Investment in LNG

David Ledesma asks why Atlantic Basin LNG is taking off

Introduction

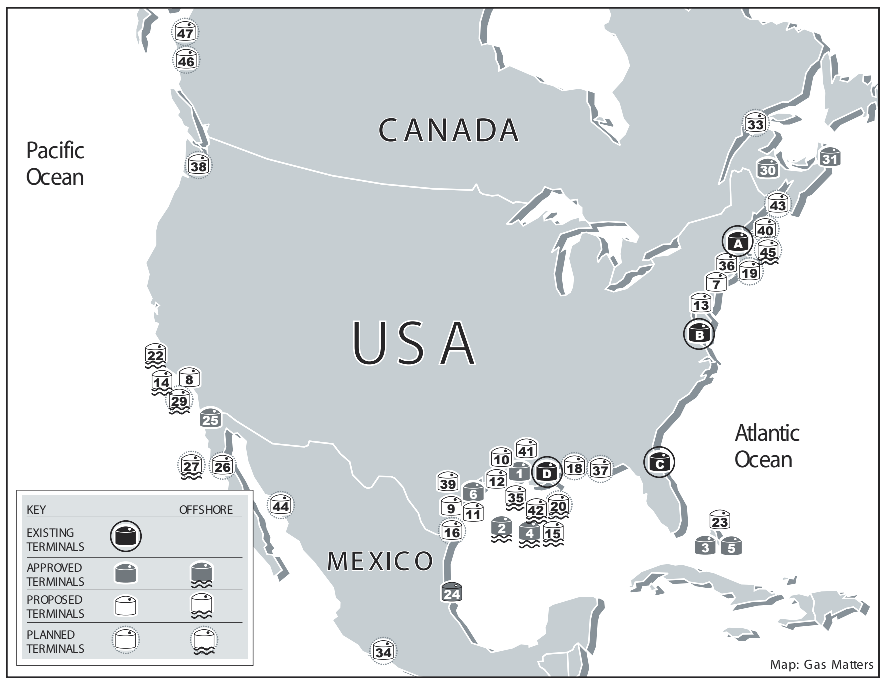
With global gas demand increasing nearly 3 per cent per annum, environmental pressures and buyers seeking to diversify from their traditional supply sources – be it through replacing their own production or by other imports – LNG is increasingly the fuel of choice. LNG suppliers are rushing to fill the demand/supply gap. In the UK, the USA, mainland Europe, Canada and Mexico, LNG is being heralded as at least part of the answer to narrowing that gap. That said, LNG currently accounts for less than 7 per cent of world gas consumption. For the countries involved in this fascinating business it represents, for buyers, an important energy source and, for sellers, a major and rapidly growing source of revenues and a means to monetise stranded gas. In 2003 122 million tonnes of LNG were transported – an increase of 25 per cent over 2000. In September 2004, world LNG supply capacity was 143 million tonnes per annum (mtpa), with 55 mtpa under construction. Global LNG capacity is expected to be nearly 200 mtpa by 2008 – doubling in less than ten years.

The business has changed considerably since the mid nineties, and it is commercial innovation that has led to the change. It has been supported by lower technical costs; new players entering the market; larger vessels (not necessarily owned by the supply projects or dominant utility buyers as they traditionally were); gas buyers' involvement in supply projects in their own right; flexible contracting terms to meet market requirements; and, creditworthy companies acquiring the complete output from LNG projects for on-selling via their own downstream facilities and/or on-selling ('trading') into different markets to improve revenues and develop new markets. What were once exclusively regional markets, with dedicated supply sources, are now in growing global communication as these developments drive new trade patterns.

Traditionally, LNG projects were developed on the back of gas reserves, on long-term contracts at oil-indexed prices. Such deals took many years to develop and were built on long-term relationships – often at governmental level. Since the mid-nineties, supply projects have been developed in growing interaction with – and often involvement from – buyers. In the Atlantic, this was pioneered by Atlantic LNG of Trinidad & Tobago, a project involving buyers from its 1992 inception and tailored from the beginning to fit tight market niches.

In the Atlantic Basin the traditional model of LNG chain development – in which the supply project develops and manages the LNG supply chain only up to the port of a utility buyer – has increasingly given way to different models of supply chain, although the new and old exist side by

Map 1: US LNG Terminals, 2004



EXISTING TERMINALS WITH EXPANSIONS
A. Everett, MA : (Tractebel)
B. Cove Point, MD : (Dominion)
C. Elba Island, GA : (El Paso)
D. Lake Charles, LA : (Southern Union)

APPROVED TERMINALS
1. Cameron*, LA : (Sempra Energy)
2. Port Pelican : (ChevronTexaco)
3. Ocean Cay (Bahamas)** : (AES Ocean Express)
4. Energy Bridge – Gulf of Mexico : (Excelerate)
5. Calypso (Bahamas)** : (Tractebel)
6. Freeport, TX : (Freeport LNG/ConocoPhillips)
25. Costa Azul, Mexico : (Sempra& Shell)
30. St. John, Canada : (Irving Oil & Chevron Canada)
31. Point Tupper, Canada : (Anadarko)

