LNG: How will new technologies in LNG impact its market?

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Energy Industry

Report

The Abdullah Bin Hamad Al-Attiyah International Foundation for
Energy & Sustainable Development

INTRODUCTION

LNG: HOW WILL NEW TECHNOLOGIES IN LNG IMPACT ITS MARKET?

Liquified Natural Gas (LNG) faces strong cost competition, both from new projects, and from coal and renewables. Simultaneously, gas is facing environmental opposition, particularly in Europe.

Which new technologies are becoming available to reduce costs, generate extra value, and improve environmental footprint? Where in the LNG value chain are they being deployed? And what business models will make the most of these new technologies?

Energy Industry Report

This research paper is part of a 12-month series published by the Al-Attiyah Foundation every year. Each in-depth research paper focuses on a prevalent energy topic that is of interest to the Foundation's members and partners. The 12 technical papers are distributed in hard copy to members, partners and universities, as well as made available online to all Foundation members.

EXECUTIVE SUMMARY

- It is vital for LNG projects to be cost-competitive, given the great expansion of competing projects, the continuation of low-cost coal, and ongoing improvements in renewable energy. This requires delivered costs of $6-8/MMBtu, equating to liquefaction costs (net of feed-gas cost) of $2.125-4.125/MMBu.
- LNG technology improvements are being driven by this cost imperative, as well as by a move to new areas such as the Arctic; a more diverse, flexible and liquid industry; and growing environmental pressures.
- LNG technology is improving across the value chain, but the most important cost reductions are in liquefaction, as this is the area of largest capex. LNG trains are probably not going to get larger, but there will be innovation in both small/mid-size train sizes.
- Key enablers for cost reductions and environmental improvements in liquefaction include modularisation, floating LNG, electric drive, automation/digitalisation, and carbon capture and storage. However, many incremental improvements are also combining to reduce costs and improve efficiency.
- Shipping and regasification offers less room for cost reductions, but more scope for innovative business models, supported by technologies such as satellite imaging and tanker tracking, advanced logistics and scheduling, and targeting small-scale markets and LNG ship bunkering.
- Technologies on their own are not fully effective; they have to be embedded in a suitable business model.

- LNG is a relatively mature technology with limited scope for dramatic cost reductions. However, significant incremental improvements are achievable, and LNG will continue to expand into new environments including deepwater, the Arctic, unconventional resources, and small and remote fields.
- This means competition to large incumbent LNG suppliers will continue. However, they can leverage these technologies to reduce their own costs.
- Small-scale LNG and 'hub-and-spoke' models for smaller markets offers access to new customers, important at a time of abundant LNG supply and relatively low prices.
- Major gas exporters have to contend with increasing environmental pressures. Improved energy efficiency, electric (including renewable) drive, methane leak reduction, and carbon capture and storage, are key technologies for reducing their LNG exports' greenhouse gas footprint. FLNG can be useful for developments in environmentally or socially sensitive areas.
- Major exporters have to consider the suitability of their organisational and business models, and what needs to change to realise the potential of digitalisation and automation, in particular.

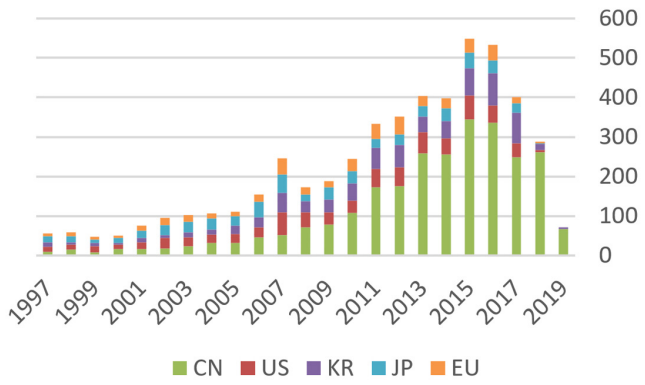
THE CURRENT LNG EVOLUTION

Liquefied natural gas (LNG) is at a crucial stage. Both supply and demand have grown explosively over the past two years and are set for further rapid expansion, but prices have plunged amid fears of over-supply. Supply has moved to exploit smaller and remote fields, unconventional gas production, and harsh environments including the Arctic. Old-fashioned cheap coal in Asia, and newly-competitive renewable energy, pose strong challenges to mass use of gas in the power sector. The LNG business model is evolving, with a shift to shorter contract terms, the emergence of smaller markets, new uses for shipping and small-scale deliveries, and more trading intermediaries. Further, signs have begun to emerge of environmental opposition to the use of gas.

