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Working Paper

## LNG and UK energy security

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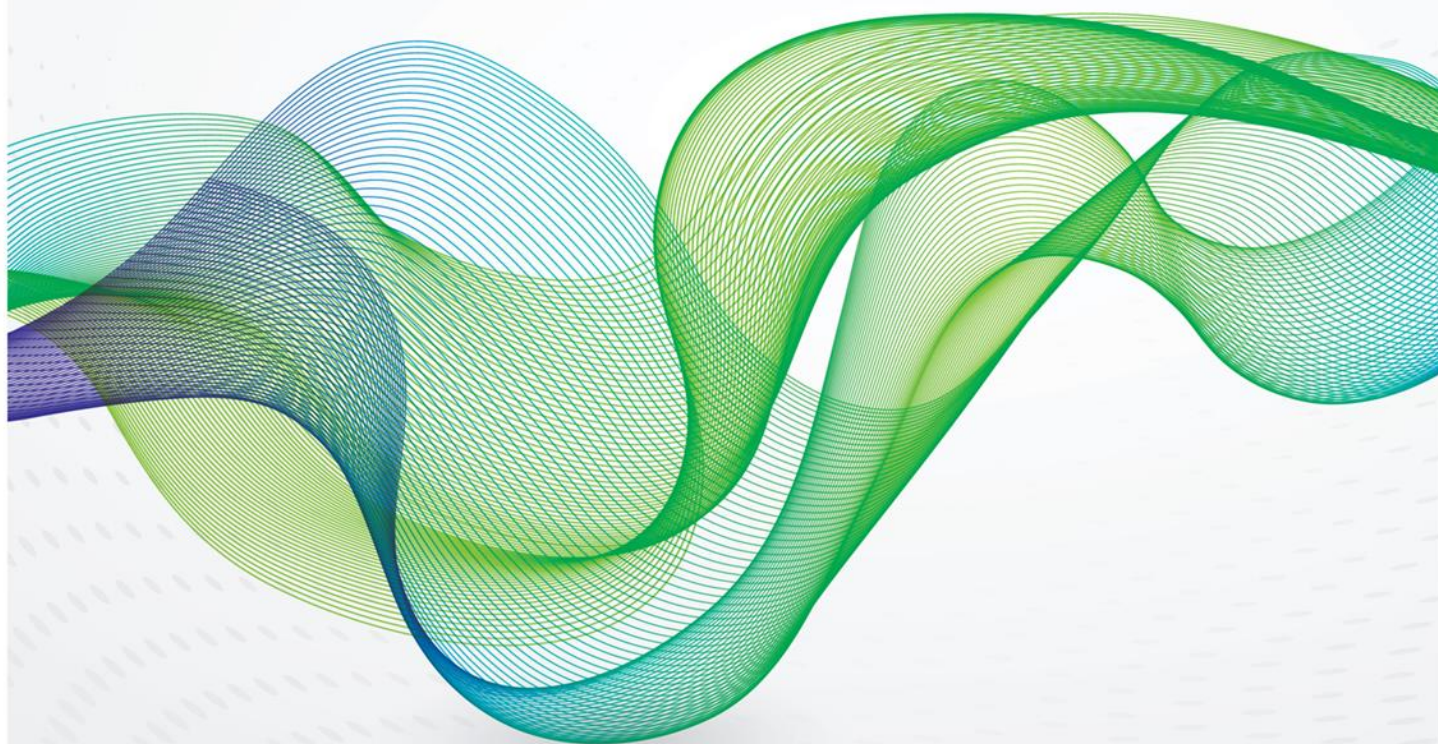
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May 2023

# LNG and UK Energy Security





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## Abbreviations and units of measurement

mcm	million cubic metres
bcm	billion cubic metres
bcf	billion cubic feet
mcm/d	million cubic metres per day
GWh/d	Gigawatt-hours per day
bcf/d	billion cubic feet per day
mtpa	million tonnes per annum (LNG)
mBTU	million BTU

## Approximate conversion factors for natural gas and LNG

### Natural gas

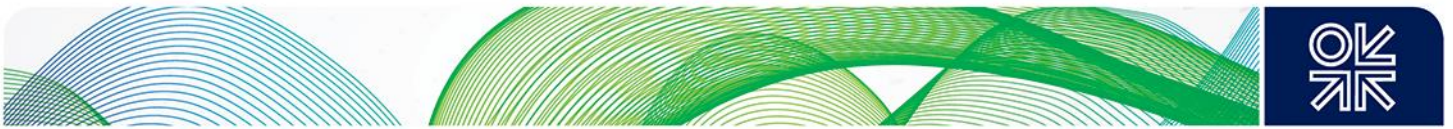
Based on an energy content of 40 megajoules (MJ) per cubic metre (cm), 1 cubic metre of gas is equivalent to 11.1 kilowatt-hours (kWh), 37,912 British Thermal Units (BTU) or 0.379 therms.

### LNG

1 metric tonne of LNG (typical density 420-470 kg/cm) is approximately equivalent in energy terms to 1.36 thousand cubic metres, 48 thousand cubic feet or 15.1 kWh of natural gas.

## Typical LNG cargo sizes

	Conventional	Mid-sized	Q Max
cubic metres LNG	140,000	170,000	265,000
metric tonnes LNG	62,020	75,310	117,395
cubic metres natural gas	84,350	102,420	159,660
trillion BTU	3.20	3.88	6.05
million therms	32.0	38.8	60.5



## Preface

The Oxford Institute for Energy Studies (OIES) is delighted to partner with UKERC in the publication of this paper on the role of LNG in UK energy security. Even before the war in Ukraine which began in February 2022, the UK had become increasingly reliant on LNG imports to support a domestic gas industry where production is in long-term decline and where storage is in short supply. The risks of this strategy have been illustrated by the turmoil in the global gas market caused by the sharp reduction in Russian pipeline gas exports to Europe. The UK, with its ample LNG import facilities, has not been short of gas and indeed has even acted as a land-bridge to continental Europe via its interconnectors, but it has suffered from high prices and the risks associated with increased global competition in a tight market. This report, written by Marshall Hall, who is a Senior Research Fellow at OIES, addresses the challenges that this new environment poses and provides recommendations on policy and regulation that can help to provide greater flexibility and security in a gas market where the need to secure supply over the longer term can be hampered by market design and by the risks inherent in the energy transition. We think that it is an important contribution on a vital topic as the UK plans its energy strategy for the next decades.

James Henderson,  
Head of Gas Research, OIES

## UKERC Research on UK Gas Security

The UK Energy Research Centre (UKERC) has studied the question of UK gas security for a number of years. Our research started in Phase-2 of UKERC and was stimulated by the UK's growing gas import dependence as domestic production fell faster than demand. We explored how the growing reliance on LNG imports had the potential to expose UK consumers to price volatility. However, the Government was satisfied that the country had sufficient physical infrastructure and a diversity of source of supply to ensure gas security. Nevertheless, it was recognised that the UK's gas market is dependent on price signals to attract the gas imports needed to meet demand. In Phase-3 of UKERC we turned our attention to the changing role of natural gas in the UK's energy system and suggested that more needed to be done to understand and manage the consequences of the expected decline in UK gas demand in line with decarbonisation targets, what we called 'gas by design.'

When Phase-4 of UKERC was commissioned in 2018-19 we determined that more research was needed to understand the role of LNG in the UK's gas security. The current report is the result of collaborative work between UKERC and OIES to fill this research gap. This turned out to be prophetic as the post-pandemic energy price crisis and Russia's war in Ukraine have underlined that the global LNG market and the UK have played a crucial role in delivering LNG to Europe. For those in the industry, much of what is in this report will not be new, but the current gas crisis has focused minds on the role of LNG and policy makers have had to scramble to understand the complexities of the global LNG market that now underpins Europe's gas security. This report provides an essential insight into the role that LNG plays in the UK's gas security and also identifies the challenges that policy makers need to address to ensure security of supply.

Professor Mike Bradshaw, Warwick Business School  
Co-Director UKERC



## Executive Summary

The Russia-Ukraine crisis of 2021-22 dramatically revealed the consequences of the changes to European wholesale gas price-formation in the last decade and exposed both the strengths and weaknesses of UK energy markets and public policy towards energy security and the affordability of gas and electricity. The valuation of uncontracted spot LNG in a commoditised global market is now the key price-setting mechanism for NBP wholesale prices and, indirectly, regulated retail gas prices – and a major influence on the need for public financial support for some UK energy consumers.

The composition of UK gas supply is unbalanced and over-dependent on attracting non-storage supply sources, especially LNG. Domestic gas production from the UKCS is the central pillar of UK gas supply security but it cannot produce more to meet peak winter demand. LNG is now the dominant source of flexible supply needed to meet peak demand given the UK's very limited seasonal gas storage capacity. The UK is now more exposed to short-term LNG markets since UK shippers and suppliers with limited access to storage cannot easily exploit periods of weaker LNG demand and lower prices to build stocks. Firm long-term LNG supply contracts are seldom financially attractive or sustainable for UK buyers.

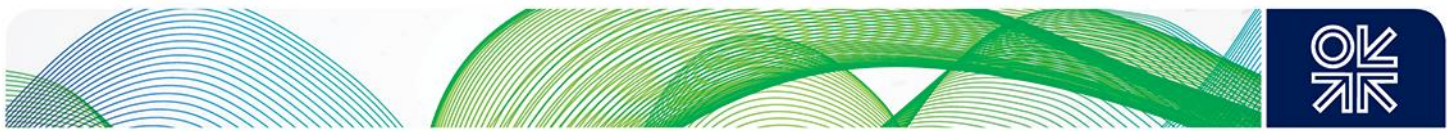
The UK's existing investment in LNG regas capacity gives good access to global LNG markets but in the absence of firm term supply contracts exacerbates price risks in meeting peak winter demand by depressing returns for storage operators. Access to more gas storage capacity and higher pre-winter stocks would reduce winter price risks to UK consumers and allow existing UK regas capacity holders to better exploit fluctuations in LNG prices. Former UK access to EU seasonal storage capacity via interconnectors may be restricted by new mandated stockholding obligations on EU suppliers.

After the creation of the new Department of Energy Security and Net Zero and the passing of the worst of the gas price crisis, the time is ripe for a fundamental review by the government and Ofgem of UK energy security to learn the lessons of the crisis and to ensure that both security and affordability are fully incorporated into policy design and regulation in the energy transition. Since natural gas and LNG will be essential to ensure a secure and affordable energy transition, more attention needs to be given to aspects of UK wholesale gas supply and market functioning, in particular UKCS taxation, gas storage and pre-winter stockholding, the UK's high network entry costs and third-party access to UK regas capacity in all market circumstances.

The UK now faces a period of more intense competition for LNG, not only from Asian economies where gas demand and imports are still growing, but also from European markets previously dependent on Russian supply. The competitive design of the UK wholesale and retail gas markets hampers the capacity of UK suppliers to buy imported gas under long-term contracts as buyers in Asia and parts of Europe do.

Policy and regulation should be better designed to ensure the UK's regas terminals remain competitive within Europe as a destination for *uncontracted* LNG as EU countries expand their own regas capacity. The flexible NTS network is a valuable asset in ensuring supply security but NTS users face the highest network entry costs among major European gas markets. A number of long-standing regulatory issues over the fairness and stability of NTS entry capacity charging, national gas quality specifications (GSMR) and NTS capacity constraint management remain unresolved. Together these may act as a barrier to marginal LNG imports just as the UK is making new investments in regas capacity at the two largest terminals and in incremental capacity on the NTS to accommodate more LNG at Milford Haven.





## 1. Introduction

This paper, commissioned originally in 2019, continues a series of UKERC papers published since 2014 on the recurring issue of UK gas supply security and affordability. It extends the supply chain analysis of earlier papers to focus on the contribution of Liquefied Natural Gas (LNG) to gas and energy supply security, conceived as both physical availability and the affordability of gas for UK consumers. Any discussion of gas supply security and the design of government policies towards gas should incorporate both physical and economic aspects since the physical supply of gas cannot be divorced from wider economic consequences arising from gas price volatility, as the energy price crisis of 2021-22 has dramatically illustrated. Physical gas supply to the UK market was adequate at all times in 2021 and 2022 but the economic damage done by the dramatic increase in international and domestic wholesale prices intensified progressively, prompting unprecedented UK government financial intervention in 2022 to protect energy consumers.

The scope of this paper is restricted to the supply of LNG to the GB wholesale gas market. It does not seek to provide a comprehensive assessment of the adequacy of the current arrangements to secure gas supply to UK consumers or to avert a network gas supply emergency arising from an interruption of supply at a gas terminal or the transportation of gas on the National Transmission System (NTS). However, it does offer some conclusions and recommendations on the content of well-designed policy and regulation regarding UK energy security. The paper does not include an assessment of the recent deficiencies of the regulation of the retail gas market but it does discuss how the competitive wholesale and dysfunctional retail market have undermined the ability of gas suppliers to sign firm term gas supply contracts.

The aim of this paper is more modest: to describe the critical role that regasified LNG plays in the GB wholesale gas market and its contribution to supply security and to explain why, under current commercial arrangements, LNG flows to the UK are so variable and why they may not always be immediately available to the wholesale market at times of domestic supply tightness<sup>1</sup>. It examines the three key elements in the commercial supply chain and describes how each element may facilitate, or hinder, the supply of re-gasified LNG to GB consumers:

- the operation of the global LNG market and the contractual arrangements under which LNG is delivered to the UK
- the capacity and flexibility provided by the three existing LNG import terminals and how this capacity is contracted, traded and utilised
- the availability and cost of network entry capacity on the NTS, investment in new capacity and the operation of the transmission network.

The paper deals with each of these three elements in turn, starting with the LNG market (Chapter 2) before discussing the three UK LNG regas terminals (Chapter 3) and concluding with the interface between LNG terminals and the NTS (Chapter 4).

### 1.1 What is LNG?

Liquefied natural gas (LNG) is produced by cooling natural gas to a temperature of about -162 °C so that it is converted into a liquid for ease of transport and storage. The process of liquefaction reduces the volume of the natural gas by a factor of about 600. As a cryogenic (ultra-low temperature) liquid, LNG must be transported and stored in containers which are insulated from heat to prevent the liquid

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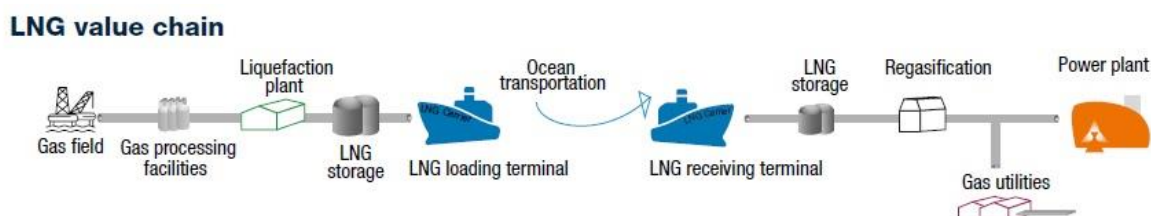
<sup>1</sup> The wholesale market, regulated by Ofgem, covers Great Britain but excludes Northern Ireland which forms part of the all-Ireland single energy market for gas and electricity. The UK has entered a series of undertakings to ensure gas supply security for Northern Ireland and the Republic.



vaporising. Seaborne cargoes of LNG are delivered in specially designed vessels to receiving terminals where the liquid may be stored until the energy is needed in gaseous form. Regasification through heating converts the liquid back into a gas for delivery into a pipeline or gas transmission network or direct to a consumer<sup>2</sup>.

LNG is mainly liquefied methane but varies in its hydrocarbon composition, density, gross energy content and the related Wobbe Index. The variation arises mainly through the differences in the composition of the feed gas and the extent of any extraction of ethane, propane and heavier compounds before liquefaction. The methane content of LNG typically varies between 87% and 97% by volume<sup>3</sup>. Although the quality variation of traded LNG is not as great as that of crude oil, the fungibility or interchangeability of LNG is sometimes restricted by the particular gas quality specifications in national downstream markets, as it is occasionally by the compatibility of LNG vessels and regas terminal facilities (or 'ship-shore compatibility').

**Figure 1: Schematic LNG supply chain**



Source: [www.liquefiedgascarrier.com](http://www.liquefiedgascarrier.com)

LNG is traded and reported in mass (tonnes), in volume (cubic metres) and as energy (million BTU, GWh or therms). European gas wholesale markets trade gas as energy (therms or MWh) and supply and demand flows are reported in volume (million cubic metres per day) or as energy (GWh/day). In this report, we follow common industry practice in recording LNG trade and LNG liquefaction and regasification capacity primarily in million tonnes per annum (mtpa), LNG storage capacity primarily in volume (cubic metres) and send-out, delivery and supply of gas in both volume (million cubic metres per day) and energy (GWh/day). A summary of the main units of measurement and standard conversion factors for LNG and natural gas is set out on page 2.

## 1.2 UK decarbonisation targets and the role of gas

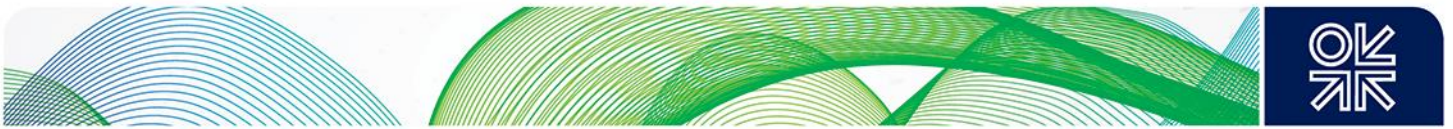
The adoption in legislation in 2019 of a net zero target for UK territorial GHG emissions in 2050 and the incorporation of the Sixth Carbon Budget in UK law in 2021 shifted the emphasis of government activity and energy policy towards decarbonisation<sup>4</sup>. However, it is not yet clear how these new demanding objectives are to be met and it may not be evident for several more years since exploration of technical, economic and policy options is still going on. In particular, it is not clear how the more stringent emission reduction targets are to be reconciled with the two other existing policy objectives of energy security and affordability brought to the fore so dramatically in 2021-22. Progressive reform of energy system operation and ownership, energy code governance and regulatory responsibilities is expected to accompany this shift in energy policy but the process of reform is at an early stage. The government confirmed in April 2022 that it will create by 2024 a new Future System Operator (FSO), separate from National Grid, with responsibilities in both electricity and gas in order to avoid conflicts of interest and to facilitate decarbonisation<sup>5</sup>. In a separate decision, in March 2022, National Grid confirmed the sale

<sup>2</sup> Basic Properties of LNG, Information Paper no. 1, GIIGNL, 2019 provides a thorough introduction to LNG.

<sup>3</sup> The characteristics of major LNG sources are set out in the GIIGNL Annual Report 2018, page 27.

<sup>4</sup> The Sixth Carbon Budget for 2033-27 was proposed by the Climate Change Committee in December 2020, accepted by the government in April 2021 and enshrined in UK law in June 2021.

<sup>5</sup> 'Future System Operator: Government and Ofgem's response to consultation', Department for Business, Energy and Industrial Strategy (BEIS) and Ofgem, April 2022.

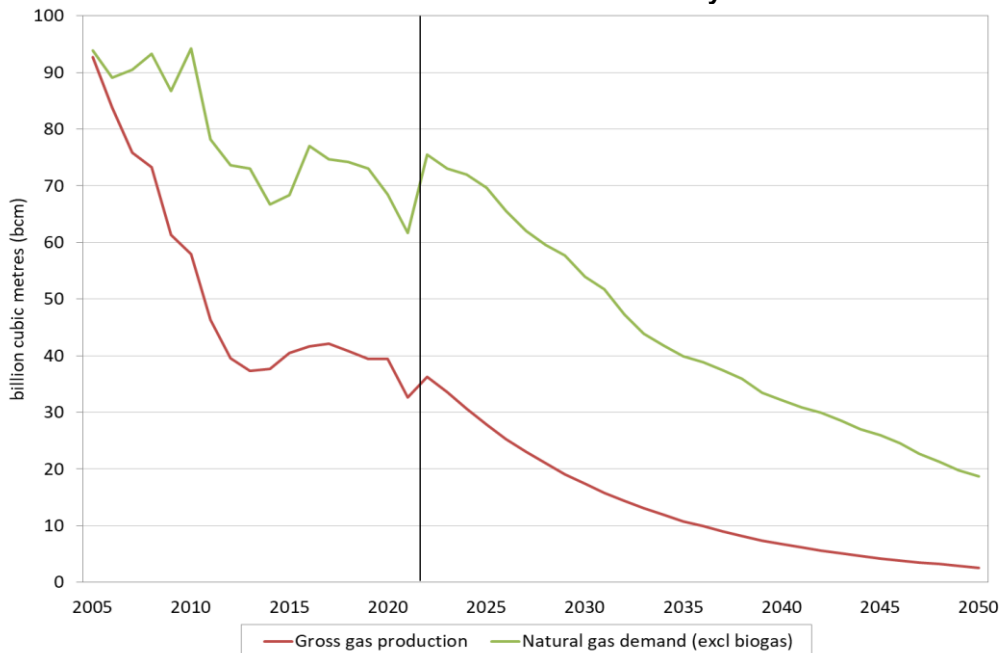


of 60 per cent of its stake in National Grid Gas Transmission (NGGT) and an agreed option to sell its remaining stake as part of a ‘strategic portfolio repositioning’<sup>6</sup> to focus on electricity. The first phase of the sale to private infrastructure investors was completed on 31 January 2023<sup>7</sup>.

The intended decarbonisation of the UK economy is being accompanied by an industry-wide effort to ‘decarbonise gas’ by replacing natural gas progressively with low-carbon gases such as hydrogen and biomethane in end-use sectors, by developing carbon capture, utilisation and storage (CCUS) and by adapting or converting parts of the transmission and distribution networks to such low-carbon gases. The gas industry has begun to investigate what may become a major transformation over the next 20 years in which the unabated use of natural gas and its share of *final* energy demand gradually decline but natural gas will retain a major role in *primary* energy supply, hydrogen production, energy storage and in providing energy system flexibility. The potential for hydrogen use in heating, industry and electricity generation, and the scope for re-purposing parts of the gas transmission and distribution networks will only be clearer once the technical and economic appraisal projects launched by National Grid and other network operators have been completed in 2024, ahead of major decisions on hydrogen currently expected in 2025-26.

It is not the aim of this paper to present projections of how the de-carbonisation of gas will proceed since the evolution of technology costs, government policies, the scale of CCS deployment and the competitive position of UK energy-intensive industry are still all highly uncertain. However, it seems very likely that the UK will be consuming, producing and importing natural gas until at least 2040 and probably well beyond. LNG imports are equally likely to be a significant part of gas supply to the UK given the expected resumption in the 2020s of the decline in UKCS gas production. Figure 2 shows the projections of UK gas demand in the Balanced Pathway to Net Zero produced by the Climate Change Committee (CCC) and the projections of future UK gas production from the North Sea Transition Authority (NSTA), formerly the Oil and Gas Authority (OGA). The demand for gas includes use of natural gas in hydrogen production with CO<sub>2</sub> capture and storage (blue hydrogen) but excludes biogas; the production projections include expected development of existing discovered resources and future discoveries.

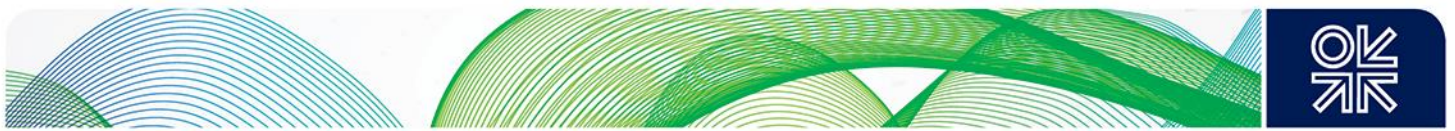
**Figure 2: UK Gas Production and Demand in Balanced Pathway to Net Zero**



Source: North Sea Transition Authority, CCC Sixth Carbon Budget

<sup>6</sup> ‘Sale of majority interest in NGGT and Metering’, National Grid press release, 27 March 2022.

<sup>7</sup> NGGT was purchased by a consortium of Macquarie Asset Management and British Columbia Investment Management Corporation; the implied enterprise value of the deal was about £9.6bn.



The central message of these projections is that throughout the period to 2050, the UK needs imported gas to meet demand. Import demand declines progressively from about 45 bcm in 2021 to about 15 bcm in 2050 and the degree of import dependence rises gradually from about 55% to 85% in 2050. Since some sources of LNG are among the lowest-cost suppliers of gas to NW Europe, and it is currently unlikely that large-scale Russian pipeline supply to Europe will resume, LNG is expected to make up a significant but fluctuating share of UK gas imports for the foreseeable future. These projections of future annual gas demand and supply do not capture an essential element in the intended decarbonisation of the UK economy, namely the provision of seasonal, daily and intra-day flexibility. Natural gas has been for decades the default marginal fuel in the UK economy, meeting any unexpected fluctuations in the demand for energy in heating and electricity generation arising from economic cycles, demand shocks and weather events and, increasingly, providing the flexibility in electricity generation to meet the variations in wind and solar output as more intermittent low-carbon capacity is connected to the grid. In other words, natural gas provides the back-up and flexibility demanded by UK consumers both in annual energy balances and in half-hourly electricity wholesale markets. If UK decarbonisation is to proceed at the intended pace and at acceptable cost, natural gas will have to continue to provide this source of flexible supply until economic low-carbon alternatives such as hydrogen or battery storage are deployed at sufficient scale. Therefore, at present, only natural gas can ensure a smooth and affordable UK energy transition. Ensuring a secure and affordable supply of gas to the UK wholesale market must underpin this ambitious transition.

An unintended consequence of the adoption since 2019 of more demanding climate targets in the UK and the EU is that there is less visibility and more uncertainty over future demand for natural gas. When considering whether to deploy further capital in upstream gas production and infrastructure, resource holders supplying the European market by pipeline now face additional commercial risks. For prospective producers, volumetric demand risk has clearly increased. If ambitious de-carbonisation targets are met, end-use demand for gas may not exist in 15-20 years in some markets. This process may even be accelerated by initiatives such as RePowerEU and the political ambition in much of Europe to end dependence on Russian gas. Furthermore, as de-carbonisation proceeds, upstream gas producers may face lower netbacks and lower financial returns through the additional costs of converting natural gas to blue hydrogen or restrictions on their commercial access to capital and a higher cost of capital.

Decarbonisation does not seem to have damaged the prospects for LNG production and trade. On the contrary, the scope for the displacement of coal in power generation in Asia was widely expected to sustain the growth in Asian LNG demand and the development of LNG liquefaction projects even before the Russian re-invasion of Ukraine in 2022. Since the invasion, Europe's determination to replace Russian supply has entailed a step-change in the demand for both uncontracted LNG, driving spot prices higher, and term contract supply, which will underpin the sanction of new liquefaction projects around the world. The intrinsic flexibility embedded in seaborne LNG means that producers and developers do not face the same market risks as pipeline suppliers. This flexibility may offer some assurance to UK energy consumers, given the extensive existing investment in the UK's LNG import terminals, but it also highlights the international competition the UK will face to secure supplies of LNG.

### 1.3 Gas security of supply: legislation, regulation and policy

The primary responsibility for UK energy security of supply lies with the government but, in the case of gas and electricity, the responsibility for delivering this public good is in practice shared with Ofgem, the independent regulator, and National Grid Gas (NGG), the privately-owned operator of the national transmission networks<sup>8</sup>. Regulation of the downstream gas industry is the legal responsibility of Ofgem which has powers to grant licences to gas transporters, shippers and suppliers. This shared

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<sup>8</sup> The sale by National Grid PLC of 60% of its stake in National Grid Gas (NGG) was completed on 31 January 2023 after regulatory approval. NGG was immediately re-named 'National Gas Transmission' but the term 'NGG' has, for the sake of convenience, been retained in this report.



responsibility for security of supply is reflected in the provisions of the Energy Acts 2004 and 2011 which require that BEIS and Ofgem jointly report to Parliament annually on the availability of gas and electricity to meet the reasonable demands of consumers in the GB market<sup>9</sup>.

The licences granted by Ofgem include conditions that require the holder to meet standards designed to promote secure and safe supply of gas and to comply with the gas industry code, the Uniform Network Code (UNC). NGG, the owner and operator of the National Transmission System (NTS), is obliged by the terms of its Gas Transporter's Licence as Gas System Operator to ensure that the NTS is capable of meeting 1-in-20 peak day demand<sup>10</sup> and that it has sufficient capacity and resilience to meet this peak demand even after the failure of the largest single piece of infrastructure, the so-called N-1 test. The operation of gas pipeline networks and interconnectors is a licensed activity but the operation of an LNG import terminal, like a beach terminal for offshore production, is not licensed.

The emphasis of the licence obligations on the System Operator is on the *capacity* and capability of the gas infrastructure and the efficient operation of daily balancing of the market through commercial incentives. There is little mention of the *supply* of gas which is viewed as an entirely commercial matter which is resolved through the operation of the gas market. Indeed, UK gas security of supply depends above all on the efficient functioning and liquidity of the wholesale gas market at the National Balancing Point (NBP) and the daily balancing activity of NTS shippers. NBP market liquidity is particularly important in the UK for attracting sources of flexible supply which can go to alternative markets, given its low level of underground storage capacity and the dependence on non-storage supply to meet peak winter demand. The UK is currently unique among major European gas markets in having very little underground storage capacity, no supply or stockholding obligations on importers, shippers and suppliers and no publicly-funded or strategic gas stocks<sup>11</sup>. The risks to which UK consumers have become exposed by this unbalanced pattern of gas supply and dependence on uncontracted LNG suddenly became apparent only in 2021-22.

The only recent legislation dedicated to gas security of supply was the EU Regulation on Gas Security of Supply (2017/1938) which sought to introduce a common EU-wide approach to supply and infrastructure standards and to promote collective security through regional gas-sharing arrangements during a gas emergency. When the UK left the EU, parts of this legislation were retained in UK law but other obligations were discarded. The N-1 infrastructure test, designed to ensure that peak demand can be met after the loss of the largest piece of infrastructure, has been retained in modified form in the annual Gas Winter Outlook published by National Grid<sup>12</sup>.

Gas supply security has been a perennial concern of UK government policy since UKCS gas production began to decline in 2000. Since 2010, BEIS, or its predecessor DECC, has commissioned or undertaken no less than six reports on gas supply security. Although the context for each report has been slightly different and the conclusions have varied in emphasis, the government has continued to adopt a non-interventionist stance, relying on the operation of competitive international and domestic markets to deliver both gas infrastructure and gas supply as and when needed. In particular, it has not been persuaded to intervene in commercial storage provision through investment incentives or to introduce minimum stockholding obligations familiar for more than 40 years in the UK market for oil products.

In 2012-13, the government rejected detailed proposals for financial measures to mitigate commercial risk and to promote the development of new underground gas storage capacity. In 2017, it accepted the arguments presented by Centrica to close the Rough seasonal storage facility on economic grounds and declined to support investment at the facility or the development of replacement capacity. At the time, Rough accounted for 3.3 bcm or 70 per cent of UK underground storage capacity and was capable of delivering up to 45 mcm/d. Rough returned to limited operation in 3Q 2022 after the Russian invasion

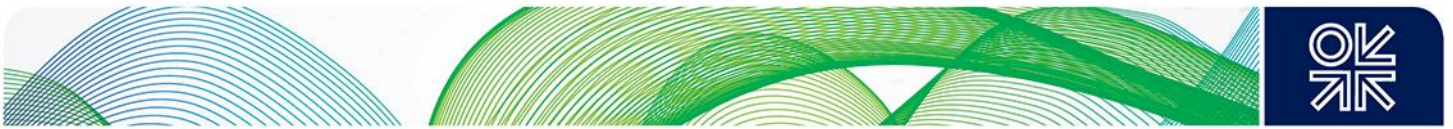
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<sup>9</sup> Statutory Security of Supply Report 2022, BEIS, December 2022

<sup>10</sup> 1-in-20 peak day demand is defined as demand on the coldest day in winter in the coldest winter expected once in 20 years.

