

Fattouh, Bassam (Ed.); Ledesma, David (Ed.)

Periodical Part

LNG in Transition: from uncertainty to uncertainty

Oxford Energy Forum: A Quarterly Journal for Debating Energy Issues and Policies

Provided in Cooperation with:

The Oxford Institute for Energy Studies, Oxford

Suggested Citation: Fattouh, Bassam (Ed.); Ledesma, David (Ed.) (2019) : LNG in Transition: from uncertainty to uncertainty, Oxford Energy Forum: A Quarterly Journal for Debating Energy Issues and Policies, ISSN 0959-7727, The Oxford Institute for Energy Studies, Oxford, Iss. 119

This Version is available at:

<https://hdl.handle.net/10419/306981>

Standard-Nutzungsbedingungen:

Die Dokumente auf EconStor dürfen zu eigenen wissenschaftlichen Zwecken und zum Privatgebrauch gespeichert und kopiert werden.

Sie dürfen die Dokumente nicht für öffentliche oder kommerzielle Zwecke vervielfältigen, öffentlich ausstellen, öffentlich zugänglich machen, vertreiben oder anderweitig nutzen.

Sofern die Verfasser die Dokumente unter Open-Content-Lizenzen (insbesondere CC-Lizenzen) zur Verfügung gestellt haben sollten, gelten abweichend von diesen Nutzungsbedingungen die in der dort genannten Lizenz gewährten Nutzungsrechte.

Terms of use:

Documents in EconStor may be saved and copied for your personal and scholarly purposes.

You are not to copy documents for public or commercial purposes, to exhibit the documents publicly, to make them publicly available on the internet, or to distribute or otherwise use the documents in public.

If the documents have been made available under an Open Content Licence (especially Creative Commons Licences), you may exercise further usage rights as specified in the indicated licence.



forum

A QUARTERLY JOURNAL FOR DEBATING ENERGY ISSUES AND POLICIES

LNG IN TRANSITION: FROM UNCERTAINTY TO UNCERTAINTY

CONTENTS

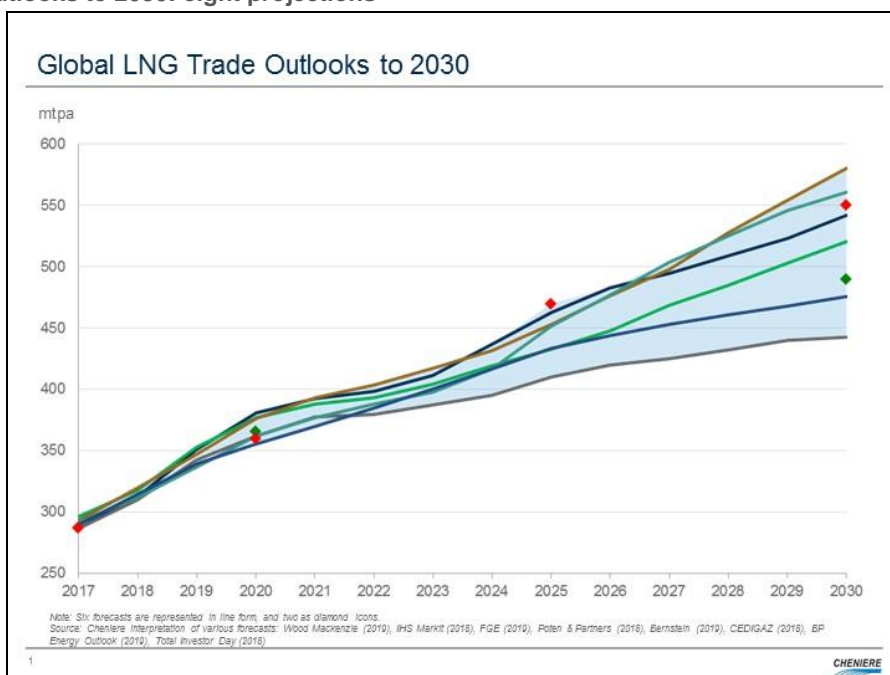
Introduction	1
<i>David Ledesma</i>	
LNG supply/demand balances, 2018–2025: Is there a problem?	4
<i>Mike Fulwood</i>	
Conditions Essential to Reaching FID on an LNG Project	7
<i>Claudio Steuer</i>	
Pipeline gas versus LNG—increasing competition in Europe and Asia	12
<i>James Henderson</i>	
LNG demand in Asia—are growth trends likely to continue	15
<i>Howard Rogers</i>	
Gas Demand in Europe—Is There a Place for LNG	20
<i>Anouk Honoré</i>	
LNG as a Transport Fuel—Is the Demand Real?	23
<i>Chris Le Fevre</i>	
Recent Evolution of European and Asian Prices and Implications for the LNG Market	25
<i>Anne-Sophie Corbeau</i>	
LNG trading, liquidity, and hedging: a new landscape for natural gas benchmarks	29
<i>Gordon Bennett</i>	
Price reviews: Are Asian LNG contract terms finally changing?	33
<i>Agnieszka Ason</i>	
how critical is Shipping to the LNG Value Chain?	36
<i>Bruce Moore</i>	
With the Cost of New Plants, Can LNG Remain Competitive?—A Contractor's Perspective	39
<i>Christopher Caswell</i>	
Is FLNG just a niche supply source?	42
<i>Brian Songhurst</i>	

INTRODUCTION

David Ledesma

This issue of the *Oxford Energy Forum* focuses on LNG's transition from its traditional, more rigid structure to a fully traded commodity. This change is happening during a time of considerable volume growth in the industry, with LNG supply expected to double between 2016 and 2020. The common theme running through this issue is one of uncertainty, be it over the level of demand or supply or the pace of technological advancement along the value chain. An interesting graph provided by Cheniere Energy compares global trade outlooks from eight different sources: consultants, majors, and other organizations. In 2018, global LNG trade was 314 million tonnes (430 billion cubic metres). By 2030, projections vary from 440 million tonnes per annum (mtpa) to 580 mtpa—a difference equivalent to nearly 50 per cent of the 2018 LNG supply level. This reflects the wide range of uncertainties that the LNG market is facing, uncertainties that will be discussed in this issue.

Global LNG trade outlooks to 2030: eight projections



Source: Cheniere

Even though the LNG chain is disaggregating, the pace of growth of the LNG business is driven by different parts of the chain operating independently. Demand growth in one country can lead to LNG supply commitment for new capacity in another country, or the growth of price hedging tools could enable different buyer and seller price aspirations to be bridged, thus enabling an LNG transaction that was previously impossible.

The market is changing fundamentally and, while there may be little to distinguish many of the new potential supply projects, innovation and technological advancement in each part of the chain is driving costs down. New commercial and sales models are enabling supply projects to meet the requirements of buyers who are themselves operating in extremely uncertain markets that are liberalizing and moving away from long-term cost 'pass through' structures. New buyers are entering the market and are able to sign long-term contracts to support the financing of new LNG supply projects, either directly or through aggregators. (An aggregator is defined as a company which purchases LNG from several sources, supplies it to several buyers, and uses its LNG portfolio to its commercial advantage.) The role of traders and aggregators is changing as they take positions along the chain to differentiate themselves, and new companies, including sellers and buyers, seek to trade LNG to gain an additional margin and reduce their risk.

The traditional LNG contract structure where the seller took the (usually oil-related) price risk, while the buyer took the volume risk through long-term take-or-pay offtake contracts, is changing fundamentally. The world today is one of varying contracts, linked through aggregators/traders or directly between buyers and sellers. In 2018, 32 per cent of LNG was delivered on a spot or short-term basis, 25 per cent of which was delivered within 90 days of the transaction date. These percentages will, no doubt,



increase further as US LNG, with no contractual destination restrictions, will enable both sellers and buyers to optimize their risks and returns by selling to the highest-value destination, with flexible markets, such as Europe, acting as the balancing mechanism.

The discussion in this issue starts with three papers on LNG supply. *Mike Fulwood* looks at the current LNG supply position and asks, 'Is the glut finally here?' before exploring the factors driving supply and demand over the coming 18 months—concluding that 'up to the end of 2020, supply growth is expected to exceed demand growth, but thereafter the growth in export capacity is projected to stall, enabling demand growth to start eating away at the excess capacity.' The article examines the OIES FID Barometer, estimating that the next 12 months may see another 60 to 80 mtpa of new LNG capacity take FID (final investment decision), in addition to the 33 mtpa already taken this year. The article then asks if there could be another glut in 2025/26 and, with a view to the impact on LNG prices, concludes there could be downward pressure on prices for the next 18 months, with prices then firming up, ahead of another potential supply glut and price weakness in 2025/26. What is clear from this article is the uncertainty and volatility that the LNG business will face over the coming five to seven years.

The challenges in bringing an LNG project to FID are examined by *Claudio Steuer*, who notes that LNG projects are among the most capital-intensive energy projects per unit of energy from well to burner tip. In an industry study, 64 per cent of the projects surveyed faced cost overruns and 73 per cent faced schedule delays. The article identifies the key LNG project development risks and sets out a list of the essential conditions to take FID on an LNG project. The management of risk along the LNG value chain is key, and the article emphasizes that 'the critical path to reaching FID in LNG projects (rather than the technical aspects of the project development) has become the underpinning of the commercial and financial dimensions of the project.' The decoupling of the established contractual structure, which results in greater complexity that could lead to project delays, has further complicated this.

The final article in the supply section, by *James Henderson*, examines whether pipeline gas is a real supply alternative for gas buyers in Asia and whether LNG will remain the major means of gas supply to these hydrocarbon-hungry markets. The article argues that, at least in some countries, pipeline gas can be an alternative to LNG, with China providing the most obvious example of a country that is maximizing its diversification options. Historically LNG imports were contracted from a wide range of LNG suppliers, thus providing supply diversity and hence security of supply, but LNG supply by ship does not come without risks. The Straits of Hormuz and Malacca are choke points that could be blocked, creating security-of-supply concerns for Asian buyers. Pipeline supply diversification reduces perceived LNG risks. China is sourcing pipeline gas from Central Asia, Myanmar, and Russia, but these pipeline gas options are not available to all Asian countries. Countries such as Bangladesh, India, and Pakistan could have pipeline supply options, which, although still risky, could give these important growth economies vital strategic as well as economic diversification.

This issue then examines LNG demand through three further papers. *Howard Rogers* focuses on Asia and asks if Asian markets will continue to see substantial demand growth or if demand will fall as countries move to renewable sources or keep using cheaper coal which could cause concerns to the LNG companies. The article asks some fundamental questions related to demand in both the new and mature Asian markets and concludes that the growth in Asian LNG demand may be at risk. Chinese LNG imports, though currently strong, are vulnerable to global trade barriers and lower-than-expected GDP growth. Other demand drivers including the uncertainty of government energy mix policy and the extent to which domestic gas production declines will impact LNG imports. These factors, together with the pace of efforts to reduce both CO₂ and particulate pollution and the potential start-up or phase-out of nuclear power, create a high level of uncertainty in the region that, in 2018, imported 75 per cent of global LNG.¹

In the second demand-focused article, *Anouk Honore* focuses on Europe to see what sectors and countries will see gas demand growth and asks a fundamental question: 'Is there a place for LNG in Europe in the 2020s?' The article identifies key uncertainties regarding the pace and scale of Europe's conventional gas production decline, due to fields depleting, or to political or environmental decisions (especially in the Netherlands related to the Groningen field), or both. Where an immediate fall in production could help relieve the potential LNG glut in Europe in 2020 and 2021, it could lead to a tightening of the market in 2023/2024. The disagreement between Russia and Ukraine over the transit of gas through Ukraine also adds uncertainty to gas supply in Europe. Further ahead, after 2025, decarbonization policies could lead to a fall in European natural gas demand.

¹ *Statistical Review of World Energy* (BP, 2019), www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2019-full-report.pdf.



The article notes that it is the demand for gas in non-European countries that will determine the volume of competitive LNG that is available for Europe, a region that provides the global flexible market for LNG, with demand driven by hub gas prices. Higher pipeline and LNG supply would impact hub prices and would determine the relative attractiveness of the European market compared to others.

Finally in this section, *Chris LeFevre* investigates the potential for additional LNG demand from the marine and road transport sectors. He notes that, although transportation is attracting a lot of interest as a new market for gas, LNG as a transport fuel faces considerable uncertainty over the breadth, scale, and rapidity of uptake. From 2020, International Maritime Organization rules will ban ships from using fuels with a sulphur content above 0.5 per cent, compared with 3.5 per cent today (unless they are equipped with scrubbers or use low-sulphur fuel). This will create a demand for LNG, but there are alternative means by which ship owners can meet these rules. The article also examines the drivers behind the development of LNG in transport and the regions and sectors where demand is likely to be most significant. Growth in LNG demand in both the marine and road transport sectors is uncertain, but is expected to be steady rather than dramatic, and is 'not expected to have a major impact on the development of the global LNG market'.

The key changes that are being used by players in the industry in driving LNG's transition to a globally traded commodity have been in pricing, risk management tools and contractual structures. In the first article in the pricing and trading section, *Anne-Sophie Corbeau* examines the roller-coaster LNG market of the past 18 months, likening it to a 'theatre piece in two acts' in which the market moved from being relatively tight in winter 2018/19, with elevated spot prices in Asia and Europe, to a period of relative oversupply, with Asian spot prices (JKM [Japan Korea Marker]) and European gas prices (NBP [National Balancing Point]) falling towards the level of US LNG exporters' operating costs. The article considers the implications of the current LNG oversupply for global LNG markets and prices, and the potential future outlook. Examining the role of JKM, the article asks whether Asian buyers will move away from oil indexation and whether LNG pricing will become commoditized (i.e. priced against its own fundamentals), arguing that the path to a fully commoditized market could be a lengthy one.

The growth of hedging tools to manage LNG market pricing exposure has been dramatic. *Gordon Bennett* argues that liquidity is the measure that determines a market's ability to provide independent price discovery and transparency and enable risk transfer between market participants. A liquid market, by enabling competition, encourages the 'most optimal allocation of an asset'. Even though there are several potential global gas trading hubs, liquidity will coalesce around a few key benchmarks. TTF (Title Transfer Facility) and JKM have emerged as global benchmarks. Whether JKM will remain Asia's only benchmark is yet to be determined, but even if other benchmarks do develop, JKM's ongoing rise in volumes and liquidity seems assured. In discussing the rapid rise of the JKM futures contracts, the ratio of the spot LNG to derivative market is 1:1, and this increased liquidity will, in itself, lead to 'more derivative volume and use for physical indexation'.

Many long-term LNG contracts are bound by strict pricing clauses, and *Agnieszka Ason* discusses how, with LNG markets in transition, LNG contracts are also changing, creating considerable contracting uncertainty for both buyers and sellers. The article notes that the push towards price flexibility has been a key focus in recent negotiations and changes to LNG contract terms in Asia. One area of importance is the inclusion of more detailed price review clauses in newer Asian LNG contracts and the potential use of price arbitrations in case of disputes. The article notes that conditions for price reviews in new Asian LNG contracts are likely to involve shorter price review periods and the inclusion of triggers; downstream market conditions are likely to become more relevant in future reviews. What is not yet clear is whether the changes in price review clauses will lead to wider changes in Asian LNG contracts.

The last section of this issue examines technology in the LNG chain. *Bruce Moore* focuses on shipping, an element that is often dismissed as being of lesser importance than other parts of the chain, but as he points out, 'no ship means no movement of LNG'. Shipping LNG is costly; LNG ships cost approximately double the equivalent oil tonnage while carrying one-quarter of the energy. The availability and cost of LNG shipping can make or break the economics of an LNG deal, whether long, medium or short term. As the sector commoditizes further, shipping, and specifically shipping costs, will become increasingly important, as will maintaining the safety record of the industry. The article challenges the traditional norm that dedicated long-term shipping is required to support the development of the LNG value chain, and examines what is required for the development of a reliable short-term shipping market.

Another area of the chain where technology is having a major impact is liquefaction, and the final two papers focus on this area of the chain. *Christopher Caswell* discusses liquefaction costs and asks whether new LNG plant costs can be competitive and



meet the industry's aspirational target cost of US\$500/tonne. He argues that this cost level is achievable as a stretch goal and challenges teams to look at new technologies and execution methods. He questions the ability to 'commoditize' plant design as a means to reduce costs outside North America. He further argues that it is important to look at projects from both a top-down and bottom-up view in order to achieve such low cost levels.

One potential method is to use offshore floating liquefaction (FLNG) units rather than larger, more expensive land-based facilities. In the final technology-related paper, *Brian Songhurst* asks if FLNG will just be a niche supply source or whether it could become a mainstream technology. The article notes that as well as project development issues, other factors are important. These include weather restrictions for berthing and loading, higher operating costs, the political importance of local content for these high-visibility projects, and the fact that most of the current undeveloped gas reserves lie onshore or close to shore. That said, it is likely, as seen in Mozambique, that FLNG has a role to play as a marginal field enabling tool for longer-term world-scale LNG production.

The editor would like to thank all the contributors to this issue of the *Oxford Energy Forum* for their fascinating articles, Amanda Morgan for copy editing, and Kate Teasdale for pulling it all together.

I hope you enjoy this issue of the *Forum*, and if you would like to discuss any of the points it makes, please feel free to contact me (david.ledesma@oxfordenergy.org) or the authors of the articles direct.

SUPPLY

LNG SUPPLY/DEMAND BALANCES, 2018–2025: IS THERE A PROBLEM?

Mike Fulwood

The glut is finally here

The long-awaited oversupply of LNG finally hit the market towards the end of 2018, leading to a sharp reduction in spot prices. The Argus Northeast Asia (ANEA) spot prices measure fell from a high of just over \$11 per million Btu (British thermal units) in October 2018 to \$5 in May 2019, while the UK National Balancing Point price fell from just over \$9 to \$5 over a similar time frame. The Asian premium has all but disappeared in 2019.

The drivers for oversupply have been slower growth in LNG imports and faster growth in supply. In 2017 total LNG imports grew slightly faster than capacity. In the first nine months of 2018 total imports grew year-on-year by 10.1 per cent, while capacity grew by 9.6 per cent. However, in the six months between October 2018 and March 2019, total year-on-year import growth slowed to 8.5 per cent, while capacity growth increased to 12.4 per cent.

The slowdown in import growth was in the Asian markets. China had been growing at almost 50 per cent year-on-year in the first nine months of 2018, but then slowed to just under 20 per cent year-on-year between October 2018 and March 2019. India had been growing strongly in the first nine months of 2018, but growth turned negative between October 2018 and March 2019. It was a similar story for Japan, Korea, and Taiwan, with growth of 8.1 per cent year-on-year in the first nine months of 2018—very strong Korea growth—and then a decline of 5.5 per cent year-on-year between October 2018 and March 2019. Growth in the other Asian markets picked up, but the supply of LNG was mostly diverted to Europe, where in the first nine months of 2018 there was no growth, but in the next six months year-on-year growth was almost 70 per cent. In the second quarter of 2019 import growth and capacity growth stabilized with some plants down for maintenance.

The growth in China has been impacted by a more gradual approach to rolling out the coal-to-gas switch in industry and commercial and residential buildings, as well as higher growth in domestic production and more pipeline imports. In India, growth has stalled on the back of higher LNG prices in early 2018 plus problems with takeaway pipeline capacity, while Pakistan has been slower to connect power plants. Warmer winter weather also affected Japan and Korea.

In effect, since October 2018, LNG import growth has been confined to China (albeit more slowly), Pakistan, and Europe, with all other markets stagnating or in decline.

The next 18 months—more of the same?

The growth in LNG supply has not yet come to an end. In the 18 months from July 2019 to December 2020, another 58 million

tonnes per annum (mtpa) or 78 billion cubic metres (bcm) of capacity will be coming onstream. This includes Sabine Pass Train 5, Elba Island, Freeport, Cameron Trains 2 and 3, Corpus Christi Train 3, Yamal LNG Train 4 and PFLNG 2 in Malaysia, plus Tangguh Train 3 in Indonesia shortly thereafter. Other plants are expected to ramp up production—such as Prelude FLNG, Cameron Train 1, Corpus Christi Train 2, the Argentine FLNG project, and Vysotsk LNG, with the Egyptian LNG plants returning to full export mode. LNG imports are expected to continue to grow, especially in China and the emerging Asian markets, but growth is slowing or even turning negative in some markets, such as Egypt, where LNG exports are resuming, and Argentina, which has just started exporting LNG from a floating plant on the back of increasing shale gas production.

The rising supply of LNG is facing competition from new pipeline projects into both Europe and China. In Europe, Nordstream 2 is expected to start up in early 2020, ramping up over time, while Turkstream's first leg should be online by the end of 2019 and its second leg a year later. The second leg of Turkstream and the expansion of the Trans-Anatolian Natural Gas Pipeline (TANAP) into Greece, together with the Trans-Adriatic Pipeline (TAP) into Italy, should all be operational in 2020 or early 2021. In China the Power of Siberia pipeline from Russia is projected to start up at the end of 2019, ramping up slowly to its full capacity over three to four years.

European production is expected to remain in decline, so even with a mostly flat demand profile, there will be an increasing import gap, which can be filled by both pipeline and LNG imports. In 2018 the imports gap was around 290 bcm, which was filled by 235 bcm of net pipeline imports and 60 bcm of net LNG imports. (There was some net injection into storage as well.) By 2022 the import gap is expected to have widened to 315 bcm, but net pipeline imports could have risen to 255 bcm and net LNG imports to 70 bcm.