*Formerly Hackberry

**US pipeline approved; LNG terminal pending in Bahamas

PROPOSED TERMINALS UNDER CONSIDERATION BY FERC
7. Fall River, MA : (Weaver's Cove Energy)
8. Long Beach, CA : (Mitsubishi/ConocoPhillips)
9. Corpus Christi, TX : (Cheniere)
10. Sabine, LA : (Cheniere)
36. Providence, RI : (Keyspan & BG LNG)

Pre-filing with FERC
11. Vista Del Sol, TX : (ExxonMobil)
12. Golden Pass, TX : (ExxonMobil)
13. Crown Landing, NJ : (BP)
23. Seafarer (Bahamas) : (El Paso/FPL)
39. Ingleside, TX: (Occidental)
41. Port Arthur, TX (Sempra)

PROPOSED TERMINALS UNDER CONSIDERATION BY US COAST GUARD
14. CabrilloPort, CA: (BHP Billiton)
15. Gulf Landing, LA : (Shell)
20. Main Pass Energy Hub, LA : (McMoRan)
22. South California Offshore : (Crystal Energy)
35. Pearl Crossing, offshore Gulf of Mexico : (ExxonMobil)
42. Compass Port, offshore Gulf of Mexico (ConocoPhillips)

PLANNED TERMINALS
USA
16. Brownsville, TX : (Cheniere)
18. Mobile Bay, AL : (ExxonMobil)
19. Somerset, MA : (Somerset LNG)
29. California - Offshore : (ChevronTexaco)
37. Mobile Bay, AL: (Cheniere)
38. St Helens, OR : (Port Westward LNG)
43. Quoddy Bay, ME : (Quoddy Bay LNG)
45. Northeast Gateway, Offshore MA : (Excelerate)

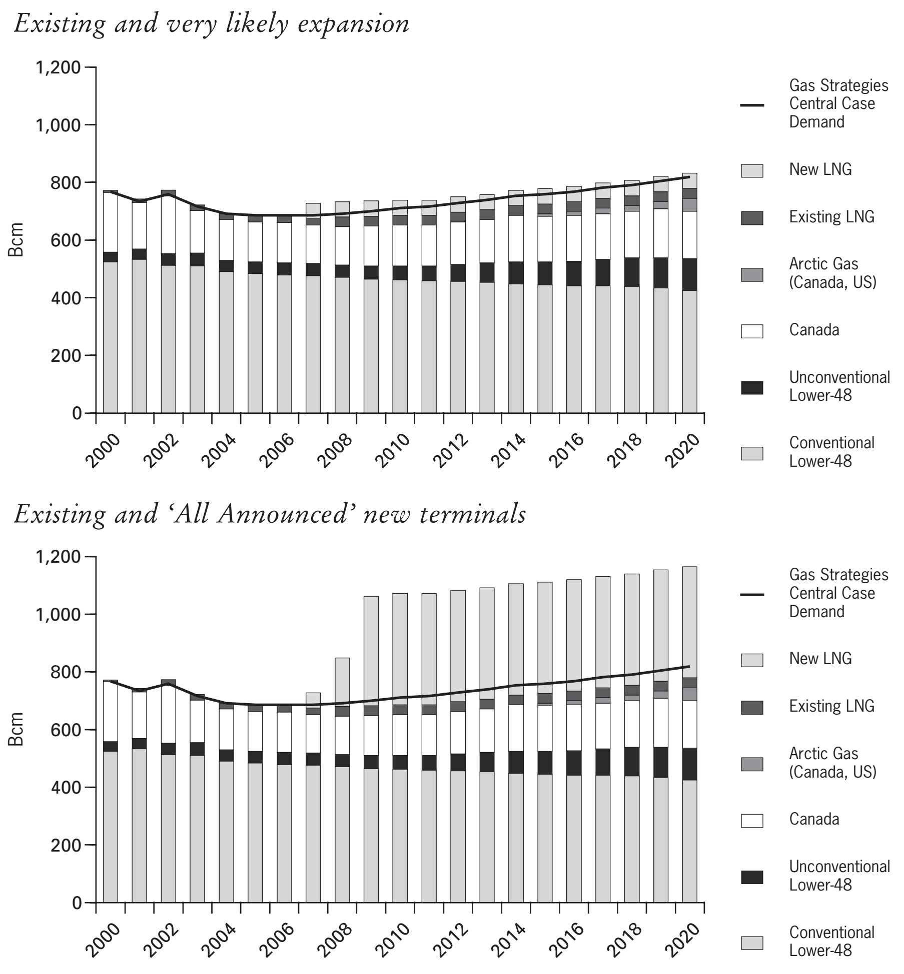
Mexico
24. Altamira, Tamulipas : (Shell)
26. Baja California : (ConocoPhillips)
27. Baja California - Offshore (ChevronTexaco)
34. LázaroCárdenas : (Tractebel/Repsol-YPF)
44. Sonora : (DKRW Energy)

