ABDULLAH BIN HAMAD AL-ATTIYAH INTERNATIONAL FOUNDATION
FOR ENERGY AND SUSTAINABLE DEVELOPMENT

Issue 23: July 2018

Al-Attiyah Foundation Research Series

Expert energy opinion and insight

Feeding Frenzy: Will there be an LNG Supply Glut?

The rapid expansion of global LNG liquefaction capacity in 2016-18 has raised concerns of a 'supply glut', in which prices would crash and cargoes struggle to be sold. But robust demand and new markets have also emerged to soak up the new supply. As multiple project proponents have emerged, many struggle for finance or are cautious on making an investment decision until they see stronger pricing and demand. Is LNG oversupply likely, and how long will it persist? What signs should investors watch for, and when is the right time for major gas exporters to decide to expand capacity?

LNG carrier Fuji LNG: Ken Hodge

Executive Summary

- **More rapid than expected demand growth** has reduced concerns of a supply 'glut' lasting to the mid-2020s.
- In response, **new final investment decisions** (FIDs) are starting to pick up.
- LNG will **not be in physical oversupply** except in rare cases – prices will adjust to match supply and demand.
- In the longer term, **possible LNG projects vastly outweigh likely demand** – the question is which go forward, and at what price?

Implications for leading gas exporters

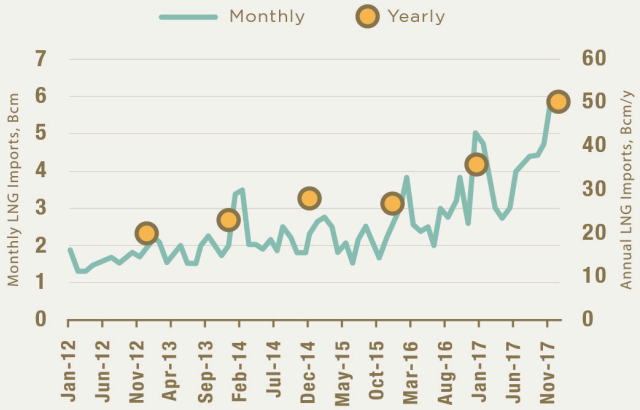
- There is a likely **window of market tightness around 2021-23** – and possibly longer if new FIDs are delayed.
- The European market is the main balancing point, but **China, India and emerging players** are the key ones to watch for growing demand.
- **Creating new markets** – by geography (S/SE Asia, Middle East, Africa) and sector, such as marine transport - diversifies demand and can ease periods of economic oversupply.
- **Cost, financing and capability** are key for new projects to make it to FID and on-time delivery – this is less of an issue for strong established players.

LNG market perceptions have swung from a glut to concerns of a future shortage

Liquefaction capacity grew quite slowly from 2011-2014, a delayed impact of the global financial crisis. It accelerated in 2015-16, and 30 Mtpa of new capacity came online in 2017 with another 40 Mtpa forecast for this year. This rapid expansion, mostly from projects in Australasia and the US, has raised fears of a 'glut' of supply into the early or even mid-2020s.

But low prices (encouraging demand), structural changes in the market, and the emergence of new buyers in the Middle East, Asia and Europe, have reduced worries of oversupply. Chinese demand has been particularly strong because of policies to reduce coal-burning and improve air quality. Demand was up 12.45 Mtpa in 2017[2] and could grow even faster if pipeline constraints can be eased.

FIGURE 01: **RECENT RAPID GROWTH IN CHINESE LNG DEMAND**[1]



LNG demand remains cyclical, price-sensitive and uncertain

LNG demand is a doubly-derived demand. Firstly, consumers require electricity or heat, which can be met in different circumstances by oil, gas, coal, nuclear and renewable power. Secondly, if they opt for gas, in many parts of the world it can be supplied by LNG or pipeline.

