LNG Markets in Transition

Anne-Sophie Corbeau
Research Fellow, KAPSARC (Saudi Arabia)

In its 52-year history, the Liquefied Natural Gas (LNG) industry has experienced its fair share of bumps in the road. Recent developments, however, suggest even more radical changes that could have been envisaged as far back as two years ago. The energy industry is going through the largest increase in LNG capacity ever, built over a period of six years: 157 million tonnes per annum (mtpa) – equivalent to twice the LNG export capacity of Qatar. These new supplies are arriving in a market environment significantly different from what the industry anticipated when investment decisions were taken. In aggregate, more capacity is being built than any sponsor expected, and LNG demand in the premium Asian market dropped in 2015 while oil and gas prices have halved compared to their original levels. Beyond these market fundamentals, other changes are already visible through stakeholders' behavior. New players are challenging existing ones in different parts of the LNG value chain, bringing new ideas and developing new business models, which could profoundly transform the way LNG is produced, traded and sold to end-users.

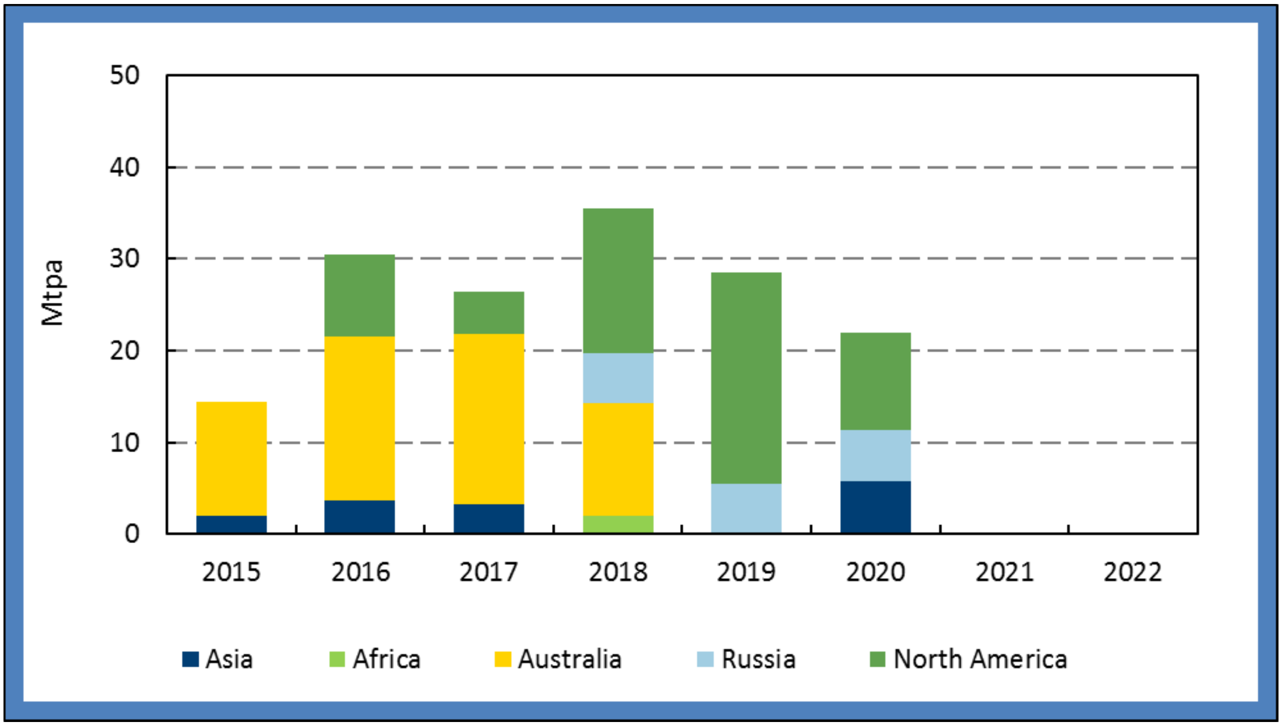
This should have been a happy story. As of June 2014, the gas industry was expecting that the large expansion of LNG export capacity would enable it to increase its share in the global primary energy mix, challenge coal in Asia, bring the advantages of a cleaner burning fuel to new LNG importing countries and help tackle energy poverty issues. It counted on Asian countries to be ready to pay a premium – at least prices close to those achieved in 2011-14 – for supply security and better air quality. A year before COP21, gas once again presented itself as the ideal partner for intermittent renewables. But despite its clear advantages, natural gas is still a fossil fuel. Most of the Intended Nationally Determined Contributions (INDCs) presented at COP21 do not consider it as a long-term solution, with the exception of those presented by gas producing countries. Ironically, coal is often preferred as a cheaper – often domestic – source of electricity. The externalities of coal-fired generation are rarely taken into account in developing countries. Many Asian countries such as Malaysia, Indonesia and Vietnam are building large coal-fired fleets. Besides, lasting high prices have given gas the label of an expensive fuel in the eyes of many importers. Consequently, the future of natural gas – and LNG – appears uncertain at this stage.