Technology is critical to meeting these challenges. But technology in isolation will not be effective. It has to be coupled with adjustments to business models.

Historically, LNG technology has advanced incrementally rather than by radical steps, given the expense of each component of the value chain, and the premium placed on reliability by consumers.

FIGURE 1 NUMBER OF LNG PATENTS CLAIMING PRIORITY, BY YEAR AND COUNTRY [i]



Although LNG has a long history, research activity has increased greatly in recent years (FIGURE 1). China in particular has increased patent claims, reaching a peak in 2015 (the drop-off since then may just reflect the delay in filing claims).

South Korea has overtaken Japan as the second most important, with the US and EU relatively under-represented.

This high level of research could indicate a significant number of innovations coming into use in the coming years.

GOING LARGE OR GOING SMALL

Cost-competitiveness needs to improve across the entire value chain to ensure strong growth for LNG. Low-cost LNG, with a modest environmental premium, is competitive against coal in a growing swathe of European countries, but it will face increasing pressure here from solar and offshore wind. Coal is the key rival in growing Asian markets – particularly India, where government policy support for gas is less than in China.

It has been argued that LNG has to be delivered to high-income markets at less than $8 per MMBtu, and to low-income markets below $6 per MMBtu, to be competitive[ii] . Assuming shipping costs of $1/MMBtu, and Henry Hub feed-gas at $2.50, with 15% of feedgas used to run the liquefaction process, that allows $2.125-$4.125/MMBtu for liquefaction capital expenditure (capex) and non-fuel operating expenditure (opex). For a project with cheaper feed-gas, or co-product liquid (condensate and natural gas liquids (NGLs), the liquefaction capex and opex could be somewhat higher.

This range equates to about $600-1200 per tonne per year of liquefaction capacity[ii]. In recent years, only Qatar (which benefits from existing infrastructure, giant scale, low feedstock costs and high associated liquids) has come in cheaper than the lower limit (US brownfield projects have been a little higher). West Africa, Russia, and the cheaper Australian projects have matched or slightly exceeded the higher level. All other projects, therefore, face a severe challenge to their economic viability, unless they can reduce costs through better project management and improved technology.

Historically, a large share of LNG cost reductions has come from larger-scale projects and trains. These realise savings in the sizing of process equipment, utilities, marine facilities, and operations.

The step-change in train size came with ExxonMobil's Qatargas-2 and Ras Laffan-3 facilities in Qatar, which at 7.8 million tonnes per year (Mtpa), were twice the size of contemporary trains and three times as big as those of the 1990s. ExxonMobil plans to employ 7.4 Mtpa trains at its Rovuma plant in Mozambique. The scale-up has reduced unit capital costs by about 40%.

Super-sizing applies to vessels too, with the Q-Flex and Q-Max tankers having 45-80% more capacity than their predecessors[iv], reducing shipping costs by about $0.5 per MMBtu.

However, large sizes bring disadvantages too. They require giant supporting gas reserves, which may not be available at all sites. A smaller number of contractors are able to handle the larger project, and the logistics, complexity and risk of project management failings are elevated. In the evolving market, few customers want to contract for 7 million tonnes of supply, and this makes marketing a single large train a lengthy process, unless the project sponsor takes the risk by absorbing the volumes into its portfolio. The upper limit of LNG train sizes has therefore probably already been reached.

Building two or more trains sequentially allows experience to be gained, and for ordering duplicate items in series, improving factory utilisation and efficiency[v]. This approach was adopted by Egyptian Idku trains 1 and 2, and by Nigeria LNG trains 4 and 5, cutting costs for the second train by 50%.

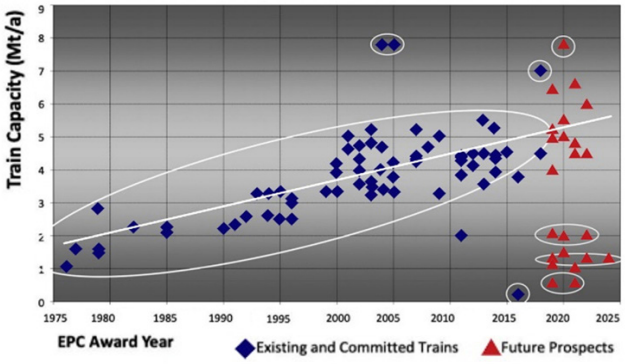
The US LNG plants have mostly opted for mid-size trains. Elba Island is notable for having opted for many more small-scale, modular trains (TABLE 1). The concept of multiple small trains enjoys simplicity but has lower efficiency and increases the equipment count and hence operational complexity and maintenance. Calcasieu Pass and Driftwood are proposing a hybrid, with large common pre-treatment units feeding many small liquefaction trains. However, it remains to be seen if this will succeed in achieving the lower costs of around $500/tonne[vi] projected[vii].