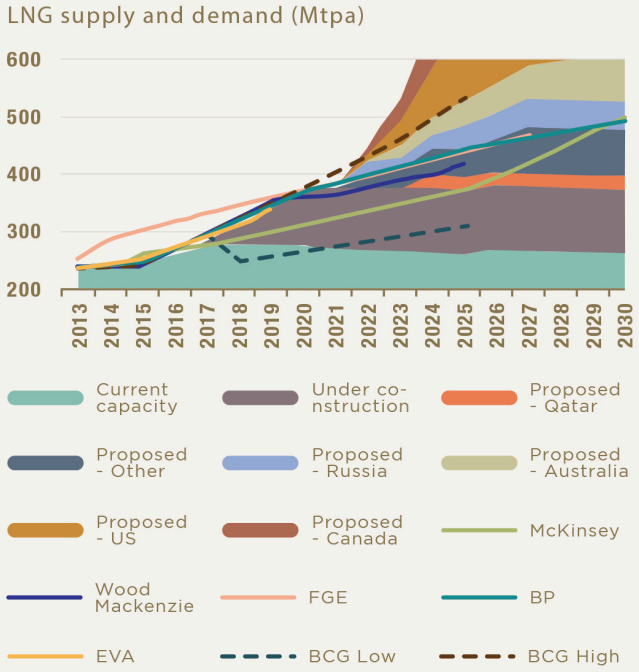
LNG, like energy generally, has always been a cyclical business, magnified by the long timelines for new upstream developments. But the business also faces growing structural challenges, relating to business models, competition, regulation and the environment.

TABLE 01: **LNG SUPPLY AND DEMAND UNCERTAINTIES**

Cyclical uncertainties	Structural Uncertainties
Demand	
Global economic growth	Competition from renewables
Trade Wars	Chinese air quality policy
Geopolitical unrest	Global climate policy / carbon price
Oil and coal prices	Subsidy removal
	Shipping demand (IMO 2020)
	Pace of Asia / Africa electrification (both demand and competition for LNG)
	Takeaway pipeline capacity (China, NW Europe)
	Emergence of new markets
Supply	
Timing of new liquefaction FIDs	Unconventional gas development (both competition and feedstock for LNG)
Geopolitical unrest	New LNG technology (e.g. FLNG)
Declines in upstream supply to older plants	Financeability of new business models
	Public / community opposition

Because of these uncertainties, forecasts of future LNG demand cover a wide range (FIGURE 2). By 2025, even leaving outside the unusually low McKinsey forecast, and the BCG low/high cases, there is a gap of 28 Mtpa between WoodMackenzie's and BP's views.

FIGURE 02: **LNG SUPPLY-DEMAND BALANCE**[3]



These forecasts suggest a slight deficit emerging around 2021. Some of the 'under construction' plants totalling 110 Mtpa by 2023 are likely to be delayed, in which case the market could be tight during 2021-23.

Out to 2030, likely demand can be met by a mix of proposed projects in Qatar, Africa and the US. If high-case demand materialises, it is likely Russia and Australia would also be required to contribute.

LNG WILD-CARDS

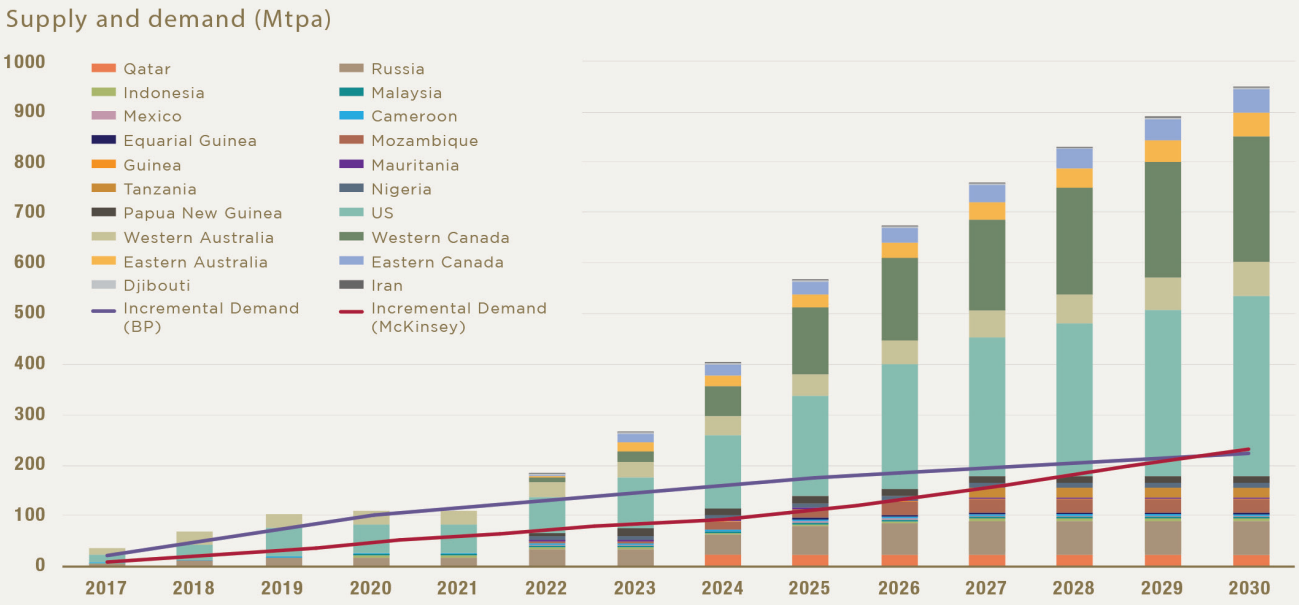
- So far, China has not added LNG to the list of US products facing tariffs, but if it did, this would hamper the further expansion of US production, as most new projects are targeting China.
- However, trade wars would dampen economic growth and fuel use, hitting oil and LNG demand and prices.
- The IMO 2020 ruling will lead to more uptake of LNG in shipping – but also leave surplus fuel oil to be dumped into the power generation market.
- Major new gas developments can turn importers into exporters – as Egypt's Zohr find is likely to do.

