



# GAS SECURITY: THE FOUNDATION OF ENERGY SECURITY

Kathryn Porter

Watt-Logic

Abstract

Britain's gas system is more fragile, and gas's role in the energy system more enduring, than current policy assumes. UK gas prices are set locally, not internationally, so domestic production directly affects what consumers pay. Gas is no longer the primary driver of rising bills, having been overtaken by network costs, and declining UKCS production outlook now threatens the viability of the pipeline infrastructure that carries it.

Britain's growing reliance on electricity imports compounds this risk, resting on an interconnector regime and neighbouring systems that cannot be assumed reliable under stress. With storage weak on both sides of the Channel and gas set to remain structurally necessary for decades, gas security is energy security and energy policy must treat it as such.

About Watt-Logic

Watt-Logic is an independent energy consultancy founded by Kathryn Porter in 2016. Originally established as a technical blog analysing electricity and gas markets, Watt-Logic has developed into an internationally recognised consultancy providing independent analysis of energy markets, policy and regulation. The business advises clients across the energy value chain, including generators, suppliers, investors, industrial energy users and financial institutions, on commercial strategy, market design, regulation, investment appraisal and energy trading.

Kathryn Porter holds a Master's degree in Physics and an MBA, and has over two decades' experience in energy and financial markets, with expertise spanning electricity, gas and oil markets, risk management, trading, infrastructure investment and energy policy. In addition to her consulting work, she is a widely published commentator on energy policy and market reform, writes a regular column for The Daily Telegraph, and has published extensively on energy security, electricity market design, net zero policy and power system resilience. She has submitted written evidence to Parliamentary select committees, given oral evidence to Parliament, and is a frequent speaker at national and international conferences and policy forums.

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## Executive Summary

Much of the current policy debate focuses on electricity and renewables, while gas, largely un-noticed, remains the foundation of Britain's energy security. It heats the great majority of homes, underpins industrial demand, and continues to provide the flexible generation that keeps the electricity system reliable.

This report examines the immediate risks to gas supply for the coming winter, the structural and long-term pressures on the wider gas system, and the extent to which gas continues to shape household bills - and finds that on every count, Britain's gas security is more fragile, and gas's role in the energy system more enduring, than current policy assumes.

**Gas prices are not set internationally**

**Gas prices are not set internationally.** A persistent claim in UK energy debate is that gas is “sold on international markets at international prices” and that domestic production therefore cannot affect what British consumers pay. This report shows the claim is false. Gas is priced regionally, at hubs connected by finite pipeline and shipping capacity, and the difference between hub prices reflects the cost and availability of moving gas between them, not some global benchmark.

**Increased UK domestic production would lower GB gas prices by displacing the most expensive marginal supply**

Britain's price history demonstrates the mechanism directly - since 2022, GB has been a persistent net exporter to the Continent, including through winter, a complete reversal of the pre-2022 pattern in which Britain imported in winter and exported in summer. The NBP-TTF spread (difference between UK and European gas prices) has moved in line with this flow reversal and now sits below the transport cost for much of the year. Spain's experience in 2022 confirms this mechanism is structural – Spain has no indigenous production, no Russian exposure and no seasonal swing of its own, yet it sustained a multi-month discount to TTF once its own export capacity was exhausted. The practical conclusion is that **increased UK domestic production would lower the price UK consumers pay by displacing the most expensive marginal supply, LNG, rather than simply being sold onto a market Britain cannot influence.**

**Gas is not generally the primary driver of rising electricity bills**

**Gas is not generally the primary driver of rising electricity bills.** Excluding carbon costs, gas accounts for around 32% of a dual-fuel bill and 26% of an

electricity bill - material, but no longer dominant. While this can change during short-term price shocks, over the longer-term, network costs, now at 25% and 27% respectively, have grown to match wholesale costs and are set on a firmly upward trajectory that gas costs are not. It is also important to note that a significant component of the wholesale cost is carbon and not gas (generally 20-25% of the wholesale electricity price is the cost of carbon allowances). NESO's transmission charge forecasts, Ofgem's RIIO-3 determinations and the escalating cost of connecting a renewables-heavy grid point to network costs continuing to rise sharply to 2030 and beyond, while the IEA expects a substantial new wave of global LNG supply to exert downward pressure on gas prices over the same period.

**The UKCS production outlook is falling and increasingly uncertain...**

**...this threatens pipeline viability as well as gas supplies**

**The UKCS production outlook is falling and increasingly uncertain, which now threatens more than just molecules.** Official forecasts have been revised down at every iteration since 2019, and the plausible range for future output - from continued fiscal deterrence to a supportive regime - now spans more than a factor of two. What official projections continue to miss however, is that offshore gathering and transmission pipelines such as CATS, SAGE and FLAGS have their own minimum viable throughput, below which hydrate formation, tariff economics and pressure loss force premature closure. A stepped, cascading risk profile results, quite different from the smooth decline shown the NSTA's modelling, and one with a real precedent in the 2018 closure of the Theddlethorpe Terminal, which forced the premature closure of 22 Southern North Sea fields.

Because many UKCS fields depend on both a gas and a liquids export route from the same platform, the fragility extends to the oil pipeline network as well. Six UK gas terminals rely on fields also dependent on the Forties Pipeline System for their oil export route.

**Britain's growing reliance on electricity imports is itself a source of gas market risk...**

**...the interconnector regime underpinning that reliance is less robust than assumed**

**Britain's growing reliance on electricity imports is itself a source of gas market risk, and the interconnector regime underpinning that reliance is less robust than assumed.** NESO has moved to more frequent use of capacity restrictions on interconnectors, a shift in practice that sits uneasily with the UK's retained EU law which still states that cross-zonal capacity should not be reduced to resolve internal congestion. On 23 June 2026, NESO issued an Emergency Instruction cutting exports to the Netherlands and sought Emergency Assistance from France, without the advance market warning that would normally precede such actions, at a time when GB's connected markets were themselves under stress.





**Neighbouring electricity systems cannot be assumed to deliver imports when Britain needs them**

**Key Norwegian reservoir levels are below 20-year lows**

**The aging French nuclear fleet is at risk of reliability issues**

**European gas storage is entering this winter at unusually low levels**

**Gas will remain structurally necessary for decades...**

**...full electrification of domestic heating will take around 40 years...**

**...gas-fired generation will continue to be essential to the electricity system when renewables generation is low**

**Electricity meets only around a fifth of the UK's total final energy demand...**

**...gas is still essential for industrial process heat and space heating dependent**

Whether this pattern is sustainable is now bound up with the unresolved question of UK re-entry to EU electricity market coupling, a negotiation in which the UK government has shown no particular willingness to hold firm on sovereign control. Indeed, a parallel negotiation on the SPS agreement suggests the opposite.

