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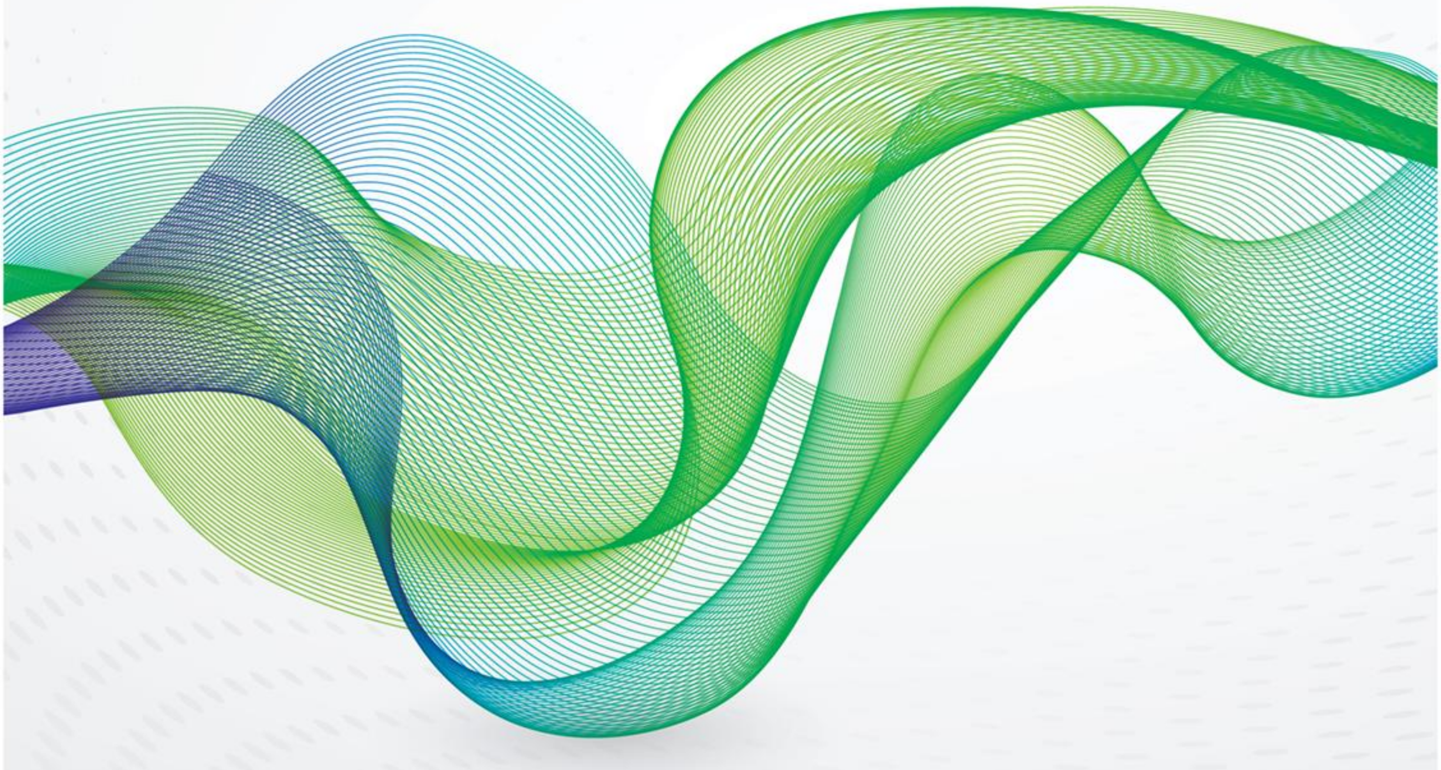
A Brave New World?

LNG Contracts in the Context of Market Turbulence and an Uncertain Future



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Executive Summary

In 2022, the global LNG market faced exceptional levels of turbulence, as European gas buyers sought to offset the loss of Russian pipeline supply with an unprecedented increase in LNG imports. The ability of European buyers to access those LNG supplies was facilitated by the flexibility embedded in the global LNG market, including the ability to purchase spot cargoes from aggregators and traders.

This paper argues that the LNG demand seen in Europe in 2022-23 is not temporary, but is now structural, and set to remain for the rest of the decade and likely beyond. In this context, European LNG buyers must reconcile the need to secure gas supply in the short-term with the long-term imperatives of decarbonisation, while LNG export project developers will only continue adding supply to the global market on the basis of firm offtake commitments, under binding long-term contracts.

The key question is: how to reconcile the short and long-term needs of buyers and project developers, to ensure that the market remains sufficiently well supplied to manage an orderly energy transition?

In addressing this question, the standout conclusions of this paper are:

- While the global LNG market is set to remain tight until 2025, the second half of the decade will see a substantial wave of new supply based on projects that have already taken FID. However, the supply-side outlook beyond 2030 is highly uncertain.
- If global LNG demand continues to grow, the market will need additional supply from projects that need to take FID in the mid-2020s, in order to launch around 2030, or else face the shift from over-supply to under-supply akin to that seen in Europe between 2019/20 and 2021/22.
- This uncertainty raises the possibility of several possible scenarios. In a ‘structural imbalance’ scenario, the market could be under-supplied if insufficient supply-side FIDs are taken in the mid-2020s, or over-supplied if supply continues grow faster than demand beyond 2030.
- A more benign, ‘structural balance’ scenario could see new liquefaction capacity taking FID in the mid-2020s on the basis of offtake agreements mostly with aggregators (portfolio players), who assume volume risk in return for earning a premium on re-selling to Europe and Asia, and end users who will only be willing to commit to contracts with destination and re-sale flexibility.
- Aggregators will play a vital role in reconciling the short and long-term needs of LNG producers and consumers. Their willingness to sign new, binding offtake agreements over the next several years, their confidence in their ability to re-sell those volumes, and the ability of LNG project developers to leverage those offtake agreements and raise finance sufficient to take FID, will be indicative of both the state of the LNG industry in the mid-2020s, and how it views its own future post-2030.

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1. Introduction

This paper begins from the premise that the global LNG market has entered a new era, in which the aim of security of supply in the short-to-medium term and the longer-term adaptation to the conditions of the energy transition must be met in parallel by European LNG buyers. The global LNG market, though tight over the past two years, is set to receive a wave of new supply between 2025 and 2028 that will leave it well-supplied out to 2030. However, the outlook for supply and demand post-2030 – in the context of the energy transition – is much more uncertain.

If global LNG supply is to grow again post-2030, it will be on the basis of Final Investment Decisions (FIDs) taken by project developers in the next 2-3 years. On the demand side, government strategies regarding decarbonisation, as expressed through policies, regulations, and taxes, are likely to have an uneven impact across the globe, and are currently set to be felt most strongly in Europe. Therefore, European gas buyers find themselves in the challenging situation of needing to meet short-term demand in a context of replacing a substantial proportion of lost Russian pipeline gas supply with LNG, while simultaneously facing uncertainty over long-term European gas demand, especially post-2030. These questions have become more pressing since mid-2021, with increased market turbulence impacting upon the pace of these developments.

This paper examines the key question of how European LNG buyers can reconcile the short and long-term imperatives, and the implications of their strategies for LNG project developers. In effect, this addresses the extent to which the interests of European buyers and LNG export project developers can be reconciled, and highlights the key role played by aggregators and traders in reconciling those interests. If the interests of buyers and project developers are not sufficiently closely reconciled, the result will be under or oversupply on the global LNG market, with prices accordingly higher or lower. Those pricing signals will consequently influence both demand and the appetite of developers to invest in new projects, within the boundaries of demand elasticity and the timeframe needed to add new supply.

In doing so, this paper begins by providing a history of LNG market development, before examining in more detail the market dynamics since 2019 (that is, the last pre-COVID, supply-long year for the global LNG market) and the ways in which the structure of the market has changed. Section 5 then unpacks the criteria that would allow parties to sign new term LNG SPAs before section 6 examines the issues of term and spot contracts, and market concentration. The last two sections then provide market outlooks for the period 2025-2030 and then for the post-2030 period. Finally, the paper draws the key conclusions, that contractual provisions and careful selection of counterparties cannot alleviate all of the risk pertaining to term SPAs, and that the balance of perceived risk and reward will continue to motivate market activity, especially by aggregators and traders as they stand between suppliers and consumers, and play a vital role in the functioning of the global LNG market as they do so.

2. Background: the history of LNG market development

The LNG market developed from a handful of 'pioneers' in the 1960s and 1970s, and remained a 'small club' in its early decades. As Stern and Koyama note:

> "In 1971, six countries were importing LNG from three exporting countries; by 2000, the 11 importing countries were facing 12 exporters. This led, especially in Asia, to what has been termed a 'relationship culture', where very long contractual commitments, together with strong shared interests in a highly capital-intensive business, resulted in considerable commercial rigidity". [1]

In this period, the business model was based on co-operative, bespoke, point-to-point, bilateral agreements, which are relatively typical for new supply chains dealing with new technologies (in this case a cryogenic supply chain). In this context, LNG delivery routes from point to point were to a significant extent conceived as something akin to 'pipelines over water', with contractual restrictions on cargo diversions (coupled with a very limited number of alternative destinations) rendering such LNG supply routes relatively fixed.

In the absence of a developed market, and more importantly, any means of price discovery, price indexation to oil and oil products was the standard in long-term LNG Sale and Purchase Agreements (SPAs). This was also the case in Europe for pipeline gas exports from the Netherlands to neighbouring countries following the discovery of the giant Groningen gas field in 1959 and the subsequent development of Dutch pipeline gas exports in the late 1960s and early 1970s.[2]

During this period, Asia accounted for the majority of global LNG imports, going on to account for at least 70 per cent of total global imports between the mid-1980s and 2000.[3] In Europe, growth in both domestic production and pipeline imports from regional neighbours – Russia, Norway, Algeria, and Libya – meant that LNG assumed a lesser role than in Asia.

Between 2000 and 2020 (that is, prior to the present gas market turbulence that began in 2021), several key developments took place in parallel, creating new opportunities for the LNG market. On the supply side, the number of export countries grew. Between 1964 and 1989, Algeria, Australia, Brunei, Indonesia, Libya, Malaysia, UAE, and the United States (Alaska) all began exporting LNG, with Qatar joining their ranks at the end of 1996, creating a group of nine exporters by the late 1990s.

With Trinidad & Tobago, Nigeria, and Oman having begun their exports in 1999-2000, they were then joined by Egypt, Equatorial Guinea, and Norway in 2005-07, Russia, Peru, and Yemen in 2009-11, Angola and Papua New Guinea in 2013-14, the United States (ex-Alaska) in 2016, and Cameroon in 2017. With 21 LNG exporting countries in 2020, Mozambique would join their ranks two years later.[4] [5]

The number of importing countries also grew: By December 2020, 40 countries had imported at least 250 million cubic metres (MMcm) of natural gas in the form of LNG between January 2008 and December 2020. Furthermore, new importers joined the club in January 2021 (Croatia), April 2022 (El Salvador), December 2022 (Germany), April 2023 (Philippines), and May 2023 (Hong Kong). [6] As the number of exporters and importers grew, so too did the size of global LNG trade: from 100 million tonnes (mt) in 2000 to 365 mt in 2020 and 400 mt in 2022.[7]

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[1] Stern & Koyama, 'Chapter One: Looking Back at History: The Early Development of LNG Supplies and Markets' in Ledesma, D., and Corbeau, A-S., 2016. *LNG Markets in Transition: The Great Reconfiguration*. Oxford University Press (page 39)

[2] Correljé, A., Van der Linde, C., and Westerwoudt, T., 2003. *Natural Gas in the Netherlands: From Cooperation to Competition?* Clingendael. https://www.clingendaelenergy.com/inc/upload/files/Book_Natural_Gas_in_the_Netherlands.pdf (page 69-70)

[3] Stern & Koyama, page 38

[4] Corbeau & Flower, 'Chapter Two: The Maturing of the LNG Business' in Ledesma, D., and Corbeau, A-S., 2016. *LNG Markets in Transition: The Great Reconfiguration*. Oxford University Press (page 44)

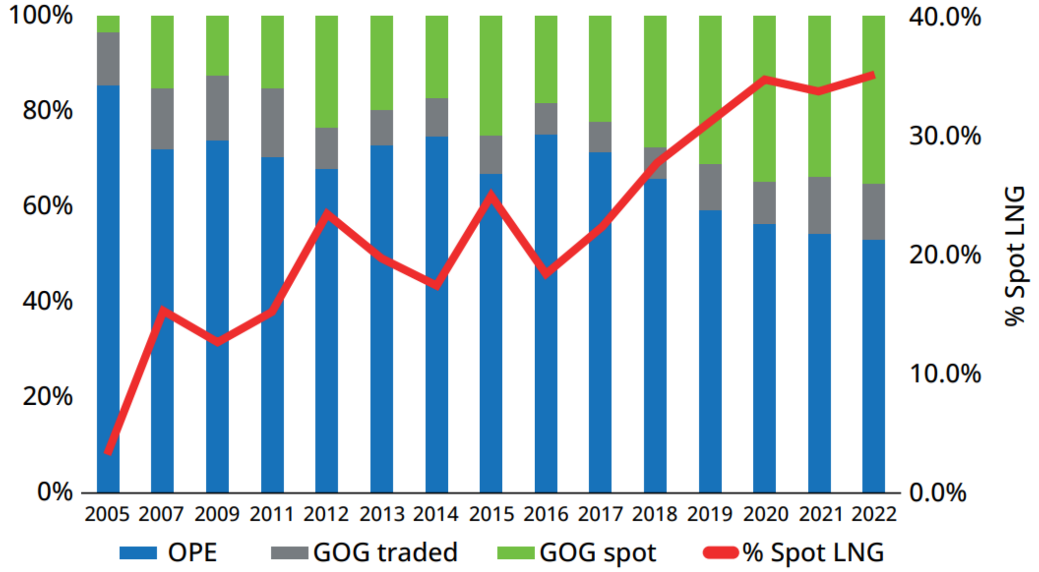
[5] Kpler LNG Platform [subscription required]

[6] This list of importers Includes Egypt, Indonesia, Malaysia, Norway, the United Arab Emirates, and the United States, which are net exporters of LNG. Israel imported LNG in 2013-2021, but none since then. Data sourced from the Kpler LNG Platform

[7] Corbeau & Flower, p.44, and Kpler LNG Platform

At the same time, the European gas market went through a process of liberalisation, traded volumes at European hubs grew,[8] LNG regasification capacity expanded,[9] [10] [11] and Europe became the balancing element in global LNG trade. By the 2010s, the European market had a combination of available regasification capacity,[12] a liquid market into which LNG cargoes could be sold, substantial seasonal storage capacity equivalent to just over one-fifth of annual European gas consumption,[13] [14] [15] and a demand-side flexible market that could absorb more supply when competitively priced (particularly in the power generation sector, where coal-to-gas switching was an option). Taken together, these developments meant that Europe became the 'market of last resort' for LNG sellers with a long position, and contributed to the growth in LNG traded on a hub-indexed, rather than oil-indexed, basis. Since 2016, the rapid growth in LNG exports from the United States added supplies to the global market that are effectively cost-plus, index-linked to the Henry Hub, and therefore also categorised as hub-indexed.

Figure 1: World Price Formation 2006 to 2022 - LNG Imports



Source: IGU, 2023 Wholesale Price Report (p.10)[16]

[8] According to Gasunie, the annual volumes traded at TTF grew from 1.35 Bcm in 2003 to 20 Bcm in 2008, 46 Bcm in 2013, and peaked at 59 Bcm in 2019, before falling back to 52 Bcm in 2020 and 2021, and 50 Bcm in 2022. See: Gasunie, 2023. *TTF Development*. https://www.gasunietransportservices.nl/en/gasmarket/market-development/ttf-development

[9] In January 2004, EU-27+UK LNG regasification capacity totalled 87 Bcma, with 10 regasification terminals in Portugal, Spain, France, Belgium, Italy, and Greece. By January 2017, the nominal annual regasification capacity had grown to 208 Bcma in 23 countries, with the UK, Netherlands, Lithuania, Poland, and Malta joining the ranks of European LNG importing countries. More recently, 43 Bcma of new capacity was added at 7 new import terminals in Krk, Croatia (Jan 2021), Eemshaven, Netherlands (Sept 2022), Inkoo, Finland (Dec 2022), Wilhelmshaven and Lubmin, Germany (Dec 2022), Brunsbüttel, Germany (Feb 2023), Piombino, Italy (May 2023), Le Havre, France (October 2023) raising the annual regasification capacity to 251 Bcma. This regasification capacity is available at 30 regasification terminals in 14 countries.

[10] Gas Infrastructure Europe, 2022. *LNG Database [21 November]*. https://www.gie.eu/transparency/databases/lng-database/

[11] Kpler LNG Platform [subscription required]

[12] The extent of available regasification capacity at European terminals in much of the 2010s is summarised by King & Spalding: "Between 2008 and 2014 European LNG terminals experienced low utilisation rates, some below 20%. 2016 saw an average utilisation rate of 20%, with the EU Commission stating that year that the LNG infrastructure in the EU was under-utilised and not optimally distributed. However, during 2017 the average utilisation rate increased to 25%, reflecting more buoyant market conditions for gas". Source: King and Spalding, 2018. *LNG in Europe 2018: An Overview of LNG Import Terminals in Europe*. https://www.kslaw.com/attachments/000/006/010/original/LNG_in_Europe_2018_-_An_Overview_of_LNG_Import_Terminals_in_Europe.pdf?1530031152 (see page 3)

[13] Europe here is defined as the EU plus UK

[14] Between January 2011 and April 2016, EU-27 gas storage capacity grew from 58 Bcm to 105 Bcm. See Gas Infrastructure Europe, 2023. *Aggregated Gas Storage Inventory - EU-27*. https://agsi.gie.eu/data-overview/graphs/eu

[15] In 2017-2019, EU+UK gas consumption ranged between 469 and 479 Bcm per year

[16] Note that OPE refers to Oil Price Escalation (oil indexation) and GOG refers to 'Gas on Gas' (hub indexation)

The LNG market became both larger and much more flexible. One consequence of these developments was the growing share of SPAs with prices indexed to either the Henry Hub in the United States or to European hubs, and the growing share of spot/short-term sales relative to long-term contract deliveries.