There is a long queue of possible new projects

FIGURE 3 shows a simplified view of incremental new capacity from announced projects (under construction and pre-FID), against BP's forecast of demand.

It can be seen that the incremental capacity only just keeps pace with demand in 2020-21. Plants currently under construction are all scheduled to be completed by 2020. After that, the hiatus of FIDs during the low price period of recent years means that new projects will only start by 2022 at the very earliest.

FIGURE 03: **FUTURE POSSIBLE LNG PROJECTS**[4]



Given likely delays and lengthy start-up problems which plants such as Angola LNG have encountered, actual project delivery in 2020-21 is likely to be lower, and the tight period would stretch into 2022-23.

Allowance also has to be made for the likely attrition of some existing plants that may run short of feedstock as local reserves deplete or the domestic market grows.

Given the demand projections, clearly most of these projects will not proceed. Some will be derailed by political problems or community opposition or incapability of the project sponsors. The contracting and labour markets in hot-spots such as Western Canada and Australia would become very tight if several major projects went ahead simultaneously (as was seen in the previous rapid development of Australian LNG and Canadian oil sands).

On the other hand, new projects can also be proposed, for instance further development of the large resources discovered off Mauritania/Senegal, Mozambique, Tanzania and Brazil, or from unconventional gas in various regions. These could reach market around 2025 onwards if they progressed quickly.

After a very slow 2017, new liquefaction FIDs are picking up. Projects to watch in 2018 and early 2019 include Shell's LNG Canada, Tellurian's Driftwood, Jordan Cove on the US west coast, Anadarko and ExxonMobil's competing projects in Mozambique, and perhaps Qatar's North Field expansion.

LNG will not be in physical oversupply except in extreme situations

The idea of a 'glut' does not mean LNG will be produced in large excess of demand. Unlike for oil, storing LNG is expensive because of the need for cryogenic tanks and the loss to boil-off.

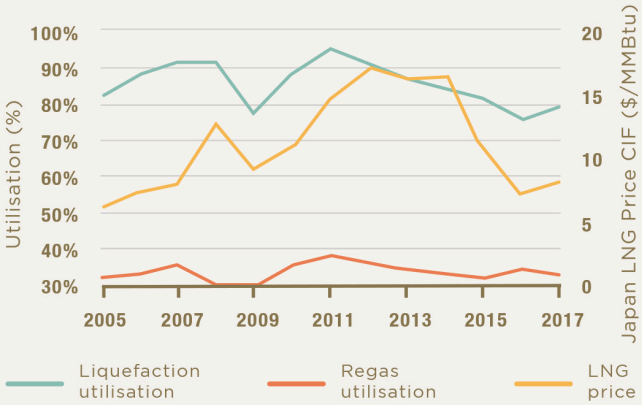
Instead of being in *physical* oversupply, LNG can be in economic oversupply – with prices too low to permit new investment (as in 2014-16). Such a glut means that spot prices particularly would be depressed, and sellers would have to offer more flexible deals to offload unwanted cargoes.

Liquefaction plants generally run at high utilisation factors, 90% on average, because of their large capital costs (FIGURE 4). In recent years, some plants have operated below capacity because of shortages of feedstock (Egypt, Oman, Arun, Algeria) or insecurity (Yemen). As the chart shows, there is some correlation of utilisation with prices, with utilisation dropping to around 80% in 2009 and again in 2014-17. In 2009, Qatar strategically limited production below its maximum as demand had slumped during the global financial crisis.