Canada
33. Quebec City, QC : (Enbridge/GazMet/Gaz de France)
46. Kitimat, BC : (Galveston LNG)
47. Prince Rupert, BC : (WestPac Terminals)

Source: Gas Matters, August 2004

side. New models range from Atlantic LNG's various models (in the latest incarnation the partners even sell their own LNG separately) to the Egyptian varieties of ELNG and Segas, the latter developed almost entirely by the buyer, Spain's Union Fenosa Gas, as well as suppliers going further downstream. An important new component to many of these models involves one or more of the selling partners securing regasification capacity, and therefore LNG market outlets. BP and Repsol pioneered this development in the Atlantic, developing the Bilbao terminal for their Trinidad LNG but others quickly followed. The Egypt LNG I & II projects are being developed by BG and Petronas (which acquired Edison's interests), based on the markets of France, Italy, the UK and the USA; the partners have secured capacity in five terminals in these countries. ExxonMobil and ConocoPhillips with partners are developing US terminals to take LNG from new projects in which they have stakes in Qatar, as are ExxonMobil and Qatar Petroleum in the UK.

Figure 1: USA Gas Supply/Demand with Two LNG Terminal Capacity Cases



Source: Gas Strategies

LNG in the USA

The USA is the world's largest gas market but the 11 mtpa of LNG imported in 2003 represents only about 2 per cent of supply (which may be small but is significantly greater than the 0.1 per cent, of the mid nineties). Forecasts from the US Energy Information Agency (EIA) show that LNG imports are expected to increase fourfold to 40 mtpa by 2008 and around 90 mtpa by 2020 (Gas Strategies views this capacity estimate to be reasonable). The growth to 2008 will be absorbed through expansions of the existing LNG import terminals and Energy Bridge, but after 2008 these volume increases will depend on the development of new LNG importation capacity (see Map 1); though only a few of the 40 plus proposed new LNG terminals will be built. Figure 1 sets out Gas Strategies' view on US gas supply/demand under two scenarios for LNG terminal development.

This planned growth is being driven by increased US gas demand and limited ability to increase either US production or imports from Canada (also facing a supply squeeze). The shortfall of supply has driven US gas prices upwards and this, combined with its lower technical cost, has made LNG competitive in the US market.

Even the small number of new LNG terminals which are likely to materialise will substantially increase LNG import capacity. Realistic fears of local opposition to terminals (with the notable exception of Texas and Louisiana where big oil's installations mean jobs and money), have led to different LNG import facility options being developed. Excelerate Energy is bringing on this year the 'Energy Bridge' concept in the Gulf of Mexico using LNG vessels with on-board regasification facilities.

Other proposed new terminals include the use of gravity-based offshore structures (ChevronTexaco's Port Pelican project is the most advanced). Though it may be easier to secure the necessary approvals for these projects, they cost more than traditional land-based terminals and are costlier to expand. Other projects plan to use existing platform.

Terminals are also being proposed and developed in countries bordering the USA, thus getting around local US opposition and the American NIMBY ('Not In My Back Yard') mentality. Several terminals are being considered in Mexico (for California), although it has its own local and political issues; the Bahamas (Florida) and Canada. Many, although not all, of these projects will target the US market but, with both Canada and Mexico facing their own gas shortages for different reasons, a market will exist in these countries too. The Shell/Total terminal at Altamira, aimed at Mexican markets, has been approved.

Besides the major LNG companies, a range of companies small and large – such as Cheniere and Sempra – are developing US LNG terminals. Cheniere secured several good sites along the gulf coast, but may not operate them itself. The most advanced project it started, Freeport LNG, is now controlled by a combination of Freeport LNG and ConocoPhillips, which also secured two-thirds of the terminal's 1.5 Bcf/day regasification capacity. Cheniere has also signed a deal with Total for some throughput capacity at its proposed Sabine Pass terminal. The future of some of its other sites – Corpus Christi, Brownsville and Mobile Bay – is uncertain due to their proximity to some of the majors' own terminal proposals. Sempra is developing Cameron LNG (formally Dynegy's Hackberry project) but although EPC bids are expected soon, LNG supply is still not secured and therefore project progress has slowed.

LNG terminal capacity assures companies a gateway into the highly liquid US market, hence the wish of many to be involved. In addition, the larger companies see the import terminals as a means to work back up the LNG value chain and secure revenue positions in LNG production projects or to monetise upstream assets. BG, BP and Shell have notably built up LNG trading organisations, acquiring terminal capacity and vessels to meet their trading needs. As the US has a liberalised gas market it means that they are able to sell gas there with minimal volume risk but at market price. Investments have been made with the view that US gas prices will remain over $3.00/MMBtu, the level at which LNG imports from the Middle East are economic, and it is Gas Strategies' view that US Gas prices will remain in the band $3.50–4.50/MMBtu to 2020.