Neighbouring electricity systems cannot be assumed to deliver imports when Britain needs them most. Norwegian reservoir levels in the zone serving North Sea Link have fallen to twenty-year lows, and Norway's political mood, reinforced explicitly by the Energy Minister's recent statement that Norway can no longer act as "the green battery of Europe", points toward less interconnection and a greater willingness to restrict exports, not more.

France, historically Britain's largest single source of electricity imports, operates an aging nuclear fleet whose high degree of standardisation creates the possibility of correlated ageing failures of the kind experienced in 2022. Both risks compound during cold, still winter weather when Britain's gas-fired generation would need to substitute for lost imports, increasing gas demand at the point of greatest system stress.

**European gas storage is entering this winter at unusually low levels** - around 61% of capacity in mid-August against a seasonal norm closer to 80%. The EU's storage mandate has again inverted the winter-summer price spread that would otherwise make storage commercially rational to fill. Britain's storage position remains weak. The country holds around sixteen days of gas demand in storage. While Centrica is willing to invest £2 billion to redevelop Rough, it requires some form of guaranteed return on which no decision has yet been taken.

**None of this is resolved by the transition to clean power. Gas will remain structurally necessary for decades for two separate reasons.**

First, the displacement of existing gas demand will take many years. Around 21 million UK homes are still heated by gas boilers and, even at the Government's target of 600,000 heat pump installations a year, replacing them all would take around 40 years. Actual installation rates remain well below that target. Industrial gas demand will also take time to replace, meaning that substantial demand for gas is likely to persist well beyond the current policy horizon.

Second, even if the electrification of heating and other energy demand proceeds broadly as planned, the electricity system itself will continue to need gas for resilience. NESO's Clean Power 2030 plan does not eliminate unabated gas generation: it retains it as the flexibility option of last resort once demand response, storage and interconnector imports are exhausted. This report shows why interconnector imports cannot be relied upon to the extent current plans assume, strengthening the case for maintaining sufficient domestic dispatchable capacity and the gas supplies needed to fuel it.

**Electricity, even fully decarbonised, meets only around a fifth of the UK's total final energy demand, leaving the great majority of the energy system including industrial process heat and space heating dependent on gas for a period measured in decades, not years.**

Gas security is energy security. It is not a subordinate concern to be addressed once decarbonisation is complete, but a foundational one that current policy, in both its production, infrastructure and storage strands, has yet to treat with the seriousness the underlying risk warrants.

## Recommendations

### Fix the broken understanding of how the gas market works

The first recommendation from this report is to fix the broken understanding of how the gas market works. It is not possible for policymakers to make good decisions if they wrongly think British gas production is sold on international markets or at global prices. Neither is true as this report will demonstrate. The British gas market uses marginal pricing and domestic production will displace more expensive LNG imports, thereby lowering the price of gas in the UK. These reductions may not be dramatic, but they will exist by virtue of the way that gas is priced. To say otherwise is simply incorrect.

### Increase UKCS production

Once it is properly understood how gas pricing actually works, it becomes abundantly clear that the only rational choice is to maximise domestic gas production. Preferring imported gas is not just environmentally irrational due to the higher emissions associated with imports, it is economically irrational. Gas from the UKCS is cheaper and cleaner than imports and should be preferred under all circumstances.

### Reduce the reliance on electricity imports

Britain's reliance on electricity imports represents a material risk to security of supply. It is not possible to compel imports – at best we can restrict exports. At times when our connected markets are short of electricity, which increasingly coincides with periods when GB is short due to the growing reliance of weather-based generation and high weather correlation, our energy security is at risk if we cannot import. On low wind days, many of our connected markets are also likely to be short, leaving just France and Norway to meet the needs of several countries including Britain. This winter, Norway's own energy security is under threat due to low water levels while the reliability of the aging French nuclear fleet cannot be guaranteed in the medium term.

### Model gas and electricity security together

The gas and electricity markets are still treated as distinct despite their obvious inter-dependencies. There is a lack of recognition that electrification of heat will take decades so discussions about decommissioning the gas grid are premature. Too little attention is paid to the fact that far more energy is carried over the gas grid than the electricity grid for the delivery of heat, and current planning for the transition is inadequate across the entire value chain from upstream production/generation, through stream transmission, distribution and storage, through to end consumption. To ensure security is maintained and costs minimised these systems need to be modelled together.

### Focus on cheap energy

This report highlights how network costs are likely to overtake fuel costs as the main drivers of higher bills. Consumers will pay more for a less secure system which is unlikely to be acceptable to them. Rapidly accelerating network costs must be brought under control, and Connect & Manage suspended in order to minimise costs to consumers and avoid building assets whose output is mostly wasted.

### No national security without energy security

Energy security should be treated as an essential element of national security. Britain cannot defend itself, maintain essential services or sustain its economy without reliable supplies of affordable energy, while the erosion of energy-intensive industry weakens the domestic industrial capability needed in a crisis. Growing dependence on imported energy and manufactured goods creates overlapping vulnerabilities to geopolitical events and competition for scarce supplies. The government should subject energy policy to an explicit national-security test, prioritising resilience, diversity of supply, sufficient domestic energy capacity and the preservation of strategically important industrial capability alongside affordability and sustainability.





# Gas, electricity and the bill

## How much does gas add to domestic energy bills?

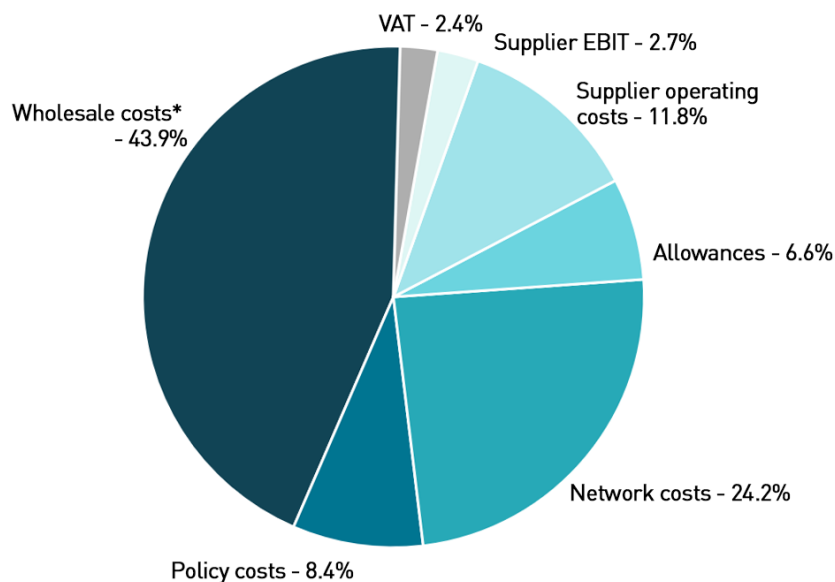
A key myth about gas is that it sets electricity prices. Gas (together with the UK ETS, the carbon pricing scheme) sets the wholesale price of electricity, but this is only around 44% of a dual fuel bill and 38% of the electricity bill. Excluding the carbon element, gas accounts for about 41% of the dual fuel bill and 35% of the electricity bill while network costs now account for 24% of the dual fuel bill and 27% of the electricity bill.