US LNG is relatively more flexible because of its higher input costs (buying feedstock gas at Henry Hub-linked rates) and the tolling-based business model of most plants, but it would still require quite extreme conditions for it to become preferable to sell gas at Henry Hub prices rather than exporting it to Europe or Asia through an existing LNG plant.

Regasification globally operates at a much lower utilisation than liquefaction, because of seasonal variation in demand, the installation of some regas terminals for security-of-supply reasons rather than regular use, and the overhang of US terminals that have been used little because of the rise of domestic shale gas.

FIGURE 04: **LNG UTILISATION AND PRICE**[5]

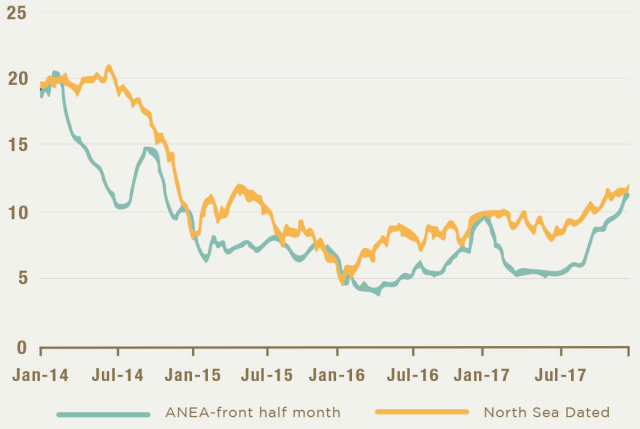


Floating regasification terminals (FSRUs) can be built within 12-18 months, much faster than the typical cycle for liquefaction plants (at least four years). So increased utilisation of existing regas, and access to additional markets via new regas terminals, can soak up oversupply faster than new liquefaction comes to market. This is a sharp change in the market compared to a decade ago, before FSRUs were widely used and when the timelines for new land-based regas terminals were similarly long. This suggests that even if any major oversupply emerges, it will not last long.

As FIGURE 5 shows, LNG prices in NE Asia approached oil parity in late 2017, despite rising oil prices. It would be difficult for them to pass oil parity for long, given fuel-switching, so these relatively high prices suggest a quite tight market.

FIGURE 05: **NE ASIAN LNG PRICES AND OIL**[6]

Northeast Asian LNG Prices test oil parity this winter, $/MMBtu



Europe is the key balancing point

If the market had been oversupplied in the Northern Hemisphere winter of 2017, LNG would have flowed to north-west Europe as the buyer of last resort (see FIGURE 3). Instead, it was attracted to China; NW Europe's imports have been approximately flat since early 2013[7].

Depending on the market situation, European LNG prices can exist in different equilibria (FIGURE 6).

In a balanced market, prices oscillate between a ceiling of oil-price equivalence and a floor of coal-to-gas switching (with increasing carbon prices, and regulatory restrictions on coal burn, that floor is likely to move up).

At times in the summers of 2016 and 2017, European (TTF) prices did fall to coal-switching levels. However, with little remaining coal generation in the UK, France and Belgium, expanding LNG imports further would require more flow to Germany, which may exceed currently existing pipeline capacity.

When the market is in 'glut', the ceiling is set by coal-to-gas switching, and the floor by the short-run marginal cost of obtaining US LNG, set by the Henry Hub price plus variable liquefaction costs and losses (often assumed at 15% of Henry Hub) plus shipping to Europe, around $0.75 per MMBtu. With Henry Hub at $3, that support level would be about $4-5.4 per MMBtu.TTF prices briefly tested the lower level in summer 2016 but not subsequently.

A real glut would require some US LNG to be shut-in. But then US gas prices would tend to fall to a level enough to incentivise even more coal-to-gas switching. LNG tanker rates would probably also fall, and that would re-open the Atlantic arbitrage.

In the possible case of a 'price war' between Russian pipeline gas and US LNG in Europe, the ceiling would be set by the short-run cost of US LNG, and the floor by the Russian short-run marginal cost. However, for now, the Russians have chosen to maintain market share in Europe by including a share of gas indexation, not an outright price war.

Finally, in the longer term, the price may move between a floor given by the full-cycle costs of new liquefaction (FIGURE 7), and a ceiling of oil-price equivalence.

