LNG

Outlook for competitive LNG supply

A number of new LNG supply value-chains are due onstream by 2025. *Claudio Steuer*, Senior Research Fellow, OIES, assesses their affordability and competitiveness.*

The final investment decision (FID) in February 2019 by LNG Canada and Golden Pass LNG will increase global LNG supply capacity by nearly 30mn t/y, surpassing all new LNG supply capacity committed between 2015–2017. LNG Canada's decision is the first major greenfield LNG FID in a remote location since the Yamal LNG FID in 2013.

If we consider the Eni FID on the Mozambique South Coral floating LNG (FLNG) project where the entire 3.4mn t/y LNG capacity was acquired by BP over the last two years, 33mn t/y of new LNG supply capacity was underpinned by major international oil companies (IOCs) and shareholders of LNG Canada and Golden Pass – Shell, Petronas, PetroChina, Mitsubishi, Korea Gas, ExxonMobil and Qatar Petroleum.

Since the abrupt drop in energy prices from mid-2014, LNG buyers and sellers have diverged on contracting terms and pricing for new LNG supply. Project developers became cautious and focused on significant cost reductions. In the absence of a mutually satisfactory contract, large IOCs and partners took their LNG supply project FID and chose to go long on LNG supply, adding to their existing portfolios, waiting for improved market conditions and LNG buyers to commit to new long-term contracts.

The surge in investment in new LNG supply capacity raised expectations for 2019–2020, and involved a record number of new LNG supply projects competing to reach FID.

The challenge to the future of gas is directly linked with energy policy and the speed of global decarbonisation which could render natural gas unburnable before it becomes unaffordable

Next global wave

There is a significant competitive advantage for LNG project developers in geographic locations with access to significant low-cost resources, proximity to high volume and/or high value markets, and opportunity to achieve competitive liquefaction project costs. Five geographic locations have high-profile for FIDs over the next two years – Qatar, the US, Russia, Mozambique, and Nigeria.

Financing multi-billion dollar projects involves equity investments, shareholder and commercial loans and, where applicable, project finance with the involvement of export credit agencies and the World Bank providing political risk insurance for countries lacking sufficient regulatory and mega-project track record. In such a complex and challenging business environment, expansion of existing projects with a proven track record and strong balance sheet also have significant competitive advantage.

Table 1 shows LNG projects under development aiming for FID during 2019–2020 and totalling 302.7mn t/y, of which almost 100mn t/y is comprised of expansion of existing projects.

Competitiveness

The competitiveness of an LNG project is defined by the capital costs of the liquefaction plant, upstream gas supply and LNG shipping costs. Hydrocarbon fiscal arrangements and financing of upstream and midstream projects also affect the competitiveness of an LNG project, but given the complexity and confidentiality of such agreements they are not covered in this analysis.

The economic efficiency of the upstream gas supply component can be improved by additional crude oil, condensate and LPG revenues which help amortise the investment needed and enable potential cost savings on an integrated project. The upstream component can require as much, or more, investment than the liquefaction plant itself.

LNG plants in remote locations require the development of comprehensive gas treatment facilities, utilities, maximum liquid recovery, potential carbon dioxide (CO_2) treatment, sequestration and storage, ancillary infrastructure, and marine facilities for LNG tankers and residential facilities. Complex LNG plants in remote locations are often in competition with other major energy projects such as refinery or petrochemical complexes for the same limited pool of experienced contractors and equipment suppliers. They are also more exposed to cost inflation from higher energy prices than less complex LNG plants in non-remote locations.

If we consider a five-year moving average cost** of LNG liquefaction ($ t/y in 2018 $ prices) after a gradual decrease over nearly three decades, a significant escalation in cost was seen from January 2003 ($357 t/y) to December 2012 ($1,874 t/y), coinciding with about 90mn t/y of remote location LNG projects developed in Australia, Yamal and two FLNG projects. The five-year moving average oil price also showed a phenomenal increase in this period (from $21.64/b to $92.10/b). The 50% decrease in unit cost in the following five years, to reach $941 t/y in December 2017, largely came from 39mn t/y of LNG supply projects developed in the US Gulf of Mexico benefitting from existing LNG regasification terminals. The marine facilities and LNG tanks of a regasification terminal represent about 50% of

