

## The supply outlook: Australia and the USA

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High oil prices in the period 2010–14 combined with the impact of growing energy demand in China and the shock of the Fukushima disaster in Japan to create a world in which high LNG prices in Asia (often above \$15/MMBtu) catalysed a wave of new LNG investment. Australia was at the forefront of this wave, and was later joined by the USA, where companies saw an arbitrage opportunity to export the rising tide of cheap shale gas to markets prepared to pay a premium price. As a result, these two countries embarked on a period of construction that, by 2020, will see them having increased their LNG liquefaction capacity by 126 mtpa. Unfortunately, this expansion is being completed at a time when LNG demand expectations are being downgraded, and prices have fallen dramatically; this will have significant consequences for future projects in both countries.

### Australia

In spite of the impact of the current downturn in prices, the gas industry in Australia has much to be proud of. Australia is set to become the largest LNG exporter in the world by the end of this decade, with sales volumes set to reach 86 mtpa by 2019, moving the country up from its second position in 2015 to overtake Qatar. Seven new projects have been developed since 2009 and these have started to come on stream since early 2015, adding to the three projects already operating. Significant innovation has accompanied this surge in industrial activity, with the first coal seam gas (CSG)-to-LNG schemes in operation in Queensland, the first floating LNG (FLNG) project set to come online offshore Western Australia, and the largest carbon dioxide (CO<sub>2</sub>)

sequestration plant being built at the Gorgon field on the North West Shelf. In addition, the intense levels of construction and the spillover effects into the rest of the economy have significantly boosted Australian GDP. However, despite these successes, the intensity of the LNG expansion in Australia has also brought unique challenges, with demand for labour and equipment causing both sharp cost escalation and project delays. These factors, combined with the appreciation of the Australian dollar during the period 2010–13, have challenged the economics of a number of the schemes that are now coming on stream. This means that if the LNG price does not return to within a range of \$10–14/MMBtu, none of these schemes is likely to generate positive returns on a full cost basis.

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Despite these setbacks, the companies involved (who have spent a combined total of over \$200 billion) must generate cash to start the process of recovering their costs and servicing debt repayments, meaning that further extensive delays are unlikely. Indeed, the start-up of production at the three CSG projects on the East Coast since late 2014 underlines the fact that progress is being made. However, the industry's growth thereafter is likely to stall as project developers struggle to generate sufficient cash to reinvest in new projects. Evidence for this is already clear in the number of possible new projects which have been cancelled or delayed in 2014 and

2015. Even brownfield expansions, which would normally be an obvious way of generating synergy from existing assets, are likely to be deferred until signs of an oil and gas price recovery emerge. Some good news can be found in the easing of cost and currency pressures on projects in production or under construction, but concerns are now emerging about the willingness of buyers to fulfil purchase obligations under current contracts. Although it seems unlikely that terms will be changed dramatically, it is clearly possible that if demand in Asia remains weaker than expected, offtakers may be forced to sell any surplus gas on the spot market, further weakening prices and competing with uncontracted equity volumes being sold by project developers. Such developments could further undermine project economics and act as an additional barrier to new projects, but it could benefit the Australian domestic market, where complaints over rising prices could be eased if spare gas becomes available. However, the federal and state budgets are set to suffer from lower tax revenues in a low-price environment, meaning that the Australian government is likely to have little opportunity to provide further investment incentives to LNG operators.

These factors suggest that we are reaching the end of the Australian LNG boom, although the extent of the country's gas resources offers the potential for further, more modest, expansion in the mid-2020s once the current global LNG oversupply has dissipated. Indeed, while a pessimistic view would suggest that Australian LNG is likely to plateau at 86 mtpa for some years, there is clearly the potential for further brownfield expansion at the



current projects. While it is difficult to tell exactly which might take FIDs for new trains in the next five years, an upside case might see up to 20 mtpa of new capacity being approved by 2020 (to come online before 2025) as and when the oversupply situation in the global market looks to be coming to an end. It would therefore not be unreasonable to assume that, if gas prices head back towards a \$10–11/MMBtu range, Australia could be producing more than 100 mtpa of LNG by the middle of the next decade in a more positive investment scenario, given the lower cost of brownfield expansion compared to the recent greenfield developments that have dominated the Australian industry.

**The USA**

The emergence of the USA as an LNG exporter has arguably caused the greatest transformation in the LNG industry in the past three decades. Not only has gas become available at prices related to a market benchmark (Henry Hub) rather than to the price of oil, but the traditional contractual model has also been challenged by the emergence of aggregators, who will purchase gas from liquefaction tolling plants and distribute it globally according to demand and price trends. As a result US LNG will provide consumers not only with new volumes of LNG but with an alternative, and competitive, marketing offer.

By mid-2016 the US Department of Energy had received 25 applications for new LNG export projects, offering potential future capacity of 311 mtpa. However, while most of these have received non-FTA approval for export sales, only six have received the more stringent FERC (the US Federal Energy Regulatory Commission) approval

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which allows construction to begin. Of these, five (with a total capacity of 64 mtpa) were under construction and one (Sabine Pass owned by Cheniere Energy) is now in production. Numerous cargoes, including two bound for Europe, have been loaded, heralding the arrival of US gas onto the global market. The Sabine Pass liquefaction facility, like the four other projects under construction, is based at existing sites with regasification (import) capacity; this reduced the initial capital expenditure and meant that the tolling fee paid by companies who have contracted to take the LNG was a relatively modest \$3.00–3.50/MMBtu. As a result, the total cost of US LNG, delivered to Europe, can be calculated as: the US Henry Hub price (at present around \$2/MMBtu) multiplied by 1.15 (to allow for gas purchase, boil off, and fuel use) plus liquefaction, transport, and regasification costs. Given the current low rate of shipping tariffs, this effectively means a landed cost in Europe of around \$6.5–7.00/MMBtu.

However, this full cost is well above the current spot price either in the UK or continental Europe, which was approximately \$4/MMBtu in mid-May 2016. US LNG exporters may therefore be forced to sell their gas at a price that is close to the short-run marginal cost in order to compete – in other words treating the tolling fee as a sunk cost. On this basis, US LNG could be sold into Europe at a very competitive price (around \$3.50–4.00/MMBtu), but the consequences for offtakers could be profound. They will clearly not be

making a return on their investment, and will actually be losing money on a cash basis as they meet their contractual obligation to pay the tolling fees to the LNG plant owners – such as Cheniere. As a result, two interesting questions emerge:

- How long will they be prepared to continue selling LNG at a loss?
- Will there be any incentive to build new LNG export facilities in the USA?

The answer to the former would seem to be ‘at least a year or two’ given the robust nature of the counterparties involved, but the answer to the latter would equally appear to be ‘there will be little new construction activity beyond the existing committed facilities’. Some project sponsors continue to trumpet the prospects for their projects, and schemes such as Golden Pass, owned by ExxonMobil and Qatargas, may have some logic within a global LNG portfolio that can maximize synergy benefits between markets and supply. However, it must now be increasingly uncertain whether any other new projects will receive FID before the end of this decade, or before the gas price in Europe (and/or Asia) rises above \$7–8/MMBtu.

**Conclusion**

As a result, although the growth of the LNG industries in Australia and the USA have transformed the global gas economy, their current state reflects the problems faced by the industry as a whole. Large projects are unlikely to make expected returns and some smaller project participants may go bust as a result. Nevertheless, the infrastructure has been built and will continue to produce while it can cover cash costs, meaning that the global oversupply of gas is likely to continue to the end of the decade at least.

