for 2008</td>
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<td>Lumut 2</td>
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<tr>
<td>Malaysia</td>
<td>8.1 MTPA</td>
<td>Commenced production in 1983</td>
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<tr>
<td>MLNG 1</td>
<td>7.8 MTPA</td>
<td>Commenced production in 1995</td>
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<td>MLNG 2</td>
<td>6.8 MTPA</td>
<td>Commenced production in 2003</td>
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<tr>
<td>MLNG 3</td>
<td>3.0 MTPA</td>
<td>First production scheduled for 2005</td>
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<tr>
<td>Indonesia</td>
<td>22.1 MTPA</td>
<td>Commenced production in 1977</td>
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<tr>
<td>Bontang A-H</td>
<td>6.7 MTPA</td>
<td>Commenced production in 1977</td>
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<tr>
<td>Arun</td>
<td>7.0 MTPA</td>
<td>First production scheduled for 2005</td>
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<tr>
<td>Tangguh</td>
<td>3.0 MTPA</td>
<td>First production scheduled for 2007</td>
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<tr>
<td>Sullawesi</td>
<td>6.6 MTPA</td>
<td>First production scheduled for 2007</td>
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<tr>
<td>Eastern Russia</td>
<td>9.6 MTPA</td>
<td>First production scheduled for 2007</td>
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1. All figures in this section are taken from BP’s Statistical Review of World Energy (2003)
India will soon commence imports of LNG, with the 5 MTPA Petronet LNG terminal in Dahej, Gujarat, scheduled to start importing LNG from Qatar in 2004. This terminal should be followed in the same year by a Shell-sponsored terminal in Hazira, Gujarat (2.5 MTPA) and later by a second Petronet LNG terminal in Kochi, Kerala (2.5 MTPA). A number of additional LNG import terminals are being planned, including Kakinada (5 MTPA), Trombay (3 MTPA), Ennore (2.5 MTPA), Jamnagar (5 MTPA), and Gopalpur (5 MTPA).

The most important recent regional development is that new LNG import markets have appeared in China, where the Guangdong project is set to import 3.7 MTPA from Australia (commencing 1996) and the Fujian project is set to import 2.6 MTPA from Indonesia (commencing 2006). As China’s year-on-year growth in primary energy consumption was the largest in the world for 2002 (at 19.7 percent) and the nation already accounts for more than 10 percent of global energy consumption, it should be of no surprise if other Chinese LNG import terminals currently on the drawing board for Zhejiang, Jiangsu, and Shandong Provinces commence development in the very near future. Ahead of the development of these proposed terminals, China National Offshore Oil Corporation signed an agreement in October 2003 to acquire about 3 MTPA from Australia’s Gorgon project and to assist the project to market further quantities in China.

There are also plans to import LNG into the Philippines (1.3 MTPA, commencing 2006, with two additional terminals under early stages of consideration) and to establish domestic Indonesian LNG trades supplying LNG from the Tangguh project in West Papua and the Donggi project in South Sulawesi to the energy-thirsty regions of West Java and East Java.

While demand in Asia for LNG is certainly set to increase in the near future, the significant levels of production capacity expected to be brought online over the coming six years indicates that supply will nonetheless exceed demand in the region, and new export markets outside the region are looking increasingly attractive to Asia’s LNG producers.
THE EARLY HISTORY OF LNG IN ASIA

To understand the current evolution of the LNG market in Asia, it is helpful to first understand the history of the emergence of LNG in Asia in the 1960s and in particular the role played by Japan in that history.

The first LNG import into Asia occurred on November 4, 1969 when the Polar Alaska, loaded with LNG from the Kenai project in Alaska, berthed at the Negishi LNG Receiving Terminal in Kanagawa Prefecture, Japan. Although the committed quantities under this first import contract were relatively small, within months of this first delivery Japanese buyers had committed to acquire more substantial quantities of LNG from Brunei. The attractiveness of LNG to Japanese buyers increased following the two oil shocks in the 1970s, and they entered into further commitments to acquire large quantities of LNG throughout the 1970s and 1980s in order to diminish Japan’s heavy reliance on crude oil.