LNG Imports to the UK

The second fully liberalised gas market with a daily gas spot market is the UK. Currently self-sufficient and an exporter of gas, the UK is expected to become a net importer of gas in 2006/7, although the 'peak day' position is already very tight and necessitates some seasonal gas imports. To meet future requirements there are plans for three LNG terminals into the UK: Isle of Grain where National Grid Transco is converting an existing LNG peak-shaving plant into an LNG receiving Terminal (3.3 mtpa, due on in 2005, with plans to increase to 10.5 mtpa); ExxonMobil and Qatar Petroleum are planning the South Hook LNG terminal at an old refinery site at Milford Haven (7.8 mtpa with plans to increase to 15.5 mtpa); and BG, Petronas and Petroplus are partners in the Dragon LNG project, also at Milford Haven (6 mtpa). New pipeline projects to import gas from Norway and The Netherlands are underway; Russia is another potential pipeline source.

Gas Strategies' view is that LNG landed and regasified in the UK can compete successfully with the new planned offshore gas developments and pipeline supplies. The UK, in gas terms, should not be seen as an island. It is linked to the continent through the Interconnector (and in the future by other fixed point connections) and the price in the UK market is expected to be set by wider European supply and demand considerations. Should all these LNG import projects go ahead, even without the expansion plans, then the UK appears likely to remain an exporter of gas for some years, supplying the continent with surpluses.

As noted above, the UK has the only fully-liberalised gas market in Europe. European countries therefore, with their supplies mainly bought under long-term contracts with oil-indexed pricing, tend to have prices well above the cost of supply. Gas Strategies sees European gas prices continuing to be oil-linked for the remainder of this decade, with some gas to gas competition while the pace of European liberalisation proceeds slowly. European gas prices will therefore act as a key driver for UK gas prices and provide a market for any surplus gas volumes which, should all the UK LNG import terminal projects proceed, include volumes freed up through LNG imports. That said, delays in project schedules and the ability of LNG importers to redirect cargoes to other markets, primarily the USA, will provide a natural check and balance on LNG import volumes and gas prices.

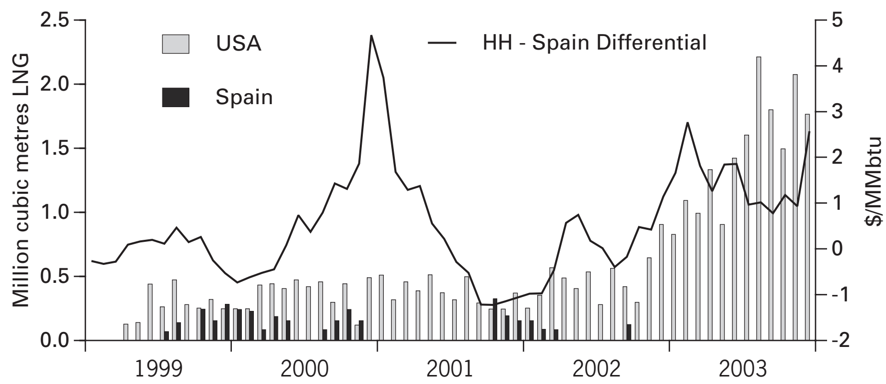
Atlantic Basin LNG Arbitrage

The distance between the European and US markets is not too far to prevent cargoes destined for one continent to be diverted to the other as contracts permit, at the cost of some disruption to shipping plans and the need for some additional shipping capacity. The primary reason for such trades is to take advantage of higher prices and it is this arbitrage opportunity that makes the Atlantic Basin so attractive to LNG suppliers and traders.

The first LNG project to really play the arbitrage game was Trinidad's Atlantic LNG. The contracts agreed with buyers allowed flexibility to divert cargoes to the higher priced market. Figure 2 shows the destination of Atlantic LNG volumes from 1999 to date vs. the Henry Hub-Spanish Gas Price differential.

When Spanish prices are high relative to the US, cargoes move to Spain. But when US prices are strong the number of cargoes moving to Spain reduces, or disappears. Also in the winter of 2003 (when almost no cargoes moved to Spain) there was additional demand for LNG from Asia. Japan's LNG demand rose in response to its nuclear power generation problems and South Korea purchased additional LNG cargoes to meet its winter peak gas demand. This extra demand meant that all additional Asian, Middle Eastern, and some Mediterranean cargoes – even a cargo from Trinidad – were heading east, resulting in reduced supply being available to meet US demand. This event, although a one-off, shows the new global dimension of the LNG business.

Figure 2: Atlantic LNG cargo destination vs. Gas Prices



Source: Gas Strategies

In 2003, approximately 20 per cent of Atlantic Basin trade was purchased on a short-term basis (i.e. not under long-term contracts). Such cargoes are priced according to the market in which they are sold and can be on a cargo by cargo basis, or as a series of cargoes. In the case of sales to the USA, most LNG sales are priced in relation to Henry Hub, but could be on a fixed price with the price exposure managed through the trading of Henry Hub futures.