Gas does not set electricity bills...

...gas - along with carbon - sets the wholesale price of electricity...

...gas and carbon together account for 44% of household energy bills and 38% of electricity bills

Dual fuel bill breakdown Oct-Dec 2026 (£ annualised)



\*Wholesale costs include UK ETS costs embedded in the gas-set electricity price (no ETS on domestic gas): est. 7% of wholesale (~£57 /yr, 3.3% of the bill), arguably a policy cost. Based on UKAs at £58 /t (ICE, 19 May-18 August 2026) and a marginal CCGT at 53% efficiency, 0.35 tCO<sub>2</sub> /MWh

Source: Ofgem, Watt-Logic

The wholesale figure shown includes the cost of UK ETS allowances, which is embedded in the price at which gas-fired plant offers into the market and cannot be separated out in Ofgem's published data. On the assumptions below, the ETS accounts for approximately 7% of the combined wholesale allowance in the dual fuel bill, or around £58 per year, (3.3% of the total bill). This would raise policy costs from £145 to around £203 a year if reclassified appropriately as a policy cost.

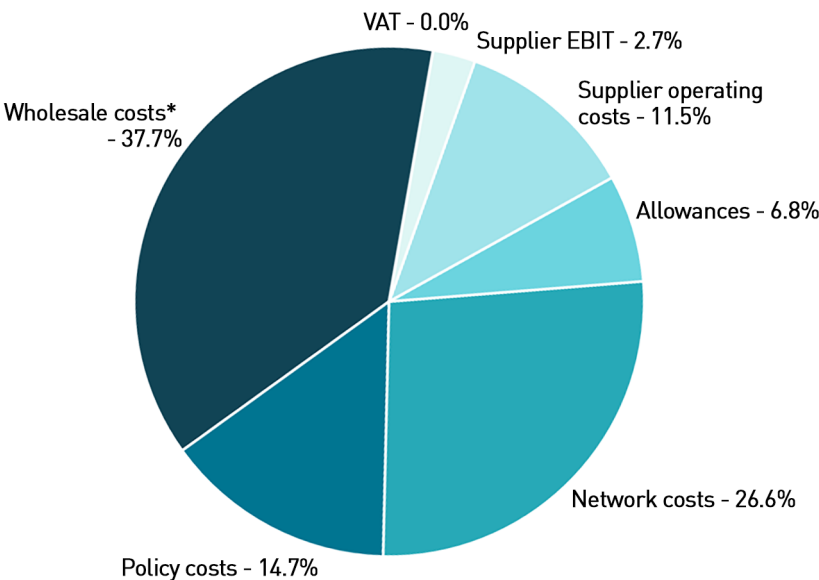
This is based on UK ETS Allowance prices from ICE daily settlements, av-

eraging £57.72 /t over 19 May to 18 August 2026 - a central figure of £58 /t is used, with a range of £51-63 /t giving 6.5 - 8.1%. The marginal plant is assumed to be a CCGT with a thermal efficiency of 53%, emitting 0.185 tCO<sub>2</sub> per MWh thermal and therefore approximately 0.35 tCO<sub>2</sub> per MWh of electricity generated. CCGTs are assumed to set the wholesale price in effectively all settlement periods.

The wholesale price per MWh is derived from Ofgem's Annex 2 direct fuel allowance using the confirmed Q4 26 typical consumption of 2.5 MWh and the GB average loss multiplier of 1.1313, the simple average of the fourteen GSP regional loss multipliers in tab "3c Electricity losses" (rows 11-24, Oct-Dec 2026 column), giving £106.47 /MWh.

This estimate is conservative because Ofgem's direct fuel allowance includes shaping and imbalance costs as well as the commodity itself, so the true commodity price is below £106.47 /MWh and the ETS share correspondingly higher. The 0.35 tCO<sub>2</sub>/MWh figure also assumes a modern, efficient CCGT sets the price - an older or less efficient plant would embed a proportionately larger carbon cost.

Electricity bill breakdown Oct-Dec 2026 (£ annualised)



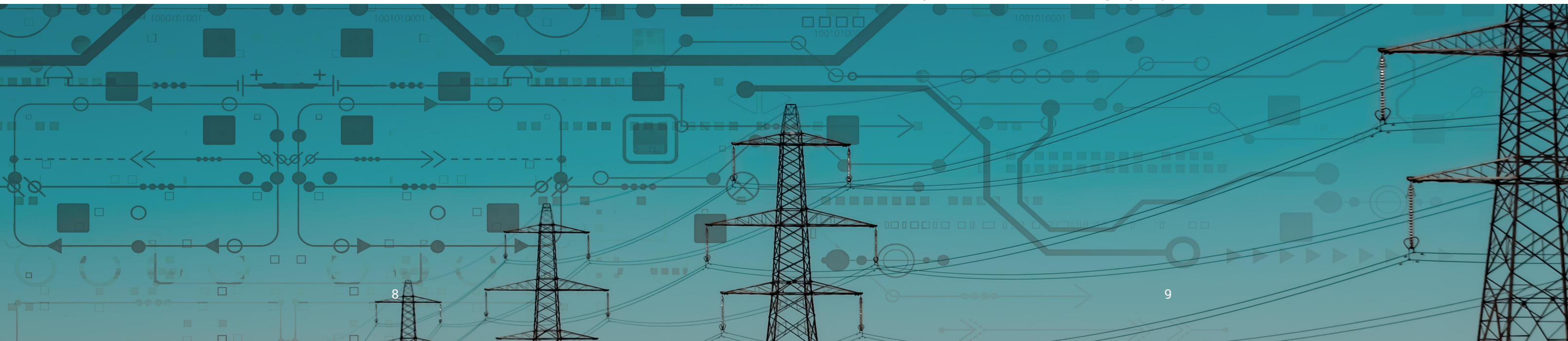
\*Wholesale costs include UK ETS costs embedded in the gas-set price: est. 17.6% of wholesale (~£57 /yr, 6.6% of the bill), arguably a policy cost. Based on UKAs at £58 /t (ICE, 19 May-18 August 2026) and a marginal CCGT at 53% efficiency, 0.35 tCO<sub>2</sub> /MWh

Source: Ofgem, Watt-Logic

Based on the same assumptions, the wholesale figure for electricity shown above includes the cost of UK ETS allowances accounting for around 17.6% of the electricity wholesale allowance or £58 per year (6.6% of the total an-

Carbon costs are rising and imposing growing pressure on wholesale electricity prices...