<sup>11</sup> Underground storage capacity is currently only 2.4 bcm, including an estimated 0.8 bcm at the recommissioned Rough storage site, little more than 3 per cent of annual gas demand.

<sup>12</sup> Gas Winter Outlook 2022-23, National Grid, 23 October 2022



of Ukraine<sup>13</sup>. Negotiations have continued into early 2023 between the government and Centrica Storage over possible consumer-funded financial support to remunerate further investment in the Rough facility and to restore capacity to 1.6 bcm in 2023-24<sup>14</sup>.

It has remained a central tenet of government policy that gas supply at prices acceptable to UK consumers is best secured by commercial participants operating freely in competitive markets without government intervention. Although the approach of successive governments in the last decade has been consistent, it has largely overlooked the fundamental changes in European gas supply and in NBP price-determination in the last decade and the rising risk of unacceptably high prices for UK consumers. Governments have preferred to rely entirely on domestic production from the UKCS and the operation of the NBP market to attract LNG and pipeline gas from Norway and the EU as and when needed. After the economic shock of the Russia-Ukraine crisis and the exposure of the public finances to wholesale gas prices through the Energy Price Guarantee since October 2022, some form of policy intervention over gas storage now appears politically feasible.

The government's most recent annual Statutory Security of Supply Report, published in December 2022, emphasises the diversity of gas supply sources and the reliance on competitive markets to ensure adequate supply. However, unsurprisingly, given the loss of Russian supply to Europe and the unprecedented rise in NBP prices in 2022, it failed to evince the same confidence as the previous year's report 'that security of gas supply will be maintained thanks to the diversity of our supply sources and the existing market mechanisms'<sup>15</sup>. In the narrow definition of security of supply preferred in such reports, UK security of gas supply had been maintained in 2022; the UK did not face the loss of physical supply and the threat of gas rationing experienced in continental Europe. However, on a wider definition, which includes the impact of high GB wholesale gas and electricity prices on consumers and the public finances, the earlier confidence had been misplaced. In other words, to concentrate only on physical supply and to pay no regard to the level of prices and price-formation is to disregard the economic harm that public policy and regulation are surely intended to mitigate.

The period since the beginning of the Russia-Ukraine crisis has been marked by unusual UK political instability and changes of personnel within government yet major energy legislation continues its passage through Parliament and successive governments have adopted political and diplomatic initiatives, but not yet new legislation, to address the issues of short-term energy security. Following the publication of the 'British Energy Security Strategy' in April 2022, the government introduced a new Energy Bill to Parliament in July 2022<sup>16</sup>. The broad aim is to promote decarbonisation and to provide the basis for future private investment in hydrogen, CO<sub>2</sub> storage and new nuclear by reforming energy sector licensing and regulation while extending current domestic consumer price protection. It is the largest legislative package in the energy sector since the Energy Act 2013 and draws on several government publications since the adoption of the net zero target in 2019. The aim of greater UK energy production in the Bill is a long-term objective to be achieved by increasing domestic renewable and low-carbon generation capacity.

In September 2022, the government established an internal 'energy supply task force', intending, it seems, to begin negotiation with gas-exporting countries such as Norway, Qatar and the US for long-term supply contract supply<sup>17</sup>. Little of substance emerged from this initiative. In the UK market, gas supply purchasing remains the responsibility of private companies and any government intervention would run the risk of undermining the principle of fair competition which underpins the market. The focus of the energy task force then appeared to switch, appropriately, to domestic infrastructure and regulation over which the government and Ofgem have direct authority.

The current government that took office in October 2022 has so far given few indications as to whether the Russia-Ukraine crisis will lead to a re-appraisal of its central tenets of energy security policy in the energy transition. The focus in 2022 has understandably been on the short-term protection of retail

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<sup>13</sup> In July/August 2022, Centrica's storage licence was renewed and Ofgem approved a TPA exemption, allowing Rough to operate with capacity of 0.8 bcm in 2022-23 and 1.6 bcm in 2023-24. Injections resumed in 3Q 2022. Since its cushion gas has been largely depleted, its contribution to winter supply in 2022-23 is expected to be limited to 4-6 mcm/d.

<sup>14</sup> 'Breakdown of gas storage talks leaves UK exposed to price surges', Financial Times, 5 February 2023.

<sup>15</sup> Statutory Security of Supply Report 2022, BEIS, December 2022.

<sup>16</sup> British Energy Security Strategy, BEIS, 7 April 2022

<sup>17</sup> 'UK struggles to secure long-term gas import deals' Financial Times, 8 November 2022.



consumers, not on longer-term supply-side measures, gas storage, demand-side management, energy efficiency, regulation or wholesale electricity market reform. As the draft Energy Bill continues its passage through Parliament in 2023, proposed amendments may seek to introduce some of these matters into the legislation.

In February 2023, the government announced that the existing government department BEIS, created only in 2016, would be broken up and its two main areas of responsibility, energy and business, would once again be separated. In what may mark a significant reform of the machinery of government, a new Department for Energy Security and Net Zero (DESNZ) was created with responsibility for both energy and climate change. Although a change of departmental name will not itself be enough to raise the profile of energy security in government thinking and action after years of benign neglect, there is now at least the promise that security, energy sector regulation and market operation will command more ministerial time and attention in the energy transition.

In March 2023, the new department published its latest plan on UK energy security<sup>18</sup> alongside the more detailed Net Zero Growth Plan. The Energy Security Plan claims the government has ‘learnt from the experience’ of the Russia-Ukraine crisis and acknowledges the opportunity to ‘improve UK energy security’ and to ‘reduce the risk of higher bills’. However, it does not set out any new concrete policy proposals regarding gas and energy security and rejects any suggestion of a change to its strategic approach. The Plan announced that DESNZ will publish an update of ‘the role of gas storage and other sources of flexibility’ in the autumn of 2023. It also confirmed that the new Future System Operator (FSO) will have a statutory mandate to ensure security of supply of both gas and electricity and will be responsible for a new medium-term Gas Supply Security Assessment. How the new FSO’s responsibilities will relate to those of DESNZ, Ofgem and National Gas Transmission (NGT) is not specified. The passage of the current Energy Bill may shed light on some of these unresolved issues.

#### 1.4 Brexit, retained EU law and regulatory alignment

The UK left the EU’s single market and Internal Energy Market (IEM), governed by the EU Network Codes, when it left the EU and the jurisdiction of the European Court of Justice (ECJ)<sup>19</sup>. Since both the EU and UK recognised the mutual benefit of maintaining free trade in energy, they agreed a comprehensive Trade and Cooperation Agreement (TCA) in December 2020, at the end of the transition period. Title VIII of the TCA covers energy, including gas and electricity, and sets out the basis for the continuation of free trade and the maintenance of competitive markets, non-discriminatory access to networks and co-operation between TSOs and regulators. The parties agreed not to endanger the energy security of the other but each party preserved the right to take measures to protect its own energy supply. The Russia-Ukraine crisis has highlighted in 2022 the benefit to the EU of interconnector gas pipeline imports from the UK<sup>20</sup>. The long-standing benefit to the UK of interconnector imports from the EU to meet peak winter demand may not be as evident so long as the tightness in European gas markets persists.

Significantly, Title VIII of the TCA includes a termination date of 30 June 2026, after which its terms will be reviewed and may be revised or allowed to expire. This raises the possibility of some regulatory divergence and new, perhaps unintended, barriers to trade in gas and electricity after 2026, particularly if the UK and EU adopt different regulatory approaches to decarbonisation. For example, in December 2021, the European Commission published its proposals for a new EU Regulation and Directive on Gas and Hydrogen which, if adopted, would be implemented in 2024-25. Unless the UK revises its own regulations and Network Codes to mirror new EU legislation, the two regulatory regimes may begin to diverge at this point.

In anticipation of Brexit, BEIS prepared a package of secondary legislation under the powers of the EU Withdrawal Act 2018 to amend domestic legislation and retained EU law to ensure it would function effectively even without a withdrawal agreement. These changes ensured legal continuity and sought to maintain confidence in the regulatory framework for energy trading. In the area of gas and electricity,

<sup>18</sup> ‘Powering Up Britain: Energy Security Plan’ and the accompanying ‘Net Zero Growth Plan’, HM Government, 30 March 2023.

<sup>19</sup> The UK left the EU on 31 January 2020 and the transition period ended on 31 December 2020.

<sup>20</sup> In summer 2022, UK exports via Interconnector and BBL were close to capacity of 75 mcm/d, making the UK the second-largest external gas supplier to the EU after Norway in the main period of storage injection.



BEIS retained the bulk of existing UK law originally enacted to comply with EU Directives and transposed most of the content of EU Regulations into UK law to ensure regulatory alignment for the immediate post-Brexit period. In some specific areas, it was more selective, discarding some aspects of EU Regulations particularly where they overlapped with existing UK arrangements or were deemed to be inappropriate. In the case of the EU Regulation on Gas Security of Supply (2017/1938), the UK government retained parts related to the infrastructure standard but discarded those which prescribed regional, intra-EU arrangements for gas-sharing at times of a gas emergency in preference for more market-based mechanisms. The existing bilaterally-agreed gas supply obligations to Ireland remained intact and unaffected.

The UK continued to revise its domestic Uniform Network Code (UNC) governing gas to comply with the EU Gas Network Codes (NCs) even after the UK had left the EU in January 2020<sup>21</sup> since it undertook to transpose EU law into UK law before it left the single market in order to minimise the risk of post-Brexit disruption to cross-border energy trade. In the area of carbon trading, the UK chose to adopt its own UK ETS separate from the EU ETS and is not, at present, linked to it. However, as far as gas trade and wholesale gas market trading is concerned, the two regulatory regimes remain closely aligned, albeit now under different legal jurisdictions. Since Brexit, the three gas interconnectors between the UK and Belgium, Netherlands and Ireland have continued to operate without any discernible disruption but the uncertainty over future regulatory divergence will persist and may hamper future investment. The UK's LNG terminals, like other sources of gas supply, have been largely unaffected by Brexit since they fall outside the scope of licensed activities and have always operated under exemptions from regulated third party access (TPA) under both UK and EU law.

The potential impact on gas markets of the introduction of the controversial Retained EU Law (Revocation and Reform) Bill (REUL) in September 2022 is, at present, far from clear. The bill passing through Parliament sets a deadline of the end of 2023 to 'review or revoke' about 4,000 pieces of secondary UK legislation that derive originally from EU law. Any such law that is not 'reviewed or revoked' by the deadline would automatically lapse, raising the prospect of UK-EU regulatory divergence. It is not yet clear whether such laws governing energy trade within the scope of the TCA will be exempt from the REUL. The exemptions from TPA at the UK's LNG terminals mean that LNG imports are very unlikely to be affected but the efficiency of UK-EU interconnector trade may be at greater risk.

### 1.5 Role of LNG in gas supply and provision of flexibility

UK gas supply to the wholesale market comprises domestic production from the UK Continental Shelf (UKCS), Norwegian pipeline supply, LNG imports, supply through the bi-directional interconnectors from the continent and domestic storage supply. The changing composition of UK annual gas supply since 2010 is shown in Figure 3. Gas production from the UK Continental Shelf (UKCS), mainly from the North Sea, has stabilised since 2013 at about 40 bcm per annum but is set to resume its gradual decline in the 2020s as new gas developments such as the Jackdaw field will not be sufficient to offset the decline from mature fields. UKCS gas supply is subject to occasional interruptions and disruption through planned offshore maintenance, as seen in summer 2021, but in the short-term, it represents a highly secure source of UK gas supply since the gas, if produced, has to be landed at UK terminals<sup>22</sup>. There is no longer any seasonal swing or price-responsive commercial flexibility in UKCS gas production; the seasonal variation is determined almost entirely by the demands of summer offshore maintenance. In 2022, UK gas production accounted for about half the gas supplied to the NTS and to the wholesale market<sup>23</sup>.

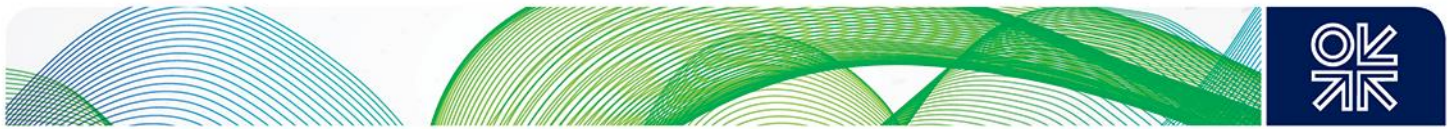
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<sup>21</sup> The ill-judged reform of Gas Transmission Charging arrangements was approved by Ofgem in May 2020, ostensibly to comply with the requirements of the EU Tariffs Network Code. This is discussed in more detail in Chapter 4.

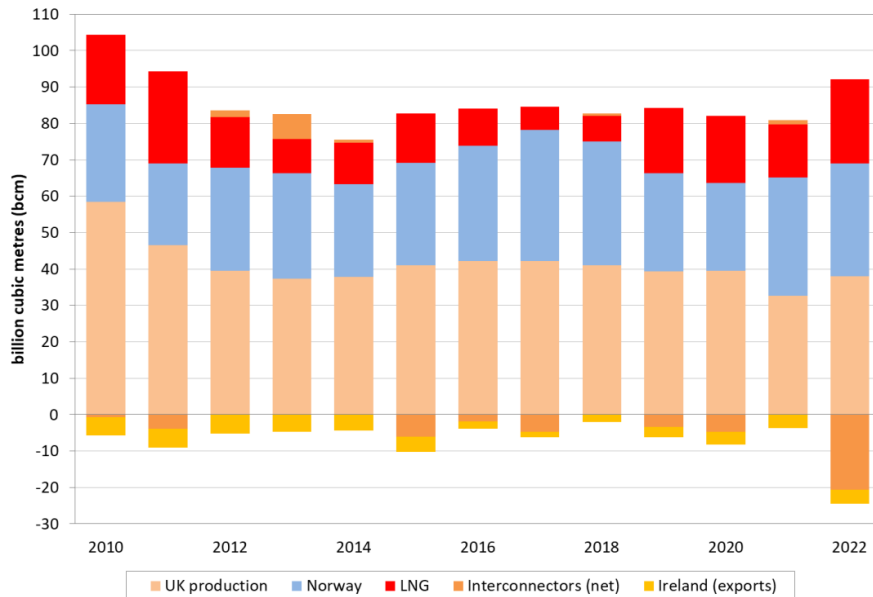
<sup>22</sup> Small volumes from UK fields in the Southern North Sea close to the UK-Dutch median line are delivered to the Dutch onshore network, not to the UK.

<sup>23</sup> Preliminary BEIS data indicate gross gas production of about 37.8 bcm and UK demand of 72.7 bcm in 2022.





**Figure 3: Composition of UK Gas Supply 2010-2022**



Source: BEIS, Energy Trends data

The UK gas market today is unique in Europe and the developed world in its very high dependence on non-storage supply of gas to meet domestic gas demand. This has sometimes been referred to as a 'just-in-time' supply system<sup>24</sup>. After the closure of the Rough 'long range' (seasonal) gas storage facility in 2017, total underground storage capacity fell to 1.6 bcm, or about 2 per cent of current annual demand. Even after the partial re-commissioning of Rough in 3Q 2022, total capacity is no more than 2.4 bcm and a further restoration of Rough capacity is in doubt<sup>25</sup>. The Medium Range Storage sites, comprising both depleted field and salt cavity storage, are capable of a maximum withdrawal rate of 117 mcm/d, less than 25 % of expected peak daily demand in a 1-in-20 winter<sup>26</sup>. This relative lack of storage capacity is attributable in part to the deterioration of storage economics after the commissioning of new LNG regas capacity in 2009-10 that now provides the main source of supply-side flexibility. The dearth of seasonal storage capacity and the absence of stockholding obligations exposes UK consumers to a greater financial risk of high wholesale gas and electricity prices at times of peak gas demand or gas infrastructure failure.

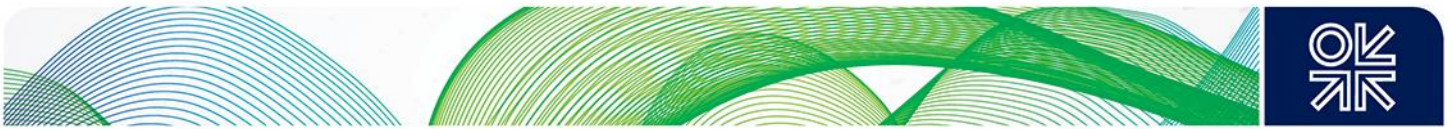
UK gas supply is characterised by very few term supply contracts and active competition between the sources of flexible, uncontracted imports: Norwegian pipeline supply, re-gasified LNG and the UK-EU interconnectors. External suppliers such as Norwegian producers or LNG suppliers which sell gas in the NBP market have no obligation to flow gas to the UK since it may be more attractive for them to meet their sales commitments by simply purchasing gas at the NBP. Norway is by far the largest source of imported gas supply to the UK, accounting for 32.5 bcm in 2021. Supply from Norway includes an element of non-discretionary supply from offshore fields to St Fergus for processing, and term contract sales to re-sellers such as Centrica<sup>27</sup>. However, most Norwegian pipeline supply to the UK is uncontracted and may be delivered via the Gassco-operated export pipeline system to either the UK or to continental Europe within pipeline capacity constraints.

<sup>24</sup> 'The expense of 'just-in-time' gas imports over gas storage', Storengy, 25 January 2021.

<sup>25</sup> 'Breakdown of gas storage talks leaves UK exposed to price surges', Financial Times, 5 February 2023.

<sup>26</sup> In the winter 2022-23 to date, the maximum storage withdrawal rate has been 70 mcm/d (17 January 2023).

<sup>27</sup> In June 2021, Centrica increased its annual contracted purchase volume from Equinor to more than 10 bcm, destined mainly for markets in the UK and Ireland.

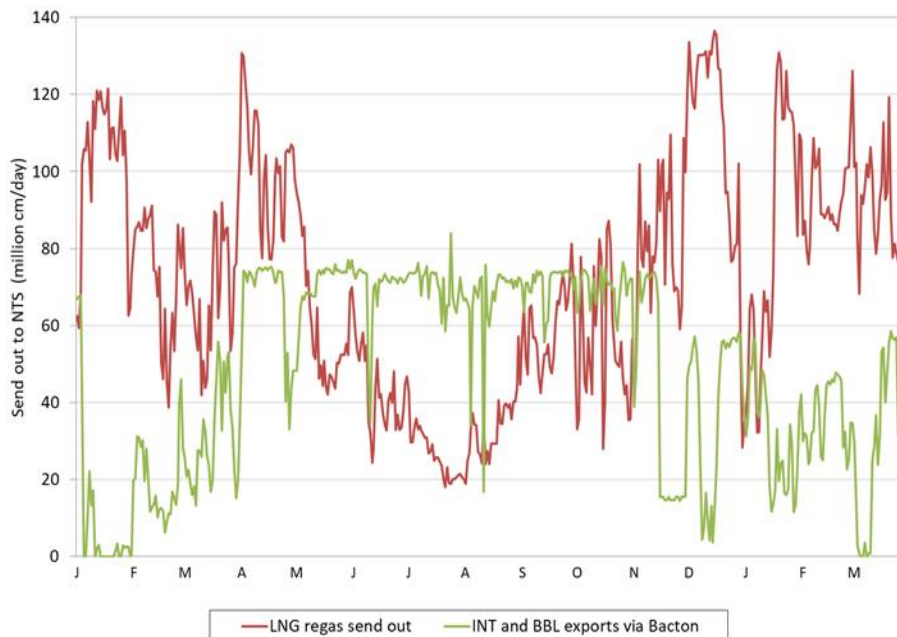


Uncontracted supply from Norway responds to market conditions and gas prices, both the differential between NBP and the Dutch TTF<sup>28</sup> price and the shape of the price curve. In pursuing its policy of ‘value over volume’, Equinor, which markets about 75% of Norwegian Continental Shelf (NCS) gas exports, will defer production if forward prices are significantly higher than prices for prompt delivery and will maximise production when prompt prices are higher, as in 2022. Norwegian exports to the UK also respond to the volume of LNG imports, falling when the global LNG market is over-supplied and deliveries to the UK are high, as they were in 2019 and 2020, and rising when LNG markets are tight and deliveries to the UK are sparse, as in 2016 and 2017. Norwegian supply thus serves as the main source of uncontracted, flexible supply accommodating the cyclical fluctuations in LNG supply to the UK.

Interconnector supply via IUK and BBL pipelines responds primarily to the geographical or basis differentials between the NBP and Zeebrugge (Belgium) and TTF markets on the continent. When the basis differential is greater than the variable cost of transportation and network entry/exit capacity in the prompt market, gas will normally flow across the interconnectors to exploit the arbitrage opportunity. Interconnector flows to the UK are usually triggered in periods of high demand in winter when the UK needs to attract additional uncontracted supply to meet demand.

The exceptional market conditions of 2022 ensured that the interconnectors operated to export gas from the UK to the EU for most of the year, not only in the summer months. Between April and November, the interconnectors maximised flows to the EU in response to the TTF premium to NBP, as shown in Figure 4. After the Russian invasion, the NTS became a key transit route for both LNG and Norwegian gas to the continent, delivering 17 bcm between March and December. This episode

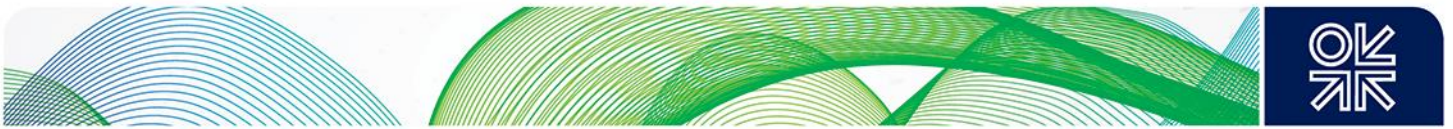
**Figure 4: Daily LNG Send-Out and Interconnector Exports Jan 2022 - March 2023**



Source: National Grid Gas / National Gas Transmission

illustrates the critical importance of the UK’s LNG regas infrastructure and the operational flexibility of the NTS and the interconnectors for the energy security of consumers in not only the UK but also Ireland and the near-continent.

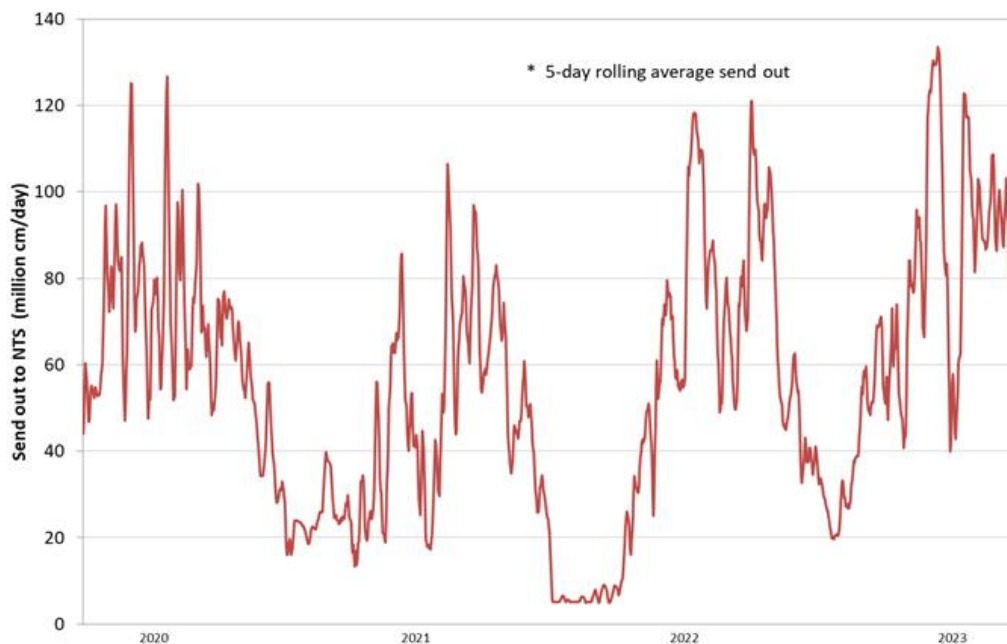
<sup>28</sup> The Title Transfer Facility (TTF) market, Europe’s largest and most active gas market, is the virtual trading hub based in the Netherlands.



The distinctive value of LNG to UK supply security lies in the flexibility of the send-out of re-gasified LNG to the NTS and its ability to respond at short notice to unexpected changes in gas demand or the loss of other sources of supply. It is the commercial and operational flexibility of each of the LNG terminals to move from minimum to maximum send-out within 4-8 hours which provides a critical element of short-term flexibility and supply security for UK consumers. However, this flexible supply role of LNG regas send-out has partly displaced the role of gas storage in meeting weather-related variations in gas demand and has undermined financial returns to storage over the last decade. Figure 5 shows aggregate daily LNG send out from the three regas terminals between October 2019 and December 2022, expressed as a five-day rolling average. It ranges from a minimum of 5 mcm/d to a maximum in mid-December 2022 of 133 mcm/d<sup>29</sup> during an extended UK-wide cold spell. On 15 December 2022, total send-out reached a new daily record of 137 mcm/d as NTS demand peaked at 417 mcm/d. Figure 5 reveals not only the seasonal pattern of send out, peaking usually in the winter months, but also its variability in response to fluctuating conditions in the global LNG market and price signals to sell or store gas in the GB wholesale gas market.

Sellers of re-gasified LNG in the wholesale market normally enjoy a degree of commercial flexibility to store or sell LNG held in tank but at times their flexibility is severely constrained. When LNG markets are over-supplied and regas terminal throughput is high, the terminals may be obliged to send out gas to create space in the storage tanks to take delivery of the next cargo. Conversely, when LNG is diverted to other markets and there are few cargo arrivals, as in 3Q 2021, the terminals may be forced to minimise send out to conserve their liquid inventory.

**Figure 5: Daily Regasified LNG Send-Out to NTS Oct 2019 - March 2023**



Source: National Grid Gas / National Gas Transmission

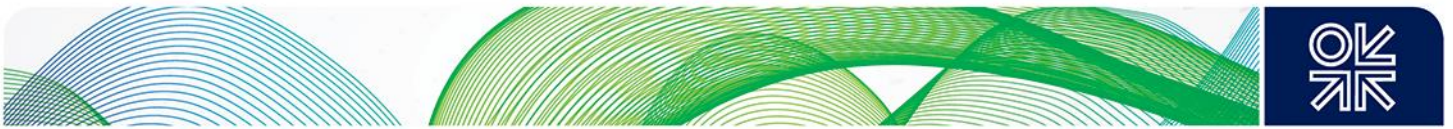
Regasified LNG has generally proved to be a reliable source of flexible supply to the NTS but its vulnerability to severe weather conditions was revealed during the 'Beast from the East' in late February/early March 2018 at a time when its price-responsive contribution to supply was most needed. The exceptionally cold weather not only raised NTS demand to a seven-year high of 418 mcm/d but also caused interruptions in gas supply from Norway, some UKCS fields, storage and, most significantly, at South Hook LNG. After a progressive decline in NTS linepack in the preceding days, NGG issued its first-ever Gas Deficit Warning on 1 March in an effort to restore market balance and to

<sup>29</sup> Peak daily send out in the winter 2019-20 was 138 mcm/d, close to their combined technical capacity.



maintain safe operations. Unexpectedly, South Hook terminal suffered several interruptions to regasification operations between 1 and 3 March attributed to the severe cold and was unable to deliver much more than its minimum send-out of 6 mcm on 1 March. This contributed to the sharp increase in within-day prices to almost 500 pence/therm before market balance was restored late on 2 March.

More recently, in January 2023, the supply of regasified LNG to the NTS from the two import terminals at Milford Haven was temporarily restricted by delays to the discharge of LNG cargoes and later by unexpected outages of compressors on the main NTS pipeline in south Wales. Unusually, high winds off south-west Britain in the period 1-15 January restricted the berthing of LNG vessels at Milford Haven, causing delays and reported diversions of cargoes to other terminals in NW Europe. As a consequence, the capacity holders were forced to reduce their send-out to conserve their existing inventory. As the vessel congestion eased on 17 January and send-out began to recover, NGG suffered a loss of pipeline compression after trips at two local compressors. This provoked a temporary constraint on Milford Haven flows to the NTS on 18 January. Once the compressors returned and all NTS entry capacity was restored, both the South Hook and Dragon terminals sent out gas at their combined maximum rate of 87 mcm/d for the following week.



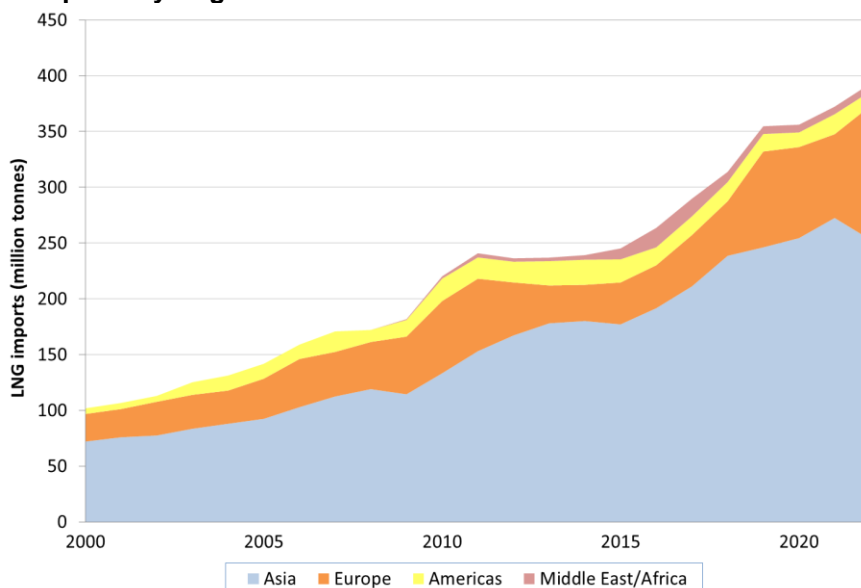
## 2. LNG Market and UK LNG Imports

### 2.1 International LNG markets: growing liquidity and commercial flexibility

The almost uninterrupted expansion of the trade in liquefied natural gas (LNG) in the last 20 years has progressively transformed both the international gas industry and what is often called ‘the geopolitics of energy’. Between 2000 and 2022, LNG trade rose from 102 million tonnes to an estimated 395 million tonnes, an average rate of growth of 6.4% per annum, well ahead of the rate of growth in world gas demand (2.4% pa). LNG now accounts for about 13% of all gas consumed worldwide. The growth has been made possible by technological progress in the upstream, such as the development of US shale gas resources and Australian coal bed methane, by economies of scale in liquefaction and entry into harsh Arctic locations and, finally, by innovative commercial arrangements throughout the LNG supply chain from wellhead production to regasification. Underpinning it all has been the relentless growth in the demand for LNG in energy-importing countries in Asia, many of which lack indigenous gas resources and are distant from sources of pipeline gas. Since climate change abatement policies are likely to encourage the further displacement of coal by natural gas in electricity generation, it is widely expected that LNG demand in the main Asian markets, China, Japan, Korea and India, will continue to underpin the expansion of LNG supply in gas-producing countries for many more years. Even before the stimulus to new projects provided by the explosion of spot LNG prices in 2021-22 and Europe’s newly-stated ambition to reduce dependence on Russian pipeline gas supply, LNG trade was widely projected to rise to 500-580 mt by 2030 (3-5% p.a. from 2021 to 2030) and to 650-750 mt by 2040.