Short-term LNG Trades and Trading of LNG

In order to encourage short-term trading of LNG several factors must be in place:

- LNG Production Capacity
- LNG Shipping
- Flexible LNG Contracts
- Sufficient LNG Import Terminal

With all these factors in place, LNG can be sold on a flexible short-term basis, which will provide a foundation for LNG trading in the Atlantic Basin. At present, limited surplus supply capacity is constraining short-term LNG trading. In the future with greater US and UK regasification capacity in place it should in theory mean that there is greater scope for short-term LNG trading. However, current plans are for a large percentage of this new regasification capacity to be tied up with specific supply projects. If this materialises as it is currently structured, there could be a reduction of this LNG trading potential.

Some Final Points

Increased demand for natural gas and reduced domestic production, together with environmental pressures, a desire for diversity and therefore, security of supply, has pulled LNG to the US and UK energy markets. In response, LNG project developers have created structures to provide the flexibility that these markets require and this, together with technical innovation, has reduced the cost of producing and transporting LNG. LNG from non-traditional sources, such as the Middle East, can now be economic in the US and UK markets.

On the market side, new types of LNG regasification facilities are being developed to meet local concerns, and this increase in terminal capacity, together with greater supply and different contractual structures, has encouraged the development of short-term LNG trading and arbitrage between Europe and the USA. All these factors have resulted in the 'take-off' of Atlantic Basin LNG and it is clear that it is an exciting place to operate in and will certainly remain so over the coming years.

Ben Smith considers the role of short-term trading in the LNG markets of the future

Until the late-1990s, the conventional wisdom had been that because LNG projects were so complex and expensive they had to be developed as fully integrated projects, from gas field to burner tip with clear dedicated revenue streams enabling project financiers to underwrite the massive costs involved. Now, as LNG is looked at as a possible answer to the demands of the massive markets of North America and Europe, can the LNG chain be sustained as the industry model or will players have to bear more risk for LNG to make an impact on the global gas market?

The model that the vast majority of greenfield LNG projects have used to date has been to secure long-term (usually 25 year) Sale and Purchase Agreements (SPA) with buyers with strong credit and to use the security of those LNG SPAs to finance the costs involved in development. Banks have been unwilling to take the risks unless all steps of the LNG chain from field development, through liquefaction, shipping, and regasification have been developed together and the banks can be comfortable that no third party can come between the customers' dollars (or yen) and the plant built with their funds. This has meant that projects have tended to have dedicated fleets of LNG tankers, whether operated by the LNG producer or the buyer, operating a 'liner trade' shuttling between the seller's liquefaction plant and the buyer's terminal. Effectively the shipping has acted as a floating pipeline.

Buyers, characterised by the Japanese monopoly utilities, have been of top grade creditworthiness, have usually had their own regasification terminals, and have often been able to secure for the project favourable financing from JBIC (Japan Bank for International Cooperation) or other similar sources. Typically they have been happy to commit to twenty-five year SPAs with prices linked to oil price indices, often with a floor price to guarantee the sponsors a rate of return. Such long-term contracts gave buyers security of supply.

As the industry matured, buyers increasingly took the initiative in terms of arranging shipping, which was often built by shipyards in the countries of the buyers (particularly in the case of Far Eastern buyers). The perceived advantages of this to the buyer were (1) national self interest – the corporate webs in Japan and Korea are tightly woven and if the utility companies could help the national shipbuilding industry then that was seen as being in the national interest; (2) economics – the shipyards of Japan and Korea were able to undercut the prices that other shipyards were able to charge and Asian buyers had confidence that they would be able to secure cheaper unit price shipping costs by purchasing and running shipping themselves compared to buying ex-ship.

The LNG industry until the mid-1990s was characterised predominantly by the supply of LNG to Japan, and from the mid 1990s to Japan and Korea, countries with no significant indigenous hydrocarbon reserves of their own. Asia still represents the biggest market (in 2002 Japan represented 49 per cent of the global market, Korea 16 per cent, and Taiwan 5 per cent).

A number of trends can be identified. The first has been that the price to get LNG (or more accurately regasified LNG) to market has dropped. This has been caused by striking technological improvements meaning that whereas in the 1980s gas liquefaction usually cost in the region of $400 per tonne of capacity, now costs are in the region of $200 per tonne of capacity, and shipping costs have come down from $1900 per cubic metre of capacity to $1200 over the same period.

The second trend is that North America and Europe are increasingly concerned about the decline of indigenous reserves of gas. This concern is manifested in two ways: prices have gone up and national governments have expressed fears of becoming dependent on a single (foreign) source of gas. Diversity of supply, and security of supply are big concerns, particularly in relation to a fuel that is usually delivered by pipeline.

The third trend is that the demand for gas is increasing. As the demand for cleaner energy in general and for power generation in particular continues, the vast majority of new generation being built is in the form of gas-fired combined-cycle power stations. This is fuelling the demand for natural gas.