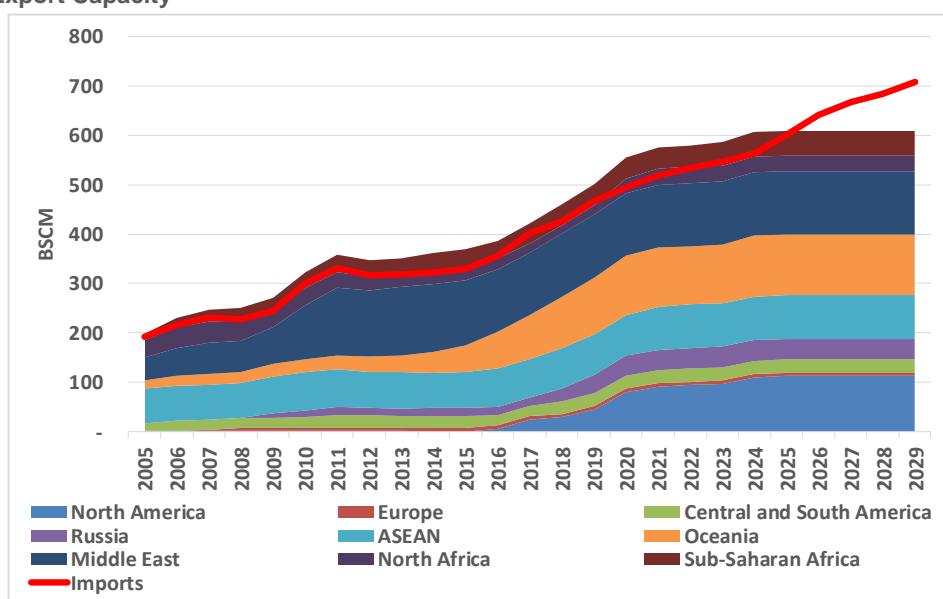
In China total demand is expected to grow from 270 bcm in 2018 to around 400 bcm in 2022. Indigenous production may rise by 50 bcm, pipeline imports by maybe 20 bcm as Russian imports ramp up, and LNG imports by 60 bcm over the same four years. Elsewhere in Asia, LNG imports may be more subdued, with Japan, Korea, and Taiwan declining slightly; but more rapid growth may be seen in the Indian subcontinent, with imports almost doubling to over 60 bcm, and the ASEAN countries may see a rise of over 50 per cent.

Up to the end of 2020, supply growth is expected to exceed demand growth, but thereafter the growth in export capacity is projected to stall, enabling demand growth to start eating away at the excess capacity.

How many more LNG FIDs are needed?

The figure below shows the expected build-up of export capacity for those projects which had taken final investment decisions (FIDs) up to the end of 2018.

Committed LNG Export Capacity



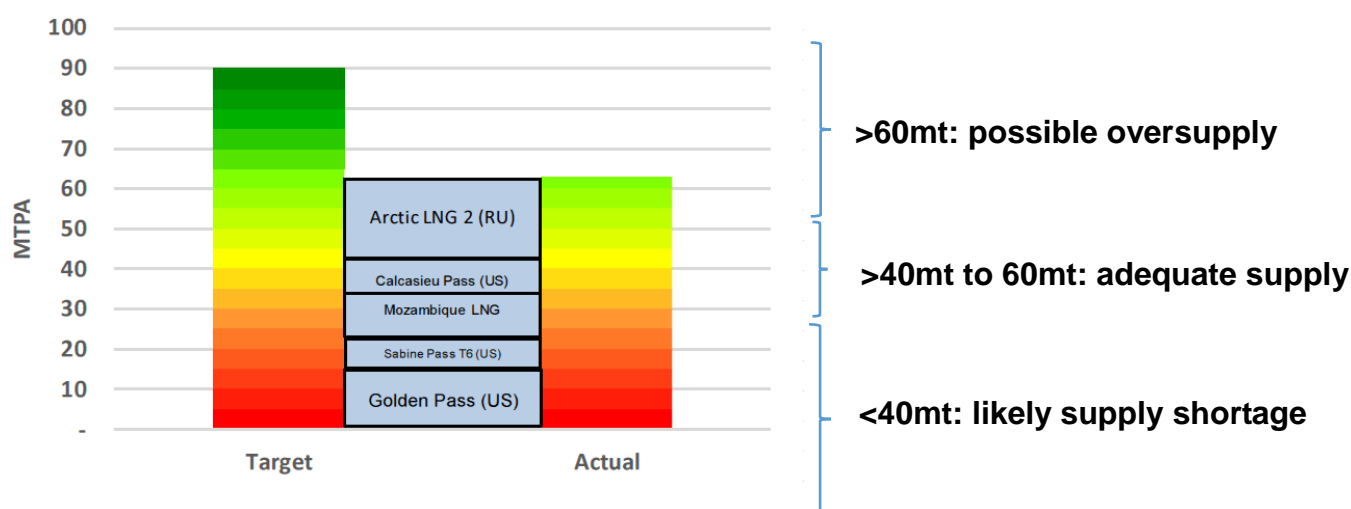
BSCM = Billions Standard Cubic Metres; ASEAN = Association of Southeast Asian Nations.

Source: OIES Analysis. Nexant World Gas Model

Capacity growth is expected to stall in 2021 and 2022, at which point import growth will start to close the gap. By 2025 the world is expected to run out of export capacity as demand increases. This suggests that more FIDs need to be taken in 2019 to fill the gap.

As at the end of August, four FIDs had been taken: Golden Pass (15.6 mtpa) and Sabine Pass Train 6 (4.5 mtpa) in the US, followed by Mozambique LNG (12.9 mtpa), Calcasieu Pass (10 mtpa), also in the US, and Arctic LNG 2 (19.8 mtpa) in Russia. This gives a total of 63 mtpa already this year. The estimated 40 mtpa to 60 mtpa that needs to be taken to fill the gap, has already been exceeded, and with the further projects that currently have the potential to take FID soon, there could be another excess of supply in 2025/26.

LNG FIDs taken to end September 2019



Source: OIES Analysis.

The maximum adequate supply level of 60 mtpa has already been passed, and there are a host of projects lining up to potentially take FID, including the following:

- Rovuma LNG (Mozambique)—15.2 mtpa
- Woodfibre LNG (Canada)—2.1 mtpa
- Qatar 4 train expansion—32 mtpa
- Multiple US projects including Driftwood, Plaquemines, and Texas LNG

In the next 12 months we could easily see another 40 or so mtpa take FID in addition to the 63 mtpa already taken this year.

Potential for another glut in 2025–26

In 2018, total available LNG export capacity was an estimated 460 bcm, while total imports plus the LNG boiled off in transit totalled some 430 bcm—a utilization rate of 93 per cent. By 2022, export capacity is estimated to rise by 26 per cent to 580 bcm, while imports plus boil-off are also estimated to rise by 26 per cent to 540 bcm, giving a marginally higher utilization rate.

With all the FIDs already taken and more possible, we are looking at a sharp rise in export capacity to some 750 bcm by 2026—130 bcm (almost 30 per cent) above 2022. Demand (LNG imports plus boil-off) will continue to rise but much more slowly, possibly only by 100 bcm, suggesting a potential glut significantly greater than what we are seeing now.

A key uncertainty in this analysis is how demand might grow in the main LNG-importing countries and regions, and what this might mean for LNG imports. We have already discussed the 2018 to 2022 period. The 100 bcm rise expected from 2022 to 2026 is likely to be led by the ASEAN countries, with the Philippines and Vietnam joining Indonesia, Malaysia, Singapore, and Thailand to add 30 bcm, and the Indian subcontinent adding 23 bcm, with Pakistan particularly strong. China's growth is likely to slow to only 23 bcm, with almost no growth in Europe. The use of LNG as a bunker fuel globally might add some 7 bcm, together with slow growth in other regions and only very minor growth in Japan, Korea, and Taiwan.



Overall Chinese demand growth is expected to be strong through 2026 with total demand reaching 500 bcm from 400 bcm in 2022. Production growth may be just under 40 bcm, but strong growth in pipeline imports from Russia and Central Asia will likely hold back LNG imports. In Europe, demand is expected to be flat, but with production declining, the import gap will likely widen by 25 bcm, split between pipeline imports and LNG imports.

China and Europe may be key areas of uncertainty, since their import gaps represent the difference between two large numbers, and LNG competes with pipeline imports, so any small changes in demand, production, or pipeline imports could materially change the outlook for LNG and rapidly eliminate the 60 to 70 bcm supply overhang in 2026—60 bcm would take utilization to 93.5 per cent, while 70 bcm would increase it to almost 95 per cent, similar to levels in late 2017 and early 2018. There are other potential pockets of growth as LNG expands into new markets, including possibly in sub-Saharan Africa.

However, there are also downside risks, notably with Chinese demand and whether the other Asian markets—outside Japan, Korea, and Taiwan—will be able to continue the expected rapid growth.

What does this mean for prices?

The dramatic fall in prices since October 2018, when Japan spot prices were over \$11 per million Btu and TTF (Title Transfer Facility) prices over \$8, was the consequence of the glut of LNG on the global markets. Asian spot prices had fallen to the ‘mid \$4’ by July of this year and were very briefly at the same level as or even below European prices. The TTF price, meanwhile, closed at \$3.27 for the July contract, as LNG flooded into Europe and storage was rapidly filled.

In the absence of shocks to the market, one of which could be a failure to reach a new deal on Ukrainian transit, there seems little reason for a material rise in prices, if there is not a very cold northern-hemisphere winter. As the growth in export capacity slows in 2021, 2022, and 2023, rising demand may start to tighten the market, pushing prices higher.

However, by 2025/26, the prospect of very significant growth in export capacity, again well in excess of possible import growth, seems likely to put downward pressure on spot prices.

Conclusions

The rapid decline in spot prices in both Asia and Europe since October 2018 has been a reflection of the growing glut of LNG supply, as import growth in Asia has stalled or even declined in some countries, and especially as Chinese growth slowed. With LNG export capacity continuing to grow through the end of 2020 and into 2021, in the absence of any demand-side shocks, the prospect is for continued price weakness for another 18 months or so.

However, not much supply is expected to come online between 2022 and 2024, and even modest growth in LNG imports will begin to chip away at the supply overhang, with prices likely to firm up. In 2019, though, there have already been four FIDs, totalling some 63 mtpa, with many more lining up to be taken in the next 12 to 18 months. This seems likely to result in another surge in LNG export capacity to come online in 2025–26, significantly in excess of potential demand growth, suggesting another glut may be in the offing.

CONDITIONS ESSENTIAL TO REACHING FID ON AN LNG PROJECT

Claudio Steuer

LNG projects are among the most capital-intensive energy projects per unit of energy from well to burner tip, given the low energy density of methane and the phase change required to enable the economic feasibility of long-distance sea transport at cryogenic temperatures and normal atmospheric pressure.

According to an Ernst & Young survey of 365 projects with a proposed investment of above \$1 billion in the upstream, LNG, pipeline, and refining segments of the oil and gas industry, 205 projects provided updated cost data, and 242 provided updated schedules. Of the projects surveyed, 64 per cent faced cost overruns and 73 per cent faced schedule delays.¹

¹ ‘Evaluating the performance of megaprojects’, in Spotlight on Oil and Gas Megaprojects (EY, 2014).

Cost overruns and schedule delays among energy projects surveyed in 2014

	Cost overruns	Schedule delays	Average budget overrun
By region			
North America	58%	55%	51%
Latin America	57%	72%	102%
Europe	53%	74%	57%
Africa	67%	82%	51%
Middle East	89%	87%	68%
Asia-Pacific	68%	80%	57%
By project type			
Upstream ^a	65%	78%	53%
Pipeline ^b	64%	50%	41%
LNG ^c	67%	68%	70%
Refining ^d	62%	79%	69%

Source: 'Evaluating the performance of megaprojects', in *Spotlight on Oil and Gas Megaprojects* (Ernst & Young, 2014).

^a Upstream projects reported an investment of \$1,080 billion in 163 projects with an average project size of \$6.6 billion. ^b Pipeline projects reported an investment of \$348 billion in 46 projects with an average project size of \$7.6 billion. ^c LNG projects reported an investment of \$539 billion in 50 projects with an average project size of \$10.8 billion. ^d Refining projects reported an investment of \$607 billion in 106 projects with an average project size of \$5.7 billion.

Estimated project completion costs at the time of the survey were, on average, 59 per cent above the initial estimate, representing an incremental cost of \$500 billion. As the survey did not capture all project completions post-FID (final investment decision), the total incremental cost could be higher still. The survey assessed the 20 largest post-FID projects and found that 13 (65 per cent) had cost overruns, averaging 23 per cent of the approved FID budget. This problem was prevalent across all project types and global regions.

Another survey, conducted by Credit Suisse,² found that 65 per cent of project overruns were caused by project management issues such as personnel, organization, and governance; 21 per cent by management processes and contracting and procurement strategies; and 14 per cent by external factors such as government intervention and environment-related mandates. Whilst factors that cause budget overruns or schedule delays are common in oil and gas projects, their impact is more profound on LNG and refining projects due to their scale, required supporting infrastructure, complexity, and cost.

A world-scale LNG plant with 10 million tonnes per annum of production capacity could easily require investments, along the value chain from wellhead to burner tip, of \$30 billion. Based on the Ernst & Young and Credit Suisse surveys, and considering approximately \$20 billion in investments are needed from the well up to and including the LNG ships, the risk of cost overruns and schedule delays could represent an additional cost of \$4.6 billion.

An LNG liquefaction project will have direct or indirect investments, or contractual arrangements (supply, tolling, or leasing), covering upstream gas supply, gas transmission pipelines, gas processing, fractionation and liquefaction plant, storage tanks and marine facilities, and ships to deliver the LNG to regasification terminals.

Essential to reaching FID on an LNG project is the treatment of risk: assessing and quantifying its likelihood and potential severity, and developing a mitigation strategy with clear accountability. LNG projects have a long business development cycle—which may span a decade from resource discovery through the conceptual phase, preliminary design and engineering, front-end design and engineering, and contract award, execution, and operation—and involve many teams from different partners and contractors. This increases the complexity of the overall task and its risk-management component.

² 'Takeaways from the Offshore Technology Conference 2013', in *Quarterly—Brazil Tracker* (Credit Suisse, January 2014).

Along the business development lifecycle of an LNG project, each development phase has an overriding focus—from selecting the right project to be developed within a portfolio, to correctly executing the selected project, and finally managing the project in an optimal manner to deliver the results as originally planned. A strong commitment to continuous planning and risk management along the project development lifecycle is essential for successful operation of an LNG project.

LNG Project Lifecycle Risk Management Framework



Source: Author adaptation of the project development and risk assessment frameworks utilised by the Shell Value Assurance review process

Identification and management of LNG project risks cover a wide spectrum of TECOP (technical, economic, commercial, organizational, and political) issues. The following is a non-exhaustive list of these issues.

- *Technical*: exploration and production (subsurface and facilities), project scope, technologies, supporting infrastructure, maintenance, and operations
- *Economic*: reserves, production, market prices, market demand, lifecycle cost, development schedule, taxes, levy, royalties, and financing cost
- *Commercial*: partners and shareholders, economic conditions, competition, contracts, procurement, legal framework, customers, financing, and insurance
- *Organizational*: joint venture participants and agreement, competencies, human resourcing, zone positions, development of local talent, knowledge management, information technology systems, procedures, policies, project management, and execution plan
- *Political*: host government, bodies of government, regulators, legislators, tax authorities, permitting agencies, industrial and community relations, shareholders, and geopolitical factors.

LNG projects require periodic, structured, and clear steps to identify, analyse, assess, monitor, and manage risks to ensure they are addressed by those best able to mitigate their adverse effect. Well-established risk mitigation strategies involve avoidance, acceptance, transfer, and control. LNG projects are well known for mitigating risks through their shareholder participants and venture structure, selection of project business model (upstream and midstream integrated, tolling, and free-on-board or delivery-at-terminal sales), and wide range of contracts covering all aspects of upstream gas supply, construction, and operation of the LNG plant, sale and delivery of LNG, financing and taxation, as well as, government fiscal arrangements (benefits, royalties and taxes), and dividend payments.



Nowhere is LNG project risk management more important than at the core of venture management and shareholder decision-making to ensure key risks have been satisfactorily addressed before a decision is taken. In an LNG project, an explicit list should be developed of conditions that must be met before key decisions are sanctioned, contracts are awarded, or an FID is reached. This is an effective way to maximize shareholder alignment and manage potential competing interests (in country or elsewhere) or secondary agendas. A non-exhaustive list of these conditions follows.

Exploration and production/gas supply:

- Sufficient proven natural gas resources for 25 years
- Shareholder and government approval of upstream gas supply plans for at least 10 years
- Presence of upstream gas supplier shareholders and government funding
- Stability of upstream fiscal terms secured for duration of gas supply to project
- First gas supply/infrastructure projects matured, Engineering, Procurement and Construction contracts negotiated and ready for award
- Agreements for gas supply to LNG plant executed.

LNG plant/shipping:

- All relevant authorizations, licenses, and permits secured including LNG export permit
- At least 70 per cent of unconditional long-term take-or-pay LNG sales and purchase agreements executed
- Sufficient LNG shipping capacity negotiated under time charter and/or acquisition ready for award
- Long-lead items identified, supplier's delivery schedule verified, and contracts ready for award
- Engineering, Procurement and Construction contracts and contractor performance bond negotiated and ready for award
- Project development schedule critical path and key remedial actions identified
- Information and communication hardware and software acquisition and training approved
- Health, safety, and environment plan for staff and contractors approved
- Key local communities and stakeholders engaged and supportive of the project
- Due diligence of key contracts, final economic plan, premises, and results conducted and approved
- Stability of midstream fiscal terms secured for duration of project
- Shareholder and government approval of plant financing plan.

Project implementation:

- All relevant shareholder and company agreements, policies, and procedures approved
- Human resources plan, succession management and local talent development approved
- Plant flawless start-up and operation plan and training and operating manuals agreed
- Shareholder zoned positions nominations approved and key staff ready to be deployed
- Knowledge management, strategic and financial planning processes defined and agreed
- Project implementation team, strategy and identification of key causes of cost and schedule overruns with preliminary mitigation plans approved
- Government and community relations staff identified; plan approved for periodic engagement to debrief communities and authorities on progress and unforeseen issues
- Project risk management strategy established that includes periodic risk assessment, impact analysis, mitigation strategy, accountability, and performance monitoring.

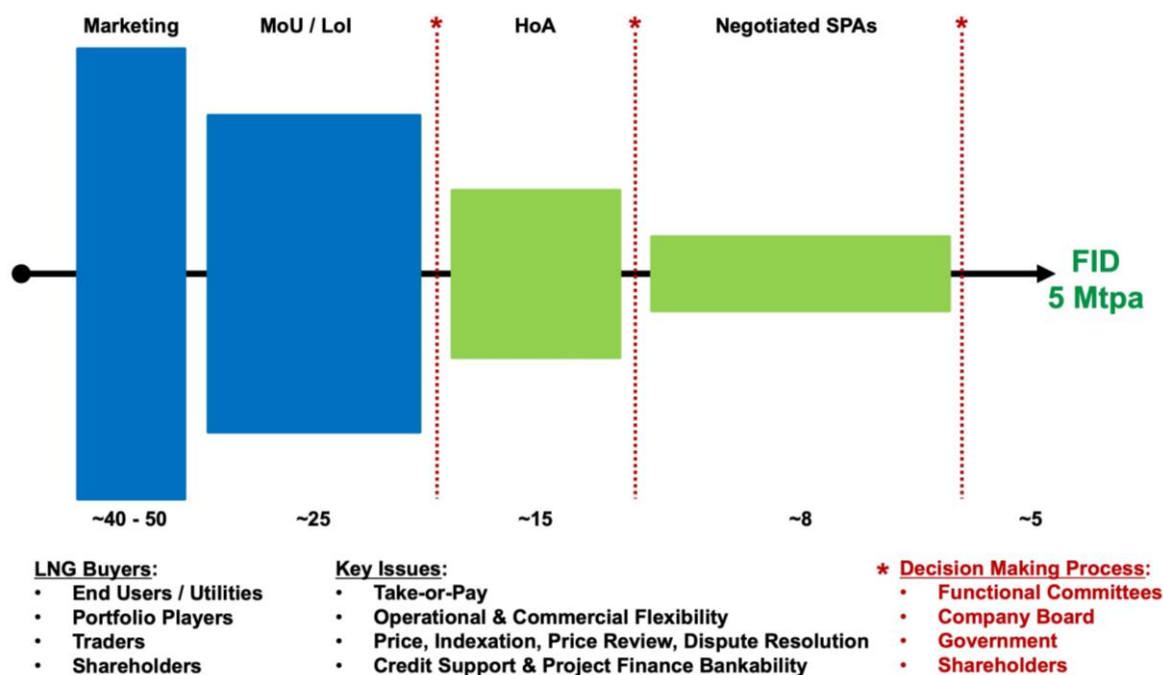
The list of essential conditions will vary from project to project, depending on location, business model, and shareholders involved. But it should cover all key areas of risk that could compromise the project's potential to create value or its ability to deliver the long-term results premised in the final project economics.

LNG project implementation performance post-FID may still disappoint due to externalities beyond the reasonable control of staff, contractors, and shareholders. A well-prepared list of essential conditions, agreed to and fulfilled before the FID, can be a powerful aid to maximizing shareholder alignment, encouraging agile decision-making, and avoiding precipitated decisions. This can provide staff and contractors with additional time and resources to meet agreed decision thresholds, avoiding greater cost and/or schedule overruns during the project implementation phase, which are so detrimental to long-term value creation for all stakeholders.

The question is—do LNG projects face greater risks and uncertainty today to reach an FID? With a 55-year track record of development and implementation of LNG projects in the most remote and challenging locations, with various technological innovations from the well to the burner tip, and wider utilization of LNG as a form of natural gas distribution for power generation, industrial and residential use, and transportation on land and sea, there is less technical uncertainty in the development and implementation of LNG projects.

However, as LNG project FIDs continue to evolve from the traditional supply point to a destination point to a portfolio of supply to a portfolio of demand, the critical path to reaching FID in LNG projects has become the underpinning of the commercial and financial agreements of the project.

LNG Project Business Development – Commercial Maturity Stages From Letter of Intention to FID



Source: SyEnergy

With greater optionality for LNG buyers and sellers to fulfil their essential conditions to reach the FID of their LNG project, export or import, comes the need to develop and mature a greater number of sale and purchase options in parallel up to the point of FID. Buyers and sellers have a wide list of operational, commercial, and financial criteria to satisfy before a medium- to long-term agreement capable of attracting project finance can be executed.