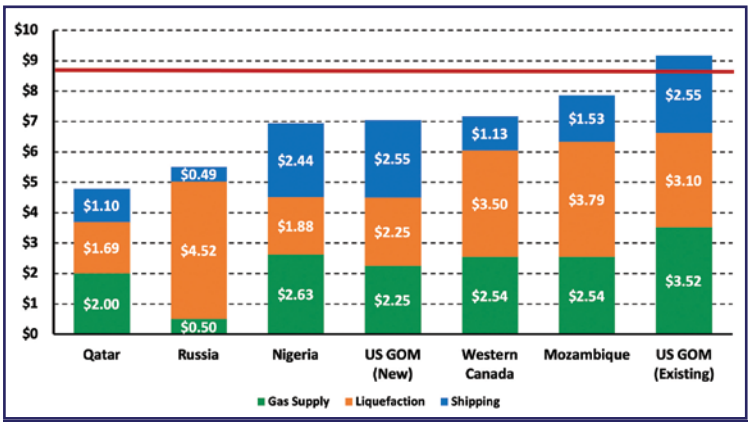

Figure 1: LNG project competitiveness in $/mn Btu – high-income market test – Japan, Korea, Taiwan or China (JKTC) 2025

Source: EIA, ICIS Global LNG Markets, Forward Curves CME Group as of 14/12/2018, SyEnergy estimates

LNG projects	Country	Leader	Type	FID	Start-up	mn t/y
Calcasieu Pass	US	Venture Global	Greenfield	2019	2022	10.0
Magnolia	US	LNG Limited	Greenfield	early 2019	2022	8.0
Golden Pass	US	*Qatar Petroleum*	*Brownfield*	*end 2018*	*2023*	*15.6*
Cameron T4-5	US	*Sempra*	*Brownfield*	*2019*	*2023*	*10.0*
Plaquemines	US	Venture Global	Greenfield	end 2019	2023	20.0
Port Arthur	US	Sempra	Greenfield	2019	2023	13.5
Driftwood	US	Tellurian	Greenfield	2019	2023	27.6
Rio Grande	US	Next Decade	Greenfield	2019	2023	27.0
Goldboro LNG	Canada	Pieridae Energy	Greenfield	2019	2023	10.0
Sabine Pass T6	*US*	*Cheniere*	*Brownfield*	*2019*	*2023*	*4.5*
Costa Azul	*Mexico*	*Sempra*	*Brownfield*	*late 2019*	*2023*	*2.5*
Jordan Cove	US	Pembina	Greenfield	2019	2023	7.8
Lake Charles T2-3	*US*	*Energy Transfer*	*Brownfield*	*2019–20*	*2023–24*	*11.2*
Texas LNG T1-2	US	Texas LNG	Greenfield	2019–22	2023–26	4.0
Bear Head T1-4	Canada	LNG Limited	Greenfield	2020–21	2024–25	8.0
Corpus Christi T1-7	US	Cheniere	Greenfield	2020–21	2024–26	9.5
Annova LNG T1-6	US	Exelon	Greenfield	2020–21	2024–26	3.0
Americas total						**192.2**
Tortue FLNG	Mauritania	BP	FLNG	end 2018	2022	2.5
Fortuna FLNG	Equatorial Guinea	Ophir	FLNG	2019	2022	2.5
Nigeria LNG T7	*Nigeria*	*Nigeria LNG*	*Brownfield*	*2019*	*2023*	*8.0*
Cameroon FLNG	Cameroon	NewAge	FLNG	2019	2023	1.4
Mozambique LNG	Mozambique	Anadarko	Greenfield	early 2019	2024	12.9
Rovuma LNG	Mozambique	ExxonMobil	Greenfield	2019	2024	15.2
Congo FLNG	Congo Brazzaville	NewAge	FLNG	2020	2024	1.4
Africa total						**43.9**
Sakhalin T3	*Russia*	*Shell I Gazprom*	*Brownfield*	*2019*	*2023*	*5.4*
Qatar T8-11	*Qatar*	*Qatar Petroleum*	*Brownfield*	*2019*	*2024*	*33.4*
Arctic 2 T1-2-3	Russia	Novatek	Greenfield	2019–20	2024–26	19.8
Papua LNG T3	*Papua New Guinea*	*ExxonMobil*	*Brownfield*	*2019*	*2024*	*8.0*
Qatar/ Russia/ Papua New Guinea total						**66.6**
Grand total of LNG projects seeking FID In 2019–2020						**302.7**
Brownfield LNG projects						**98.6**
Greenfield LNG projects						**204.1**

Table 1: Potential LNG and FLNG projects aiming for final investment decision (FID) in 2019–2020 (brownfield projects in italics)
Source: Reuters, Bloomberg, Upstream, Petroleum Economist, ICIS Global LNG Markets and Argus Global LNG

the capex of a liquefaction plant of 10–15mn t/y capacity.