Japan’s dominant influence in Asia and world LNG markets from their infancy cannot be underestimated. With imports of about 73 MTPA Japan currently accounts for almost 49 percent of all LNG trades worldwide, and some 70 percent of all LNG movements in Asia are presently headed for the Japanese market.

Japanese LNG SPAs founded today’s LNG production capacity in the US (first producing in 1969), Brunei (1972), Indonesia (1977), Abu Dhabi (1977), Malaysia (1983), Australia (1989), Qatar (1996), and Oman (2000). When other north Asian countries began to plan for the import of LNG, the Japanese model was adopted as their benchmark because of its obvious stability and so something of the old order was perpetuated in the first SPAs for the sale of LNG into South Korea (which commenced in 1986) and Taiwan (1990).

Several features of the original Japanese SPA, still in force today, are worthy of note:

**The Buyer.** The buyer is a creditworthy gas or power utility, such as Tokyo Electric Power (TEPCO), Tokyo Gas, or Osaka Gas. Each of these gas or power utilities holds an authorized monopoly franchise over a geographically defined downstream business area and therefore enjoys the prospect of a reliable, long-term revenue stream from its committed end-users.

**Duration.** The primary desire of a Japanese LNG buyer was to lock in a long-term, stable supply of LNG. As price, market, and project risks could largely be passed through to its end-users, the buyer would be concerned to ensure long-term security of supply and consequently the typical duration of an SPA would be for between 20 and 30 years.

**Price.** The price of LNG is indexed heavily against crude oil price movements, principally by reference to a formula comprising a fixed component plus a variable component equal to an agreed percentage of the Japanese Customs Clearing (or JCC) price for Japanese CIF crude oil imports. In the mid 1980s, a series of SPAs providing for the supply of LNG from Indonesia shifted the reference for the variable component from the JCC price to the FOB price for Indonesian crude oil exports. This linkage to imported oil prices was originally made at a time when Japanese power generation was heavily (about 50 percent) dependent on fuel oil as a primary feedstock and so, as about 70 percent of Japan’s LNG imports are intended for power generation, the decision to index LNG prices against imported oil prices would have made sense since this was the majority competing fuel. The pricing mechanism has remained relatively static over the past 30 years as these SPAs typically did not provide for price review or reopening.

**Take-or-Pay.** With LNG typically constituting a relatively small proportion of the buyer’s overall feedstock purchases, the buyer could typically meet the seller’s requirement to enter into an annual take-or-pay commitment equivalent to 100 percent of the annual contract quantity, with offtake flexibility being achieved only through the usual take-or-pay adjustments and possibly some downward flexibility.

**Flexibility.** The principal concern of the buyer would be to secure a reliable supply of LNG and it would be of less concern that the SPA should contain provisions for upward and downward volume or cargo scheduling flexibility. To further diminish the need for within-contract flexibility mechanisms, a buyer would typically invest heavily in gas storage facilities, such as the Sodegaura terminal that commenced operations in 1973 and that presently boasts 35 tanks with an aggregate storage capacity of more than 2.6 million kilolitres.
Shipping. LNG was typically sold ex-ship, with the buyer paying a bundled price for LNG covering commodity and transportation costs. It was not until supplies commenced under SPAs entered into effective 1983 for the supply of LNG from Indonesia’s Bontang project that the first FOB sales into Japan occurred, although this arrangement was an exception rather than the rule and subsequent contracts with the North West Shelf and Qatargas projects were entered into on an ex-ship basis.

Against the revenue stream that would be generated under such SPAs, the LNG sellers were readily able to secure third-party debt financing on a limited recourse basis for the development of their LNG production and transportation facilities. Consequently this form of purchase and finance arrangement became the benchmark for the project financing of LNG liquefaction and transportation projects worldwide.

Asia’s LNG market has evolved in recent years and the contractual terms of the first-generation Japanese SPAs, which were eminently appropriate during the 1960s to 1990s, might now begin to look somewhat dated. With an increase in traded volumes and the number of market participants over the last three decades, the Asia LNG market has developed increasing liquidity and today’s LNG buyer is looking to reallocate project risks and rejuvenate the economic matrix in new-generation LNG sales arrangements.