TABLE 1 RECENT LNG PROJECTS AND TRAIN SIZES[viii]

Country	Project & company	Train number & size, Mtpa	FID year
US	Sabine Pass, Cheniere	6 x 4.5	2012
	Cove Point, Dominion Energy	1 x 5.25	2014
	Cameron, Sempra / Total	3 x 4.5	2014
	Freeport, Total	4 x 5	2014
	Corpus Christi, Cheniere	3 x 4.5	2015
	Elba Island, Kinder Morgan	10 x 0.3	2016
	Golden Pass, ExxonMobil / QP	3 x 5.2	2019
	Calcasieu Pass, Venture Global	2 x 5	2019
	Port Arthur, Sempra / Saudi Aramco	2 x 6.75	2019
	Driftwood, Tellurian	5 x 5.5	2019-20
Russia	Yamal LNG, Novatek / Total	3 x 5.5	2013
	Arctic-2, Novatek / Total	3 x 5.5	2019
Canada	LNG Canada, Shell	2 x 7	2018
Mauritania / Senegal	Tortue, BP / Kosmos	1 x 2.5 (FLNG)	2018
Mozambique	Rovuma, ExxonMobil / ENI	2 x 7.6	2019
Papua New Guinea	Papua, Total	2 x 2.7	2019
	PNG Train 3, ExxonMobil	1 x 8	2019
Qatar	Qatargas expansion	4 x 7.8	2019

This bifurcation is shown in FIGURE 1. From 1975 to about 2017, trains steadily increased in size, with the unusually large Qatari trains which were about twice the size of their 2005 contemporaries. But from 2015 onwards, there has been a wide spread, with most trains of 'traditional' size around 4-6 Mtpa, a few large ones of 7-8 Mtpa, typically in remote locations with a single main cryogenic heat exchanger, and many projects with small trains. The 'small' trains fall into three groups: those designed to be modular, quick and simple to build; those for floating LNG (typically in the 1.4-2.5 Mtpa range); and those designed for ship bunkering or other small-scale uses (many more very small projects, such as for trucking and local distribution, are not captured in the data).

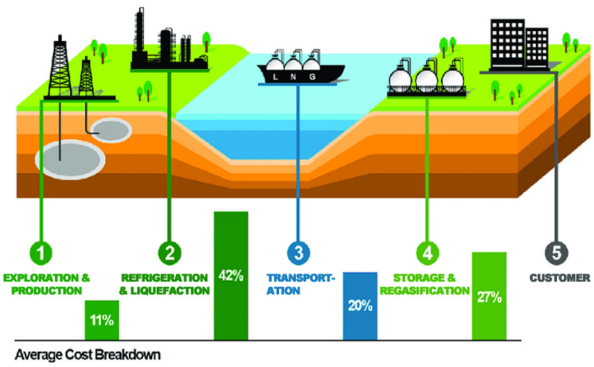
FIGURE 2 LNG TRAIN SIZES BY CONTRACT YEAR[ix]



COST-COMPETITIVENESS IS EVER MORE ESSENTIAL

The most capital-intensive part of the LNG value chain is in liquefaction. Of course, the exact shares vary by project, particularly the upstream cost.

FIGURE 3 SHARE OF CAPITAL COST THROUGH THE LNG VALUE CHAIN[x]



Upstream

LNG projects have benefited from the general advances in upstream and construction technology. US shale gas, in particular, has become available at prices consistently around $2-2.50 per MMBtu, underpinning the viability of American LNG plants.

Projects based on deepwater gas fields have only become economically feasible quite recently, with examples in Mozambique and Mauritania/ Senegal taking final investment decision (FID) in 2019, and other potential in the eastern Mediterranean. Greater Tortue/Ahmeyim floating LNG (FLNG) off Mauritania/Senegal will be the deepest-water project in Africa, at about 2000 metres[xi].