In 2021, 44 countries imported LNG, compared to just 11 in 2000. The steady expansion of the market for LNG reflects a wide variety of factors: the diversification of gas supply from a dominant pipeline supplier, the replacement of declining domestic production, the geopolitical obstacles to pipeline gas supply, the need to back up intermittent renewables generation and, in many smaller markets, the introduction of gas into the energy mix for the first time. Asian countries accounted for almost 75 per cent of total LNG imports in 2021, as illustrated in Figure 6. After a period of relentless growth since its first imports in 2006, China (78 mt) overtook Japan (74 mt) in 2021 to become the world’s largest LNG importer, a position it ceded in 2022 as its ‘zero Covid’ restrictions temporarily depressed its LNG imports.

**Figure 6: LNG Imports by Region 2000-2022**



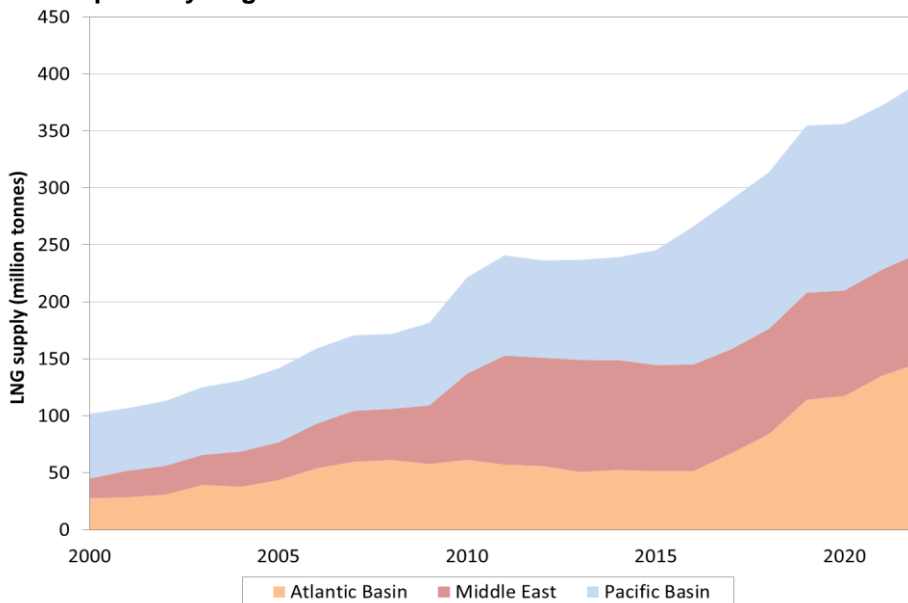
Source: GIIGNL annual reports, Kpler estimates for 2022



Most of the LNG moving to customers in the largest Asian markets (Japan, China, Korea, India and Taiwan) is delivered under term sales and purchase agreements (SPAs) with LNG producers in the Middle East, Australia or ASEAN countries. Such term contracts typically include oil-indexed prices and take-or-pay obligations. Europe has long been a much smaller market for LNG than Asia and a smaller share of its LNG imports is delivered under long-term contracts with LNG producers<sup>30</sup>. Europe's share of world LNG trade has fluctuated in the last decade between 14% and 30% as it has traditionally served as the world's 'balancing market', absorbing more LNG when the global market is oversupplied, as in 2019 and 2020, and importing less when the market is tight, as in 2013-16 and 2021. The Russian invasion of Ukraine in 2022 has now transformed Europe's role in the LNG market. From being the 'market of last resort' for LNG sellers, in 2022 Europe became the highest-value market for LNG in the world. The new political determination of the EU to reduce dependence on Russian gas has raised its demand for LNG, bringing European buyers into competition with Asian buyers in term contract and spot markets and temporarily forcing LNG prices beyond the means of many low-income developing countries.

The supply side of the world LNG market has been marked, especially in the last decade, by a growing number of LNG sources and suppliers. Between 2000 and 2021, the number of countries exporting gas as LNG rose from 12 to 19. In 2000, Indonesia, Malaysia and Algeria were the three largest LNG producers but by 2021 Australia (80 mt), Qatar (77 mt), and the United States (68 mt) had assumed these positions. Since 2015, both the US and Russia, the world's largest producers of gas, have emerged as large exporters of LNG to the Atlantic Basin market. Neither international oil nor coal markets have seen such rapid supply-side change on a comparable scale or at a comparable pace.

**Figure 7: LNG Exports by Region 2000-2022**



Source: GIIGNL annual reports, Kpler estimates for 2022

Capital investment in new liquefaction projects has remained highly cyclical and sensitive to fluctuations in LNG demand, capital costs and the term contract prices that Asian buyers are prepared to pay. Secure offtake from creditworthy buyers and acceptable term contract prices remain essential for gas resource holders and lenders to invest in and to finance new liquefaction projects. As shown in Figure 7, the rate of LNG supply growth in the last 20 years has not been uniform, creating periods of over-supply as new supply entered the market and tight markets in which supply lagged the growth in demand. The accelerated growth in LNG trade between 2009 and 2011 marked the major expansion of Qatari liquefaction capacity to 77 mtpa. The later expansion phase between 2016 and 2019 reflected

<sup>30</sup> The reduction in Russian deliveries to Europe in 2022 raised Europe's LNG imports to a record level of 120 mt in 2022, taking its share of world trade up to about 30 per cent.



a wider range of new projects: the first LNG exports from the US Gulf Coast in 2016, the commissioning of new projects in Queensland, Australia and the first exports from Yamal LNG in northern Russia in 2018. Both periods of expansion were accompanied by an increase in the share of LNG delivered to Europe as the balancing market. In 2021, more than one third of world LNG supply came from the Atlantic Basin, principally from the US, Arctic Russia and Nigeria, the highest share since 2008. The expansion of US LNG exports since 2016 has benefited mainly European buyers whose imports from traditional sources of short-haul LNG (Nigeria, Algeria and Egypt) have been broadly flat in recent years.

In 2000, LNG trade was dominated by long-term 'point-to-point' contracts between original suppliers and large buyers with take-or-pay provisions; very limited volumes were delivered outside these long-term, oil-indexed term contracts. This pattern of 'pipeline LNG' was gradually eroded by new sources of LNG supply, the emergence of LNG 'aggregators' and traders with several sources of equity or purchased LNG and downstream market liberalisation which forced buyers to manage the volume and price risks in their LNG purchase contracts. The contracting behaviour of both buyers and sellers gradually changed as more uncontracted LNG became available to the spot and short-term markets. According to GIIGNL, the share of spot and short-term volumes (delivered under contracts of less than four years duration) has risen from about 5% of total world LNG in 2000 to 37% (136 mt) in 2021, slightly lower than in 2020 as Chinese buyers increased their long-term contract volumes. Within this figure, true spot volumes, delivered within three months of the transaction, were 31% (116 mt) of total imports<sup>31</sup>. By 2021, the world LNG market had emerged as an actively traded commodity market with established spot market liquidity, both free-on-board (FOB) and delivered ex-ship (DES), growing derivative markets and the active participation of producers, traders, aggregators and buyers.

The long process of commoditisation of the LNG market has been accelerated by three events: first, the Fukushima disaster of March 2011, which led to the shutdown of almost all Japanese nuclear reactors; secondly, the emergence of the US as an exporter of LNG in 2016, based on the success of its upstream 'shale gas revolution' and, thirdly, the Russian invasion of Ukraine in February 2022. The halt to nuclear generation in Japan in 2011 unexpectedly raised its demand for LNG by 20 mtpa and stimulated spot market sales in Asia by incentivising LNG contract holders to divert cargoes from lower-value markets. The later development of US LNG exports, beginning in 2016 from Cheniere's Sabine Pass liquefaction plant on the US Gulf coast, laid the ground for a more profound and durable change in LNG markets, namely the development of freely tradeable LNG supply, capable of being delivered to any destination, at prices related to Henry Hub. This created a major new source of flexible, market-responsive LNG supply at prices unrelated to oil, in contrast to traditional oil-indexed supply sources which seek to maintain stable LNG production in all market circumstances. The Russian invasion of Ukraine in 2022 marked an even greater demand-side shock than Fukushima, leading to the diversion to Europe of about 40 mtpa of existing LNG exports. The scale of the price response in Europe induced many of the holders of flexible LNG, including Asian companies, to release cargoes to the European market for the first time.

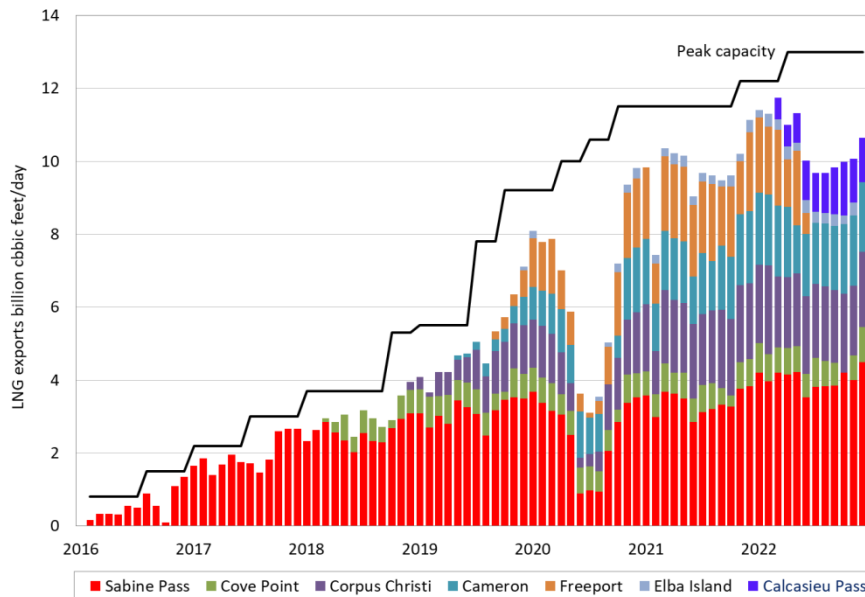
There is no equivalent of OPEC in the global gas or LNG market. Most gas exporters are members of the Doha-based Gas Exporting Countries Forum (GECF) but it has not acted as a venue for co-ordinating export supply. Unlike crude oil producers, LNG producers have never restrained their collective output to protect prices but they have, as sellers of LNG at oil-indexed prices, benefited indirectly at times from OPEC's efforts to re-balance oil markets. The remarkable expansion of Henry Hub-related LNG exports from the US since 2016 has introduced a new price-responsive source of supply to the global LNG market which may contribute to re-balancing temporarily over-supplied or tight markets. For example, in the summer of 2020, when worldwide demand for gas and LNG fell sharply due to the Covid-19 pandemic, many US export capacity holders did not exercise their option to lift LNG cargoes because, temporarily, they could not recover the cost of the LNG and shipping in either European or Asian markets. In consequence, US LNG exports more than halved in June-August 2020 before recovering strongly later in the year, as shown in Figure 8.

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<sup>31</sup> The classification of LNG trade presents a number of difficulties since individual cargoes may be delivered FOB under a long-term contract and later delivered DES to a regas terminal under a spot contract, or vice versa, and cargoes may change hands several times. The GIIGNL data represent the best available published source and reliably identify the long-term trends.



**Figure 8: Monthly US LNG Exports by Facility Jan 2016 - Dec 2022**



Source: US EIA 'LNG Monthly' and 'Liquefaction Capacity Table'

By the end of 2022, there were seven liquefaction plants on the US Gulf and east coasts with total baseload nameplate capacity of 87 mtpa (11.4 bcf/d), exceeding that of both Qatar and Australia; peak capacity achievable for short periods is estimated to be 13.9 bcf/d.<sup>32</sup> Exports from these US plants are capable of being delivered to almost any market in the world and have stimulated both changes in LNG contract pricing and injected liquidity into the LNG spot market, notably in Europe. In 2021, US LNG cargoes were delivered to no fewer than 33 of the world's 44 LNG-importing countries.

## 2.2 European LNG supply, regional arbitrage and hub-price determination

Europe's role as the 'balancing market' for the global LNG market between 2010 and 2020 was increasingly difficult to perform even before the Russian invasion of Ukraine in February 2022. This former role is now effectively redundant. As Gazprom progressively cut pipeline supplies and Europe sought to reduce its dependence on Russia, Europe had to turn primarily to the LNG market to replace former Russian supply. Indeed, LNG deliveries to Europe rose to record highs in 2Q 2022 and reached a new annual record of 120 mt for the year as a whole. The EU announced in March 2022 its intention to 'reduce Russian imports by two-thirds by the end of 2022'<sup>33</sup> and Germany, Europe's largest gas market, announced its ambition to eliminate its dependence on Russian gas by mid-2024. Germany imported LNG directly for the first time in late-2022 and is seeking to commission five FSRUs<sup>34</sup> by the end of 2023 and two onshore regas terminals by 2025<sup>35</sup>. In the short term, with limited scope to increase LNG production, there will be even more intense competition between European and Asian LNG buyers and new competition within Europe between existing and new buyers.

In 2022, Europe (EU-27, the UK and Turkey) imported an estimated 120 mt of LNG, comprising firm contracted volumes delivered under long-term contracts, deliveries under flexible contracts and spot cargo purchases<sup>36</sup>. The US, Qatar and Russia were the largest suppliers to Europe in both 2021 and 2022. Total nominal European regas capacity at onshore terminals and at operating FSRUs in 2021 was 184 mtpa. Only Spain has more regas capacity than the UK but in 2022 both Spain and France imported more LNG than the UK. Figure 9 shows the evolution in European LNG imports since 2010,

<sup>32</sup> 'US LNG export capacity will be world's largest by end of 2022', US EIA, 9 December 2021.

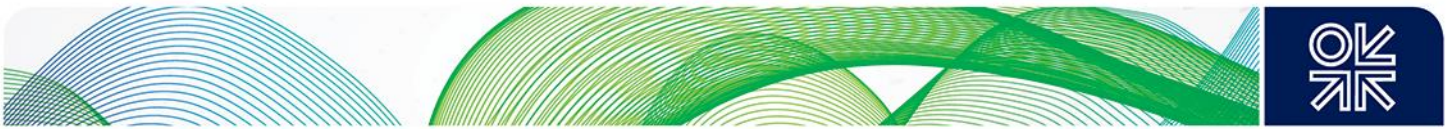
<sup>33</sup> European Commission press release, 8 March 2022.

<sup>34</sup> Floating Storage and Regasification Units, vessels moored offshore to which LNG vessels transfer their cargo.

<sup>35</sup> German Chancellor's statement to Bundestag, 27 February 2022.

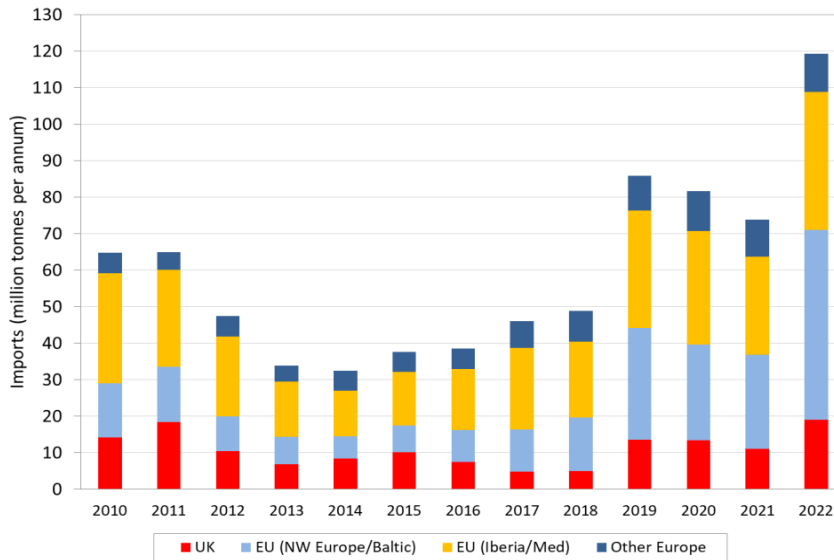
<sup>36</sup> IIGNL data for 2021 show European imports under long-term contracts of 45.4 mt (60%) and imports under short-term contracts (<4 years) and spot purchases of 29.7 mt (40%). In 2022, the share of spot purchases is expected to be much higher.





in particular the sharp rise in 2019 and 2020 under the weight of global LNG over-supply, the modest decline in 2021 as the market tightened dramatically and, finally, the extraordinary surge in imports in 2022 as Europe scrambled to replace Russian pipeline gas. Term contract volumes, especially from Algeria and Nigeria, are more significant in Iberia, France, Italy and Turkey, whereas in the more liquid hub markets of NW Europe flexible supply arrangements and spot purchases are more common. Oil-indexation has remained in some LNG contracts to southern Europe but in NW Europe, deliveries are usually priced against TTF, or NBP for most deliveries to UK terminals.

**Figure 9: European LNG Imports by Region 2010-22**



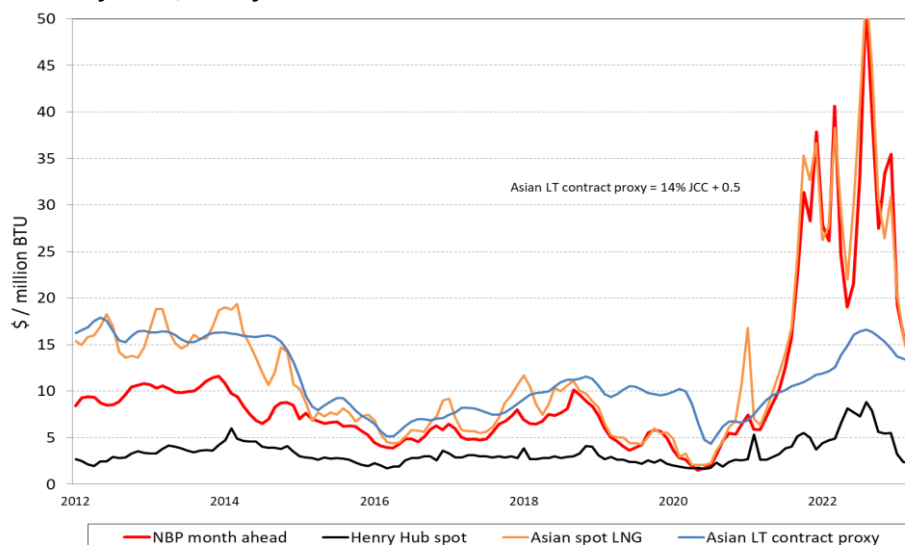
Source: GIIGNL, OIES projections for 2022 based on Kpler data

The key to understanding the dynamics of global LNG trade flows and the behaviour of European gas prices lies in the relationship between firm term contracts for LNG, which form the backbone of supply to Asia, and the balance of supply of, and demand for, *uncontracted* LNG outside these term contracts. The pricing of LNG under long-term contracts was originally indexed to oil prices in the absence of competitive downstream markets for natural gas in the main gas-importing regions of Asia and Europe. Although oil-indexation of LNG has disappeared from much of Europe, it remains the most common basis of contract pricing in Asian markets where LNG prices are indexed with a lag to either the so-called Japanese Crude Cocktail (JCC) or to Brent. When Asian buyers need more LNG to meet domestic gas demand, they will either increase nominations within their term contracts or will buy in the spot market, whichever source of supply is cheaper. A process of term-spot arbitrage has ensured that Asian spot LNG prices have in the past tended to track oil-indexed term contract prices, except at times of acute LNG over-supply, such as 2019-20, or acute excess demand for LNG, as in 2021-22.

In the period of high oil prices above \$100/bbl in 2011-14, which coincided with the period of strong LNG demand in Japan after the Fukushima-related nuclear shutdowns, Asian spot LNG prices traded at a persistent premium to European spot LNG values linked to TTF and NBP, as shown in Figure 10. There was insufficient uncontracted LNG to meet Japanese demand and those LNG producers and traders with uncommitted spot cargoes and access to shipping were able to earn supra-normal margins of \$5-10/mBTU by diverting LNG from the Atlantic Basin to Asia. As LNG supply increased and existing contracts gradually became more flexible, LNG trading volumes increased and excess profits in arbitrage trading diminished, or the benefits were shared more equitably between producers and traders through diversion-sharing payments.



**Figure 10: Monthly NBP, Henry Hub and Asian LNG Prices Jan 2012 – Mar 2023**



Source: Argus Media

Access to LNG shipping is an indispensable part of participation in the global LNG market, both to ensure performance of long-term contracts and to exploit arbitrage opportunities between regions. Spot charter rates for LNG carriers are highly volatile because short-term demand for shipping is highly dependent on arbitrage opportunities and the demand for long-haul voyages from the Atlantic Basin to the Far East, so project developers and term LNG contract holders typically own or lease vessels under long-term contracts to minimise their exposure to the spot market. The concentration of LNG supply from a few major suppliers and on specific routes, in particular through the Suez and Panama canals, also makes LNG trade and spot values sensitive to shipping delays and disruption. This tends to reinforce the tendency to integrate LNG supply and shipping more closely than in the crude oil market.

The start-up in 2016 of Henry-Hub related US LNG exports introduced a new tranche of supply capable of delivery almost anywhere in the world. The destination flexibility of US exports ensured that the link between TTF/NBP prices in Europe and spot LNG prices or Japan Korea Marker (JKM) assessments in Asia was strengthened through more active and efficient arbitrage to exploit inter-regional spreads<sup>37</sup>. Since 2016, TTF and NBP prices have become more closely correlated and aligned with Asian spot LNG and JKM prices, with TTF trading normally at a discount to JKM to reflect the lower shipping costs of moving US LNG exports to NW Europe than to NE Asia. US domestic gas prices continue to serve as the floor for global gas and LNG markets. In the mid-2000s, when the US was a net importer of LNG, Henry Hub prices served as the floor to world LNG values as the lowest-value import market for uncontracted LNG. Today, more than 15 years after the US ‘shale gas revolution’ and the emergence of the US as a major LNG exporter, Henry Hub prices still set the floor to world traded gas prices as the source of feed gas to the market for freely tradeable LNG.

The NBP wholesale gas price is determined by the obligations on NTS shippers to balance their positions each gas day (5am-5am) and the complex interplay of competing storage and non-storage sources of indigenous and imported supply and constantly fluctuating demand for gas from heating, power generation and industry. The bi-directional interconnector pipelines between the UK and Belgium (INT) and the Netherlands (BBL) ensure arbitrage between prices of NBP and TTF, the larger hub market based in the Netherlands. Although very little gas comes directly from the continent to the UK<sup>38</sup>,

<sup>37</sup> The Japan-Korea Marker or JKM benchmark price is Platt’s daily assessment of the delivered ex-ship (DES) value of spot LNG cargoes delivered to Japan, Korea, Taiwan and China.

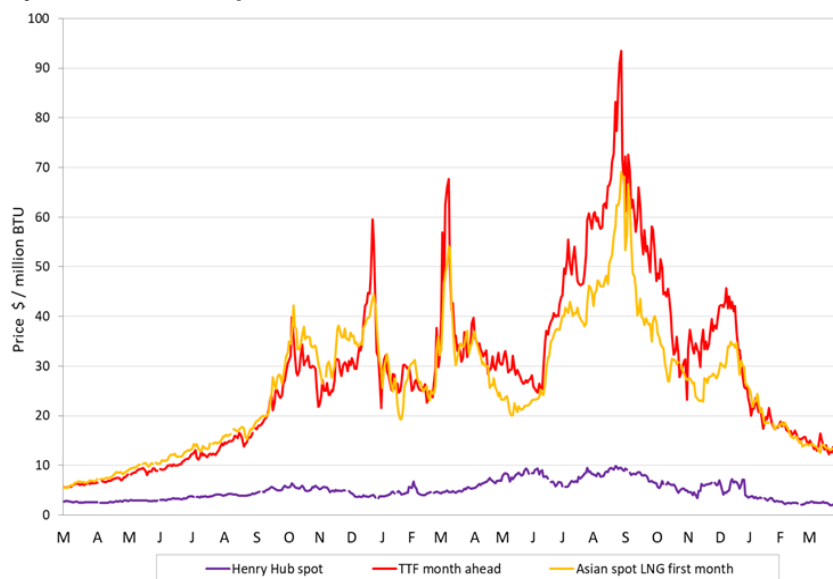
<sup>38</sup> Unusually, in the winter 2021-22 (Oct 2021-March 2022), the UK was a net exporter of gas through the Interconnector and BBL pipelines, not a net importer.



the dependence on interconnector imports to meet peak UK winter demand means that the NBP market functions as part of the wider European market in which Norway and LNG are the main sources of supply to both the UK and EU. Since 2016, TTF has been the principal European locus of hub price-determination and the main wholesale market for hedging and trading<sup>39</sup>.

In the past, both NBP and TTF prices tended to trade in a range set, at the lower end, by competition between coal and gas in marginal electricity generation (the so-called ‘coal-switching value’ of gas) and, at the upper end, by the oil-indexed values at which gas was available under term pipeline contracts from Russia or Norway. Beginning in 2009-10, in the over-supply created by the 2008-09 financial crisis, this process of price-formation gradually broke down. First, oil-indexed term contracts prices were progressively re-negotiated and replaced by hub-indexed contracts with less volume flexibility available to the buyers and, secondly, the scope for fuel-switching by electricity generators was progressively restricted by the phasing out of coal-fired generation. Power generation economics also became more heavily influenced by the fluctuating cost of carbon allowances within the EU ETS. The contractual reforms, sought initially by gas buyers in 2009-10, were promoted by EU policy-makers to encourage more competitive wholesale markets and completion of the internal energy market. However, they also entailed a gradual shift of pricing power from buyers and re-sellers of gas to producers and external suppliers. As European buyers were losing volume flexibility in supply contracts, the Dutch government decision in 2018 to finally phase out Groningen production by 2023 reduced indigenous supply-side flexibility further. Non-storage supply flexibility to the NW European market now lies almost entirely in the hands of external suppliers.

**Figure 11: Daily Hub Gas and Spot LNG Prices Mar 2021 – Mar 2023**



Source: Argus Media

The consequence of these changes in price-formation has been a notable increase in TTF and NBP hub price volatility since 2018, exacerbated by the fluctuations in demand in 2020-21 associated with the Covid-19 pandemic. European hub prices are still bounded at the lower end by US Henry Hub prices, as they were in 2008-09 and 2020, but they have lost any natural ‘convergence value’ to the upside. As Gazprom restricted the supply of uncontracted gas to European markets in the summer of 2021, NBP and TTF prices rose relentlessly since European buyers were forced to compete for limited uncontracted LNG with Asian buyers at a time when the recovery from the pandemic began to raise gas demand everywhere. By mid-2021, LNG had become the marginal, price-setting source of gas to the European market, effectively turning the role of Europe from the ‘market of last resort’ for LNG to

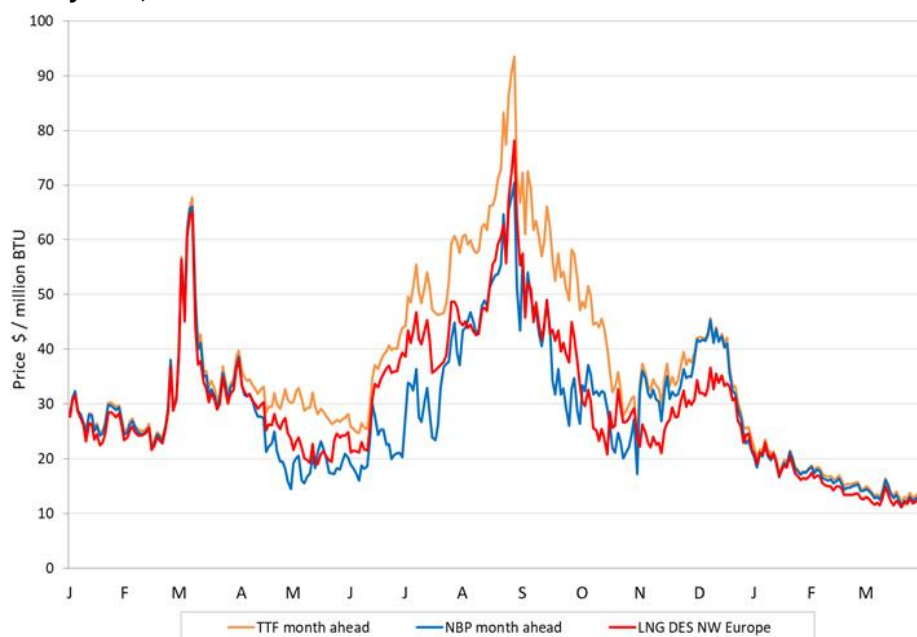
<sup>39</sup> Trading activity in the TTF market now far exceeds NBP activity. In 2021, the total volume of TTF in all trading venues was 53,431 TWh, compared to 6,641 TWh for NBP.



the highest-value market for LNG anywhere in the world. This created a self-reinforcing upward spiral in both TTF and Asian spot LNG prices to more than \$40/mBTU in October and December 2021, as shown in Figure 11. The Russian invasion on 24 February 2022 triggered another spike in TTF and spot LNG prices above \$50/ m BTU in early March. From April 2022, as Russian supplies to Germany via Nord Stream 1 were restricted further, TTF moved to a substantial premium to Asian spot LNG values. After a modest retracement in April and May, both European and Asian spot LNG prices set new highs again in late August as gas resellers sought to build inventories before the northern hemisphere winter. Prices of this magnitude and the associated daily price volatility are without precedent in European gas market history<sup>40</sup>. By February 2023, TTF and NBP prices had fallen back to levels last seen in August 2021.

Attention has naturally focused since late 2021 on the level and extreme volatility of European gas prices. Rather less attention has been given to the dislocation of price differentials and the de-coupling of TTF and NBP prices from the end of March 2022. This was particularly evident in day ahead and the month ahead markets where NBP has traded at a large discount to TTF, as shown in Figure 12. This reflects the growing tightness in the TTF market through the summer storage injection season even after pipeline flows from Norway and the UK to the continent and LNG regas capacity in continental NW Europe was fully utilised. The UK market was physically well-supplied throughout this period by reliable production on the UKCS and by LNG imports as pipeline exports from Bacton via the interconnectors to Belgium and the Netherlands ran close to maximum (75 mcm/d) from 1 April.

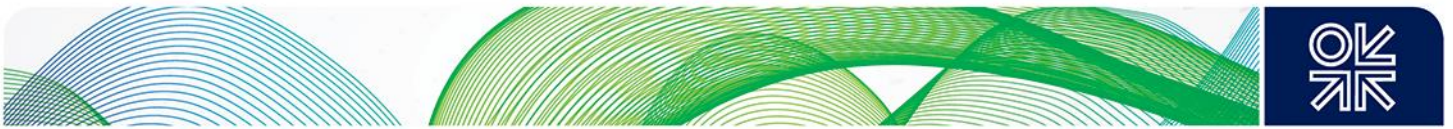
**Figure 12: Daily TTF, NBP and LNG DES Prices 1 Jan 2022 – 31 Mar 2023**



Source: Argus Media

Figure 12 shows also the assessed daily spot value of LNG delivered ex-ship (DES) in NW Europe compared to month ahead TTF and NBP prices in 2022-23. The fluctuations in the relationship between LNG DES values and TTF and NBP markets reflect largely the short-term availability of regas capacity in NW Europe. Until 1Q 2022, the LNG DES value tracked TTF and NBP month ahead prices at a modest discount, reflecting regas and network entry costs, but as existing regas capacity in the EU became congested from April, DES values fell towards the lower NBP price and the UK emerged as a transit route for LNG to reach the EU via the interconnector pipelines INT and BBL. For most of the summer, except for a period in June-July, LNG DES values tracked NBP prices at a premium and TTF

<sup>40</sup> The Quarterly Gas Review Issue 18, August 2022, OIES provides a concise summary of European gas markets following the Russian invasion in February 2022.