COMMERCIAL TERMS FOR LNG SALES

The anticipated additional demand for LNG from the new market participants could coincide approximately with a number of original and extension Japanese, South Korean, and Taiwanese SPAs coming up for renewal. For these new market entrants and renewing buyers, there is a golden opportunity to secure better, more flexible terms for the supply of LNG in what is being widely characterized as a buyers’ market.

The following aspects of the seller/buyer relationship are areas where change could occur:

Duration. Compared to the traditional SPA model, which typically has a duration of up to 30 years, shorter term (e.g. three to 10 year) LNG supply contracts may be negotiable, so that the buyer is locked into a particular contractual relationship only for that lesser duration and thereafter is free to seek alternative arrangements. In a market where there is expected to be an excess of supply and a matrix of contractual and economic terms that is trending towards providing greater benefits to buyers, shorter term commitments will enable buyers to have security of supply over the medium term without substantially locking themselves out from currently unobtainable benefits that might be secured from LNG sellers over the coming few years.

Take-or-Pay. The reduction of effective take-or-pay commitment levels may be possible to achieve. High take-or-pay levels are required by sellers to provide a guaranteed revenue stream to facilitate the financing of their liquefaction and associated facilities. Buyers might be resistant to agreeing to high take-or-pay levels when buying from brownfield LNG facilities where the initial capital costs of those facilities have already been recovered by the seller. Furthermore, as LNG increasingly forms a greater percentage of a buyer’s supply of feedstock (in Japan, for example, LNG currently constitutes about 33 percent of feedstock for power generation and 90 percent of town gas feedstock), then the ability of that buyer to sustain large take-or-pay commitment levels decreases and greater flexibility is required to accommodate variability in the demand of downstream end-users.

Volume Flexibility. The SPA might contain volume flexibility mechanisms whereby a portion of the annual contract quantity might be optional over several short-term periods within a longer term SPA, or volumes might be variable within each contract year or on a year-to-year basis so that the buyer can modulate its annual LNG cargo commitments (upwards or downwards, although likely to be subject to a prescribed volume or cargo limit) in order to meet downstream market requirements. For a seller, the provision of volume flexibility will help to retain market share as otherwise a buyer might contract for lower quantities and secure its flexibility through spot or short-term contracts from alternative suppliers as and when needed.
**Destination Clauses.** There may be a relaxation of the traditional restrictions to allow the buyer the ability to freely resell its contracted cargoes into other markets where there may be spot-selling opportunities or to enable several buyers to collaborate to take advantage of different seasonal demand patterns, available shipping capacity, or coordinated annual programmes and lifting schedules. An LNG seller might be encouraged to relinquish LNG resale controls, designed to prevent its customers from taking advantage of arbitrage and other market opportunities at its expense if the economic benefits of the resale opportunities are to some extent shared with that seller.

**Shipping Control.** Where the buyer is able to take delivery of LNG on an FOB basis, the flexibility associated with ship scheduling will pass to the buyer, and this will in particular better enable the buyer to manage the potential exchange or resale of LNG cargoes and to re-route cargoes to its own alternative terminals. Standardized technical specifications for LNG ships and regasification facilities will also help facilitate multiparty trades, although conditions at existing terminals may hamper the ability of a buyer to fully utilize shipping flexibility (e.g., many existing Japanese terminals are presently unable to accommodate the draught and displacement associated with vessels of a size greater than about 135,000 cubic meters capacity).

**Pricing.** There may be movement away from fixed escalation price mechanisms to short-run price packages, spot market price indexation, and pricing referenced against fuels other than, or in combination with, crude oil or against power prices in order to better reflect the buyer’s downstream market. Pricing flexibility can also be secured through mechanisms such as periodic price reviews and most-favoured-nation (matching) provisions.