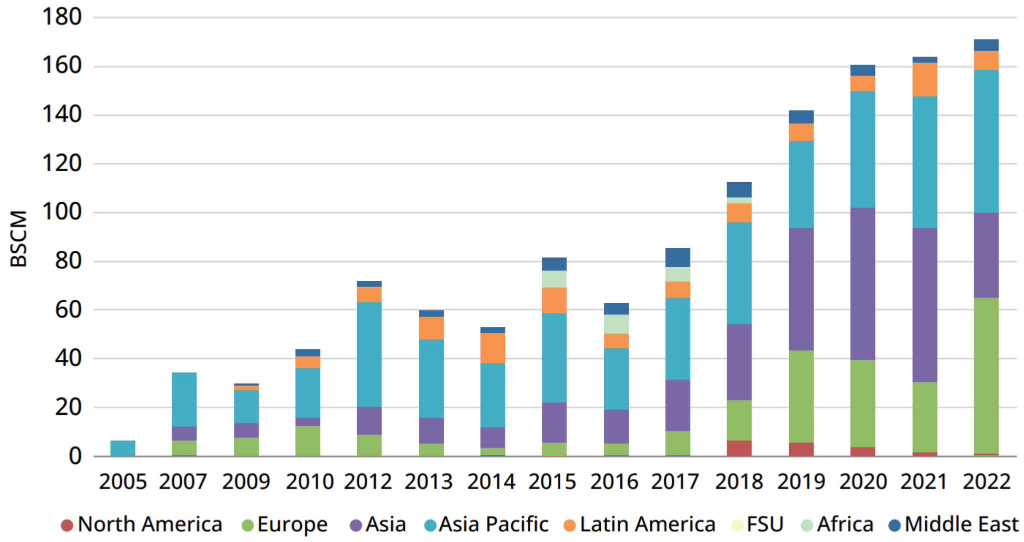
As the latest International Gas Union (IGU) wholesale gas price survey notes, between 2005 and 2022, the share of oil indexation in global LNG imports fell from just over 85 per cent to 53 per cent, while the share of 'gas on gas' (hub indexation) rose from just under 15 per cent to 47 per cent. Since 2016, the rapid and substantial growth in US LNG exports (indexed to the Henry Hub) has been a significant driver of this growth.[17] [18] [19] While SPAs that are at least partially indexed to oil continue to provide the basis for a substantial proportion of the LNG supply to Asia, such oil-indexed contracts also remain in Europe (including Turkey). In Europe, the share of hub-indexed supplies rose from 67 per cent in 2021 to 76 per cent in 2022, in line with a substantial rise in LNG imports overall, and spot LNG imports in particular.[20] [21]

This rise in European spot LNG imports in 2022 was made possible by cargo diversions from markets that either did not need (in the case of China), or could not afford (in the case of Pakistan), hub-indexed cargoes at the time, as the IGU note in their 2023 wholesale gas price survey:

> "Many of these spot LNG cargoes were diverted from China, where the GOG [Gas-on-Gas] share fell to 27 per cent in 2022 from 49 per cent in 2021, and Pakistan, where the GOG share fell to 17 per cent in 2022 from 41 per cent in 2021." [22]

The rise in European hub-indexed, spot LNG imports since 2017 illustrated in Figure 2 (below) highlights the supply-led growth in such imports between 2017 (just under 10 Bcm) and 2019-20 (35-40 Bcm), the slight contraction amid a tight market in 2021 (just under 30 Bcm), and finally the sharp rise in 2022 (almost 65 Bcm) as European buyers sought to offset the decline in imports from Russia.

Figure 2: Gas-On-Gas (GOG) Spot LNG Imports 2005 to 2022



Source: IGU, 2023 Wholesale Price Report (p.26)[23]

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[17] According to the IGU 2022 Wholesale Price Report, in 2021, around 30 bcm of oil-indexed LNG was imported into Spain, France, Italy, Turkey, Portugal, Poland and Greece. In the same year, Europe also imported 62 bcm of hub-indexed LNG.
[18] IGU, 2022. *Wholesale Price Report*. https://www.igu.org/resources/2022-wholesale-price-report/ (p.54)
[19] IGU, 2023. *Wholesale Gas Price Survey*. https://www.igu.org/resources/wholesale-gas-pricesurvey-2023-edition/ (p.11)
[20] According to the IGU 2022 Wholesale Price Report, in 2021, around 30 bcm of oil-indexed LNG was imported into Spain, France, Italy, Turkey, Portugal, Poland and Greece. In the same year, Europe also imported 62 bcm of hub-indexed LNG.
[21] IGU, 2023. *Wholesale Gas Price Survey*. https://www.igu.org/resources/wholesale-gas-pricesurvey-2023-edition/ (p.10)
[22] IGU, 2023. *Wholesale Gas Price Survey*. https://www.igu.org/resources/wholesale-gas-pricesurvey-2023-edition/ (p.11)
[23] Note that OPE refers to Oil Price Escalation and GOG refers to 'Gas on Gas' (i.e., hub indexation)

In terms of global LNG imports, the share of spot sales rose from less than 5 per cent in 2005 to 35 per cent in 2022 (see Figure 1).[24] The IGU 2023 report also referred to data from the Group of International LNG Importers (GIIGNL) to highlight the difference between two definitions of 'spot': a more generous definition refers to contracts of one year or less, while a stricter definition refers to volumes delivered within three months of purchase. The latter definition accounted for 28 per cent of total imports in 2022.

Overall, the global market is now one in which half of LNG imports are hub-indexed and more than one-third are purchased on a spot basis, with the difference being term contracts indexed to hubs. In the context of these market developments, aggregators and traders have taken on an increasingly prominent role, especially with regard to taking on the risk posed by basis differentials, between Henry Hub and oil-indexed supply on one hand and hub prices in the European market on the other.[25]

As Ledesma noted in 2016:

> "Under the aggregator model, the supply chain is driven by cost optimisation, minimisation, and the optionality to capture price differentials, rather than relying on a fixed supply from one point to a specific market point… Under this model, the aggregator uses its own credit rating to source the LNG and takes a margin for doing this (thereby adding costs to the end buyer as the aggregator will want to make a margin). The buyers are happy to pay this margin as it will give them access to a larger number of LNG sources, while placing the risk on the aggregator. The growing volumes of LNG available from aggregators have enabled more buyers to get into the LNG market, as they do not need to enter into long-term offtake agreements directly with LNG producers, and the aggregator provides greater contractual flexibility…
>
> In addition to the aggregator companies that buy, sell, and trade LNG as part of their wider energy portfolio, the 2010s have seen different companies getting involved. Traditional oil, and also non-energy, trading companies, such as Vitol, Gunvor, Mercuria, Trafigura, and Glencore-Xstrata have also begun to trade LNG. LNG buyers (such as ENGIE – formerly GDF Suez, and also Gas Natural and Iberdrola) as well as some Asian end users (such as JERA – a joint venture of Tokyo Electric and Chubu Electric, and also KOGAS and PetroChina, to name just a few) are also trading as a means of optimising their portfolios and they are positioning themselves to take on the role of trader."[26]

If anything, the trend identified by Ledesma in 2016 has intensified since then, driven by the emergence of the United States as a major LNG exporter. Net exports from the United States (outside Alaska) began in 2016 (1.7 mt), reached 75.7 mt in 2022, and are likely to surpass 80 mt in 2023.[27] Much of that capacity is contracted to aggregators and traders. According to Kpler, of the 63 mtpa of LNG currently contracted for purchase under SPAs for export from the United States (that is, under supply contracts which began before 1 December 2023 and have not yet expired), 14.5 mtpa (23 per cent) is contracted to aggregators[28], 3.2 mtpa (5 per cent) to traders[29], and 2 mtpa (3 per cent) contracted to Cheniere itself for spot sale, along with 3.7 mtpa (6 per cent) to companies that mostly produce and market LNG and wish to add supply to their portfolio. This provides roughly 23.4 mtpa of US LNG that is relatively flexible, compared to 18.0 mtpa (29 per cent) contracted to European utilities, 20.3 mtpa (33 per cent) contracted to Asian utilities,[30], and 0.6 mtpa (1 per cent) contracted to other buyers.[31]

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[24] IGU, 2022. *Wholesale Price Report*. https://www.igu.org/resources/2022-wholesale-price-report/ (p.24)

[25] Ledesma, D., and Fulwood, M., 2019. *New Players New Models*. OIES Presentation, April 2019. https://www.oxfordenergy.org/publications/new-players-new-models/

[26] Ledesma, 'Chapter Three: The Changing Commercial Structure' in Ledesma, D., and Corbeau, A-S., 2016. *LNG Markets in Transition: The Great Reconfiguration*. Oxford University Press (pages 122-124)

[27] Kpler LNG Platform [subscription required]

[28] BP, Shell/BG, Pavilion, and TotalEnergies

[29] Glencore, Gunvor, Trafigura, and Vitol

[30] Includes producers such as Pertamina (Indonesia) and Petronas (Malaysia) and LNG project companies, such as New Fortress Energy, Woodside LNG

[31] Kpler LNG Platform [subscription required]

Therefore, in terms of buyers, roughly 60 per cent of US LNG contracts are destined for end users and the remainder is effectively destination-flexible. However, 75 per cent of those contractual volumes are recorded as FOB, 12 per cent DES, and 13 per cent FOB/DES, so the level of destination flexibility is even higher than the profile of buyers would suggest, allowing even end users to re-direct unnecessary cargoes.

In this context, buyers are able to diversify their risk, not only geographically (given the growth in global LNG supply and in particular with the emergence of the United States as a 'new' LNG exporter since 2016), but also in terms of price index and contract length. This has given rise to a two-phase trade that works on a mix of long-term (15-20 year) contracts and flexible short-term and spot volumes. Since the emergence of the growing spot trade, as noted earlier, many buyers operate a portfolio model of term and spot volumes, although the mix varies from buyer to buyer depending upon their market conditions and their ability/appetite for trading.

To conclude, the global LNG market is now a constellation of regional markets with varying degrees of liberalisation (most significantly, the United States, Europe, and Asia), contract terms of varying lengths (from spot and short-term[32] to very long-term), price formulations with varied indices, and a wide cast of commercial players operating across multiple markets at different points in the value chain, with their own specific interests and priorities. This was the situation when the global LNG market entered a period of unprecedented turbulence, from the oversupply that began in 2019 and worsened during the first wave of the COVID-19 pandemic in 2020, through to an exceptionally tight market in 2022.

3. The fundamentals context: LNG benchmark supply and price since 2019

The global LNG industry has experienced a rollercoaster of market oversupply and undersupply since the beginning of 2019 – the last 'normal' (albeit supply-long) year before the COVID-19 pandemic. The demand-side shock associated with the COVID-19 lockdowns and related decline in economic activity led to oversupply and record low prices in mid-2020. The monthly average prices of US Gulf Coast LNG FOB[33] and the landed price of LNG in North-Western Europe fell below 1.95 USD/MMBtu between April and July 2020, while the monthly average price of landed LNG in North-East Asia fell below 2.40 USD/MMBtu in the same period.

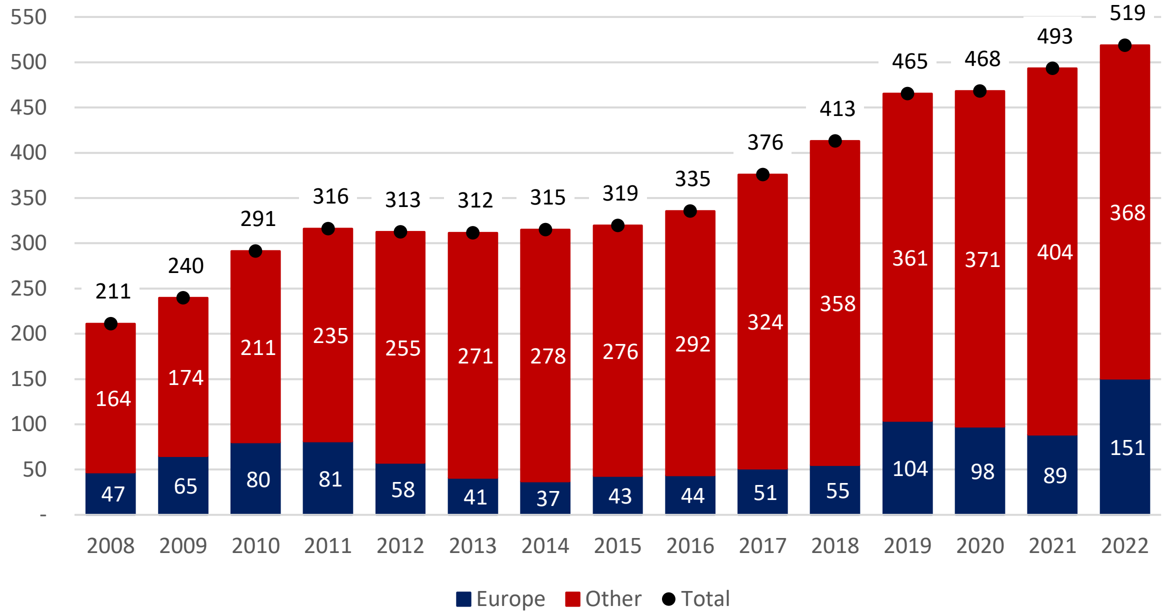
As the global economy re-opened in 2021 and global LNG demand increased, a series of unrelated curtailments in LNG supply from different suppliers meant that global LNG supply from outside the United States actually fell by 6.5 Bcm year-on-year between 2020 and 2021.[34] It was only the 31.6 Bcm year-on-year increase in supply from the United States that enabled total global LNG supply to grow by 25.1 Bcm year-on-year. Therefore, although global LNG supply did grow in 2021 (as illustrated in Figure 3), it did not grow as much as it would otherwise have done had the curtailments not occurred, and the large growth in US supply was mainly a rebound from the sharp decline in 2020 that saw many cargoes shut in (as discussed later, at the beginning of section 5.1.2).

[32] Short-Term is defined by the International Group of LNG Importers (GIIGNL) as less than four years. See: GIIGNL, 2022. *Annual Report 2022*. https://giignl.org/wp-content/uploads/2022/05/GIIGNL2022_Annual_Report_May24.pdf (see page 4)

[33] Free On Board: "If LNG is delivered FOB, title and risk will shift to the buyer when the LNG is loaded on to the ship and the buyer is responsible for arranging the vessel. Accordingly, unless there are other contractual provisions that purport to limit the buyer's ability to resell or send the LNG to whatever destination it chooses, under an FOB contract, the buyer may have almost complete destination freedom (subject to shipping and other commercial constraints)". See: Global Arbitration Review, 2019. *Destination Restrictions and Diversion Provisions in LNG Sale and Purchase Agreements. Lexology – Global Arbitration Review*. https://www.lexology.com/library/detail.aspx?g=ba7a4881-e722-4f90-875e-37aa641ce444

[34] For example, shortages of feedgas, unplanned maintenance, maintenance delayed from 2020 by the COVID lockdown restrictions, and the closure of Snøhvit LNG at Hammerfest (Norway) due to a fire.

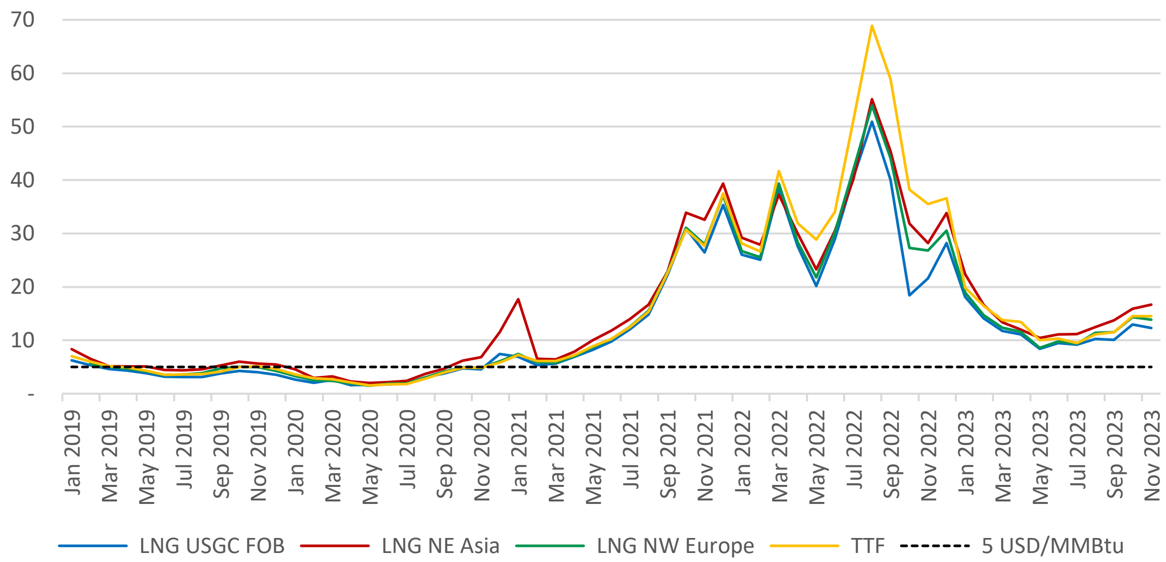
Figure 3: Annual Global Net[35] LNG Imports (Bcm of natural gas per year)



Source: Data from Kpler LNG Platform. Graph by the author.

In short, available LNG production and export capacity actually fell in 2021 due to outages, and growth in actual supply volumes were due to higher utilisation rates of the capacity that remained online. This tightening of the market was felt particularly strongly in H2-2021, as expressed in the benchmarks illustrated in Figure 4, with benchmark prices rising almost continuously from April to December 2021.

Figure 4: Monthly Average Global LNG Benchmark Prices, 2019-2023 (Nominal USD/MMBtu)



Source: Data from S&P Global (NE Asia) and Argus (US/Europe), graph by the author. All prices are front-month.