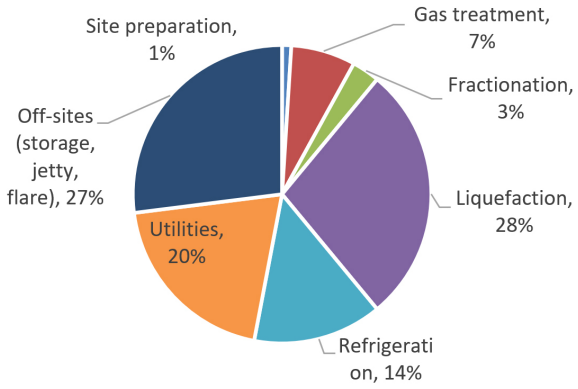
The nature of the upstream resource has an important influence on liquefaction costs. Dry gas reduces processing costs, but has little benefit from associated liquids. Contaminated gas (hydrogen sulphide and/or carbon dioxide) raises pipeline and processing costs significantly. Remote, smaller or deepwater fields may gain from a floating liquefaction solution.

Improvements in upstream from predictive maintenance, high-spec computing for reservoir simulation, massive hydraulic fracturing, microseismic monitoring, drone surveying, subsea production and processing, and other techniques reduce the cost of gas feedstock, but will not specifically be covered here.

Liquefaction

With the largest item of capital cost in the liquefaction segment, this is where most improvement has to come. FIGURE 4 shows typical shares of capital cost for each part of the liquefaction plant. It can be seen how plants based on pipeline-specification gas from a grid, as in the US, benefit in saving on treatment and fractionation. Brownfield expansions or conversions of import terminals can save significantly on utilities and off-site items.

FIGURE 4 BREAKDOWN OF TYPICAL LNG PLANT COSTS[xii]



Beyond increased size and synergies at brownfield locations, liquefaction processes have made various performance gains. A large part of this is achieved by various incremental improvements, optimisation, and standardisation[xiii]. For instance, aeroderivative turbines, first used in the Darwin LNG plant instead of industrial frame turbines, reduce feedstock gas consumption by 20-25%, improve uptime by 2% and have lower weight and footprint[xiv]. Expanders for end flash increase output by about 1%[xv]. Lithium bromide chillers can reduce liquefaction energy by 10-30% and increase train capacity by up to 30%[xvi].

The 'two trains in one' concept pioneered by ConocoPhillips uses one train of highly reliable equipment, such as heat exchangers, served by two trains of turbines and compressors. Even if one compressor trips, the train can continue operating at about 75% of capacity.

There has been some experimentation with the core liquefaction processes. Of liquefaction projects hoping to reach final investment decision (FID) in 2019, 7 are using Air Product's C3MR, historically the most popular process; one is using ConocoPhillips' optimised cascade (the second-most popular historically); one the Shell DMR (the Shell/Gazprom Sakhalin-2 Train 3 project); two the Air Products APX; two the GE Modular SMR; and one each Chart's IPSMR, Black & Veatch's PRICO and LNG Limited's OSMR, none of them well-known previously.

The choice of process represents a trade-off of capital cost, reliability, efficiency and scale. Mixed refrigerant systems are likely to continue to dominate onshore. For floating LNG, non-flammable refrigerants in expander systems will be preferred because of their higher safety and lower space requirement, though they need higher compression power.

Helium, present as a small component in many feedgas streams (North Field in Qatar has 0.04% He, Bayu Undan in Australia 0.1%), has risen in price in recent years as some traditional sources have run out[xvii]. In September's auction of US federal government helium, prices reached $279.95 per thousand cubic feet (compared to spot LNG prices of about $4.50 per Mcf). Ras Laffan in Qatar, and the Darwin LNG plant in Australia, have installed helium recovery systems, which use cryogenic methods to recover helium from the nitrogen rejection unit[xviii], providing a useful additional revenue stream.

Four significant changes offering the potential for step-changes in cost are modularisation, FLNG, electric drive, and automation/digitalisation.

Modular, off-site construction is intended to avoid the disadvantages of extensive work in high labour-cost jurisdictions such as Australia, or in remote and harsh locations. Capex savings can be about 10%. However, it requires more up-front design work, and transporting and installing large modules can be difficult[xix]. So far, the Australian experience has been mixed.