**Aggregated Parties.** Japanese buyers have historically banded together when buying LNG, a practice which provided them with additional negotiating strength. The future may see a replication of this practice on the seller side, with sellers from different projects cooperating to provide greater flexibility and cost efficiency as the market becomes leaner. Deliveries under SPAs might cease being supply source specific and could be made from a variety of LNG production projects. It is instructive to note that in November 2002, representatives of the LNG producers in Malaysia, Indonesia, and Brunei signed an agreement to cooperate through the use of production surpluses and transportation capacity in order to provide their customers with greater security of supply and to help stabilize LNG prices.

Evidence of a new order in LNG contracting in Asia can be found in recent trades where buyers have had some success in changing the usual contract formula. The renewal terms for the Malaysia LNG foundation contracts with TEPCO and Tokyo Gas were signed in March 2003, by which the original contracts were extended for an additional 17 years with the buyers having an option for a further five-year extension term. The annual contracted quantities for the two buyers amounts to 7.40 MTPA (4.80 MTPA for TEPCO and 2.60 MTPA for Tokyo Gas), a proportion of which (0.7 MTPA for TEPCO and 0.5 MTPA for Tokyo Gas) is periodically renewable throughout the contract term. Of the aggregate contracted quantity, up to 5.6 MTPA is to be transported ex-ship by Malaysia International Shipping Corp and the remaining quantity of up to 1.8 MTPA is to be transported FOB by the buyers. In addition, the two buyers are reported to have received an attractive price discount.

These renewal terms were signed at the same time that MLNG Tiga entered into an agreement for the sale of 0.54 MTPA over the course of one year to TEPCO and not long after, MLNG Dua and Chubu Electric entered into what is essentially an LNG sales master agreement with variable quantities, programming, and prices over a three-year period.

New generation SPAs could soon become the commercial envy of buyers locked into existing long-term, relatively inflexible contracts and there may be a clamour to renegotiate those contracts in the buyers’ favour. Existing SPAs will not go away just because market circumstances have evolved such that they are potentially rendered unfashionable, however, and agreed evolution maybe the best option for the parties in the interests of preserving at least some form of contract.
Existing SPAs typically contain little or nothing in the way of provisions (such as force majeure or material adverse change protection) that might afford relief to a contracting party that has seen prevailing economic circumstances deteriorate such that the original commercial foundation for the contract is lost. Despite this there may be a willingness on the part of contracting parties to consider some form of renegotiation. This has happened for example in the US gas market of the 1970s and 1980s and the UK gas market of the 1990s, and is also happening today in certain southeast Asia gas markets.

**BREAKING UP THE TRADITIONAL LNG VALUE CHAIN**

Although there are several ways in which LNG liquefaction, shipping, and regasification projects may be structured, in Asia, as elsewhere, there has typically been a relatively rigid demarcation of the liquefaction and shipping facilities, owned by sellers, and the regasification facilities and downstream sales and distribution networks, owned by buyers. This order is usually structured in the image of an LNG value chain by which value accrues moving from upstream to downstream through the process of gas production, liquefaction, shipping, regasification, distribution, and eventual sale.

This demarcation is fragmenting, however. Three factors in particular are contributing to the break up of this traditional view of LNG project structuring:

**Shipping.** This is fast emerging as an area where much greater competition between shippers for market share is feasible, and the boundaries are particularly being crossed where buyers of LNG on an FOB basis participate in the shipping function. By directly investing in the LNG shipping business a buyer can participate in spot market sales and cargo exchange and redirection opportunities and reduce the overall cost of imported LNG by redirecting the profit margins otherwise collected by third party shippers.

**Buyers.** A key issue for sellers is the changing identity of LNG buyers. Recent changes in the way LNG is bought and sold have arisen at least partially in consequence of energy sector deregulation throughout Asia, allowing new participants to enter the market. Probably the most significant change in the evolution of LNG markets is the changing nature of downstream gas and power markets, which have proved to be the weakest link in the traditional LNG value chain. Power generation continues to be the major anchor for LNG demand but the nature of the market has changed as the liberalisation of downstream energy markets has created a whole new class of buyers, more likely to be IPPs than state entities, with no government backing and holding either unreliable PPAs or the merchant risk of selling into a power pool. Increased competition has also meant that buyers have a new priority to secure much more flexible purchase terms as their downstream markets evolve rather than focusing predominantly on security of supply.