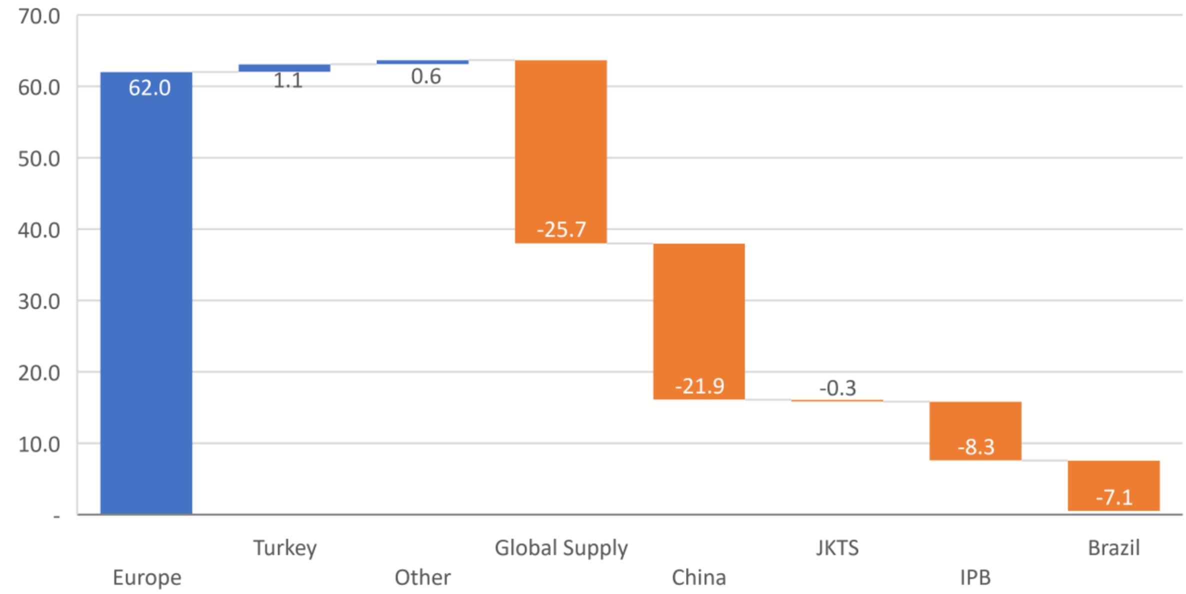
Finally, the flow of Russian pipeline gas to Europe declined in 2022, with Russian pipeline supply to Europe 79 Bcm lower in 2022 than it had been in 2021. That loss was partially offset by lower European

[35] The use of net supply prevents the double-counting of re-exported volumes and accounts for a share of gross Indonesian exports being committed to the domestic Indonesian market

gas demand, which fell by 66 Bcm year-on-year in 2022 vs 2021. However, while 2021 saw net European storage withdrawals of 22 Bcm, 2022 saw net storage injections of 31 Bcm, as Europe prepared for a winter with substantially less Russian pipeline supply. The combination of 66 Bcm less demand and 53 Bcm more storage injection effectively meant that Europe needed 13 Bcm less supply in 2022, in a year when Russian pipeline supply fell by 79 Bcm. In order to cope with the loss of Russian pipeline volumes, Europe therefore needed 66 Bcm more supply. Given that non-Russian pipeline supply (from Norway, Algeria, Libya, and Azerbaijan) rose by just 5 Bcm year-on-year, most of that additional supply was sourced from the global LNG market.[36]

The need for additional LNG supply – and the willingness to pay high prices for spot LNG cargoes – saw European LNG imports grow to record levels. In 2022, net LNG imports into Europe[37] grew by 62 Bcm year-on-year.[38] While global supply grew by 26 Bcm, Chinese LNG imports fell by 22 Bcm, imports into the established markets of North-East Asia (Japan, South Korea, Taiwan, and Singapore) remained flat, imports into the price-sensitive Asian markets (India, Pakistan, and Bangladesh) fell by 8 Bcm and imports into Brazil fell by 7 Bcm (due to higher levels of hydroelectricity production). Elsewhere, imports into Turkey rose by 1 Bcm and imports into the rest of the world (taken together) grew by approximately 0.6 Bcm (see Figure 5). In short, Europe benefitted from higher LNG supply and imports into the rest of the world that were either flat or fell, but with the result that the global LNG market tightened considerably. Therefore, around half the growth in European LNG imports in 2022 was provided by growth in global LNG supply and around half was provided by the diversions of LNG cargoes to Europe from other markets.

Figure 5: Global LNG Market Balance in 2022 vs 2021 (Bcm of natural gas)



Source: Data from Kpler LNG Platform, graph by the author. JKTS refers to Japan, South Korea, Taiwan, Singapore. IPB refers to India, Pakistan, and Bangladesh.

In North-Western Europe, despite the year-on-year decline in gas demand as prices rose rapidly, the summer of 2022 saw regasification terminals (at Dunkerque, Zeebrugge, and Gate Rotterdam) and pipelines from Norway running at full capacity, along with the interconnector pipelines between the UK

[36] Data on European pipeline imports sourced from: ENTSOG, 2023. *Transparency Platform*. https://transparency.entsog.eu/#/map. Data on storage sourced from Gas Infrastructure Europe, 2023. *Aggregated Gas Storage Inventory (AGSI).* https://agsi.gie.eu/

[37] EU-27 plus the UK, excluding Turkey and Norway

[38] LNG data from Kpler LNG Platform [subscription required]. Data on Russian pipeline flows to Europe sourced from: ENTSOG, 2023. *Transparency Platform*. https://transparency.entsog.eu/#/map

and Belgium/Netherlands (enabling the UK to act as a 'land bridge' for additional LNG imports into North-Western continental Europe). The loss of Russian supply via the Nord Stream pipeline, combined with other infrastructure reaching full capacity, led to congestion pricing in that region. As a result, the TTF front-month price rose above the landed price of LNG in North-Western Europe, as LNG suppliers competed for slots at regasification terminals (refer back to Figure 4).

By February 2023, the addition of new LNG regasification capacity at Eemshaven in the Netherlands (where the first cargo arrived in September 2022) and at Wilhelmshaven, Brunsbüttel, and Lubmin in Germany (where the first cargoes arrived between December 2022 and February 2023) eased some of the regasification congestion, thus reducing the differential between TTF and the landed price of LNG in North-Western Europe. However, the overall tightness of the European and global markets meant that the LNG benchmark prices remained around 14-16 USD/MMBtu in February 2023. As the seasonal reduction in demand allowed the balance to ease, monthly average front-month prices of LNG in North-East Asia, spot LNG in North-Western Europe, and front-month prices at TTF all fell below 10.50 USD/MMBtu in May-July 2023, before a combination of geopolitical and supply-side developments, combined with the seasonal increase in demand, brought those prices back to 14-16 USD/MMBtu in October-November 2023.

In effect, the need to replace Russian pipeline supply has resulted in the European market shifting from its role as a backstop, or balancing element, for the global LNG market to a premium market in its own right, where European buyers are willing to outbid other buyers in more price sensitive markets, and compete for spot cargoes with buyers in the developed Asian economies. This change has been largely focused on North-Western Europe (where the loss of Russian pipeline supplies since 2022 has been most acute). In these changed circumstances, the renewed emphasis on security of supply has put the spotlight back on long-term SPAs, but for delivery into a hub-based, liberalised market.

It is in this context, with higher rates of European LNG imports and the consequent tighter global LNG market both expected to remain for the next several years, that this paper examines the key question of how Europe can achieve security of supply in a liberalised market while satisfying the needs of LNG export project developers (in order to ensure that a sufficient number of supply-side FIDs are taken to support continued growth in LNG supply beyond the late 2020s), and the related question of supplier and buyer needs can be reconciled in a changed market.

4. A new era? What has changed since 2019?

In terms of LNG supply and demand, the market balance shifted from oversupply in 2019 (which became extreme oversupply in mid-2020 during the first round of COVID-19 lockdowns) to a tight market in the second half of 2021 that tightened dramatically in 2022 before easing somewhat in 2023. This market tightness – and associated price levels - changed the outlook for LNG buyers for the next several years and beyond.

In the years leading up to 2019, substantial new supply volumes were added from a small group of suppliers. Between 2013 and 2019, global LNG exports grew by almost 50 percent, from 243 mt to 362 mt. That growth was concentrated in five countries (Papua New Guinea, Australia, the United States, Angola, and Russia) whose combined exports grew by 121 mt, from 34 mt to 155 mt. Supply from the rest of the world fell by 2 mt in the same period, with modest growth in eight exporting countries not sufficient to offset declines in a further seven exporting countries. But between 2019 and 2023, the United States was the only exporter to maintain substantial growth. Effectively, the years prior to 2019 saw supply rising faster than demand, and in the years since 2019 the opposite has been true.

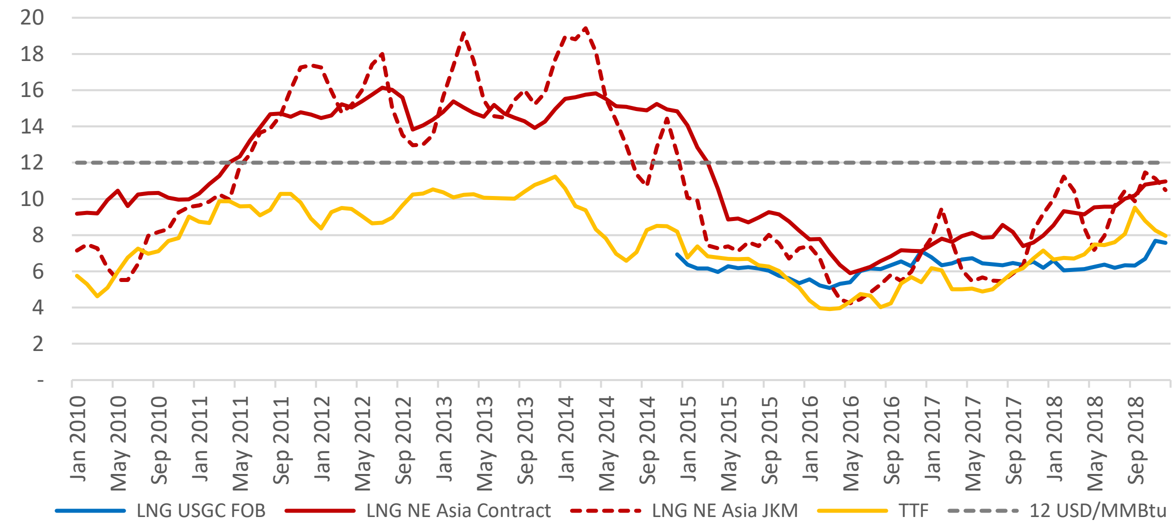
Under conditions of supply growth up to 2019, buyers were in a good position to buy spot and allow term contracts to account for a smaller proportion of their expected supply needs. The tightening of the market since 2021 was strongly influenced by the decline in Russian pipeline gas supply to Europe, which fell from a pre-COVID peak of 179 Bcm in 2019 to 142 Bcm in 2021, 63 Bcm in 2022, and is likely to be around 25 Bcm in 2023. Those Russian volumes are highly unlikely to return, and could fall further to around 12 Bcma if transit via Ukraine ceases at the end of 2024. The need to permanently replace most Russian pipeline gas has created new LNG demand in Europe, which will not be a temporary, two-year phenomenon, but structural and longer-lasting.

These developments increased the range of opportunities for developers of US LNG export projects, whose projects were due to either come on stream or ramp up during this period, and underpinned the Final Investment Decisions (FIDs) reached in the past two years, including the substantial expansion of Qatari LNG export capacity.

In the near term, this tighter market has moved the industry to 'a new paradigm' in terms of price levels, albeit a temporary one until the global supply-demand balance shifts again when large volumes of new LNG supply enter the market in the mid-to-late 2020s. This remains true even though prices have declined significantly from their exceptional highs in the second half of 2022, given that prices remain high by pre-crisis standards.

Here it is worth remembering that in the period 2006-2020, in nominal terms, any monthly average price for TTF above 12 USD/MMBtu would have been considered exceptionally expensive (as seen in H2 2008), and prices above 13.50 USD/MMBtu would have been a record. In North-East Asia, monthly average prices above 12 USD/MMBtu would have been a record in the 2015-18 period, but would have been more normal in 2011-14. In short, prices in the range of 14-20 USD/MMBtu – as seen in Q1 2023 and likely again in mid-winter 2023/24 – are exceptionally high by standards of Europe pre-2020, and expensive by Asian standards in that same pre-crisis period.

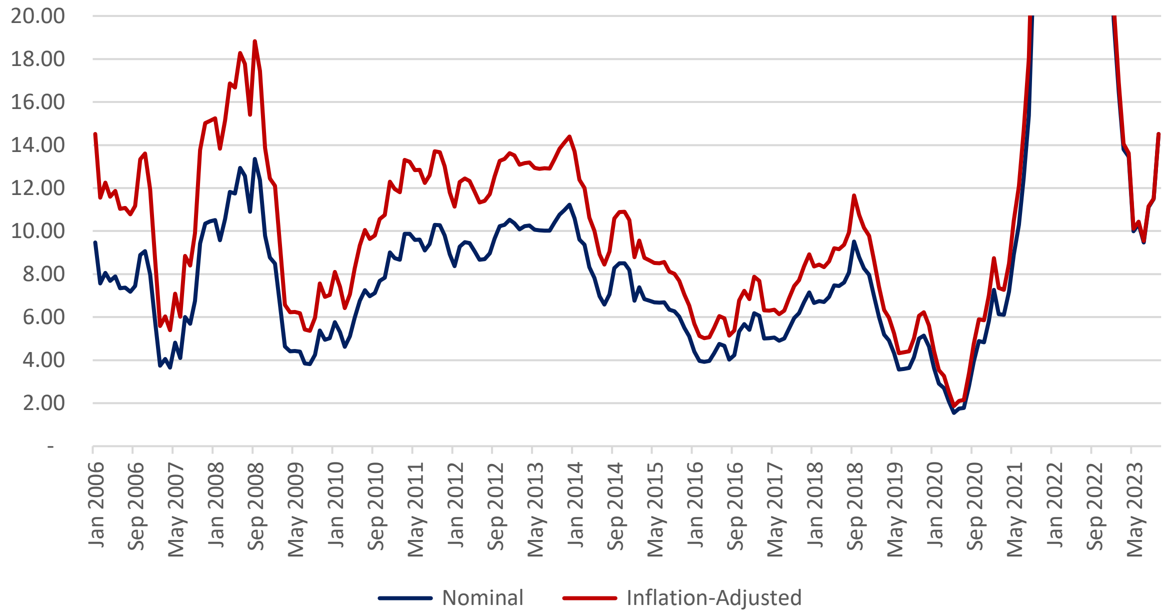
Figure 6: Monthly Average Global LNG Benchmark Prices, 2012-2018 (Nominal USD/MMBtu)



Source: Data from S&P Global (NE Asia weighted average contract price and JKM spot price) and Argus (LNG US Gulf Coast FOB and TTF). Graph by the author. All prices are front-month.

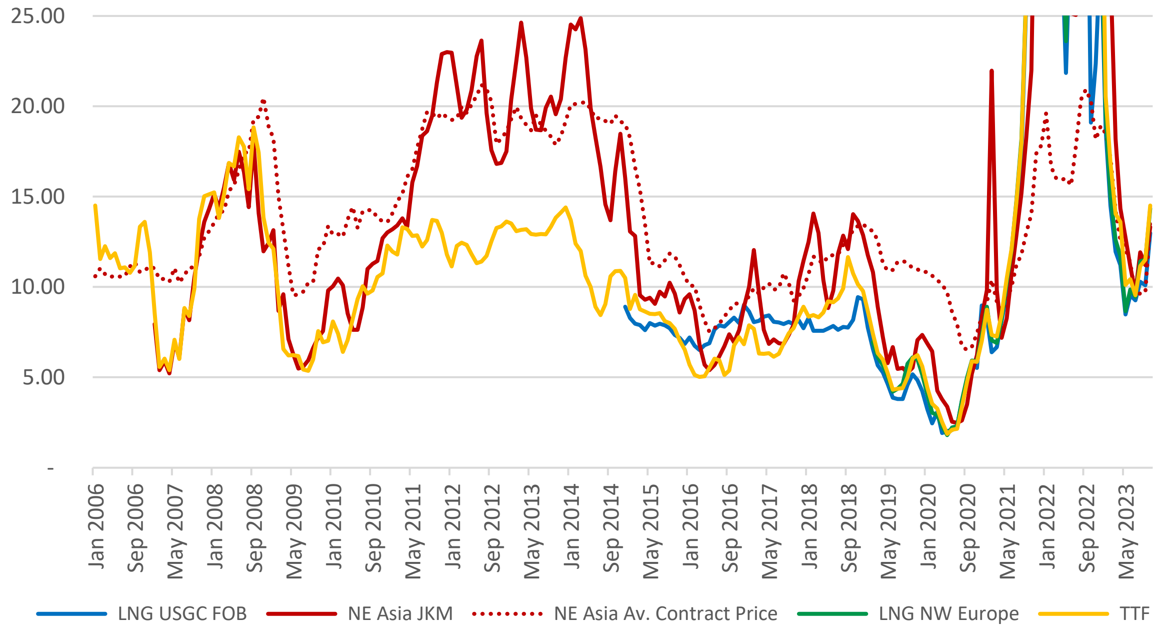
However, that analysis is based upon nominal prices. Clearly, nominal TTF prices at 8-11 USD/MMBtu (as they were in 2011-2014) would have been considered significantly more expensive in the broader economic context of the time than 8-11 USD/MMBtu in nominal prices would be today, in December 2023. In the European context, it is possible to use Harmonised Consumer Price Index data for the EU (expressed in a percentage monthly rate of change) to back-calculate the value of 1 USD/MMBtu in previous months, relative to October 2023, all the way back to 2006, and apply this ratio to historic prices in relation to both TTF and other LNG benchmarks.

Figure 7: Nominal vs Inflation-Adjusted TTF Prices to October 2023 (USD/MMBtu)



Source: Nominal front-month TTF price data from Argus, Harmonised Consumer Price Index data from Eurostat.[39] Inflation-adjusted price calculation and graph by the author. Scale capped at 20 USD/MMBtu to allow comparison of nominal and inflation-adjusted prices prior to 2021.

Figure 8: Inflation-Adjusted Benchmark LNG Prices to October 2023 (USD/MMBtu)



Source: Nominal front-month price data from S&P Global (NE Asia) and Argus (US/Europe), Harmonised Consumer Price Index data from Eurostat. Inflation-adjusted price calculation and graph by the author. Scale capped at 20 USD/MMBtu to allow comparison of nominal and inflation-adjusted prices prior to 2021.

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[39] Eurostat, 2023. *HICP - monthly data (monthly rate of change) - prc_hicp_mmor__custom_8926999*. https://ec.europa.eu/eurostat/databrowser/view/prc_hicp_mmor__custom_8926999/default/table?lang=en

When this calculation is applied to TTF pr ices from 2006 to the present (as in Figure 7), it shows that inflation-adjusted (to October 2023) prices in the range of 14-20 USD/MMBtu were experienced from November 2007 to October 2008, and that inflation-adjusted prices in the range of 11.00-14.50 USD/MMBtu were seen in every month from December 2010 to March 2014, quite aside from the period between June 2021 and April 2023 that saw inflation-adjusted prices in excess of 12 USD/MMBtu spike at 74 USD/MMBtu in August 2022. Therefore, in a European context, the prices of around 14.50 USD/MMBtu seen in October-November 2023 are within the range of inflation-adjusted prices seen in 2007-08, and only slightly higher than inflation-adjusted prices seen in 2010-2014. The inflation-adjusted European prices above 20 USD/MMBtu that were seen between September 2021 and January 2023 were indeed exceptional, but prices since then (and the TTF forward prices of 11.30-13.50 USD/MMBtu out to Q1 2026[40]) are in the range of merely 'expensive' in the historical context.

Looking beyond Europe to the other major importing region, Asia, the inflation-adjusted LNG prices for both the weighted average contract prices and JKM spot prices reported by S&P Global[41] shown in Figure 8 demonstrate that inflation-adjusted prices in the range of 14-25 USD/MMBtu were seen from January 2011 to March 2015 (contract prices) and from May 2011 to December 2014 (JKM prices). Asian contract LNG prices also hit the 14-20 USD/MMBtu range between December 2007 and January 2009, and were consistently around 10-12 USD/MMBtu in 2006-07 and 12-14 USD/MMBtu in 2009-10. With both spot and contract prices at 10-12 USD/MMBtu in 2018, the spot prices fell away amid the supply-long global LNG market of 2019.