In the same way as modularisation, FLNG concentrates work in highly-productive shipyards in countries such as South Korea[xx]. Floating plants save on the cost of pipelines to shore. They can avoid construction in environmentally or socially sensitive onshore areas. They can also exploit smaller resources, and be re-deployed at the end of field life.

FLNG has only emerged recently as an option, with Petronas's Satu 1.2 Mtpa plant off Malaysia starting operations in 2016, Cameroon (1.2 Mtpa) in 2017, and Tango in Argentina (0.5 Mtpa) and Shell's Prelude (3.6 Mtpa) in Australia in 2019. Both Satu and Tango have been relocated from their original locations, proving the flexibility of FLNG[xxi].

Technical challenges of FLNG[xxii] include the requirement for the process to deal with winds and waves; and for all the units to fit safely in about a quarter the footprint of an onshore plant. It remains a relatively immature technology with significant room for improvement.

Electric drive is being considered for new plants such as Chevron's Kitimat in Canada. The compressors and other units would be run by an electric motor with grid power, in Kitimat's case from hydroelectricity. This minimises the site's carbon dioxide emissions, and can save on costs and improve reliability. Diesel generators are retained for emergency back-up.

As renewable energy becomes more competitive, it may increasingly be used in windy and/or sunny locations.

For instance, powering Australia's LNG industry on renewables would require 3.4 GW of power, and save 410 billion cubic feet (Bcf) of gas annually, almost the east coast's entire demand. Shell is developing a 120 MW solar farm in Queensland to power its operations there[xxiii], and ConocoPhillips plans to replace a gas turbine at Darwin LNG with a battery.

Automation/digitalisation offers improvements and savings particularly in operations, in the same way as for other oil and gas facilities. Predictive maintenance[xxiv] and 'internet of things' (IoT) monitoring[xxv] reduces downtime[xxvi]. Additive manufacturing (3D printing) can be used to fabricate spare parts on site from a stock of raw materials, reducing inventory, supply vessel visits and repair times for remote locations. 'Digital twins' of infrastructure, being implemented by McDermott for Greater Tortue/Ahmeyim, enable optimisation and problem-solving without

interrupting operations. Automation in general reduces the personnel requirements, particularly advantageous for remote and offshore locations.

However, simply digitalising' is not enough. Numerous systems may have to be integrated, possibly by a main automation contractor[xxvii]. The enormous amount of data produced has to be sensibly interrogated, with the involvement of specialist data scientists and analysts. Business processes and training have to be adapted so that the insights from data analytics can actually be used in a timely way to affect decisions, operations. and floating storage.

Shipping

Membrane containment systems cut daily boil-off from 0.15% to 0.1%, and with re-liquefaction to less than 0.07%. Lower boil-off in turn boosts the incentive for higher fuel efficiency[xxviii]. In shipping, moving from steam turbines to low-speed diesel, dual fuel or tri-fuel engines, has improved fuel efficiency by 25-30%.

Lower boil-off and higher efficiency in turn allows LNG vessels to make longer voyages economically efficient. This increases the opportunity for trading, arbitrage and floating storage.

With increasing trading and short-term or spot sales, an end to many destination restrictions, and a much greater diversity of suppliers and customers, route logistics and optimisation is becoming more important and valuable.

Artificial intelligence (AI) and 'big data' analytics, combined with ship tracking and satellite imagery, are being used by companies such as Kpler to inform LNG traders[xxix]. They have already made the business dramatically more transparent, allowing near real-time tracking of flows between specific points. Other 'big data' and remote sensing indicators can point to shutdowns of industrial facilities, surges in economic growth, heatwaves or cold snaps, or other factors that might cause cargoes to be diverted towards or away from certain locations.

Regasification

The break-through in regasification has come from the deployment of floating storage and regasification units (FSRUs). These have 10-20% of the capex of an onshore plant (although this is made up for in ongoing lease costs), and have much faster installation times, and greater flexibility as they can easily be re-deployed, or have additional vessels added if demand increases. FSRUs have been in operation now for about 10 years, so are not a new technology, but they continue to improve. Deployed capacity doubled from 44 Mtpa in 2013 to 83 Mtpa in 2016[xxx].

Technology improvements have concentrated on boosting energy efficiency. Open-loop technologies and recondensers can reduce operating costs up to $100 000 per day, and air heating reduces terminal capex by 1% [xxxi]. Advanced controls improve the stability and safety of gas flow[xxxii].

