

Financing LNG in a risky market

In a tight market, securing investment for an export project should be straightforward, but high LNG prices, a shortage of EPC contractors and high costs make financing a risky business. By Terry Newendorp, chairman and chief executive, Sophie Guiny, analyst, and William Clark, senior associate, Taylor-DeJongh



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GONE ARE the days when LNG was an affair between Japanese utilities and a select few producers, involving clearly defined risks. Today projects are characterised by higher market risks and flexibility, as well as construction and political risks. The financing of projects has become increasingly complex and is exacerbated by the changing price environment. Lenders must re-evaluate their level of comfort with project risks for a new generation of deals that are larger and more uncertain than before.

The closing of the financing of Qatargas 4, in August 2007, highlighted the new reality. Compared with the landmark Qatargas 2 financing, in 2004, Qatargas 4's project costs amounted to \$6bn, against \$8.5bn for the earlier project, which was double the size in terms of production capacity – 15.6m tonnes a year (t/y) compared with 7.8m t/y.

Qatargas 4 is in many ways representative of the new generation of LNG deals. Its cargoes are bound for the US and Spain – as opposed to Japan for Qatargas 1 – underpinned by some long-term contracts, but with a built-in flexibility enabling the project sponsors to seize arbitrage opportunities for cargo diversions.

LNG supply crunch

High LNG prices are the result of increased global gas demand, driven by new entrants to the market (such as China, India), and rising demand from traditional importers eager to increase gas supply from diversified sources and increase energy production from a less environmentally damaging feedstock. Global LNG trade amounted to 211bn cubic metres (cm) in 2006, compared with 137bn cm in 2000, according to Cedigaz.

Supply constraints and high prices have led project sponsors to seek more remote and untested locations to secure energy supply, such as west Africa, Yemen and Papua New Guinea.

There is a large volume of stranded gas in west Africa, especially in difficult, deep-water locations. Multiple projects have been proposed in the region, and some are under construction. Equatorial Guinea, for example, has just 73bn cm of proved gas reserves, which are already feeding the one-train, 3.7m t/y EG LNG project. But a plan to source additional supplies from stranded reserves offshore Nigeria and Cameroon could lead to the expansion of the project.

Yemen has 485bn cm of proved gas reserves and could produce 6.7m t/y of LNG for the next 25 years. However, investors must take security risks into account, such as attacks on pipelines in the



Bontang LNG. Indonesia must buy cargoes on the spot market to meet its contractual obligations

Marib region and on foreign workers, and a shifting political environment. Despite the problems, the \$3.7bn Yemen LNG project hopes to take advantage of the supply crunch. Having been delayed since its conception in early 1992, as a result of beneficial market conditions the plant is under construction and due on-line in 2009.

Another result of the global LNG supply constraint is the changing influence of national oil companies (NOCs). NOCs have come to own 10-times more oil and gas reserves than international oil companies (IOCs), leaving the IOCs with unrestricted access to only 7% of the total global hydrocarbons reserves. In recent years, Russia, which holds over 26% of the world's gas reserves, has increased the role of its NOC, reducing investment opportunities for IOCs.

State-controlled Gazprom signalled a changing environment in Russia when, at the end of 2006, it purchased 50% plus one share of the Sakhalin 2 LNG project for \$7.45bn from a consortium led by Shell. By forcing IOCs out, Russia has capitalised on rising oil and gas prices to guarantee increased cash returns. And as other governments adopt similar methods, IOCs can expect a more difficult ownership and operating environment in the future. This development could pose significant downside risks for the global LNG market – with production under the management of less-efficient, state-controlled vehicles, output will probably fall short of market expectations. This, in turn, will support the upward price trend.

Other factors contributing to the LNG supply crunch are production set-backs and rising domestic demand in producer countries. In 2005, Indonesia was the world's leading LNG exporter, but falling output from the Arun and Bontang fields, which

feed the country's two export terminals, and rapidly increasing domestic gas demand have left the country struggling to meet its contractual commitments. Despite renegotiating contracts with its main offtakers, Indonesia must buy cargoes on the spot market to meet its obligations. The credibility of Indonesian supply was damaged further by the decision to divert half the output of the under-construction Tangguh project to the domestic market.