As with Europe, Asian spot prices were exceptional from mid-2021 to the beginning of 2023. However, the recent prices since February 2023 of up to 17 USD/MMBtu in winter and down to 10 USD/MMBtu in summer, and forward prices of 12-16 USD/MMBtu out to Q1 2026, were a common experience for Asia over most of the period from 2006 to 2014 (and only slightly lower in 2018).

The key point is that while the period was from Q4 2021 to Q1 2023 was exceptional, the market dynamics since then are suggestive of a supply-demand balance that is tight, rather than in sustained crisis. The expectation is that such tightness will last until the next large wave of LNG supply, as discussed in more detail later. As a result, prices are likely to remain 'expensive but not exceptional' for the next two years, relative to the inflation-adjusted historical context of the past 15 years. What has changed since 2019 is that the traditional wide 'Asian premium' during times of market tightness may have disappeared for the foreseeable future. This is the result of new, structural LNG demand in Europe, and the continued growth in LNG market flexibility, which allows sellers more opportunities than ever before to seek price arbitrage between the two markets.

The exceptional price levels of 2021-23 and the 'expensive but not exceptional' price levels that are likely to persist out to 2025 created meaningful economics and a supportive environment for new LNG supply projects. They also increased the importance of short-term financial planning (especially for Europeans, compared to the benign period of 2015-2021). This specifically concerns liquidity, hedging, and the implications of non-performance of contracts. Given that – due to higher prices – the negative consequences of non-performance of contracts by supply-side counterparties are so much greater, this led to a renewed focus on security of supply and the reliability of suppliers. In particular, this means that for Europe, the 'primary preference' is for supply from OECD countries, like the United States, or suppliers that have already proven their reliability, like Qatar.

Finally, opinions appear to have shifted regarding the role of gas in the energy transition. In 2019 and 2020, it was a widely-held view that gas had only a relatively short time left in Europe, and many companies were making promises regarding their emissions. But amid the European gas price crisis of 2022, environmental issues slipped to the third-place priority behind price and security of supply in the 'energy trilemma', albeit perhaps only temporarily until the market tightness eases again in the second

[40] S&P Global, 2023. *Refinitiv EIKON Platform – LNG (Spot and JJC-Indexed), TTF, and HH Prices (Monthly)*. https://emea1-apps.platform.refinitiv.com/web/cms/?navid=10241573 [subscription required]
[41] S&P Global, 2023. *Dimensions Energy Price Portal*. https://dimensionspira.spglobal.com/landing-page [subscription required]

half of the 2020s. While the European Commission supported gas infrastructure projects designed to aid supply diversification (through its Projects of Common Interest and Connecting Europe Facility) and has supported national governments who themselves have backed new gas-related infrastructure (such as German government support for new regasification capacity), the European Commission remains committed to its long-term decarbonisation goals.

This highlights the important point that an orderly energy transition requires the supply-demand balance of existing fuel consumption to be maintained. From a buyer/importer/consumer perspective, this likely means that the policy-driven decline in fossil fuel demand should be at least as rapid (if not more so) than the decline in supply. The ability to maintain supply – through imports that are to a significant extent underpinned by term SPAs – is clouded by uncertainty around the future of natural gas in Europe, in the sense that it is now more accepted as a transition fuel in the 2020s, but the longer-term focus remains on decarbonisation, rendering the future for gas in Europe uncertain.

European buyers in particular may be worried about signing 20-year contracts, when changes in European environmental regulations might make the final years of that contract rather difficult. One practical example of this was provided in March 2023, when the European Commission tabled a legislative proposal for a Directive that would outlaw the conclusion of long-term contracts for unabated 'fossil gas' with a duration beyond the end of 2049.[42] However, this proposal has not yet been passed into law and it has not prevented several European buyers – TotalEnergies, Shell, and Eni – from recently signing new 27-year LNG SPAs that will not expire until 2053, as discussed later in this paper.

5. What criteria would allow parties to sign new SPAs?

5.1. Price formation: indexation and price level

5.1.1. The view from US exporters

For LNG export project developers in the United States, the absolute preference is to sell based on Henry Hub. Doing anything else represents cross-indexation exposure, which makes it more difficult to acquire project financing for the development of liquefaction capacity. In that regard, even if lenders become more willing to lend against pricing constructs other than Henry Hub indexation, or developers start to equity fund more of their projects (something which is starting to happen in response to higher costs of borrowing)[43], it remains hard to see US pricing moving far away from the current construct.

Only once the project is fully financed, on the basis of long-term SPAs indexed to the Henry Hub, and the project company is generating cash for their balance sheet, can they undertake optimisation by selling additional volumes under different indexation, such as oil-indexed or JKM-indexed into Asia, or TTF indexed into Europe, to achieve additional sales volumes to counterparties that are unwilling to buy on a Henry Hub-indexed basis.

Sellers of US LNG are also keen to emphasise that a major advantage of contracting for liquefaction capacity but retaining the option of whether or not to lift the cargo is that it limits the size of the financial risk compared with sourcing LNG from elsewhere on a term contract with 'take-or-pay' commitments (implying an obligation to lift every cargo) and oil-indexed pricing, where the risk could be as wide as the potential differential between the two bases for indexation.

5.1.2. The view from aggregators

That risk of cross-indexation exposure is also an issue for LNG aggregators and traders. In the summer of 2020, the decline in European hub prices to record lows meant that, once the price at which

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[42] Proposal for a DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on common rules for the internal markets in renewable and natural gases and in hydrogen - General approach. https://data.consilium.europa.eu/doc/document/ST-7911-2023-INIT/en/pdf (see pages 58, 142, and 250)
[43] Evans, C., 2023. US LNG Projects' Debt Financing Costs Spike. *Energy Intelligence*, 7 November. https://www.energyintel.com/0000018b-a6a3-d38b-ab9f-f7a3de5e0000

aggregators and traders could off-take LNG in the United States and the cost of trans-Atlantic shipping and European regasification were taken into account, it was no longer economical for off-takers to lift cargoes. As a result, 170 cargoes from the United States were reportedly cancelled in mid-2020 with capacity holders still paying the liquefaction capacity charges (tolling fees) under their long-term contracts.[44] Such cancellations may be viewed as a more cost-effective means of managing short-run oversupply on the LNG market, when compared to the more rigid take-or-pay provisions of traditional LNG long-term SPAs. Indeed, without those cancellations, the rebalancing of the global LNG market in mid-2020 would have been significantly more disorderly.

Between May and December 2022, the challenge of cross-indexation exposure became apparent for those entities that were selling LNG into Europe, given the divergence between TTF and the delivered price of spot LNG cargoes in North-Western Europe, as illustrated in Figure 4. For suppliers of LNG into North-Western Europe that held regasification capacity (which is, most of them), there was no problem, if they were receiving cargoes at a 'TTF-minus' price, whereby the discount to TTF reflected the need to factor in regasification and network entry costs before re-selling at the prevailing TF price. However, sellers of LNG into North-Western Europe that did not hold regasification capacity – for example, because they were selling on a short-term basis – found that either slots were not available on the secondary market for regasification capacity, or if slots were available, the price of that capacity was rising rapidly. If they were selling spot cargoes to those who did hold regasification capacity, the need to compete with other sellers of spot LNG cargoes (who also did not hold regasification capacity themselves) drove down the price of spot LNG in the region relative to TTF prices.

The ability to sell spot LNG cargoes at prices discounted relative to TTF depended on the price at which those sellers were themselves receiving the LNG cargoes. If an aggregator or trader was receiving cargoes at 'TTF minus' (to take into account expected regasification and network entry costs), but had not secured regasification capacity ahead of time because they expected to be able to purchase such capacity on the secondary market, then the need to sell the cargoes at the prevailing spot LNG price was indeed a problem.

They would certainly have faced stiff competition from aggregators or traders who receive their gas from the United States on a 'cost-plus' basis (for example 115 per cent of Henry Hub plus 2.50-3.00 USD/MMBtu tolling fee for liquefaction capacity) or those aggregators and traders receiving LNG from non-US projects under SPAs indexed to crude oil or oil products, which were highly likely to be 'in the money' relative to both TTF and North-Western European spot LNG prices in 2022.

For example, between October 2021 and December 2022, the monthly average price of US LNG Gulf Coast FOB (as reported by Argus) fluctuated between 7.42 and 13.06 USD/MMBtu. During the same period, the spot price of LNG in North-Western Europe fluctuated between 21.80 and 53.97 USD/MMBtu, while monthly average TTF front-month prices fluctuated between 26.60 and 68.88 USD/MMBtu. The spreads between the source of supply in the United States and the selling market in Europe were more than sufficient to generate profits even when selling spot LNG cargoes at the discounted spot price (subject to finding a European buyer that held regasification capacity and could thus make use of a spot LNG cargo), let alone when utilising regasification capacity to sell into TTF at the prevailing price.

That said, it cannot be assumed that US LNG capacity holders lifting cargoes on a Henry Hub price basis and selling into Europe on TTF basis made profits in 2022 quite as exorbitant as the wide spreads would suggest. This is because many, if not most, of the buyers of US LNG (intending to re-sell into the European market) would have hedged their price exposure, locking in margins at a narrower spread. Also, these companies could have experienced serious financial liquidity issues as they managed these widening spreads on the traded market.

[44] International Energy Agency, 2021. *Gas Market Report Q2-2021 – Global Gas Review 2020*. https://www.iea.org/reports/gas-market-report-q2-2021/global-gas-review-2020

From the perspective of aggregators, sourcing LNG from around the world (either on a Henry Hub cost-plus basis from the United States or on an oil-indexed basis from elsewhere) and selling into the European market (based on TTF), the differences between the fundamentals underlying these indices are worthy of mention.

The global oil market is deep and liquid, but has proven susceptible to influence by geopolitical events and OPEC policy. The US internal gas market, with the Henry Hub as a benchmark price, is also deep and liquid, with gas production that is both substantial and able to react to pricing signals by ramping drilling activity up and down. TTF is liquid, but with Russian pipeline supply to North-Western Europe having ceased in 2022, it is strongly influenced by imports from a single supplier (Norway). The role played by Norway may not be a problem in terms of market competition, given the multiple sellers and buyers of Norwegian pipeline gas and the pricing of that supply at hub prices. However, the impact of physical disruptions in supply from a single source were apparent in the summer of 2023, when Norwegian supply was curtailed by both planned and unplanned maintenance.

Given that the United States has emerged as the single largest source of LNG supply to Europe, the differential between Henry Hub and TTF (plus liquefaction costs in the United States, trans-Atlantic LNG shipping, and regasification in Europe) are key to ensuring the continued flow of US LNG across the Atlantic. That differential is underpinned by the United States being structurally supply-long, with dry gas production having doubled from 18.1 trillion cubic feet (Tcf) (513 Bcm) in 2005 to 36.4 Tcf (1,031 Bcm) in 2022,[45] while the loss of Russian pipeline supplies exposed Europe's dependence on imports.

5.1.3. The view from European buyers

Regarding total European (including Turkey) supply, combining production, pipeline imports, and LNG imports, hub indexation is now the dominant pricing construct, accounting for 82 per cent of total supply in 2022, with oil-indexation accounting for the remaining 18 per cent. Almost all production, 82 per cent of pipeline imports, and 76 per cent of LNG imports are hub-indexed.[46]

Within Europe, the highest shares of hub indexation in total supply are found in Scandinavia/Baltics[47] (95 per cent), North-Western Europe[48] (94 per cent), and Central Europe[49] (87 per cent). In South-Eastern Europe[50] (69 per cent) and the Mediterranean[51] (63 per cent) the lower shares of hub indexation reflect greater use of oil-indexation in long-term pipeline and LNG import contracts. With hub indexation dominant in both total European supply, and LNG imports (especially those outside Turkey and the Iberian Peninsula), it is to be expected that the preference of European LNG buyers is for TTF indexation, as part of a desire to not be 'out of step' with the majority of the traded market.

5.1.4. TTF as the European benchmark for price indexation in LNG SPAs

Although the de-coupling between TTF and spot LNG that occurred in 2022 reflected temporary conditions of rapidly declining pipeline supply to North-Western Europe from Russia via Nord Stream, at a time when all other supply routes into North-Western Europe (Norwegian pipelines, pipelines from the UK to North-Western continental Europe, and the three major LNG import terminals at Dunkerque, Zeebrugge, and Gate Rotterdam) were being used at their full capacity, and LNG sellers were competing for access to regasification slots at terminals in North-Western Europe – in effect, congestion pricing – it does raise an important question regarding the use of TTF as a point of indexation in LNG contracts: what factors drive the TTF price?

Specifically, TTF primarily reflects the gas supply-demand balance in North-Western Europe, including regional production, pipeline supply from Norway, pipeline supply from the UK (via the interconnections

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[45] Energy Information Administration, 2023. *U.S. Dry Natural Gas Production*. https://www.eia.gov/dnav/ng/hist/n9070us2A.htm
[46] IGU, 2023. *Wholesale Gas Price Survey*. https://www.igu.org/resources/wholesale-gas-pricesurvey-2023-edition/ (p.10 & 65)
[47] Scandinavia/Baltics: Estonia, Finland, Latvia, Lithuania, Norway, Sweden.
[48] NW Europe: Belgium, Denmark, France, Germany, Ireland, Luxembourg, Netherlands, UK.
[49] Central Europe: Austria, Czech Republic, Hungary, Poland, Slovakia, Switzerland.
[50] SE Europe: Bosnia, Bulgaria, Croatia, FYROM, Romania, Serbia, Slovenia.
[51] Mediterranean: Greece, Italy, Portugal, Spain, Turkey.

between the UK and Belgium/Netherlands), and LNG imports that have been regasified and injected into the pipeline system. Previously, this supply portfolio in North-Western Europe included pipeline supply from Russia delivered via both the Nord Stream pipeline and the Yamal-Europe pipeline to northern Germany, but those supplies have now stopped and are unlikely to return. If there were to be a return to congestion pricing, then the problem of price decoupling could return.

The availability of new LNG regasification capacity – and curbing of demand – in North-Western Europe meant that such congestion pricing did not return in summer 2023. This was despite the fact that Norwegian pipeline supply to North-Western Europe was significantly impacted by maintenance between mid-April and early October (and in particular in two periods from mid-May to mid-July and again from late August to early October). For comparison, between April and October 2022, the premium of monthly average front-month prices at TTF over NBP (as a percentage of the NBP price) ranged from 29 per cent to 58 per cent. By contrast, the TTF premium in summer 2023 peaked at 8-11 per cent in April-May before falling to 0.2-2.3 per cent for the period between June and October.[52]

In addition, the use of TTF as basis for trading physical volumes in other parts of the European market means that TTF is also influenced by developments in those regions, including those with limited or no access to LNG (for example, in Central Europe).[53] This use of TTF reflects the smaller market sizes – and consequent lesser liquidity – of national gas markets in Central Europe. It also reflects the fact that, for example, were supply to Central Europe be restricted for some reason (such as the end of Russian gas transit via Ukraine when the transit contract expires on 31 December 2024), alternative supplies to the region are likely to be sourced from neighbouring European countries, for example from Germany to Austria and to Slovakia via the Czech Republic, and from Italy to Austria. Those alternative supplies are likely to originate in the form of additional LNG imports into Germany and Italy, with those LNG supplies priced according to TTF.

It is possible that some market participants, particularly aggregators and traders selling into Europe, may question the risk of TTF decoupling from spot LNG prices again in the future. By contrast, NBP is perceived by some to be more reflective of the balance of physical LNG supplies in North-Western Europe, particularly given that UK annual regasification capacity substantially exceeds UK annual LNG demand. Yet even here, the lack of seasonal storage in the UK means that a mid-winter cold snap, combined with any unplanned restriction in supplies from Norway (as happened on 1 March 2018) could cause prompt NBP prices to spike.[54] However, a short-lived disruption (of several days) would have a lesser impact on the front-month prices that are more likely to be used as a basis for indexation in LNG supply contracts than on the day-ahead prices. Likewise, while Spanish supply is dominated by LNG, thus rendering the Spanish market arguably more reflective of the global LNG market balance, the importance of Algerian pipeline supply and continued role of oil-indexed, long-term contract LNG supply into the Iberian peninsula offer two important caveats to an argument that the Spanish is more representative of international LNG trends than TTF, given the physical influence of supply via a single pipeline from a single supplier, and the pricing influence of dynamics on international oil markets.

A final point to be made regarding TTF as a source of price indexation in LNG contracts is the role of TTF in hedging and speculation by an array of market participants, just as Henry Hub and oil markets are also sites for hedging and speculation. This was seen in summer 2022, when TTF prices rose to exceptional levels in August that arguably were not justified by the fundamentals of supply and demand in North-Western Europe at the time. Again, in early October 2023, TTF front-month prices reacted strongly to news of potential industrial action at Australian LNG plants and to the Hamas attack on Israel, causing prices to rise by 30 per cent from 11.81 USD/MMBtu to 15.31 USD/MMBtu between 6

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[52] Price data from Argus Direct [subscription required]

[53] Most supply to Central Europe is pipeline, although CEZ has 2.6 mtpa of regasification capacity at Eemshaven, to bring LNG to the Czech Republic via the Netherlands and Germany

[54] Vaughan, A., 2018. UK running out of gas, warns National Grid. *The Guardian*, 1 March. https://www.theguardian.com/business/2018/mar/01/uk-is-running-out-of-gas-national-grid-warns-freezing-weather

and 10 October.[55] In short, while TTF is primarily driven by fundamentals in North-Western Europe, it is also influenced by fundamental dynamics in the global LNG market (due to the significant role of LNG in supply to North-Western Europe), fundamental dynamics elsewhere in Europe, and the activities of a constellation of physical buyers, aggregators, traders, and speculators. Indeed, the very number of market participants and the associated liquidity this provides are what makes the TTF so attractive to its participants.

When the market is tight – as it has been since late 2021 – even relatively small shifts in the supply-demand balance or publication of market news can cause volatile shifts in prices. Then, if a price rally begins, this attracts market participants that are paper trading solely for profit, rather than to acquire physical supply. Conversely, when the market is supply-long, developments outside North-Western Europe may have only limited impact on TTF prices. An example of this is the cold spell of weather in North-East Asia in January 2021 that pulled LNG cargoes away from Europe. Because North-Western Europe remained well supplied from seasonal storage and pipeline suppliers, TTF prices did not respond dramatically to the events in Asia and shift in LNG supply.