LNG project developers without sufficient balance sheet capacity and needing to raise substantial project finance mitigate this risk by maturing a larger number of potential LNG buyer agreements up to FID. This requires additional human resources in commercial, legal, and financial functions, and a structured decision-making process involving project staff, advisors, shareholders, and governments to ensure alignment.

Large international oil and gas companies with substantial balance sheet capacity and activities along the natural gas value chain have, in principle, the ability to reduce the time required to reach an FID by incorporating the new LNG supply into their global trading portfolios and executing new medium- to long-term LNG supply agreements when buyers and market conditions are more favourably aligned.



The ability of large shareholders to underpin an LNG project FID with their own supply portfolio will require balance sheet capacity, reducing the need for project financing at FID, providing additional time to reduce project completion and commercial risk, and affording the opportunity to pursue project financing later, increasing the chances of securing more competitively priced loans.

The decoupling of LNG project construction contract awards, execution of medium- to long-term LNG sales and purchase agreements, and project financing by large international oil and gas companies comes at a price—greater internal complexity involving capital allocation decisions, and a bias towards larger LNG projects with opportunities for value creation in the upstream, midstream, and downstream components to justify the larger enterprise.

PIPELINE GAS VERSUS LNG—INCREASING COMPETITION IN EUROPE AND ASIA

James Henderson

Until relatively recently, the gas market has largely been regarded as a regional phenomenon, with the commodity either being produced and consumed within the same country or being traded between nearby countries. The foundation of this trade has been extensive pipeline networks, and there are numerous examples of cross-border connections which have linked major exporters and important consumers. Pipelines from the US to Canada and Mexico, Bolivia to neighbouring countries in South America, and North Africa to Europe provide significant examples of the more traditional regional trade patterns, but of course the extensive pipeline exports from Russia to Europe are the most well-known, and increasingly controversial, example.

By contrast, the Asian gas market has been dominated by LNG. This is mainly because the largest traditional markets have been relatively remote—Japan and Taiwan are islands, and South Korea is a peninsula cut off from access to piped gas. Furthermore, efforts to connect Asian countries via a pipeline network have largely failed due to a deficiency of indigenous gas reserves in the region and the lack of a coordinating body (such as the EU in Europe). The most significant recent attempt has been the Trans-ASEAN Gas Pipeline, but hopes of a multinational pipeline system in the East are now fading. As a result, LNG, sourced both from relatively proximate exporters such as Indonesia and from more remote locations in Australia and the Middle East (predominantly Qatar), has dominated.

One factor that pipeline and LNG exports have historically had in common is that they have been based on expensive multiyear developments that could only be justified, by both the companies involved and the banks providing the finance, on the basis of long-term contracts, which were generally based on a price linked to oil. This placed the volume risk with the buyer (who would guarantee to purchase gas over, for example, a 20-year period) and the price risk with the seller (who would offer gas at a discount to a key competing fuel, namely oil).

However, this traditional model has now started to break down, catalysed by the introduction of the Third Energy Package in the EU, which has liberalized the market and stimulated competition between all forms of gas supply, and the arrival of US LNG, which is priced relative to the Henry Hub spot price. The EU has also encouraged its member countries to increase the diversification of their supply options, which has led to the construction of numerous receiving facilities where LNG can be regasified and dispatched into the pipeline network.

Of course, the fact that LNG is largely regasified before use and sent to consumers in a gas pipeline underlines the fact that it is exactly the same product as gas imported via pipe, so the competition between the two is in reality competition between alternative sources of natural gas. The key difference, though, comes in the flexibility of the product being offered, as pipelines by their nature connect one seller with one buyer, while LNG offers the opportunity for redirection to any customer prepared to pay the highest price. This has not always been the case, as LNG contracts have often included destination clauses that have restricted on-sale, but the introduction of US LNG exports that have largely been sold FOB in the Gulf of Mexico (and therefore with no destination restrictions) has dramatically changed the market. Both sellers and buyers have now become accustomed to trading LNG in order to optimize their risks and returns; and with Europe offering a liquid and competitive market where gas can always be sold at the prevailing market price, the foundation for a truly competitive global gas market has been laid.

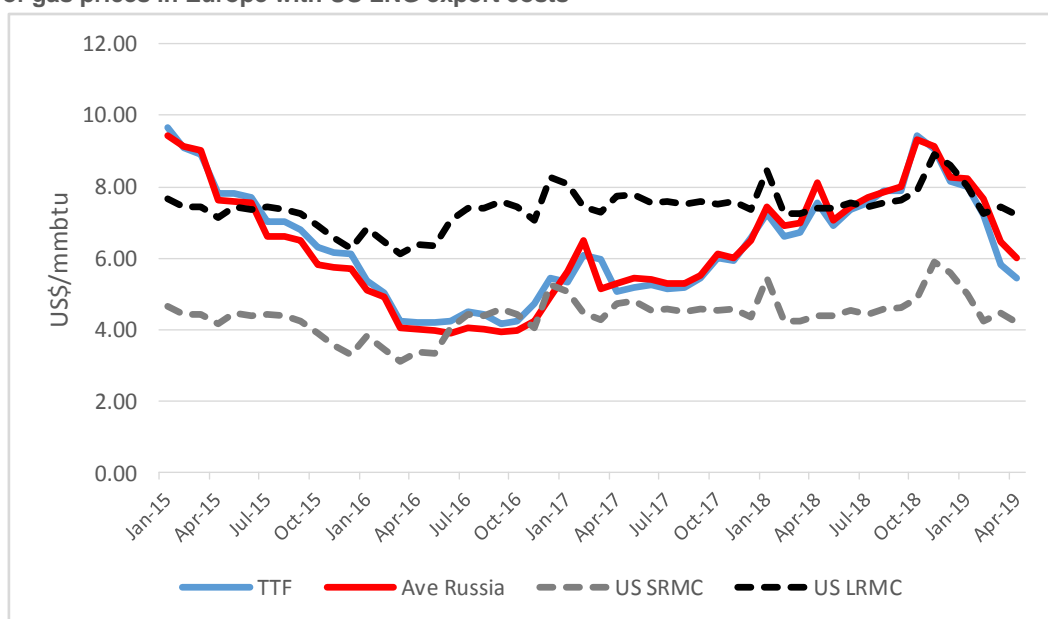
Competition in Europe between Russian gas and LNG

That this competition is manifesting itself in Europe is not really a surprise, as it is arguably the most diversified gas market in the world. Indigenous gas supply, although declining, still plays an important role; pipeline imports arrive from North Africa,

Norway, Russia and soon from Azerbaijan, while the continent's 220 billion cubic metres (bcm) of LNG regasification capacity gives it access to a host of other suppliers.

In reality, though, the competition boils down to Russian pipeline gas versus LNG, as the other sources of pipeline imports are effectively at capacity, with the rivalry heightened because at the margin it would appear that the competition is between Gazprom and new US LNG exports. US LNG, based on the Henry Hub price plus other costs of supply, has become a proxy for the marginal cost of LNG, either on a long-term basis including all fixed costs (liquefaction in particular) or on a short-term cash basis, and it would appear that the Russian gas price to Europe, which now tracks the spot market very closely, fluctuates between these two levels according to whether the market as a whole is under- or over-supplied.

Comparison of gas prices in Europe with US LNG export costs



Source: Data from Argus Media.

TTF = Title Transfer Facility; Ave Russia = average price of Russian gas sold in Europe; SRMC = short-run marginal cost; LRMC = long-run marginal cost.

It would certainly appear logical for Gazprom, with its fixed pipeline export infrastructure, to want to maintain a gas price between the short- and long-run marginal costs of a major competitor. On the one hand, the goal is to maximize revenues and profits by avoiding too low a price (there is no need for the price to fall below the short-run marginal cost of US LNG, as it will then logically be shut in) while on the other hand, it would not make sense to push the price above the long-run marginal cost for an extended period, as this would create greater competition in the long run by encouraging new LNG projects to be developed.

That said, there are inherent constraints in the competition between pipeline gas and LNG in Europe. From a Russian perspective, the obvious constraint is pipeline capacity. In the winter of 2017/18, when there was a significant cold snap, it became apparent that the Russian export system was already full on some days, with any flexibility being provided by the transit system through Ukraine, as Nord Stream and the Yamal–Europe system were consistently full. This raises the issue of politics, of course, and the potential constraints that could be placed on the Russian export system if Ukraine transit ends in January 2020, and/or the EU blocks the new Nord Stream 2 pipeline, and/or the EU finds a way to constrain flows to Europe through the Turk Stream pipeline across the Black Sea. This highlights the important, if obvious, issue that pipelines are strategic geopolitical assets and that the ability of gas supplied through them to compete with alternative sources of supply will always be driven by more than commercial factors.

LNG, on the other hand, offers a different perspective because at the margin, once it is on the water, it can be diverted to whichever market is the most profitable. This is particularly relevant in a tight market, when prices are rising because supply is short, with Asia being viewed as the most likely premium market because of its dependence on LNG. Conversely, in a loose market with plentiful supply, LNG can be diverted to whichever market is available and has space for it—at a price. This tends to be Europe, because of its liquid market and its current excess of receiving capacity (which even in 2018 was only used at an



average rate of around 30 per cent). As a result, the competition between LNG and Russian pipeline gas in Europe tends to be most obvious in times of oversupply (such as the first half of 2019), when the flexibility of LNG flows clashes with the flexibility inherent in Russian export contracts at the market price in Europe.

Are we about to see the same dynamics in Asia?

An obvious question, given the growth of gas markets in Asia, is whether pipeline gas can provide an interesting competitive alternative in the East as well as in the West. Despite the apparent failure of the Trans-ASEAN Gas Pipeline, it would appear that the answer, at least in some countries, is yes, with China providing the most obvious example of a country that is maximizing its diversification options.

Having become a gas importer in 2009, China has developed a multilayered approach to gas supply. As with the EU, indigenous production plays an important role, and in this case a growing one, albeit with some uncertainty about the pace of future growth from the country's shale resources. Nevertheless, the pace of demand growth (which averaged more than 15 per cent a year in 2017 and 2018) means that the import requirement has been growing, and a 'compass' of import options has been developed. From the West, pipeline infrastructure has been constructed to bring gas from Central Asia, with Turkmen gas as the foundation, supplemented by exports from Uzbekistan and Kazakhstan set to bring up to 65 bcm by the mid-2020s. From the South, a pipeline has been constructed from Myanmar with a capacity of 12 bcm, although only 4 bcm is currently being exported. Both of these sources of gas have seen major Chinese investment in the supply countries, meaning that Beijing has developed significant influence over its imported gas.

In the East, a growing number of regasification terminals have been built to allow diversification into LNG imports from multiple sources. Initial contracts were signed with Australia, but China has now become the fastest-growing market for LNG in the world, meaning that all new projects are keen to offer their output to one of the many Chinese buyers. Mozambique LNG, for example, would have been unlikely to take its final investment decision in June 2019 without at least one contract in place for sales to China. Regasification capacity at the end of 2018 totalled 73 million tonnes (mt), with this set to rise to 78 mt by the end of 2019 and to as much as 100 mt (about 135 bcm) by the end of 2020. With demand set to reach around 340 bcm by then, this means that LNG could supply more than one-third of total Chinese gas demand.

However, this supply does not come without risks, and these are not dissimilar to the risks associated with pipeline gas in Europe. In China, though, they concern the actions of the US rather than Russia. On a geostrategic level, the Chinese authorities are concerned that, although their LNG imports come from multiple sources, their routes to market are potentially a risk because they could be closed off by the navy of a competing power—the most obvious risk being the US Pacific Fleet. All LNG from the West would tend to pass through the Malacca Straits, a choke point that could be blocked, while other supply would pass through the South China Sea and could also be obstructed by the US Navy. Given the current antagonism between Washington and Beijing, which has escalated into a trade war that includes tariffs on US LNG imports to China, the security-of-supply implications for the Chinese economy are significant.

As a result, the northern axis of the Chinese gas import compass has become much more important. Pipeline gas from eastern Siberia provides a potentially vital source of supply (up to 38 bcm per annum by 2025) that could clearly displace LNG that might otherwise have been delivered to China. Although it comes with the same strategic risk that all pipelines bring, namely a long-term exposure to a foreign power for a vital energy source, it would seem that the Chinese authorities feel relatively confident in their bargaining power over Russia in this instance, given that the gas would otherwise be stranded. Indeed, negotiations for a further two pipelines, one in the Far East from Sakhalin and one in the West via the Altai region of Russia, are underway but are effectively at the behest of the Chinese authorities. Nevertheless, the option to authorize these two new routes provides further negotiating power both with Russia and with LNG suppliers, as the threat of reducing future LNG demand by contracting for another long-term pipeline deal from Russia can keep negotiations over new LNG contracts honest.

Indeed, the Chinese authorities have gone even further in 'playing off' LNG and pipeline supplies by taking an interest in Russia's expanding Arctic LNG projects, run by Novatek on the Yamal and Gydan peninsulas. Chinese companies have taken equity in both, and a 3 mt per annum contract has been signed with Yamal LNG, as China seeks to have an interest not only in LNG supply but also in the development of the Northern Sea Route, which can provide an important strategic artery to Europe. In addition, a Chinese company (Beijing Gas) has been in negotiation with Rosneft over possible gas exports, demonstrating China's ability to create competition between the three main players in Russia's gas industry.

Russian gas pipelines to China



Source: OIES.

Of course, these options are not available to all Asian countries, as their gas markets are not as large and their geographical location does not offer such opportune diversification options. Nevertheless, for some the example of China can provide a good pointer to future supply planning. India, for instance, already imports LNG and is looking to explore opportunities for pipelines from the Middle East and Central Asia, while Bangladesh and Pakistan may also be able to promote both forms of imports.

At the end of the day, of course, LNG and pipeline gas are homogeneous products, but the different elements that they bring to an import portfolio, in both commercial and political terms, can offer important strategic as well as economic diversification.

DEMAND

LNG DEMAND IN ASIA—ARE GROWTH TRENDS LIKELY TO CONTINUE?

Howard Rogers

Asian markets in 2018 accounted for 72 per cent of global LNG demand, and LNG imports grew 13 per cent compared to 2017. In 2018 the International Energy Agency identified Asian markets as the primary driving force for future gas demand. Given the low expectations in general for domestic production growth and long-distance gas pipelines, the region is expected to continue to require growing volumes of LNG. While the total Asian growth trend is robust, growth in individual markets is more variable.

Japan and South Korea report gas statistics to the International Energy Agency, but the reporting of sectoral consumption patterns in other Asian markets is infrequent and lacks transparency. Gas and LNG consumption growth is generally policy driven. While high gas and LNG prices may dampen demand, this is a lagged phenomenon and may equally be due to slower economic growth. For these reasons, predictions of future LNG demand growth are difficult to make with any confidence and require frequent adjustment in the light of current import data. Given the region's importance for future LNG consumption, and the lag of (in general) four to five years from FID to LNG project start-up, this adds to the cyclicity of the LNG sector.

This article describes the main Asian LNG markets and their outlook, with key insights summarized in the conclusion.

LNG imports: annual growth rates in selected Asian markets

	2005–2010	2010–2015	2015–2018
China	n/a	14.8%	38.2%
India	15.7%	10.6%	12.3%
Japan	3.9%	3.3%	–0.5%
South Korea	8.5%	–1.3%	9.8%
Taiwan	10.1%	4.1%	5.9%
Asia total	7.9%	5.1%	10.0%

Sources: GIIGNL, Platts.

Data for 2005–2010 were not available for China.

Japan

With LNG imports of 111 billion cubic metres (bcm) in 2018, Japan remains the largest LNG market, with very small levels of domestic production (including synthetic natural gas). Almost two-thirds of its LNG imports are consumed in the power sector, followed by industry at 18 per cent; residential and commercial use account for the balance. The Fukushima disaster of 2011 saw Japan increase its LNG imports by some 27 per cent as LNG, oil products, and coal provided the power generation lost as Japan's nuclear fleet was gradually taken offline. The decline in LNG imports from 2015 to 2018 came in response to the rise in solar and to the restart of nine reactors beginning in late 2015.

Three factors are likely to drive the level of future Japanese LNG consumption: the pace and extent of further nuclear restarts (of the 50 plants operable at the time of the Fukushima disaster, 20 have, or are likely to be, permanently retired), the further expansion of renewables, and the success of aggressive government policy in reducing national energy consumption through increased efficiency. The outlook is for a decline in future LNG imports which by 2030 could be between 77 and 94 bcm per annum (bcma). March 2019 LNG imports were down 8.1 per cent from March 2018.

China

The Chinese appetite for growing and highly seasonal LNG imports has generated headlines over the past three years and has been deemed responsible for the winter peaks in Asian LNG spot prices over this period. In 2018 China imported 69 bcm of LNG. Chinese gas demand grew by 15 per cent from 2016 to 2017 and by 13 per cent from 2017 to 2018. Gas demand growth has been to a large degree driven by government policy to switch from coal to gas, mainly in the residential and industrial sectors. The likely extent and pace of this dynamic in the future is uncertain, especially in the context of slowing economic growth and international trade. While domestic production continues to grow (meeting 56 per cent of Chinese demand in 2018), China is relatively mature in terms of conventional gas resources. The extent to which shale gas, tight gas, coalbed methane, and synthetic gas can maintain domestic production growth is a concern.

China imports some 16 per cent of its supplies as pipeline gas from Turkmenistan and Central Asia and minor amounts from Myanmar. At the end of 2019 it will begin importing Russian gas from the Power of Siberia pipeline, drawing on East Siberian fields. Whilst China represents the fastest-growing destination for new LNG supply projects, its demand could wane should the momentum of the coal-to-gas policy slow. At present spot/short-term LNG represents a low-cost supply source; otherwise gas is relatively expensive in China, being either oil-indexed contract pipeline or LNG or high-cost base domestic supply. On the upside, the failure of domestic supply to grow significantly could increase LNG demand in general. Projections of China's LNG requirements in 2030 range from 132 to 163 bcm. Wood Mackenzie projects that 'economic slowdown, a more considered approach on coal-to-gas switching and increased domestic infrastructure availability will mean LNG demand will slow in 2019, from the 40–45 per cent growth we have seen in 2017 and 2018.'¹

South Korea

In 2018, South Korea surprised the market by importing 57.7 bcm of LNG—a 21 per cent increase over 2017. Nuclear outages in 2018 (due to component safety concerns) saw an increase in LNG consumption in the power sector. This appears to have been a temporary factor, with imports in February 2019 falling back below those of 2018 on a monthly basis. Longer term, South

¹ WoodMac: gas prices to drop as LNG FIDs hit record figures in 2019', LNG World News', January 8th 2019, <https://www.lngworldnews.com/woodmac-gas-prices-to-drop-as-lng-fids-hit-record-figures-in-2019/>.



Korea's policy of reducing its nuclear and coal generation should favour LNG. The outlook for South Korea's LNG requirements in 2030 ranges from 61 to 69 bcm, as LNG is emphasized by government policy at the expense of nuclear and coal-fired generation.

Taiwan

In 2018, Taiwan imported 22.9 bcm of LNG. Its LNG imports have been growing at 3–4 per cent per year from 2015. Like South Korea, Taiwan wishes to reduce its nuclear generation capacity, although it is unclear whether the original target of 2025 will be met. It is expected that LNG import growth will continue at 2–3 per cent per year, with the outlook for 2030 at between 29 and 33 bcm. Taiwan is expanding its LNG import capacity with a goal of reaching 41 bcma of nameplate capacity by the late 2020s.

India

Despite its potential for significant future economic growth, the outlook for gas and LNG demand in India is problematic. In part this relates to the complex system of administered prices and supply allocation between demand sectors, the lack of a plan to build an extensive gas transmission infrastructure across the country, and the lack of a substantial domestic space-heating requirement to anchor this. India's domestic gas production declined in 2010–2016 (as a consequence of problems with the KG-D6 field reservoir), but this appears to have stabilized at around 32 bcma in 2017 and 2018. Gas consumption jumped from 50.8 bcm in 2016 to 61.2 bcm in 2018. LNG imports have benefitted, increasing from 20.9 bcm in 2015 to 29.6 bcm in 2018. In part this has been due to temporary tax reliefs/subsidies to encourage the use of LNG in power generation. India is embarking on new LNG regasification terminal projects: the new Ennore terminal (5 million tonnes per annum [mtpa]), the expansion of the existing Dahej terminal from 2.5 to 17.5 mtpa, and the Dharmra terminal on the east coast will be completed by 2022. The completion of the Kochi pipeline and Dabhol LNG complex breakwater is also intended to safeguard against typhoon disruption by 2022.

India's future LNG demand depends on future growth in the industrial sector (particularly fertilizer manufacture) and the power sector (where some form of government support is required to bridge the gap between the cost of coal- and gas-fired generation in the interest of ameliorating particulate pollution). While India has the potential to become a large LNG-importing market, infrastructure constraints preventing gas from reaching customers and the affordability of some sectors will continue to suppress demand outlooks. An indicative outlook for India's 2030 LNG imports ranges from 42 to 52 bcma.

Indonesia

The world's largest LNG exporter until 2005, Indonesia has experienced a steady decline in LNG exports as its domestic demand has outstripped domestic production growth. Indonesia also exports pipeline gas to Singapore (7.3 bcm in 2017, although this is expected to decline and end in 2025) and Malaysia (0.7 bcm in 2017). Indonesia's gas demand is expected to see modest growth in the future while its production, apart from increases due to projects such as Tangguh coming onstream, is expected to see gradual, long-term decline. In recent years some 15 per cent of Indonesia's LNG output has been supplied to its own archipelago markets. This trend is expected to continue; by 2030 Indonesia's LNG position may range from being a net exporter of 3.5 bcma to a net importer of 2 bcma.

Malaysia

Malaysia's LNG exports have plateaued since the late 2000s/early 2010s. Like Indonesia, Malaysia is focusing on coal for power generation growth requirements. Gas consumption declined gently in the mid-2010s but recovered in 2017 and 2018. The outlook for Malaysia is driven by the relative growth of demand versus a mature and slowly declining domestic production base. Malaysia already imports LNG from other countries to meet demand in its archipelago markets. As domestic production declines, Malaysia's LNG production surplus is expected to shrink during the 2020s. By 2030 its net exports of LNG could range from 6 bcma to a deficit of 1 bcma.