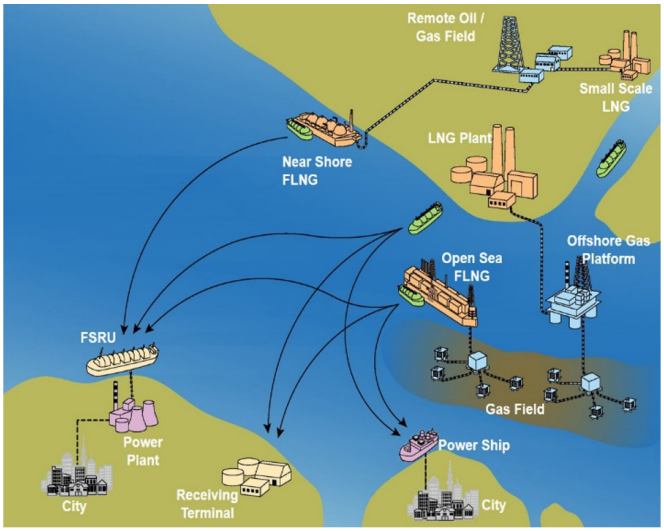
Gains can be made even at existing terminals. These involve recovering boil-off gas, and tapping 'waste cold' for district cooling and boosting power plant efficiency. About 25% of the potential for waste cold recovery is realised in Japan[xxxiii]; Middle East import terminals in particular could benefit from the availability of district cooling.

NEW RESOURCES AND ENVIRONMENTS DEMAND NEW TECHNOLOGIES

The arrival of unconventional gas (shale/tight gas and coal-bed methane) as an LNG feedstock has underpinned the creation of the US, western Canadian and eastern Australian LNG industries. Some of these pose challenges, such as the slow ramp-up, low liquids content and dewatering required for coal-bed methane.

The situation of LNG plants is becoming more varied (FIGURE 5), including deepwater FLNG, nearshore FLNG, small-scale LNG, and different delivery options (floating terminal, conventional onshore terminal, or directly to power generation, which could also be floating).

FIGURE 5 DIFFERENT TYPES OF LNG PROJECTS[xxxiv]



Alongside deepwater (discussed under FLNG), the most significant step into a new environment has been the expansion of Arctic LNG production, first with Snøhvit in Norway (start-up in 2007), Sakhalin-2 (technically sub-Arctic but with similar challenges of low temperatures and sea-ice) in 2009, then with the much larger and harsher-environment Yamal LNG in Russia, commissioned in 2017, to be followed by Arctic-2 LNG, a third train at Sakhalin-2 (2021), and perhaps by projects such as Alaska, and Shtokman in the Barents Sea.

Key issues in Arctic environments include:

- Building on permafrost (which is, worryingly, increasingly undergoing melting), requiring deep piling, and using thermosyphons to refreeze permafrost disturbed during construction.
- Using low-temperature materials for piping and structures[xxxv].
- Avoiding over-cooling in winter;
- Warming piping and machinery.
- Using modularisation as much as possible to minimise outdoor construction work.
- Weatherising the liquefaction plant to avoid the build-up of snow on production equipment, minimise heat loss, but still allow adequate ventilation[xxxvi].
- Managing sea-ice, such as injecting bubbles to minimise residual ice, and monitoring weather conditions.
- Ice-class and ice-breaking tankers, with reversible thrusters and strengthened hulls.
- LNG transhipment, to limit the use of costly ice-class LNG tankers to ice-prone routes, using ordinary tankers to pick up cargoes for the rest of the voyage.

CREATING NEW BUSINESS MODELS AND ADDING VALUE

Recent over-supply and low prices for LNG has spurred a search for new markets. The International Maritime Organisation (IMO)'s regulations limiting the sulphur content of ship bunker fuels, coming into force in January 2020, have raised the profile of (zero sulphur) LNG for ships (see the Al-Attiyah Foundation Research Series Issue 18, February 2018). From 2023, the IMO is expected also to take action to reduce marine carbon dioxide emissions; LNG cuts CO2 by about 28% as compared to fuel oil.

Take-up of LNG-fuelled ships has been limited by the costs of retrofitting and the larger fuel tank required. Carbon fibre tanks, saving 80% of the weight of conventional tanks, are one possible improvement[xxxvii].

LNG sellers are seeking to target smaller markets. This includes islands, such as the Caribbean, where a 'hub-and-spoke' model of distribution, using smaller vessels from a single transhipment point, may be more economically feasible and easier to schedule[xxxviii]. Advanced logistics and scheduling software can help facilitate such business models.