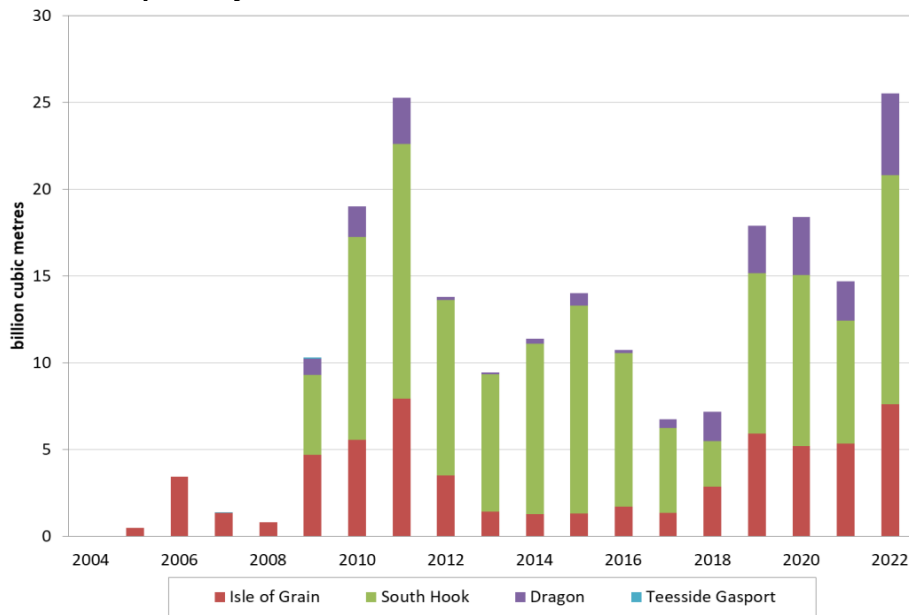
at a sizeable discount since UK terminals were able to accept LNG cargoes whereas those on the near-continent remained at or close to capacity. As market attention turned in November to the peak winter demand period (December-February), a surge of LNG arrivals, especially from the US, forced LNG DES values once again to a discount to both TTF and NBP month ahead prices but by the end of 2022 all three values had once again converged.

### 2.3 UK LNG imports: diversity but no firm term contracts

In the context of the global LNG market, UK is a medium-sized market, smaller than Spain and comparable in size to France or Turkey. In 2021, the UK imported 10.5 mt of LNG, down from 13.4 mt in 2020. This represented only 3% of world LNG trade, compared to an average of 4% over the period 2010-20. In 2022, the Russian invasion of Ukraine triggered a price-induced surge in UK LNG imports mainly to transit gas to the EU via the two interconnector pipelines. Full-year UK imports in 2022 reached a new annual record of 19 mt (25.6 bcm), amounting to more than one third of estimated UK gas demand. Tanker tracking sources report the arrival of 251 LNG cargoes in 2022 from 13 countries, up from 137 cargoes in 2021<sup>41</sup>.

Figure 13 shows reported annual LNG imports by UK terminal between 2004 and 2021 and an estimate for 2022 based partially on tanker tracking data. The fluctuations since 2010, when all three terminals were fully operational, from a peak in 2011 to a trough in 2017 and a new peak in 2022, reflects primarily the variations in the state of the world LNG market, especially the demand from, and arbitrage opportunities to, Asia.

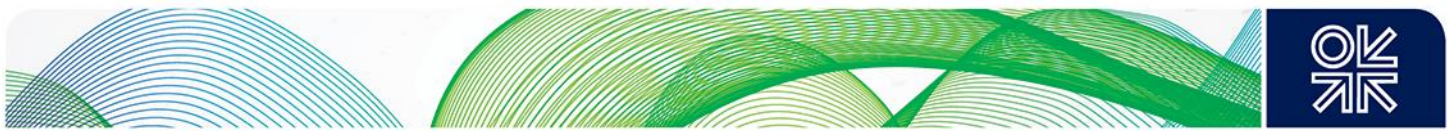
**Figure 13: UK LNG Imports by Terminal 2004-2022**



Source: DUKES 2022. OIES projection for 2022

The variation in UK demand for imported gas is only a minor influence on LNG imports. When LNG markets have been tight, as in 2012-13 and 2017-18, LNG suppliers have delivered or sold fewer cargoes to the UK. Conversely, when LNG markets have been over-supplied, as they were in 2019-20, the UK received more cargoes. In this respect, 2022 marked a major reversal of past trends since it combined an exceptionally tight LNG market and record UK imports.

<sup>41</sup> Whether expressed in mass, energy or gas-equivalent volume, statistical discrepancies arise between reported UK imports of LNG and reported supply of re-gasified LNG to the UK wholesale market due to boil-off gas at regas terminals, changes in terminal stocks, occasional exports and truck deliveries from the Grain terminal. Monthly and annual government gas data assume that terminal use of gas is 1.5% of the quantity delivered to the NTS.



Between 2010 and 2021, the South Hook terminal, supplied exclusively with Qatari LNG until 2018, accounted for two-thirds of the UK's total LNG imports. The terminal received more LNG than either the Grain or Dragon terminals in every year except 2018, when imports to the Grain terminal slightly exceeded those at South Hook. In 2021, deliveries to South Hook and Dragon fell more than 20 per cent as the LNG market tightened but deliveries to the Grain terminal rose slightly, highlighting the differences between the supply sources and the commercial behaviour of the capacity holders in the three terminals. All three terminals recorded a large increase in cargo arrivals in 2022.

Most of the LNG imported into the UK is not delivered under firm term, arm's-length LNG supply contracts but is more accurately described as either deliveries of LNG within an integrated supply chain, deliveries under flexible supply agreements or spot purchases by terminal capacity holders. Primary regas capacity is held by nine companies but may be sold in the secondary market to third parties with access to LNG cargoes, allowing them to deliver LNG and sell the gas at the NBP. Primary capacity holders have invested in long-term capacity contracts, typically of 20 years duration, to gain access to the GB market but it remains the case that LNG cargoes are delivered to the UK only when there is no higher-value alternative market available to the cargo owner. In this respect, delivery of LNG to the UK represents the exercise of an option by the LNG supplier or capacity holder, not the fulfilment of an existing contractual obligation. The financial commitment made by the primary regas capacity holder to secure this option is represented by the combined costs of the contracted regas capacity (typically for 15-20 years) and the associated purchase of NTS entry capacity.

The liquidity of the NBP wholesale market underpins all LNG imports to the UK since it provides a reliable 'route to market' for LNG producers and cargo owners. For companies with a portfolio of supply sources and sales contracts, NBP market liquidity allows more efficient management of volumetric and price risks in their LNG portfolios. It permits LNG producers and sellers to accommodate the seasonality and fluctuating demand of their term contract customers by delivering more LNG to the UK when term contract buyers 'turn down' their nominations, or delivering less to the UK when term contract demand increases. This ensures that LNG output does not have to be curbed when term customers' demand declines unexpectedly, as at the onset of the Covid-19 pandemic, and that any unexpected LNG production problems associated with feed gas supply or plant operation do not immediately affect deliveries to its term customers.

Access to a liquid wholesale market such as TTF or NBP allows LNG portfolio players to manage their price and margin risk by selling gas forward well ahead of physical delivery. As delivery approaches, if it is no longer attractive to deliver the LNG to the UK market, the gas sold forward can be bought back and the LNG cargo 'pulled' from the UK and delivered to a higher-value sale elsewhere. Active LNG portfolio players will use the liquidity provided by the NBP and TTF markets in this way to undertake a process of continuous re-optimisation of their portfolio to maximise financial value, retaining as long as possible the flexibility to deliver LNG to the highest-value available market. Market reports of LNG cargoes being diverted in mid-voyage to alternative destinations just days from their original destination are common in volatile markets. Only if the NBP-related price achievable in the UK market represents the highest-value option will the physical LNG cargo be delivered to the UK.

The liquidity of the NBP market confers benefits for LNG suppliers, especially the larger portfolio players, but in most market circumstances there is little incentive to commit firm supply to the UK market. It is flexible access to the NBP market which sellers seek, not firm term sales commitments. From the perspective of UK downstream gas marketers, there is a similar disincentive to signing firm term LNG supply contracts unless the cost of regas capacity allows LNG to be delivered to the NBP at a discount to prevailing prompt NBP prices. The liquidity of the NBP market is, in a sense, a barrier to the signing of firm term LNG supply contracts. Centrica, the largest supplier to the UK retail market under the name of British Gas, is one of the few UK suppliers to have signed a medium-term LNG supply contract for UK delivery. Centrica contracted for long-term capacity at the Grain terminal in 2005 and 2007 in the second and third phases of the terminal's construction<sup>42</sup>. In February 2011, Centrica signed a three-year LNG deal with Qatargas for 2.4 mtpa delivered to Grain, a deal which was twice extended, with

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<sup>42</sup> See Figure 17 for Grain regas capacity holders



modifications of the annual quantity, until the end of 2023. The current contract for 2 mtpa includes provision for delivery to alternative higher-value markets and in recent years only a fraction of the headline annual quantity has been delivered to the UK. Tanker tracking data suggest that only two Qatargas cargoes (0.25mt each year) were delivered to Centrica at the Grain terminal in the last three years (2020 to 2022).

The competitive nature of the UK wholesale gas market and Ofgem's failure in recent years to regulate the retail market adequately have exacerbated the difficulty of bearing the financial risks of term LNG supply contracts<sup>43</sup>. Between 2010 and 2021, Centrica's share of the GB retail market declined from 44% to 27% as numerous new entrants were able to undercut the established 'big six' suppliers, some by offering gas and electricity at unsustainable prices who were later forced into insolvency or administration. The introduction of the ill-designed retail price cap in 2019, ostensibly to prevent suppliers' excessive profits, further undermined the viability of term contract supply. Today, few sellers in the UK industrial, commercial or retail gas markets have the balance sheet, the market share or the appetite to bear the financial risks of firm term LNG supply obligations.

Among current retail suppliers, only Centrica and Shell hold primary capacity at UK regas terminals. The connection between LNG trading on one hand and domestic UK retail supply on the other has become more distant and more tenuous in the last decade. The commoditised, international LNG business is complex and volatile and demands quite different skills from the more prosaic, regulated, low-return business of physical supply to UK retail consumers. The experience of Centrica, the UK's largest retail supplier, illustrates this separation. It has an international LNG portfolio, comprising its Qatari contract, a long-term US supply contract with Cheniere, future supply from Mozambique LNG and regas capacity at the Grain terminal, but the LNG business operates entirely separately from its UK retail supply business. In late 2020, at a time of major corporate restructuring, Centrica was reported to be seeking a buyer of the LNG business<sup>44</sup>. It decided to retain it after the increase in profitability in 2021 and in 2022 concluded a new agreement to purchase US LNG FOB for 15 years<sup>45</sup>. Its commitment to continue to supply LNG to the UK is likely to be measured in the next few years by whether it seeks to extend its Grain capacity holdings beyond 2029.

Over the last decade, UK LNG imports have become progressively more responsive to global LNG market price dynamics and liquidity. Since 2016, the origin of LNG imports has become progressively more diverse, as Figure 14 illustrates. In the period 2013-16, Qatari LNG accounted for more than 90% of arrivals, supplemented mainly by irregular deliveries from Trinidad and Algeria to the Grain and Dragon terminals. The first cargoes from the US and from Yamal LNG in Arctic Russia were imported in 2017. By 2019, both US and Russian LNG were regular, price-responsive sources of UK supply, in addition to deliveries from 8-9 other sources, including occasional re-exports from France and Belgium. In 2021, Qatari LNG comprised just 40% of total LNG imports as the tight market led Qatar Petroleum to deliver more LNG to its Asian term customers, vacating capacity at South Hook for increased imports from the US.

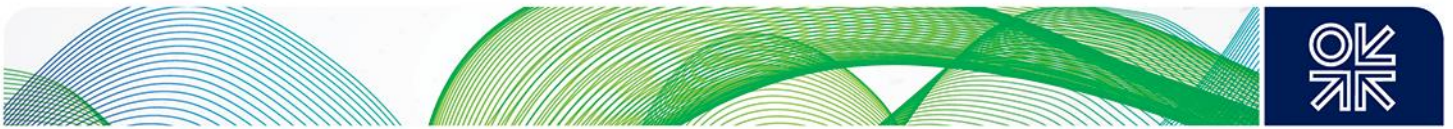
As Figure 14 shows, the amplitude of the monthly variation in LNG imports has increased in recent years as price-responsive optimisation of LNG portfolios has become more active. For example, in 3Q 2021, only six cargoes (0.7 bcm gas equivalent) were delivered to the UK, the lowest level in 3Q since 2009. After the temporary famine abated, in January 2022 no fewer than 33 cargoes (3.3 bcm) were delivered to the UK, setting a new monthly record for both imports and terminal send-out to the NTS.

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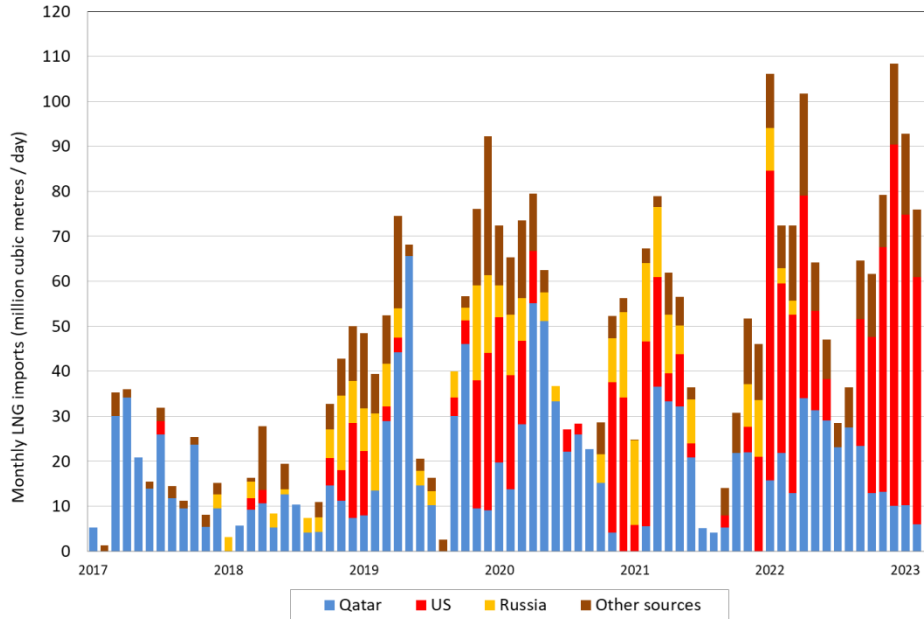
<sup>43</sup> Review of Ofgem's regulation of the energy supply market, Oxera, 3 May 2022

<sup>44</sup> 'UK Centrica seeks to sell off its LNG portfolio', Wall Street Journal, 27 November 2020.

<sup>45</sup> 'Centrica signs LNG Heads of Agreement with Delfin', Centrica press release, 9 August 2022.



**Figure 14: Monthly UK LNG Imports Jan 2017 – Feb 2023**



Source: BEIS Energy Trends, Argus Media

This monthly record was later exceeded in December 2022 when LNG imports and send out both reached 109 mcm/d in response to a two-week cold spell. After the Russian invasion of Ukraine in February, the UK placed an embargo on Russian LNG but total LNG imports continued at a high level from a wide range of sources, reaching a second peak of 2.8 bcm (29 cargoes) in April. From the end of March, the UK became in effect a major transit route to the EU via the two interconnector pipelines once regas capacity on the near-continent became fully utilised. In the summer of 2022 (April-September), the UK exported a record 12.7 bcm (69 mcm/d) via the Interconnector and BBL pipelines to the continent, based in part on record LNG imports.

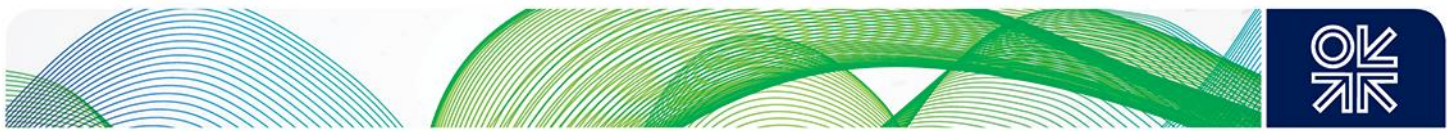
Most of the increase in LNG imports into the UK and EU in 2022 came as uncontracted cargoes from the US, reflecting the contractual flexibility of US LNG exports to respond to unexpected changes in LNG demand. The threefold increase in UK imports from the US meant that in 2022, for the first time, annual US imports (9.4 mt) exceeded Qatari imports (5.7 mt), and by a wide margin. More than half the cargoes delivered to the UK in 2022 (132) were from US liquefaction plants and almost half the US cargoes (61) were delivered to South Hook where they exceeded the number (but not the volume) of Qatari deliveries (54).

Although the focus is naturally on imports of LNG, it should be noted that the UK has at times exported LNG - and may do so again in future. Between 2015 and 2018, occasional LNG cargoes were exported from the Grain terminal as capacity holders took advantage of the terminal's ability to re-load LNG aboard large vessels to sell to higher-value markets. In addition to small-scale loadings of 5-10,000 m<sup>3</sup> for NW European destinations, at least 16 full-size cargoes of 75-175,000 m<sup>3</sup> were reported to have been exported from Grain between March 2015 and July 2018 to a variety of EU and non-EU destinations. In 2016, LNG re-exports from Grain amounted to 0.50 bcm gas equivalent compared to imports of 1.71 bcm. Such exports, undertaken to optimise the value of existing LNG inventory, do not require regulatory authorisation or an export licence. The two terminals at Milford Haven are not capable of re-loading vessels and have never re-exported LNG.

#### 2.4 Qatari LNG export expansion and UK regas investment

Qatar lost its status as the world's largest producer of LNG in 2021 but it is widely recognised as the lowest-cost supplier of LNG to global markets. The low cost of feed gas production from the giant offshore North Dome gas field, the economies of scale at its liquefaction trains at Ras Laffan and the value of the natural gas liquids extracted from the rich feed gas confer a sustainable supply cost advantage on Qatari LNG exports unmatched by even US shale gas-based projects. The Qatari LNG





industry was developed from the 1980s by two separate companies, Qatargas and Rasgas, both controlled by Qatar Petroleum, in conjunction with minority foreign company partners. Qatargas and Rasgas were merged in 2018 and Qatar Petroleum changed its name to Qatar Energy in October 2021. All LNG assets and operations, including those in the UK, are owned and controlled by Qatar Energy (QE) and all its LNG is delivered as part of a highly integrated supply and trading operation, mainly to Asian customers under long-term contracts.

The current annual nameplate capacity of the 14 liquefaction trains in Ras Laffan is 77 mt. In recent years, production and exports have been consistently close to nameplate capacity, as shown in Figure 15. In 2021, after a long moratorium on future investment, Qatar Energy took the decision to expand its domestic production capacity to 110 mtpa by approving the North Field East project. The new capacity is expected to be commissioned in phases between 2024 and 2026. A second expansion project, North Field South, is currently under consideration. If approved, it would take total domestic liquefaction capacity to 126 mtpa. Qatar Energy will also add LNG supply to its expanded portfolio from the Golden Pass export project (16 mtpa) on the US Gulf coast, currently being developed with ExxonMobil and due to be commissioned in late 2024 or 2025.

Qatar exports 85-90% of its LNG under oil-indexed, long-term SPAs, mainly delivered ex-ship (DES) to Asian buyers on owned or long-term chartered vessels. These SPAs, typically of 10-20 years duration, include a tolerance of 5-10% of the annual contracted quantity to accommodate the intrinsic uncertainty over demand in the buyers' end-use markets<sup>46</sup>. The remainder of the portfolio is delivered under flexible, non-binding arrangements with third parties and to European regas terminals such as South Hook and Zeebrugge where QE holds capacity. Such flexible sales may include occasional spot sales to third parties but QE is not a significant supplier to the spot market. All the commercial arrangements for delivery to the UK, both to South Hook and to Centrica at the Grain terminal, are flexible and do not represent firm term commitments. Qatar Energy's over-riding commercial priority is to meet its binding obligations to its long-term customers, not to deliver LNG to NW Europe.

Qatar was the largest supplier of LNG to the UK between 2009 and 2021 but in 2022 imports from the US exceeded those from Qatar. Between 2011 and 2017, Qatari LNG accounted for 90% of all UK imports but in the last four years (2018-22) it has fallen back to 30-50%. The corollary of this diversification of UK LNG imports is the diminishing importance of the UK market as a destination for Qatari LNG, as illustrated in Figure 15 which shows the destination of Qatari exports over the last decade. In 2011, soon after commissioning of new Qatari liquefaction capacity, deliveries to the UK represented 20% of Qatari exports but by 2021 this had fallen to no more than 5% as sales to customers in Asia reached a new high.

The South Hook terminal, majority-owned by QE and part of the integrated Qatargas 2 supply chain, has been the most common UK reception terminal but Grain has also received occasional Qatari cargoes under flexible supply agreements, notably Centrica's contract with Qatargas<sup>47</sup>. The commercial terms under which LNG is supplied to QE-controlled South Hook Gas, the primary holder of capacity at the South Hook terminal, are commercially sensitive and have not been disclosed publicly. However, the commercial arrangements appear to be highly flexible. It is understood that there is no binding, enforceable obligation on QE to deliver LNG to South Hook and that it can reduce deliveries if prior notice is given to the terminal and to South Hook Gas (SHG). However, if QE wishes to keep the terminal cool and in operation, it has to deliver about one QMax vessel (265,000 m<sup>3</sup>) per month to the terminal, or about 1.5 mtpa. In 2018, a time of strong Asian demand for Qatari LNG, deliveries to South Hook were an estimated 1.8 mt, not much above this operational minimum. As long as QE has higher-value sales opportunities to its Asian term customers, Qatari LNG will not normally be delivered to South Hook, or to other discretionary markets in NW Europe.

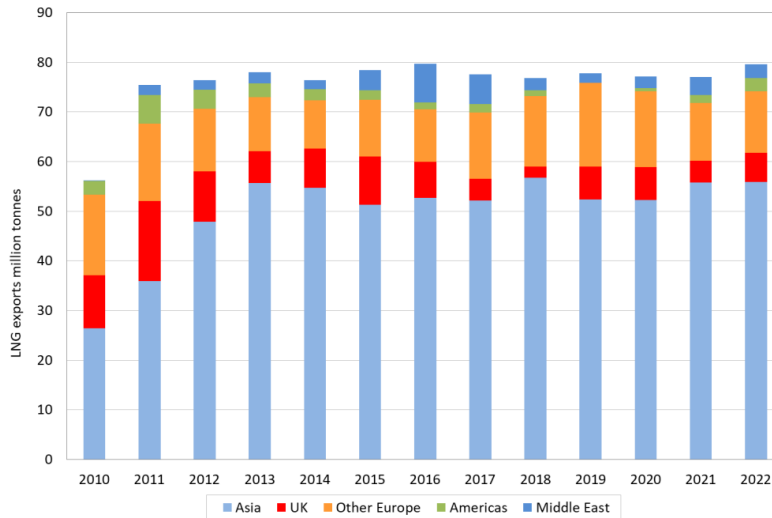
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<sup>46</sup> The GIIGNL Annual Report 2021 includes a comprehensive summary of all Qatar's term supply contracts.

<sup>47</sup> The shareholders of Qatargas 2 are Qatargas (QE), ExxonMobil and Total Energies.



**Figure 15: Qatari LNG Exports by Destination 2010-22**



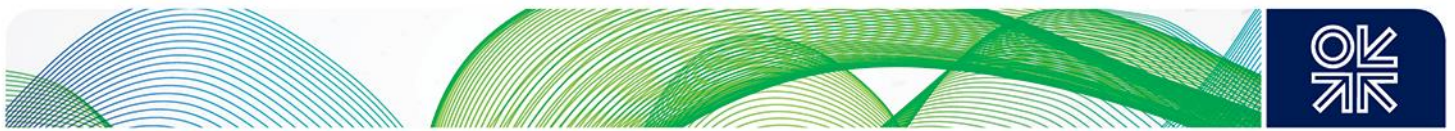
Source: GIIGNL, estimates for 2022 based on Kpler data

Since 2018, QE has become more active in optimising the value of its combined Qatargas-Rasgas portfolio in response to increased volatility of regional price differentials and in seeking to realise the value of South Hook capacity through secondary sales of capacity to third parties. This move to more active portfolio management is reflected in the increase in the amplitude of monthly variations of deliveries of Qatari LNG to the UK since 2018 shown in Figure 14. In the winters of both 2020-21 and 2021-22, when demand from Qatar’s term customers has been strong, there were extended periods of up to 2-3 months when no Qatari LNG was delivered to South Hook and all cargoes arriving at the terminal were from the US<sup>48</sup>. In January 2022, a period of record arrivals and send-out at South Hook, 12 of the 16 cargoes were from the US. Since the arrangements behind this shift of supply sources to South Hook are commercially sensitive and not disclosed, it is not clear whether this was achieved by Qatar Energy through bilateral swaps between Asia and the Atlantic Basin, by separate sales and DES purchases at South Hook or by letting regas capacity to holders of US LNG, or a combination of these possibilities. Whatever the commercial basis, it serves as a reminder that QE-controlled regas capacity at South Hook is no longer used solely for Qatari LNG supply in response to the changes in global LNG markets described above.

In October 2020, Qatar Energy reached a 20-year agreement with Grain LNG to purchase 7.2 mtpa of capacity at the Grain terminal from 2025<sup>49</sup>. After completion of the expected de-bottlenecking at the South Hook terminal in 2025, Qatar Energy will control primary capacity rights at South Hook and Grain equivalent to almost half the UK’s expanded regas capacity of 46 mtpa. Unless there is a fundamental and unexpected change in Qatar Energy’s commercial model or in UK gas market regulation, this increase in contracted capacity is unlikely to be accompanied by any new obligation to supply LNG to the UK. Qatar Energy’s holdings of regas capacity have so far not raised competition concerns in the UK as they have at times in the EU. The European Commission launched a preliminary investigation into destination restrictions in some Qatari LNG supply contracts in 2018 and raised concerns over a 25-year deal agreed in 2019 to purchase all capacity at the Zeebrugge terminal but had dropped the investigations by early 2022. Qatar Energy’s regas position in the UK after 2025 may not in itself raise concerns over competition in the GB wholesale gas market but it should serve as a stimulus to Ofgem and the government to ensure proper scrutiny of the functioning of the secondary capacity market to ensure that such a dominant position could not be abused in future to the detriment of UK gas consumers.

<sup>48</sup> According to vessel tracking sources, no Qatari LNG cargoes were delivered to South Hook between 3 November 2020 and 28 February 2021 (115 days), or between 21 November 2021 and 17 January 2022 (56 days). Deliveries have so far been more frequent and regular in winter 2022-23.

<sup>49</sup> Grain LNG’s Phase 4 expansion and capacity sale is discussed in more detail in Chapter 3.



Any discussion of LNG and UK gas supply security requires, firstly, an understanding of the commercial arrangements under which LNG is delivered to the UK and how regas capacity in the UK is utilised and, secondly, an assessment of the political, commercial and physical risks that might in future interfere with such deliveries. In the UK, attention naturally turns first to the risks to Qatari supply since Qatar has been the UK's largest LNG supplier and the largest investor in regas capacity. The risks to the *physical* supply of Qatari LNG are analogous to those of any LNG supply source: an interruption to upstream feed gas supply and the safe operation of the liquefaction plants, shipping and regas facilities. In this respect, the integrated Qatari operations have so far demonstrated themselves to be highly secure and reliable. The background of Middle East tension between the Arab Gulf states and Iran presents a potential additional element of supply risk, captured in the familiar scenario which includes the closure of the Straits of Hormuz and an interruption of both oil and LNG exports from the ports in the northern part of the Persian Gulf.

Qatar has long been a reliable Middle East ally of the UK and there exist close diplomatic, military and business ties between the two countries. Nonetheless, Qatari deliveries to the UK might in future be interrupted in the unlikely event of a political or diplomatic rupture between the two countries. It should be added that Qatar has never imposed politically motivated sanctions or restrictions on the export of its LNG and the UK has never introduced any trade sanctions on LNG imports before it banned the reception of Russian LNG vessels in March 2022.

The principal risks of a loss of Qatari LNG to the UK market appear to be commercial, rather than physical or political, given the absence of any binding contractual supply obligations. This means that any unexpected, partial reduction of LNG production at Ras Laffan would immediately restrict the volume of uncontracted LNG available to flexible markets like the UK since Qatar Energy would give preference to its long-term contract customers. The risk of a loss of supply to the UK would be greatest when LNG markets are tight and spot prices are above oil-indexed term contract values since contract buyers would have an incentive to maximise their nominations. In such circumstances, it would be essential for UK gas supply security that regas capacity held by Qatar Energy in the UK was freely available to third parties to allow them to deliver alternative supplies of LNG.

Discussions over LNG supply appear to form part of regular diplomatic and ministerial discussions between the UK and Qatar. In November 2021, after a period of low Qatari deliveries to Europe and rising European wholesale gas prices, it was reported that the UK government had conducted talks with Qatari authorities about a possible term contract for LNG supply and arrangements for Qatar to act as a 'supplier of last resort' in a gas supply emergency<sup>50</sup>. No information emerged as to how such possible new arrangements might be implemented. In 2022, amid renewed government interest in long-term import contracts, the Qatari Energy Minister, Saad al-Kaabi, confirmed its commitment to being 'a major player in supporting the UK' but indicated that its new projects would not be producing LNG before 2025<sup>51</sup>. The publicity given in 2021-22 to the issue of Qatari LNG supply to the UK marked an unusual expression of government concern over not only short-term gas supply but also longer-term energy supply security. However, unless it abandons the principle of fair competition in wholesale market supply, the government can do little to influence the purchasing of gas or LNG by privately-owned companies or to promote energy security through long-term contracts with Qatar or any other supplier. As far as LNG is concerned, its principal contribution to energy security will come from ensuring that the operation of the UK's secondary regas capacity market is efficient and that UK network entry costs are competitive with its EU competitors.

## 2.5 US LNG Exports to Europe

It is difficult to over-state the impact of US LNG exports on the global LNG market in the last decade. Since they began in 2016, US LNG exports from the Gulf coast and east coast, underpinned by onshore shale gas production, have transformed the LNG market by increasing supply-side competition and provoking changes to both LNG contracting strategies and contract pricing. Henry Hub-related LNG now competes with oil-indexed supply from more established supply sources in the Middle East and

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<sup>50</sup> 'UK asks Qatar to become gas 'supplier of last resort'', Financial Times, 5 November 2021.

<sup>51</sup> 'UK struggles to secure long-term gas import deals' Financial Times, 8 November 2022.

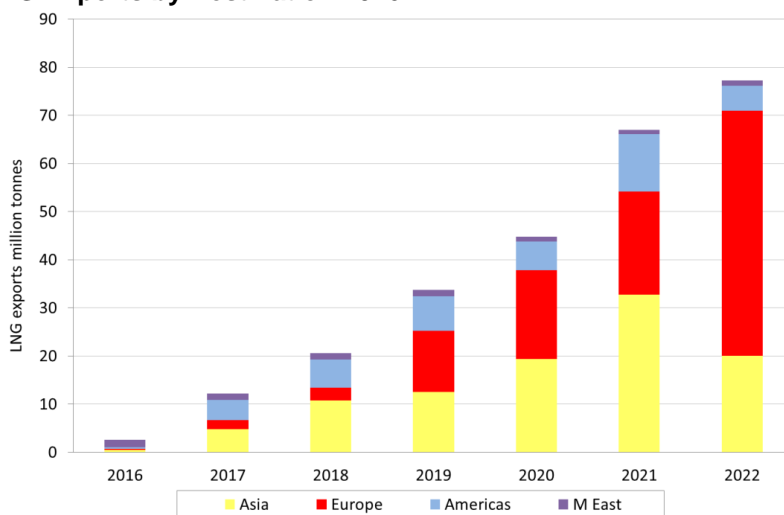


the Pacific Basin. The US did not overtake Qatar and Australia to become the world’s largest LNG exporter in 2022, but, more importantly, it had already become the principal source of freely tradeable LNG to the global market. According to GIIGNL, at least 25 different companies, comprising mainly Asian re-sellers and portfolio players such as Shell, Total and BP, held long-term contracts for LNG supply from the six liquefaction projects in operation at the end of 2021<sup>52</sup>. US LNG also forms a central part of the supply portfolios of active commodity traders such as Vitol, Gunvor, Glencore and Trafigura.