**Equity Participation.** The crossover between the separated components of the LNG value chain is highlighted where the seller becomes an equity participant in the regasification terminal and even the downstream facilities (in order to protect its investment through being part of the LNG demand curve) and the buyer becomes an equity participant in the upstream interests, often beyond the liquefaction plant and into the gas reserves themselves (to share in the project risks and profit sharing).

A recent example of this from Asia is the Guangdong LNG import project in China, where BP (a prospective, but not the ultimate, supplier of LNG) took a 30 percent equity stake in the terminal project and CNOOC, part of the LNG purchasing consortium, took an equity interest of about 5 percent in the finally selected source of LNG supply, the North West Shelf. Another example comes from the Bayu-Undan project in Australia/Timor-Leste, where TEPCO and Tokyo Gas together acquired just over 10 percent of the upstream project equity and have signed a 17-year SPA for the entire LNG output, which they will be responsible for shipping on an FOB basis.

Consequently, the traditional LNG value chain (if indeed the notion of a chain-like structure can still be held to apply) must be analysed as a whole and individually by reference to each component. These changes do not necessarily weaken the chain, however. Rather, they redefine it and in some instances can make it stronger.
There has been historically little room for a spot market for LNG sales and trading to develop in the Asia region. A relative lack of liquidity generated by high levels of commitment of production capacity, onerous take-or-pay levels, limited cargo resale, exchange and redirection rights, and a lack of excess shipping availability have all combined to limit the evolution of a shorter term market. Despite this, in 2002, cargoes into South Korea made up 16 percent of the worldwide LNG spot trade and Japan’s share of the global LNG spot trade business hovers at around 3 percent.

There has been more recent speculation as to whether the growing relaxation in the rigidities traditionally associated with LNG shipping and sales contracting in Asia might result in the region being pushed to the forefront as the proving ground for the development of a spot market for LNG trading. A spot market for LNG will not appear overnight and cannot be manufactured, but it may be that the more flexible forms of contract described above and prospectively greater volumes of LNG and incremental shipping capacity that may become available for short-term trading will combine to facilitate the growth of such a market.

As increasing amounts of uncommitted LNG supply enter the market as de-bottlenecking, expansion projects and new liquefaction schemes are undertaken without sales contracts fully underpinning the additional production capacities. In addition, as LNG ships are built for trade without reference to specific projects, buyers and sellers may be further encouraged to be more adventurous and innovative in addressing requests for flexibility and shorter-term arrangements than they previously may have been.

Short-term and spot trading of LNG is likely to increase as the market gradually becomes more liquid, as multiple LNG supply sources, ships, and demand markets work together to generate the necessary flexibility. Even if such trading does not dominate the market, it will become an increasingly important supplement to mid- and long-term contracts to provide flexibility over supply security, and this in turn could create a set of dynamics for change that could affect the market.

Greater liquidity in Asia’s LNG market could also be achieved by the exchange, redirection, or backhaul of shipped LNG cargoes between projects and markets, particularly as any insistence on cargo destination restriction clauses is challenged by buyers in new contract terms.

Increased market depth has also enabled the introduction to the market of the LNG trader – an aggregator who does not possess the upstream or downstream asset base of traditional energy market participants and who buys and sells gas in the expectation of a positive margin and whose creditworthiness is typically a factor of its on-sale customers. The energy traders to emerge globally to date have primarily been subsidiaries of major energy companies, such as BP Gas Marketing, Shell Western LNG, BG Gas Marketing, Coral Energy Resources (Shell), and Total Power & Gas. In Asia, the only really active LNG trader to date has been Shell Eastern LNG, which in May 2002 contracted to purchase up to 3.7 MTPA for five years from the North West Shelf project, targeting markets outside of north Asia, such as India and the US.