...in the most recent price cap period the ETS represents about 18% of the wholesale electricity price





nual electricity bill). This would raise policy costs from £126 to around £184 a year.

For Q4 26 and Q1 27 there will be no VAT applied to electricity bills. This will save households around £24 in total based on average consumption and an estimated 24% increase in bills for Q1 27<sup>1</sup>.

### The rising impact of network costs

When the price cap began in 2019, the four main components, wholesale, policy, network and supplier operating costs were roughly equal on the electricity bill. However these have diverged significantly over time. (Although the cap began in 2019, Ofgem publishes comparative data back to 2017 which are used in this analysis.)

“...if I look at the non-commodity costs—policy costs and network costs—certainly some of the modelling that we have suggests that you could get to a position by 2030 where, if the wholesale price was zero, bills would still be the same as they are today because of the increase in those non-commodity costs...”

- Chris Norbury, CEO, E.ON UK  
evidence to the DESNZ Select Committee<sup>2</sup>

Non-commodity costs are an increasing driver of household energy bills

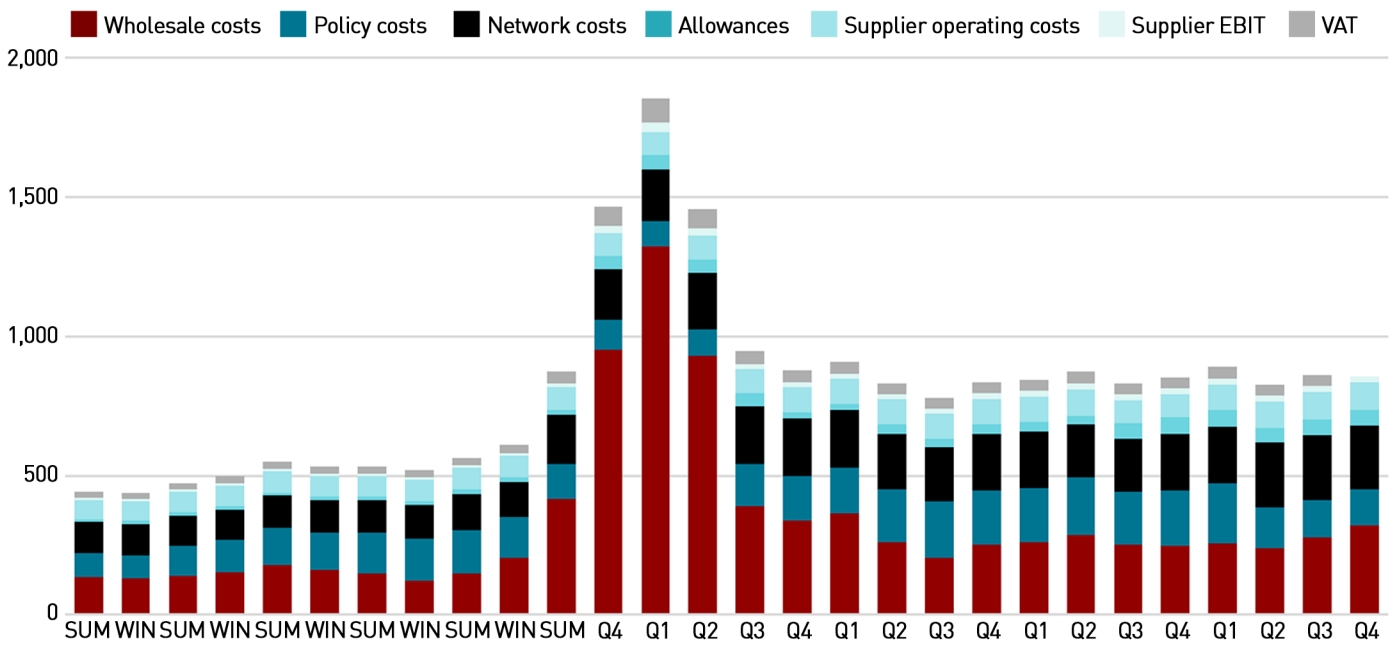
Network costs have increased by the same proportion as wholesale costs since 2017...

...while wholesale costs rose dramatically in 2022-23 they subsequently fell

Obviously during the gas crisis of 2022-23, the wholesale component rose dramatically, but it has since fallen. Unfortunately some of the reduction has been offset by rising network costs, and this element is expected to grow rapidly over the coming years. Between the first price cap in Summer 2017 and the most recent one in Q4 2026, wholesale electricity costs in the cap doubled, as did network costs while policy costs increased by almost two thirds. In contrast, supplier operating costs were only one third higher which is slightly below where they would be if they had increased in line with inflation (according to the Bank of England inflation calculator, £73.28 in 2017 would be worth £101.19 today – supplier operating costs are

<sup>1</sup> <https://www.heraldscotland.com/news/national/uk-today/26557341.energy-price-cap-january-rise-forecast-martin-lewis-warning/>  
<sup>2</sup> <https://committees.parliament.uk/event/25089/formal-meeting-oral-evidence-session/>

Electricity bill breakdown (£ annualised, volume adjusted)



Source: Ofgem, Watt-Logic

currently at £100.67).

Network costs are increasingly coming under scrutiny. In its Clean Power 2030 advice, Energy system operator NESO said that in order to meet the target, it would be necessary to “build all planned transmission network on time, which involves twice as much in the next five years as was built in total over the last decade”. Clearly this is a significant level of investment, necessary to connect renewables to the grid and to reinforce the existing grid to ensure the electricity they generate can be transmitted to consumers.

Wind and solar have low energy density, are intermittent, and are often “distributed” – that is connected to low voltage distribution networks. Generation that has low energy density requires more land, but also more wires to connect it – an 800 MW gas power station requires a single grid connection that is typically short (the distance to the transmission system being generally not great).

An 800 MW windfarm requires 60 turbines each of which must be connected, usually to a central hub that is then connected to the grid. However, a windfarm typically has a capacity factor of around 30% versus over 90% for a gas power station which means that in order to generate the same amount of electricity in one year as the gas power station, the windfarm would need 180 turbines, and 180 sets of wires, at a cost that is likely to be many times that of the gas power station's connection cost. Worse, many windfarms are located in places lacking existing grid infrastructure so the length of the connection from the hub to the grid will be much longer than the connection between the gas power station and the transmission system.