LNG from US plants is supplied under a variety of contractual arrangements: free-on-board (FOB), delivered ex-ship (DES) and under tolling agreements under which feed gas producers purchase liquefaction capacity. Most of the existing long-term contracts take the form of a take-or-pay commitment for liquefaction capacity at a fixed fee which creates an option, but not an obligation, to take delivery of an LNG cargo at a Henry Hub-related price. Typically, the contractual FOB LNG price is 115% Henry Hub price plus a fixed fee of \$2.0-3.50/m BTU. If prices in export markets do not cover the costs of the LNG and shipping costs, or demand falters, the buyer may decide 45-60 days before delivery to cancel the cargo. In this important respect, US LNG export contracts, unlike traditional term supply contracts, do not represent firm term contract supply.

US LNG contract holders and offtakers enjoy the flexibility to sell FOB to traders and portfolio players or to deliver to almost any market in the world. Indeed, this destination flexibility has been an essential element of the business model of US LNG developers. Since 2016, Korea, Japan and China have been the largest-volume destinations for US exports, followed by Spain, the UK and France. In 2022, the UK imported cargoes from all seven US export plants, except the smallest, Elba Island. US LNG export flows have become highly responsive to regional price spreads. Since mid-2021, when European hub prices began to rise in response to reduced Russian pipeline supply, a rising proportion of US exports have gone to Europe since it offered higher netbacks than Asian and Latin American markets. In 2022, about two-thirds of all US exports (77mt) went to Europe as Asian contract holders sold their cargo availabilities or capacity rights to portfolio players and LNG traders. This marked shift in the destination of US exports is illustrated in Figure 16.

**Figure 16: US LNG Exports by Destination 2016-22**



Source: GIIGNL, estimates for 2022 based on monthly EIA data

Baseload US LNG capacity has grown at a spectacular pace in six years to reach 87 mtpa in 2022. The rate of expansion will slow until the start-up of the Qatar Energy/ExxonMobil’s Golden Pass terminal (15.6 mtpa) and Venture Global’s Plaquemines facility (12 mtpa) in 2024-25. Golden Pass is the first US LNG export project which has not relied for its financing on the conclusion of offtake agreements

<sup>52</sup> A seventh plant, Venture Global’s facility at Calcasieu Pass, exported its first commissioning cargo in March 2022 and began commercial operations in May.



with third parties. Its output is expected to be incorporated into the existing QE/ExxonMobil portfolio which includes the South Hook regas terminal. A number of other US liquefaction projects are approaching final investment decision (FID), which could take total US export capacity to 114 mtpa in 2025 and to more than 130 mtpa by 2028. In September 2022, Cheniere Energy, the largest US LNG exporter with 45 mtpa of capacity, outlined its short-term aim to raise capacity at its Sabine Pass and Corpus Christie plants to 60 mtpa and a long-term potential of 90 mtpa<sup>53</sup>.

Further growth in capacity is likely to be set primarily by the rate at which creditworthy offtakers are willing to assume Henry Hub-related LNG in their portfolios under 15-20 year contracts. The recent signing of new offtake agreements with Chinese buyers and the new wave of firm demand from Europe are expected to allow at least two new projects to proceed to FID in 2023. The Federal Energy Regulatory Commission (FERC) has recently relaxed its environmental restrictions on the construction of new onshore infrastructure to take feed gas to LNG export plants. However, domestic political obstacles to the approval of new projects may arise in future if LNG export demand for gas raises Henry Hub prices sustainably much above the \$2-5/mBTU range in which they traded between 2016 and 2021. In the ten months after the Russian invasion, Henry Hub prices averaged almost \$7/mBTU and briefly approached \$10/mBTU in August. In 2022, LNG export demand for domestic gas will exceed 11 bcf/d, about 13% of total domestic demand of 83 bcf/d. Cheniere is already the largest buyer of gas in the US market to supply up to 5 bcf/d of feed gas to its two liquefaction plants at Sabine Pass and Corpus Christi on the US Gulf coast. The price response to a further increase in export demand to about 16 bcf/d by 2026-27 will depend, above all, on the willingness and ability of shale gas resource holders and producers to deploy new capital to expand their production to meet this rise in export demand.

Even before the Russian-Ukraine crisis, the expansion of US exports had been a welcome development for European LNG buyers because it offers an incremental supply of short-haul, tradeable LNG from a politically reliable source. The supply-side risks are primarily commercial, to which one may add the seasonal hurricane-related risk of interruption from US Gulf coast plants. From a US project developer's perspective, Europe is now capable of offering netbacks which match or exceed those from more distant Asian markets. The shipping costs of a 10-15 day voyage from the US to Europe are much lower than a 25-40 day voyage to Asian markets but it may be more difficult to recover Henry Hub-related costs in Europe than in less competitive Asian markets where regulation generally allows LNG importers to recover the weighted cost of gas from many sources from domestic consumers.

There has been a strong geopolitical element to the promotion of US LNG exports since 2012, particularly in Europe where they have been presented as a means of reducing dependence on Russian pipeline supply. The backing of the US government and US project developers was instrumental in underpinning the development of the first LNG import facilities in Poland and the Baltic States. However, broadly speaking, the export of US LNG has been left to the market and the commercial decisions of project developers, offtakers and buyers. This has not prevented European governments from seeking to influence US LNG exports after the dramatic tightening of the market in 2022. In March, a month after the Russian invasion of Ukraine, the US government and the European Commission announced a Task Force on Energy Security with the aim of raising US LNG exports to the EU by 15 bcm (11mt LNG) in 2022 and consolidating demand in the EU for an additional 50 bcm (37mt LNG) by 2030<sup>54</sup>. In December 2022, the new UK Prime Minister and the US President announced a new UK-US Energy Security and Affordability Partnership to double UK imports of US LNG from the levels seen in 2021<sup>55</sup>. Both the EU and UK aims were comfortably exceeded in 2022 through the free operation of LNG markets. Even without such political involvement, the competition for US LNG among European and Asian buyers will at times be intense in the coming years.

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<sup>53</sup> 'Cheniere announces 20/20 vision long term capital allocation plan', press release, 12 September 2022.

<sup>54</sup> 'Joint Statement by European Commission and United States on European Energy Security', European Commission, 25 March 2022.

<sup>55</sup> 'US and UK announce new energy partnership', UK government press release, 7 December 2022.



### 3. UK Terminal Capacity, Capability and Commercial Operation

#### 3.1 LNG import capacity and investment

The UK gas industry was involved in the early development of LNG, in receiving experimental cargoes from Lake Charles, Louisiana in 1958 and in constructing the world's first onshore terminal at Canvey Island to import the first commercial cargoes from Algeria in 1964. However, the discovery of gas in the UK North Sea in 1965 and the rapid development of offshore fields from the late 1960s put an end to the UK's interest in LNG even though France, Belgium and Italy continued to import supplies from Algeria.

The political preference in the UK, unlike the Netherlands and Norway, for market-led development of resources on the UK Continental Shelf (UKCS) by private companies led to a rapid expansion in oil and gas production in the 1980s and 1990s but an equally rapid decline after 2000. As the scale and pace of resource depletion and production decline became apparent, it was evident that the UK would need to secure more imported gas by pipeline or as LNG to meet existing domestic demand and to build the associated import capacity. Between 2003 and 2005, final investment decisions were taken to construct not only the three LNG regas terminals in operation today but also the Langeled pipeline from Norway to Easington and the BBL pipeline from the Netherlands to the UK, all with government support but without state financial support.

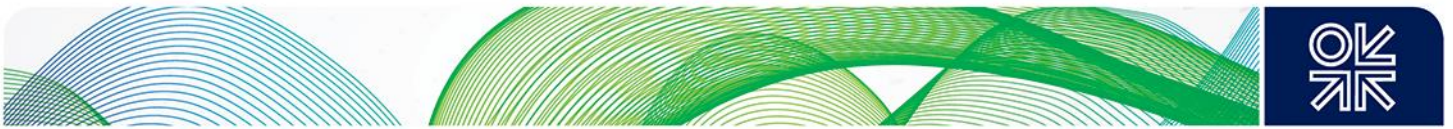
The first large-scale import project was undertaken by National Grid, the owner and operator at the time of the National Transmission System (NTS), which recognised the opportunity to use an existing industrial site on the Isle of Grain to develop the first LNG import terminal for third-party use. In 2004, the partners of Qatargas II and a joint venture of two existing LNG suppliers, BG Group and Petronas, committed themselves to construction of two import terminals at Milford Haven in south-west Wales. This required major investment by National Grid Gas (NGG) to build a new high-pressure pipeline linking Milford Haven to the existing NTS. The two terminals began importing LNG in 2009 and the pipeline project was completed in 2012. By the time of the commissioning on the third phase of the Grain terminal at the end of 2010, the regas terminals we see today were essentially completed. The total nominal annual capacity of the three terminals is almost 36 mt or 48 bcm, well over half the annual UK demand for gas at any time in the last decade. The main physical features of the three terminals, including the key peak send-out capacity, are set out in Figure 17.

**Figure 17: UK LNG Import and Regasification Terminals at End 2022**

Terminal	Owner	Operator	Start-up	Capacity	Storage capacity		Send-out capacity	
				mtpa	million m3	Tanks	GWh/day	mcm/day
Grain LNG	National Grid	Grain LNG	2005	14.8	1.00	8	645	58
South Hook	Qatar Energy 67.5%, ExxonMobil 24%, Total 8%	South Hook LNG Terminal	2009	15.4	0.78	5	650	58
Dragon	Shell 50% Ancala 50%	Dragon LNG	2009	5.6	0.32	2	290	26

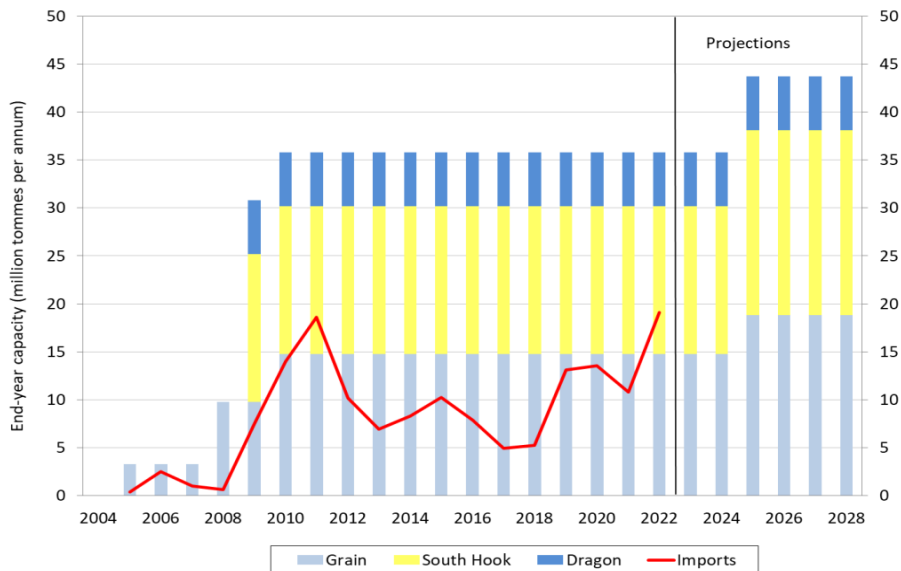
Source: GIIGNL, BEIS, National Grid

In February 2007, Excelerate Energy commissioned a low-cost LNG import facility called the Teesside GasPort in north-east England. Designed to avoid the higher capital cost and long lead-time of a conventional onshore terminal, the facility imported limited quantities of LNG direct to the NTS in both 2007 and 2009 but was mothballed in 2015. Trafigura, the commodity trading company, acquired a lease on the facility in 2017 and announced in 2022 its intention to re-activate it in conjunction with an FSRU but so far it has not been re-commissioned. Since the demand for and cost of FSRUs leapt after Europe's 'pivot to LNG' in March 2022, the economics of such new LNG import capacity in the UK have deteriorated, at least temporarily.



There have been no significant changes to the physical capability of the three onshore terminals since 2010 but in 2018 both Grain LNG and South Hook LNG took the first steps to increase capacity by 2025-26. After an ‘open season’ in 2019-20 revealed industry demand for new capacity, Grain LNG drew up a flexible bidding process which culminated in an agreement to sell capacity for 25 years to Qatar Energy and to expand the terminal’s physical capacity by 3.9 mtpa, including a new storage tank. Since the terminal expansion could be accommodated without major investment in the regulated onshore network, it did not require approval from Ofgem. In 2018, South Hook LNG applied to NGG to increase NTS entry capacity at Milford Haven to accommodate higher terminal send-out and additional LNG imports from the US and Qatar. The associated project needed to reinforce the local transmission network was approved by Ofgem in December 2021<sup>56</sup>. If the project is confirmed by a final commercial agreement between NGG and South Hook Gas in 2023, the nominal annual capacity of the South Hook terminal will increase by 3.9 mtpa. Figure 18 shows total end-year LNG regas capacity between 2004 and 2028, assuming that both the Grain and South Hook expansions are completed by the end of 2025. At a time of climate policy emphasis on reducing UK gas demand in all end-use sectors, it is not unreasonable to ask whether the incremental regas capacity (both base and peak send-out) will ever be fully utilised, even if UKCS gas production declines as expected.

**Figure 18: UK Annual LNG Import Capacity 2004-2028**



Source: BEIS, GIIGNL, terminal operators

### 3.2 Grain LNG

The Grain LNG terminal, owned and operated by National Grid, was the first of the modern LNG import terminals to be commissioned in the UK when it received its first cargo in July 2005. Built on the site of a former oil refinery and an LNG peak-shaving plant, the current terminal in north Kent was constructed in three phases built in rapid succession in 2004-10. The commercial model of the Grain terminal is distinctive in the UK in that the ownership of the terminal is entirely separate from the ownership of the capacity. Grain LNG is the owner and operator of the terminal infrastructure but does not deliver the LNG or sell the gas from the terminal. Grain LNG (GLNG) is part of National Grid Ventures and lies outside the scope of its current UK regulated activities as owner and operator of gas and electricity infrastructure networks. As noted earlier, in 2022 National Grid announced the sale of 60 per cent of its regulated UK gas transmission business but confirmed it will retain sole ownership of Grain LNG.

<sup>56</sup> ‘Western Gas Network Project: Needs Case Decision’, Ofgem, 14 December 2021.



The first phase of 3.3 mtpa was constructed between 2002 and 2005 based a 20-year capacity commitment by BP and Sonatrach, the Algerian state-owned company. The second phase of 6.5 mtpa, approved before the first was completed, was underpinned by long-term capacity commitments from Centrica, Gaz de France and Sonatrach. Grain LNG commissioned the third phase in 2010, adding a further 5 mtpa of capacity, based on commitments by Centrica and two new entrants, EOn and Iberdrola. At the end of 2022, after the investment of £1.1 bn in the three phases, the total nominal capacity is 14.8 mtpa, shared among six companies or their successors after a series of corporate transactions<sup>57</sup>, as shown in Figure 19.

**Figure 19: Grain LNG Phases and Capacity Holdings**

	Completion	Capacity mtpa	Capacity buyers	Contract expiry
<b>Phase 1</b>	2005	3.3	BP, Sonatrach	2025
<b>Phase 2</b>	2008	6.5	Centrica, GdF (Total), Sonatrach	2029
<b>Phase 3</b>	2010	5.0	Centrica, Iberdrola (Pavilion), EOn (Uniper)	2029
<b>Phase 4</b>	2025	3.9 *	Qatar Terminal Ltd (QE)	2050

\* QE agreed to purchase 7.2 mt, comprising new capacity and expiring Phase 1 capacity

Source: Grain LNG

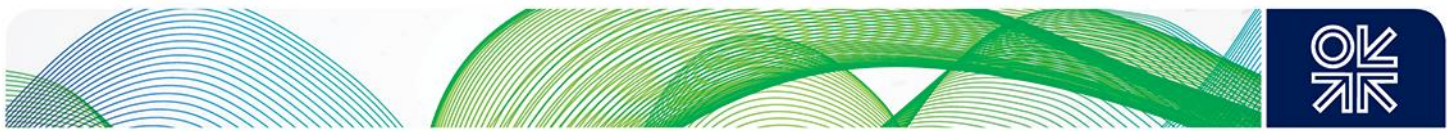
The configuration of the Grain terminal is characterised by its extensive storage capacity and operational flexibility. The eight tanks have a total liquid storage capacity of 1 million m<sup>3</sup>, equivalent to about 0.55 bcm of underground gas storage capacity, which confers additional operational and commercial flexibility for capacity holders. The terminal has two jetties, one capable of receiving QMax vessels (266,000 m<sup>3</sup>) and the other capable of unloading QFlex vessels (217,000 m<sup>3</sup>). Grain LNG also has facilities which allow re-loading of LNG aboard vessels, the cool-down of vessels and the loading of road tankers to serve the growing inland commercial and industrial market for LNG. Between 2015 and 2018, Grain exported occasional cargoes of LNG as capacity holders sold to higher-value destinations. In 2021, truck deliveries accounted for about 1% of the terminal's throughput of LNG. The terminal is also considering investment in small-scale LNG to serve the expanding small vessel and LNG bunker market in NW Europe. Grain LNG is also unique among UK regas terminals in having not only access to the NTS but also a connection to the local distribution zone (LDZ) network, the South East LDZ, operated by Scotia Gas Networks. The send-out to the LDZ is seasonal, accounting for an estimated 2.8 mcm/day in 2021, or 20% of total terminal send-out.

National Grid originally planned to begin construction of Phase 4 in 2014-15. In June 2013, it was granted an exemption from regulated third party access (rTPA) by Ofgem and the European Commission for the expected new capacity. However, Grain LNG was unable to conclude commercial agreements for the new capacity at a time of weak demand for capacity in Europe and the exemption was revoked in 2015. In November 2019, as demand for capacity was recovering, GLNG launched an open season for Phase 4 and invited indicative bids for additional berthing slots, liquid storage capacity and regasification capacity for 15-25 years from mid-2025. The capacity of 7.2 mtpa offered by Grain LNG comprised both new capacity and existing Phase 1 capacity for which contracts expire in 2025.

The open season elicited a high degree of market interest. After final bids by interested parties were submitted in June 2020, GLNG announced in October 2020 that it had reached a 25-year agreement with Qatar Terminal Limited (QTL), a subsidiary of QE, from mid-2025. The public statements accompanying the agreement did not specify the capacity contracted by QTL, merely its duration, but press reports suggest that QTL will take all the 7.2 mtpa offered in the open season and 380,000m<sup>3</sup> of storage capacity, making it by far the largest capacity holder in the terminal from 2025. All capacity at the terminal is currently sold out until 2029.

<sup>57</sup> In 2016, EOn transferred its oil and gas assets to Uniper; in 2018, Engie (formerly GdF-Suez) sold its LNG business to Total Energies and in 2019 Iberdrola sold its LNG assets to Pavilion Energy.





The agreement allowed National Grid to begin investment in an additional tank and vaporisation capacity, which will take total nominal annual capacity from 14.8 mtpa to about 18.7 mtpa. Total capital investment of £425 million by National Grid will be spread over five years beginning in 2021. Since GLNG did not apply for an exemption from regulated TPA, the capacity provided in this agreement will be subject to TPA and, from 2025, the terminal will comprise both exempt and non-exempt capacity. This will be the first capacity at a UK terminal not exempt from rTPA.

In July 2022, GLNG launched an invitation for non-binding expressions of interest in existing capacity which becomes available in 2029 when contracts signed in 2008-10 for Phase 2 and Phase 3 capacity expire. GLNG indicates that more than one-third of the terminal's send-out capacity (27 mcm/d) and storage capacity (360,000 m<sup>3</sup>) will become available in 2029 and that it will consider shorter-term contracts of five years duration as well as long-term commitments of 10-20 years. It is expected to launch a formal binding auction in 2023 or 2024. The value of regas capacity in NW Europe in 2022-25 is currently very high because of the Russia-Ukraine crisis but uncertainty over European gas demand, LNG flows and the eventual resolution of the crisis pervades the outlook for the 2030s.

### 3.3 South Hook LNG

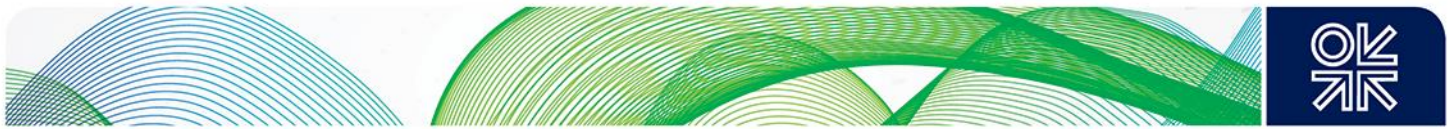
The South Hook terminal was constructed from 2004 as part of the integrated Qatargas II joint venture supplying gas from Qatar's giant North Field. The first LNG cargo was delivered in March 2009 and the terminal was fully commissioned in 2010. The terminal is owned and operated by South Hook Terminal (SHT) which is owned by Qatargas II participants, Qatar Energy (67.5%), ExxonMobil (24.15%) and Total (8.35%). The terminal's current primary capacity of 15.6 mtpa is held by a single entity, South Hook Gas (SHG), under a 20-year contract with SHT. SHG is a joint venture between Qatar Energy (70%) and ExxonMobil (30%) and a registered shipper on the NTS. It holds entry capacity at Milford Haven to deliver gas to the NTS but does not itself sell the gas in the wholesale market. SHG sells gas at the outlet of the terminal to ExxonMobil Gas Marketing Europe (EMGME) which re-sells it in the NBP wholesale market or to end-users.

South Hook is still primarily an 'own use' terminal intended to secure market access for LNG from Qatar, with ownership of the LNG supply, terminal and primary capacity all held by entities connected to the Qatargas II participants. Deliveries to South Hook were exclusively of Qatari LNG until 2018 when SHG made its first sales of unutilised capacity in the secondary market and the terminal began to receive intermittent deliveries of third party LNG from the US. From 2024, deliveries are expected to include cargoes from the Golden Pass liquefaction plant on the US Gulf coast currently under construction by Qatar Energy (QE) and ExxonMobil.

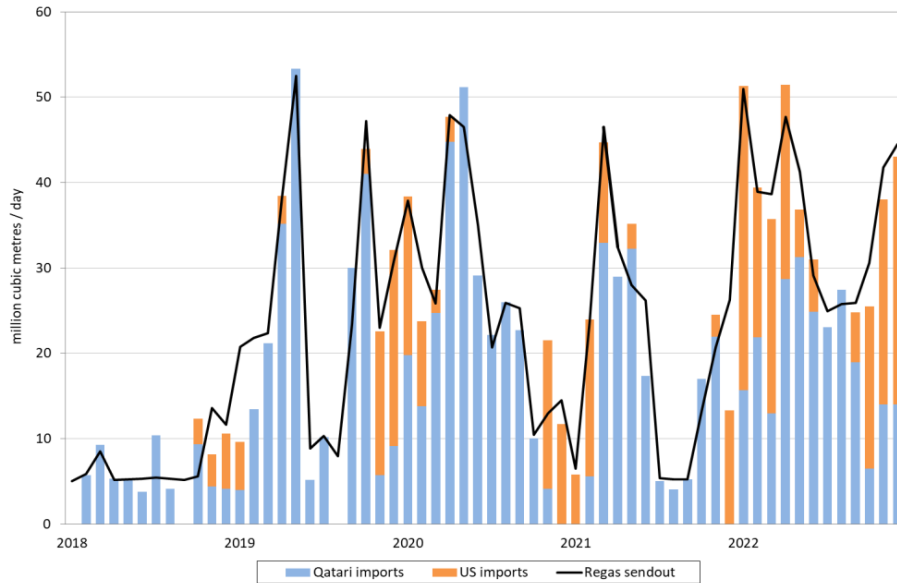
There have been no significant modifications to the vessel reception, storage or vaporisation facilities at the terminal since it was commissioned. The vessel berths and unloading facilities at the terminal are designed to accommodate the largest QMax LNG carriers with cargo capacity of 265,000m<sup>3</sup> which were constructed as part of the Qatargas II project. Boil-off gas from the five tanks is not consumed on site or locally, so the terminal has a constant minimum send out to the NTS of about 5mcm/day. There are no truck loading, LNG bunkering or vessel re-loading facilities at the terminal.

In the early years of operation, all the cargoes delivered to South Hook were from Qatargas II. The increased demand from Japan after the Fukushima disaster in 2011 led to more Qatari LNG being sold to Asian buyers, mainly under term contracts. The LNG supply arrangements between Qatar Energy and SHG are confidential but the pattern of deliveries to the terminal indicates that QE enjoys the contractual flexibility to sell to the highest-value markets and to pull cargoes from the UK when it is economic to do so. Gas imports at South Hook peaked at 14.7 bcm in 2011 but hit a low of 2.7 bcm in 2018 before rising again in 2019 and 2020 amid LNG market over-supply. In the first 12 years of operation (2010-21), the average utilisation of nameplate capacity at South Hook was an estimated 44%, far higher than at Grain (18%) and Dragon (18%), reflecting its position as part of the integrated Qatari LNG supply chain.

Figure 20 shows monthly imports of Qatari and US LNG and regas send-out at South Hook over the last five years 2018-22. It reveals the remarkable growth in third-party, short-haul US imports and the unusual pattern of long-haul imports from Qatar with cargo arrivals from Ras Laffan in every month of the year, unlike the previous four years. Total imports in 2022 were an estimated 13.2 bcm, slightly below the record year of 2011.



**Figure 20: South Hook Imports and Regas Send-out Jan 2018 - Dec 2022**



Source: BEIS, Kpler, Argus Media

In 2016-18, QE developed plans to invest in new liquefaction capacity in the US and Qatar. These were accompanied by plans at South Hook to expand the capacity of the terminal to accommodate more LNG imports and higher send-out. In particular, SHT sought to alleviate the constraints on the use of the terminal’s peak send-out capacity of 813 GWh/d, established in a short-duration test on 10 May 2016. Send-out above the terminal’s base capacity of 650 GWh/d (58 mcm/d) was seldom achievable because of pipeline constraints in the South Wales part of the NTS operated by NGG. In April 2018, South Hook Gas (SHG) submitted a Planning and Advanced Reservation of Capacity Agreement (PARCA) application to NGG to increase firm entry capacity by 163 GWh/day (15 mcm/d) at the Milford Haven entry point to provide improved access to the existing technical send-out capacity of the terminal<sup>58</sup>. This was the first, and remains so far the only, PARCA application to increase entry capacity made to NGG. In response, NGG developed the Western Gas Network Project (WGNP) to meet SHG’s PARCA request<sup>59</sup>. If the project is completed, as expected, in 2025-26, the nominal capacity of South Hook will be raised to 19.5 mtpa, even though the expected modifications to the terminal itself will be modest in scale and limited to the vaporisation and nitrogen ballasting facilities.

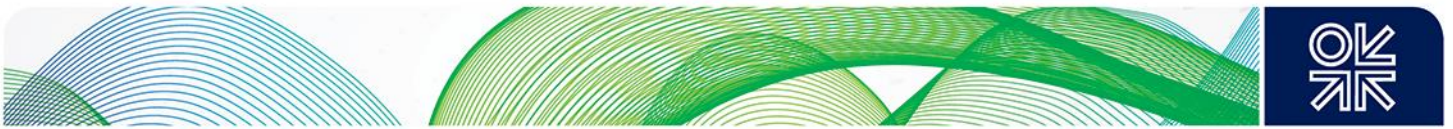
In parallel with the PARCA application, in October 2018, South Hook LNG Terminal (SHT) applied to Ofgem for an exemption from regulated third party access (rTPA) for the planned incremental capacity of 3.9 mtpa for at least 25 years. The application was ostensibly based on the Golden Pass liquefaction project on the US Gulf coast, approved in February 2019 and due on stream in 2024-25, but it could equally provide a destination for the major expansion at Ras Laffan approved in 2021 and due to begin operation in 2025. In May 2020, Ofgem granted SHT a 25-year exemption which was confirmed by the European Commission in December 2020. Unlike the position at Grain LNG, all capacity at South Hook LNG will remain exempt from rTPA until expiry of the original exemption in 2035.

### 3.4 Dragon LNG

Dragon LNG is the smallest of the three UK terminals with nameplate capacity of 5.6 mtpa or about 7.6 bcm per annum. Construction of the terminal on the site of a former oil refinery at Milford Haven was completed in 2009, by which time its ownership was shared equally by BG Group and Petronas, the Malaysian state-owned company. BG Group and Petronas also each held half the capacity of the terminal under a 20-year commercial agreement which expires in 2029. The purchase of NTS entry capacity by Dragon capacity holders and by South Hook Gas, the sole capacity holder at the adjacent

<sup>58</sup> PARCA Phase One Works Report, National Grid, 14 December 2018, available on Ofgem website.

<sup>59</sup> The proposed investment in the NTS and the PARCA process is discussed in more detail in section 4.5

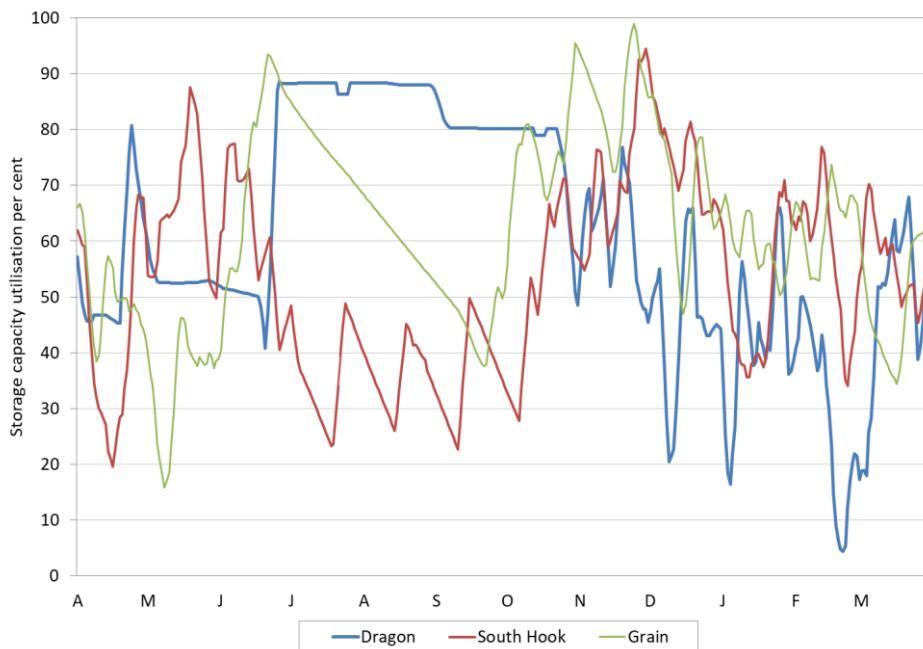


South Hook terminal, underpinned the major investment by National Grid from 2006 to build a major new gas pipeline to accommodate flows from the two new terminals. The first cargo was delivered to the Dragon terminal in July 2009.