> “Effectively the shipping has acted as a floating pipeline”

The fourth trend is that LNG has become the latest Big Thing in the hydrocarbons industry and every global player is keen to be able to show shareholders that it has a stake in the fuel being heralded as the solution to declining oil supplies. The causes of this phenomenon are probably partly the following:

- Most oil and gas companies’ reserves of oil are aging, and those reserves that have not yet been exploited will be expensive and difficult to exploit; whilst looking for oil many companies have come across large reserves of gas, either gas fields or in the form of associated gas. Such reserves have been discovered but never exploited unless they were close to a potential market. Exploiting discovered reserves is much cheaper and lower risk than finding new reserves in politically or technically challenging circumstances.
- As environmental standards increase, the demand for gas (as a cleaner burning alternative to oil) has increased and the desire for oil companies to cut CO_2 by stopping the flaring of associated gas has also increased.
- LNG projects can be very profitable and, if well managed, can be a useful PR asset as well, showing companies overcoming technical adversity through the use of cutting edge technology to bring wealth to developing countries and ecological benefits to developed ones without even a hint of an oil spill.
- LNG excites investors, so the involvement in an LNG project can have a disproportionate effect on companies’ share prices.

The LNG bubble effect has two consequences; firstly, players who perhaps are not big enough to take a stake in a whole chain are making ‘merchant’ investments in pieces of the chain (the classic examples are the terminals proposed for North America, but could also include such players as Golar, who, whilst admittedly having a long history in LNG, have focused on investing aggressively in LNG shipping – in addition to their existing fleet of seven they currently have six vessels under construction all without long-term charters lined up). Secondly, LNG projects are increasingly going ahead in circumstances that have in the past been too technically or politically challenging to make them worthwhile. Perhaps the best example of this is the Sunrise project that has had to get East Timor and Australia to decide on the sovereignty of the reserves that it intends to exploit and is looking at building the first floating liquefaction plant in order to exploit those reserves under the Timor Sea.

The fifth trend is that oil and gas companies are now much bigger than they were even ten years ago. Whereas in 1993 the total cost of an LNG chain of liquefaction plant, shipping, regasification terminal and a power plant would have represented 25 per cent of BP’s market capitalisation, now it represents 2 per cent. This means that oil majors are now less dependent on project financing, and the strict financial structures insisted on by the banks. The majors have the scope to try and structure things in more flexible ways.

The sixth trend is the involvement of regulators. In Europe the European Commission has concluded lengthy negotiations with Gasprom, Sonatrach and Nigeria LNG agreeing not to put destination clauses restricting where cargoes can be delivered into contracts for the supply of LNG to Europe.

Looking at these trends it would be easy to conclude that LNG was on the cusp of moving to the oil trading model where production and consumption were connected with liquid markets and traders were able to match supply and demand according to market forces. On the surface all the required ingredients are there: increasing production, large liquid markets (which in the case of many markets are already trading gas on a commodity basis), a (relatively) easily transportable commodity, uncommitted shipping and terminals and buyers keen to contract with a variety of producers.

The role that LNG looks set to take is as the swing producer delivering gas to whichever market (Far East, Europe or North America) has the highest prices. LNG will be sold on a spot basis and traded just like crude. This, so the theory goes, will lead to a globally linked price of gas that will only be connected to the oil price by the demands of the market rather than through prices linked to oil indices as at present.

So why are spot cargo trades still such a tiny proportion of the LNG trade? In 2002 spot trades accounted for less than 10 per cent of cargoes delivered and Golar recently reported that spot requirements remained minimal for the second quarter of 2004. There is no doubt that sales of LNG on terms other than long term (i.e. 25-year terms) are growing (as late as 1999 short-term LNG trades were about 3.5 per cent of the total), and a large portion of those can be accounted for by the unprecedented flexibility that Atlantic LNG, the Trinidad producing company, gave its buyers to trade amongst themselves – meaning that in 2002 (despite 50 per cent of Atlantic's production being allocated to the Spanish market) over 90 per cent of it ended up in US terminals.

The obvious answer is that most projects developed up until now have their production fully committed (or almost fully committed) to long-term supply contracts and the flexibility granted under those contracts is limited. It may be trite to observe that long-term contracts generate long-term relationships but this too means that, to the extent that volumes are available in excess of those contracted under long-term contracts, existing customers are offered the cargoes first, usually on the same terms as the cargoes committed to on a long-term basis, meaning that such cargoes are not really being exposed to market forces in the same way that the oil spot market works. When Tokyo Electric suffered from the shut-down of a large number of its nuclear power plants in the summer of 2002 this did not have a particularly big effect on the global LNG industry. Yes, Tokyo Gas did end up buying more LNG to help make up the generation shortfall (and was helped by a relatively cool summer and measures to conserve energy) but those extra cargoes were, on the whole, acquired from existing suppliers on the terms of existing contracts.

It is true that probably the biggest impact on the spot cargo market has been the terms that Atlantic LNG offered its customers. Admittedly Trinidad and Tobago is well placed to be able to play off the two giant markets of North America and Europe but it does appear that the genie is out of the bottle and that buyers are asking for flexibility in their contracts that would have been unheard of in the early 90s.