Because wind and solar are often connected to distribution networks, they require both distribution and transmission network investments to connect them and then ensure their electricity is moved to where it is needed. The scale of the renewables build-out planned by the Government implies a massive increase in network investment, which is recovered through bills.

The network cost element of the electricity bill includes transmission and distribution costs which reflect the cost of building and maintaining high and low voltage grids, as well as the costs of balancing the transmission system. Balancing is the process by which supply and demand are balanced in real time at all points on the grid, which is necessary for the technical operability of the grid. Simply put, if this balance is not properly maintained electrical equipment connected to the grid will disconnect in order to prevent damage, potentially leading to blackouts.

Network costs are rising rapidly as part of the Clean Power 2030 plan...

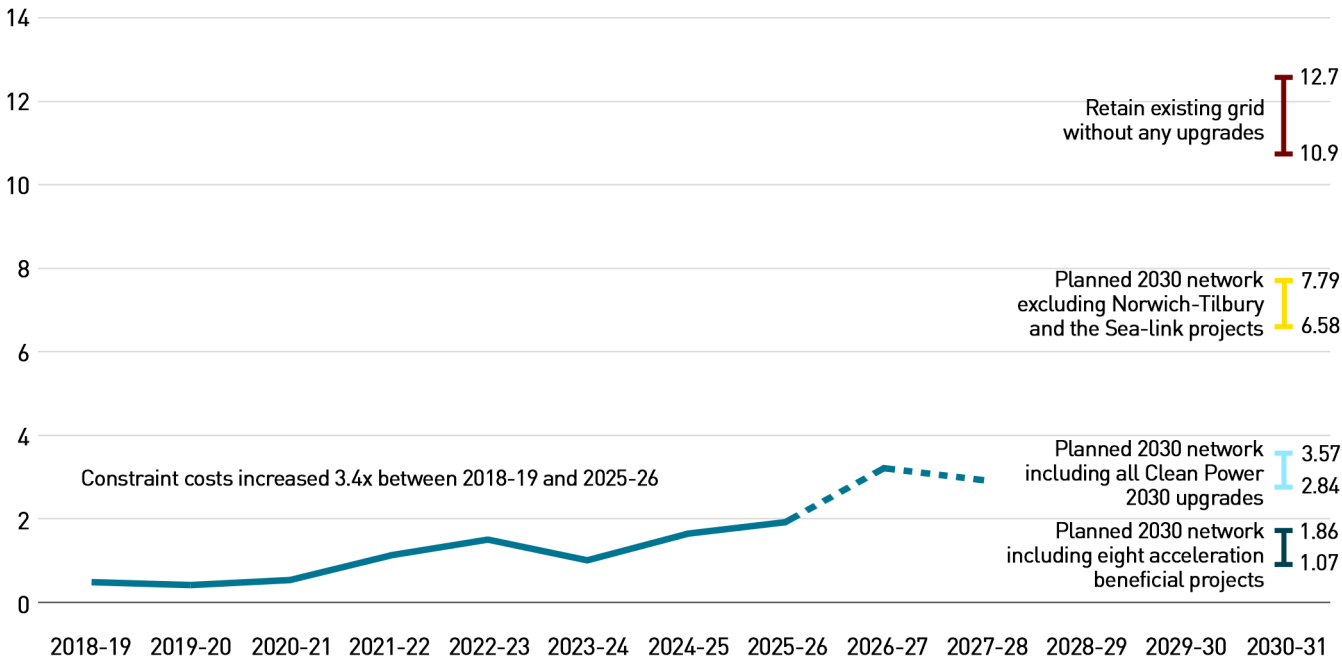
...renewable generation has low energy density and requires more wires than equivalent conventional generation





In the past the main variation in this balance was on the demand side, primarily driven by weather – consumers adjust their energy usage based on temperature, the time of day (including light levels, mealtimes etc). However, the addition of intermittent, weather-dependent generation has now created significant variability in generation where gusts of wind and clouds impact the output of wind and solar in real time. These factors increase the number and volume of balancing actions – market interventions undertaken by the system operator – needed to balance the grid, at significant additional cost. These balancing costs are also recovered through the network component of bills.

Constraint costs (£ billion)



Source: National Audit Office

A further element of network costs is constraint payments. Because there is not enough grid capacity to transmit the output of some renewable generators, particularly Scottish windfarms, their output cannot be used, and their output is curtailed. Constraint costs more than trebled between 2018-19 and 2025-26 to £1.9 billion<sup>3</sup>, and are forecast to peak between £2.4 billion

<sup>3</sup> <https://www.nao.org.uk/reports/upgrading-the-electricity-transmission-network/#downloads>

**The intermittency of wind and solar also adds to network costs through balancing costs**

The National Audit Office has criticised Connect & Manage which allows windfarms to connect to the grid despite the grid lacking the capacity to accommodate them

It says cost control is poor since the costs are recovered through bills rather than public expenditure

and £7.2 billion in 2030<sup>4</sup> and could rise as high as £12.7 billion if grid upgrades are not delivered.

A recent report by the National Audit Office has been deeply critical of the “Connect and Manage” approach which has allowed windfarms to connect to the grid without the necessary infrastructure being in place to allow their output to be delivered to consumers, and poor cost control around planned grid upgrades, attributing this to the fact costs are recovered through bills rather than taxation.

“DESNZ has allowed renewable electricity generation to expand faster than the grid, which has led to increased constraint costs. Successive governments’ ‘connect and manage’ approach has allowed new generation projects to connect before the network was ready...”

Grid upgrades are funded through electricity bills rather than public expenditure and are not supported by a full business case, options appraisal, or assessment of overall value for money...

Delivering all the grid upgrades by 2030 will be very challenging. There remain significant planning, supply chain and system access risks and some of the projects are already forecast for delivery after 2030,”

- National Audit Office, Upgrading the electricity transmission network

NESO’s data on constraints are difficult to understand as it publishes multiple datasets with variations on the name “constraints” and whose definitions appear not to be consistent year-on-year. These are discussed in the Appendix.

To summarise, the network costs in electricity bills comprise transmission system costs (TNUoS), distribution system costs (DUoS) and balancing costs (BSUoS) which includes constraint costs. There are other, smaller elements for example supplier of last resort (SOLR) costs are recovered through network costs, but TNUoS, DUoS and BSUoS are the main cost

<sup>4</sup> <https://www.neso.energy/document/362561/download>





components.