5.1.5. Conclusions regarding price indexation

For operators of US LNG export projects, it is clear that Henry Hub indexation is standard, and so project operators are clear on the strategies of their competitors. LNG aggregators, traders, and utility buyers are also keen to monitor the activities of their competitors. Are they signing oil-indexed or Henry Hub indexed contracts? Stepping out of line with the majority is perceived to be a risk, even if it is assumed to be profitable. Regarding US LNG deliveries to Europe, the sellers are seeking Henry Hub cost-plus, but the ultimate market is TTF. From the perspective of European buyers, they can see that sellers expect the buyers to take the price risk, regarding the differential between Henry Hub and TTF.

The most important point here is that, in the past, when prices were much lower, the situation was easier for market participants to manage, because the price movements were smaller in absolute terms, as were the potential differentials between benchmarks. But with much higher prices, the consequences of different price outcomes are much, much greater. A practical outcome is the strain it places on the balance sheets of those wishing to participate in the market. In the past, large aggregators with strong balance sheets would assume the risks associated with differentials between bases for indexation (for example, between Henry Hub or Brent and TTF). But in the context of higher prices, a balance sheet that previously enabled aggregators to sign long-term SPAs without huge financial exposure now needs to be substantially larger. On a short-term basis, it is still possible to buy a cargo on one index and sell on another, but signing a large-volume SPA for 20 years with cross-indexation exposure is a significant commercial risk even for those with the largest balance sheets.

5.2. Contract length

Developers of LNG export projects tend to seek contracts of 15-20 years in length, to keep their finance costs down by spreading the costs over a longer period. In that regard, they consider their SPAs to be financial assets. Regarding their counterparties, the view of market participants is that while Chinese buyers have no problem signing up for 20 years, there is variation among Japanese buyers who may be looking for 15 years, depending on their market position. For European buyers, not only do they face higher costs of hedging in the context of high prices (as with any LNG buyer at present), but they also face uncertainty in terms of environmental regulations. It is clear that European environmental regulations will become more stringent in the next two decades, but the pace and ambition of that change is difficult to predict. Hence, those European LNG buyers tend to seek shorter term lengths in their SPAs, ideally closer to 10-12 years. For the aggregators and traders sitting between the project developers and the final buyers in Europe, the ability to take on long-term contracts depends partly on their ability to find European end buyers willing to take on long-term SPAs, and partly on their ability to trade away volumes in case of a decline in European LNG demand before their offtake contracts expire.

[55] Price data from Argus Direct [subscription required]

5.3. Destination restrictions

For US LNG export project developers, the clear preference is to sell FOB with prices based on the Henry Hub. The desire to sell FOB not only simplifies the situation for the seller, but also allows them to sidestep the volatility seen in the LNG shipping market over the past two years. Conversely, it is precisely that volatility in the shipping market that makes DES/DAT[56] [57] more attractive to buyers in times of tight markets and higher spot charter rates. It is worth noting that long-term charters can enable shippers to manage the risk of short-term, spot charter rate volatility, albeit requiring a longer-term commitment on the part of the shipper.

In the context of US LNG exports, the historical development of their business model influenced the preference for FOB. Many of the companies involved were project developers who had to raise significant debt and equity (from nothing) to create the projects, and did so on the basis of a utility/cost-plus model that would deliver a low but secure rate return that could be taken to banks and potential equity partners to secure such debt and equity financing. The nature of the companies meant that they had no prior experience of shipping, and so had a preference to sell FOB. To an extent this changed as they gained experience, with some companies in particular moving into the shipping sector. For example, according to Kpler, Cheniere now has 26 LNG carriers under charter, which enables it to undertake its own deliveries, even though the company remains mostly focused on providing capacity to offtakers from its liquefaction plants.

For aggregators and traders, having the flexibility to divert the cargoes somewhere else is a tool for managing economic and regulatory risk, and a way of optimising their positions, so it plays in both directions. It is good for making more money, and it is a means of protection from losses. Specifically, in the pre-crisis global LNG market, Asia was the premium market and Europe was considered a backstop. But with Europe now a premium market in its own right, the arbitrage between Europe and Asia is a source of value for aggregators and traders. Therefore, having flexibility of being able to move cargoes between those markets is essential for aggregators and traders signing new long-term SPAs.

For aggregators (portfolio players) portfolio optimisation implies generating the best value on any given day from the optionality in their portfolios. Trading around their physical portfolios – made possible by having destination flexibility with regard to supplies – can create additional value, but it also carries additional risk and entails a cost of participation, especially when the market is volatile. For ‘pure traders’, who trade for revenue generation, the prevailing higher prices mean that the financial commitments needed to hold open positions in the traded market are now greater relative to their balance sheets, which makes it more challenging to trade, even if the potential rewards are greater.

For European and Asian utility buyers, the primary value of destination flexibility in term SPAs lies in the ability to re-sell term contract cargoes at times of lower demand, just as the spot market offers them the means of purchasing additional spot cargoes during times of higher demand.

Whether achieved by buying FOB or inserting destination flexibility into DES/DAT contracts, the ability to trade long-term contract volumes away from Europe is seen as advantageous by buyers, given the uncertainty over European long-term LNG demand (in particular influenced by progress in the energy transition and related environmental regulation). For European buyers, Asia is seen as a ‘backstop’ market that will continue taking LNG cargoes even if European LNG demand declines after 2030.

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[56] Delivered Ex Ship (DES) is now often now also referred to as Delivered At Terminal (DAT). Unlike FOB, this includes the cost of shipping and insurance for the delivery.

[57] “If LNG is delivered DES (or DAT), the seller retains title and risk until the LNG is unloaded at its destination, and the seller is responsible for shipping costs. In such a case, the SPA will identify a specific delivery port (often in the buyer’s home market) and the buyer may have no destination freedom at all, unless the parties have added provisions providing that the buyer may request delivery to other destinations, often referred to as diversions (or deviations)”. See: Global Arbitration Review, 2019. *Destination Restrictions and Diversion Provisions in LNG Sale and Purchase Agreements. Lexology – Global Arbitration Review*. https://www.lexology.com/library/detail.aspx?g=ba7a4881-e722-4f90-875e-37aa641ce444

5.4. Security of supply and counterparty reliability

5.4.1. The importance of strong contracts and trustworthy counterparties

As a means of ensuring counterparty reliability, LNG export project developers seek financially strong, credit-rated counterparties willing to sign SPAs with strong force majeure clauses, in order to ease the process of securing project finance. In this regard, large aggregators with strong balance sheets are more attractive counterparties than smaller, niche buyers with weaker credit ratings, and new liquefaction project developers would often prefer to sell to stronger credit rated and experienced LNG buyers, even for smaller volumes and/or at slightly lower prices.

Likewise, where a buyer is considering its options of LNG supply from new projects, it would consider the reliability of the export project. Projects can seem 'too good to be true' by offering seemingly very attractive conditions, only to face greater challenges in securing project finance and therefore in taking FID, and thus turn out to be 'ghost' or 'phantom' projects that are either significantly delayed or do not materialise at all.

Furthermore, for LNG buyers, the issues of security of supply and counterparty reliability once the export project is up and running, although important in the past, have become absolutely crucial in the present high-price environment. Specifically, this is because of the increased financial consequences of contract non-performance by a supply-side counterparty, given the substantial costs of obtaining alternative supply. In 2022, the market saw supply disruptions in relation to cargoes from Nigeria (due to issues with feedgas supply) and from the Freeport export terminal in the United States (which was closed from June 2022 to February 2023 due to a fire). In such cases, buyers of LNG from these projects have potentially incurred considerable costs in sourcing alternative cargoes which often cannot be passed on to the end buyers. Specifically, high prices mean that the financial losses incurred by a counterparty not performing under the contract have become much, much greater.

5.4.2. Price volatility in 2022: an extreme example of the risks of non-performance

For example, in Q2 2022, an LNG trader buys LNG under a long-term, oil-indexed contract at 8 USD/MMBtu, with the intention of selling it into a European hub-based market area at 30 USD/MMBtu.[58] A prudent LNG trader would financially hedge the spread between the oil-indexed price and front-month hub price before loading the cargo, and in doing so, take on an obligation to deliver a cargo of LNG to that hub market area to match the obligation to repay the hedge. If the trader does not receive a cargo as expected under their long-term contract, their obligation to supply a cargo of LNG to the hub market area has not disappeared. Consequently, the trader is then obliged to go to the hub and repurchase a volume equivalent to the LNG cargo. But in the meantime, for example, by Q3 2022, the hub price may have risen substantially, say, to 60 USD/MMBtu.[59]

So, the trader will have to bear the additional cost of sourcing the replacement cargo, assuming a price difference of 30 USD/MMBtu between sourcing a replacement cargo at 60 USD/MMBtu and selling it into the hub market area at the previously-agreed 30 USD/MMBtu. When multiplied by 3.64 million MMBtu (the average capacity of an LNG carrier[60]), that becomes a cash loss of USD 109m on a single cargo (though this may be mitigated in the case of non-supply due to non-force majeure reasons). This also does not account for the USD 80m of profit that would have been made buying at 8 USD/MMBtu and selling at 30 USD/MMBtu, had the supplier provided the original cargo. These losses are vastly higher than the losses that would have been accrued due to a cargo cancellation under pre-crisis price levels.

[58] The average price level for front-month contracts at TTF in Q2 2022

[59] The average price level for front-month contracts at TTF in Q3 2022

[60] A cargo of 160,000 m3 of LNG equates to 96 million cubic metres of natural gas. Assuming a gross calorific value of 40 megajoules per standard cubic metre, this 96 mmcm of natural gas equates to 3,840 million megajoules. 1 MMBtu equals 1,055.056 Megajoules. Therefore, 3,840 million megajoules equals 3.64 million MMBtu.

In the ten years between Q4 2009 and Q4 2019 (i.e., pre-COVID), quarterly average TTF front-month prices ranged from 3.77 USD/MMBtu to 10.98 USD/MMBtu. The quarter-on-quarter growth in quarterly average prices never exceeded 1.26 USD/MMBtu (between Q3 and Q4 2012)[61] and the quarter-on-quarter decline in quarterly average prices never exceeded 2.19 USD/MMBtu (Q4 2018 to Q1 2019).[62] Taking the same example as above, but with an oil-indexed cargo purchased at 5 USD/MMBtu for sale at 8 USD/MMBtu, and supply-side non-performance at a time of rising prices meaning that a replacement cargo must be purchased at 9.26 USD/MMBtu. On an average-sized cargo of 160,000 m3 of LNG, the 1.26 USD/MMBtu loss on re-selling the replacement cargo would be USD 4.6m, while the 3 USD/MMBtu of foregone profit from the planned sale of the original cargo would equate to USD 10.9m of planned profit not earned. Therefore, the effective loss would have been USD 15.5m - less than one-tenth of the effective loss in the first example.

The former may be an extreme example, given the exceptional price volatility and price levels that occurred in 2022 (and a simplification that excludes the costs of shipping and any liability payments), but when placed in comparison with the pre-crisis LNG market up to the end of 2019, it serves to illustrate the financial ramifications of non-performance at a time of volatile markets, and the importance of counterparty reliability. This applies not only to the commercial reliability of the counterparty, but also the reliability of feedgas supply to the liquefaction plant, the technical reliability of the plant itself, and the stability of the country in which the plant is located. Although the physical risks themselves may only be partially alleviated, it has also become more important than ever to cover those risks in the bilateral contracts between parties.

5.5. Risk-sharing, liability, and force majeure

Building on the discussion in the section above, in the context of 'higher financial stakes', the issue of risk-sharing, and the related questions of liability and force majeure when things do go wrong – have become even more important to all parties concerned in LNG trading and to all SPA counterparties. With that in mind, a point that may seem logical and even obvious, but one that bears further analysis, is that the nature of risk and the question of which parties should bear that risk, are perceived differently by different stakeholders. Understanding those differences and how they may be reconciled is fundamental to ensuring LNG supply in the coming decades, given that such supply will be underpinned by new supply-side project FIDs and long-term SPAs.

From the perspective of US export project developers, the major risks are capex, cost overrun, and the cost of financing. By contrast, the risk related to feedgas supply is limited to physical pipeline connections from the export plant to the main grid, given that feedgas is sourced from the national pipeline system rather than dedicated fields. Indeed, it would therefore be difficult to call force majeure unless there was a technical problem that prevented the supply of feedgas reaching the plant. Outside the United States, the risks of interruptions in feedgas supply when that feedgas is sourced from a dedicated field must be added to the risks of capex, financing, and cost overrun.

In technological terms, risks increase when the project is developed on a greenfield site, on the basis of feedgas from production at dedicated offshore fields (such as at Delfin LNG in the US), or on the basis of new liquefaction technology (such as the 'Arctic Cascade' technology used in the fourth train of Yamal LNG in Russia). To this may be added risks associated with the local political context, whether that relates to the social, political, and economic stability of the host country (as seen in Mozambique). Instability and/or changes in government could yield changes in conditions for foreign investors, in relation to regulatory frameworks, taxation, or even physical security.

As discussed above, the risk undertaken by traders and aggregators is not only the risk of significant divergence between the price of supply and the price of sale,[63] but also the risk in Europe of divergence

[61] Slightly higher than the increases in quarterly average prices of 1.16-1.18 USD/MMBtu in Q3-Q4 2016, 2017, and 2019

[62] Data from Argus Direct [subscription required]

[63] For example, LNG sourced from the US based on Henry Hub and sold into Asia at oil-indexed or JKM-indexed prices or oil-indexed LNG sourced from outside the US and sold into Europe at hub-based prices

between the landed spot price of LNG and the nearest hub. Such a divergence between the landed price of LNG in North-Western Europe and the front-month TTF price was illustrated in Figure 4 at the start of this paper. Such a risk may be considered a ‘normal market risk’.

A less frequent, and more dramatic, risk for an LNG aggregator or trader would be non-performance of contract by their supply-side counterparty. The potential cost (losses) for the LNG aggregator/trader have already been discussed above. Taking this a step further, the question of liability – and the limitations on liability - is critical.

Specifically, if a supplier faces a force majeure situation and cannot fulfil their obligation to provide a cargo of LNG to an LNG aggregator/trader, limited liability means that the supplier is not required to source a cargo of LNG from the global market and provide it to the LNG aggregator/trader, in the same manner that the LNG aggregator/trader must source an equivalent volume for the final buyer that is their SPA counterparty. In such a situation, both the supplier and the aggregator/trader make a loss. If the liability were entirely borne by the supplier, the question of reliability of physical supply from the source project would not matter to the LNG aggregator/trader, only the reliability of their counterparty operating that project, insofar as they are likely to prove reliable in fulfilling their commitments through the acquisition of alternative cargoes in such a situation. It is precisely the sharing of liability when things go wrong that puts a premium on supply-side counterparties that are deemed ‘reliable.’

A common refrain from all LNG market participants is that risks should be borne by the parties that are competent to take those particular risks. The lowest levels of price risk are borne by infrastructure companies that develop LNG export projects in the United States (either selling LNG cost-plus under long-term SPAs or selling liquefaction capacity under long-term contracts) and by LNG buyers in Europe that purchase LNG at prices indexed to TTF to ensure that those supplies are competitive with supply from European production and pipeline imports that are also priced according to TTF. The greatest financial risks – and greatest potential financial rewards – are in the hands of aggregators and traders, who bear the risks of cross-indexation exposure, but also the potential for realising substantial margins when prices in the destination markets rise significantly above the cost of supply.

To conclude, it is possible to distinguish between two types of risk. On the one hand, there is ‘normal market risk’, such as volume risk for buyers with long-term contracts (who may see demand decline below their take-or-pay commitments in their long-term SPAs), price risk for aggregators and traders facing cross-indexation exposure, and cost overruns for export project developers.

On the other hand, there is ‘risk when things go wrong’. For export project developers, this could be technology failure, failure of feedgas supply, or even short-term weather-related problems (such as the snow storms that negatively impacted US LNG production in February 2021). For aggregators and traders, it could be a failure of contractual performance by their supply counterparty that is not fully covered by limited liability provision in that contract.

While normal, ongoing market risk is usually balanced by the possibility of financial reward for the parties concerned, the risk of ‘things going wrong’ (usually for a short period) must be covered by the liability and force majeure clauses of contracts between parties. The prevailing higher prices since the second half of 2021 mean that the consequences of such negative events requiring reference to liability clauses are much greater, lending greater importance to those liability clauses and their wording.

5.6. Stable regulatory frameworks, ESG, and carbon-neutral LNG

For LNG buyers in Europe, the stability of regulatory frameworks regarding fossil fuel consumption can be a source of risk, especially in relation to long-term contracts. Specifically, this concerns the regulation of the importation and consumption of fossil fuels in the context of European Commission targets to reduce EU greenhouse gas emission by 55 per cent (relative to 1990) by 2030, and to achieve climate neutrality by 2050.[64] Even a 10-year LNG SPA signed this year would take the final years of that contract

[64] European Commission, 2023. 2030 *Climate Target Plan*. https://climate.ec.europa.eu/eu-action/european-green-deal/2030-climate-target-plan_en

beyond 2030, while a 20-year LNG SPA would be valid well into the 2040s, as the EU is approaching its 2050 target. The worry for buyers locked into long-term SPAs is that in order to meet those emissions reduction targets, more stringent measures (whether tax-based or regulatory) could be needed to discourage fossil fuel consumption, leaving LNG buyers over-contracted. The counterpoint risk, mainly for regions outside Europe, is that Europe underperforms on its energy transition plans, and continues to import significant volumes of LNG without having directly contributed to development of supply capacity overall, due to not signing term SPAs that underpin investment in new production and liquefaction capacity.

For buyers, one way of navigating this risk (in addition to the destination flexibility in long-term SPAs discussed earlier), which could enable European LNG buyers with long-term contracts to trade away cargoes to other markets if demand for LNG in Europe becomes constrained – is to include the issue of sustainability in LNG contracts. Specifically, LNG buyers are now more than ever concerned with knowing the upstream and transportation emissions associated with LNG cargoes, especially publicly-traded companies that answer to increasingly environmentally-conscious investors. This is particularly relevant given debates over carbon accounting and attribution of emissions. For example, in 2021, Chevron, QatarEnergy, and Pavilion published their methodology (referred to as their 'Statement of Greenhouse Gas Emissions') for calculating greenhouse gas emissions through their value chains, to aid the process of measurement, reporting, and verification of those emissions.[65] The following year, Cheniere began providing Cargo Emissions (CE) Tags to their long-term customers, showing the emissions associated with each cargo, therefore providing its customers with reliable information to offset emissions should they choose to.[66]

So-called 'carbon neutral LNG' uses reductions in emissions elsewhere ('carbon offsets' that are often not associated with the country or industry for which the LNG is provided) to offset the emissions associated with an LNG cargo. For example, in 2020, TotalEnergies reported its first carbon neutral LNG cargo (shipped from Australia to China), with emissions being offset by investment in a wind farm in China and a forest protection project in Zimbabwe.[67]

Elsewhere, NextDecade (developer of the Rio Grande LNG export project in the United States, which reached FID in July 2023[68]) is offering 'low carbon' LNG, by using a carbon capture and storage (CCS) facility to capture and store 5 million tonnes of CO_2 per year relative to the 27 million tonnes of LNG it expects to produce annually.[69]

Such offerings of information on emissions associated with cargoes, carbon offsets, and 'low carbon' LNG are perceived to be critical for European buyers (especially European utilities), given the European Commission climate targets, somewhat important in the developed Asian economies (such as Japan), and less important in China, where the consumption of coal currently poses a far greater challenge to the reduction of China's CO_2 emissions than its LNG imports. Looking ahead, there is scope for the development of gaseous fuels that are physically carbon-neutral, such as green LNG (developed from biogas converted into biomethane) or synthetic LNG (for which captured CO_2 is added to green hydrogen produced via electrolysis using zero-carbon electricity), but these face significant cost challenges and will take time to develop at scale. It also remains to be seen whether carbon offsets will be sufficient to meet European buyers' demands, or whether only decarbonised gaseous fuels will be acceptable in the longer term. This also begs the question of who will pay for these measures.