Small-scale LNG can be delivered to ports and then broken into parcels (a common model in China, which has about 20 Mtpa of small-scale capacity). Or, it can be produced from wellhead or pipeline gas at small modular plants. This LNG can then be supplied by truck, rail or barge for users including transport, small industrial users, and remote power plants, a 'virtual pipeline'. Many import terminals in Europe are running at low utilisation factors, and imports for small users could help optimise capacity usage.

This is a very different business model from large-scale deliveries to a power plant or pipeline entry point. It will demand an intimate knowledge of the customers, and an ability to manage logistics and local regulations, where AI solutions may be valuable. Companies such as GE, Kinder Morgan, Shell and PGNiG (Poland) are already engaged in different segments of this 'virtual pipeline' model, such as GE's 'LNG In a Box'[xxxix].

Future businesses can build off the experience of LNG. In particular, hydrogen has attracted attention. Kawasaki from Japan has sought to leverage its experience from cryogenic LNG storage into the storage of hydrogen . Regasification terminals could perhaps be retrofitted to import hydrogen as well, while the business models of the LNG industry since the 1960s can be a guide for a future international hydrogen value chain. Australia and the Middle East are likely hydrogen export points to countries such as Japan.

ENVIRONMENTAL PRESSURES ARE GROWING, AND REQUIRE NEW THINKING

Oil and gas companies are under growing environmental pressure. In Europe in particular, and in some US towns, there are tendencies to try to move directly from coal and oil to renewable energy and electricity, without moving through a phase of large-scale gas use. Part of this is due to concerns over leaks of methane, a powerful greenhouse gas (see the Al-Attiyah Foundation Research Series Issue 30, February 2019); partly because gas itself releases carbon dioxide when burnt, even though it is less carbon-intensive than oil and gas. The environmental and social impacts of upstream facilities are a further worry.

Where viable, FLNG helps reduce the onshore disruption and potential for community opposition. It may face objections from governments, though, because of lower job creation in the host country.

Methane leakage is being addressed by better monitoring, including by light aeroplanes, drones and satellites. A number of quite routine and low-cost measures, including 'green completions' for wells, addressing leaks, eliminating flaring, stopping the use of pneumatic valves, and recapturing boil-off gas, can cut methane leaks substantially.

Carbon dioxide is a more tricky problem. LNG is inherently a more energy-intensive way of delivering gas than by pipeline.

CO2 emissions in liquefaction, transport and regasification are reduced by the energy efficiency measures discussed above. The direct electric drive, using renewable energy, mentioned for Kitimat cuts emissions to 0.1 tonne CO2 equivalent per tonne of LNG, compared to a typical 0.3 tonnes CO2/tonne LNG.

Fields with naturally high levels of carbon dioxide in the feed gas can reinject it instead of venting it. Gorgon LNG[xli] has been required by the Australian government to capture contaminant CO2, at 3.4-4 million tonnes per year, although it has problems in start-up[xlii].

Qatari Minister of State for Energy Affair H.E. Saad Al Kaabi announced in October 2019 that Qatar Petroleum had commissioned a 2.1 million tonne/year carbon capture plant, and that its forthcoming LNG expansion would boost capture to 5 million tonnes annually by 2025[xliii].

Carbon capture, use and storage (CCUS) may become increasingly important, as it would virtually eliminate emissions from LNG plants. Total is investigating coupling cryogenic separation of CO2 with its liquefaction units[xliv]. The EU is believed to be considering standards that would ban gas imports into the bloc with a carbon footprint higher than some to-be-determined level. But ultimately, gas will have to be coupled with CCUS in end use, or converted to hydrogen or petrochemical products, to avoid emissions throughout the value chain entirely.