NESO expects total transmission network charges (TNUoS) to increase from £8.9 billion in 2026/27 to £13.6 billion by 2030/31<sup>5</sup>. Most of this is recovered from consumers rather than generators, with the “demand residual” rising from £7.52 billion in 2026/27 to £11.75 billion by 2030/31. For a domestic customer this amounts to £93.48 in 2026/27, some 10.6% of the average electricity bill, rising to around £120 by 2030/31 on the domestic residual band alone. For 2026/27 in isolation, average transmission demand residual tariffs are forecast to rise by 94% against the previous year.

These figures represent the lower-bound of what network costs are likely to be. Firstly, NESO’s forecast was published in September 2025 and built on Ofgem’s draft RIIO-ET3 determinations - the final determinations of 4 December 2025 raised the approved investment by 16%<sup>6</sup>.

NESO’s own sensitivity analysis illustrates how wide the range is: against a base case of £57.2 billion across the five-year period, funding the transmission owners’ published business plans in full would require £94.8 billion and increase the demand residual by 80 per cent. The transmission owners decline to endorse even the base case, with National Grid Electricity Transmission stating that it does not recommend the use of any forecast produced before final determinations were released.

Secondly, even these figures may prove conservative, because the costs on which they are based are escalating rapidly. EDF, drawing on Ofgem’s consultation documents, estimates that transmission construction costs have risen two to three times since the transmission owners’ initial forecasts, and reports that its own generation projects are experiencing average connection delays of two years, with the worst exceeding five<sup>7</sup>. Ofgem’s reporting on eight projects in Scotland found an average implied cost increase of 283%, with some as high as 467%.

Only three of the twenty-six large projects under Ofgem’s Accelerated Strategic Transmission Investment (“ASTI”) scheme have received full funding to date, so the great majority of the programme has yet to be priced at all. EDF notes that Ofgem approved funding for at least twenty-one projects during 2026 alone, but that the actual costs of those decisions have not been published, making independent assessment impossible.

The direction of revision has been consistently upward - Ofgem’s 2022 ASTI framework estimated that the projects required for the 2030 target at around £23 billion but by December 2025 that figure had become over £70 billion for the five years to 2031, with NESO identifying a further £89 billion beyond 2030.

Thirdly, transmission is not the whole of the network cost. Electricity distribution falls outside the RIIO-3 settlement agreed to date entirely: RIIO-ED2 runs until March 2028 with RIIO-ED3 covering 2028 to 2033. Distribution network operators are due to submit business plans in December 2026 with final determinations not expected until late 2027.

Since transmission accounts for roughly £93 of the £232 of network costs in the current electricity price cap, the larger part of the network stack has no published cost forecast beyond 2028 at all. Taken together, Ofgem expects network charges across the RIIO-3 sectors to add around £108 a year to household bills by 2031, in 2023/24 prices, before any distribution increase is known.

Ofgem forecasts the transmission element of a dual fuel bill rising from £44 in 2025 to £105 by 2030. Applying that increase to the current network cost of £240.86 per electricity customer (normalised for volume), and holding the distribution element constant, would take network costs to approximately £300 a year by 2030 – an increase of around 25%. Applying the same increase to distribution costs would increase network costs to £575 a year, an increase of around 139%.

<sup>5</sup> <https://www.neso.energy/document/367801/download>

<sup>6</sup> <https://www.ofgem.gov.uk/sites/default/files/2025-12/RIIO-3-Final-Determinations-overview.pdf>

<sup>7</sup> <https://www.edfenergy.com/about/an-electric-britain/transmission-costs-need-greater-transparency-and-strategic-review>

## Other drivers of bills

Returning to the rest of the bill - the supplier operating profit component rose from £8.44 in 2017 to £23.02 now reflecting the need to allow suppliers to build a profit cushion to protect against market downturns. Prior to the gas crisis, Ofgem severely restricted supplier profits to a degree that was later deemed to undermine their financial resilience. After half of the suppliers in the market failed in late 2021-late 2022, Ofgem introduced various measures to ensure suppliers would be better able to withstand market shocks including a higher profit allowance, although at around 2.5% it is still very low compared with other sectors of the economy.

Another element which was negligible in 2017 but is now having an impact on bills is the Allowances component. These are various adjustments that have been added over time to correct for various market factors, and now represent just over 6.5% of bills. These allowances do not exist to pay for energy or its delivery but to compensate suppliers for the costs and risks of operating within the regulated market:

- The Headroom Allowance is a buffer against uncertainty, recognising that a cap set in advance cannot anticipate every cost a supplier will face;
- The Industry Charges Allowance, introduced in July 2025, covers the charges levied on suppliers by the institutions of the market itself such as settlements and code administration, ombudsman fees, the regulator’s own licence fee and similar. These costs are not new, but they are also not within the control of suppliers – an efficient supplier is not able to reduce its exposure to them any more than an inefficient supplier can. Ofgem has split them out for this reason when previously they were included in supplier operating costs;
- Debt Related Costs, introduced at the same time, is an explicit provision for bad debts that is revenue that suppliers will never collect because consumers do not pay – this is controversial as it embeds moral hazard into the cap structure with consumers who do pay their bills subsidising those who do not;
- The Adjustment Allowance was a temporary mechanism allowing recovery of accumulated bad debt from the crisis period, that has now fully unwound;
- The Payment Method Administrative Costs and the Payment Method Adjustment Percentage together formed the payment method uplift, reflecting the higher cost of serving prepayment and standard credit customers. These allowances were removed in July 2025 and replaced by Levelisation, which spreads that differential across all customers rather than loading it onto those who do not pay by direct debit and are the least able to bear it.

Taken together these allowances have risen from £10.26 per electricity customer in April 2017, when the cap was introduced, to £60.25 in July 2026, an increase of almost six times, on a consistent consumption basis.

“Per point of delivery, the cost to serve in the UK is about £100 per annum. In France, it is €45, which is half, more or less. It is actually less than half. This is not to do with the wholesale price or the gas marginal cost et cetera. It is driven by the fact that we have very complex regulation that has become stratified over the years,”

- Simone Rossi, CEO EDF UKgiving evidence to the DESNZ Select Committee

The largest single component is debt - at £27.33 per customer, the debt allowance alone is now nearly three times the entire allowance cost from



The cost to serve in the UK is far higher than in other countries such as France because of the non-commodity costs added to bills

2017. Industry charges account for a further £19.28, headroom has roughly doubled to £9.01 as the bill it is calculated against has grown, and levelisation adds £4.63. Excluding debt, the increase is a little over three times.