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65 Chevron, QatarEnergy, and Pavilion, 2021. *The SGE Methodology: GHG Methodology for Delivered LNG Cargoes*. https://www.chevron.com/-/media/chevron/sustainability/documents/SGE-methodology.pdf

66 Cheniere, 2023. *Climate – What are Cheniere's Cargo Emissions Tags?* https://www.cheniere.com/our-responsibility/climate

67 TotalEnergies, 2020. Total Delivers its First Carbon Neutral LNG Cargo. *Press Release*, 20 October. https://totalenergies.com/media/news/communiques-presse/total-delivers-its-first-carbon-neutral-lng-cargo

68 NextDecade, 2023. NextDecade Announces Positive Final Investment Decision on Rio Grande LNG Phase 1. *Press Release*, 12 July. https://investors.next-decade.com/news-releases/news-release-details/nextdecade-announces-positive-final-investment-decision-rio

69 NextDecade, 2023. *Rio Grande LNG*. https://www.next-decade.com/rio-grande-lng/

Finally, although the gas market turbulence of the past two years has placed a greater emphasis on price and security of supply, thus relegating environmental impact to third place in the ‘energy trilemma’ for now, there is a sense that the environmental pressure on participants in the LNG market regarding emissions will return. Yet despite the clarity of corporate statements delivered to the market in the pre-crisis period, it is notable that some of the commitments by market participants made regarding ESG (Environmental and Social Governance), have, in some cases, been ‘walked back’ by a public emphasis on security of supply.

Taken together, these points suggest that although the LNG industry would like assurance from governments in Europe that natural gas does not need to ‘disappear in the next five years’, there is also an acceptance that natural gas remains a fossil fuel and that the industry itself needs to take the lead in pursuing decarbonisation, both to prove that the ESG commitments made prior to 2021 were sincere and to ensure that the product offering is still acceptable to the European market even if emissions regulations do become more stringent.

6. Market development: the balance between term and spot contracts, and market concentration

6.1. Market development and the balance between term and spot contracts

In recent decades, the global LNG market has developed from a fixed market dominated by long-term, point-to-point contracts with oil-indexed prices and little flexibility to a merchant market with more flexibility, multiple bases for indexation, and a greater role for aggregators and traders. The oversupply in 2019 and 2020 placed considerable strain on some long-term SPAs and made spot purchases commercially attractive. In that context, European buyers perceived an abundance of supply and the related possibility of acquiring cargoes as and when they were required on European hubs, whether that was TTF, NBP, PSV, or Mibgas. There was less appetite for entering into substantial term SPAs with significant take-or-pay commitments, especially if the prices in those SPAs did not offer any notable competitive advantage relative to the prevailing hub prices.

The reduction in Russian pipeline gas supply to Europe between 2021 and 2023 has incentivised some buyers to increase the share of long-term contract supply in their portfolio, due to concerns over their ability to secure cargoes in a market that is not only tight at present, but also that appears set to remain structurally tight for the next couple of years. In particular, this is influenced by the views of the buyers on whether or not Russian pipeline gas is likely to make a notable return to the European market. This has increased the attractiveness of term SPAs for supply from the United States, due to the fact that US LNG supply is not only perceived to be stable and reliable, but because the US gas market is structurally long compared to the structurally short European market, meaning that over an extended period of time, there is likely to be a differential between Henry Hub and European hubs sufficient to keep buyers of US LNG (whether traders, aggregators, or European utilities) ‘in the money’, even when the costs of shipping and regasification are accounted for.

However, this renewed focus on long-term contracts does not mean that the development of a merchant LNG market is going into reverse. It is simply that, within a liberalised, flexible, merchant LNG market, the emphasis on spot transactions that was only natural during a supply glut (as in 2019 and 2020) has, as to be expected, shifted back towards term contracts in a time of tight markets and concerns over access to supply. It is also worth noting that the measurement of spot purchases by the International Gas Union (IGU) and Group of International LNG importers (GIIGNL) is on an import basis, measured by arrivals at the import terminals. Many of the ‘spot LNG cargoes’ are sourced from LNG producers under long-term FOB contracts and then re-sold, especially with regard to cargoes originating in the United States. In effect, it is a situation of long-term contract exports and spot or short-term contract imports, with aggregators and traders standing between the LNG exporters and the final buyers.

Therefore, the signing of new long-term contracts by final buyers represents a shift in emphasis, rather than the abandonment of spot transactions entirely. Spot transactions will continue to perform an important market function in terms of adding flexibility to a portfolio and providing scope for optimisation, allowing players to trade away volumes at times of lower demand from their final consumers, and source additional volumes above and beyond the term contracts at times of higher demand. Moreover, the share of spot transactions in total LNG sale and purchase volumes are likely to grow again post-2025, as the next large wave of supply enters to the global LNG and balance of 'market power' (currently weighted in favour of sellers due to the tight market) shifts back towards the buyers, who will find it easier to source volumes without taking the volume risk of term contracts than they do at present.

6.2. Market concentration

At the time of writing, the benchmark prices for LNG for both FOB exports from the US Gulf Coast and the Argus assessments for LNG landed in North-West Europe and North-East Asia are back in the range of USD 14-16 per MMBtu. Such levels may be characterised as 'expensive' rather than 'exceptional', as discussed earlier. However, the outlook for the supply-demand balance for the next two years appears to be one of continued market tightness until the next wave of supply reaches the market, it appears unlikely that benchmark LNG prices will return to their pre-crisis levels before 2025.

On the supply side, the global market is dominated by three major supply sources, the United States, Qatar, and Australia. In the period January to November 2023, they exported 72-78 mt each, with their combined exports of 224.3 mt accounting for precisely 60 per cent of global LNG exports in that period. A second group of a further six exporters (Russia, Malaysia, Indonesia, Algeria, Nigeria, and Oman) exported 10-30 mt each, with their combined exports of 104.5 mt accounting for 28 per cent of global LNG exports in the same period. Finally, a group of a further eleven exporters[70] accounted for the remaining 12 per cent of global LNG supply, with combined exports of 45.2 mt, each exporting 1-8 mt.[71] The next substantial supply wave is due to reach the market in 2025-28, with most new supply coming from the United States and Qatar, cementing their positions as the world's leading LNG exporters.

On the demand side, the next several years are likely to see European LNG demand sustained, given that total European gas demand is unlikely to fall much further, after the year-on-year declines in 2022 and 2023, and the volume of Russian pipeline supply that was lost in 2022 is unlikely to return. Chinese LNG demand is likely to recover and resume growth, although demand in the developing Asian economies (India, Pakistan, and Bangladesh) may remain subdued until prices fall further.

Given the global LNG market balance outlook to the end of 2025, LNG benchmark prices in Europe and Asia could feasibly remain in the 10-15 USD/MMBtu range in the northern hemisphere summer months, and somewhat higher during the winter months. Such summer prices would be similar to inflation-adjusted adjusted TTF prices in 2010-2014, and winter prices similar to inflation-adjusted TTF prices in 2007-08. In Asia, such summer and winter prices would be within the range of inflation-adjusted prices in much of the period from 2006 to 2014/15, and perhaps even slightly lower than the sustained high Asian prices seen from late 2011 to early 2014.

In this regard, the barriers to trading generated by higher prices – larger margin calls, and the need for bigger balance sheets in order to hold open positions – that are likely to remain for the next two years mean that the global LNG trading market could become increasingly concentrated in the hands of a smaller number of larger players. While downstream utility buyers may find trading for supply portfolio optimisation more challenging, and smaller traders with smaller balance sheets find that they can hold fewer open positions, even the larger aggregators (such as Shell, BP, and TotalEnergies) and larger traders (such as Vitol and Trafigura) are finding that they can 'do less with the same amount of money'.

[70] Papua New Guinea, Trinidad & Tobago, United Arab Emirates, Brunei, Norway, Peru, Angola, Egypt, Equatorial Guinea, Mozambique, Cameroon

[71] Data from Kpler LNG Platform [subscription required]

Taken together, the renewed focus on long-term contracts and market concentration, while retaining a variety of bases for indexation, spot trading, and a role for aggregators/traders, does not reflect a return to the less flexible market of a previous era. Rather, it signifies attempts to manage risk in a context where higher prices mean higher stakes and higher barriers to market entry. It does so in the context of a long-term energy outlook influenced by the energy transition, whereby (in Europe and other developed economies, at least) long-term economic growth no longer implies long-term growth in energy demand, and even long-term growth in energy demand no longer implies long-term growth in demand for unabated fossil fuels. As such, the near-term (2023-2025) risks associated with continued high prices are compounded by uncertainties over longer-term gas demand in Europe and elsewhere out to 2030 and beyond.

7. Market outlook for 2025 to 2030

7.1. The supply-side outlook: The United States, Qatar, and elsewhere

The cycle of 'feast and famine' in the global LNG market over the past several years – with oversupply and record low prices in mid-2020 giving way to undersupply and record high prices in mid-2022 – is set to continue, with the global market set to be structurally tight until the end of 2025 followed by a wave of new supply that could outpace growth in demand and tip the market into oversupply.

7.1.1. Supply from Qatar

Qatar has one LNG liquefaction complex, at Ras Laffan, which consists of 14 trains with a combined nameplate capacity of 77 mtpa. From an initial 16.1 mtpa of capacity in 2000, a period of expansion saw that capacity rise to 30.2 mtpa from eight trains at the end of 2007, before a further six (7.8 mtpa) trains between 2009 and 2011 brought total capacity to the present 77 mtpa.[72] Since then, debottlenecking has allowed actual exports to exceed that nameplate by several mtpa, with exports between 2012 and 2022 in the range of 77.9 and 80.2 mtpa. For comparison, similar levels of annual LNG exports (76-80 mtpa) were first reached by Australia in 2019 and the United States in 2022.[73]

In 2005, Qatar Petroleum announced a moratorium on the expansion of production from its North Field, from which Qatar draws almost all of its gas production, to avoid 'flooding the market'. Seeing increasing competition from Australia and the United States, Qatar Petroleum lifted that moratorium in 2017, paving the way for an expansion of Qatar's LNG export capacity.[74] That expansion will take place on the basis of additional gas production from two areas: North Field East (NFE) and North Field South (NFS), with new liquefaction capacity to match the rise in production. The first of four 8 mtpa liquefaction trains at NFE is scheduled for launch at the end of 2025 or early 2026, following FID in 2021,[75] while the ramp-up at NFE and the addition two more 8 mtpa trains at NFS are scheduled for completion by the end of 2027.[76] The expansion project will add 48 mtpa of Qatari LNG export capacity, meaning Qatar's total LNG export capacity is set to rise from 77 mtpa at present to 125 mtpa by the end of 2027.

[72] GIIGNL, 2013. *GIINGNL Annual Report 2012*. Published 10 April. https://giignl.org/wp-content/uploads/2021/07/giignl_the_lng_industry_2012.pdf (also available via https://giignl.org/resources2/) (see page 21)
[73] Kpler LNG Platform [subscription required]
[74] Finn, T, & Tay, M., 2017. Qatar restarts development of world's biggest gas field after 12-year freeze. *Reuters*, 4 April. https://www.reuters.com/article/us-qatar-gas/qatar-restarts-development-of-worlds-biggest-gas-field-after-12-year-freeze-idUSKBN175181/
[75] GIIGNL, 2021. https://giignl.org/qatar-takes-fid-on-33-mtpa-lng-liquefaction-project/
[76] Qatargas, 2023. NFE project milestones: jacket installations completed and mega trains contract awarded. *The Pioneer (Qatargas corporate magazine)*, Issue 163, Q1 2023. Pages 4-5. https://www.qatarenergylng.qa/english/MediaCenter/The%20Pioneer/The%20Pioneer%20163%20EN.pdf

7.1.2. Supply from the United States

In the United States, additional supply is expected from new projects (which have taken FID) at Golden Pass (three 6 mtpa trains, with the first train scheduled for launch in H1 2025)[77] [78] and Plaquemines (Phase 1 in 2024 and Phase 2 in 2026, each of 10 mtpa).[79] In March 2023, Sempra reached FID on Phase 1 (two trains totalling 13 mtpa) of its Port Arthur project, and received approval from the US Federal Energy Regulatory Commission (FERC) for Phase 2 (also 13 mtpa) in September 2023, thus paving the way for Phase 2 to reach FID, subject to securing sufficient offtake contracts. Trains 1 and 2 from Port Arthur Phase 1 are scheduled to launch in 2027 and 2028, respectively.[80] [81] In July 2023, NextDecade reached FID on Phase 1 (17.6 mtpa) of its Rio Grande project, with the three trains scheduled for launch between 2027 and 2028. [82] If FID is reached on trains 4 and 5, the Rio Grande project will grow to 27 mtpa.[83] Taken together, these new projects that have reached FID will add 58.6 mtpa of new US LNG export capacity between 2024 and 2028, rising to 81.0 mtpa if FID is reached at Phase 2 of the Port Arthur and Rio Grande projects.

In addition to these new projects, Cheniere took FID on a 10 mtpa expansion of its Corpus Christi liquefaction terminal in June 2022, with the first new supply expected by the end of 2025.[84] [85] Cheniere is also planning an expansion of its Sabine Pass export terminal, where the current capacity is around 30 mtpa from six trains. The expansion involves the construction of three more 6.5 mtpa trains from 2025 onwards, with first gas by 2030 and full capacity by 2032. However, it is reported that Cheniere wants 90 per cent of the planned liquefaction volumes to be committed under long-term contracts before it can take FID. [86] [87] Therefore, the Sabine Pass expansion is a prominent example of the question raised in the introduction of this paper: whether supply-side LNG projects can secure a sufficient volume of SPAs to underpin FID and add to global LNG supply post-2030. At the time of writing, Cheniere has signed six SPAs relating to the Sabine Pass expansion project: In May and June 2023, Cheniere concluded deals with Korean Southern Power (KOSPO), Equinor (Norway), and ENN (China), followed

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[77] Golden Pass LNG, 2023. *Export Project*. https://www.goldenpasslng.com/operations/export-project

[78] The shareholders in the Golden Pass project are QatarEnergy (70%) and ExxonMobil (30%). The project reached FID in Q1 2019 and is currently under construction. Golden Pass LNG, 2023. *About: Shareholders*. https://www.goldenpasslng.com/about/about-golden-pass#shareholders

[79] The Plaquemines project is being developed by Venture Global. FID on Phase 1 was taken in May 2022 and FID on Phase 2 was taken in March 2023:

Venture Global, 2022. Venture Global announces final investment decision and financial close for Plaquemines LNG. *Press Release,* 25 May. https://venturegloballng.com/press/venture-global-announces-final-investment-decision-and-financial-close-for-plaquemines-lng/

Venture Global, 2023. Venture Global announces final investment decision and financial close for phase two of Plaquemines LNG. *Press Release,* 13 March. https://venturegloballng.com/press/venture-global-announces-final-investment-decision-and-financial-close-for-phase-two-of-plaquemines-lng/

[80] Sempra, 2023. Sempra Launches Port Arthur LNG Project. *Press Release*, 20 March. https://www.sempra.com/sempra-launches-port-arthur-lng-project

[81] Sempra, 2023. Port Arthur LNG Phase 2 Project Receives Federal Energy Regulatory Commission Authorization. *Press Release*, 21 September. https://sempra.mediaroom.com/2023-09-21-Port-Arthur-LNG-Phase-2-Project-Receives-Federal-Energy-Regulatory-Commission-Authorization

[82] NextDecade, 2023. *NextDecade Corporate Presentation – November 2023*. https://nextdecadelng.wpenginepowered.com/wp-content/uploads/2023/02/NextDecade-Corporate-Presentation-11.13.23.pdf

[83] NextDecade, 2023. NextDecade Announces Positive Final Investment Decision on Rio Grande LNG Phase 1. *Press Release*, 12 July. https://investors.next-decade.com/news-releases/news-release-details/nextdecade-announces-positive-final-investment-decision-rio

[84] Cheniere, 2022. Cheniere Announces Positive Final Investment Decision on the Corpus Christi Stage 3 Liquefaction Project. *Press Release*, 22 June. https://lngir.cheniere.com/news-events/press-releases/detail/252/cheniere-announces-positive-final-investment-decision-on

[85] Disavino, S., 2023. U.S. LNG producers poised to leapfrog rivals with three new projects. *Reuters*, 23 February. https://www.reuters.com/business/energy/us-lng-producers-poised-leapfrog-rivals-with-three-new-projects-2023-02-16/

[86] Cheniere, 2023. Cheniere eyes Sabine Pass LNG expansion. *Argus Direct*, 23 February. https://direct.argusmedia.com/newsandanalysis/article/2422922

[87] Cheniere, 2023. Cheniere Initiates Permitting Process for Significant Expansion of LNG Export Capacity at Sabine Pass. *Press Release*, 23 February. https://lngir.cheniere.com/news-events/press-releases/detail/272/cheniere-initiates-permitting-process-for-significant

by an SPA with BASF (Germany) in August, and SPAs with OMV (Austria) and Foran Energy Group (China) in November 2023.[88] [89] [90] [91] [92] [93] The first five SPAs, totalling 5.6 mtpa (86 per cent of the capacity of train 1 of the expansion project, are subject to a positive FID on that first train. The fifth SPA (for 0.9 mtpa) is subject to a positive FID on the second train of the expansion project.

Elsewhere in the United States, projects that have not yet taken FID but are reportedly moving in that direction include Sempra planning an expansion of its Cameron LNG liquefaction plant with the addition of another 6.75 mtpa train,[94] Calcasieu Pass 2 (which had contracted offtake for half of its planned 20 mtpa by June 2023, according to Venture Global),[95] and Lake Charles (where Energy Transfer has contracted 7.9 mtpa of offtake and has non-binding agreements for a further 3.6 mtpa, compared to plans for total capacity of 16.45 mtpa from three 5.5 mtpa trains).[96] Together, these projects could add a further 43.2 mtpa of US LNG export capacity by the end of the present decade, which could be followed by supply from Cheniere's expansion of Sabine Pass from 2030 onwards.

