The impact of falling oil and gas prices on non-US LNG producers

James Henderson

The fall in the oil price from a high of $115 per barrel in mid-2014 to around $65 per barrel in May 2015 has clearly impacted the revenues and commercial outlook of LNG producers and consumers, given the strong historic link between LNG contract prices and oil. The LNG contract price is generally negotiated in relation to a slope, which captures the link in percentage terms between the oil price in US$ per barrel and the LNG price in US$ per MMBtu. On an energy-equivalent basis, the LNG price would be 17.5 per cent of the oil price, but in order to ensure the competitiveness of gas the slope is normally negotiated within a 13–16 per cent range, depending on the market conditions at the time and the consequent bargaining positions of buyer and seller. A standard assumption is that the average slope is 14.85 per cent (plus a fixed element of $0.5/MMBtu), meaning that at an oil price of $115 the LNG price would be just over $17.50/MMBtu, while at $65 it would fall to around $10.00/MMBtu. LNG contracts generally also include 'kink points' which limit the upside and downside for both buyers and sellers (creating what is known as an 'S curve'), but even with this modification it is obvious that a $50 fall in the oil price will have had a significant impact on LNG suppliers. However, there is a broad range of outcomes across the LNG supply chain due to the differing economics of projects in various countries.

Qatar

Qatar has existing infrastructure that can produce and sell 77 million tonnes a year into the global LNG market, and although its pricing strategy has been based on a strong link to oil prices in Asia, its low cost of supply means that its projects are very robust even at a low price. The 'liquids credit' brought by the condensate it produces alongside its gas output dramatically reduces the breakeven cost of its LNG supply, allowing a 10 per cent rate of return to be generated at a gas price of below $0.50/MMBtu when the oil price is $80 per barrel. The most important issue for Qatar in the current global gas market, therefore, has less to do with managing costs and more to do with a concern over how to maximize revenues in a world where gas prices have fallen – not only due to lower oil prices, but also because global LNG supply is starting to rise, while at the same time demand in Europe is falling, and rising less quickly than anticipated in Asia. As a result, Qatar is unlikely to end its moratorium on increasing LNG supply above 77 Mt in the near future, even though expansion of its facilities would have very robust economics; its main goal therefore will be to optimize the balance between sales to Asia and

'THE MOST IMPORTANT ISSUE FOR QATAR [IS] … HOW TO MAXIMIZE REVENUES IN A WORLD WHERE GAS PRICES HAVE FALLEN.'

Europe, given the changing dynamics in both markets.

Australia

Most other LNG producers outside the USA are not in as fortunate a position as Qatar; the capital cost of new liquefaction plant has been rising over the past few years, meaning that the breakeven cost of many new projects is high at a time when prices have dropped sharply. The starkest example of this trend can be seen in Australia, where the rapid expansion of the LNG industry has led to a shortage of labour and equipment that has caused dramatic cost inflation. Examples of cost overruns and delays include the Gorgon project in Western Australia (where an initial cost estimate of $37 billion has risen to $54 billion, while first LNG has also been delayed by 2–3 years), and the three coal seam gas projects in Queensland (where costs have risen on average by around 25 per cent, accompanied by a one-year delay in first production). As a result, the long run marginal cost breakeven price for Australian gas is in the range $10–14/MMBtu, well above the current LNG price, meaning that all the new projects risk losing money for their sponsors.

'… THE BREAKEVEN COST OF MANY NEW PROJECTS IS HIGH AT A TIME WHEN PRICES HAVE DROPPED SHARPLY.'

However, despite these problems, Australian LNG output from six new projects is set to rise by a combined 58 million tonnes a year by 2018, as the new schemes were committed to long before the oil price decline and will therefore proceed as the majority of the capital cost has been sunk. Furthermore, approximately 80 per cent of the new gas has been sold under long-term contracts, meaning that the lower oil-linked price now being received could have three major consequences:

1. Project sponsors will be desperate to generate extra revenues by selling their remaining 'traded' gas at any price above short-run marginal cost, meaning that further pressure will be brought to LNG spot prices.
2. Some companies may come under pressure as they struggle to meet their commitments to repay project financing, meaning that industry consolidation and/or asset sales are a possibility. (The example of Shell's acquisition of BG, which is a major player in the Queensland Curtis LNG project, is one example of this trend.)
3. The deterioration in project economics could actually encourage the more robust Australian project sponsors to accelerate plans for brownfield expansion of their schemes. While this is somewhat counter-intuitive, brownfield development would allow the generation of cost synergies that can improve overall project economics, even at lower oil and gas prices, and could therefore be attractive if and when the global gas supply and demand balance starts to tighten in the 2020s.