This growth is nothing to do with the cost of energy. It is a measure of how much more it now costs to operate a regulated supply business - to carry consumers who cannot pay, to fund the institutional machinery of the market, and to bear the risk that a cap set months in advance proves inadequate. Together the Allowances now exceed the suppliers' allowed profit of £23.02 per customer by a factor of nearly three. The energy retail market has become materially more expensive to run, and those costs fall on the customers who do pay. At the same time, more and more interventions are needed to prevent the market from breaking, to a degree that "market" is increasingly an inappropriate term for something that operates to a large extent based on the direction of the regulator rather than any conventional market forces.

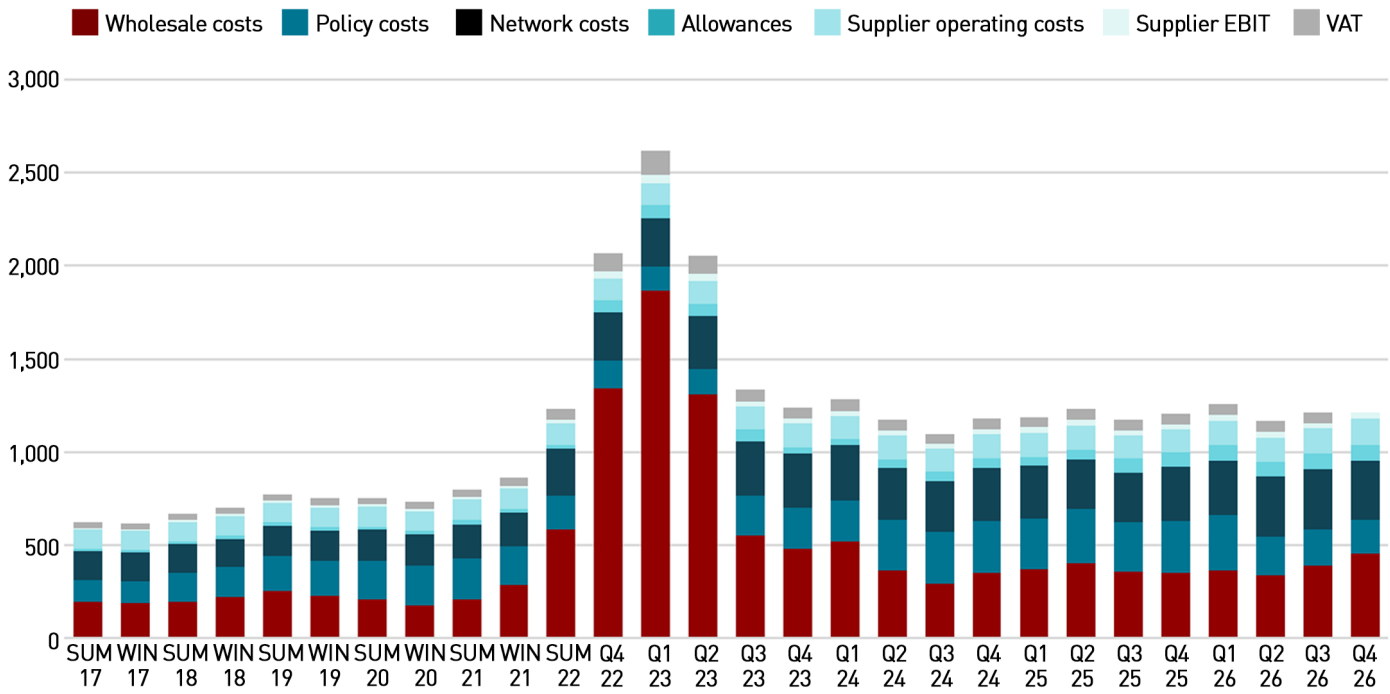
Inflation-adjusted figures give a more realistic view of real cost increases

While the raw price cap figures published by Ofgem suggest today's cap levels are much higher than they were before the 2022-23 gas crisis, it is important to note that Ofgem quotes nominal cap data – a proper comparison should adjust for inflation. The chart below shows the Ofgem cap data, with the CfD costs moved from the wholesale category to policy costs (as above) and adjusted for inflation using Office for National Statistics Consumer Price Index data<sup>8</sup>

On a real £2026 basis, wholesale costs from Summer 2017 to Q3 2026 (a more reasonable comparator than Q4 2026 to avoid seasonal effects) have increased by 1.5x rather than 2x as in the nominal analysis above. Network costs are also around 1.5x higher while policy costs are 1.2x. As noted above, supplier operating costs are very slightly lower while supplier EBIT is double to 2017 level rather than 2.7x per the nominal analysis. Allowances are 4.25x higher. The total electricity bill in real terms is 40% higher than it was in 2017, instead of almost double as indicated in the nominal

8 <https://www.ons.gov.uk/economy/inflationandpriceindices/timeseries/d7bt/mm23>

Electricity bill breakdown (£ annualised, volume adjusted, £2026)



Source: Ofgem, Office for National Statistics (CPI), Watt-Logic

In real terms electricity bills are 40% higher than in 2017...

...dual fuel bills are 1.45x higher

Network costs are expected to keep rising in the coming years...

...while gas prices are set to fall as new LNG supplies around the world loosen the market

analysis. While this is still a meaningful increase there is a big difference between being 40% higher and being 100% higher in affordability terms.

Applying a similar analysis to the dual fuel bill, the total household cost for gas and electricity together in real terms is 1.45x higher in Q3 2026 than in 2017, compared with 2.01x higher under the nominal analysis.

What this demonstrates in very clear terms is that network costs have risen by the same proportion as wholesale costs over the life of the price cap (noting that the wholesale component contains a significant element of carbon costs which changed from the EU to the UK market in 2021). This materially undermines the argument that gas is the primary driver of bills. It was during the gas crisis of 2022-23, but even the current war in Iran is not having anywhere close to the same effect on bills, and prices retreated significantly after the shock to follow the same trajectory as network costs.

Network costs are contracted, regulated and certain to rise - Ofgem's impact assessment forecasts the transmission element of a household bill rising 140% by 2030, and the distribution element is yet to be determined. Gas prices face no comparable structural pressure. The IEA expects around 300 bcm a year of new LNG liquefaction capacity by 2030, a net supply increase of some 250 bcm, which it forecasts will place downward pressure on prices<sup>9</sup>. The near-term outlook has been disrupted by the closure of the Strait of Hormuz, which the IEA estimates will remove 140 bcm cumulatively to 2030 and delay the easing by around two years, but that is a delay to a rebalancing, not a reversal of it<sup>10</sup>. The asymmetry is very clear – the network component of the bill is committed to rise, the gas component is expected to fall.