It is not true, however, to say that the development of a spot market is simply evolution over time. Atlantic LNG has given its customers an interesting degree of flexibility and its customers have been able to trade their cargoes in value-adding ways. Oman LNG, on the other hand came to market slightly after ALNG but its customers are predominately in the Far East (Dahbol, Osaka Gas and Kogas). OLNG has some short-term customers but on the whole the OLNG contracts are 'typical' long-term LNG contracts with relatively restrictive destination clauses.

It is interesting to contrast the effect on the LNG industry of TEPCO's nuclear crisis (a situation involving one of the industry's key customers), with the gas price spike in the USA in the winter of 2000/01 (involving a relatively small LNG market). Whereas all suppliers (except Libya and Alaska but remarkably including the North West Shelf Project in Australia) scrambled to get cargoes to the States that winter, increased demand by Kogas and the Japanese buyers tended to be satisfied utilising existing relationships in a quiet and less dramatic fashion.

There are a large number of trends indicating that a market in LNG spot cargoes will develop and many players are positioning themselves to be ready when it happens, but the markets that the LNG industry is primarily reliant on (Japan and Korea) are not traded markets and the monopoly gas and electricity providers in those markets show little interest in developing spot markets. The primary impetus for change appears to need to come from the customers, and they are not desperate for change yet.

As Europe and the USA begin to represent a larger proportion of the LNG market, so the market forces in those countries will have a bigger effect on the industry. Already projects serving those markets are showing more of the flexibility required to develop spot markets.

What will this mean for project financing? The trend seems to be for the risk to shift up the supply chain and this is likely to continue. BP has recently concluded a contract with the US company, AES, to supply LNG to AES's IPP projects in the Dominican Republic for twenty years. The contract does not specify the source of the LNG, risk is on BP to source it. Will this be the way of the future?

Julia R. Richardson and John H. Burnes, Jr. look at the developing US LNG market

The United States is the largest natural gas consuming country in the world. As is true with other commodities, however, US demand for gas is outpacing the supply. The US domestic drilling rig count has nearly reached a three-year high, and continues to grow. But the consensus is that both domestic US supply and traditional imports from Canada are stagnant, if not declining, and unlikely to keep up with the projected growth in demand. At the same time, US gas prices have tripled since 1995, averaging roughly $5 per MMBtu throughout 2004.

Given North America's dwindling natural gas supplies and growing demand, both the government and the natural gas industry are looking to LNG imports to ease the shortfall. This rosy scenario for the LNG industry has its obstacles, however. One of the limiting factors is the amount of US regasification terminal capacity. There are four currently operating import terminals in the mainland USA (in Louisiana, Georgia, Maryland and Boston), plus one in Puerto Rico, and the LNG imported at those existing terminals currently supplies about 2–3 per cent of the US gas market. LNG could account for as much as 10 per cent of the market within the next three to four years, if the projected new terminal capacity comes on line by 2007, with LNG imports growing by 16 per cent per year between 2002 and 2025, according to the US Energy Information Administration (EIA). The questions are whether that capacity will be available, and when it will be constructed.

More than fifteen federal applications for LNG facilities are pending before the US Federal Energy Regulatory Commission ('FERC') (onshore projects) and the US Coast Guard (offshore projects). Both federal agencies are moving rapidly to review and approve new projects. Part of the reason for this flurry of proposals is the light-handed regulatory scheme created by FERC to stimulate new import projects. Congress passed a similarly business-friendly regulatory regime for offshore projects at the end of 2002. Although all the existing terminals have been reactivated, expansions have been approved, and additional expansions are being proposed, no new terminal construction has yet started. FERC has approved two new onshore terminals, and the US Coast Guard (which has a one-year time limit on its review) has approved two terminals, all four in the Gulf Coast area, but none of these recently approved projects are yet under construction. Apart from the US based terminals, a further number of new terminals have been proposed to be constructed in Mexico whence in theory natural gas could be delivered into the USA. It's highly unlikely, however, that any new terminals will be operational by 2007. Given the complexity of these construction projects, and the need to obtain supply arrangements and financing, the new terminals are at least 3–4 years away.

In addition, the industry's extraordinarily enthusiastic response to the market has been dampened to some extent by strong community opposition to a number of projects. Proposals for onshore terminals in California, Alabama and Maine have been withdrawn by their proponents as a result of community opposition. That local opposition is based largely on the emotive issues of safety and security concerns. On the other hand, the four projects in the Gulf Coast area recently approved by FERC and the US Coast Guard were not seriously opposed, and the commonly held view, therefore, is that projects may be easier to site in the Gulf Coast area. This result would be unfortunate for consumers, however, because that location requires significant transportation to the most weather sensitive markets in the Midwest and Eastern states. On the plus side, however, it means there would be less stranded pipeline infrastructure.

At the present time, expansion of existing terminals is still the best hope for new capacity in the short term. The four existing LNG terminals supply about 800 to 1.1 Tcf annually to the US market, if they are operating at their maximum capacity. Already announced expansion plans would raise the annual capacity of the existing LNG terminals to 1.7 Tcf by 2007–2008. The terminals are expected to import 630–650 Bcf this year, up from more than 500 Bcf in 2003 and double the amount imported in 2002.