7.1.3. Supply from elsewhere

Outside the United States and Qatar, projects that have taken FID and are under construction, including LNG Canada, Kitimat (13.2 mtpa) and Woodfibre (2.1 mtpa) in Canada, Energia Costa Azul (ECA) LNG (3.25 mtpa) and Altamira (4.2 mtpa) in Mexico, Greater Tortue Ahmeyim (GTA) FLNG (2.4 mtpa, Senegal-Mauritania), Tango FLNG (1.4 mtpa, Congo), will add 26.55 mtpa of new capacity in the period 2023-2027, of which half will come from LNG Canada alone. In addition, Mozambique LNG (12.9 mtpa), led by TotalEnergies, took FID in 2019 but was halted following a terrorist attack in April 2021. As of September 2023, TotalEnergies aims to commence operations at Mozambique LNG in 2028.[97]

7.1.4. The overall supply picture

Taken together, the 48 mtpa of additional supply from the Qatari North Field expansion and the 68.6 mtpa of supply from the United States that has already reached FID will add a combined 116.6 mtpa of LNG supply by 2028 to a global market that saw supply of 398.8 mt in 2022 (an increase of 29 per cent), while the new capacity additions outside the United States and Qatar that have taken FID will add just 26.6 mtpa, or 39.6 mtpa if Mozambique LNG is included.

Overall, the projects in the United States, Qatar, and elsewhere (excluding Mozambique) that have already taken FID will add 143.2 mtpa of new global LNG supply by 2028 – an increase of 36 per cent over the volume of LNG exported in 2022. In addition, even if only half of the US projects that intend to

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[88] Cheniere, 2023. Cheniere and KOSPO Sign Long-Term LNG Sale and Purchase Agreement. *Press Release*, 16 May. https://lngir.cheniere.com/news-events/press-releases/detail/277/cheniere-and-kospo-sign-long-term-lng-sale-and-purchase
[89] Cheniere, 2023. Cheniere and Equinor Sign Long-Term LNG Sale and Purchase Agreement. *Press Release*, 21 June. https://lngir.cheniere.com/news-events/press-releases/detail/278/cheniere-and-equinor-sign-long-term-lng-sale-and-purchase
[90] Cheniere, 2023. Cheniere and ENN Sign Long-Term LNG Sale and Purchase Agreement. *Press Release*, 26 June. https://lngir.cheniere.com/news-events/press-releases/detail/279/cheniere-and-enn-sign-long-term-lng-sale-and-purchase
[91] Cheniere, 2023. Cheniere and BASF Sign Long-Term LNG Sale and Purchase Agreement. *Press Release*, 22 August. https://lngir.cheniere.com/news-events/press-releases/detail/284/cheniere-and-basf-sign-long-term-lng-sale-and-purchase
[92] Cheniere, 2023. Cheniere Announces Long-Term Integrated Production Marketing Agreement with ARC Resources. *Press Release*, 29 November. https://lngir.cheniere.com/news-events/press-releases/detail/289/cheniere-announces-long-term-integrated-production
[93] Cheniere, 2023. Cheniere and Foran Energy Group Sign Long-Term LNG Sale and Purchase Agreement. *Press Release*, 2 November. https://lngir.cheniere.com/news-events/press-releases/detail/288/cheniere-and-foran-energy-group-sign-long-term-lng-sale-and
[94] LNG Prime, 2023. Sempra eyes two LNG expansion FIDs in 2024. *LNG Prime*, 7 August. https://lngprime.com/lng-terminals/sempra-eyes-two-lng-expansion-fids-in-2024/88131/
[95] Venture Global, 2023. Venture Global and SEFE Announce 20-year LNG Sales and Purchase Agreement. *Press Release*, 22 June. https://venturegloballng.com/press/venture-global-and-sefe-announce-20-year-lng-sales-and-purchase-agreement/
[96] Lake Charles LNG, 2023. *Newsroom*. https://energytransferlng.com/Newsroom.html
[97] TotalEnergies, 2023. 2023 Strategy & Outlook. *Presentation*, 27 September. https://totalenergies.com/investors/investors-presentations (see slide 27)

launch by 2028 actually achieve FID,[98] it would add a further 32.8 mtpa of US LNG export capacity beyond that which has already achieved FID. Under these conditions, it is conceivable that an additional 176 mtpa of global LNG export capacity could be added by 2028 (a 44 per cent increase over global LNG supply in 2022). More dramatically, if the Mozambique LNG project were restarted and launched by 2028, and around two-thirds of the US projects reportedly close to FID came to fruition, the growth could be closer to 200 mtpa – a 50 per cent increase over 2022.

7.2. Contracts for US and Qatari LNG

LNG supply to the European market from the United States and Qatar is notable for two reasons. Firstly, it accounted for 50 per cent of EU-27 plus UK LNG imports in 2020-21, rising to 60 per cent in 2022 and the 2023 year to date, giving it a substantial market share. Secondly, they are the only large suppliers to operate substantially across both the European and Asian markets. For comparison, virtually no Australian LNG is supplied to Europe. Supply from Russia's Yamal LNG liquefaction terminal (the third largest source of LNG supply to Europe after the US and Qatar) has generally been directed towards Europe with lesser volumes delivered to Asia, albeit with scope for volumes trans-shipped at Zeebrugge to be delivered onwards to destinations beyond Europe.

7.2.1. Contracts for US LNG

Most of the existing contracts for US LNG are not due to expire until after 2030, with just 1.75 mtpa of contracts for US LNG are due to expire by 30 April 2024, and a further 1.2 mtpa of contracts are due to expire by 31 December 2029. This is not surprising, given that the United States only began ramping up its LNG exports in 2016. The split between contracts held by aggregators and traders on the one hand, and utilities/industrial consumers in Europe and Asia for existing supply volumes was discussed earlier (see page 4). The key point remains that most US LNG is flexible: Around 75 per cent is FOB plus another 13 per cent FOB/DES, thus leaving only 12 per cent DES. The split between end users and re-sellers is approximately 60-40, meaning that even end users currently buying LNG from the United States are likely to have destination flexibility.

Turning to the 92.7 mtpa of contracts for future LNG supply from the United States, which are due to take effect between 1 January 2024 and 1 January 2028, 29.2 mtpa (31.5 per cent of the total) are contracted for sale to Asian utilities and industrial consumers and 24.4 mtpa (26.5 per cent) are contracted for sale to European utilities and industrial consumers, meaning that 58 per cent of the contracts for future LNG supply from the United States are contracted to end users. A further 11.6 mtpa (12.5 per cent) is contracted to aggregators, 6.5 mtpa (7 per cent) to traders, 11 mtpa (12 per cent) to major US entities that are likely to sell on a destination-flexible basis,[99] 8 mtpa (8.5 per cent) to companies that mostly produce gas and are likely adding to their portfolio of supply,[100] and 2 mtpa to other buyers.[101] Of these contracts, 89 per cent are FOB, 3 per cent are DES/DAT, and 8 per cent are listed as FOB/DES (denoting destination flexibility within a given destination region). As with the contracts for existing supply, the DES/DAT contracts are almost entirely for supply to utilities and industrial consumers. Finally, as the table below illustrates, even the contracts for supply to utilities and industrial buyers are mostly FOB, implying significant flexibility for those buyers to re-direct and re-sell supplies that they do not need.

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[98] Port Arthur Phase 2 (13 mtpa), Rio Grande Phase 2 (9.4 mtpa), Calcasieu Pass 2 (20 mtpa), Lake Charles (16.45 mtpa), and Cameron LNG expansion (6.75 mtpa) – 65.6 mtpa in total

[99] Chevron, ConocoPhillips, and ExxonMobil

[100] Includes producers such as Equinor (Norway), Pertamina (Indonesia), Petronas (Malaysia) and LNG project companies, such as Excelerate Energy, New Fortress Energy, and Woodside LNG

[101] Devon Energy & EQT Production

Figure 9: US LNG contracts for utilities/industrial consumers in Europe and Asia (mtpa)

	Europe	Asia
Current FOB	14.0	12.5
Current FOB/DES	2.0	4.1
Current DES	2.7	3.7
Future FOB	20.8	22.6
Future FOB/DES	2.3	5.1
Future DES	1.4	1.6

Source: Data from Kpler LNG Platform, table by the author. Note that 'current' refers to contracts that are currently active, while 'future' refers to contracts with start dates after 1 December 2023, up to 1 January 2028.

Overall, this suggests that the vast majority of US LNG that is either currently supplied to the market, or is set to do so in the next several years, is either being sold to entities that aim to re-sell those volumes (aggregators, traders, major US entities, and producers that wish to add to their portfolio of supply), or is destined for end users that retain the flexibility to re-direct and re-sell those cargoes if necessary.

7.2.2. Contracts for Qatari LNG

The situation regarding supply from Qatar is rather different. Qatar has only one LNG liquefaction complex, at Ras Laffan. That terminal consists of 14 trains, with a total capacity of 77 mtpa. The 14 trains provide offtake to eight joint ventures, with QatarEnergy being a majority shareholder in each, as illustrated in Figure 10. Overall, QatarEnergy (via Qatargas) has a shareholding in 72.4 per cent of the JVs, equivalent to 56.3 mtpa of capacity. ExxonMobil holds 18.5 per cent (14.3 mtpa), ConocoPhillips and Shell each hold 3 per cent (2.3 mtpa), and TotalEnergies holds 1.8 per cent (1.4 mtpa). The remaining 1.2 per cent (0.9 mtpa) is held by Mitsui, Korea RasGas LNG, Itochu, and LNG Japan.

Figure 10: Shareholders in JVs at Ras Laffan

	Participants	Launch	Capacity
Qatargas 1 (T1-3)	Qatargas	1996-98	9.5
Qatargas 2 (T4)	Qatargas (70%), ExxonMobil (30%)	2009	7.8
Qatargas 2 (T5)	Qatargas (63%), ExxonMobil (18%), TotalEnergies (17%)	2009	7.8
Qatargas 3 (T6)	Qatargas (69%), ConocoPhillips (30%), Mitsui (2%)	2010	7.8
Qatargas 4 (T7)	Qatargas (70%), Shell (30%)	2011	7.8
RasGas 1 (T8-9)	Qatargas (63%), ExxonMobil (25%), Three Others (12%)	1999-00	6.6
RasGas 2 (T10-12)	Qatargas (70%), ExxonMobil (30%)	2004-07	14.1
RasGas 3 (T13-14)	Qatargas (70%), ExxonMobil (30%)	2009-10	15.6
Total			**77.0**

Source: Data from Kpler LNG Platform for shareholdings in JVs, GIIGNL Annual Report 2012 for capacities.[102]

According to data from Kpler and GIIGNL, the contracts held for LNG exports from Ras Laffan are 80 per cent DES/DAT and 20 per cent FOB, with 1-2 mtpa (1-2 per cent) FOB/DES.[103] [104] Both sources allocate most of the contract volumes to one of the eight JVs listed in the table above, and some to QatarEnergy (formerly Qatargas). The two sources also note around 8 mtpa of contracts for supply to aggregator entities that are shareholders in the JVs (Shell and TotalEnergies), although Kpler adds a further 8.4 mtpa contracted for supply to ExxonMobil, while GIIGNL does not. Finally, the two sources

[102] GIIGNL, 2013. *GIINGNL Annual Report 2012*. Published 10 April. https://giignl.org/wp-content/uploads/2021/07/giignl_the_lng_industry_2012.pdf (also available via https://giignl.org/resources2/) (see page 21)
[103] Kpler LNG Platform [subscription required]
[104] GIIGNL, 2023. *Annual Report 2023 - The Global LNG Industry in 2022*. https://giignl.org/wp-content/uploads/2023/07/GIIGNL-2023-Annual-Report-July20.pdf (see pages 24-25)

do differ somewhat in the total amount contracted for supply from Ras Laffan at the end of 2022: Kpler reports a figure of 89.8 mtpa (not including the volumes allocated to ExxonMobil) while GIIGNL reports a figure of 81.7 mtpa.

The character of the counterparties receiving Qatari LNG is also interesting. With the exceptions of Eni, ExxonMobil, Shell, and TotalEnergies, the recipients of (overwhelmingly DES) Qatari LNG cargoes are entities likely to consume the cargoes they receive, rather than re-sell them. According to the contract data from Kpler, which includes the supply contracted to ExxonMobil, 63.5 per cent of contracted volumes are for Asian LNG buyers seeking supply for their home markets,[105] 20 per cent are for European utilities,[106] 13 per cent are for aggregators (Eni, Shell, and TotalEnergies), and the remaining 3.5 per cent is contracted to the Kuwait Petroleum Company.

The difference between the Kpler and GIIGNL data notwithstanding, the key point remains that, in contrast to the structure of US LNG exports, Qatari exports are all sourced from a single complex at Ras Laffan, around 80 per cent of the volumes exported from Ras Laffan are destination-specific (DES), the majority of buyers are either end users (utilities and industrial gas users) or Asian buyers that will sell the volumes into their domestic markets rather than trade them internationally, the ratio of Asian to European buyers is around 3-to-1, almost three-quarters of the shareholding in JVs operating at Ras Laffan is held by QatarEnergy, and QatarEnergy (either through its shareholdings in the JVs or by holding supply contracts directly) holds roughly 80 per cent of the total contracted volume.

For its North Field East expansion project, QatarEnergy formed joint venture (JV) companies with TotalEnergies,[107] Eni,[108] ConocoPhillips,[109] ExxonMobil,[110] and Shell.[111] In each of these JVs, QatarEnergy holds a 75 per cent stake. The JVs with TotalEnergies, ExxonMobil, and Shell each hold a 25 per cent stake in the NFE project, the JVs with Eni and ConocoPhillips each hold 12.5 per cent. Therefore, QatarEnergy will hold a 75 per cent stake in the NFE project overall, while each of its partners hold stakes of 6.25 per cent or 3.125 per cent. For its North Field South project, QatarEnergy retained a 75 per cent shareholding, offering 25 per cent to foreign partners: TotalEnergies and Shell hold 9.375 per cent each, and ConocoPhillips 6.25 per cent.[112] [113] [114] This model of retaining approximately 75 per cent shareholding (while bringing in aggregators that also market cargoes around the world as JV participants) is similar to the approach taken with the existing liquefaction complex at Ras Laffan.

The first contracts for supply from the North Field East and South expansion projects were signed in 2022. In November 2022, it was announced that, in accordance with two newly-signed SPAs, "a ConocoPhillips wholly owned subsidiary" would deliver up to 2 mtpa (DES) from the NFE and NFS projects to the Brunsbüttel liquefaction terminal in Germany, for 15 years starting from 2026 and

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[105] CNOOC, PetroChina, Sinopec, and Suntien Green (S&T International) in China; JERA, Kansai Electric, and Tohoku Electric in Japan; KOGAS in South Korea; CPC in Taiwan; GAIL, IOCL, BPCL, GSPC, and Petronet in India; Pakistan State Oil (PSO); Petrobangla (Bangladesh); Petronas in Malaysia; PTT LNG in Thailand

[106] Centrica (UK), Naturgy & Endesa (Spain); RWE (Germany); Orlen (Poland); OMV (Austria); Edison (Italy); and EDF (France)

[107] QatarEnergy, 2022. QatarEnergy selects TotalEnergies as its first partner in the North Field East expansion project. *Press Release*, 12 June. https://www.qatarenergy.qa/en/MediaCenter/Pages/newsdetails.aspx?ItemId=3715

[108] QatarEnergy, 2022. QatarEnergy selects Eni as its second partner in the North Field East expansion project. *Press Release*, 19 June. https://www.qatarenergy.qa/en/MediaCenter/Pages/newsdetails.aspx?ItemId=3716

[109] QatarEnergy, 2022. QatarEnergy selects ConocoPhillips as its third partner in the North Field East expansion project. *Press Release*, 20 June. https://www.qatarenergy.qa/en/MediaCenter/Pages/newsdetails.aspx?ItemId=3717

[110] QatarEnergy, 2022. QatarEnergy selects ExxonMobil as its fourth partner in the North Field East expansion project. *Press Release*, 21 June. https://www.qatarenergy.qa/en/MediaCenter/Pages/newsdetails.aspx?ItemId=3718

[111] QatarEnergy, 2022. QatarEnergy selects Shell, concludes international energy company partner selection in the NFE expansion project. *Press Release*, 21 June. https://www.qatarenergy.qa/en/MediaCenter/Pages/newsdetails.aspx?ItemId=3720

[112] QatarEnergy, 2022. QatarEnergy announces partnership with TotalEnergies in the North Field South expansion project. *Press Release*, 24 September. https://www.qatarenergy.qa/en/MediaCenter/Pages/newsdetails.aspx?ItemId=3724

[113] QatarEnergy, 2022. QatarEnergy announces the selection of Shell as a partner in the NFS expansion project. *Press Release*, 23 October. https://www.qatarenergy.qa/en/MediaCenter/Pages/newsdetails.aspx?ItemId=3731

[114] QatarEnergy, 2022. QatarEnergy selects ConocoPhillips as a partner in the NFS expansion project. *Press Release*, 30 October. https://www.qatarenergy.qa/en/MediaCenter/Pages/newsdetails.aspx?ItemId=3733

2027.[115] In addition, in the same month, QatarEnergy signed a 27-year SPA with Sinopec for 4 mtpa (DES), starting from 2026.[116] Five more SPAs for supply from NFE and NFS were signed in 2023, of which four had durations of 27 years, starting from 2026: 3.5 mtpa to TotalEnergies for DES to Fos Cavaou,[117] 3.5 mtpa to Shell for DES to Gate Rotterdam,[118] 1 mtpa to Eni for DES to the FSRU Italia at Piombino,[119] and 3 mtpa to Sinopec for DES to its terminals in China.[120] The fifth SPA was signed with Petrobangla for 1.8 mtpa for 15 years from 2026 (with no mention of a specific terminal destination).[121]

There is even overlap between Qatari and US LNG supply, insofar as QatarEnergy Trading LLC (a subsidiary of QatarEnergy) will offtake and market 70 per cent of the LNG production at Golden Pass in the United States, once the project launches in the first half of 2025.[122]

In terms of current contracts, there is a clear contrast between the more traditional Qatari SPAs (mostly DES and with final consumers as offtakers) and the more flexible supply from the United States (where even contracts with end users are generally FOB). In terms of new contracts for supply that will reach the market in 2024-2028, the contracts for supply from the United States are split 60-40 between end users and those who are likely to re-sell the volumes, with even the volumes sold to end users mostly FOB. Only a small number of contracts for new supply from Qatar have been signed so far, but they are all long-term DES, and mostly have aggregators, rather than end users (such as utilities and industrial gas consumers) as their counterparties. So far, 10 mtpa of Qatari supply from NFE/NFS is contracted DES for deliver to Europe and almost 9 mtpa for delivery to China and Bangladesh, giving a total of 18.8 mtpa of SPAs signed and almost 30 mtpa of the Qatari expansion capacity (48 mtpa) not yet contracted.