Yet, the storm clouds brewing on the horizon did not prevent LNG supply investments. As of June 2014 – a couple of months before oil prices started to drop and the Chinese economy began to show signs of weakness, around 100 mtpa had already been sanctioned to start in 2015-20. Interestingly, only one U.S. project – Cheniere's Sabine Pass trains 1 to 4 – belonged to that group. But additional U.S. LNG projects joined the herd on the heels of Cheniere, attracted by the large arbitrage between Asian and U.S. gas prices that could be captured by feeding increased Asian demand. Between August 2014 and late 2015, five additional projects and one project expansion, representing around 47 mtpa, were approved. Such large capacity additions would not be a problem if there were a market to absorb them. But even though gas prices plummeted, gas-fired plants remained largely uncompetitive against coal in the absence of a carbon price or tax. Additionally, low crude and oil product prices meant that these fuels remained competitive in the industrial, transport and power sectors, reducing the incentive to switch from oil to gas.

As new LNG projects started operating during 2015 and 2016, the dynamics of the global gas markets suddenly changed and started to reflect the oversupply. LNG supply did increase in 2015, albeit only by 6 mtpa due to outages in existing LNG plants and startup delays of new plants. Stronger growth is expected with around 35 mtpa of new LNG capacity starting operations (including the restart of Angola LNG). 2016 will certainly be remembered as the year of the first LNG cargo shipped from the U.S. Lower 48, but also a time when gas prices in Europe and Asia started to move in tandem again, dropping to around $4/MMBtu in spring. These two trends – rising supply and lower gas prices – are prompting sellers to search for new markets and countries to consider the LNG option with renewed interest. The latter trend became visible in 2015 as Jordan, Egypt and Pakistan started importing LNG. In 2016, new floating storage and regasification units (FSRUs) and floating storage units (FSUs) were commissioned in Colombia, Jamaica, Malta and Abu Dhabi. Looking ahead, countries with undeveloped and nascent gas markets could start importing LNG. These include Latin America (Costa Rica, Panama, El Salvador, Cuba); Southern Africa (Namibia and South Africa); West and North Africa (Morocco, Ivory Coast, Ghana, Benin, Senegal); and Asia (Myanmar, the Philippines). Such markets pose a different problem to investors: the transport infrastructure is limited, demand centers are small, creditworthiness is low and there is a need for anchor customers and project finance. They are also small, at least in the early stages, which means that they will contract to buy small volumes of LNG, multiplying the negotiating efforts of sellers. They are also extremely price sensitive: while there is a lot of interest in LNG at prices around $4-6/MMBtu, what will happen if and when prices rebound to higher levels?

A potential market squeeze beyond 2020 is currently the greatest worry of investors and buyers alike. Up to 2020 the pipeline of new LNG projects is very healthy. (See Figure 1 on the next page.) But with only two Final Investment Decisions in 2016 – train 3 of Tangguh in Indonesia and Woodfibre LNG in Canada, the LNG supply outlook beyond 2020 is very thin. The start date of a few projects will probably slip by about one year compared to the initial announced date. Delayed commissioning were seen in Australia and the United States. Some were due to technical difficulties, such as those experienced by the Gorgon LNG project in Australia, but project sponsors may have delayed the start of others in order not to worsen existing oversupply. As prices have dropped and future LNG demand is uncertain, LNG projects are struggling to move forward. Only the most competitive ones will be able to move ahead, brownfields such as Tangguh or those able to bring a competitive advantage including Woodfibre. It is notable that these projects are small (3.8 mtpa and 2.1 mtpa, respectively), which is a far cry from the 15 mtpa Gorgon or 22.5 mtpa Sabine Pass plants. They may also suit market needs better as buyers hesitate to commit for large volumes and long durations.

Figure 1
LNG Capacity Additions, 2015-22



Buyers have become more demanding about what they are ready to accept in terms of contractual conditions. Contract renegotiations in Asia have been relatively unusual compared to Europe, where pricing and flexibility elements were renegotiated in many long-term contracts after the 2009 oil price collapse. Some Asian utilities, on the other hand, sustained heavy losses during the period 2011-14. Their demands as such focus on three different aspects: 1) pricing mechanisms, 2) flexibility and 3) final destination clauses. Asian buyers want gas to be more competitive. While Petronet, the Indian company set up to import LNG, is asking for a 10 percent supply reduction from Gorgon LNG in Australia, there is also a general push from Japan, Singapore and China to index LNG prices on an Asian hub that would better reflect the region's supply/demand dynamics but this has yet to be created. Current market conditions are pointing to a five to 10-year period from 2017 onward where oil indexation will coexist along with Henry Hub plus netbacks based on European spot prices and regional indices such as Platt's Japan/Korea Marker. Creating a transparent and liquid hub could take a decade. However, a transition to hub pricing could accelerate if term and spot prices diverge significantly; for example, if oil prices rebound and spot gas prices remain low due to LNG oversupply. There are still some crucial elements that need to be put in place in many of these markets, including pricing liberalization and access to LNG terminals, except for in Singapore.