Thailand

Thailand's gas has been somewhat stagnant for the past five years. Its domestic production has been falling, leading to a rise in LNG imports from 1.8 bcma in 2014 to 5.6 bcma in 2018, as pipeline gas imports from Myanmar declined from 9.7 to 8.3 bcma from 2014 to 2017. Assuming modest future growth in gas demand and stable future pipeline imports, the key to future LNG import prospects is the underlying decline in future domestic production. The outlook for 2030 is for 22.5 to 26 bcma of LNG imports.



Singapore

With gas dominating in the power sector, demand is growing at just under 3 per cent per year. With no domestic production, Singapore's non-LNG supply comprises pipeline imports from Malaysia and Indonesia. It is Singapore's policy to phase out pipeline imports by 2025 and import only LNG. Despite a reduction in LNG imports from 2017 to 2018 (from 3 to 2.4 bcma), the outlook, assuming domestic production decline and the progressive reduction in pipeline imports, is for 2030 LNG imports in the range of 18 to 22.5 bcma.

Pakistan

Gas demand for the past four years has been growing at some 4 per cent per year, and domestic production has been static and more recently declining. The latent demand for gas in power generation is being partially met by oil-product-fuelled power generation resulting in brown-outs when this fails to meet demand. Assuming that floating storage and regasification units (FSRUs) and perhaps a land-based regasification unit are installed by 2030, Pakistan's LNG imports could range from 21.5 to 27.5 bcm.

Bangladesh

While gas demand has recently been fairly static, this is in part due to constrained supply, as domestic production has reached a plateau. LNG imports commenced in 2018. The potential of this market is driven by the underlying decline in domestic production and the ability to provide (in the first instance) additional FSRU LNG import infrastructure. By 2030 LNG imports could range from 14 to 16.8 bcma.

Vietnam

Pakistan and Bangladesh provide an analogue for Vietnam, whose domestic production has peaked and is in decline. Assuming FSRUs are positioned by 2020, imports could rise by 2030 to a range of 8.3 to 10.2 bcma. Some 10 LNG terminals are currently at the planning stage, and domestic coal supplies are becoming progressively more expensive to extract.

Philippines

The Philippines could follow Vietnam in becoming an LNG import market as its domestic production declines in the early 2020s. LNG imports could start in 2023, and by 2030 could be in the range of 1.7 to 3 bcma.

Asian LNG imports: 2018 Actuals and Future Trends

Low case	2018	2020	2025	2030
Japan	111.0	108.3	90.5	77.0
South Korea	57.7	55.5	58.8	61.0
Taiwan	22.9	23.8	26.3	29.0
China	69.1	82.0	115.9	132.4
India	29.6	29.0	36.3	41.9
Indonesia	3.8	5.0	11.0	14.2
Malaysia	1.9	3.0	4.6	8.3
Thailand	5.6	7.8	15.2	22.5
Singapore	2.4	5.0	11.2	17.8
Pakistan	9.2	11.0	16.4	21.6
Bangladesh	0.8	3.2	8.5	13.9
Vietnam	—	1.4	4.7	8.3
Philippines	—	—	0.8	1.7
Total	314.0	334.9	400.1	449.7

High case	2018	2020	2025	2030
Japan	111.0	108.5	96.2	93.9
South Korea	57.7	59.2	63.7	68.7
Taiwan	22.9	24.3	28.2	32.6
China	69.1	112.0	138.0	163.4
India	29.6	32.6	41.3	51.5
Indonesia	3.8	5.0	13.2	19.3
Malaysia	1.9	3.0	8.1	14.9
Thailand	5.6	8.5	17.4	25.9
Singapore	2.4	6.0	13.5	22.4
Pakistan	9.2	12.3	20.4	27.5
Bangladesh	0.8	4.2	10.6	16.8
Vietnam	–	1.6	6.0	10.2
Philippines	–	–	1.4	3.0
Total	314.0	377.2	457.8	550.3

Delta	2018	2020	2025	2030
Japan	–	0.2	5.8	16.9
South Korea	–	3.7	5.0	7.7
Taiwan	–	0.5	1.9	3.6
China	–	30.0	22.1	31.0
India	–	3.6	5.0	9.6
Indonesia	–	–	2.2	5.1
Malaysia	–	–	3.5	6.6
Thailand	–	0.7	2.2	3.4
Singapore	–	1.0	2.2	4.6
Pakistan	–	1.3	4.0	5.9
Bangladesh	–	1.0	2.1	2.9
Vietnam	–	0.3	1.3	1.9
Philippines	–	–	0.6	1.3
Total	–	42.2	57.7	100.5

Source: OIES, Rogers.

Conclusions

Asian LNG demand, with a potential background of slowing GDP growth due to global trade barriers, is currently highly dependent on the continued strength of Chinese LNG imports. Other Asian LNG markets face a variety of demand drivers. Key trends and questions at the country level include the following.

- *Japan:* The pace and extent of future nuclear restarts, the energy conservation drive, and renewables capacity growth are all likely to influence LNG import requirements.
- *China:* To what extent will the current policy-driven coal-to-gas switching continue to bolster LNG demand? Factors that may discourage this trend include increased Central Asian and Russian pipeline import volumes and a potential GDP-driven consumption slowdown. Factors that may strengthen it include the drive to reduce particulate emissions and the challenges to high-cost domestic production, particularly of nonconventional gas.
- *India:* From a GDP perspective, this market has potential, but the lack of a space heating market to drive significant gas transmission networks introduces downside risk.
- *South Korea and Taiwan:* These countries' pace and commitment to reducing nuclear and coal generation is key but uncertain.

- *Indonesia and Malaysia:* While domestic production is mature, domestic gas demand is held in check by a preference for coal in power generation. This may change if government policy evolves. The point at which these countries become net LNG importers is highly sensitive to such developments.
- *Bangladesh, Pakistan, the Philippines, Singapore, Thailand, and Vietnam:* With pipeline gas supply or domestic production having established gas as a key part of the energy mix, the ongoing decline of existing gas supply sources has set the stage for growing LNG imports.

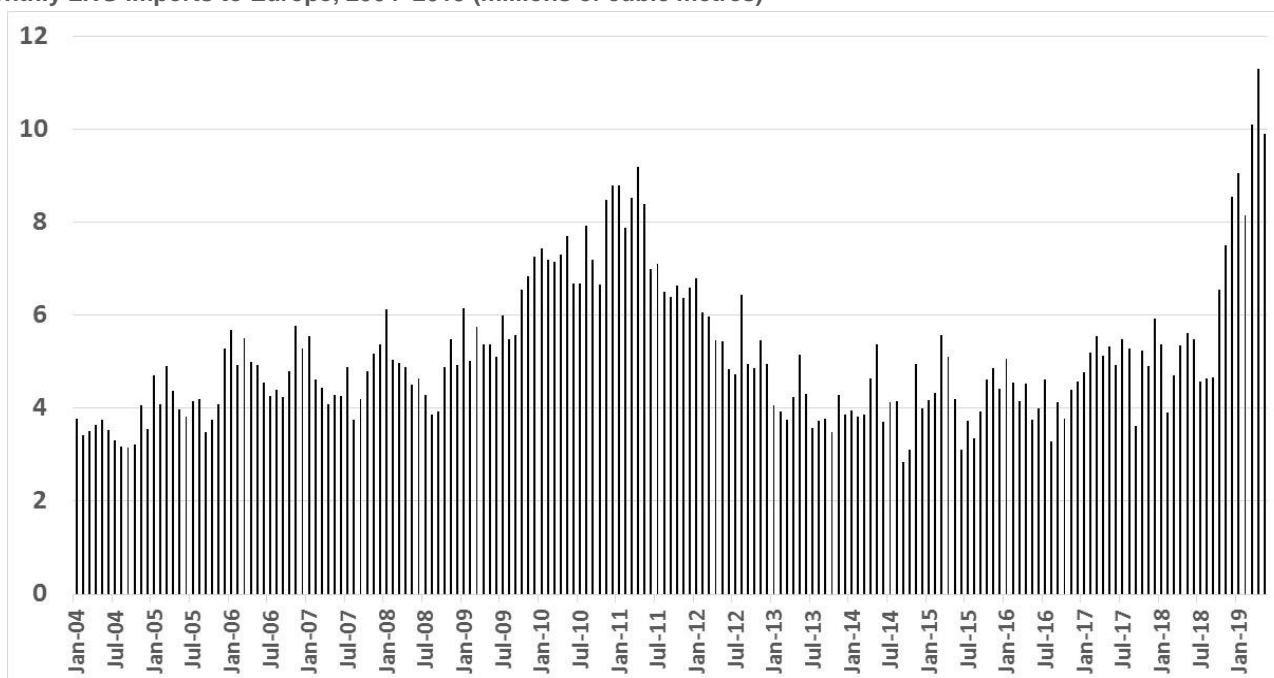
That said, the unpredictability of government energy mix policies (including issues related to CO₂ and particulate pollution and nuclear phase-out/restart), and of the extent to which domestic production decline will necessitate LNG imports, makes projections highly uncertain.

GAS DEMAND IN EUROPE—IS THERE A PLACE FOR LNG?

Anouk Honoré

In 2018, the European market(s) represented almost 16 per cent of the global LNG market (GIIGNL 2019 Report).¹ Volumes imported to the region vary greatly from one year to another. This is because Europe is acting as the swing market for LNG. As a result, the region is expected to help balance the market at times of high Asian demand, as seen after 2011 following the Fukushima disaster, but also help to absorb any LNG surplus coming on to the market, as expected in the 2020s. With regasification terminals only being used at about 28 per cent of their capacity,² Europe could import a lot more LNG relying only on its existing infrastructure. But is there a place for LNG in Europe, especially up to 2030?

Monthly LNG imports to Europe, 2004–2019 (millions of cubic metres)



Source: Platts LNG database.

Europe is not an LNG market per se—it is a market with a demand for gas, which can come in the form of indigenous production, imports via pipelines, or LNG. After a continuous decline between 2010 and 2014, natural gas demand in Europe started to rise again in 2015–17. This was due to a combination of colder than average months in winter (higher energy consumed for heating), economic recovery, and increasing gas deliveries to the power sector because of coal-to-gas switching.

¹ GIIGNL, *Annual Report 2019* (© GIIGNL - International Group of Liquefied Natural Gas Importers, 2019).

² GIIGNL, *Annual Report 2019* (© GIIGNL - International Group of Liquefied Natural Gas Importers, 2019).



In addition, low hydropower in the south and limited nuclear availability in France created a set of special circumstances, which enhanced the use of gas-fired power plants in the generation mix. With the normalization of these special circumstances and milder temperatures, natural gas demand in Europe (35 countries) declined in 2018 for the first time in three years and reached 536 billion cubic metres (bcm).³

The future place of natural gas in Europe's energy system will determine the need for imports, including of LNG. But this future faces major uncertainties as a result of climate change policies.

The decarbonization of energy systems is a major part of the European Union's (EU's) policy agenda; it is committed to reducing its greenhouse gas (GHG) emissions to 80–95 per cent below 1990 levels by 2050. The decarbonization of the electricity sector through the integration of renewables has been regarded as the first step in a wider strategy. Between 2007 and 2017, the share of renewables grew from 5 to 18 per cent (excluding hydro), with the largest increase in the form of onshore wind and solar. Both are intermittent sources of power generation, and one of the key challenges posed by this rapid evolution was how to integrate a large and growing share of intermittent generation into the power system.

This approach has catalysed disruptions in the traditional structure of the electricity sector, and by extension the role of gas in the electricity mix. While in the past, combined cycle gas turbines (CCGTs) were traditionally run on baseload power, they are increasingly required to provide backup for variable renewable resources. New projects involve smaller and more flexible plants; and as plants that back up renewable plants run for fewer hours, this may also result in lower and more unpredictable gas demand.

Nonetheless, the role of natural gas in European power generation could increase in the late 2010s and early 2020s, thanks to the expected decline of coal in the generation mix. With tightening legislation on GHG emissions, increasing carbon prices, a ban on subsidies on all coal plants from 2025, and their prospective phase-out at the EU and/or national level, generators will soon have to make decisions about the future their coal plants. Options include retrofitting control technology and continuing to operate within the new limits, applying for derogation (if possible), limiting their operating hours to less than 1,500 annually (the threshold below which emissions limits are less stringent), and shutting down.

All these measures suggest a sharp decline in coal generation in the early to mid 2020s. Of course, not all coal plants will be replaced, and certainly not all by natural gas; but if the closure of a large number of coal plants happens quickly, there may be no time for alternative plants or grid extensions to be built, and gas-fired plants may be called back into the mix at both peak and baseload times.

Nuclear phase-out in Germany by 2022 and in Belgium by 2025, other potential limits placed on existing (or new) nuclear plants, and delays in construction will also provide some opportunities for natural gas, at least until further low-carbon capacities are developed in Europe.

So far, the electricity sector has been the main focus of low-carbon policies; but if Europe is to meet its objectives, decarbonization efforts will need to expand to other sectors, including the heating and cooling sector. This sector is the largest energy user in Europe; in 2015 it represented **about 50 per cent of the final energy demand**.⁴ **Although the sector is moving towards low-carbon energy, about two-thirds of its energy demand is still met through the direct combustion of fossil fuels, and over 40 per cent from natural gas alone.** The main focus of EU decarbonization policies for heating and cooling production so far has been on two main types of measures: energy efficiency and the promotion of renewables (essentially for final energy demand, although some work is also being done on district heating systems). The implementation of low-carbon options faces critical energy challenges with few simple answers, and neither the impacts nor the time frames are likely to be uniform across Europe.

In the building sector, the main options include efficiency improvements (upgrading boilers, developing combined heat and power (CHP) and fuel cells, and switching to more efficient heating systems, all of which could potentially still include natural gas as an input), raising the renewables share (replacing fossil fuels with renewables, installing hybrid systems—which may include gas—and repurposing the gas network for hydrogen), electrifying the heating sector from a zero-carbon electricity supply, and expanding heat networks. Active policies promoting low-carbon options in buildings only started in the early 2010s, and the effects may take time to materialize in the European market, where buildings are old and not energy-efficient.

³ Eurostat data.

⁴ Honoré, A., 'Decarbonisation of heat in Europe: implications for natural gas demand', Oxford Institute for Energy Studies (2018).



Nonetheless, some efficiency gains—through thermal refurbishments and minimum energy efficiency requirements for new buildings—may start to lower demand for space heating in the second half of the 2020s.

Reducing carbon emissions in the industrial sector and reaching the 2050 targets will essentially depend on a mix of energy efficiency, electrification of heat (and heat recovery techniques), fuel switching (to biomass or hydrogen as feedstock and/or fuel), and carbon capture utilization and storage (CCU/CCS). The heterogeneity across subsectors and energy uses will be one of the main challenges in designing a framework to decarbonize the sector and some subsectors will be more complex to decarbonize than others. For example, cement, steel, ethylene, and ammonia are characterized by high emissions from feedstock and high-temperature heat processes. Because not all technologies and fuels are capable of achieving high temperatures, fossil fuels, including natural gas, can be more easily displaced by traditional renewable energies for low-temperature applications than for high-temperature applications. As a result, only natural gas used in low-temperature applications (about 48 bcm) could realistically be replaced by low-carbon sources in the 2020s (provided that these can meet both commerciality and acceptability requirements). In addition, energy (including gas) demand in the industrial sector may increase slightly due to favourable economic conditions and fewer options to improve energy efficiency than in the residential sector, especially in energy-intensive industries.

To summarize, natural gas demand in the three main sectors which make up about 80 per cent of the European market—power, residential, and industrial—is expected to remain high at least in the first half of the 2020s and maybe up to 2030. Use of gas in the transport sector may also expand if adequate support is provided for public entities and businesses to use LNG and compressed natural gas (CNG) in road and maritime transport to improve air quality, and for the use of LNG as a bunkering fuel in European ports. Important growth rates are expected in this sector, but starting from a very low base, with limited effects on the regional total.

Following on from this, there are several reasons to be carefully optimistic about gas demand in Europe in the next five and maybe even 10 years. It will not return to the strong growth seen in the 2000s, but it is likely to remain fairly high. However, natural gas is a fossil fuel, and efforts will need to be made towards decarbonization (by developing CCS and increasing the production of green gas such as biomethane or hydrogen) sooner rather than later if it is to maintain a share in the energy mix, certainly after 2030 but potentially even before. As part of the EU long-term strategy ‘A Clean Planet for All’, gas will contribute to the decarbonization of the energy sector, but its role in the EU energy mix will increasingly be in its decarbonized form.

Does this mean that there will be a place for LNG in Europe in the 2020s?

In 2018, indigenous production covered about 46 per cent of Europe’s needs, while imports via pipeline accounted for 41 per cent and LNG for 13 per cent.⁵ One of the main uncertainties concerns the pace and scale of the region’s conventional production decline due to resource depletion and/or political decisions—especially in the Netherlands, where the government decided in March 2018 to phase out production from the giant Groningen field as quickly as possible, and no later than 2030. There are reasons to believe that, if more earthquakes occur like the one in May 2019, production could be reduced even faster than expected. This would alleviate some of the LNG glut in Europe for 2020 and 2021 and help balance the market, but it would then add to the tightening of the market in 2023/2024, when Nord Stream 2 could be needed, depending on Asian LNG demand trends.

After 2025, demand for natural gas (especially unabated gas) may start to soften as a result of decarbonization policies. Nonetheless, indigenous production of biomethane and hydrogen from electrolysis is unlikely to exceed 15–25 bcm by 2030. This will not replace the decline of conventional production which this author’s estimates at about 113 bcm in this timeframe (compared to 2018 in a Europe of 35 countries including Norway). Therefore, gas imports will be the key to meeting regional needs, and Russian gas and LNG are likely to be the main sources competing to provide these. Therefore, the main challenges for LNG in Europe in the 2020s will be the dynamics in other markets, especially in Asia, where LNG can potentially be sold more profitably, and the competition with Russian gas, but Europe will welcome the diversification of gas supply sources and routes provided by a growing and ever more flexible global LNG market

⁵ Eurostat data and Platts LNG database.



LNG AS A TRANSPORT FUEL—IS THE DEMAND REAL?

Chris Le Fevre

LNG as a transport fuel continues to attract considerable interest and is establishing itself as a specific new market for gas. Nevertheless, questions remain over the breadth, scale, and rapidity of uptake. LNG can provide significant environmental advantages over traditional petroleum products, most notably as a marine fuel, where a global limit of 0.5 per cent sulphur in fuel oil will be introduced in 2020, but also in some road transport applications. This article reviews the drivers behind the development of the market for LNG as a transport fuel in the light of recent developments and identifies the regions and sectors where demand is likely to be most significant.

A range of markets

Whilst the use of natural gas as a transport fuel has been a feature in some markets for many years, the use of LNG is a recent phenomenon, and the reasons for adoption vary between countries and sectors.

The environmental attraction of natural gas as a transport fuel is primarily based on the fact that it emits virtually no nitrogen oxides, particulate matter, or sulphur oxides. LNG provides a particularly concentrated form of natural gas, and this is important in the marine sector, where the International Maritime Organization's (IMO's) limits on sulphur in fuel oil - 0.1 per cent in the mandated Emission Control Areas in North America and Europe, and 0.5 per cent globally starting in 2020 - could lead to a significant displacement of heavy fuel oil. The lower levels of emissions coupled with relative high energy density are also attractive in some markets where diesel-fuelled heavy-goods vehicles (HGVs) are a significant source of atmospheric pollution.

The cost of LNG as a transport fuel is generally lower than that of oil-based products, though the capital cost of the new vessel or vehicle may be higher. This financial trade-off means that LNG is likely to be most attractive in high-utilization sectors that will achieve early pay-back.

When considering the prospects for LNG, it is important to recognize that there are important differences between the road and marine markets:

- In land transport there is a role for both LNG and compressed natural gas (CNG), whilst LNG is the sole option in marine. LNG is mainly used in HGVs, buses, and trains, but not in cars, whilst CNG can be used in most types of road vehicles.
- There are presently low-carbon alternative fuel options in road transport - most notably electricity - that are not yet available in marine. Evidence from some markets such as China suggests that this is causing the land-based natural gas transport market to undergo a transition from smaller natural gas vehicles to larger ones, which, following on from the previous point, offers greater opportunities for LNG.
- Road transport is susceptible to a range of state-based incentives for alternative fuels that generally don't apply in the marine sector. This in part reflects the fact that most marine fuel is not subject to tax, but also the greater levels of state intervention in road transport for environmental reasons.

Barriers to uptake

Despite its environmental and financial advantages, LNG faces a number of obstacles. In marine, LNG is not the only solution to meeting new fuel standards: vessel operators may opt to use sulphur scrubbers in conjunction with cheaper high-sulphur fuel oil, burn more expensive low-sulphur diesel, or opt for ultra-low-sulphur fuel oil, which is being developed by a number of refiners. The preference for staying with liquid fuels is evident from data from DNV GL,¹ which show that in June 2019 there were around 320 LNG-fuelled ships either in operation or under construction (excluding LNG carriers). By comparison, the equivalent number for those fitted with sulphur scrubbers was over 3,500.

In road transport, environmental drivers mirror the split noted in a recent OIES study between Europe, where the key driver is decarbonization, and many countries in Asia, where the focus is on air quality.² LNG does not provide a zero-carbon option; this, coupled with recent evidence that cleaner diesel engines have closed the atmospheric emissions 'gap' between gas and

¹ On-line database provided by DNV GL, www.veracity.com/

² J. Stern, *Challenges to the Future of Gas: Unburnable or Unaffordable?* (Oxford: Oxford Institute for Energy Studies, 2017), www.oxfordenergy.org/wpcms/wp-content/uploads/2017/12/Challenges-to-the-Future-of-Gas-unburnable-or-unaffordable-NG-125.pdf.



petroleum-based fuels, significantly reduces one of the strongest arguments for LNG in HGV transport. Whilst there is scope for using biomethane in the transport supply chain, and this plays well into the decarbonization agenda in Europe, the scope for bio-LNG appears relatively limited.