FIGURE 07: **FULL-CYCLE COSTS FOR NEW LNG PROJECTS**[9]

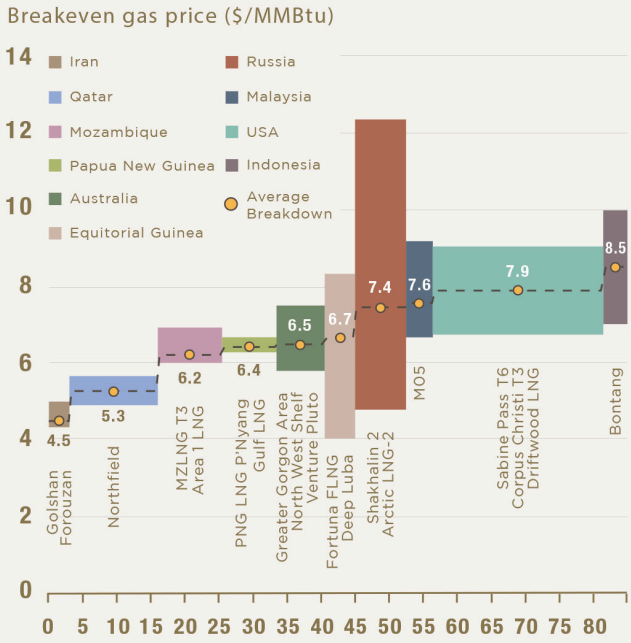
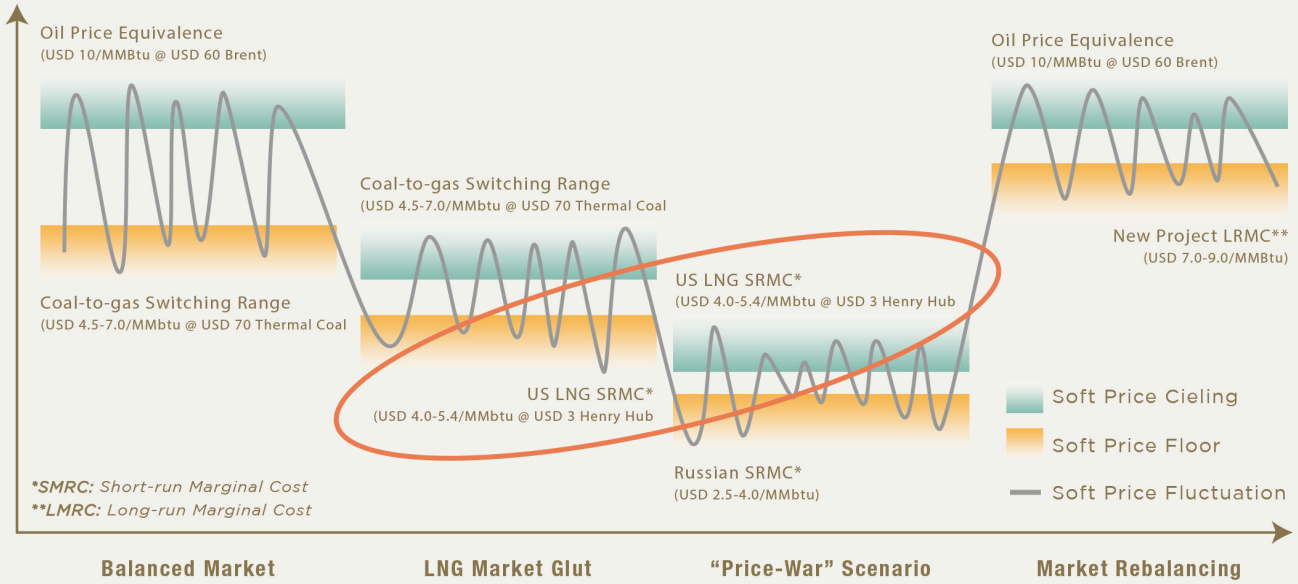


FIGURE 06: **EUROPEAN SPOT LNG PRICE ANCHORS**[8]



Not oversupply – but challenges for sellers, financiers and buyers

The competitive environment and the emergence of new business models is challenging for upstream developers.

Not all projects with low costs will necessarily be developed – the cheapest projects on FIGURE 4 are in Iran and unlikely to go ahead as long as stringent US sanctions are in place. For the more solid projects, break-evens range from Qatar's announced 23 Mtpa at $5.3 per MMBtu, up to new US projects around $7.9 per MMBtu and Indonesia at $8.5 per MMBtu.

Beyond this is a long tail of higher-cost projects, not shown on the chart, particularly in western Canada and Australia. They will have to reduce costs substantially to go ahead, or risk low returns and even balance-sheet impairments if prices fall after they are sanctioned.