If Qatar and Australia can ultimately benefit from new brownfield development over the longer term, countries and companies planning to develop brand new greenfield projects are set to be hit hardest by the current low-price environment. Two particular examples of this issue are Canada and East Africa (Mozambique and Tanzania).

Canada

As of March 2015, applications had been made for 25 LNG export projects in Canada, with four of these on the East Coast, two for supply to US plants in Oregon, and 19 for plants in British Columbia. This last group has been the main focus of attention for foreign investors who have been keen to exploit the country's large conventional and unconventional resources at a time when demand for pipeline exports to the USA has been in sharp decline. As a result the national government and the relevant provincial authorities have been keen to encourage an alternative route for exports to the growing Asian market, which is only 8–11 days away from Canada's west coast. However, this proximity is offset by the operational and political difficulties inherent in bringing gas an average distance of around 1500 km over the Rocky Mountains to LNG plants on the coast, also traversing land owned by First Nations peoples who are keen to extract value from the process. These logistical and operational difficulties have caused the average breakeven price for Canadian LNG to be around $11.50–12.00/MMBtu, meaning that project sponsors have been keen to price the gas under oil-linked contracts assuming an oil price of $100 or more. In consequence, the fall in the oil price over the past 12 months has led to most Canadian projects being postponed, officially or unofficially, until market conditions improve after 2020, despite the best efforts of the government to improve the fiscal conditions.

'… THE FALL IN THE OIL PRICE OVER THE PAST 12 MONTHS HAS LED TO MOST CANADIAN PROJECTS BEING POSTPONED …'

East Africa

A similar story is also unfolding in East Africa, although with slightly different drivers. Huge gas discoveries have been made offshore Mozambique and Tanzania that could support multi-train

LNG projects, and the large resource base located close to the planned liquefaction facilities can provide a relatively low upstream cost for the projects. However, the legal, political, and logistical issues involved in developing a huge greenfield project from scratch in a country where new regulatory and legislative regimes will need to be put in place before any major investment takes place, had created issues for project sponsors even before the oil price declined. In addition, the establishment of brand new service and supply bases, as well as the cost of importing all the necessary equipment and manpower, means that the breakeven price of East African LNG delivered to Japan is around $10.50/MMBtu, again encouraging the operators to seek oil-linked contracts (on the assumption that these would result in a high price) and thus undermining their hopes of rapid development at a time of global LNG surplus and lower prices.

Russia

One other country where LNG projects have also been postponed is Russia, although here it is a combination of lower oil price plus US and EU sanctions that have led to a re-think of strategy. Gazprom and Rosneft have both effectively pushed back projects

'… THE OUTLOOK FOR RUSSIAN LNG HAS BEEN SHARPLY REDUCED OVER THE PAST 12 MONTHS.'

in the Far East that were targeted at the Asian market (Vladivostok LNG and Sakhalin 1 LNG respectively), while the one Russian project that is progressing (Novatek's Yamal LNG) is still awaiting final project financing agreements. Sanctions have undermined the ability of all Russian companies to access capital markets, whether the companies themselves are sanctioned or not, and the risk of LNG equipment being added to a future sanctions extension has also put off potential customers who were already hesitant to commit to Russia during a time of geopolitical uncertainty. When this impact of sanctions has been combined with a lower oil price environment, which has limited the ability of Russian companies to go it alone, the outlook for Russian LNG has been sharply reduced over the past 12 months.

Conclusion

In conclusion, it is no surprise that all LNG producers have been significantly affected by the decline in the oil price. Worst hit have been those companies with greenfield projects yet to take FID decisions, many of which are now likely to be postponed for at least two to three years. Although the owners of brownfield sites and new projects about to come on stream have also been hit, their competitive position is stronger as costs have already been sunk, with the result that the point-forward economic prospects are more robust, as long as the project sponsors can still afford the financing costs. For those that cannot, consolidation or asset sales will be the likely outcome. From a pricing perspective, two other outcomes are worth noting. Firstly, any un-contracted output from projects already in production or set to come on stream will put further pressure on an already saturated market. And secondly, the pressure from consumers to shift away from oil-linked contracts is likely to recede for a time; nevertheless the new lower oil price environment (combined with the convergence of global LNG spot prices on a netback basis across Europe, Asia, and the USA) could continue to catalyse a debate about the future of price formation mechanisms in LNG contracts. Indeed consensus between consumers and producers on a hybrid formula based on a basket of oil and market prices may now be achievable given the closing of the disparity between the various alternatives.