Key future markets

As noted above, the most promising markets for LNG are marine and HGVs. However, the evidence to date suggests that the adoption of LNG is most likely in subsectors where some critical conditions are present.

In the marine sector, the most important such conditions are likely to include operation in Emission Control Areas (already subject to the IMO limit on sulphur of 0.1 per cent), presence of large vessels with regular and predictable journey patterns, and high levels of government support for new shipping investment favouring LNG.

In the road sector, critical factors include high utilization levels, long and regular delivery routes, and a strong consumer brand presence (indicating a desire to demonstrate positive environmental performance).

In both marine and road sectors, the case for LNG is also helped where operators are owners of their vessels or trucks and, because LNG is more likely in new builds, where there is a relatively high level of vessel/vehicle turnover.

Based on these conditions, LNG is most likely to be adopted as a fuel by cruise ships, large container vessels, passenger and vehicle ferries, bulk carriers, and of course LNG tankers. DNV GL statistics show that in June 2019, of the 320 LNG-fuelled ships either in operation or under construction (excluding LNG tankers), most were ferries (26 per cent), tankers (21 per cent), container ships (12 per cent), or cruise ships (10 per cent)³. One other significant category is offshore support vessels, which had a 12 per cent share. These vessels are concentrated in Norway, which has been at the forefront of LNG adoption in marine and has provided particular incentives for new LNG-fuelled shipping.

LNG usage in road transport is still at a relatively early stage (with the exception of China), but take-up is most evident amongst large national or international carriers including large retail chains and major hauliers.

Looking at the regional dimension, the picture is mixed. In China, as suggested above, there is increasing focus on the use of LNG by HGVs. The market has been helped by an extensive domestically produced LNG supply chain developed to serve off-grid gas users. There were an estimated 350,000 LNG HGVs at the end of 2017, and sales of LNG HGVs received a further boost from restrictions on diesel freight movements introduced in 2017 to reduce atmospheric pollution. Similar restrictions on coastal and riverine shipping could help LNG in these sectors as well.

In Europe and the United States, most of the growth in LNG use to date has been in the marine sector. This is to be expected, as the IMO's Emission Control Area restrictions have been in force since 2015. Developments in the truck and bus sectors have taken longer to materialize.

In Europe, a number of large haulage companies have started to make significant moves towards gasifying their vehicle fleets. One of the main drivers behind the development of the LNG supply chain has been the Blue Corridors project. The project is now completed and claims to have promoted the purchase and operation of 140 LNG trucks consuming about 14,200 tons of LNG and the construction of 12 refuelling stations. However, because of the decarbonization requirement, biomethane is an increasingly favoured option for large vehicles, and these users may increasingly opt for CNG, as this presents an easier route for blending conventional and renewable gas.

In the United States, gas use in road transport has been largely driven by the increasing availability of low-cost gas arising from the growth in shale gas production. Whilst initial expectations were that LNG-fuelled vehicles would play a growing role in long-distance haulage, this has not proved to be the case. Where there are no pre-existing liquefaction facilities, LNG is relatively expensive compared to CNG, and the LNG market appears to have stalled.

Demand outlook

In the marine sector, most forecasts suggest that global demand for LNG will be in the range of 25 to 30 million tonnes per annum (mtpa) by 2030. This would require that, very approximately, between 2,000 and 6,000 new or converted vessels would be fuelled by LNG by then. As at June 2019 there were only around 320 vessels in operation or under construction, so building a fleet of the size needed to fulfil the forecasts would be challenging. The author's research concludes that a demand level of around 15 mtpa (20 billion cubic metres) by 2030 is a more realistic prospect.

³ On-line database provided by DNV GL, www.veracity.com/



This outlook could change, however. For example, there are nearly 150 'LNG ready' vessels that could switch to LNG relatively cheaply and quickly. Furthermore, to date only a small number of major shipping operators have made a clear commitment to new-build LNG-fuelled ships. If other large companies start to follow their lead, demand could increase more rapidly. (This forecast excludes LNG carriers. If all of these were to switch exclusively to LNG, this alone could represent around 17 mtpa of demand by 2030.)

In the road sector, most volume growth is expected to be in the Asia Pacific region, with China and possibly India at the forefront, and some countries in Europe are expected to develop a niche market. Overall volumes could be in the region of 10 billion cubic metres by 2030, though it should be noted that in China some of this may come from domestically produced LNG.

To conclude, LNG is making some headway in marine and road transport. Growth is concentrated in particular sectors and countries and is likely to be steady rather than dramatic. Whilst the total transport market could be of some significance by 2030, it is not expected to have a major impact on the development of the global LNG market.

PRICING AND TRADING

RECENT EVOLUTION OF EUROPEAN AND ASIAN PRICES AND IMPLICATIONS FOR THE LNG MARKET

Anne-Sophie Corbeau

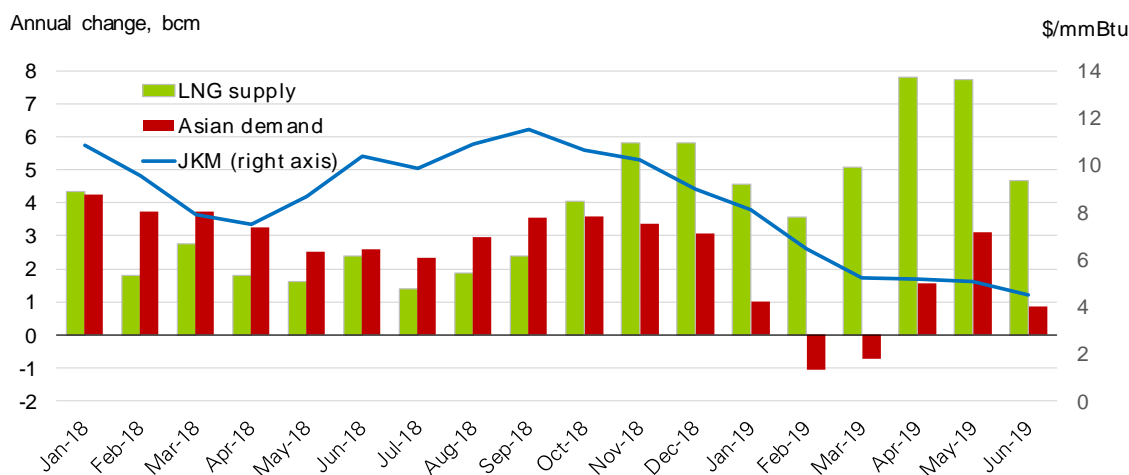
The past 20 months have been a roller-coaster period for global LNG markets as well as for regional gas prices. They have unfolded like a theatre piece in two acts: the first act featured a relatively tight global LNG market, with elevated spot prices in Asia and Europe; the second witnessed the start of the much-anticipated LNG oversupply, with Asian (Japan Korea Marker—JKM) and European (National Balancing Point—NBP) gas prices tumbling to the level of US LNG exporters' operating costs.

The first act, which stretched till the beginning of October 2018, saw incremental LNG supply volumes being almost entirely absorbed by Asian countries. Asian prices in winter 2017/18 spiked to over \$10 per million British thermal units (mmBtu) due to the unexpectedly high LNG demand in China, as industrial and residential users switched from coal to gas. Thereafter, in summer 2018, Asian and European spot prices surprised by increasing in a counter-seasonal way, to above \$10/mmBtu and \$7.5/mmBtu respectively, on the back of tight LNG markets; they were also supported by higher oil, coal, and carbon prices.

The second act started in October 2018. The move from one act to another was particularly visible through the evolution of additional LNG supply, compared to incremental LNG demand in Asia. During 2018, the latter exceeded incremental LNG supply almost every month until October, when the trend reversed. From then on, incremental LNG supply increased to much higher levels—up to 8 billion cubic metres (bcm) per month—as new plants started operating or ramped up in Australia, Russia, and the United States; meanwhile, LNG demand growth in Asia weakened under the combined pressure of warmer weather and nuclear power plant restarts in Japan. The weakness in Asian demand was compounded by a much lower Middle East and North African LNG demand. Consequently, JKM and NBP prices have continuously dropped since then, and at the time of writing (August 2019), they had reached \$4.4/mmBtu and \$3.4/mmBtu, respectively, less than half their level a year before.

The results of that double whammy were two tangible signs of oversupply: a sharp price drop, well below the oil-linked gas prices and down to around the level of estimates of US LNG exporters' operating costs (about \$3.5/mmBtu in Europe in August 2019); and surplus LNG cargoes being diverted to Europe. The significance of the latter is that the region acts as the residual market: it is the only market capable of absorbing surplus LNG volumes thanks to its significant regasification capacity, third-party access, and spot market prices.

Incremental LNG supply vs incremental Asian demand and JKM prices



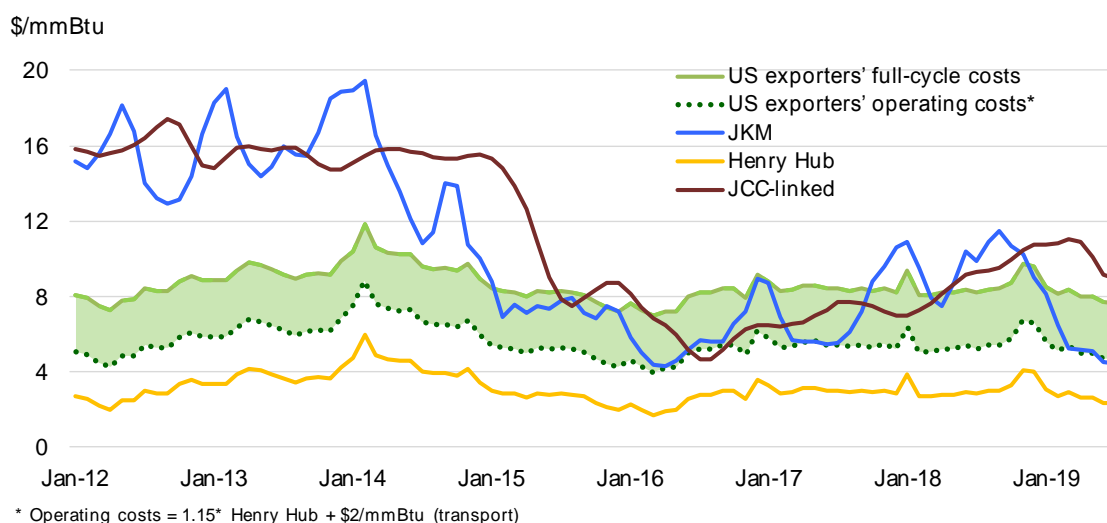
Source: IHSMarkit, S&P Global Platts.

Europe's LNG imports increased to above 8 million tonnes in March and April 2019 (over 11 bcm per month), the highest levels ever recorded in this region and more than twice the levels observed during the same period in 2018. This happened in a context of high Russian pipeline gas flows to Europe and high levels of storage. Consequently, European gas prices sank to below the coal-switching parity level, creating additional gas demand in the power sector. US LNG exporters' operating costs effectively act as a floor to European prices, below which US LNG capacity will begin to be less than fully utilized or even shut in. If, as seems likely, the capacity of European markets to absorb high volumes of LNG and Russian pipeline gas over the coming months diminishes as storage levels are replenished, something will have to give.

What are the implications of the current LNG oversupply for global LNG markets and prices?

First, based on current trends it seems likely that this oversupply will continue for another couple of years, and that Asian and European gas spot prices will be depressed until markets tighten again. Many things can influence the length and size of that oversupply, including global economic growth, other commodity prices, and of course weather, which had a tremendous influence on 2018 energy demand. But as large additions of new LNG supply are expected in both 2019 and 2020, the die is cast: it is unlikely that Asia will be able to absorb it all. China, which is the driving force behind LNG demand growth and which absorbed 37 bcm over the past two years, may see slower gas demand growth going forward and will start importing Russian pipeline gas near the end of 2019, dampening LNG imports growth thereafter.

JKM vs oil-linked gas prices and US LNG exporters' costs



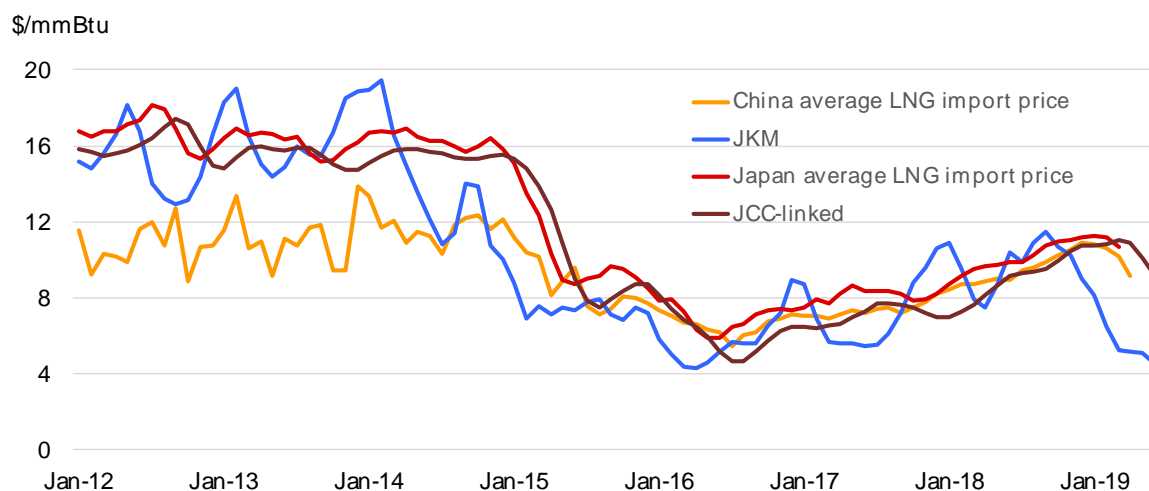
* Operating costs = $1.15 \times \text{Henry Hub} + \$2/\text{mmBtu}$ (transport)

Source: S&P Global Platts, author's calculations

US exporters' operating costs = $1.15 \times \text{Henry Hub} + \$2/\text{mmBtu}$ (transport)

Second, JKM and oil-linked contract prices have diverged. While there is a lot of attention to JKM, most LNG in Asia today is still sold based on oil-indexed contracts, typically linked to the Japanese Crude Cocktail (JCC). Japan and China prices have largely followed oil indexation (JCC), not JKM. The lower levels of China LNG prices before 2015 were due to initial LNG contract pricing at fixed low levels.

JKM vs oil-linked gas prices, China and Japan average LNG import prices



Sources: S&P Global Platts, IHSMarkit, author's calculations.

Over the past few years, JKM prices have broadly followed the trend set by oil-linked contract prices. This is more obvious when comparing the annual average of JKM to that of the oil-linked gas price, removing the seasonal pattern. There is a 96 per cent correlation between the two prices, the only notable divergence being in 2015 when Asian LNG demand dropped and oil prices collapsed.

In the case of a relatively balanced market, like in 2017, JKM featured the typical seasonal pattern of the northeast Asian regions, hovering around the oil-linked gas price. Periods of tightness—like winter 2017/18, when China's LNG demand increased markedly—were translated into JKM at a premium. At times, JKM has also been at significant discounts to oil-linked gas prices: that was the case over 2014–15, as Asian LNG demand abruptly slowed and even dropped for the first time since the economic crisis in 2009. As LNG oversupply started in late 2018, a gap between JKM and the oil-linked gas price started to emerge. As of July 2019, this gap reached around \$4.5/mmBtu, the same level as JKM itself. That would incentivize Asian buyers to nominate less LNG under their long-term contracts and seek LNG volumes sold at JKM spot prices.

Third, this begs the question of whether Asian buyers will move away from oil indexation. Indeed, this sort of divergence in Europe in 2009–10, due to the economic crisis and the previous LNG supply wave, resulted in many European buyers renegotiating their long-term contracts with their suppliers. A large number moved away from oil indexation towards spot indexation. Consequently, the share of oil indexation in Europe declined from about 80 per cent in 2005 to around 60 per cent in 2010 and down to 25 per cent in 2018, according to the International Gas Union.

However, it is unsure whether Asian buyers are ready to move fully to JKM as an index in long-term contracts, even though JKM LNG swap volumes traded on the Intercontinental Exchange and Chicago Mercantile Exchange have surged over the past two years. JKM is a price assessment, but not a fully traded price such as NBP and TTF (Title Transfer Facility). When the move away from oil indexation took place in Europe, NBP and TTF were already liquid trading hubs. Despite the significant progress made by China, Japan, and Singapore in terms of market opening and liberalization supporting the creation of their own hubs, nothing as liquid as NBP or TTF exists yet. Only a couple of preliminary LNG offtake agreements using JKM as a benchmark have been signed so far, notably between Tellurian and offtakers such as Total and Vitol. Some buyers and sellers may be ready to include JKM in term contracts within a pricing basket mixing different indexations. Still, JKM is widely considered the Asian LNG spot price benchmark, even if this is not a traded price. Looking forward, the fact that recent contracts signed by portfolio players do not yet have a fixed destination makes it possible that some of these volumes are sold at JKM prices, further enhancing LNG commoditization.

An additional consequence of the oversupply is that buyers are taking advantage of the current market weakness by pushing for more favourable pricing conditions. Buyers may want to opt for one or a mix of indexations, including oil indexation, JKM, and/or various other spot indexations, providing hedging against various risks.

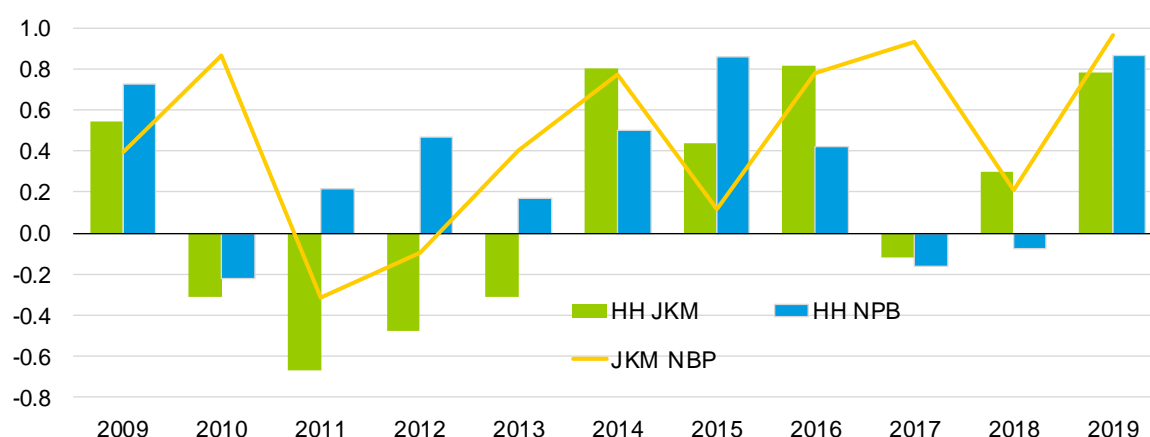
Oil indexation itself is multifaceted, and recent contracts have tended to have lower slopes, down to 11 per cent instead of the usual 14–15 per cent. At oil prices around \$50/barrel, this can yield a price \$1.5–2.0/mmBtu lower.

Attempts are still being made to index long-term LNG contracts to other commodities. In early 2019, Shell and Tokyo Gas signed an LNG contract indexed to coal. While this indexes gas to another commodity for which price movements are not related to the gas market, it correctly identifies the main competitor of natural gas in the power market: coal, no longer oil. In Asia, gas represents 12 per cent of power generation, compared to almost 60 per cent for coal in 2018 (around 25 per cent and 50 per cent respectively if one excludes China).¹ Coal-fired generation in Europe was also higher than gas-fired generation in 2018. The relationship between coal, gas, and carbon prices in Europe impacts their respective moves: low gas prices are currently incentivizing additional gas demand in the power sector as they drop below the coal-switching level.

For those looking at US LNG supplies, formulas are changing too: liquefaction fees proposed in most recent projects such as Calcasieu LNG are lower than the \$3.0–3.5/mmBtu observed in the first wave of US LNG. Tellurian is reported to have a totally different approach to the tolling fee, having project partners investing in equity in an integrated project and getting low-cost LNG in return. Finally, US producer Apache is said to have signed a deal to supply Cheniere using a price mechanism linked to JKM. This signals the interest of US producers to be exposed to global LNG prices, especially Asian spot prices, and reinforces JKM as a credible benchmark for Asia. Finally, the cost-plus approach that US LNG has initiated highlights an important, though often simplified, component of the price: shipping costs. This matters in determining not only the final price in various markets, but also the differential between European and Asian markets, and therefore the attractiveness of each market to US LNG exporters and re-export patterns.

Finally, will there be more convergence between regional spot prices? Over the past few years, there has been much talk about a growing convergence between Asian, European, and US spot prices. Looking at the correlation between monthly Henry Hub, JKM, and NBP prices on an annual basis, the correlation between NBP and JKM has increased over time, reflecting these markets' competition for LNG imports. Given that the US only started exporting LNG in 2016 and imports negligible amounts, low correlations over 2010–13 at a time of high oil prices are perfectly understandable. In 2018, the correlation of NBP and JKM with Henry Hub was especially hampered by Henry Hub increasing in the last quarter of 2018, while NBP and JKM started to tumble. But as we have moved into oversupply, the correlation between the three prices has dramatically increased.

Correlation between JKM, Henry Hub, and NBP prices



Sources: S&P Global Platts, author's calculations.

Note: 2019 values represent the first six months; HH = Henry Hub.

¹ BP, *BP Statistical Review 2019* (2019), <https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html>.



The final question is: when and if LNG moves to commoditization (by being priced against its own fundamentals), what will drive the various regional gas prices, and will there be an increased correlation between gas prices? BP projects² that the United States will be a leading LNG exporter by 2040, making it quite likely that prices will eventually be set by the liquefaction and transport differentials to the United States. But the path towards that stage could be a lengthy one, as buyers currently seek different formulas and approaches. As the number of buyers and sellers increases, there is not yet a predominant pattern in terms of what buyers want—in prices but also flexibility—and what sellers are willing to accept.