"the USA has quickly moved into the ranks of the top five LNG importers in the world"

If sufficient terminal capacity can be built, what is a realistic expectation for the US LNG market? Some industry experts predict that it will support more than 10 Bcf/day, perhaps as high as 13 Bcf/day within the next few years. In 2003, roughly 500Bcf was imported into the USA, with 51 per cent going to the terminal at Lake Charles, Louisiana; 30 per cent to Everett LNG in Boston; 11 per cent to Elba Island in Georgia, and 8 per cent to Cove Point LNG in Maryland (which only started import operations in September of that year). 2004 will reflect a full year's operation at Cove Point where an ambitious expansion plan has been announced.

Thus, in just a few short years, the USA has quickly moved into the ranks of the top five LNG importers in the world. The issue then arises as to whether this rapidly expanding new market will alter the traditional LNG market model, in which very long-term supply agreements are matched to equally long-term terminal capacity agreements. This traditional model has been a fundamental requirement of importers and lenders, and has tied specific supply sources to specific terminals. The domestic US gas sales market, on the other hand, has evolved into a market dominated by spot market sales, and fewer long-term firm transportation agreements.

The existing terminal operators seem to be following the traditional model to a large extent, as they or their shippers appear to be locking in long-term LNG import agreements tied to specific overseas liquefaction facilities. Many of the new terminals are also announcing similar arrangements. In turn, the long-term capacity agreements may well provide the financial assurances needed at the production end of the supply chain.

Another factor inhibiting the development of a robust spot market in LNG is the interchangeability of LNG with domestic gas supplies. Although there exists a wide range of Btu content around the world, US terminals are often designed with specific gas quality specifications, often tied to the expected source of international supplies. Some may have engineering or environmental limitations on the LNG that they can accept, or will have to modify their facilities to be more flexible.

On the other hand, there has been a significant amount of spot sales activity in recent years, as importers scrambled to take advantage of current market opportunities while development of long-term supply facilities and arrangements lagged behind. EIA reports that short-term, or spot imports, have increased, and attributes that trend to the growing involvement of major diversified oil and gas companies with upstream LNG assets. In other words, LNG can be diverted to the USA by liquefaction plant owners with available short-term supplies. The most common source of those supplies, whether short- or long-term, has been Trinidad and Tobago. Trinidad has dominated the US market for the last four years, accounting for nearly 75 per cent of total LNG imports. But other countries, such as Algeria, are ramping up their short-term sales.

If the major oil and gas producers are able to commercially link production facilities to multiple North American import terminals, the global spot market in LNG would obviously be enhanced. Seven of the top twenty US gas producers are now pursuing LNG projects, and at least three large Canadian projects are in the permitting process. In addition, the development of the US LNG market is attracting new potential suppliers to global LNG trade such as Russia, Australia, Bolivia, Norway and Egypt. Significantly, one-third of the current orders for LNG tankers through 2007 are not committed to a specific LNG project, which is a departure from historical industry practices and important for further development of the spot market for LNG.

If current growth levels continue, the United States will surpass Japan as the largest LNG importer in the world, but this is crucially dependent on the construction of the new import terminals that are in the planning stage. If this takes place and suppliers multiply as seems likely, and a favourable regulatory climate is maintained, the conditions will be created which could lead to a global spot market.

Investment in Power Generation

Lindsay Tuthill discusses theory and investment in new electricity generating plant

Energy, and specifically electricity, could well be claimed to be one of the most crucial inputs for achieving and sustaining the levels of productivity and economic growth experienced in the developed nations of the world. Indeed, an economy based upon the creation, distribution and sales of any variety of goods and services could not be created, let alone sustained, without the provision of vast amounts of energy. With the vast majority of the developed world's electricity generated through the combustion of fossil fuels, however, there exists a large negative externality problem associated with the gaseous and particulate emissions in the electricity generating industry. Most of the energy data and regulatory history mentioned in this article will focus on the experience of the United States, but the conclusions are readily generalised.

The emissions that have received the most attention in environmental policy circles over the past twenty years include greenhouse gases (carbon dioxide, methane, nitrous oxide, among others) and sulphur dioxide. As with any externality, the problem with the emissions from fossil fuel-fired electricity generation is the fact that the environmental damage is incurred, but this damage is not accounted for in the firm's production costs. In the United States, there have been several acts of legislation passed regulating and limiting the emissions of various gases at different times, but the first national, long-term environmental program based around the trading of emissions permits was established by Title IV of the Clean Air Act Amendments of 1990. Though this legislation affected only sulphur dioxide emissions, it was the first practical example of an economically efficient solution to the environmental externality problem associated with electricity generation. With the increased discussion of global warming and the negative effects of carbon dioxide (CO_2) and other greenhouse gas emissions, it can only be assumed that some form of legislation regarding the emissions of these pollutants is impending – we just can't be certain as to the date or degree of its arrival.

The problem facing electricity generating firms, then, is as follows. They know that given current conditions, generating electricity from coal is significantly cheaper than generating from gas – or from renewable sources. They are aware that their nation's livelihood effectively rests on their