CONCLUSIONS

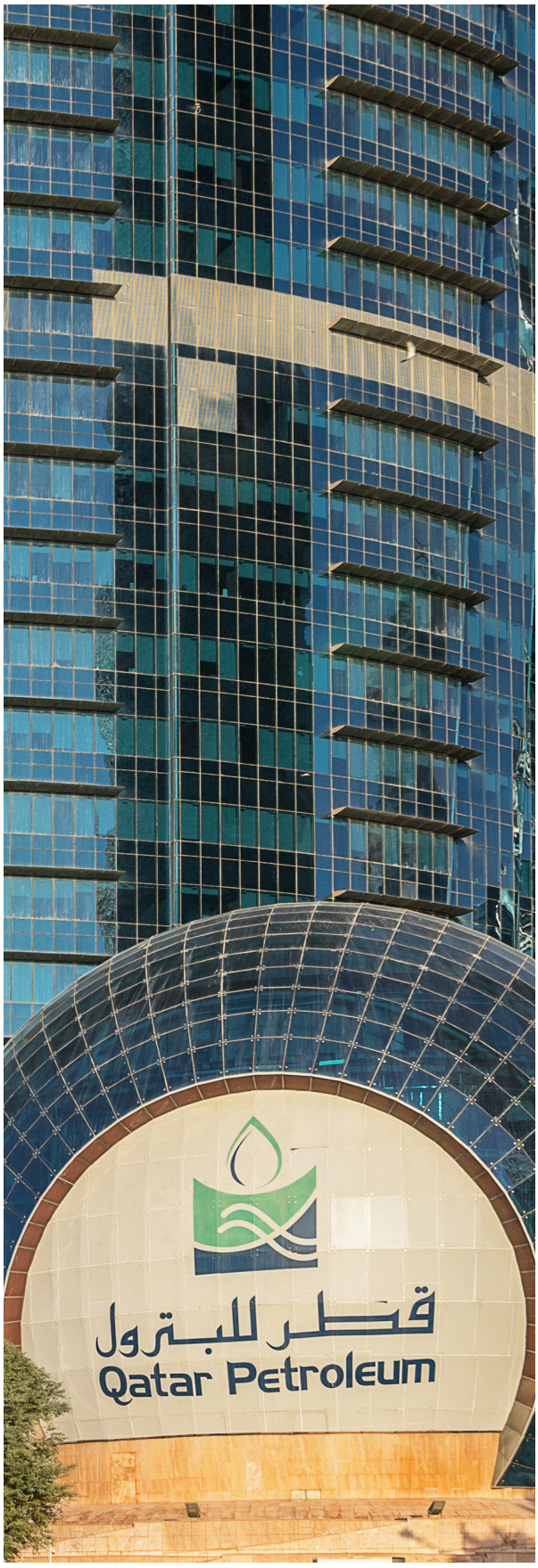
To be cost-competitive against coal and renewables, LNG needs to be delivered to markets at a cost of no more than $6-8 per MMBtu. Only the best LNG liquefaction projects are currently achieving or even close to this benchmark, notably in Qatar, some brownfield US projects, Russia, West Africa and a few Australian projects.

As a relatively mature technology, LNG liquefaction, shipping and regasification is unlikely to see major breakthroughs. The most important recent innovation, the FSRU, is already well-established. FLNG for liquefaction is now also a commercial technology, though it has significant room for optimisation. LNG research has greatly ramped up since the early 2000s, particularly in China, though it remains to be seen how many of these patents make it to commercial application.

Incremental improvements will continue, though. Digitalisation, automation, AI and advanced analytics will significantly improve design, construction, operations and logistics.

Environmental performance will continue to gain ground as a key area, to the point that poorly-performing LNG facilities might not even be able to access markets such as the EU. Improved energy efficiency, electric (including renewable) drive, and CCUS, are the key components of reducing LNG's greenhouse gas footprint.

New small-scale systems, and LNG bunkering, give access to a wider range of markets, potentially with more room for value creation, including through advanced logistics.



APPENDIX

[i] Qamar Energy research using Google Patents; patents by year of priority; search for "natural gas liquefaction"

[ii] 'Challenges to the Future of Gas: unburnable or unaffordable?', Jonathan Stern, OIES Paper NG 125, December 2017

[iii] https://www.oxfordenergy.org/wpcms/wp-content/uploads/2019/03/Outlook-for-Competitive-LNG-Supply-NG-142.pdf

[iv] https://corporate.exxonmobil.com/en/Energy-and-environment/Energy-resources/Natural-gas/Liquefied-natural-gas/Fueling-the-future-cleaner-burning-natural-gas-demand-forecasted-to-triple-by-2040

[v] https://www.oxfordenergy.org/wpcms/wp-content/uploads/2018/10/LNG-Plant-Cost-Reduction-2014%E2%80%9318-NG137.pdf

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Barzan Tower, 4th Floor, West Bay, PO Box 1916 - Doha, Qatar

Tel: +(974) 4042 8000, Fax: +(974) 4042 8099
www.abhafoundation.org

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