Since 2009, utilisation of Dragon’s regas capacity has been consistently lower and more variable than at South Hook or Grain. The terminal was not conceived as part of an integrated LNG supply chain and the two primary capacity holders did not hold firm term LNG supply contracts that required delivery to Dragon. BG Group produced gas on the UKCS but neither BG Group nor Petronas had significant downstream gas positions, preferring to sell as shippers in the wholesale NBP market. For both capacity holders, Dragon offered simply an NBP delivery option within their LNG portfolios. After the Fukushima disaster in March 2011, BG Group and Petronas diverted much of their respective LNG portfolios to higher-value Asian markets and delivered fewer cargoes to Dragon. Between 2012 and 2017, the rate of annual capacity utilisation failed to reach even 10 per cent in any year. In 2012 and 2013, the Dragon partners were restricting deliveries to the terminal to an absolute minimum necessary to keep the terminal cool. They even considered temporarily decommissioning the terminal by allowing it to ‘warm up’. In the end, the potential loss of commercial flexibility and the operational risks of later re-commissioning led to the decision to keep the terminal in operation.

In 2017, Shell completed the purchase of BG Group, acquiring both its stake in Dragon LNG and its capacity holding. This gave Shell, already the largest LNG supplier in the world, direct access to UK regas capacity for the first time. In 2019, Petronas sold its 50% ownership of Dragon LNG, the terminal owner, to Ancala Partners, a midstream infrastructure investor, but retained its capacity holding. There were no changes to the commercial operation of the plant arising from either of the

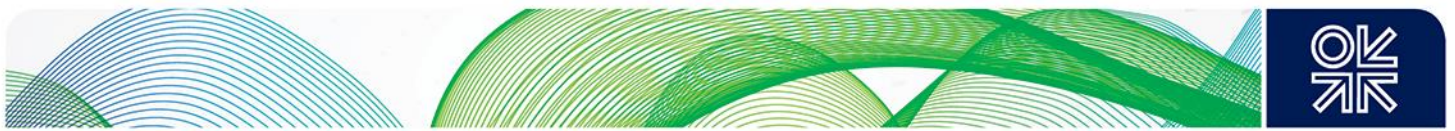
**Figure 21: Dragon’s Storage Capacity Utilisation April 2021 - March 2022**



Source: National Grid Gas

changes of ownership, which has reinforced the separation of the terminal owner from the terminal users. Throughputs remained low in 2018 before rising to 3.3 bcm (44% capacity) in 2020 amid Covid-related over-supply of LNG and an estimated record of 4.7 bcm (62%) in 2022.

The Dragon terminal has only one berth and can accommodate fully-laden Q-Flex vessels (217,000 m<sup>3</sup>) but not the largest Q-Max vessels (265,000 m<sup>3</sup>). This minor constraint on LNG supply flexibility is offset by the relatively high maximum send-out rate of 290 GWh/day or 26 mcm/d, a level frequently reached in winter 2022-23. It also enjoys the commercial flexibility arising from the commissioning in



2018 of a boil-off gas re-liquefaction plant which is unique among conventional regas terminals worldwide. Boil-off gas from the two tanks is re-liquefied, allowing the terminal not to send out gas to the NTS for protracted periods. This commercial flexibility is illustrated in Figure 21 which shows that Dragon retained high levels of LNG stocks through the period July-September 2021 when very few cargoes were delivered to the UK. By contrast, Grain drew heavily on its inventory even at minimum send-out and South Hook operated with intermittently low stocks in this period. The chart also shows the greater variability of Dragon's inventory in 2021-22, between 5% and 90% of capacity, compared to the other two terminals. Dragon LNG, unlike the Grain terminal, is not capable of re-loading LNG onto a vessel and has never exported LNG from the UK. There are no truck loading or LNG bunkering facilities at the terminal and, given its remoteness from potential centres of demand, investment in such facilities is unlikely. There are no published plans to expand capacity or to modify the terminal's current configuration.

### 3.5 Commercial arrangements within terminals

The three existing UK terminals have different commercial models, reflecting the differences in their equity ownership, capacity holdings and physical capabilities and flexibility. South Hook LNG remains primarily an 'own use' terminal designed to receive LNG from the portfolio of Qatar Energy, principally from Ras Laffan. By contrast, Grain LNG operates as independently-owned infrastructure offering third parties in the LNG industry a high degree of commercial flexibility. Dragon sits between these two models since the terminal and capacity are still partly under the common ownership of Shell and its operation is highly sensitive to both the global LNG market and NBP wholesale market prices.

All the primary capacity at the three terminals is booked under long-term contracts, typically for 20 years, entered into at the time of the original capital investment. These contracts between the terminal owner and the primary capacity holder confer rights to a certain number of vessel berthing slots per year, to the LNG tank storage capacity and to regasification or send-out capacity. The relation between these three key elements and the contractual terms regarding slots, storage capacity and minimum and maximum send-out will depend on the physical capability of the terminal and will determine the commercial flexibility in LNG supply and gas send-out enjoyed by the capacity holder. The terms of these underlying long-term contracts for capacity are confidential. At the Grain terminal, there is some variation in the terms of the contracts associated with the three existing phases of the terminal.

At South Hook, all primary long-term capacity is held by South Hook Gas (SHG), a joint venture of QE (70%) and ExxonMobil (30%). At Dragon, it is shared by Shell and Petronas and at the multi-user Grain terminal it is owned by six companies (see Figure 17). All three terminals are currently exempt from regulated TPA rules but the long-term capacity holders are required by regulation to facilitate secondary market trading of their unused capacity<sup>60</sup>. The secondary market comprises mainly 'bundled' capacity access, comprising slots, storage capacity and regas capacity. Any sales and purchases of capacity in the secondary market, typically for short periods, are freely and bilaterally negotiated and there is no obligation to publicly disclose the transactions. Capacity at all three terminals has been sold at various times in the secondary market, providing direct access to the wholesale market to LNG suppliers or traders as an alternative to simply selling LNG delivered ex-ship (DES). In addition to such sales to third parties, at Dragon and Grain primary capacity holders frequently swap or sell slots, storage capacity and send out capacity for mutual benefit. Buyers of capacity in the secondary market will also have to purchase NTS entry capacity, either from NGG in a capacity auction or from an existing entry capacity holder, in order to flow gas to the NBP wholesale market.

Capacity holders are required to release berthing slots that they have not sold and do not intend to use, the so-called 'use-it-or-lose-it' (UIOLI) provisions designed to prevent hoarding of capacity. These unused slots are disclosed publicly at all three terminals but the relatively short notice of the slot availability (typically 10-14 days) makes this a 'last resort' mechanism that is difficult for third parties to use even if they are registered beforehand with the terminal to do so. It is understood that the UIOLI

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<sup>60</sup> All three terminals publish information regarding secondary capacity: 'Access to Secondary Terminal Capacity at South Hook LNG Terminal', South Hook LNG; 'Third Party Access Arrangements', Grain LNG; 'Guide to Secondary Capacity Access at Dragon Terminal', Dragon LNG.



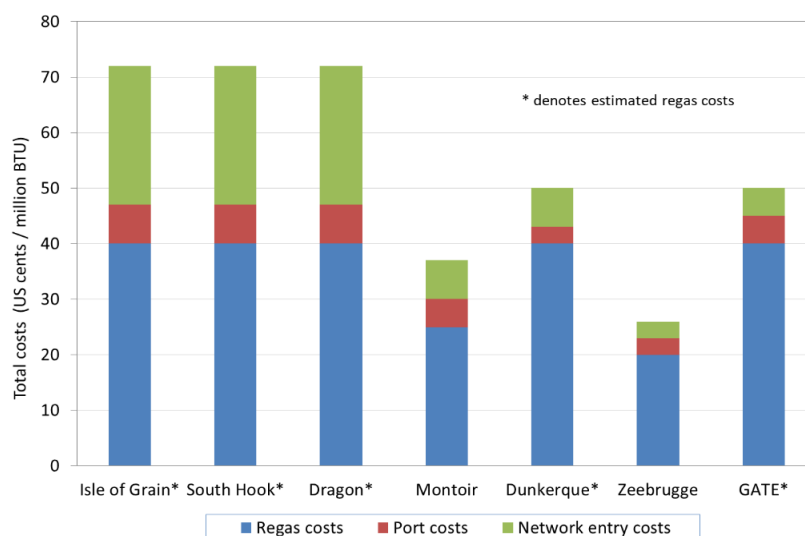
provisions have never been used by third parties at any of the three terminals to bring spot LNG cargoes to the UK market; all purchases of secondary capacity appear to have been bilaterally negotiated before the UIOLI mechanism has been triggered.

### 3.6 The costs of delivering LNG to the UK market

The cost of importing LNG cargoes and delivering gas to the NBP market comprise three elements: the cost of capacity paid to the terminal owner, port costs associated with the vessel and the cost of network entry capacity to deliver re-gasified LNG to the National Transmission System (NTS). For terminals which are exempt from regulated TPA, there is no obligation on terminal owners to publish their tariffs. The terminal costs paid by current primary capacity holders at the three UK terminals are confidential since they are all exempt from regulated TPA. Port costs payable to the local port authorities are usually published and are based on the size and type of vessel. There is some transparency over NTS entry capacity costs but it is not possible to identify the costs incurred by primary capacity holders at individual terminals. Entry capacity is typically purchased in the regular auctions held by National Grid Gas (NGG) and may have been purchased at different prices in auctions held over the last decade or more. The reserve price in each auction, adjusted regularly by NGG, is published but the buyers of capacity and the price paid are not disclosed.

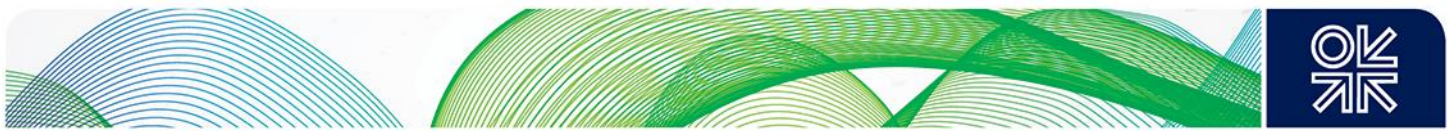
Figure 22 shows the estimated costs of delivering LNG to the three UK regas terminals and four adjacent terminals in continental NW Europe. The most striking feature of the chart is the higher estimated cost of delivering LNG to the UK (70 c/mBTU or about 5 p/therm) compared to competing terminals on the continent (25-50 c/mBTU or 1.7-3.7 p/therm). Most of this higher cost is attributable to the higher network entry costs in the UK. The higher total costs should be seen in the context of the commercial flexibility that the UK terminals offer their capacity users and the liquidity of the wholesale gas market compared to those on the continent.

**Figure 22: Comparative Indicative Costs for NW European Terminals**



Source: Wood Mackenzie, 2021

Two of the terminals (Zeebrugge and Montoir) are regulated and publish tariffs; the others are exempt from rTPA and do not. For the exempt terminals without a published tariff, the cost of using the terminal ('regas costs' in Figure 22) are assumed to be a uniform 40 cents/mBTU or about 3 p/therm but in reality there may be considerable variations, even within the same terminal. The largest element of the regas costs will be a fixed tariff payable to the terminal regardless of use of the capacity. This is designed primarily to remunerate the capital costs of the terminal and its fixed costs of operation such as leases, local taxes, staff and energy. There will typically be a smaller variable cost element associated with each cargo delivered to the terminal, for example for the use of nitrogen ballasting or propane injection facilities.



Network entry costs at regas terminals vary widely across Europe, reflecting the different costs of operating transmission networks and wide differences in the approaches taken by national regulatory authorities (NRAs) to cost allocation and recovery. The cost of entry capacity at Milford Haven and Grain is estimated at 25 c/mBTU (about 2p/therm), several times greater than the comparable cost in France, Belgium or the Netherlands. Although this disparity in entry costs may in part reflect the remuneration of the approved capital costs of the investment in the NTS by NGG in 2006-12 to accommodate LNG imports, it represents, at the margin, a source of competitive disadvantage in delivering LNG to the UK rather than to the near-continent.

This competitive disadvantage applies not only to LNG imports but also to pipeline deliveries to the GB market. Indeed, entry costs on the NTS are by far the highest among the major gas markets of NW Europe for all sources of gas, especially for new bookings of entry capacity, as discussed in section 4.4<sup>61</sup>. At a time of extreme market tightness and price volatility, this GB entry cost disadvantage may seem insignificant but when market conditions return to near-normal and LNG regas capacity on the continent increases, such marginal differences may become more influential in attracting marginal LNG supply.

### 3.7 Regulation of third party access and the secondary capacity market

The nature and extent of the regulation of LNG regas terminals was a contentious matter in the early stages of the liberalisation of European gas markets. The EU's First Gas Directive 1998 gave Member States discretion to introduce either regulated TPA (rTPA) or negotiated TPA (nTPA) but the Second Gas Directive 2003 permitted only rTPA, reflecting concerns that access to regas capacity might restrict gas market competition. However, interconnectors, storage facilities and LNG import terminals were able to apply for an exemption from the requirement to offer third party access (TPA). The reason for this exemption for LNG terminals, later incorporated into section 19C of the UK Gas Act, was to promote investment in such infrastructure since it was recognised that investors may be deterred by the TPA requirements<sup>62</sup>. Since the GB gas market was already more competitive than most other EU markets and the UK government was determined to facilitate new investment, the UK chose to grant exemptions from TPA to the three regas terminal projects being planned in 2003-2005. The exemptions granted were of 19-25 years in length to match the commercial agreements between the terminal owners and the primary capacity holders. The consequence is that all existing capacity at the three UK LNG terminals is exempt from rTPA, based on exemptions granted by Ofgem in 2004.

The UK legislation passed to implement the Second Directive requires that a successful application for an exemption meet a number of criteria: to promote security of supply; not to damage competition or the operation of an efficient gas market; and the risk of the investment was such that it would not be made without the exemption. Exemptions may be granted for construction and for modifications to increase capacity. The approval of the European Commission was also required for any exemptions.

The attraction for the project developers of an exemption was the alleviation of the requirements regarding the regulation of tariffs and third party access which were seen as potentially diluting expected financial returns. Ofgem granted the exemptions for 19, 20 or 25 years on the grounds that the terminals would have 'an overall positive impact on competition and security and diversity of supply for the UK' and that they might not be built unless the exemptions were granted<sup>63</sup>.

Although exemptions from rTPA give project developers more commercial flexibility, they still require terminal owners and operators to ensure secondary market access to capacity that primary capacity holders are not using and to put in place anti-hoarding 'use-it-or-lose-it' (UIOLI) arrangements to provide access as a 'last resort' mechanism. The conditions attached to the exemptions also specify that the terminal owner is obliged to provide information to Ofgem to monitor the exemption and to National Grid Gas for the efficient operation of the gas transmission system. However, the exemptions do not require

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<sup>61</sup> Interconnector (Fluxys) estimated average GB entry costs for monthly capacity in February 2022 at 3.0 pence/therm and those in Netherlands, Germany, France and Belgium in the range 0.6-1.5 pence/therm. Presentation to Westminster Energy Forum by Steven de Ranter, Interconnector, February 2022.

<sup>62</sup> The provision of the EU Gas Directive 2003 regarding LNG terminals was transposed into UK law by the Gas (TPA) Regulations 2004 of 26 August 2004, giving Ofgem formal powers to grant exemptions from rTPA.

<sup>63</sup> Ofgem final views on Grain LNG exemption application, December 2004. The exemption for Grain LNG was granted even though the final investment decision was taken in 2003. The first phase of the terminal was commissioned in 2005.



public disclosure of information about capacity or throughput charges paid by terminal users, thereby preserving commercial confidentiality for owners and operators. Ofgem may decide to review an exemption if it receives complaints that the arrangements for secondary trading or the anti-hoarding mechanisms are not effective. If such complaints were upheld, or the exemption conditions were breached, Ofgem could revoke or withdraw an exemption.

The adoption of the EU's Third Energy Package in 2009, comprising a new Gas Directive and Gas Regulation, modified the legal framework for the UK's LNG terminals. The aim of the Third Package was to complete the internal energy market and to promote efficient and interconnected wholesale gas markets through the development of a series of EU Network Codes designed to harmonise capacity access and trading rules. Ofgem launched a public consultation in September 2011 and released new guidance in April 2012, intended primarily to provide clarity for prospective new investors<sup>64</sup>. Most of the legal provisions of the Third Energy Package regarding LNG relate to terminals operating within a regulated TPA regime, not a regime in which all capacity is exempt. Ofgem did not revise the existing exemptions or the criteria for future exemptions. Its guidance merely provided clarification on several issues:

- auctions and open seasons are the preferred market-based mechanisms to allocate capacity and to determine tariffs paid for LNG terminal capacity;
- transparency and public information provision, particularly over UIOLI arrangements, would be required to ensure effective and fair access;
- new powers of monitoring and enforcement would be used, if necessary, to ensure compliance with rTPA exemption conditions.

In 2012, following an open season to test market demand for new capacity, Grain LNG applied for an exemption for its proposed Phase 4 which would add 6.2 mtpa to the existing capacity. After consultation, Ofgem granted the exemption since it met the criteria set out in legislation but it reduced the period of the requested exemption to 19 years and required the UIOLI anti-hoarding arrangements to be approved by Ofgem in advance of commissioning. In the event, Grain LNG decided not to proceed with Phase 4 as demand for new capacity receded and the exemption was formally revoked on June 2015.

In 2018, South Hook LNG Terminal (SHT) launched a PARCA application to increase the network entry capacity at Milford Haven to permit an increase in its send-out capacity and applied to Ofgem for an exemption from regulated third party access (rTPA) for the planned incremental capacity. Ofgem granted the exemption for an additional 3.9 mtpa of capacity for 25 years in May 2020. The European Commission approved the exemption, with minor amendments, and Ofgem confirmed the exemption in December 2020. This extends the horizon for exempt capacity at the South Hook terminal from 2034 to 2050.

In 2019, as demand for regas capacity in NW Europe strengthened, Grain LNG launched another open season for a combination of new capacity and existing capacity which became available in 2025. The two-phase process was concluded with an agreement in October 2020 between GLNG and Qatar Terminals Limited (QTL), a subsidiary of QE, for the sale and purchase of 7.2 mtpa of capacity for 25 years until 2050. Significantly, Grain LNG did not apply for a rTPA exemption for the new capacity, or for an extension of the exemption for the existing capacity. This demonstrated that new capacity could be both constructed in the UK and existing capacity sold under long-term agreements without the need for an exemption from rTPA. From 2025, there will be, for the first time, regas capacity in the UK which is subject to the requirement of regulated TPA.

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<sup>64</sup> 'Guidance on the regulated TPA for LNG facilities in Great Britain', Ofgem, 13 April 2012.



The co-existence, from 2025, of both the new exempt capacity at South Hook and the new non-exempt capacity at Grain, both controlled by Qatar Energy, is striking but it is not yet clear what differences it will make for the terminal operator or the capacity holder. Inevitably, this development and the Russia-Ukraine crisis in 2021-22 raise several questions about LNG regas regulation:

- is the UK's permissive regulatory regime, designed to promote investment in import capacity, still necessary and appropriate?
- are the arrangements for secondary capacity trading and UIOLI functioning properly and the exemption conditions being met?
- given the greater role LNG supply now plays in NBP price-determination, should the increase in the concentration of UK regas capacity holdings be given greater weight in Ofgem's regulation of the GB gas market?

There is no evidence in the public domain that the current regime of regas terminal exemptions from regulation is damaging supply security or competition in the GB market. All three terminals publish guidance on third-party access through the sale of a 'bundled' product comprising a berthing slot, access to LNG storage and firm send-out capacity, and comply with the requirement to offer a 'last resort' UIOLI mechanism<sup>65</sup>. In practice, the secondary regas capacity market appears to have been active and to have functioned well in 2021-22, allowing more LNG to enter the UK market in response to market price signals, but the extent of capacity trading is still largely unreported.

In 2022, LNG traders are understood to have purchased individual slots, or 'strips' of several slots in consecutive months, sometimes many months ahead, including some under option arrangements. Secondary capacity appears to have been sold to third parties at all three terminals even though the propensity of primary capacity holders to enter the market varies considerably. The delivery of 61 US LNG cargoes to South Hook in 2022 was facilitated in part by the more active sale of 'South Hook Bundles' (slots) by SHG since 2020 under framework agreements with prospective 'additional' users. At Grain LNG, which received 51 US cargoes in 2022, some of the six primary capacity holders also sold slots to third parties in addition to trading slots between themselves. It is understood that some UK slots have been offered and sold with accompanying NTS entry capacity. Unlike the position at regulated EU terminals like Zeebrugge that sell slots in public auctions, the prices at which UK regas slots are sold are not disclosed for commercial reasons. However, it is evident that the price of UK slots did not reach the astronomical levels seen in the EU at the height of the crisis in 2Q 2022 since access to the TTF market was dependent on securing capacity in the UK-EU interconnectors<sup>66</sup>.

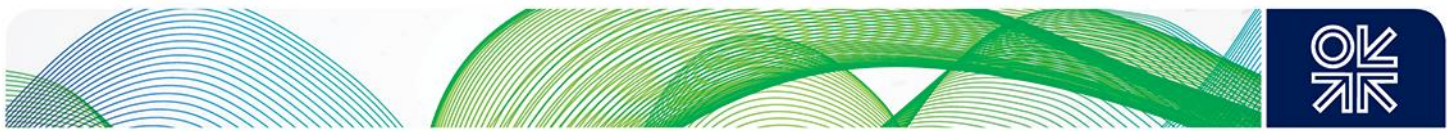
There is no evidence that the secondary market to UK regas capacity is not functioning as it should. However, the question of third party access to UK regas capacity under the current regulatory regime in all market circumstances has become more pertinent since the onset of the Russia-Ukraine crisis. Ensuring third-party access to unused producer-controlled infrastructure capacity, such as Gazprom's storage capacity in Germany, through temporary administration of such assets was essential to mitigating the damage provoked by the politically-motivated reduction of Russian gas supply. The UK has so far been spared the physical supply uncertainty seen in continental Europe and the UK has never suffered a politically-motivated restriction of gas supply, apart from the self-imposed ban on Russian LNG imports from March 2022. However, after a decade of benign neglect of this regulatory issue, a review of Ofgem's oversight of the market and of the powers of Ofgem and the UK government regarding domestic infrastructure in extreme political and market circumstances would now be appropriate, as part of a wider re-assessment of UK energy security.

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<sup>65</sup> 'Access to Secondary Terminal Capacity at South Hook LNG', South Hook LNG and 'Third Party Access Arrangements', Grain LNG.

<sup>66</sup> In May/June 2022, some slots at Zeebrugge and other continental terminals were reported to have been sold at auction for \$25-30million or \$5-6/mBTU, more than 10 times normal prices before the crisis.





### 3.8 LNG storage capacity and inventory management

The contribution of the three LNG regas terminals to UK energy supply security arises not only from their LNG import capacity and access to world LNG markets but also from their combined liquid storage capacity and the ability to raise their send-out very quickly to meet increases in gas demand or to compensate for interruptions to supply from other sources. In this respect, the behaviour of the terminals as a source of flexible supply to the NBP wholesale market has something in common with that of underground gas storage sites.

All land-based regas terminals are required, for operational reasons, to retain a minimum inventory of LNG to keep their storage tanks and unloading lines cool. This is referred to as the 'heel', which normally represents about 5 per cent of total storage capacity. This minimum inventory is included in the definition of operating inventory which is submitted by the terminal operators to NGG and published daily under REMIT regulations<sup>67</sup>.

At the end of 2022, the combined liquid storage capacity at the three terminals amounted to 2.1 million m<sup>3</sup>, almost half of which was located at the Isle of Grain terminal<sup>68</sup>. This combined storage operating capacity is equivalent to 13,750 GWh or about 1.25 billion m<sup>3</sup> of conventional underground gas storage capacity. By comparison, the capacity at the seven Medium Range Storage (MRS) underground gas storage sites amounted to about 1.6 billion m<sup>3</sup>. The recently partially re-commissioned Rough facility adds an additional 0.8 bcm of capacity but its injection and withdrawal rates are not yet commensurate with this figure<sup>69</sup>. The maximum daily send-out from the regas terminals is estimated at about 138 mcm/d compared to a maximum withdrawal rate from the underground storage sites of 117 mcm/d<sup>70</sup>. Since the decommissioning of the Rough seasonal gas storage facility in 2017, the liquid storage at the three regas terminals has assumed a much more important role in ensuring adequate supply at times of peak winter demand, as demonstrated during the so-called 'Beast from the East' late-winter cold snap in February/March 2018 and the two-week cold spell in mid-December 2022.

Utilisation of UK LNG storage capacity varies widely in response to the rate of LNG imports, the demand for gas and the structure of NBP prices in the wholesale market. For example, in 2018, the overall utilisation rate varied from 14% of capacity (1,845 GWh) in late March, soon after the late-winter cold snap, to a peak of 95% (12,840 GWh) in late October as the rate of UK imports rose in an increasingly over-supplied LNG market (see Figure 23). In aggregate, there is a weak seasonal pattern to the stockholding. Stocks are typically, but not invariably, built up over the summer months and drawn down to low levels towards the end of winter in February/March but the seasonal pattern is not particularly strong or uniform. LNG storage does not in this respect behave like seasonal underground storage which tends to be more sensitive to seasonal variations in demand and seasonal NBP price spreads. Indeed, the pattern of LNG send out more often displays similarities with fast-cycle underground storage in responding to daily and intra-day price volatility.

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<sup>67</sup> Daily sendout and storage data for each terminal can be found on the National Grid website under Gas Transmission and 'Transmission operational data'

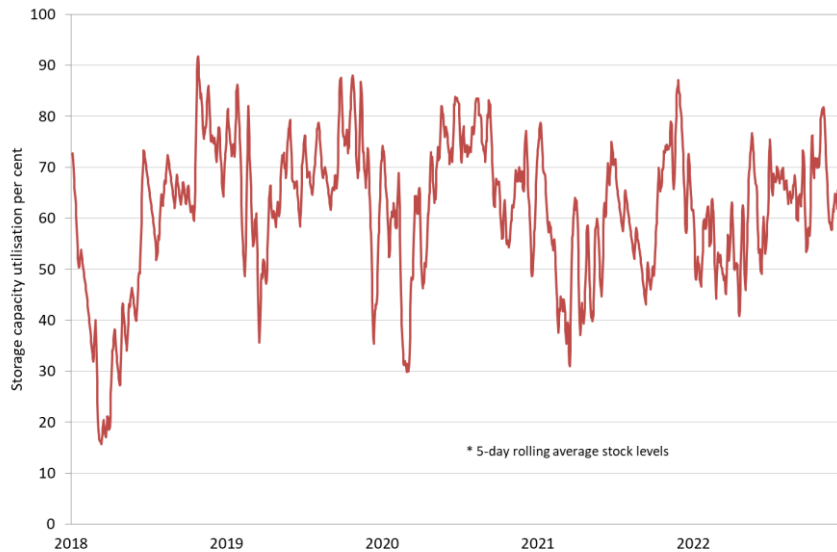
<sup>68</sup> Completion of the Phase 4 expansion at Grain LNG in 2025 will raise the terminal's storage capacity to 1.2 million m<sup>3</sup> but this is expected to be followed by the retirement of the older, smaller tanks.

<sup>69</sup> Available capacity at Rough in January 2023 is recorded by National Grid Gas as 800 mcm.

<sup>70</sup> Digest of UK Energy Statistics 2021, July 2022 (Table 4.4)



**Figure 23: Storage Capacity Utilisation at LNG Terminals Jan 2018 - Dec 2022**



Source: National Grid Gas

Stockholding patterns at all three terminals are occasionally synchronised in response to fluctuations in the global LNG market or in UK gas demand. For example, in late January 2019, all three terminals held high stocks (>90% of capacity) after a period of high imports and relatively weak UK winter demand. Conversely, there have been occasions when the stock position at the three terminals has been quite different, reflecting what appears to be a greater sensitivity at Grain and Dragon to NBP time spreads and the incentive or disincentive to hold inventory. For example, in early September 2019, stocks at South Hook were exceptionally low after a slowdown in Qatari deliveries to the UK but stocks at both Grain and Dragon were close to peak levels as capacity holders had hedged their inventory at higher prices for delivery in the coming winter.

Short-term operational factors such as vessel delays or diversions to other markets affect inventories at all three terminals. However, as expected, inventories at the 'own use' South Hook terminal appear to be more closely associated with management of the Qatari LNG portfolio than the variations in the level or structure of NBP prices. The public notification of LNG cargo arrivals at UK terminals is closely watched, not only by NBP gas traders but also by those in National Grid Gas responsible for operational management of the NTS, as a possible clue to changes in gas send-out in the coming days or weeks.

Over the 5-year period from January 2018 to December 2022, the Grain terminal has the highest average level of liquid inventory (4,250 GWh), well above that of South Hook (2,940 GWh) and Dragon (1,220 GWh). This reflects not only the greater storage capacity but perhaps also the greater number of primary capacity holders at Grain LNG, each of whom has a minimum contractual stockholding requirement in its agreement with the terminal owner. Inventories at Dragon appear to be managed more actively than at South Hook or Grain in response to the changing shape of the NBP forward price curve. Its zero send-out capability means that the capacity holders are able to retain high stocks at above 90% of capacity for extended periods if forward NBP prices favour stockholding, as occurred in both 3Q 2019 and 3Q 2020. Stocks levels at South Hook vary somewhat less than at Grain and Dragon, consistent with its principal role as part of the integrated Qatari LNG supply chain to the UK.

The flexibility at any LNG regas terminal to supply gas to the NTS is, at any given time, closely related to the inventory held in tank and the expected arrival of LNG vessels. If inventories are low and close to minimum operating or contractual levels, the flexibility to deliver gas to the NBP wholesale market is very limited and entirely dependent on the arrival and discharge of the next LNG cargo. Equally, if inventories are very high and close to tank tops, the stockholder will also lack flexibility since it may be obliged to send out gas to create ullage (spare capacity) for the next LNG cargo delivery. If inventories are either very high or very low there is little or no flexibility or commercial discretion available to the stockholders. The greatest flexibility is enjoyed when the existing stocks are moderate and there is clear 'line of sight' over future LNG cargo arrivals.



There are no legal or regulatory obligations on terminal operators and capacity holders to keep a minimum level of inventory at the regas terminals. However, regas capacity holders with LNG inventory are able to contract voluntarily to hold LNG on behalf of the NTS operator as part of the Operating Margins scheme. NGG (now NGT) is obliged under the Uniform Network Code (UNC) and its Gas Safety Case to hold a minimum Operating Margin (OM) to meet possible supply losses, to maintain system pressure and to address safely a gas system emergency. Each year, it conducts a competitive tender in which storage operators, LNG terminal operators, interconnectors and gas-fired generators are invited to bid. In 2022-23, NGG initially tendered for 869 GWh (78 mcm) for the peak winter months but after the Russian invasion and the greater risk to GB supply, it revised this peak quantity to 989 GWh (89 mcm). NGG does not disclose the names of the bidders or winners in the auction but participants at two of the three terminals have regularly participated in the OM scheme and have been awarded OM contracts in the last three years<sup>71</sup>.

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<sup>71</sup> Operating Margins Statement 2022-23 (Feb 2022) and OM Report 2022-23 (August 2022), National Grid Gas. For the winter 2022-23, NGG contracted a total OM volume of 989 GWh with a maximum deliverability of 650 GWh/day.