The need for flexibility is driven by increasing uncertainties on future demand, both at a country and company level. For example, a Japanese buyer would be struggling to forecast Japan's future LNG demand, which depends on policy decisions on nuclear, renewables, energy efficiency and the relative competitiveness of gas and coal. Additionally, the liberalization in the gas and power sectors means that such a buyer has to be more competitive than its peers. Meanwhile, the increase in spot and short-term LNG trade seems almost inevitable. It accounted for 28 percent of global LNG trade in 2015, and could represent up to 43 percent by 2020. This increase will be driven by additional quantities of uncommitted LNG, portfolio LNG, flexible U.S. LNG, Qatar LNG and limited extension of expiring contracts. Added together, these elements point to a more challenging environment for long-term contracts as buyers hesitate to commit for the usual 20 years and ask for shorter durations.

Final destination clauses from long-term contracts are another area of discontent. They are seen as an obstacle to the free movement of LNG and to the creation of trading hubs. Japan is particularly active on that specific issue and its Fair Trade Commission has been investigating whether such clauses are impeding free trade of LNG. They are likely to be the first ones to be removed from contracts.

Sellers are increasingly worried that buyers' demands have become too one-sided and how far negotiations could go. LNG is a capital intensive and cyclical business. Long-term commitments from buyers are still regarded as essential for projects to move ahead, notably because banks regard these elements as an essential part of project financing. But creditworthy buyers with long-term visibility are becoming a rarity and while new companies in existing markets and new would-be LNG importing countries are emerging, they do present a risk due to a potential lack of financing, payment issues and inadequate infrastructure. New markets and additional demand in developing markets are the hope of the LNG industry, but would contracts with such buyers convince lenders? Or does that lead to the inevitable rise in portfolio players who would directly secure LNG supplies from new facilities and then sign secondary sales contracts. This effectively transfers the risk to portfolio players, which could end up being long in supply at a time of market surplus. Such players have already taken an increasing role in the LNG business. Half of the long-term contracts signed in 2015 and most of the short-term contracts had "portfolio" as the origin, which means they were not attached to a specific LNG export plant.

Beyond that, sellers fear that contract sanctity itself could be at risk. So far very few contracts have been canceled in the LNG industry. During renegotiations, buyers and sellers strive to find an acceptable solution. One key development to watch will be the U.S. LNG export plants where the off-takers have to pay the liquefaction fee regardless of whether they take the LNG or not. So far, low market prices in Europe and Asia mean that off-takers have to consider the liquefaction fee as a sunk cost. Should this situation continue, the weakest off-takers may have difficulties sustaining multimillion dollar losses and may seek to renegotiate or cancel their contracts. This would have far-reaching consequences as banks would begin to look at buyers and the sanctity of contracts in a totally new light.

Endnotes

This article is based on the main findings of the KAPSARC/OIES book: LNG Markets in Transition: the Great Reconfiguration, (Oxford University Press, 2016).

Author Biography

ANNE-SOPHIE CORBEAU
Research Fellow, KAPSARC (Saudi Arabia)

Ms. Anne-Sophie Corbeau is a Research Fellow at KAPSARC. She has over 15 years of experience in the energy industry with a focus on global gas markets. She is the co-editor of the KAPSARC/OIES book, LNG Markets in Transition: The Great Reconfiguration (2016). Before joining KAPSARC, she worked for the International Energy Agency and IHS CERA. Ms. Corbeau joined the IEA in 2009 as Senior Gas Expert at the Gas, Coal, and Power Division. She was responsible for managing the research on global gas markets, with a particular focus on short- to medium term developments. She was the main author of the publication, "Medium Term Gas Market Report," and also authored and co-authored several publications on China, India, trading hubs and LNG markets.

Prior to this assignment, Ms. Corbeau worked at IHS CERA (Cambridge Energy Research Associates) as Associate Director of the European Gas team. As a specialist in European gas market fundamentals and demand forecasting, she was responsible for updating the short- and long-term market outlooks for natural gas supply and demand, and prices in Europe. Prior to joining CERA, she worked in the fuel cell area.

She holds an M.Sc. in Energy Engineering from the Ecole Centrale Paris and an M.Sc. in Energy Engineering and Economics from the University of Stuttgart.