LNG TRADING, LIQUIDITY, AND HEDGING: A NEW LANDSCAPE FOR NATURAL GAS BENCHMARKS

Gordon Bennett

LNG liberalization—the move from a procurement structure to one that is market-based—has been the catalyst for natural gas globalization, creating a virtual pipeline between continents. Against this backdrop, liquidity is key to understanding the development and evolution of natural gas benchmarks, particularly in fast-growing demand regions such as Asia. And as LNG globalization transforms the landscape, new fundamentals will determine which hubs across Asia, Europe, and the US achieve and maintain their benchmark status.

In Asia, LNG liberalization has enabled the region to overcome a lack of pipeline infrastructure—producing Asia's first natural gas benchmark with LNG contracts settled against the Platts LNG Japan Korean Marker (JKM). The success of JKM raises the question of further evolution - whether stakeholders will continue using existing pipe gas benchmarks in the US and Europe, or if new benchmarks will emerge. In addition, if LNG is viewed as a virtual global pipeline, the development of a supporting freight market could provide important price transparency for transportation between major trading centres.

So what factors are necessary for benchmark status? And how do market fundamentals and liquidity interact to realize this?

Liquidity is an important measure in determining a market's ability to achieve its main purposes: provide price discovery, transparency, and allow for efficient risk transfer between participants. A liquid market also fosters efficient competition, encouraging the optimal allocation of an asset. A market is considered liquid if participants can easily transact large volumes with limited impact on asset prices and low transaction costs. Liquidity also dictates decisions around whether to trade—the size of an order that can be executed, order sizes available at different price levels, and the ability to execute a timely trade to minimize slippage losses.

Critically, well-functioning spot markets are the nexus of forward markets, in that they are an important factor in achieving benchmark status. In Europe, the UK National Balance Point (NBP) and Dutch Title Transfer Facility (TTF) are already well-functioning spot markets, and JKM is now establishing itself as a credible spot market through factors such as the use by Platts of the Market on Close methodology in the determination of the JKM price assessment.

TTF edges out rivals

Europe has liquid spot and futures markets for natural gas, coal, carbon, and electricity, which facilitate fuel switching in its electricity-producing sector. Because of Europe's effective response to changes in natural gas prices, it can absorb excess supply of LNG which is not sold in Asia. In other words, the liquidity of Europe's natural gas markets, in combination with excellent gas infrastructure, supports its role as the world's balancing market for LNG.

However, established hubs can also lose benchmark status.

Gas hubs are marketplaces—whether virtual or physical—run by hub operators, where participants can transfer the title on natural gas already present in the transmission system to other market participants. This service, together with standardized contracts, can help the development of a liquid gas market.

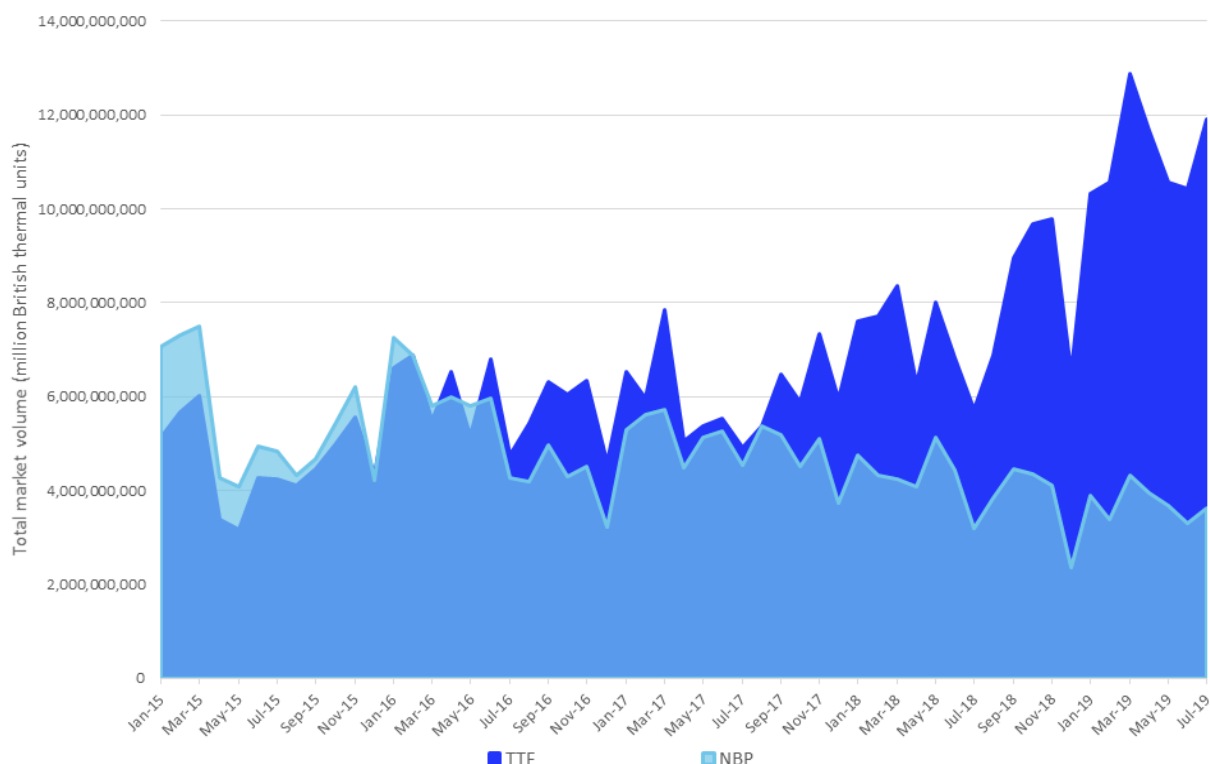
As Europe's first actively traded natural gas hub, the sterling-denominated NBP initially benefited from strong North Sea production, robust consumption, and supportive market regulation. Following the European Union's Third Energy Package for

² BP, *Energy Outlook 2019* (2019), <https://www.bp.com/en/global/corporate/energy-economics/energy-outlook.html>

the internal energy market and inspired by the NBP, policymakers, market participants, and the Netherlands hub operator established the euro-denominated TTF. Like NBP, TTF is a virtual hub.

Over the past approximately five years, liquidity at TTF has grown relative to NBP. This development was driven by the rise of gas-on-gas indexation in northwest Europe, which increased the need for hedging and bolstered liquidity of the forward market, amid a preference for Euro-denominated contracts.

Traded volume, TTF and NBP

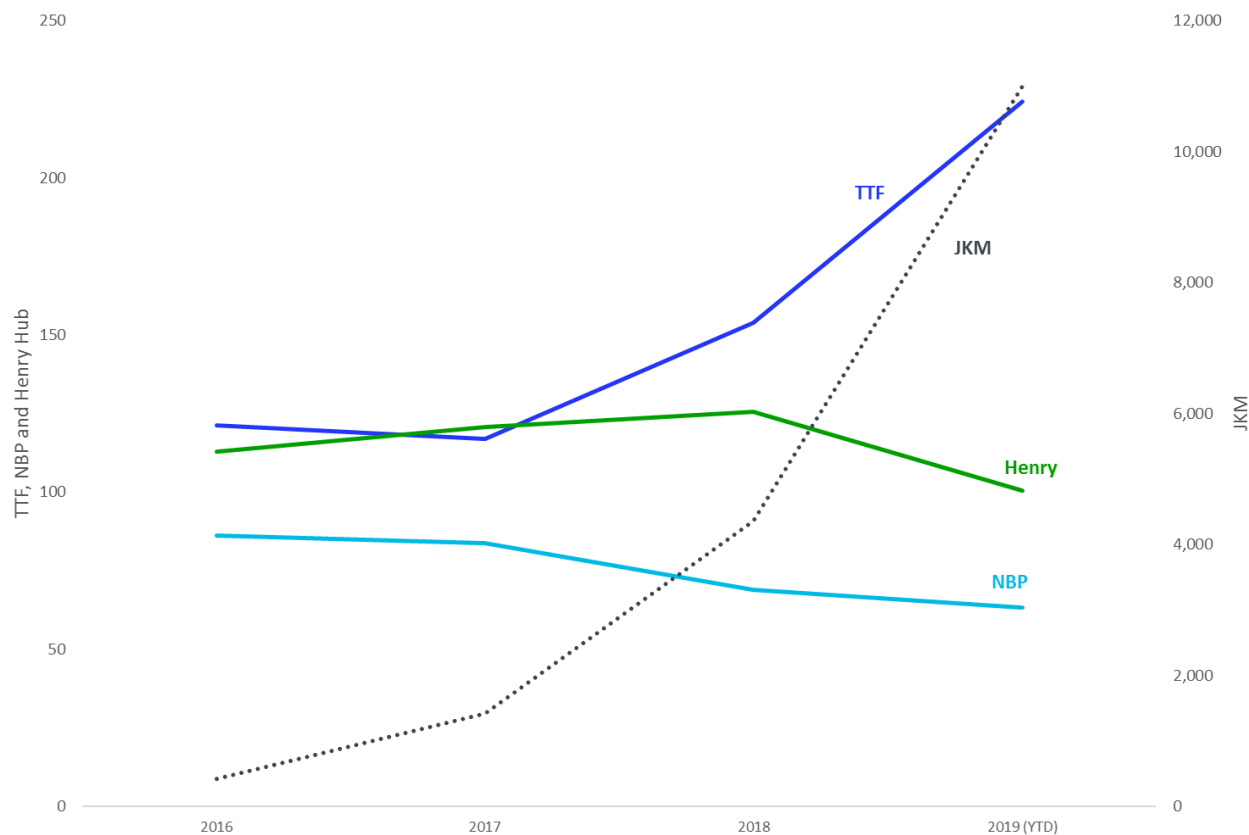


Sources: CME, EEX, ICE, LEBA.

Today, TTF has replaced NBP as Europe's main gas hub and benchmark price, a clear case of liquidity coalescing around the most suitable benchmark for a given market. The network effect of markets has already supported the rise of TTF—as its momentum attracts new users, its value and utility are boosted for current and future customers. Already in 2019, TTF's volume surge (42 per cent year-on-year) is likely driven by its role as the global balancing market for LNG. This virtuous cycle of liquidity looks set to continue as TTF becomes more internationalized and embedded across financial markets, cementing its benchmark status as the Brent equivalent of natural gas. The development of the liquidity of these benchmark hubs can be illustrated by means of the change in churn rates; the proportion of the trading volume to physical demand. The figure below shows the development of key natural gas benchmarks since LNG liberalization provided the catalyst for the creation of a global natural gas market, and illustrates the rising prominence of both TTF and JKM.

Are there credible challengers to TTF? German lawmakers have put the obligation on domestic pipeline operators to merge the two existing market areas, NCG (NetConnect Germany) and Gaspool, by 1 October 2021. However, reaching this final stage of market consolidation in Germany is a very complex and costly exercise and is not expected to improve liquidity. Instead, the German energy market regulator and industry concluded that any further market integration should include at least both German market areas and the TTF. Many stakeholders, in particular traders, took the view that the liquid TTF market provides them with sufficient opportunities to hedge their exposure to the German gas markets. In addition, with gas-on-gas pricing substantially complete in Europe and the dramatic associated rise in TTF liquidity, any attempt by Germany or other challenger hubs to create a benchmark would need to be compelling enough to change entrenched market behaviour.

Churn rates for benchmark hubs (2015 = 100)



Sources: CME, EEX, ICE, Nasdaq, LEBA, Enerdata, International Gas Union.

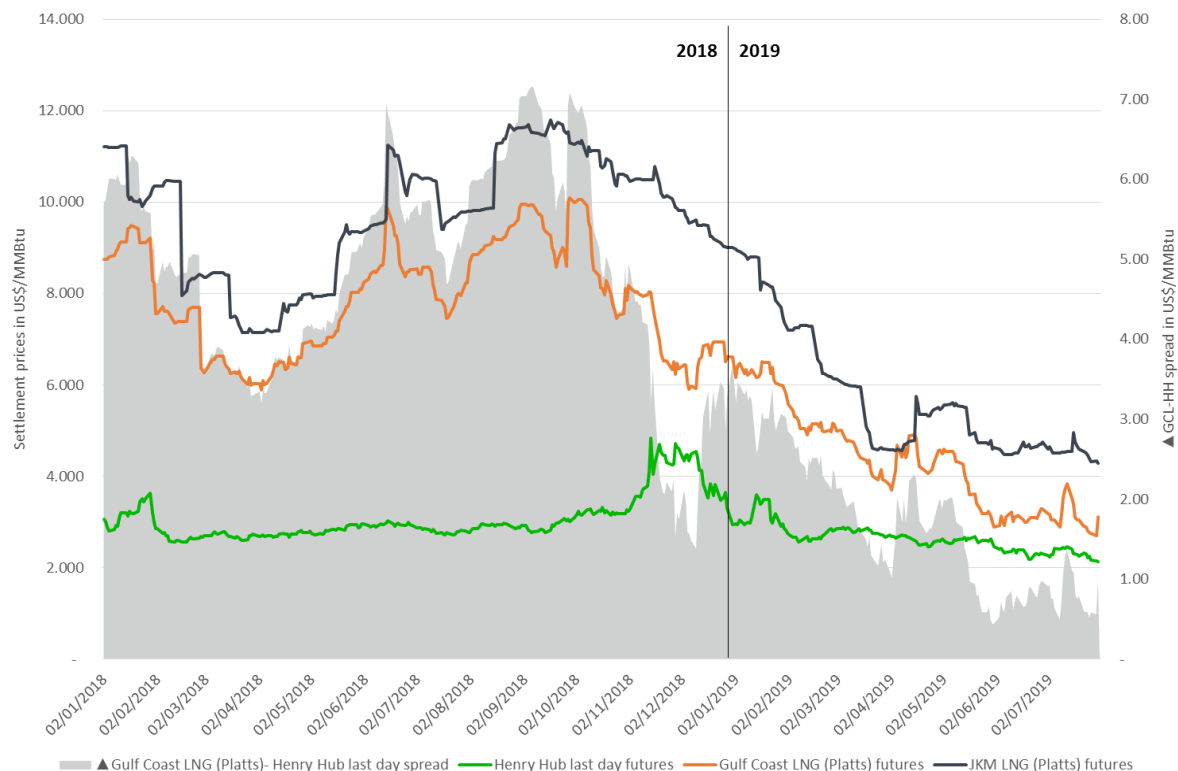
The future of Henry Hub

In the US, Louisiana's Henry Hub is the most well-known natural gas hub, connecting on and offshore pipelines from Louisiana, Texas, and the Gulf of Mexico. Yet over the past decade, the shale gas revolution has turned the US into a net exporter of gas—with Marcellus and Utica in the northeast and Permian, Haynesville and Eagle Ford in the south, all having greater proved reserves than the Gulf Coast in the US. Locational pricing has come to the fore, challenging Henry's status.

While Henry Hub continues to be important due to entrenched market behaviour, its dislocation from pricing in North America presents a compelling catalyst for change. As the first US company to export LNG, Cheniere Energy exclusively used Henry Hub indexation before 2015 in their take-or-pay-style sale and purchase agreements. The indexation to Henry provided a perfect hedge for Cheniere's feed gas exposure, whilst the fixed capacity payments in the region of \$3 per million Btu (British thermal units) provided the certainty of revenues to finance the expansion of Cheniere's liquefaction facilities. In late 2015, however, Cheniere started to enter deals with the large European utilities Électricité de France and ENGIE, utilizing European benchmarks such as TTF.

In addition, the use of Henry Hub predates a global natural gas market; it began at a time when there was clear margin differential between it and natural gas markers in Europe and Asia, providing a compelling price advantage for buyers to take Henry-indexed contracts whilst providing an effective hedging marker for US exporters. Now, low global natural gas prices, driven by a healthy supply of LNG from around the world, mean tighter margins and a buyer's market. New export facilities in the US will find it more challenging to tie themselves to the Louisiana marker. This is illustrated in the figure below by means of the significant moves in the spread between the price on Henry Hub and US Gulf Coast LNG and the fact that the latter is closely correlated to the price of LNG in North East Asia.

Front month settlement prices of Henry Hub vs. LNG



Source: ICE.

As recently as June 2019, further evolution in global natural gas dynamics impacted contract structure, with the announcement of Cheniere and Apache's long-term gas supply agreement, which will be indexed to global LNG prices. This is potentially significant in two respects: instead of Cheniere back-to-backing its feedgas exposure through a risk transfer to the buyer of LNG, it is now managing its feedgas exposure through a risk transfer to the seller of the feedgas. So whilst the end buyer of LNG may be more hesitant to accept the risk transfer, the dislocation in price formation within the US between shale basins and Henry Hub (where we have recently seen negative pricing in the Permian Basin) enables US shale exploration and production companies to accept this risk transfer, and provides them with more upside to access global natural gas pricing.

Will China's rise result in a new Asian benchmark?

As seen in Europe, the move from oil-on-gas to gas-on-gas pricing will be a determinant in the growth of JKM. Underpinning this is the fact that LNG pricing in most long-term LNG sale and purchase agreements is based on the price of crude oil. The decoupling of oil and LNG prices is putting pressure on that pricing structure and will help speed the transition, along with the unwinding of these legacy contracts.

With Asia as the key buyer of global LNG, and Europe as the world's balancing market, the interplay between Europe's TTF and JKM will underpin pricing formation for global natural gas. JKM has already hit key milestones—the ratio of the spot LNG to derivative market is now 1:1, indicating the same amount of trading in derivatives as physical markets. In this way, a virtuous cycle of liquidity will feed more derivative volume and use for physical indexation. JKM's broader use underscores its credibility—recent agreements between Tellurian and Vitol and between Tellurian and Total both used transaction prices based on JKM, and noted its suitability for a global portfolio. These deals were groundbreaking as the first deals struck by a US exporter to an Asian natural gas benchmark.

Meanwhile, China is expected to lead global demand for natural gas and LNG over the coming decade, as it seeks alternatives to coal amid intense policy pressure to reduce air pollution and meet its climate change objectives. Some analysts believe that once energy market reforms in China occur, supporting cleaner fuels and growth in gas consumption, China's ability to switch fuels for its power sector will overtake Europe's. They note that China will have increasing flexibility in conventional power generation, and suggest the global natural gas price could therefore be set in China.



Yet market shifts may not necessarily determine benchmark status, and China faces some challenges, with its push to establish yuan-denominated benchmarks in oil and other commodities still nascent. JKM has already been updated to reflect the spot market value of cargoes delivered ex-ship into China and Taiwan, as well as Japan and South Korea. Given current momentum, the time it would take to address hurdles to a Chinese benchmark could see the network effect around JKM overcome any challenger price marker.

Conclusion—benchmarks for a global market

As new deal types proliferate, a range of hedging products remains critical. Some players who signed deals when LNG exports were still nascent say contracts must change so that a greater portion of market risk is borne by LNG projects rather than buyers. In April, NextDecade's 20-year agreement with Royal Dutch Shell was the first long-term contract with US-produced LNG to be indexed to Brent, boasting full destination flexibility. And Tokyo Gas recently signed a long-term deal with Royal Dutch Shell, in what was believed to be the first time a coal pricing index was used with an LNG contract.

While benchmark contenders may emerge, experience has shown that liquidity will continue to coalesce around a few key benchmarks—and other hubs or markers will trade as a basis to these, in the absence of a breakdown in market fundamentals. In addition, the existing network of major gas hubs and markers is sufficient for global liquidity, now connected by LNG freight movements across continents.

Despite being a driver of global LNG demand, China illustrates that supportive fundamentals alone may not necessarily be sufficient to create new benchmarks: structures which support liquid international trading are equally critical. On the flipside, Henry Hub demonstrates that new fundamentals—price divergence from key supply sources—can also challenge established price markers, as illustrated by TTF surpassing NBP.

Amid market upheaval—the liberalization of LNG, a shift towards gas-on-gas pricing, and the decoupling of oil and natural gas markets—TTF and JKM are emerging as robust and distinct global benchmarks. Whether JKM will remain Asia's only benchmark is yet to be determined, though its ongoing rise seems assured.

PRICE REVIEWS: ARE ASIAN LNG CONTRACT TERMS FINALLY CHANGING?

Agnieszka Ason

With LNG markets in transition, LNG contract terms are changing as well. The push towards price flexibility is at the heart of recent changes to LNG contract terms in Asia. One of the key paradigm shifts in Asian LNG contracts is a growing acceptance of price review clauses. This article discusses the emergence and key elements of these clauses, focusing on novel features of Asian price reopeners.

Price review clauses

A price review clause offers the most straightforward way to request a revision of a contract price which, during the life of a long-term LNG supply contract, may become untenable to either party. While European LNG contracts have routinely included price review clauses since the 1960s, price reopeners did not feature in most Asian LNG contracts until the 1990s. In more recent Asian LNG contracts, price reopeners are becoming standard. Such a clause could read as follows:

- No earlier than after the first 10 Complete Contract Years, and within 6 months after the beginning of every 5 Consecutive Contract Years, a Party may give a Price Review Notice to the other Party to renegotiate the Contract Price.
- Following the issuance of the Price Review Notice, the Parties shall meet and discuss the matter in good faith with a view to agreeing what Price Adjustment (if any) is required. The then current levels and trends in the price of oil and gas in the Asia-Pacific region shall be the basis for good faith discussions.
- Any Price Adjustment agreed by the Parties shall take effect in respect of all Deliveries of LNG under this Agreement on or after the date of the Price Review Notice. Until any Price Adjustment has been agreed, the Contract Price shall be determined on a provisional basis under the formula prevailing prior to the Price Adjustment.



The three standard components of a price review clause—conditions for a price review, price review process, and price review methodology—are discussed in turn below.