## 4. NTS Entry Capacity, Operations and Investment

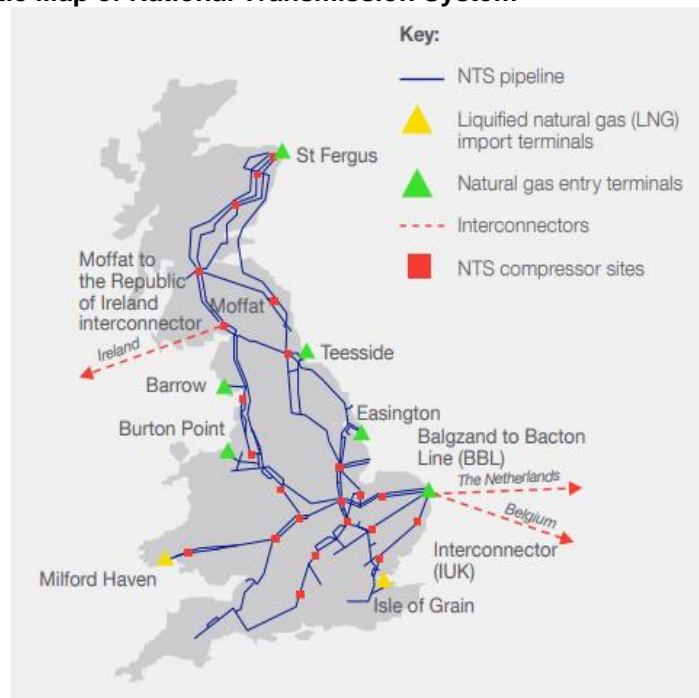
### 4.1 NTS regulation, ownership and operations

Access to the National Transmission System (NTS), until recently wholly-owned and operated by National Grid Gas (NGG), is essential as the ‘route to market’ for LNG received at UK regas terminals. The availability and cost of NTS entry capacity, the capability of the NTS to handle the fluctuations in regas send-out and the efficiency of the trading arrangements between the UK and the EU all have an important influence on the competitiveness of the UK as a destination for LNG and the contribution that LNG makes to UK supply security.

With the exception of the limited volume of gas which enters the local distribution zone (LDZ) at the Grain LNG terminal, or is delivered as LNG to trucks, all re-gasified LNG delivered from the three UK import terminals enters the NTS through network entry points at Milford Haven and the Isle of Grain. There is a single entry point at Milford Haven which serves both the South Hook and Dragon terminals. In 2021, an estimated 95% of energy delivered by the three terminals was sent out to the NTS. Figure 24 shows the location of the two entry points as part of the wider NTS network.

The NTS in Great Britain, comprising 4,740 miles of high-pressure pipelines and 23 compressor stations, is now 60% owned by a consortium of private investors and 40% by National Grid plc<sup>72</sup>. NGG was re-named National Gas Transmission (NGT) in February 2023 to reflect the change of ownership. It undertakes this regulated activity under a detailed licence issued under the Gas Act 1986 which grants it certain powers and imposes obligations to ensure the safe and efficient operation of the network. Gas transmission is regulated by Ofgem which sets price controls designed to generate an allowed annual revenue for NGG and a reasonable return on its investment<sup>73</sup>. The current

**Figure 24: Schematic Map of National Transmission System**



Source: National Gas Transmission

<sup>72</sup> The consortium comprises Macquarie Asset Management and British Columbia Investment Management Corporation.

<sup>73</sup> The Regulated Asset Value (RAV) of NG’s UK transmission business was £6.6 bn at the end of March 2022. In 2021-22, UK gas transmission generated an adjusted operating profit of £654m and a return on equity of 7.8%.



regulatory period under the so-called RIIO-2 price controls came into effect on 1 April 2021 and will run for five years until 2026. National Grid's Grain LNG terminal is an unregulated activity, separate from NGG, and forms part of National Grid Ventures.

The UK's gas and electricity networks operate under different price controls but both networks have separate allowed revenue streams for the Transmission Owner (TO) and for the System Operator (SO). Formerly, the TO and SO for the gas network were bundled within National Grid Gas. The common ownership of the TO and SO in gas transmission created some operational synergies but did not permit transparency over gas network planning and use and may have encouraged an 'ownership bias' in the operation of the gas network. In electricity, the System Operator was transferred in April 2019 to a legally separate business, the Electricity System Operator (ESO), in order to improve the transparency of National Grid's activities as system operator, to address possible conflicts of interest between National Grid and electricity suppliers and to promote innovation.

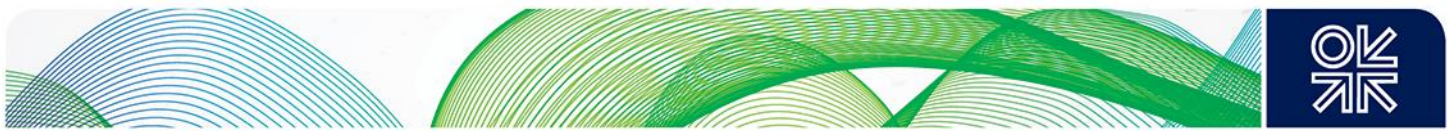
In January 2021, Ofgem recommended to BEIS the full separation of the ESO from National Grid to create a new Independent System Operator (ISO) and suggested that the ISO could incorporate network planning functions for gas. BEIS and Ofgem conducted a consultation in the summer of 2021 on the future of system operation for both electricity and gas and the appropriate functions of a new Future System Operator (FSO) in order to pursue the UK's net zero target. In April 2022, BEIS and Ofgem announced that a new independent, publicly-owned FSO will be set up by 2024 'to drive progress towards net zero while maintaining energy security and minimising costs for consumers'.

The main features of the proposed new regulatory regime are as follows:

- the FSO will assume not only the existing roles of the current ESO but also the planning, forecasting and strategic functions for the gas network currently performed by NGT;
- the new FSO will be regulated under licence from Ofgem;
- it will not be responsible for real-time operations and balancing of the gas system or the functions of the Network Emergency Co-ordinator; the operation and balancing function will remain with the gas network owner;
- the duties and objectives of the FSO will include achieving net zero, ensuring security of supply of electricity and gas and delivering an efficient and economical gas and electricity system;
- the reform will be phased in by 2024 through new primary and secondary legislation, new licensing arrangements and amendments to existing energy codes.

The effect of the proposed reform would be to integrate the strategic planning of the electricity and gas networks but to separate the planning of the gas network from its real-time operation. While this may confer advantages in the scheduling of decarbonisation investment in both networks, it could add to complexity in the management of the existing gas network. After more evidence on the scope and potential for the use of hydrogen in the gas networks is available, the government is expected to decide on the precise design of the new regulatory arrangements. It is difficult to over-state the importance of the remit and responsibilities of the new regulatory arrangements for the future of both natural gas and hydrogen in the UK and the course of UK decarbonisation.

The impetus to create a new independent FSO for electricity and gas arose from the UK's adoption of a net zero target in 2019 and the desire to create a clear new remit for integrated development of the electricity and gas networks in a 'whole system' approach. However, it is not yet clear how the policy objective of security of supply of gas will be framed in the objectives of the FSO and how the introduction of a new publicly-owned body alongside BEIS, Ofgem and National Grid as electricity network asset owner will help to resolve the trade-offs between the three main policy objectives of decarbonisation, affordability and security of supply. Some delay in the ambitious schedule for the implementation of the regulatory and institutional reforms would not be surprising.



Against this background of UK decarbonisation and regulatory reform, in March 2021, National Grid PLC announced its intention to sell a majority stake in NGG as part of a major portfolio restructuring designed to rebalance its UK asset base towards electricity<sup>74</sup>. The conclusion of the sales process was reached in March 2022 with an agreement with a consortium of infrastructure investors led by Macquarie Asset Management for the sale of 60% of NGG. The transaction was completed in January 2023. National Grid will hold a remaining 40% minority stake in NGG in a new holding company as a 'discontinued operation' and is expected to complete the sale of this remaining stake in 2023 or 2024. This transaction marks, in effect, the withdrawal of National Grid from the regulated UK gas business although it will retain its ownership of Grain LNG, the owner of the Isle of Grain terminal. The transfer of ownership is expected to facilitate more transparent competition between electricity on one hand and natural gas and hydrogen on the other in the process of UK decarbonisation.

## 4.2 NTS entry capacity booking

Any company wishing to deliver regasified LNG to the NBP wholesale market has to hold a shipper's licence, granted by Ofgem, to become an NTS user and then needs to purchase entry capacity at the relevant NTS entry point. National Grid Gas (NGG) is obliged to make available to shippers a minimum level of firm capacity at each Aggregated System Entry Point (ASEP) in a series of auctions and may also release 'non-obligated capacity' at an ASEP at its discretion. This minimum level of firm or baseline capacity to be released by NGG at each entry point is set out in its Transporter Licence and the Entry Capacity Release Methodology Statement determines how NGG releases this capacity for sale to shippers. For each entry point, capacity is made available on either a firm or interruptible basis. Once shippers have acquired entry capacity, they have an entitlement or right to flow gas onto the NTS. This is sometimes referred to as the 'ticket to ride' principle. Entry capacity is offered and traded in kWh/day.

NGG offers firm entry capacity to shippers under a range of auction mechanisms: a Quarterly System Entry Capacity (QSEC) auction held annually in March offering quarterly capacity up to 16 years forward, the Annual Monthly System Entry Capacity (AMSEC) auction offering monthly capacity up to 18 months forward and rolling monthly auctions for capacity one month ahead. In 2022, NGG added weekly auctions for the first time following adoption of an amendment to the Uniform Network Code<sup>75</sup>. Firm capacity is offered in these auctions only if it has not been previously purchased in an earlier auction. Interruptible capacity may also be offered, when available, for one day in the 'day ahead' capacity market. Shippers may also purchase firm entry capacity, if available, within the gas day. All entry capacity is offered on a pence per kWh per day basis, payable whether or not the capacity is used by the shipper.

The pattern of shippers' demand for NTS entry capacity for flexible, intermittent sources of supply such as LNG regas terminals, interconnectors and storage sites is naturally quite different from demand at beach terminals from the UKCS or NCS. In order to make shippers' booking of entry capacity more efficient and better adapted to the pattern of LNG delivery, in 2021 South Hook Gas proposed the introduction of weekly entry capacity auctions as a modification of the UNC. After industry consideration, the proposal was approved by Ofgem and implemented in April 2022.

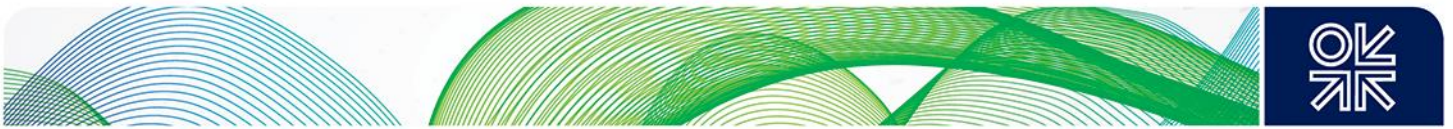
The firm obligated entry capacity at the Milford Haven entry point, which serves both the South Hook and Dragon terminals, in 2022-23 is 950 GWh/d (86 mcm/d) and at the Isle of Grain entry point it is 700 GWh/d (64 mcm/d)<sup>76</sup>. Together they account for more than 15 per cent of total NTS obligated entry capacity. Only the beach terminals at St Fergus and Easington have higher obligated capacity. Capacity at Milford Haven entry point may be used by shippers delivering gas from either the South Hook or Dragon terminals. Figure 25 shows the baseline entry capacity and the capacity sold at the Milford Haven and Isle of Grain entry points by quarter to 2030. Baseline capacity at Milford Haven is expected

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<sup>74</sup> National Grid announced the purchase of Western Power Distribution, the UK's largest electricity distribution business, the sale of part of its US electricity assets and the intended sale of a majority stake in NGG.

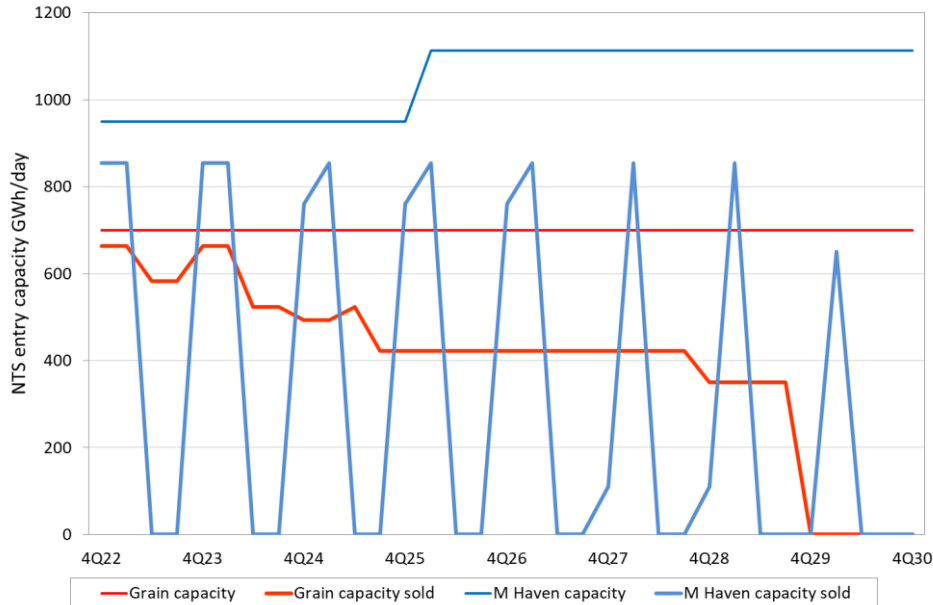
<sup>75</sup> UNC Mod 752S: Introduction of Weekly Entry Capacity Auctions, implemented 24 April 2022.

<sup>76</sup> In regulatory terms, the 'Non-incremental Obligated Entry Capacity' at any entry point is the sum of the Licence Baseline Capacity, established in the Transporter's Licence in 2015 and the legacy 'TO Entry Capacity' determined between 2015 and 2017.



to increase from the current 950 GWh/day to 1,113 GWh/day from January 2026, marking the planned reinforcement of the inland transmission network as part of the Western Gas Network Project (WGNP). The baseline entry capacity at the aggregated Isle of Grain entry point (combining NTS1 and NTS2) is unchanged at 700 GWh/day throughout the next eight years but may possibly be expanded after the Phase 4 expansion of the terminal in 2025.

**Figure 25: NTS Entry Capacity Bookings at LNG Terminal Entry Points**



Source: National Grid, Dec 2022

All entry capacity holdings are anonymous and the prices at which the capacity has been purchased in the regular auctions are not disclosed. Part of the current capacity holdings at both entry points were purchased as long-term commitments made in 2005-10 to underpin the NTS investment which accompanied the regas terminal investment. At both entry points, 90-95% of the baseline capacity is booked in the next three winter periods (October-March) but the pattern of booking at Milford Haven, presumably mainly by capacity holders at South Hook, shows a strong seasonal pattern which is virtually absent at the Grain entry point. This indicates either the differences between the economic tests which had to be met by long-term bookings at Milford Haven and Grain, or the higher value regas capacity holders at South Hook and Dragon attach to entry capacity in the winter months, or a combination of these factors. This commercial approach has so far been vindicated by the winter peak in arrivals and send-out at the two terminals. There are currently no firm bookings of Grain entry capacity beyond 3Q 2029 and none at Milford Haven beyond 1Q 2030. Analysis of the historical capacity auction results shows that there have been no additional bookings of entry capacity at Grain since March 2017 and only minor additions to entry capacity holdings at Milford Haven, mainly in the winter months.

### 4.3 Network Capability and Constraint Management at Milford Haven

LNG imports and regas terminal send-out place particular demands on NGG's management and operation of the NTS. As System Operator, NGG manages the system in accordance with its System Management Principles Statement in order to physically optimise the system, to maintain safe and reliable operations and to avoid capacity constraints. A capacity constraint arises where NGG is unable to flow gas on or off the NTS at a particular location and cannot, or may not be able to, provide the capacity already purchased by shippers. NGG is obligated to release baseline entry capacity and is incentivised to maximise the release of further (non-obligated) entry but, in doing so, it may expose itself to the cost of managing constraints if it sells too much. In order to minimise the costs of constraint management, NGG faces a financial cost target within the Capacity Constraint Management (CCM) incentive. The total obligated level of entry and exit capacity within the NTS is far greater than peak



demand and at many points of the network the level of obligated *capacity* exceeds the *capability* of the network to accommodate them. Therefore, there is an inherent risk of short-term capacity constraints at many locations.

National Grid Gas addresses the capability of the network and provides a detailed regional assessment of the risk of constraints in its Annual Network Capability Report (ANCAR). In its most recent ANCAR, NGG concludes that the current entry and exit capabilities are sufficient to meet all supply and demand scenarios in all seven NTS zones, except in South Wales and the South East, where the three LNG terminals are located<sup>77</sup>. In recent years, the constraint risk has proved to be higher at Milford Haven because of the particular configuration of the NTS network in South Wales and the distance of the entry point from centres of demand. The frequency of capacity constraints at Milford Haven in recent years and a wish to expand South Hook's peak send-out capacity lay behind the PARCA application in 2018 by South Hook Gas to expand NTS entry capacity. A final investment decision on this application is expected in 2023.

NGG has a number of operational tools, such as modifying network flows, to address constraints. If these are not sufficient, it can deploy a range of commercial tools, such as locational purchases or buying back capacity from shippers, provided the shipper agrees to surrender it. The economics of high-value LNG cargo operations at regas terminals makes it more difficult to reach commercial agreement between shippers and NGG over capacity buybacks than at other entry points. This is particularly true at times of high and volatile NBP prices. Commercial tools will usually entail a financial outlay for NGG but above a certain threshold the cost of capacity constraints is passed directly to shippers and to GB consumers<sup>78</sup>. In the most severe constraint cases, NGG is permitted to issue a Terminal Flow Advice (TFA) if the integrity of the NTS is at stake. At an entry point, a TFA would prohibit the flow of any gas to the NTS at that location for a specified period and the affected shippers would receive no compensation.

In April 2022, NGG took the unprecedented step of requesting from Ofgem an urgent derogation from its Licence in order to modify the release of entry capacity at Milford Haven between May and October 2022<sup>79</sup>. According to its assessment of network capability, the NTS would not be able to accept in the summer months a continuation of the very high volume of flows from the Milford Haven entry point seen in January and early April. At the time of the request, it was widely expected that the reduction of Russian pipeline supply to continental Europe would entail high levels of LNG imports to the UK in the summer of 2022 for transit to the EU via the interconnectors. Consequently, NGG requested from Ofgem, at very short notice, approval to withhold from the market part of the unsold capacity at the entry point between May and September.

In its submission, NGG cited the expected low level of UK demand in the summer months, the high level of scheduled network maintenance, limitations on local compressor stations in the South Wales part of the network and the imminent start of weekly auctions of entry capacity. NGG estimated the summer capability from Milford Haven at 680-850 GWh/d (62-77 mcm/d), well below the baseline capacity of 950 GWh/d (86 mcm/d) and sought approval to withhold the release and sale of weekly and monthly entry capacity, in addition to its right to withhold daily capacity. NGG warned that if it were not permitted to withhold capacity as requested, it might be forced to incur constraint management costs of £180-500 million per month, to be borne by shippers and ultimately by consumers. This estimate clearly represented a 'worst case scenario' for NGG but it did not include the *potential* consumer benefit of lower NBP prices if the request was refused. However, the warning succeeded in emphasising the consequences of the unavoidable summer restrictions on network capability.

After a very short consultation period, without independent expert scrutiny, Ofgem approved NGG's request despite opposition from some LNG capacity holders who believed that NGG assessment was too cautious and would serve to deter LNG cargo deliveries to the UK by restricting Milford Haven entry capacity<sup>80</sup>. NGG was therefore relieved of its obligation to release all firm baseline capacity at Milford

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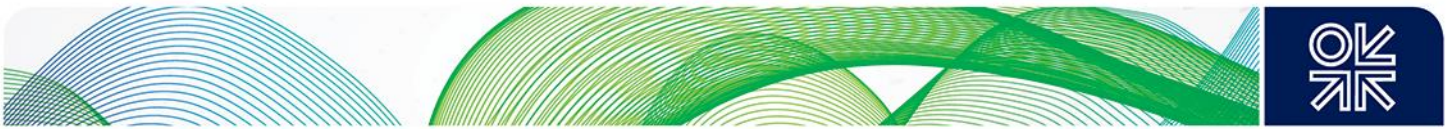
<sup>77</sup> Annual Network Capability Assessment Report, National Grid, June 2022

<sup>78</sup> In the current gas year 2022-23, the CCM incentive restricts NGG's exposure to +/- £5.2m per annum – any costs of constraint management beyond this range are passed directly to NTS shippers and consumers.

<sup>79</sup> National Grid Transmission Consultation on Entry Capacity Release Methodology Statement, Joint Office of Gas Transporters, 19 April 2022

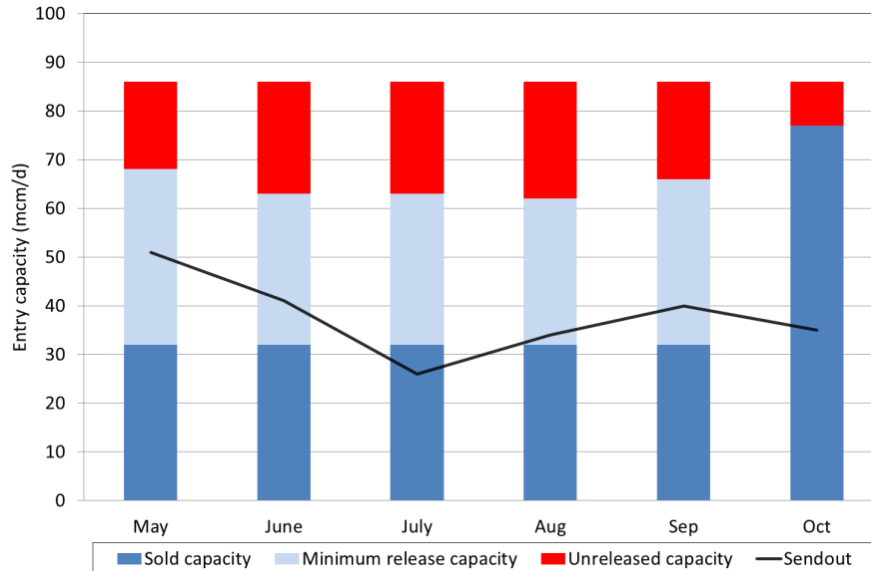
<sup>80</sup> Decision on the Entry Capacity Release Methodology Statement, Ofgem, 9 May 2022.





Haven for six months. It later arranged to monitor network capability through the summer months and to keep shippers informed of possible changes in its capacity release but the derogation was essentially implemented as approved.

**Figure 26: Restrictions on Entry Capacity at Milford Haven in 2022**



Source: National Grid Gas (May 2022)

Figure 26 shows the volumetric impact of the restrictions on the release of entry capacity at Milford Haven in the summer of 2022 and the combined send-out of the South Hook and Dragon terminals between May and October. It is not possible to say with any confidence whether, or to what extent, the unprecedented restrictions on entry capacity affected the delivery of LNG cargoes to Milford Haven in the summer of 2022. Perhaps some individual holders of uncontracted LNG cargoes were deterred from committing cargoes to South Hook or Dragon because of perceived additional commercial risk but, in aggregate, the impact does not appear to have been significant. Indeed, utilisation of South Hook appears to have held up surprisingly well, send-out remaining above 25 mcm/d every month, whereas at Grain, where no restrictions existed, few cargoes were delivered and NTS send-out was effectively zero from June to August.

The constraints revealed at Milford Haven in 2022 have underscored the mismatch between firm entry capacity and network capability and the dependence of the UK's *effective* LNG import capacity on seasonal variations in UK gas demand. If the Western Gas Network Project (WGNP) to reinforce the NTS in South Wales proceeds, it will mitigate the risk of constraints on entry capacity but will not eliminate it completely. Since the restrictions on capability may be repeated each summer, in December 2022 NGG began a consultation with shippers as to how the position should be managed in future<sup>81</sup>. Based on a projected cost to consumers of up to £20m per day of constraint at Milford Haven, NGG set out its intention to restrict the release of entry capacity to 63-68 mcm/d between May and September 2023. After the consultation, NGG proposed to Ofgem that, in the summer of 2023, the restrictions on capacity release will be aligned with the planned Gassco maintenance on Norwegian export infrastructure in May/June and August/September when NCS flows to the UK are expected to fall. In short, NGG proposed to 'fine tune' its restrictions by offering capacity up to the level of its network capability by offering capacity mainly in the weekly, not the monthly, auctions. In February 2023, Ofgem initially rejected NGG's proposals and insisted that it conduct another industry consultation and appoint an independent expert. In April, Ofgem announced its decision not to allow the withholding of capacity in the summer of 2023, reflecting its view that the risk of shippers nominating flows at Milford Haven above the capability of the network was low. Although the decision will reassure prospective LNG

<sup>81</sup> National Grid Transmission letter on Entry Capacity Release Methodology Statement, 9 December 2022.



terminal users and shippers in 2023, it leaves unresolved the issue of the release of Milford Haven entry capacity for the summer of 2024 when the network capability in South Wales will be limited by planned work on the WGNP and the local Wormington compressor.

The restrictions of summer entry capacity at Milford Haven in 2022 remind us of the sensitivity of NTS capability and LNG sendout capacity to the erosion of UK summer gas demand by renewables generation and the loss of storage injection demand. Some reform of the release of baseline entry capacity at Milford Haven in the summer may be desirable and necessary in future but the commercial risks of restrictions could be mitigated by stronger Capacity Constraint Management (CCM) incentives on NGT and better public scrutiny of the estimated costs to which GB consumers are exposed.

#### 4.4 NTS entry capacity charging

The allowed revenue to cover the total costs of operating the NTS, amounting to about £1.1 billion per annum in 2021-22, is set by Ofgem's price control formula for the transportation of gas. This revenue is, in principle, recovered 50/50 from entry and exit charges and is divided into elements for the Transmission Owner (TO) and the System Operator (SO). Revenue is collected from shippers (users) through a combination of capacity-based charges for 'transmission services' and commodity-based charges for 'non-transmission services'<sup>82</sup>.

A radical reform of the GB gas transmission charging regime was introduced on 1 October 2020 in order to comply with the EU Tariff Network Code (TAR NC), which took effect in April 2017, and to address the unsustainable trend whereby GB shippers were increasingly booking only low-cost short-term entry capacity products and the recovery of allowed revenue was increasingly dependent on a floating TO commodity charge. After a long, inconclusive process of industry discussion led by NGG, Ofgem decided upon a postage stamp methodology with a uniform entry and exit charge at each location and UNC charging arrangements which required that transmission service revenue is recovered only through capacity charges. The reforms were encapsulated in UNC Modification 678A approved by Ofgem in May 2020. All new capacity bookings from 1 October 2020 became subject to a floating capacity charge, revised each gas year, with the notable exception of certain fixed price capacity contracts signed before 6 April 2017 (the so-called 'existing contracts').

The reform led to a step-change in entry costs for most shippers on 1 October 2020, an increase in the price of most capacity products and immediate changes in the competitive position of individual shippers, not least those arising from the disparity between 'existing contracts' and new entry capacity bookings. It also led to the under-recovery of NGG's allowed revenues in 2020-21, exacerbated by the impact of Covid-19, forcing it to implement alternative short-term remedies to raise revenue. The reforms also entailed a series of unintended or unanticipated economic consequences for storage sites and for the secondary trading of fixed price capacity acquired under existing contracts; it also led to the over-recovery of revenues by NGG under its Capacity Constraint Management (CCM) incentive.

In May 2021, National Grid voiced its own dissatisfaction in an open letter in which it says that the new regime introduced in October 2020 'is not functioning as intended', that there remain 'underlying structural issues' of instability and unpredictability in entry tariffs and that it has created glaring disparities between capacity holders and shippers in the prices paid for the same capacity<sup>83</sup>. National Grid Gas believes that 'further change to the charging regime is essential and that there is a need to act swiftly (with Ofgem and gas shippers) to address the shortcomings'. In its letter of response, Ofgem indicated that it was ready to support the necessary work on future changes to the UNC and urged NGG to avoid interventions that could undermine market confidence<sup>84</sup>. Some of the distortions and anomalies created by the reform have been ameliorated or mitigated by subsequent UNC modifications or licence changes. However, the 'structural issues' regarding stability, competition and market efficiency still remain after Ofgem rejected NGG's proposed corrective measure, UNC Modification 790, in March 2022. A further industry attempt at reform is expected in 2023 but may once again fall foul of Ofgem's narrow legal interpretation of compliance with the EU Tariffs Network Code (EU TAR NC).

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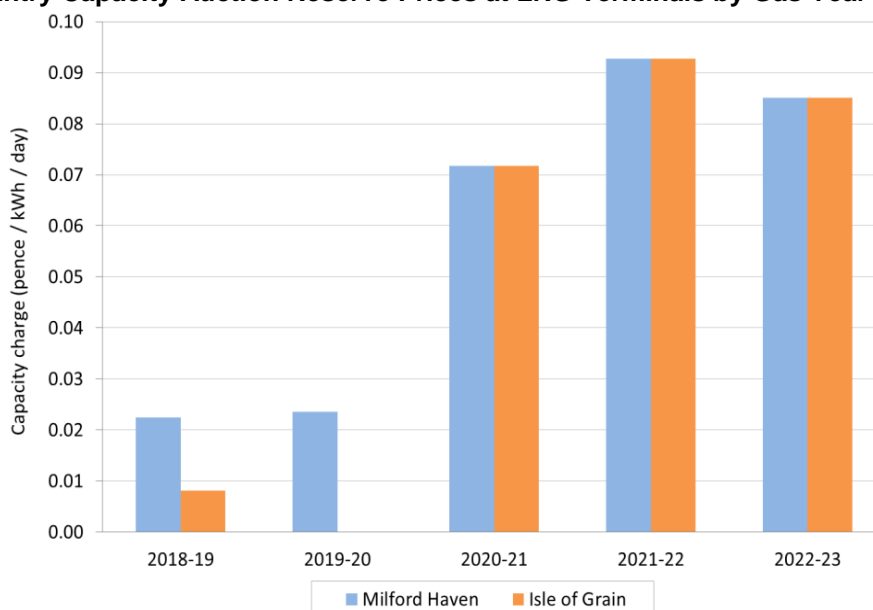
<sup>82</sup> The principles and methodology on which NTS transmission charges are based is set out in the Uniform Network Code (UNC): Transportation Principal Document Section Y – Charging Methodologies.

<sup>83</sup> National Grid open letter 'Future of Gas Transmission Charging', 28 May 2021.

<sup>84</sup> Ofgem letter 'Future of Gas Transmission Charging', 4 June 2021



**Figure 27: Entry Capacity Auction Reserve Prices at LNG Terminals by Gas Year**



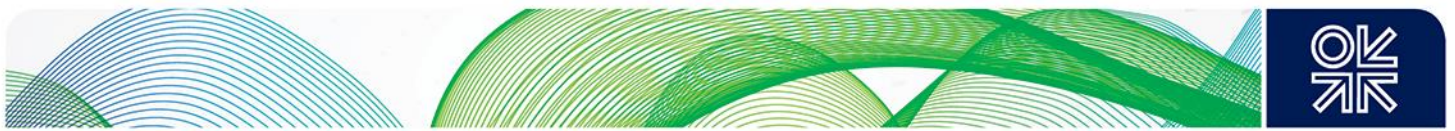
Source: Gas Transmission Transportation Charges, NGG, September 2022

Shippers at Milford Haven and Isle of Grain entry points appear to have emerged largely unscathed from the entry capacity charging reforms introduced in 2020, or at least they have been much less adversely affected than shippers at other GB entry points. Since shippers at the three regas terminals held most of their firm entry capacity under fixed price ‘existing contracts’ signed before April 2017, they did not face an immediate large step-increase in their entry costs in October 2020. Furthermore, a sizeable share of LNG sendout enjoys the benefit of flowing under these ‘existing contracts’. Indeed, the competitive position of LNG shippers within the GB wholesale market has been enhanced compared to the interconnectors where shippers faced a large increase in entry costs. The reform raised the reserve price in entry capacity auctions at Milford Haven from 0.0235 pence/kWh/day in gas year 2019-20 to 0.0717 pence/kWh/day in 2020-21, as shown in Figure 27. The increase was even greater at the Grain entry point since it had previously enjoyed a substantial discount to the reserve price at Milford Haven and the reforms unified the reserve price for all beach terminal entry points and LNG entry points. This industry-wide increase in new capacity costs is the principal reason that network entry capacity costs at UK regas terminals are appreciably higher than in other LNG-importing countries in NW Europe (see section 3.6 and Figure 20).