Nigeria has also experienced setbacks in moving planned new export projects to the construction phase as a result of rapidly rising development costs and concerns about stability in the Niger Delta. There have also been government demands for increased gas supply for domestic power generation. However, the country has significant gas reserves and if all planned projects were to proceed, the country could be exporting around 70m t/y of LNG by early in the next decade.

Challenging times for sponsors

Having deposed Indonesia, Qatar is the world's leading LNG exporter and will remain so for the foreseeable future – since the start-up of the country's industry in 1997, exports had soared to nearly 22.5m t/y in 2006. However, domestic demand increasingly competes with exports for the vast North Field's reserves – Qatari consumption of 18.4bn cm/y in 2006 was up by 12% on 2005. A moratorium on further development of the North Field until new reservoir models are complete means LNG exports will plateau in 2010, albeit at a massive 77m t/y.

The LNG supply crunch also has consequences for import projects. The struggle to secure cargoes, combined with permitting difficulties, has led to the cancellation or postponement of several projects in North America, including Québec and Kitimat in Canada, Chevron's Coronado Islands in Mexico and Shell's Gulf Landing in Louisiana.

Difficult market conditions make the financing of liquefaction projects challenging. Planned export plants have been particularly affected by the rise of global engineering, procurement and construction (EPC) costs, driven by soaring raw-materials prices – in particular for steel and nickel – linked to the exponential demand for construction services.

Additionally, the large number of energy construction projects is putting pressure on a limited number of qualified EPC contractors and leading to labour shortages, which result in delays and further cost increases. Until recently, contractors would sign lump-sum turnkey contracts and offer completion guarantees, but now sponsors must bear the brunt of construction risk. The increase in raw-materials prices affects long-lead-time items, such as storage tanks, in particular and contractors are no longer prepared to lock in a price for these items when the contract is signed. Some level of certainty is available for labour costs, but the finite supply of qualified workers is a cause of delays. Contractors are, therefore, reluctant to commit to completion guarantees, leaving sponsors exposed to higher levels of construction risks.

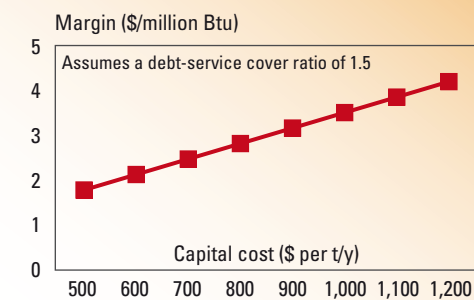
Cost overruns and delays

Cost overruns and delays challenge the potential profitability and bankability of projects. But delays and cost overruns have become commonplace for liquefaction projects. Qatargas 2 was forced to delay its start-up by six months, while the capital costs for Sakhalin 2 have nearly doubled from initial estimates to \$20bn.

Taylor-DeJongh has set up a generic LNG project to analyse how growing capital costs affect net margin (market price less feedgas costs, operating expenditure, shipping and regasification) required to achieve sufficient debt-service cover ratios. Figure 1 highlights the effect of escalating costs on a generic LNG project that costs \$800 per t/y of capacity and shows the net margin (escalated at 1% a year) required to maintain a minimum debt-service cover ratio of 1.5 throughout the life of the debt (10 years post completion). The project is in an emerging-market country and all-in cost of debt (including fees) of 7.8% is used; the gearing level is set at 70% and the tax rate at 25%.