Conditions for a price review

Temporal triggers

Price reviews in Asian LNG contracts can typically be triggered after a set number of years from the date of first delivery and at regular intervals throughout the life of the contract. Most Asian LNG contracts from the 1990s provided for a price revision at intervals of five to ten years. Modern contracts tend to stipulate shorter price review periods, typically of four or five years. Narrower price review intervals offer more flexibility to request a revision of the contract price. But Asian LNG contracts still very rarely stipulate that a price review can be requested outside the regular price review periods, or based on the occurrence of some specified circumstances. The limited availability of non-period reviews necessarily constrains the parties in their attempts to revise the price, ultimately forcing them to await the next time window to submit their request.

Limited role of downstream market conditions

Grounds for a price review are very limited in Asian LNG contracts. Most notably, they are unlikely to include a 'significant change in economic circumstances in the buyer's market'—the price review trigger mentioned most commonly in European contracts. This peculiarity of Asian LNG contracts derives from the historical capability of Asian buyers to pass through price increases to their customers. The lack of reference to the buyer's market conditions is likely to change in the future, especially considering that liberalization of Asian LNG markets will inevitably mean that the buyers will operate in a more competitive environment limiting their ability to pass through the costs of LNG and maintain profitability at the expense of end-users. Asian buyers can, therefore, be expected to build protection against price increases into renegotiated or newly drafted price review clauses.

Price review process

Good faith discussions

Negotiations in the Asian context, often referred to as good faith discussions, are routinely the first step in a price review process. The contractual basis for good faith discussions is rather vague in most Asian LNG contracts. In particular, price review clauses like the example set out above often do not stipulate a negotiation period or recourse in the event of failed negotiations. The length, and prospects, of price review discussions can therefore prove uncertain and potentially discourage a price review request. Price review clauses stipulating strict time limits for good faith discussions, and specific actions in the event of their failure, should offer a more favourable, but still rare, setting for a price review process. These more detailed price review clauses, which are most likely to be found in newer contracts, typically provide for one of three options if negotiations do not lead to a new agreed price. First, some Asian LNG contracts state that the contract 'shall remain in full force' even if the parties fail to agree on a price adjustment. Second, some Asian LNG contracts offer both parties the right to terminate the contract if they are unable to agree on a price adjustment. The third, and in the long run arguably most important, alternative now being adopted in some recent Asian LNG contracts is for the price review mechanism to provide that in the event the parties fail to agree on a new price within a specific time frame, either party may submit the dispute to an external dispute settlement mechanism like arbitration or expert determination.

Arbitration

Arbitration is the preferred dispute resolution method in European long-term LNG and gas supply agreements. For a variety of reasons, including the traditional Asian preference for non-adversarial dispute resolution mechanisms, and the close-knit nature of the LNG sector, Asian LNG contracts have not adopted the European preference for arbitration and only required the parties to 'meet and discuss' the contract price. However, the attitude towards arbitration is now changing in Asia. The emergence of new players and the expansion of capital-intensive LNG projects, in particular, have led to a greater push towards price review clauses offering recourse to arbitration primarily as a means to hedge against the risk of protracted price review discussions. As a result, recent Asian LNG contracts increasingly provide for arbitration as the second step after good faith discussions have been conducted for a stipulated period of time.

As for the earlier Asian LNG contracts, the availability of recourse to price review arbitration is uncertain. In particular, the absence of an express right within the price review clause to refer a failure to agree on a new price to arbitration is likely to prevent arbitration in relation to the setting of the price.



Apart from contractual barriers, arbitration under an Asian LNG contract may also face practical impediments. For example, industry evidence suggests that some parties to Asian LNG contracts, especially state-owned companies, will never allow a dispute to reach the arbitration stage. As fittingly described by one party interviewed as part of OIES's research, in such cases, arbitration effectively becomes a Damocles sword hanging over both parties' heads to force a negotiated solution.

Expert determination

Expert evidence has always played a vital role in LNG price review arbitrations. Parties have traditionally built their cases, and arbitrators decided these cases, on multiple expert reports. Some contracts expressly require the submission of narrowly defined, mainly purely technical, questions for determination by an expert.

Determination by an expert (or panel of experts), as a separate dispute resolution process with the expert acting as an independent decision-maker, has never evolved into a full-fledged alternative to arbitration in price reviews arising from European contracts. In that regard, Asian LNG contracts seem to differ from their European counterparts. Industry input suggests that some Asian price review clauses submit the resolution of an entire price review dispute exclusively to an expert. Other Asian contracts provide for expert determination as one option. For example, a contract may stipulate that the parties may agree to refer any dispute to an expert for determination if they feel that, in view of the nature of the dispute, this will be more suitable than arbitration. In at least one case, the parties entered into a dispute resolution agreement that effectively replaced arbitration with expert determination for their price review.

Price review methodology

Most price review clauses in Asian LNG contracts offer very little guidance as to the factors that should be taken into account. Strikingly, some Asian LNG contracts (including the most recent) do not specify any instructions or parameters at all for the price review, potentially exposing the contract parties to the risk of undesirable results. The lack of guidance on methodology should not cause major problems as long as the decision on the price adjustment remains in the hands of the parties. But problems are likely to arise if informal good faith discussions fail. Parties contemplating recourse to a third-party dispute settlement, in particular, may feel uncomfortable leaving this vital decision to an external actor whose powers are not constrained in any tangible manner by the contract. In response to such concerns, a wide variety of measures can be adopted to limit the discretion of arbitrators or experts hearing a price review claim. Strategies which are, arguably, most suited for Asian LNG contracts are briefly discussed below.

Limits to the decision-making process

First, the parties can instruct arbitrators or experts as to how they should (or should not) arrive at their decision. To that end, they can specify factors, parameters, or evidence to be considered (or excluded) in a price review. The parties may also set a threshold on retroactivity and the relevant time perspective of the price review, and define, for example, the extent to which the future impact of a price change should be relevant.

Limits to structural changes to the price formula

In addition, or as an alternative, the parties may limit structural changes to their price formula. Parties to Asian LNG contracts, in particular, may be inclined to reserve wholesale structural changes to a limited set of circumstances. For example, they can allow for a change from an oil-indexed price to a hub-based price only in the event of a liquid gas hub being created in the buyer's market. Furthermore, the parties can prohibit changes to specific components of the price formula, like slope or constant, or expressly exclude application of specific indexes like the Japan Korea Marker or Henry Hub.

Quantitative limits to the price revision

Finally, the parties may specify a range within which the contract price can be increased or decreased. To that end, the contract can refer to specific maximum and minimum figures, or an acceptable percentage change, or stipulate a gradual transition to a new price formula over a period of years. These or other quantitative limits can feature in isolation, or together with limits to the decision-making process or to the scope of structural changes to the price formula.

Risk of overly prescriptive limits

Although the limits to the powers of an external decision-maker may play an important role in protecting parties from the uncertainties of the price review, some of these limits may prove too prescriptive and limit arbitrators' or experts' ability to provide a commercially sound decision. It is therefore essential that any limits remain sufficiently flexible and facilitate, rather than compromise, a price review process.



An alternative to such limits, and theoretically preferable, would be careful due diligence preceding the choice of an external decision-maker. In particular, the parties entrusting an individual with the decision on the contract price should have confidence that that person is experienced and well versed in international gas markets and the intricacies of the LNG business and that the final outcome will be acceptable to them (and, ideally, reflect the market price). Arguably, the parties could be inclined to allow such an individual more discretion in determining the contract price. But the practical difficulty of this solution lies in the fact that the contract is typically drafted long before any person is considered for such an appointment. Indeed, a stronger emphasis on the issue of price review methodology at the time the contract is drafted may constructively inform the decision on the most suitable external dispute resolution mechanism to be incorporated into a price review clause under a particular contract.

Conclusions and outlook

The lack of price review clauses in Asian LNG contracts, and the limitations to existing clauses, have historically translated into a low number of revisions to prices under long-term contracts in the Asian markets. In the future, and possibly the near future, the number of LNG pricing disputes in Asia is likely to increase. As soon as Asian LNG buyers and sellers develop a more systematic approach to price reviews, this is likely to be reflected in the content of price review clauses. In general, price review clauses in newly drafted or renegotiated contracts can be expected to become more detailed and to stipulate more flexible terms for a price review.

Conditions for price reviews in new Asian LNG contracts are likely to involve shorter price review periods and to increasingly provide for non-temporal triggers. Downstream market conditions, in particular, are likely to become more relevant in future price reviews. The most significant changes to contract terms governing the price review process are likely to focus on post-negotiation options. For the sake of certainty and efficiency, these options are likely to be reduced to a binary choice between third-party dispute settlement and contract termination. Capitalizing on the lessons learned over several decades of price reviews in Europe, parties to Asian LNG contracts can be expected in the future to opt for arbitration. It can also be expected that expert determination will play a more significant role in Asia than it has in European price reviews. Contract terms governing price review methodology will likely continue to be determined on a case-by-case basis but to become more prescriptive.

An overarching question is whether changing price review clauses, which are likely to incentivize price reviews, will result in more comprehensive changes to Asian LNG contract terms. In particular, it remains to be seen whether price reviews will be limited to a case-specific revision of a price under a particular contract, or whether they will cumulatively trigger broader changes to price formation, contract duration, destination flexibility, or other fundamentals in Asian LNG contracts.

TECHNOLOGY

HOW CRITICAL IS SHIPPING TO THE LNG VALUE CHAIN?

Bruce Moore

Is shipping critical to the value chain? At a simple level this is akin to asking if buying a ticket is critical to winning the lottery. Yes, it is an inherent part of the physical process. LNG production is only worthwhile where the distance between gas field and market is too far to warrant building a gas pipeline. Cryogenic pipes—those that carry liquefied gas—are expensive and commonly no longer than the length of the jetty which leads to a ship. So no ship means no movement of LNG.

But surely there are enough ships in the world? Oil fields are developed by and large without any requirement for dedicated shipping to transport their product to market. Instead, ship owners are happy to invest in tonnage and make this available for both short- and long-term charter, resulting in a deep and liquid tanker market. The vessels themselves are largely standardized, and the price of oil is largely inelastic to tanker charter rates. Disruptions in the oil value chain due to transportation constraints are exceptionally rare, except in the case of armed conflict or political strife.

The world of LNG shipping has, however, traditionally behaved very differently, for a number of reasons. Chief among these is the greater capital cost of the ships; for oil, very large crude carriers have typically cost \$90–100 million to build, versus \$180–230 million for an LNG ship. As with the LNG production and receiving terminals, the high capital cost of the ships has necessitated dedicated project financing. All parties seek clear allocation of risk along the whole value chain, from upstream wellhead to end user burner tip—the whole commercial chain being known as the ‘cashflow waterfall.’ This has resulted in a dedicated physical supply chain servicing each LNG production facility, to either a single or small number of dedicated

customers. The final investment decision for any upstream LNG project is not made until certified upstream reserves, production plant construction contracts, shipping charter parties, and gas sales contracts are all in place. And this tends to lead to vessels designed to trade to a narrow range of ports, operating under very long-term (20-year) charter parties.

The LNG industry will always require large sums of capital for investment in production, supply, and customer facilities, so an underpinning from a proportion of dedicated long-term contracts will probably always be required. But as we see elsewhere in this issue, there is now a growing short-term LNG cargo market. Hence demand for shipping contracted on a short-term basis is now also strong, and growing; many industry players wish to move LNG but without long-term commitment to tonnage.

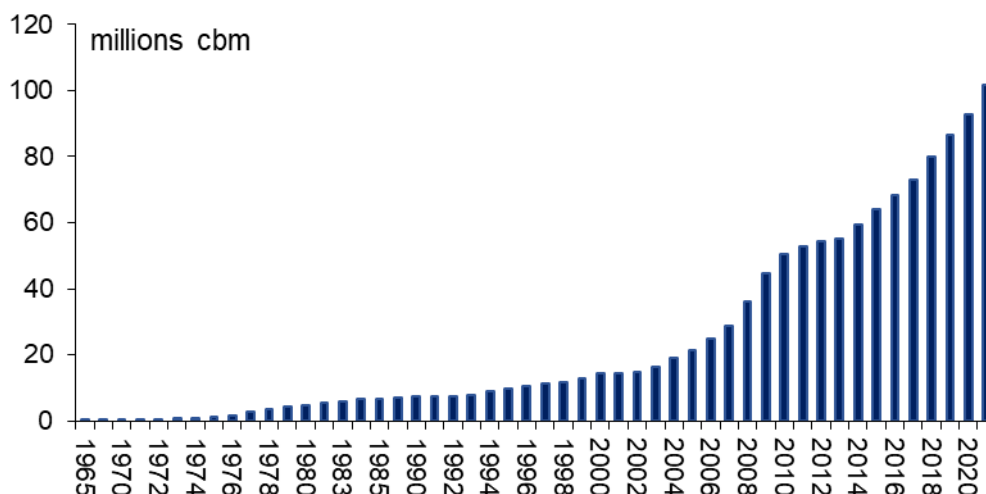
This began most significantly when ships built in the late 1970s and early 1980s reached the end of their long-term charters. The production plants they served were still producing, but often at lower rates as reserves began to decline. Some of these ships then became available for short-term charter. At the same time, some gas markets, notably in Europe and the United States, began to liberalize, and LNG producers sought to monetize excess production not lifted by their long-term customers. Integrated majors such as BP and BG (now part of Shell) sought to construct trading 'webs' of supply and demand points, with flexibility to move cargoes to whatever location resulted in the highest overall value. Both older 'off charter' ships and new ships ordered without dedicated trading routes formed critical transportation elements.

So a more useful question today might be, 'How critical is dedicated long-term shipping to the LNG value chain?'—or better still, 'Can I rely on the spot market to move my cargoes? Has the shipping world responded to this change in demand?' The answer to these questions is probably 'Yes, but it depends.' Let us examine what is required for the development of a reliable short-term shipping market, what is actually in place today, and how this might change in the near future.

Vessel supply

The capacity of the world LNG fleet is growing almost exponentially. Not only have vessel numbers increased, but the average size of new ships has increased from about 128,000 cubic metres in 2000 to about 175,000 cubic metres today.

Global fleet capacity



Source: Howe Robinson.

However, of the current approximately 600-vessel world LNG carrier fleet, only around 15 per cent of vessels are made available for short- or medium-term hire with any real frequency. And, considering the most modern and efficient vessels in terms of fuel and cargo capacity, this starts to become more select: so far this year only around 15 of the more fuel-efficient (MEGI/XDF) ships have appeared on the short-term market.

The makeup of the order book, however, is very significant. Of the 120 larger conventional vessels currently under construction, 45 do not yet have a charter secured. Independent owners—especially the more entrepreneurial European owners—are increasingly happy to place vessel orders first and search for charters later. Whether this shows faith in the fundamentals of the industry to deliver long-term charters, or in the growing spot market, is of course open to debate. Overall, however, we can see increasing numbers of vessels being made available for short-term hire.

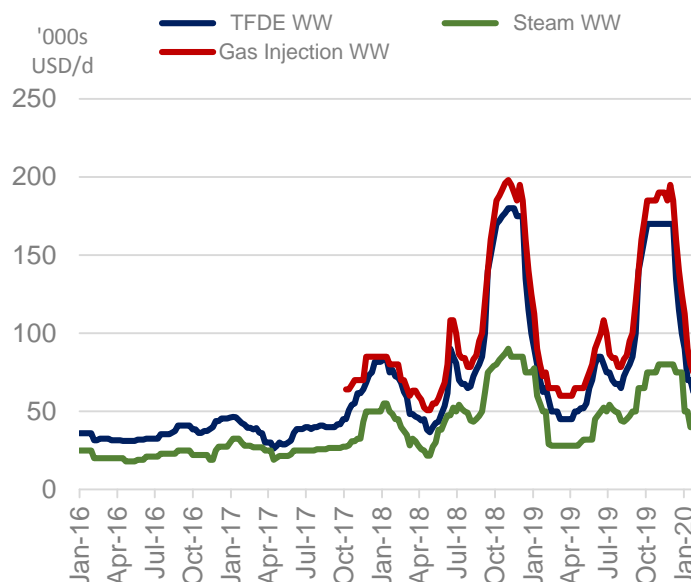
Charter rate volatility

Vessels on the short/medium-term market fall into three main categories:

- older vessels where their original long-term charter has expired
- 'portfolio' ships that are usually engaged within a liner route or trading web business for a single charterer, but have some short-term time available
- more modern vessels reserved by their owners for the short/medium-term market.

It is common in the tanker trade for owners to invest in new tonnage and reserve this for the spot (short-term) charter market. Owners have confidence that this market will be sufficiently liquid to enable them to keep their vessels employed most or all of the time. The charter rates they achieve will vary, but charter rate risk is at the heart of their business and they are skilled at making the timing judgements required to take best advantage of volatility. Volatility is precisely what draws them to the market. And recent short-term time-charter rates for LNG ships have seen similar volatility. Short-term rates for modern vessels have varied between the high \$20,000s and about \$180,000/day. But can owners be reasonably sure of employment for their vessels in this short-term market? Even though the vessel investment picture is improving it is becoming rarer for modern tonnage to remain without charter business for more than a few weeks.

Short-term charter rates for LNG ships



Source: Howe Robinson.

Still rare in the LNG market are sales of second-hand vessels, especially of more modern tonnage. Such sales are common in other shipping sectors, and 'asset plays'—buying tonnage at times of low prices in the hope of selling later in inflated markets—form the mainstay of many ship owners' business strategies. It would take a bold owner, however, to make this the heart of a strategy for investment in relatively expensive LNG vessels. This has a knock-on effect on how LNG vessels are financed; as so few resales are made, there is little data on which to base assessments of potential future resale values. This inability to assess 'residual value risk' is difficult for lending banks, which are wary of taking even implied risks on ship values. Hence, LNG shipping is the territory of borrowers with a strong track record of honouring shipping loans. As resales become more common, this will enable more confident appraisal of residual value risk, and hence more liquid lending to a wider range of new-entrant LNG vessel owners.

To summarize, there is certainly demand for short-term LNG vessels, and supply is doing its best to catch up. For a truly deep and liquid market, however, further factors must be considered, principally standardization, information flow, and maintenance of safety standards.



Standardization

There are currently around 34 active LNG load ports and 134 discharge ports. So a ship built to fit in just one of each will not be much use in a short-term market. And yet traditionally LNG ships were built for very specific routes, usually from one load port to a limited range of discharge ports. In a world of flexible short-term ‘tramp’ shipping, vessels need to be compatible with a wide range of ports. Such standardization is essential not only for the ships themselves; ports need to be agile in their acceptance procedures for ships, and charterers need to be clear and reasonable with owners with regard to their ship vetting procedures. As ever, the LNG world can learn from the tanker trade, where vessel and port standardization, port control, and vetting processes—such as the OCIMF SIRE (Oil Companies International Marine Forum/Ship Inspection Report Programme) system, and TMSA (Transportation Marketing and Sales Association) management self-assessment—are nimble enough to facilitate the rapid contracting required to meet short-term vessel requirements. The contracting terms themselves are, of course, equally important: rapid contracting depends on well-understood, fair, and balanced charter parties. The development of contracts such as ShellLNGTime is to be most welcomed.

Flow of information

Any efficient market depends on the flow of information—cargo requirements, vessel availability, data on vessel–port compatibility, and the satisfaction of vetting and regulatory requirements. Some such information—for example, terminal compatibility requirements—can and should be shared more openly than the LNG industry is used to doing.

In a sector where the number of owners and charterers is growing exponentially, however, merely bringing the two parties together becomes more and more important. Traditionally, this is the role taken by ship brokers, who facilitate transactions, share important but more confidential information in a more sensitive fashion, and work to prevent or if necessary mediate disputes. Relationships, as always, still matter.

Safety

The LNG shipping industry boasts a proud safety record maintained over many years. Since the first industry cargo in 1964 there has not been a single major accident attributable to the cargo itself. Arguably the historic liner-trade nature of the business, and common cost pass-through maintenance regimes, have enabled this focus on safety and reliability. But the nature of the trade is changing; and in the tanker world, any major incident could have severe ramifications for the industry. Agile but robust ship inspection and vetting processes must be maintained. Ultimately, safety on board is the ship owners’ responsibility, despite the pressures on crewing and maintenance costs that arise in inevitable short-term charter market downturns. However, it is in all industry players’ interests both to ensure that the shipping market delivers returns over the long term that allow responsible owners to crew and maintain their ships safely and reliably, and not to tolerate those who do not consistently achieve such standards.

Conclusions

At a rather obvious level, without shipping there is no LNG value chain. Growth in the short-term and spot LNG cargo market will always be constrained without corresponding expansion of the short-term LNG shipping market. The size of the world LNG ship fleet is growing at an unprecedented level—but will the LNG shipping world take the best lessons from other trades and promote short-term liquidity, whilst maintaining its hard-earned reputation for safety and reliability? The quality and number of new entrants into this market would suggest a resounding ‘yes’.

WITH THE COST OF NEW PLANTS, CAN LNG REMAIN COMPETITIVE?—A CONTRACTOR’S PERSPECTIVE

Christopher Caswell

In recent years, many articles have been written about natural gas supply and demand, the commercial viability of LNG as a fuel, and the overall fit of LNG in the current and future energy landscape. While natural gas can be viewed as a baseload fuel, an intermittent fuel, and/or a transition fuel, LNG will be a significant part of our energy future as long as it is competitive with other forms of transportable energy. To support the growth of liquefaction capacity (i.e. new LNG projects), cost competitiveness, especially in the near term, challenges the developers, owners, operators, designers, and builders of LNG projects to meet the short and long-term economic targets of a project.



Considering the cost of recently completed projects, and the need for new projects to be cost competitive, the question is: can project developers and engineering, procurement, and construction contractors (EPCs) meet the current expectations of the LNG industry? For brevity, this article will focus on new projects in North America, a region for which there is a lot of discussion of the viability of new LNG projects.

Recently, several projects have been completed for which the final investment decisions (FIDs) were taken during the upturn of activity around 2010. These projects have brought into operation a new wave of LNG production capacity and have drastically affected the value of LNG in the spot market and the ability of new projects to sign LNG supply contracts at historical prices and margins. Soon after this flurry of FIDs, the industry experienced a pullback in project sanctions, due to an expectation of future oversupply, which resulted in very few FIDs being taken in the last few years.