The charging regime which emerged from the poorly-managed process of reform in 2020 has left Great Britain with network entry charges which are the highest among NW European countries (France, Germany, Belgium and Netherlands)<sup>85</sup>. The costs for new entry capacity bookings are many times higher than the marginal cost of flowing gas within existing bookings. This complex and highly differentiated, dual charging structure means that 90 per cent of entry revenues are collected from only 30 per cent of entry capacity bookings<sup>86</sup>. The reforms adopted in 2019-20 now appear to have placed too much weight on rigid compliance with the EU TAR NC, just as the UK was leaving the EU, and too little on wholesale market competition, stability and fairness. The risk for the wholesale market now is that if the process of tariff reform drags on and regulation is deemed to be unstable, unpredictable or unfair, some GB market participants will reduce their activity and even perhaps withdraw. Once the energy price crisis of 2021-22 abates and its lessons are digested, the current charging regime deserves a thorough and expert review based on the objectives of stability, competition and fairness.

<sup>85</sup> ‘Impact assessment: consideration of adjustments to NTS charging regime’, Cambridge Economic Policy Associates (CEPA), March 2021

<sup>86</sup> ‘Pressures and Strategic Challenges Facing GB and International Markets’, presentation to Westminster Energy Forum by Interconnector Fluxys, 22 February 2022.



#### 4.5 Investment in NTS to accommodate LNG import capacity

The current arrangements for access to NTS entry and exit capacity were conceived and implemented at a time when UK demand for gas and for capacity were growing. The regular QSEC auctions for entry capacity would signal shipper demand and trigger investment by NGG in new capacity, subject to an economic test. Since about 2010, there have been few such investment signals and participation in the capacity auctions has waned as both UKCS production and UK gas demand has declined and shippers sought more flexible access to the NTS in response to more market price-sensitive supply patterns. Recognising this progressive change, NGG launched an industry consultation and review of capacity access arrangements in 2020 and published a review of the future issues and options, but few recommendations, in September 2021<sup>87</sup>. Major decisions were left for the regulator, the proposed new system operator and new owners of the gas network. It is expected that the sale by National Grid PLC of a majority stake in NGG in 2023 and the forthcoming creation of a new Future System Operator (FSO) will ensure that many of the complex decisions over hydrogen, network reconfiguration, investment and charging will not be addressed before 2024-26.

The commitments made in 2004 by the developers of the two regas terminals at Milford Haven to purchase long-term entry capacity underpinned the construction of the new high-pressure pipeline from Milford Haven to Tirley in western England and the reinforcement of the network in South Wales. The project was recognised at the time as delivering ‘critical national infrastructure’. The delivery of the project, constructed between 2006 and 2012, cost £1.15bn in 2009-10 prices, well above the allowed costs of £908m<sup>88</sup>. This project remains the largest investment in the NTS in the last 30 years. It is worth noting that Ofgem recognised as early as 2006 that NGG might not be able to deliver all the firm entry capacity it had sold and that it had a potential future capacity liability under the terms of the UNC. In other words, the potential Milford Haven constraint management issue discussed above was anticipated even as the pipeline was being constructed.

LNG continues to stimulate investment in the NTS to expand the capability of the existing network and to provide access to incremental firm entry capacity. In April 2018, South Hook Gas (SHG) made an application to NGG under the Planning and Advanced Reservation of Capacity Agreement (PARCA) arrangements for additional firm entry capacity of 163 GWh/d (15 mcm/d) at Milford Haven. Soon after, in November 2018, South Hook LNG Terminal (SHT) submitted its application to Ofgem for an exemption from regulated TPA for the proposed incremental capacity.

SHG’s PARCA application began a multi-phase process to assess the technical and economic options for NGG to meet its request, which developed into the WGPN. NGG is obliged to look at all means of delivering the incremental capacity without investment but the scale of the request will require both pressure uprating of the main pipeline from Milford Haven and the construction of a stretch of new pipeline in two locations in the west Midlands.

In June 2021, NGG submitted the final ‘needs case’ to Ofgem for approval of WGPN. After a period of public consultation, Ofgem approved the project in December 2021. The expected cost of the WGPN has not yet been disclosed publicly for commercial reasons but it is understood to be by far the largest NTS investment project since the original construction of the high-pressure pipeline from Milford Haven. The PARCA process is currently in Phase 2. After NGG has gathered bids from contractors and the capital costs are known, the project will proceed only if SHG is willing to meet 50 percent of the NPV through an irrevocable commitment to purchase sufficient firm capacity and if Ofgem is satisfied that consumers’ financial exposure is justified by the benefits of additional supply security. Only then will construction begin and the incremental capacity be released. A final investment decision is expected in 2023. SHG will underpin the project but the financial risk will be shared with all NTS shippers whose future entry charges will include any of NGG’s permitted revenues not recovered by capacity bookings at Milford Haven. If the project proceeds as expected, construction work will commence in 2024 and

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<sup>87</sup> Long Term Access Review: Project Consultation Report, National Grid, September 2021.

<sup>88</sup> Decision on the ex-post efficiency review of NGGT’s Milford Haven pipeline project, Ofgem, 3 Dec 2015. Ofgem determined that the project’s costs included about £200m of avoidable over-spend, 25% of which was borne by NGGT and 75% by consumers.



will be completed by late 2025 or early 2026. The investment at the South Hook terminal itself is expected to be modest in scale and limited to incremental vaporisation and nitrogen ballasting facilities. At present, there are no published plans to increase entry capacity at the Grain entry point associated with the Phase 4 development of the terminal but such an increase cannot be excluded.

#### 4.6 Gas Quality Regulation and LNG supply to the NTS

There are no quality restrictions on the LNG imported into the UK but the gas entering the NTS from the regas terminals has to meet two different sets of gas quality specifications. The first is the statutory gas quality included in the Gas Safety (Management) Regulations 1996 (GSMR) which governs the safe conveyance of all gas in networks serving UK consumers. The second is the set of gas quality specifications described in the bilateral Network Entry Agreement (NEA) negotiated by each terminal with National Grid Gas (NGG), the operator of the NTS. The safe use of gas in the UK, and GSMR in particular, is the responsibility of the non-departmental government body, the Health and Safety Executive (HSE), which falls within the scope of the Department of Work and Pensions (DWP). The current GSMR gas quality was established in 1996 when the UK was self-sufficient in gas produced from the UKCS, based on empirical research on gas safety conducted mainly in the 1980s.

The GSMR gas quality comprises a set of nine characteristics or parameters, including the key Wobbe Index (WI), which measures the interchangeability of gas and is expressed in MJ per normal cubic metre (MJ/m<sup>3</sup>). The Wobbe Index, sometimes referred to as the Wobbe Number, is calculated from the calorific value of the gas and its relative density<sup>89</sup> and varies with the composition of the gas. The gas quality specified in the bilateral NEAs typically includes additional parameters but incorporates GSMR as the minimum gas quality for all terminals<sup>90</sup>. There is some variation in the gas quality in NEAs for NTS entry terminals, depending on the quality of the UKCS or imported gas delivered to the entry point. The terms of the NEA at each of the three regas terminals are understood to be very similar but only the South Hook terminal (SHT) has agreed to allow them to be published by NGG.

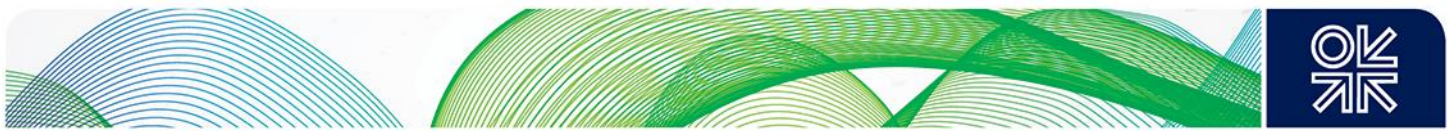
The most notable feature of the UK's current GSMR gas quality, compared to standards in other major European markets, is the narrowness of the WI range (47.2 – 51.41 MJ/m<sup>3</sup>) and in particular the very low level of the upper limit. The pan-European gas industry's EASEE-Gas gas quality incorporates a WI range of 46.5 – 54 MJ/m<sup>3</sup>. Since most international traded LNG has a WI of between 51 and 56 MJ/m<sup>3</sup>, there is *prima facie* a mismatch between the WI range in GSMR and the supply of LNG which now makes up 20-30% of UK gas supply and represents a key marginal source of flexible supply. This mismatch is managed at the regas terminals principally by nitrogen ballasting which involves the injection of low-WI nitrogen gas into the regasified LNG to reduce its heat content and Wobbe Index to bring it below the GSMR limit-value of 51.41 MJ/m<sup>3</sup>. The higher the WI of the imported LNG, the higher the nitrogen ballasting costs and CO<sub>2</sub> emissions associated with complying with this tight GSMR limit-value. If nitrogen production and injection capacity at a regas terminal is fully utilised or unavailable, the range of LNG sources capable of being imported will, of course, be more restricted. The costs of nitrogen ballasting are borne initially by the terminal but passed on to regas capacity holders, to shippers and ultimately to UK gas consumers.

At present, Grain LNG has extensive nitrogen production and injection facilities whereas Dragon LNG and South Hook LNG possess more limited facilities relative to their capacity. In its published terms and conditions for prospective users<sup>91</sup>, GLNG sets out a maximum WI of the LNG delivered to the terminal of 53.01 MJ/m<sup>3</sup>, indicating the operational flexibility to either blend LNG in tank or to inject nitrogen in order to comply with the GSMR limit of 51.41 MJ/m<sup>3</sup>. In contrast, the South Hook terminal was designed to receive 'lean' Qatari LNG with a relatively low WI and until early 2022 had received only LNG from Qatar or from US plants that remove most of the non-methane compounds (ethane, propane and butane) through extraction at source before liquefaction. The range of LNG supply sources at Grain and Dragon has been wider than at South Hook, reflecting both contractual supply arrangements and the greater tolerance of LNG with a higher WI.

<sup>89</sup> The Wobbe Number is defined in the Gas Safety (Management) Regulations 1996, Schedule 3.

<sup>90</sup> National Grid's Gas Ten Year Statement (GTYS) 2021 includes the reference parameters and limit values which serve as guidance for NEAs (Table A3.1, p.75). Variation of both oxygen and CO<sub>2</sub> content will be considered by NGG.

<sup>91</sup> 'New Shipper Access Code Version 1, National Grid Grain LNG, 15 May 2020, p.37.



It became increasingly evident in the early 2010s that GSMR needed to be reviewed and revised in response to three factors: the growth of UK gas imports, the closure of all LNG peak-shaving facilities which provided LNG to remote off-grid areas of Scotland and the desire to accommodate lower-carbon biomethane and hydrogen into the gas networks. Scotia Gas Networks (SGN) undertook an Ofgem-funded study in Oban in 2015-16 to assess the impact of using higher WI gas and concluded that the upper limit could be safely relaxed from 51.41 to 53.25 MJ/m<sup>3</sup>. It observed that the current GSMR allows only 10% of the world's LNG supply to enter the UK market without further processing; if the WI limit were to be relaxed to 53.25 MJ/m<sup>3</sup>, then 90% of the world's LNG supply could do so<sup>92</sup>. In describing the cost of maintaining the current GSMR range as 'grossly disproportionate to the risk of raising the upper WI limit to 53.25 MJ/m<sup>3</sup>', SGN cited an estimate by NGG that if the upper limit were raised, an estimated £325m per annum could be saved in *projected* nitrogen ballasting costs in 2020. A more recent estimate by NGG puts the operating cost savings in 2021 close to £90m p.a..

In 2016, the Institute of Gas Engineers and Managers (IGEM), the professional body responsible for technical standards in the UK gas industry, set up a working group, with a wide range of participants and the approval of the HSE, BEIS and Ofgem, to consider the establishment of a new gas quality standard. Over the course of five years, the Gas Quality Standard Working Group (GQSWG), which included National Grid Gas and the HSE, commissioned and reviewed empirical research from a variety of sources concerning gas safety, security of supply and the decarbonisation of gas. It finally concluded its work by drafting a proposed IGEM Gas Quality Standard, submitting all the evidence to the HSE and publishing its final report in May 2021<sup>93</sup>. Figure 28 summarises the WI range of traded LNG, GSMR and the proposed IGEM standard.

**Figure 28: Wobbe Index Range of LNG and Gas Quality Standards**

Source	Wobbe Index	Comments
Traded LNG sources	51 - 56	Approximate range
Existing GSMR standard	47.2 - 51.41	Unchanged since 1996
EASEE-Gas standard	46.5 - 54.0	National variations within EU
IGEM proposed standard	46.5 - 52.85	Recommended by GSWG May 2021
HSE GSMR recommendation	46.5 - 51.41	Impact assessment Oct 2021

Source: GIGNL, GSMR, EASEE-Gas, IGEM and HSE

In October 2021, the HSE released its initial impact assessment of the IGEM proposal<sup>94</sup>. It identified its 'preferred option' which entailed a lowering of the lower end of the GSMR WI range (from 47.2 to 46.5 MJ/m<sup>3</sup>), permitting greater access to the NTS for low-CV gas from some fields in the Southern North Sea, but it rejected the IGEM proposal to increase the upper limit-value from 51.41 to 52.85 MJ/m<sup>3</sup> on safety grounds. It also proposed extending the exemption on oxygen content to permit greater use of biomethane and to simplify GSMR by removing two minor unnecessary parameters. In the view of the HSE, increasing the WI upper limit-value would slightly increase the already exceptionally low risk of fatalities through carbon monoxide (CO) poisoning and that such an increase in risk was 'not tolerable within UK law'.<sup>95</sup>

In its assessment of the IGEM proposal, the HSE concluded that the safety-related evidence presented by the GQSWG in favour of an increase in the upper limit of the WI was either too limited or inconclusive. However, its reasoning in the impact assessment is less than persuasive. The HSE recognises that the safe use of gas primarily depends on the installation, servicing and inspection of gas appliances and proper ventilation to prevent the accumulation of flue gases. Yet it appears to have concluded that gas

<sup>92</sup> 'Opening up the gas market', Scotia Gas Networks, October 2016

<sup>93</sup> Gas Quality Standard Working Group Project Closure Report, IGEM, May 2021

<sup>94</sup> Impact Assessment: Summary Intervention and Options, HSE, October 2021.

<sup>95</sup> The primary legislation, the Health and Safety at Work 1974, does not permit the HSE to approve changes to any regulations which would increase the safety risks faced by workers or consumers.



quality limits have to be set in a way that compensates for deficiencies in the installation, servicing and inspection of gas boilers and room ventilation. Its assessment does not refer to gas safety evidence from EU countries which permit a higher upper WI limit-value without an assessed increased risk of CO poisoning. Furthermore, the HSE gave limited weight to the continued safe use of gas with a WI of up to 53.25 MJ/m<sup>3</sup>, higher than the upper limit proposed by IGEM, in Oban and other localities since 2016 under a specific exemption from GSMR granted by the HSE itself.

After initial agreement of the HSE position by BEIS ministers, the HSE launched a public consultation on its 'preferred option' in January 2022 which effectively precluded any relaxation of the upper WI limit-value<sup>96</sup>. The submissions to the consultation on this issue revealed some opposition to the HSE position and scepticism over its approach to both risk assessment and the tolerance of risk. Following conclusion of the consultation in March 2022, the HSE originally expected the government to adopt the new GSMR gas quality in secondary legislation in the summer of 2022 for implementation later in the year. However, a final decision and implementation was delayed by the changes of government in 2022 and the energy price crisis which highlighted the importance of access to LNG markets for UK security of supply.

There is little in the HSE impact assessment to show how the assessment of gas safety risks was conducted and how the trade-offs between competing policy objectives and the costs and benefits of raising the upper WI limit were considered. There is, at present, no comprehensive cost-benefit analysis in the public domain that includes the potential energy security and economic benefits for UK consumers. But there is a more fundamental question as to whether the HSE is assessing risks and risk tolerance consistently and sensibly. In particular, it seems to have placed excessive weight on the minimal increase in absolute risk of CO poisoning if the upper limit of the WI were increased and too little weight on two other elements (1) the extremely low existing level of risk faced by consumers in the use of gas compared to other activities and (2) the significant improvement in gas combustion safety observed since the 1990s<sup>97</sup>. As other submissions to the consultation point out, the HSE's analysis did not include the risk of winter fatalities arising from higher gas prices and fuel poverty in low-income groups<sup>98</sup>.

The HSE's refusal to approve even a modest increase in the upper WI limit-value will have an adverse impact on UK gas security of supply because the UK gas market has become, and will remain, more dependent on flexible *uncontracted* LNG and pipeline imports to meet peak winter demand. This promises to far outweigh the smaller, welcome benefits of allowing more inflexible low-CV gas from the UKCS and biomethane to enter the NTS. The HSE's decision will also continue to restrict the volume of flexible Norwegian gas delivered by pipeline to St Fergus. It may require additional investment in nitrogen ballasting at South Hook, raising the cost of delivering LNG to the NTS, or will constrain the sources of LNG available to UK regas capacity holders, especially when lean Qatari LNG is not being delivered to the UK. The increased competition for LNG within Europe since the Russian invasion of Ukraine has brought these supply-side issues to the fore. The question of what happens if, for any reason, the UK no longer has access to low WI sources of LNG is simply not addressed by the HSE impact assessment.

The HSE's position was approved by government in early 2023 and adopted in law through a statutory instrument on 9 March 2023 as the Gas Safety (Management) (Amendment) Regulations 2023. The first revisions to GSMR came into effect on 6 April 2023 and the reduction in the lower WI limit-value will be effective from 6 April 2025. At this stage, the seven-year long process to review and revise the GSMR gas quality appears to have been a major missed opportunity. The reduction of the lower WI limit is welcome and sensible but the decision not to raise the upper limit of the WI range is paradoxical. The GSMR review process was expressly initiated to accommodate rising pipeline gas and LNG imports but has ended with no changes in GSMR that facilitate imports.

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<sup>96</sup> HSE public consultation 'Revision of GSMR 1996', 28 January-21 March 2022.

<sup>97</sup> 'Comments on HSE proposal not to increase upper limit of WI', Dave Lander Consulting, IGEM Technical Services paper, March 2022.

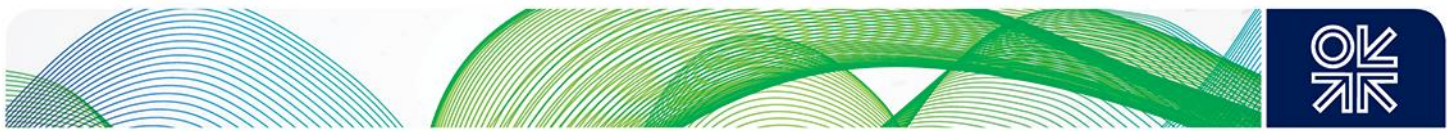
<sup>98</sup> 'Decision factors relevant to the increase in the upper Wobbe Index limit', DNV, IGEM Technical Services Paper, March 2022.



The outcome favours small-scale, inflexible domestic sources of gas but does nothing to facilitate large-scale, *flexible* imported sources of supply. All the sources of flexible, uncontracted gas available to the UK are from imported sources, whether by pipeline or as LNG, and the competition for gas within Europe has already become more intense. Furthermore, the UK remains an anomaly in Europe regarding the narrowness of the WI range in its national gas quality standard. If the LNG market remains tight throughout 2023-25, there may be reasonable calls to review the new GSMR, long before the proposed 5-year review period. In the current circumstances, DESNZ would be well-advised to devise some contingency arrangements for a rapid relaxation of the WI range if LNG and gas markets once again become very tight.

In contrast to the inertia over GSMR, the gas quality limits in an NEA may be amended if the terminal or capacity holder applies successfully to modify the Uniform Network Code. In 2016, Grain LNG applied to change the maximum oxygen content in its NEA from 0.001mol% (10ppm) to 0.02mol% (200ppm) to broaden the range of LNG the terminal could handle, in particular to accommodate US LNG cargoes which might lead to gas with up to 60 ppm oxygen entering the NTS or the LDZ, especially during vessel discharge. Despite some unsubstantiated concerns expressed by storage operators, the UNC Modification 581S was approved and quickly implemented. In a similar move in May 2018, South Hook LNG terminal successfully raised a UNC modification (UNC 645S) to relax the oxygen content in its NEA by the same magnitude. The purpose was to widen its commercial range of LNG supply sources and to ensure that nitrogen ballasting did not entail a breach of another GSMR parameter, the Incomplete Combustion Factor (ICF), which could lead to NGG curtailing gas flows from the terminal. In both cases, the original and the revised limit values for oxygen content were more stringent than the GSMR limit of 0.2mol% (2000ppm). In both cases, the industry-led process of UNC modification proved its worth in correcting outdated gas quality limit-values which might restrict LNG flows to the NTS.





## 5. Conclusions and recommendations

The conclusions of this paper may be divided into four broad categories: the operation of the global LNG market and NBP price-formation, the economic risks associated with the current pattern of UK gas supply, the value and the constraints of UK regas terminal capacity and the NTS network and, finally, the implications and recommendations for UK policy-makers and regulators.

### LNG market and NBP price-formation

The extraordinary rise in European hub prices and the huge increase in daily price volatility arising from the Russia-Ukraine crisis of 2021-22 revealed the growing commercial flexibility, liquidity and maturity of the global LNG market. The crisis also showed how the changes to European gas supply and wholesale price-formation in the last ten years have removed restraints on NBP prices and raised financial risks to which UK consumers and the public finances are now exposed.

The gas price crisis caused by the Russia-Ukraine conflict turned the LNG market on its head, driving European wholesale gas prices to the highest in the world, causing a sharp divergence of NBP and TTF prices and making LNG unaffordable for lower-income developing countries. The price reaction in Europe might have been even more severe; only an unexpected reduction in Asian LNG demand in 2022 and the sale of some of its contracted LNG to Europe prevented even higher prices. US exports emerged as the key source of flexible, uncontracted LNG to European markets. UK LNG imports reached a new annual record of 19 million tonnes (25 bcm) in 2022 and deliveries from the US exceeded those from Qatar for the first time, indicating that the secondary regas capacity market is working as intended.

The valuation of uncontracted spot LNG in a liquid, commoditised global market is now the key price-setting mechanism for NBP and TTF wholesale prices and, indirectly, for regulated UK retail gas prices. Given the regulation of retail energy prices since 2019 and the extent of public financial support in 2022-23 to protect UK consumers from unaffordable prices, the fluctuations of the global LNG market have become *de facto* an important unpredictable element in public sector finances. Well-designed reform of GB electricity market arrangements (REMA) would diminish this influence.

Barring an early end to the Russia-Ukraine conflict and the unlikely resumption of Russian exports direct to the EU, the more intense international competition for both spot and term contract LNG supply is expected to persist in 2023-24 until new, large-scale LNG projects, mainly in the US and Qatar, come on stream in 2025/26.

### UK gas supply: LNG is now critical for flexibility

The UK has a diverse but highly unbalanced pattern of gas supply dependent on non-storage supply to meet peak winter demand since it lacks large-scale domestic gas storage. It is almost entirely dependent on NBP prices being high enough to attract uncontracted supply, especially LNG, away from other competing markets in Asia and Europe. Without access to gas storage, UK LNG buyers are unable to fully exploit periods of lower LNG prices to allow suppliers to build pre-winter inventory, leaving UK consumers with a high degree of exposure to 'just-in-time' LNG purchases at the time of greatest gas use in winter.

The central pillar of UK gas supply security is domestic production from the UKCS but it cannot respond to changes in UK demand or to short-term NBP prices. After a strong rebound in 2022, UKCS gas production is expected to resume its long-term gradual decline. There are few sources of firm, term supply of imported gas. With the exception of the small Qatar Energy-Centrica contract due to expire at the end of 2023, there are no term contracts for LNG delivered to the UK. As long as competition and regulation of the UK gas markets militates against firm term supply contracts, any government policy designed to enhance gas supply security and to diminish price risks for UK consumers will have to focus on the provision of commercial storage capacity or stockholding obligations for UK suppliers to underpin demand for new domestic storage capacity.



LNG regas send-out confirmed its critical role in meeting peak winter demand by sustaining send-out of 130 mcm/d, or about one-third of NTS demand, for two weeks in mid-December 2022. However, the strong competitive position of LNG regas send-out in flexible supply makes it more difficult to find an economic basis to expand gas storage capacity, at the Rough site or elsewhere. The value of existing UK regas capacity and UK energy security would both be enhanced by improved access to domestic seasonal storage.

### Regas capacity and NTS network infrastructure

The UK's existing LNG infrastructure ensured that it weathered the crisis of 2021-22 far better than much of continental Europe. Not only did the UK not suffer a direct physical loss of gas supply but its favourable access to global LNG markets allowed it to become an important transit route for gas to the EU via the Interconnector and BBL pipelines. Between April and December 2022, the UK exported more than 17 bcm to the EU via the interconnectors, stretching to the limit at times the capability of the NTS to absorb LNG entry flows at Milford Haven and Grain and to export gas from the Bacton exit points via the interconnectors.

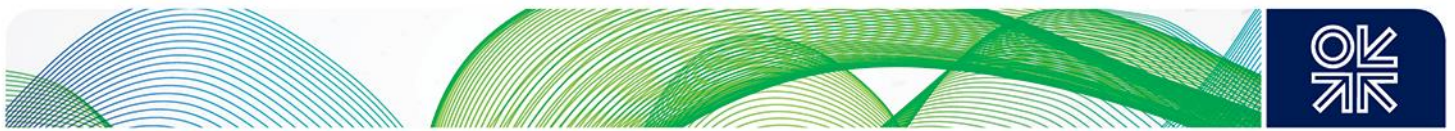
The role of LNG from Qatar in UK imports has diminished progressively since 2016 but Qatar Energy's UK regas *capacity* position is set to expand significantly. After the purchase of long-term capacity at the Grain LNG terminal from 2025 and the expansion of peak sendout capacity at South Hook in 2025, Qatar Energy will indirectly hold almost half the regas capacity at UK terminals and a key influence over peak LNG send-out and in NBP price-determination. This increase in concentration in the holding of regas capacity need not be a concern for gas market competition provided Ofgem's scrutiny and oversight of the secondary regas capacity market and wholesale market trading is strengthened.

The UK's three regas terminals, like the NTS, are part of the UK's critical energy infrastructure. The government has acquired new powers under the National Security and Investment Act to review and to block investment or transfers of ownership but it is not clear whether it enjoys similar powers in respect of capacity rights in such infrastructure to ensure continued market access to such capacity at times of political crisis or severe gas supply shortage.

The National Transmission System (NTS) has proved itself an essential element in the supply chain between the global LNG market and the UK consumer. The NTS capacity trading arrangements, the charging regime, the capability of the network, the management of capacity constraints and even the regulation of gas quality all influence the competitive position of the UK regas terminals as a destination for LNG within Europe. Regulation in some of these areas needs urgent reform.

The capability of the NTS to accommodate high volumes of LNG sendout from the two terminals at Milford Haven emerged unexpectedly in April 2022 as a constraint on the UK's ability to import LNG when gas demand is low in the summer months. Ofgem's approval of restrictions on the release of firm entry capacity to avert capacity constraints at Milford Haven in the summer of 2022 may not have prevented any LNG imports but such restrictions may do so in future. The large Western Gas Network Upgrade project to reinforce the NTS in south Wales, due for completion by early 2026, will alleviate but not eliminate the risk of summer capacity constraints. A review by Ofgem of the adequacy of current incentives for NGG to manage capacity constraints and improved scrutiny of requests by NGG not to release capacity would serve to reassure LNG suppliers and shippers of reliable access to the NTS and the NBP market in future.

The UK has the highest gas network entry costs anywhere in NW Europe. In the volatile gas markets of 2021-22 this cost disadvantage was barely significant but it may in future erode the competitive position of UK regas terminals once markets and supply patterns stabilise. The flawed reform of entry capacity charging implemented in 2020 to comply with the EU Tariffs Network Code created a distorted, unfair and unstable charging regime. Recent industry efforts to address these structural problems have foundered on Ofgem's very rigid interpretation of compliance with the EU Tariffs Network Code. Resolution of this issue within the current legal framework deserves the renewed attention of both Ofgem and DESNZ in 2023.



### Implications for policy-makers and regulators

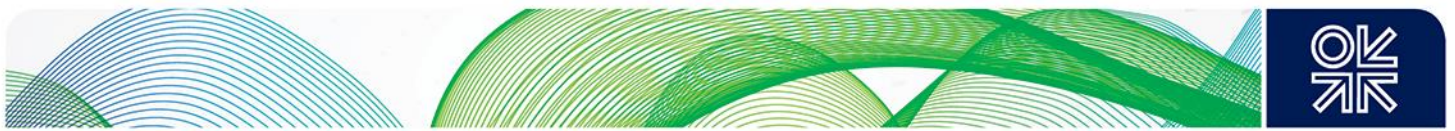
The energy price crisis of 2021-22 and the creation of the new energy department (DESNZ) presents the UK government and Ofgem with an opportunity to conduct a thorough and urgent review of UK energy security legislation and gas market regulation with a focus on NBP price-formation and mitigation of economic and financial risks, not just risks to physical supply, and making sure the UK remains a competitive destination for LNG and gas from all sources. The Energy Bill currently in Parliament provides an opportunity to address some of the benign neglect of gas and energy security issues over the last decade.

Anticipation of falling gas demand in the energy transition, the proposed conversion to hydrogen in end-use and the absence of physical gas supply interruptions in 2021-22 should stimulate such a review, not deter government from conducting one. The recent exposure of the public finances to UK wholesale energy prices should lead government to consider new measures to prevent and to mitigate the economic risks that gas price volatility presents for affordability, energy security and the energy transition. As far as gas supply security is concerned, the era of the UK's total reliance on the operation of markets with minimal intervention may now have run its course.

Any such review should include the unresolved issue of domestic gas storage and pre-winter stockholding by UK suppliers. The competing policy tools of providing financial incentives to raise storage capacity (at Rough or elsewhere), the introduction of compulsory stockholding obligations or much wider demand-side restraint (DSR) incentives deserve to be re-visited in the light of what we have learned about how gas markets actually work and the geo-political and macro-economic risks the UK faces.

In seeking to make the UK a competitive European destination for LNG and gas from all sources, and to keep a competitive wholesale gas market, the government and Ofgem should focus not on securing term supply contracts from individual suppliers but on assuring the proper functioning of the secondary regas capacity market, on better-designed network capacity charging arrangements and stronger incentives to improve NTS capacity constraint management.

The long review of the statutory GB gas quality standard (GSMR) finally ended in March 2023 without any revision by the HSE of the upper limit of the Wobbe Index range. This is a major missed opportunity and highlights the weakness of integrated UK policy-making and risk assessment in this area. Maintaining the current, very restrictive upper limit value (51.41 MJ/m<sup>3</sup>) will act as an economic barrier to the import of LNG from many sources, will make UK regas terminals slightly less competitive within Europe and will restrict UK access to some sources of uncontracted LNG just as competition within Europe is intensifying.



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