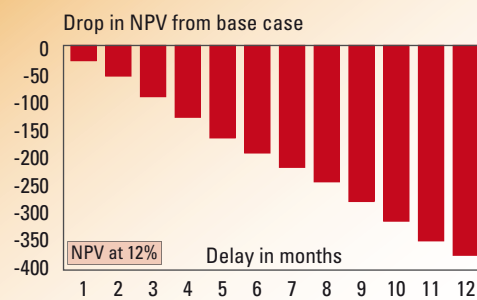
Project delays tend to occur after financial close and, consequently, have a greater effect on project returns than bankability. Although liquidated damages can in part cover some of the costs of delay, it is ultimately the sponsor's burden, and in a non-recourse financing its obligation, to shoulder the costs. Figure 2 shows the cumulative loss in net

Figure 1: Effects of rising capital cost on margin



Source: Taylor-DeJongh

Figure 2: Effects of delay on net present value



Source: Taylor-DeJongh

present value (at 12%) of a delay over the course of 12 months, for a generic \$800 per t/y plant.

Evaluating a project's profitability requires the assumption of a base-case price for LNG – market prices in recent years have been in the range of \$5.50-7.00/m Btu – but lenders' and sponsors' views can be difficult to reconcile. Lenders tend to favour conservative estimates, under which, with high capital costs and construction risks, developers will be challenged to show sufficient strength to reassure credit committees. Sponsors are likely to base their project strategies on stronger price assumptions, reflecting high energy prices and prolonged demand strength.

The lack of a global LNG market complicates price assumptions, in particular for projects intending to sell into both the Pacific and Atlantic basins, because the pricing structures vary considerably. Traditionally, LNG pricing terms in the Pacific basin have been linked to a crude-oil-index formula. But over the past decade, the degree of parity with crude has fluctuated. During a lull in the market from 2001-02, buyers were able to negotiate more favourable terms that set low ceilings and, in some cases, flat prices.

The sellers' market

Recently, however, as supply has tightened and demand has risen, the market has shifted in favour of the seller and contractual terms are returning to the traditional crude index. LNG is still sold at a discount to oil, but the tightness of the market has forced buyers to pay higher prices in exchange for supply security. The emergence of China and India as buyers has reinforced this trend.

Tight supply has also led to growing competition from alternative fuel sources such as coal and nuclear power. In the longer term, traditional oil-indexation formulae are unlikely to remain and competing fuels will apply downward pressure on prices. Although buyers' tolerance for higher LNG prices may not last forever, a dramatic fall to 1990s' levels seems improbable and this should be reflected in base-case prices.

In the Atlantic basin, LNG remains a marginal fuel. Pricing is established in reference to dominant fuels, especially pipeline gas. In the US, LNG demand fluctuates heavily according to the weather and LNG has traditionally been a back-up fuel to coal and pipeline gas. But, more recently, there has been renewed interest in LNG, which has spurred numerous receiving terminal projects.

Planned regasification capacity is likely to exceed demand, although not all these terminals will be built – several projects have already been cancelled. The difficulty faced by many projects in securing supply could help balance regasification capacity with demand, maintaining upward pressure on prices.

In Europe, LNG competes with pipeline supply from North Africa, Russia and Norway. Concerns over supply security and a desire to diversify sources mean long-term demand for LNG is guaranteed, consequently, the European market should become the main price setter in the Atlantic basin.

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Robust energy prices should give both sponsors and lenders more confidence in allowing a certain amount of price risk in new liquefaction projects. High capital costs temper this optimism, however, and require high prices over the entire project life to provide sufficient debt coverage and returns to sponsors comparable with previous LNG projects. Despite high prices, lenders are reluctant to allow for much price risk, as market downturns could leave them significantly exposed to projects unable to meet their obligations. Risks must, therefore, be balanced on a project-by-project basis, carefully evaluating viability with record-high prices, but also record-high capital costs.

Some sponsors are avoiding this issue by bypassing project finance and using all-equity project structures, such as EG LNG and Angola LNG. Others are still following the debt-financing route and crafting innovative structures to mitigate construction and price risks, while allowing some level of flexibility to benefit from what is very much a sellers' market. ●



If all planned projects were to proceed, Nigeria could be exporting around 70m t/y of LNG by early in the next decade. However, the country has also experienced setbacks in moving planned new export projects to the construction phase