The current period of limited project sanctions has resulted in intense cost pressure to configure new projects that must align with the current commercial spread between the cost of feed gas supply plus liquefaction (sometimes monetized as a tolling fee in dollars per million Btu [British thermal units]) and the projected LNG sales value. If new projects do not meet these aggressive commercial targets, they will have difficulty competing against existing supply.

From the perspective of a contractor who only has influence over one part of the LNG value chain's cost—the capital expense (capex) of the liquefaction plant—the source gas cost and LNG price volatility are obvious major risks in sanctioning new projects. Even the most well-configured projects with the least technical and execution risk at the lowest offered cost are challenged by today's economics.

Examples of natural gas and LNG pricing, 2014–2018

(blue text represents high spreads, and red text represents low spreads)

	Spread to NBP			Spread to Asia		
	NYMEX HH	NBP	Delta	NYMEX HH	Asia DES	Delta
High—2014	\$4.07	\$11.23	\$7.16	\$4.59	\$20.15	\$15.56
Low—2014	\$4.21	\$6.06	\$1.85	\$4.40	\$9.73	\$5.33
High—2015	\$2.71	\$8.48	\$5.77	\$2.88	\$10.15	\$7.27
Low—2015	\$2.37	\$4.97	\$2.60	\$2.88	\$6.53	\$3.65
High—2016	\$2.79	\$6.74	\$3.95	\$3.26	\$9.32	\$6.06
Low—2016	\$2.83	\$3.55	\$0.72	\$1.94	\$4.09	\$2.15
High—2017	\$2.83	\$8.85	\$6.02	\$2.60	\$11.30	\$8.70
Low—2017	\$3.38	\$4.63	\$1.25	\$3.33	\$5.50	\$2.17
High—2018	\$2.98	\$10.22	\$7.24	\$2.82	\$11.82	\$9.14
Low—2018	\$3.63	\$6.73	\$3.10	\$4.55	\$8.62	\$4.07

Source: Argus data, author's analysis.

NYMEX = New York Mercantile Exchange; HH = Henry Hub; NBP = National Balancing Point; DES = delivered ex-ship.

The table above shows intense volatility within each year and over the five-year period. Robust price spreads between feed gas supply cost and regional value to support new projects was present as recently as 2014, but the volatility among the highs and lows shows how difficult it is to sanction projects that have to purchase feed gas with so much uncertainty. When these spreads are thin, as they are today, the capital cost (CAPEX) of LNG projects is often seen as the main area to apply pressure.

Contractors see only two ways to overcome these challenges—either through low-cost projects (resulting in lower tolling fees) or through a shift in the economics back to higher sales prices and less drastic volatility. Since the contractors want to do something positive but have no influence over gas markets, the pressure has been on driving down CAPEX, also measured as a unit cost or US\$/tonne of production.

When cost competitiveness is questioned, a common reaction from contractors is: competitive with what? Does CAPEX need to be competitive with the lowest price spreads shown in Table 1 or does it need to be competitive among EPCs who are skilled in the engineering and construction of projects? In a perfect world, both would be in balance—the CAPEX of new capacity would fit the expected rate of return in every supply/demand pricing scenario.



There has always been pressure to build low-cost facilities, as contractors often compete with each other either in FEED (front-end engineering design) competitions or in EPC bidding. Even though competition is a healthy way of achieving competitive bids, the pressure has shifted from each project being evaluated on its own merits to an industry standard on cost. It is now commonplace for all projects to meet or beat the 'aspirational cost' of US\$500/tonne.¹

Many published analyses have focused on the concept of unit cost and the difficulties in comparing projects to each other solely based on unit cost.² While US\$500/tonne is an aggressive target, a simple target based only on CAPEX and capacity is truly aspirational if site-specific factors are seen as irrelevant. Simply put, you cannot deliver an LNG project at a challenging site for US\$500/tonne, no matter what a developer or contractor does.

As the years have gone by and few projects have been sanctioned, the constant rhythmic beat of US\$500/tonne has permeated the marketplace, regardless of region. Since the recent downturn or 'LNG glut', buyers have become used to low LNG tolling fees, which must correlate to low CAPEX liquefaction projects. When viewed from the bottom (details) up, there is not much room to manoeuvre to cut cost. Have our design margins become so tight or our projects so complex that we penalize the projects before they even start?

Over time, the aspiration has become an expectation, but expectations are always seen in a specific lens or from the top-down point of view. Even though most projects have not been delivered at this aspirational cost, the industry may be suffering from the malaise of 'price addiction'³—addicted to low unit costs and setting targets well below the aspirational cost regardless of the certainty of outcome. Through basic human interaction, we will continue to manipulate each other, based primarily on the lure of low price and less on high value, service, or the strength of working relationships.

While LNG unit cost targets are aggressive, the industry has still evolved to try to meet these targets. In the previous wave of North American FIDs, which all embraced conventional plant configurations and technologies, commercial project results were a mixed bag. Even the most commercially successful facilities did not achieve US\$500/tonne. It is well beyond the scope of this article to analyse what combination of technical and commercial factors contributed to the success or challenges of individual projects; however, it is clear that the combination of aggressive lump sum turnkey pricing and optimistic schedules put considerable risk on projects.

In the pause of FIDs mentioned previously, owners and contractors had to look to new ways to achieve low-cost projects that could be delivered successfully. In one approach, projects have looked at size and scale (e.g. small and mid-scale LNG) as a way to build large facilities with multiple LNG trains. Permutations within these configurations (e.g. liquefaction technology choices and modular strategies) added new options to investigate. As a result, these initiatives—such as flipping to economies of unit scale over economies of scale—have resulted in many projects that appear competitive with the 'design one, build many' strategy.⁴

Even as the LNG world evolves to match the changing economic climate, the industry is pushing towards the goal of commoditizing LNG project delivery in North America faster than the project execution community can deliver. Is the LNG industry destined to become a commodity-based industry, as we have told ourselves in publications, conferences, and forums? Commoditization is based on the simplicity and reliability of US\$/tonne and ignores many other important factors. Commoditization takes a great deal of work through successful iterations of manufacturing and delivery. Is the LNG industry commoditized to the degree of cellular phone service or electricity supply?

Through talk only, and not the delivery of actual projects, we have attempted to commoditize the LNG industry into a tightly defined band of cost and value. A good bit of work has resulted in moving LNG to a commoditized space; the premise and impending execution of economies of unit scale for large LNG plant capacities is a move to commoditize the design and supply of the in-plant scope of an LNG facility.

Unfortunately, there are no project results that support the new configuration theories and the current unit cost targets. This is not to say that success will not happen—it may even happen sooner than we expect, but it is not without execution risk. There are limited LNG EPC project data points spread across 50 years since the first baseload projects in Algeria. While 50 years is a

¹ C. Caswell, *LNG and the Great Reformation* (paper presented at the Gastech Conference, Tokyo, 2017).

² H. Kotzot et al., *LNG Liquefaction—Not all Plants are Created Equal* (paper presented at the LNG15 conference, Barcelona, 2017).

³ S. Sinek, 2009, *Start with Why* (New York: Penguin Books, 2009).

⁴ C. Caswell, *Does (Train) Size Really Matter?* (paper presented at the LNG 2019 conference, China, 2019).



long time, there are not enough data points even since 2000 to assure the outcome of these new aggressive targets. For today's projects, site advantages are the factors most able to reduce unit costs. Period.

In comparison, other industries such as refining and ammonia have had a long history of technology development and project delivery. There are many times more refineries and ammonia plants than LNG facilities. These facilities have seen decades of innovation and successful project delivery. They are much closer to commoditization and certainty of outcome than the LNG industry.

EPC contractors cannot influence the ends or the middle of the LNG chain (gas production, shipping, and customer distribution). Project developers and their partners have to do what they do best—configure LNG infrastructure projects well, estimate realistically, and execute to plan. Contractors will not support project estimates with a low probability of success. Aggressive pricing to meet aspirational cost targets without either a highly reliable execution plan or satisfactory contingency will result in continued frustration in the LNG industry. A vicious cycle of bidding low and risking loss is not sustainable—*certainty of outcome* should be the mantra of the current wave of projects.

In summary, will EPCs accept that the industry is already commoditized? Will companies trim their design margins and experience-based contingencies to beat an aspirational cost target and put their probability of success at significant risk? Will the industry accept that the economics on the demand side of the LNG equation are currently in a down-cycle and that projects have to be priced in a realistic way based on a life-cycle economic forecast?

Can new LNG plant costs both be competitive and meet expectations? Yes, they can. A top-down view looks at the aspirational target of \$500/tonne as a stretch goal and challenges teams to look at new technologies and execution methods. A bottom-up view methodically and deliberately assembles a plant cost which can be accurately estimated and successfully executed by reputable EPC contractors with manageable risk. The key to meeting current expectations is to look at projects with both a top-down and bottom-up view to determine a cost and schedule with manageable risk and a high certainty of outcome.

IS FLNG JUST A NICHE SUPPLY SOURCE?

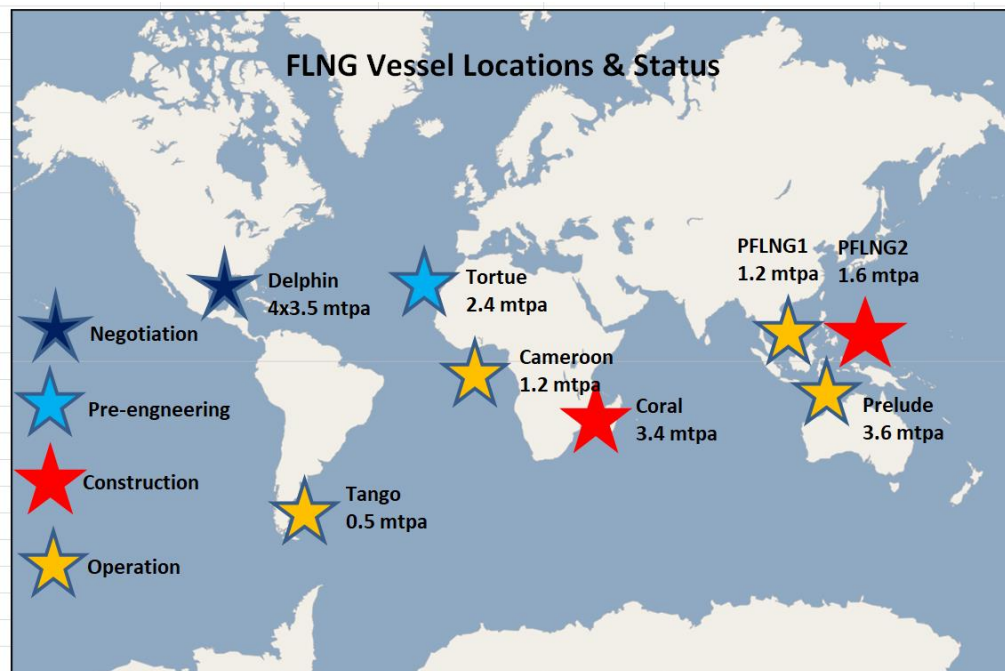
Brian Songhurst

The concept of installing liquefaction facilities offshore on a floating structure (floating LNG or FLNG) has been studied since the mid-1970s. These studies culminated in the award of five major projects in the early 2010s—Shell Prelude and two vessels for Petronas in 2011; PFLNG1, PFLNG2, and the Caribbean FLNG barge in 2013; and the Golar Hilli for Cameroon in 2014. As of today, four of these projects are operating—Prelude, PFLNG1 (Satu), Golar Hilli, and Exmar Caribbean FLNG, now relocated to Argentina and renamed Tango. PFLNG2 (Rotan) was postponed but is now in construction, with operation expected to commence in 2021.

In addition to the five units mentioned above, one more is in construction (Coral), one in pre-engineering (Tortue), and one at an advanced stage of negotiation (Delfin). It has just been announced that the preliminary engineering for the Tortue project has been awarded to KBR, and Golar LNG has been chosen to provide the FLNG vessel, which will be based on a converted tanker, Gimi, similar to the Cameroon vessel. The Coral FLNG is currently under construction in Korea and is due for delivery in 2022.

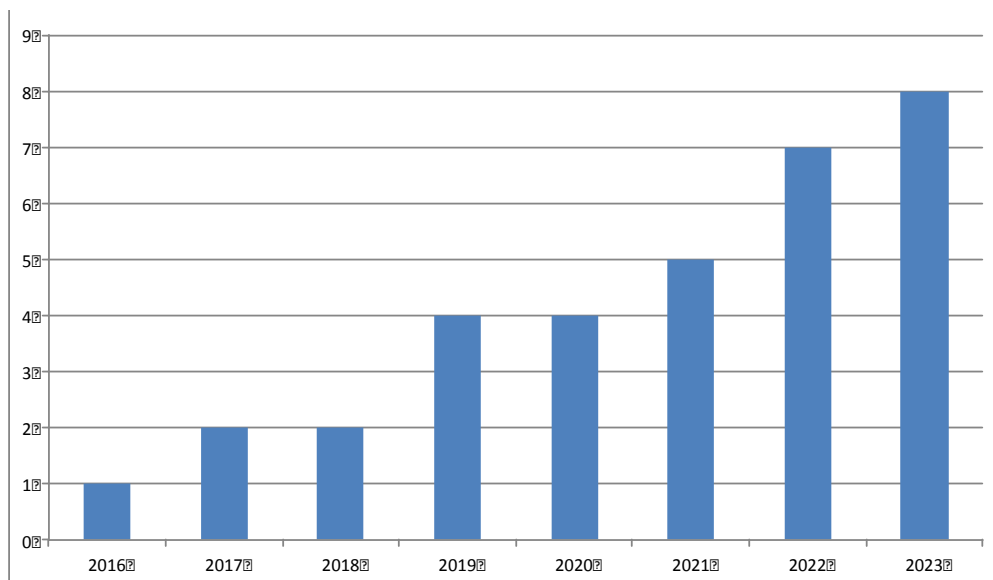
This rate of progress appears slow. But the LNG industry is by tradition relatively cautious, and the application of new technology has to be carefully assessed to ensure that it will deliver both technically and commercially. A recent review by the author of industry attitudes to FLNG risk found a range from cautious optimism to rejection. This is quite different from the attitude expressed about the 'sister' technology of floating storage and regasification units, which is regarded as well proven and acceptable although still relatively new (the first unit started up only 25 years ago). But liquefaction is a far more complex process.

FLNG vessel locations and status



Source: OIES Songhurst, based on public data.

Aggregate number of FLNG vessels by start-up year



Source: OIES Songhurst, based on public data

This article explores key factors that are likely to affect the scope of FLNG's role in LNG production.

Physical capacity limitations

Placing a liquefaction plant on an LNG tanker limits the plant's size and production capacity. The Prelude vessel is the largest offshore floating structure in the world at 488 metres long and 74 metres wide and displaces 600,000 tons—five times that of a world-class aircraft carrier! Yet it only produces 3.6 million tonnes per annum (mtpa)—just less than an industry-standard onshore train of 4 mtpa. Golar LNG's vessels are based on converted Moss-type tankers with the liquefaction facilities placed on sponsons, giving overall dimensions of approximately 300 metres long and 60 metres wide—still physically very large—and



producing 2.4 mtpa. Compare this to the recent Sabine Pass onshore plant, which has 6 trains producing some 27 mtpa. To match this production would require 7 Preludes or 11 Golar vessels.

On-stream time

A major weakness of FLNG is the unpredictable availability of the offloading system due to the dependence on sea conditions of both the berthing of the offtake tanker and the connection of loading arms. This is of particular concern in open-ocean conditions and less so at inshore locations, for example Cameroon. The preliminary arrangements for the Tortue development appear to include an extensive offshore breakwater which is apparently intended to address this issue.

Weather-related delays in offloading could limit FLNG's potential to become a world-scale source of LNG and position it as better aligned to a spot market or niche supply role. However, this risk could be mitigated by operators if they were able to offer a backup supply to meet the contracted production.

Attitude to risk

As mentioned earlier, the industry is still generally very cautious about the risk of this new technology. The general view has been that 'we may do it if we have to, but we would rather invest in an onshore project.' This attitude is likely to change as confidence builds with more FLNG units coming on stream, but will limit current expansion, particularly if a developer has onshore or nearshore gas fields available for development. Shell often referred to the Prelude as a technology development project intended to identify challenges and test solutions to them. On the other hand, the approach by Golar LNG seems to be quite different, in that it is offering a commercial solution based on proven components and risk aversion does not appear to be significant. Having said that, it should be noted their current projects are in less challenging environments—Cameroon inshore and Tortue inside a breakwater. So this is not a true like-with-like comparison.

Offshore gas reserves

A significant factor in determining if FLNG will be niche or world-scale will be the number and size of future offshore gas fields available for development compared to those onshore. Recent finds in East Africa indicate there is a lot of gas offshore Mozambique and Tanzania; but the main developers, ExxonMobil and Anadarko, favour an onshore solution. However, Eni have favoured a first-phase FLNG solution, which is currently under construction (Coral FLNG). A recent report stated that 80 per cent of the world's gas reserves were located in 10 countries, with Iran, Qatar, and Russia by far the largest. These locations are predominately onshore or nearshore, and thus likely to be processed by onshore plants. For major LNG production, the offshore fields need to be remote, and these appear to be less prevalent than onshore or nearshore fields. This suggests that FLNG is likely to remain more of a niche source.

Costs

It is too early to get an accurate view of FLNG costs. The current capital cost estimate ranges widely, from \$3,000/tpa (tonne per annum) capacity for Prelude to \$600/tpa for Golar LNG. But the price of the unit is only part of the cost. For example, at Tortue, considerable additional capital cost will be added by the construction of an offshore breakwater and related infrastructure.

The most significant cost disadvantage of FLNG is the cost of operations, which is significantly higher offshore due to the remoteness and the need to transport personnel and equipment by helicopter or supply boat and possibly even mobilize floating cranes or hotels. Offshore operations are inherently more expensive than onshore, particularly if the onshore plant is located in an established industrial area.

Marginal fields enabling technology

Drawing a parallel with early offshore oil production's use of floating production storage and offloading (FPSO) vessels, FLNG can be regarded as a technology that makes it possible to estimate the longer-term performance of a particular reservoir before making a final investment decision on the major production scheme. This argument would tend to favour FLNG being considered more as a marginal field enabling tool than for longer-term world-scale LNG production. FLNG's flexibility as a reusable asset lends itself to this application.

Reusable asset

One of the major advantages of FLNG has been argued to be the ability to relocate a plant to a new field (originally envisaged as an end-of-field-life solution). This has already been demonstrated twice, with the Caribbean FLNG (Tango) unit relocated



from Columbia to Argentina and Petronas Satu relocated from Sarawak to Sabah. Had these facilities been developed as onshore plants, they would have been expensive sunk costs. In hindsight it is interesting to note that had the Egyptian liquefaction plants at Idku and Damietta been developed as floating units, they could have been relocated during the six-year period during which no gas was available. A recent article stated the compensation for nonproduction at Damietta was around \$2 billion. Thankfully gas supplies have now become available.

Local content

One issue with the use of FLNG is the lack of local labour and materials. The facilities are normally fabricated in East Asian shipyards and installed offshore using international marine equipment, which standardizes the construction process and reduces costs. However, this leaves very little opportunity for local content on projects that have high in-country visibility. This could be a deciding factor in the choice between onshore and offshore processing. For example, in Mozambique, onshore has been favoured for the main development by ExxonMobil and Anadarko, and it is understood that local content has been an important part of that decision. Eni has decided to go the FLNG route with the Coral facility, but this has been reported as a method to get early production and revenue, perhaps implying that longer-term production could occur onshore.

Conclusions

Based on the factors discussed above, FLNG appears likely to remain a niche supplier. The physical size requirement would necessitate 7 Preludes or 11 Golar LNG units to match the production of a single unit such as Sabine Pass. This alone makes it difficult to see FLNG becoming a significant proportion of world-scale LNG production. The weather restrictions for berthing and loading, higher operating costs, lack of potential for incorporating local content, and onshore or nearshore location of most current undeveloped gas reserves make it even more likely that FLNG will be a niche supplier.

That said, it is interesting to note that oil FPSOs also began as niche players, employed as early production systems and facing major challenges to their acceptance for use in the Gulf of Mexico. Today there are 180 units worldwide, and they represent a significant share of the world's crude oil production.

So perhaps the role of FLNG in world-scale LNG production will turn out to be more significant than projected in this article as more units are brought on stream, confidence in the technology increases, and costs are reduced. Time will tell.

.....

CONTRIBUTORS TO THIS ISSUE

Agnieszka Ason is visiting research fellow at the Oxford Institute for Energy Studies.

Gordon Bennett is managing director of Utility Markets at the Intercontinental Exchange.

Christopher Caswell is director of Global LNG Technology and Development at KBR.

Anne-Sophie Corbeau is head of gas analysis at BP.*

Bassam Fattouh is director, Oxford Institute for Energy Studies and editor of the Oxford Energy Forum.

Mike Fulwood is senior research fellow at the Oxford Institute for Energy Studies.

James Henderson is director, Natural Gas Research Programme at the Oxford Institute for Energy Studies.

Anouk Honoré is senior research fellow, Oxford Institute for Energy Studies.

David Ledesma, is senior research fellow, Oxford Institute for Energy Studies and co-editor of this issue.

Chris Le Fevre is senior fellow, Oxford Institute for Energy Studies.

Bruce Moore is senior broker for LNG at Howe Robinson Partners.

Howard Rogers is chairman, Natural Gas Research Programme, Oxford Institute for Energy Studies.

Brian Songhurst is research associate, Oxford Institute for Energy Studies.

Claudio Steuer is senior research fellow, Oxford Institute for Energy Studies.

The views expressed here are those of the authors. They do not necessarily represent the views of the Oxford Institute for Energy Studies or any of its Members nor the position of the present or previous employer, or funding body, of any of the authors.

*She is also the co-editor, with David Ledesma, of LNG in Transition—the Great Reconfiguration, published by OIES in 2016 (www.oxfordenergy.org/shop/lng-markets-in-transition-the-great-reconfiguration/).