Historically LNG production from Asia has been earmarked for consumption within Asia’s markets and there has been little or no opportunity for the commitment of Asia LNG cargoes to other markets, although occasional spot cargoes have been exported outside of the region. There has in particular been a paucity of LNG trade heading to the US from Asia, and this situation has primarily arisen as there has been relatively little demand for LNG imports into the US from any source (e.g., in the US gas market LNG imports presently make up around only 5 percent of total imports) and because the existing four import terminals are located on the east coast and Gulf of Mexico, making cost-effective shipping of LNG from Asia a challenge. Things are set to change, however.

There is presently in the US an insatiable increase in the demand for gas, primarily as a feedstock for power generation, which is set to outstrip current levels of domestic gas production and imported gas by pipeline. There is much discussion about a possible gas export pipeline from...
Alaska to the Lower 48 states but this is unlikely to make an appearance before 2011, if at all. Hence LNG has come into focus as a potential source of energy supply.

The decision by the US Federal Energy Regulatory Commission (FERC) issued in December 2002 to adopt a non-open access policy, allowing LNG import terminal owners to exclusively use terminal capacity themselves without being required to comply with the open access requirements imposed on natural gas pipeline operations, has encouraged a slew of import terminal proposals to be lodged with the FERC for its approval. There are currently at least three proposed import terminals for the west coast of the US and a further six being discussed for Baja California, Mexico, which could then supply regasified LNG by pipeline into the US.

The recent incursion into Iraq has focused attention on the possibility of sourcing much-needed supplies of energy from the Middle East for the US market. Evidence of this can be seen in the July 2003 agreement between Qatar Petroleum and ConocoPhillips for the supply of 7.5 MTPA of LNG to the US from 2009, and the October 2003 agreement between Qatar Petroleum and ExxonMobil for the supply of 15.6 MTPA of LNG into the US also commencing in 2009.

Despite the undoubtedly massive low-cost pool of gas reserves across the Middle East that could be developed, the US will be reluctant to set the same scene for Middle East gas production dominance as the region has historically enjoyed for oil. The US will not have forgotten how the price of oil quadrupled following the first oil crisis in 1973 and then doubled again after the second crisis in 1978-79.

To counter a geography of gas supply that has too heavy a reliance on the Middle East and that breeds concern over long-term political and economic instability, the US will be keen to diversify its prospective sources of LNG supply. Currently LNG supply into the US is heavily skewed in favour of Trinidad, with substantial quantities also sourced from Algeria and Nigeria. Contracts already committed for future purchases will increase LNG quantities taken from currently marginal suppliers, most notably Qatar and Australia, and will introduce new sources to the import mix, such as Egypt, Equitorial Guinea, and Norway.

Asia will assume a growing importance in the minds of US energy planners as a credible counter-weight to the potential hegemony of Middle East LNG exports and already the seeds of such development are growing. A number of Asia’s LNG producers have realized that the development of the US market will provide alternative demand centres and so enable the monetization of gas reserves that might otherwise remain stranded in the wake of a loose supply-demand balance in Asia.

Australia’s Greater Sunrise LNG project has contracted for the sale of about 90 percent of its capacity and the Gorgon LNG project has contracted to sell about 80 percent of capacity into Mexico and the US west coast. Indonesia has prospectively contracted with Sempra Energy and Marathon for the export of combined quantities in excess of 12 MTPA into Mexico, and these volumes are likely to underpin one or more of the Donggi, Tangguh, and Bontang Train I liquefaction projects.

Demand from the US for LNG from Asia might also give rise to moderate price inflation, giving sellers the hope of achieving prices that are greater than the benchmark prices set in Asia by the various Chinese LNG import projects, for example. On the other hand, LNG prices in the US have historically been significantly lower than LNG import prices in Asia as they have been priced by reference to Henry Hub pipeline gas prices, where much greater market liquidity and gas-to-gas competition combine to impose deflationary pressure on gas prices.

The growth in Asia/US LNG trades will also be an important factor in globalizing gas markets and in harmonizing price and other LNG supply terms that hitherto have been determined on an almost exclusively regional basis.