Buyers too face challenges from the abundance of choice. They have to judge which projects have a realistic chance of going ahead, in order to secure enough supply for their needs. This task is eased by the removal of destination clauses in Europe and Japan, making it easier to offload surplus cargoes. But traders and portfolio players will continue to gain as key intermediaries by matching uncertain pools of supply and demand, as well as the short-term purchase contracts now demanded by buyers with the longer-term sale agreements still required by lenders.

This new LNG market structure is challenging to financiers, featuring as it does shorter contract terms, more use of portfolio resellers and traders, non-traditional liquefaction projects (FLNG, shale- and coal-bed methane supply), smaller project proponents and non-traditional, less creditworthy offtakers.

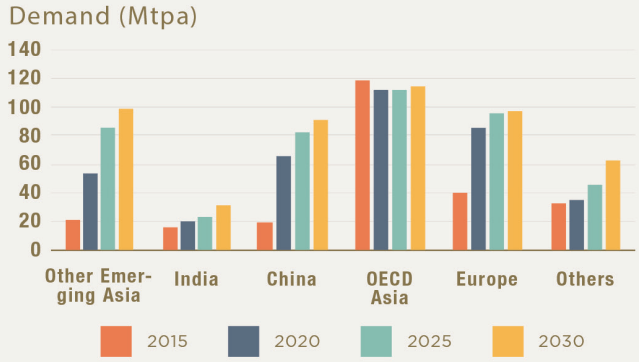
Most of the volume of proposed liquefaction projects is in OECD countries – US, Canada and Australia – posing less political risk but potentially more concerns over environmental and community opposition. Buyers and developers are also wary of Australia and Canada because of their history of cost overruns and delays in energy megaprojects.

It remains to be seen how much the usual long-term financing models can be adapted to underpin new liquefaction, particularly those backed by smaller or start-up players rather than supermajors or large national oil companies. The strong competition makes it challenging to sign up enough sales agreements for a particular project to go ahead. For instance, FID on Fortuna floating LNG in Equatorial Guinea, backed by Ophir, not a traditional LNG developer, has been pushed back from 2016 to 2019 after problems securing finance. However, the broadening of the liquefaction business should mean access to a much wider range of investors. It also diminishes the possibility for strategic delays in projects by dominant players.

Nevertheless, established, reliable, low-cost LNG producers will be in the strongest position to add additional trains. This applies particularly to Qatar. Brownfield expansions of proved projects such as Sabine Pass, Papua New Guinea (PNG), Gorgon, Sakhalin-2 and Yamal also look advantaged.

Demand growth is mostly in Asia

FIGURE 08: **DEMAND BY REGION**[10]



As FIGURE 8 shows, the majority of LNG demand growth is expected to be in emerging Asia, including China and India. China's strongest growth is seen in the near-term, with other emerging Asian countries contributing the bulk of growth from 2025 onwards. Other non-traditional markets such as the Middle East, Latin America/Caribbean and in future Africa will overall grow quickly from a smallish base, but individual importers come and go as domestic supplies compete (as in Egypt, for instance). Shipping demand also has potential for strong growth from minimal levels today, but this is still uncertain and dependent on regulation, pricing spreads and infrastructure development.

Meanwhile, the traditional markets of Japan, South Korea and Taiwan are large but fairly stagnant. European demand increases in the near term because of attractive prices, the entry of new (albeit small) importers such as Malta, Croatia and Lithuania, and declining indigenous supplies but is then quite flat due to improving efficiency and greater use of renewables.

Conclusions: Implications for leading gas exporters

2018 and 2019 will see the arrival of more liquefaction capacity, which may pressure prices for a time. However, the prospect of a prolonged oversupply and depressed prices looks less likely now, unless there is a serious worldwide economic slowdown.

Instead, major gas exporters have the opportunity to take advantage of current low construction costs and a likely window of tight markets around 2021-23. After that, new supply is likely to arrive. But the market will be larger and more stable if another price spike can be avoided. A sharp rise in LNG prices in the early-mid 2020s would run the risk of a 'gold-rush' of new proposed projects, leading to cost inflation and a renewed glut. It would also damage new markets, many of which are very price-sensitive.

The challenge for new project developers is different from that

of established players. They have to differentiate their project – on breakeven cost, finance ability and delivery reliability – in a crowded field. Many large and economic resources will remain stranded because of government incapacity, and environment or community opposition. Conversely some smaller, less-favoured projects may be nimble enough to go ahead as market sentiment shifts.

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