Qatar and Nigeria LNG train 7 are the only two LNG projects which pass all high/low-income market tests, providing ample opportunity to sell all volumes displacing less competitive alternatives. **Figure 1** shows the competitiveness of LNG into the Japan, Korea, Taiwan and China (JKTC) markets. The new wave of US Gulf of Mexico (GOM) LNG projects seeking to implement innovation in technology, train sizes, equipment suppliers, financing and upstream integration fare well in this analysis, subject to their ability to demonstrate technical, operational and commercial viability, and deliver the expected cost reductions. Sakhalin II LNG train 3, as a brownfield expansion with major oil and condensate revenues, is anticipated to feed gas and LNG supply into high-income markets. Mozambique LNG has impressive onshore liquefaction cost targets considering the remote location. Mozambique's geographic location reduces LNG shipping costs to the promising south and south-east Asian markets. Furthermore, Mozambique's ability to secure competitive gas supply cost and supportive fiscal provisions are strategic to supplying the growing low-income India, Pakistan and Bangladesh (IPB) markets.

A bright future

Given the estimated energy prices, liquefaction and shipping costs, project developers wishing to mitigate future uncertainties are best advised to minimise all costs along the value-chain.

The outlook for competitive LNG supply raises confidence of a bright future for gas, particularly for the high-income markets of Northwest Europe (NWE) and Japan, Korea, Taiwan and China. This allows some time for the industry to reduce costs ahead of lower sustained oil prices of about $50/b and gas prices close to $6/mn Btu in NWE and the growing low-income markets of India, Pakistan and Bangladesh.

Brownfield expansions and greenfield projects implementing technology innovation, competitive procurement strategies, commercial business models, project financing and synergies with upstream projects should do well. The LNG industry has the capacity to reduce costs further.

Integrated LNG projects with oil, natural gas and liquid revenues will continue to enjoy the most competitive foundation for an LNG supply project. The ability to generate project capex and operational synergies and revenue from liquid hydrocarbons, also provides significant price flexibility for LNG – as exhibited by Qatar, Russia and Nigeria LNG projects. Qatar has a high condensate yield when producing natural gas, enabling it to price natural gas at the level necessary to reach FID on new supply projects. Russia and Nigeria have significant oil production, liquids, associated and non-associated gas production to feed an LNG plant, and feed-gas price is either a percentage of the delivered LNG price or determined by government energy policy to stimulate export revenue.

Resource-rich countries need to promote energy policies supporting complex interconnected energy projects – particularly greenfield LNG. The timeliness of such projects ensures that production of energy resources will unlock social and economic benefits before demand has decreased significantly or production ceased to be economically viable.

The outlook for LNG supply is maximised by the industry's ability to continue lowering the cost of world-scale plants, increasing the viability of small-scale LNG and FLNG projects, reducing total investment and simplifying financing of LNG projects. This will increase the range of viable LNG projects closer to end-user markets, lowering logistic costs and supporting faster adoption of natural gas and LNG as a transportation fuel on land and sea, thus accelerating the commoditisation of gas and LNG underpinning future merchant LNG projects.

For as long as the industry remains supply constrained, LNG suppliers will tend to maximise business with higher-income markets to reduce overall project complexity and increase profit. Even if it is economically feasible to supply LNG to low-income markets, buyers in such markets may find it difficult to secure LNG supplies, or may have to pay a higher price, resulting in the future of gas being uncertain for such low-income markets until LNG supply becomes unconstrained.

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*This article is based on a recent Oxford Institute for Energy Studies (OEIS) paper entitled *Outlook for Competitive LNG Supply* reviewing seven LNG supply value-chains from Mozambique, Nigeria, Qatar, Russia, the US (existing Gulf of Mexico supply projects and new ones under development) and Western Canada capable of producing new supplies of LNG by 2025. Special attention was given to LNG's ability to meet the affordability and competitiveness test proposed by Jonathan Stern's paper *Challenges to the Future of Gas: unburnable or unaffordable?*, where LNG needed to reach high-income markets at a maximum of $8/mn Btu and low-income markets at a maximum of $6/mn Btu.

**Oil, gas and LNG spot and long-term energy prices estimated for 2025 based on historical information from the EIA, ICIS Global LNG Markets, CME Group Forward Curves, as of mid-December 2018, and regression analysis where needed. Affordability and competitiveness tests were developed for high-income markets (Northwest Europe [NWE] and Japan, Korea, Taiwan and China [JKTC]) and low-income markets India, Pakistan and Bangladesh (IPB). All LNG shipping cost calculations assume a 180,000 cm ME-GI LNG tanker and, for Qatar, a Q-Max 267,000 cm SSD LNG tanker; long-term charter with bunker fuel compliant with IMO 2020; port fees, and Suez and Panama tolls calculated for 2018 and escalated by 2%/y up to 2025.