The more traditional conditions attached to Qatari LNG have not prevented several European buyers (Shell, Eni, and TotalEnergies) and one US company contractually obliged to supply the cargoes to Europe (ConocoPhillips) from signing 10 mtpa of DES SPAs for Qatari LNG that will not expire until 2053 – three years after the EU 2050 climate neutrality target. The nature of these four buyers is such that even if they cannot divert their Qatari cargoes away from Europe, they are likely to have destination-flexible contracts for LNG supply from other sources that could be diverted, if European gas demand were to decline substantially during the energy transition, perhaps leaving room for only limited volumes of gas consumption that is abated post-combustion.

8. Market outlook beyond 2030

The investment in new LNG supply that is set to reach the market in 2025-2028 would not have been approved without sufficient binding SPAs to underpin that investment (or in the case of Qatar, confidence that such SPAs will be achieved). However, to the extent that those LNG offtake agreements were signed with aggregators and traders, rather than utilities and industrial gas consumers, those aggregators and traders will face greater competition to market those supplies on the spot market, to the extent that they have not already re-sold those supplies under binding SPAs to final consumers.

[115] QatarEnergy, 2022. QatarEnergy, ConocoPhillips sign long-term supply agreement of Qatari LNG to Germany for at least 15 years. *Press Release*, 29 November. https://www.qatarenergy.qa/en/MediaCenter/Pages/newsdetails.aspx?ItemId=3738

[116] Habibic, A., 2022. Qatar and China sign 27-year LNG supply deal. *Offshore Energy*, 21 November. https://www.offshore-energy.biz/qatar-and-china-sign-27-year-lng-supply-deal/

[117] QatarEnergy, 2023. QatarEnergy and TotalEnergies sign a 27-year LNG supply agreement for up to 3.5 mtpa to France. *Press Release*, 11 October. https://www.qatarenergy.qa/en/MediaCenter/Pages/newsdetails.aspx?ItemId=3775

[118] QatarEnergy, 2023. QatarEnergy, Shell sign 27-year LNG supply agreements for up to 3.5 mtpa to the Netherlands. *Press Release*, 18 October. https://www.qatarenergy.qa/en/MediaCenter/Pages/newsdetails.aspx?ItemId=3776

[119] QatarEnergy, 2023. QatarEnergy, Eni sign 27-year LNG supply agreements for up to 3.5 mtpa to Italy. *Press Release*, 23 October. https://www.qatarenergy.qa/en/MediaCenter/Pages/newsdetails.aspx?ItemId=3777

[120] QatarEnergy, 2023. QatarEnergy, Sinopec sign historic North Field South partnership and 27-year LNG supply agreement. *Press Release*, 4 November. https://www.qatarenergy.qa/en/MediaCenter/Pages/newsdetails.aspx?ItemId=3779

[121] QatarEnergy, 2023. QatarEnergy signs a 15-year LNG supply agreement with Bangladesh. *Press Release*, 1 June. https://www.qatarenergy.qa/en/MediaCenter/Pages/newsdetails.aspx?ItemId=3758

[122] QatarEnergy, 2022. QatarEnergy Trading to offtake and market 70% of LNG produced by Golden Pass. *Press Release*, 26 October. https://www.qatarenergy.qa/en/MediaCenter/Pages/newsdetails.aspx?ItemId=3732

This is likely to result in downward pressure on prices, and could stimulate demand in markets that are able to absorb those volumes. It also highlights the key role of aggregators and traders providing flexibility to the global LNG market.

With that in mind, the outlook for the rest of the present decade appears reasonably clear, in terms of supply rising faster than demand, but with demand outside Europe being stimulated by lower prices. However, the outlook beyond 2030 is clouded by rather more uncertainty, given the debates over the future of unabated fossil fuels, especially in Europe, and the uncertainty regarding long-term LNG demand in the rest of the world. Specifically, two very different scenarios for the global LNG market post-2030 may be discerned.

The first scenario – which could be termed a 'structural imbalance' scenario – is one of significant uncertainty impacting long-term decision making, resulting in significant undersupply or oversupply. Regarding potential undersupply, the outlook for demand in the 2030s could remain subdued, based on the prospect of unabated natural gas becoming 'unburnable' in Europe and unaffordable elsewhere,123 with European buyers unwilling to commit to long-term SPAs for fear of being burdened with cargoes that they cannot use sometime between 2030 and 2040, and project developers unable to secure project financing without long-term SPAs. In such a scenario of only limited additions to global LNG supply post-2030, the market could be significantly undersupplied if European demand does not, in fact, decline faster than the combination of European production and European imports from pipeline suppliers whose own production may well have peaked by 2030, such as Norway, while demand outside Europe, spurred into growth by the expected 'supply glut' and related low prices of the late 2020s, remains robust.

Conversely, potential oversupply could occur on the basis of several factors. In Europe, gas demand could remain subdued by high prices until 2025 and then not rebound thereafter, with the energy transition then gathering pace post-2030, causing European gas demand to decline more rapidly than non-LNG gas supply to the European market. Outside Europe, a lack of infrastructure build-out that could support demand, such as pipeline transmission systems and gas-fired power stations, combined with developing countries bypassing the 'gas bridge' away from coal and moving directly to renewables, and additional supply due from projects that have already taken FID or are expected to do so in the very near future could tip the market into an oversupply in the late 2020s that lasts into the 2030s.

A second scenario – which could be termed a 'structural balance' scenario – is one in which the permanent loss of Russian pipeline gas in Europe encourages European governments to support their companies in signing long-term SPAs as a means of securing access to supplies, while a combination of prices notably higher than in the pre-2021 period and developers achieving long-term SPAs could encourage more supply-side FIDs. This process has already begun, given the supply-side FIDs and long-term SPAs discussed earlier in this paper. In this scenario, the global LNG market could grow in size, and with European LNG demand relatively secure for the next 10-15 years, the tightness of the global market could depend on growth in other markets, especially China and the developing world. This would be the 'middle path' between the significant undersupply or oversupply of the first scenario.

In either scenario, given that the new projects and expansion projects that have already taken FID and are due to hit the market in the late 2020s are already 'locked in', the size of the global LNG market in the 2030s will depend to a significant extent on how much new supply is added on the basis of FIDs taken in the next 2-3 years with the aim of 'first gas' reaching the market around 2030.

For LNG suppliers, there is a sense of a limited time window for signing long-term SPAs with European buyers, because of European requirements regarding long-term carbon neutrality. From an LNG buyer perspective, there is also a concern that if sufficient number of FIDs are not taken, then the long-term outlook post-2030 could be one of persistent under-supply in the market, providing upward pressure on prices. In contracting terms, the global LNG market currently sits in a specific time window, in which the

[123] Stern, J., 2017. Challenges to the future of gas: unburnable or unaffordable? *OIES Paper NG 125*, December. https://www.oxfordenergy.org/publications/challenges-future-gas-unburnable-unaffordable/

signing of new long-term SPAs is still possible, and many market participants feel that window could close in the next several years.

The possibility of continued (and, indeed, growing) demand for LNG in the world outside Europe – at the right price – is partly predicated on the need to displace coal in China, India, and other countries that are currently importing less LNG than might otherwise be the case due to high prices, and partly due to rapidly growing electricity demand in Asia, especially in the ASEAN countries, which also implies a need for LNG as a source of supply for gas-fired power generation. If LNG prices do eventually come back down to levels that are affordable in more price-sensitive markets, there could be a return to growth in LNG demand in developing countries. Indeed, this is already starting to happen, with buyers in India, Pakistan, and Bangladesh using tenders to secure LNG cargoes at below 15 USD/MMBtu during summer 2023, although sub-10 USD/MMBtu seems to be the pricing point at which more buyers in those countries feel comfortable coming back into the market. Given the wave of supply due to hit the market between 2025 and 2028, prices below 10 USD/MMBtu could once again become the norm, at least in summer. Whether several years of low prices amid oversupply in the late 2020s is sufficient to encourage the build-out of infrastructure that would support long-term gas demand in countries outside Europe that need to reduce coal consumption, remains uncertain.

If LNG does displace coal in Asia in the long-term, the outcome could be a ‘two-speed market', where LNG is still regarded as a relatively ‘green' fuel in developing countries, in parallel with increasingly stringent environmental regulations in Europe that could ultimately curb European demand for LNG by the mid-2030s. However, Europe's own gas production is likely to be markedly lower by the mid-2030s. The Norwegian Petroleum Directorate forecasts that Norwegian gas production will peak before 2030,[124] and there remains significant uncertainty over long-term Algerian gas production (given the factors of rising domestic demand and uncertainty over potential future production increases). Therefore, there remains uncertainty over the extent to which European gas demand will decline more quickly than non-LNG supply, thus leaving open the possibility of European LNG imports being sustained into the 2030s and only declining later.

Clearly, there is significant uncertainty in the outlook beyond 2030. On the supply side, the sheer volume of post-FID projects currently under construction mean that the dramatic growth in global LNG supply over the next five years is assured. However, in the context of a potentially oversupplied market and many countries committed to long-term decarbonisation, the likelihood of further supply-side FIDs in the late 2020s that would add to supply in the early 2030s remains highly uncertain.

On the demand side, the questions of decarbonisation in developed economies and the affordability of LNG in developing economies imply a wide range of possible demand levels by the end of the present decade, and through the 2030s. Such uncertainty on both sides of the ledger creates the potential for substantial over or under-supply on the global LNG market in the 2030s, rendering it unsurprising that market participants on either side of the supply-demand balance are looking to long-term SPAs to secure their sales or supply, and in particular, to aggregators to take on the volume risk and to destination flexibility as a ‘backstop' to guard against being over-contracted for supply into a specific market.

9. Conclusion

Since the beginning of 2020, the global LNG market has experienced unprecedented volatility, from record low prices and cargo-shut-ins in mid-2020 to record high prices in 2022. In Europe, a combination of a reduction in overall gas demand and record high LNG imports were vital in offsetting the substantial decline in pipeline gas supply from Russia in 2022 while still allowing storage to be filled ready for winter 2022/23.Those record European LNG imports caused a ripple effect in the wider global LNG market, as Europe benefitted from supply growth, a decline in Chinese LNG demand, and a decline in imports

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[124] Norwegian Petroleum Directorate, 2023. *Exports of oil and gas - Expected volumes of sales gas from Norwegian fields (1995-2035) [updated 6 October 2023].* https://www.norskpetroleum.no/en/production-and-exports/exports-of-oil-and-gas/

into price-sensitive Asian markets. The substantial share of spot purchases in global LNG trade, and destination flexibility in term contracts, were key factors in enabling that reallocation of supply in 2022.

Looking ahead, European LNG demand looks set to remain elevated for several years, and probably beyond 2030. On the supply side, substantial growth in supply on the basis of projects that have already taken FID is assured out to around 2028. Beyond that, with a large volume of potential LNG supply currently in the pre-FID stage, a key question is how to balance the interests of LNG buyers and sellers, to ensure security of supply to the European market and security of demand for project developers preparing to take FID.

While the spike in European hub prices in 2022 made oil-indexed supply attractive for a brief period, it also highlighted the risks of cross-indexation exposure. The reality is that hub indexation is dominant on the European market. With the United States as the single largest LNG supplier to the European market, the differentials between the price of US Gulf Coast FOB cargoes (largely determined by Henry Hub) and European hub prices (TTF in particular) will be key to ensuring the flow of LNG from West to East across the Atlantic. That differential will also determine the profitability of aggregators, as they offtake US LNG and sell it into the European market, and by extension, their ability to perform that role. The differential between TTF and JKM as the Asian benchmark will also influence the extent to which LNG from the Middle East flows west to Europe or East to Asia.

For some market participants, the rollercoaster of the past 2-3 years has left them more risk-averse. For others, taking on more risk may be necessary regarding cross-indexation exposure, by simply taking a position in the market rather than hedging that position, due to the higher costs of hedging. Finally, some players may be forced to reduce the volume of trading that they conduct, due to the greater financial resources needed to hold open positions (and so meet margin requirements). The net effect of these developments could be a temporary reduction in liquidity in the global LNG market, which is likely to return in the second half of the present decade, as supply volumes grow, prices fall, the market becomes less volatile, and the potential size of differentials between Henry Hub, TTF, and JKM falls.

This paper examined the key issues in the long-term supplier-buyer relationship, and the conditions that would enable two sets of counterparties to enter into a mutually acceptable term SPA. Those issues include: i) price formation; ii) contract length; iii) destination restrictions; iv) security of supply and counterparty reliability; v) risk-sharing, liability, and force majeure; and vi) stable regulatory frameworks, ESG, and carbon-neutral LNG. The resulting picture that emerged is one of both sets of counterparties (buyers and sellers) attempting to manage the near-term tight market conditions while simultaneously planning for both a much looser market from 2025 to 2030, and for a much more uncertain future thereafter, when the global LNG market could face substantial over-supply or under-supply.

In terms of challenges faced by the counterparties, near-term price volatility and uncertainty over long-term price levels mean that cross-indexation exposure is a major risk that must be managed, especially by aggregators and traders that are prepared to bear that risk in return for financial reward. In a similar vein, while project developers need long-term SPAs to underpin project finance, European buyers in particular (specifically utilities and other end users) are reticent about taking on offtake commitments that could be unsustainable if the European energy transition gathers pace and gas demand declines. Finally, given the financial implications of non-performance of contract by a counterparty, security of supply underpinned by counterparty reliability has become crucial.

These issues may be partially resolved within the framework of term SPAs, insofar as destination flexibility (with contracts being either FOB or DES/DAT with permission to divert cargoes), risk-sharing, and liability provisions can alleviate the consequences of a buyer either finding themselves over-contracted or facing an unexpected shortfall in supply. Likewise, LNG market participants are seeking assurances from European governments and the European Commission that they will not be urged into signing new term SPAs to cover current and near-term market tightness, only to find those contracts no longer commercially viable in the 2030s as more stringent environmental regulations are enacted. At present, approaches relating to emissions quantification, measurement, reporting, and verification (QMRV), carbon offsets, carbon capture and storage, 'carbon neutral' LNG, and low-carbon gaseous fuels are being developed, but it remains to be seen whether this is sufficient in a context of broader national and EU-wide emissions reductions targets.

A key conclusion to be drawn is that contractual provisions and careful selection of counterparties can only alleviate part of the risk associated with participation in the global LNG market, and especially with regard to signing term SPAs. Beyond this is the sense that not all risk can be alleviated, and that not only should the risks be borne by those in a position best suited to doing so, but also that risks should be relative to the rewards on offer for taking those risks. For example, the developer of a brownfield LNG export terminal in the United States offering a 'traditional' SPA for LNG cargoes FOB at 115 per cent of the Henry Hub price plus a 2.50-3.00 USD/MMBtu tolling fee, the risk and reward are relatively limited, even in a volatile market. Likewise, a European buyer that is able to source LNG delivered to the TTF market area at a TTF-indexed price (so that it is always comparable to pipeline supply from Norway, local production, and supply from the UK into North-Western continental Europe), the price risk is reduced, while volume risk is managed by the ability to divert cargoes to other markets.

Clearly, the risk and reward accrue to a significant extent to the aggregators and traders, especially those sourcing LNG either Henry Hub cost-plus from the United States or oil-indexed from elsewhere at a competitive slope, with arbitrage possibilities between Europe and Asia. They may have suffered during the record low prices in mid-2020 and profited from basis differentials when supplying LNG to European buyers under term SPAs at TTF-indexed prices in 2022, although the lock-in of differentials through hedging ahead of time mean that the losses and gains were unlikely to have been as great as the movement in prompt spot prices might suggest. While it is reasonable to expect the global LNG market (and the European gas market in particular) to remain tight for the next 2-3 years, and to loosen significantly when the next wave of LNG supply arrives (especially in 2025-2028), the uncertainty towards 2030 and beyond makes the current negotiation of term SPAs a challenging endeavour. In those circumstances, it would not be surprising to see market concentration, with smaller players finding the barriers to market participation more difficult to surmount than ever.

The emergence of Europe as a premium market in its own right, shedding its previous role as 'market of last resort' for global LNG, but with decarbonisation visible on a shifting horizon that could arrive much sooner or much later than expected, has intensified near-term European LNG demand without providing assurances of long-term European LNG demand. The major volume and price risks are inexorably entwined, as market participants could find themselves over-contracted in an oversupplied market or under-contracted in an under-supplied market, and thus facing prices that are too low or too high for comfort.

Between 2015 and 2022, global LNG supply rose rapidly, and the supply-long market of 2019 was tipped into oversupply by the 'Black Swan' of COVID-19 in 2020. Yet the return to a tight market just twelve months later was tipped into a European gas crisis by the loss of Russian pipeline supply in 2022, with the effects felt across the global market. Without those two major events in 2020 and 2022, it is likely that the global gas market would have seen another supply-long year in 2020 that gradually gave way to tightness out to 2025, in time for the next wave of supply. In effect, rendering the global LNG market cyclical in a manner similar to the global oil market. Indeed, the impact of unexpected and geopolitically-related events on the market also marks a point of similarity between LNG and oil. For the global LNG market, the cycle will continue from tightness in the mid-2020s to a supply glut in the latter half of the decade. But post-2030 future is more uncertain, with LNG demand in the developed economies rendered uncertain by climate policies, and the emergence of a 'two-speed' LNG market a distinct possibility.

The past five years have demonstrated the ability to the global LNG market – and its participants – to be flexible enough to cope with the challenge of substantial changes in the supply-demand balance within a relatively limited timeframe. A combination of pricing signals provided by hub-indexed supplies, suppliers and consumers responding to those pricing signals, and a mix of destination flexibility in term contracts, spot sales, and portfolio optimisation by aggregators and traders were crucial to meeting that challenge. Those are the tools that will be at the disposal of market participants as they meet the challenge of balancing supply and demand in the rest of this decade and beyond.

Returning to the central question of this paper, it may be concluded that FIDs on new supply post-2030 will only be taken in the mid-2020s if suppliers can see sufficient potential reward in return for the risk of investment in the context of an uncertain future. That will likely be demonstrated by the achievement of offtake agreements, most likely primarily with aggregators and traders. Moreover, those aggregators and traders will only take on the volume risk, by signing the SPAs that will enable new supply projects to reach FID, if they too can see a commercial reward for doing so, and an appetite from end users for long-term supply.

In that regard, the extent to which suppliers are confident enough to take such FIDs and buyers confident enough to sign the SPAs that will underpin those FIDs, will tell us much about how the LNG industry views its own future beyond 2030. The lessons of recent history will not be lost on those market participants, as they may well recall that despite the potential oversupply in the second half of the 2020s, an insufficient number of supply-side FIDs reached in the next several years could see the market tip from oversupply to undersupply in a relatively short period of time post-2030, just as it did post-2020.