**FINANCING NEW PROJECTS**

Traditionally the development of liquefaction and transportation facilities was undertaken by LNG sellers through the provision of third-party financing collateralized against the expected revenue stream due under a long-term take-or-pay based SPA entered into with a creditworthy buyer (e.g., such as under the Japanese purchase and finance model).
Project development on the back of long-term baseload contracts will remain the aim of sellers but it is likely that in the new order things will have to be done differently. As the traditional LNG value chain reshapes itself, it will require a fresh perspective from lenders and project participants in order to develop and finance LNG projects.

New LNG import markets are often diverse, fragmented, and in the early stages of development, and this is particularly so in Asia. It is proving difficult for LNG sellers to assemble sufficient committed contractual volumes to underpin the development of greenfield liquefaction projects without full-capacity coverage.

The alternative is, notwithstanding the lack of full-capacity coverage, to initiate the development of new liquefaction facilities with uncommitted capacity in the hope of developing offtake markets as the project evolves. This represents a significant departure from the philosophy of the traditional Japanese purchase and finance project development model since a critical link in the LNG value chain is created without the rest of the chain being in place.

An example of such a development in Asia comes from Malaysia, where the liquefaction facilities at Bintulu were developed and financed by the project participants, often ahead of or at best simultaneously with the acquisition of contracts for the sale of LNG. The project sponsors made a financial commitment to proceed with the MLNG Tiga expansion project in the year 2000 to commence production in 2003. The first buyer (Tohoku Electric) was only signed in 2001 and by the end of calendar year 2002 the project only had three buyers signed to offtake an aggregate of 2.98 MTPA, less than half of the project’s installed capacity. The risk paid off, however, and additional buyers were signed during 2003 so that although the total installed capacity has not been contractually dedicated, the sponsors have secured sufficient commitment to underpin the project.

Committing to liquefaction projects ahead of securing committed offtakers is a more viable option for expansion projects where both capital and operating costs should be lower as essential infrastructure will already be in place and economies of scale can be exploited. Project risks should also already be well defined from previous experience. For the development of greenfield projects, however, the risks of committing ahead of a verified demand curve are greater. This does not mean such commitment will not occur, and a willingness to commit to construction prior to substantial offtake contracts being secured has been evidenced in the Sakhalin 2 LNG project, where the project sponsors (Shell, Mitsui, and Mitsubishi) awarded major contracts for the design, engineering, procurement, and construction of major infrastructure facilities (including for platform topsides and substructures, onshore processing plant, LNG terminal, and LNG tanks) on the strength of MOUs for less than half of the installed capacity of the first of two trains.

As technological developments and economies of scale continue to reduce liquefaction and shipping capital costs, and as buyers are increasingly assuming responsibility for (and therefore the cost of) transporting LNG, sellers might be better able to assume the initial development risk and finance at least some part of the cost of their facilities on the strength of their balance sheets. This will also better enable the parallel processing of liquefaction plant development, where project sponsors overlap development tasks instead of completing them sequentially, thereby benefiting from time savings through accelerated completion. Sellers might later be able to secure a refinancing of their interests once the liquefaction project is proven to be operating successfully and, with much of the market risk then mitigated, such refinancing could be obtained on attractive terms.

The challenge for lenders is to become comfortable with the concept of financing the development of a liquefaction project at the outset where that project has yet to secure LNG sales commitments equal to the full output capacity of the plant. In this regard, some of the lessons previously learned from the financing of merchant power facilities might usefully be applied.
The demand for gas in Asia is set on a path of continued growth, and LNG is at the heart of the evolution of Asia’s gas markets. This demand growth will be more than matched by what could be a doubling of regional LNG production capacity over the next five years, which could easily saturate the market in Asia. The opening up of the US to LNG imports from Asia will also spur sellers to make new investments and will enhance progress towards less regional and more global gas markets.

There are many challenges ahead. Perhaps the most immediate challenges face sellers, to develop and finance sustainable projects in the face of increasing fragmentation of the old world order and to control the seemingly insatiable appetite of buyers for leveraging a position that they presently enjoy because of the upper hand that demand has over supply.

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