9 <https://www.iea.org/reports/gas-2025/executive-summary>

10 <https://www.iea.org/reports/gas-market-report-q3-2026/executive-summary>





## Gas markets are regional not international

### How gas actually trades

It is often said that gas markets are international and that UK gas production is “sold on international markets at international prices”. This statement is not an accurate reflection of either the global gas market or global gas prices. The global gas complex comprises two distinct types of price marker, and conflating them is the source of most of the confusion in this debate.

#### Gas hubs

The first type is hub pricing attached to a physical pipeline network. There are two types of hubs. Virtual trading points are markets where wholesale gas traded is delivered anywhere within the (typically high pressure) pipeline system, with separate transactions for entry to and exit from the system. Gas is notionally everywhere in the balancing zone at once, and a trade at the hub transfers ownership without reference to location.

Examples of virtual trading points include the British hub, known as the National Balancing Point (“NBP”), the Dutch Title Transfer Facility (“TTF”), the Zeebrugge Trading Point (“ZTP”) in Belgium, Trading Hub Europe (“THE”), Germany’s single market area, created on 1 October 2021 by merging Gaspool and NetConnect, Point d’Échange de Gaz (“PEG”) in France, Punto di Scambio Virtuale (“PSV”) in Italy and Punto Virtual de Balance (“PVB”) in Spain. NBP used to be the primary European hub, reflecting the UK’s strong domestic production, but in recent years, TTF has taken over as the main European benchmark.

Physical hubs are specific interconnection points where pipelines meet and title changes hands at that point. Henry Hub is the paradigm, an actual interconnection near Erath in Louisiana. North American marketers generally work this way: Waha at the Permian interconnect in West Texas, SoCal Border at the California entry points, AECO (Alberta Energy Company) in Alberta and Dawn in Ontario. The Central European Gas Hub (“CEGH”) began life as a market for commercial gas trading near the strategic Baumgarten transit node in Austria, where Russian gas entered central Europe and where the Slovak, German, Italian and Hungarian systems meet. However since 2013 it has operated as a virtual trading point for the whole country.

Hub prices are locational prices, with the difference between being the “basis” which represents the cost of moving gas from one point to the other, and the value of the capacity required to do it. Basis is not a residual or a rounding error, it is a traded quantity in its own right, and increasingly treated as such. In July 2026, Platts launched a new set of European hub differential assessments, publishing each hub against reference markets including TTF, THE, CEGH and PVB, in response to growing interest in spread analysis. In North America gas at one hub can trade at a fraction of the price of gas at another on the same continent, connected by the same network, in the same hour. Geography sets the price of piped gas, not the “world market”.

#### Seaborne markers

The second type of gas price market is the seaborne marker, based on shipments of liquefied natural gas (“LNG”) by ship. The main seaborne market is the Japan-Korea Marker (“JKM”) used in Asia, north-west European and Mediterranean delivered ex-ship (“DES”) assessments, and free-on-board (“FOB”) markers at loading terminals such as Sabine Pass in the US.

Because a cargo on the water can be diverted, these markers can converge, but only to the extent allowed by freight, boil-off and regasification costs, and only for that are not contractually committed to a specific delivery point. Seaborne markers are derived prices: a DES assessment is the net-

back of a destination hub less the cost of reaching it, and an FOB price is the highest such netback across competing destinations. The mechanism is visible in the assessments themselves - a north-west Europe DES LNG marker will sit at a substantial discount to TTF when regasification and onward capacity are the binding constraint. The price is derived from the hub to the cargo, not from some global price to the hub.

### Basis of pricing

In the early days of the gas markets, gas prices were not set independently, but based on the value of the alternative fuel the buyer would otherwise have bought, less the cost of transporting the gas. The principle is generally attributed to Groningen in the Netherlands, and it was logical at the outset of the gas era because customers had to be persuaded to switch from oil products to the new fuel, which required gas to be priced relative to, but below, the energy source they already used<sup>11</sup>. Also, for some reason, the gas community did not believe that prices should be set by the forces of supply and demand for gas.

The netback structure also solved a financing problem: the international high-pressure pipeline network that carried Dutch, then Russian, Norwegian and eventually British gas across Europe was funded on this basis, with the price in the destination country linked to competing fuels with the producer receiving that revenue less transport. Destination clauses ensured the gas actually reached the market it had been priced against<sup>12</sup>.

In continental Europe the competing fuels were oil products - principally fuel oil and gasoil - and contracts were indexed accordingly. These were long instruments, typically twenty to twenty-five years in length, and the arrangement deliberately traded away responsiveness for stability: prices tracked oil with volatility smoothed by moving averages, which underpinned very large investments in upstream developments, pipelines and terminals, but meant gas prices did not reflect the supply and demand balance of the gas market itself.

This funding model was further supported by a volume provision known as “take-or-pay” whereby the buyer was required to either buy a minimum volume of gas or pay as if it had. This meant the producer took price risk through the indexation formula, and the buyer took volume risk through an obligation to pay for a minimum annual quantity whether or not it was lifted. The guaranteed volume ensured that the long-term project finance for the construction of the gas assets (production and pipelines) could be recovered. For as long as contract price approximated market price the arrangement worked as intended<sup>13</sup>.

It stopped working when the two diverged. By the 2000s, long after most of the pipelines had been paid for, and independent gas pricing based on gas market supply and demand had emerged, European utility buyers found themselves having to pay for oil-indexed volumes they could only resell at much lower hub-based gas prices. This led to significant losses among European utilities in the period between 2009 and 2014. Contemporary analysis noted that the stakes in the resulting disputes involved considerably more than payment for under-lifted volumes, and that major concessions on take-or-pay levels would, subject to infrastructure constraints, materially change the competitive position of the gas concerned<sup>14</sup>. The episode reshaped the European utility sector and is the principal reason that take-or-pay obligations and contract tenors are markedly less onerous today than they were two decades ago.

11 <https://www.oxfordenergy.org/wpcms/wp-content/uploads/2020/04/Insight-68-A-Comparative-History-of-Oil-and-Gas-Markets-and-Prices.pdf>

12 [https://www.oecd.org/content/dam/oecd/en/publications/reports/2008/05/development-of-competitive-gas-trading-in-continental-europe\\_g1gh8c13/9789264042179-en.pdf](https://www.oecd.org/content/dam/oecd/en/publications/reports/2008/05/development-of-competitive-gas-trading-in-continental-europe_g1gh8c13/9789264042179-en.pdf)

13 [https://link.springer.com/chapter/10.1057/9780230370944\\_12](https://link.springer.com/chapter/10.1057/9780230370944_12)

14 <https://www.econstor.eu/bitstream/10419/306942/1/OEF-079.pdf>



Gas prices are set using marginal pricing...

...this means the most expensive source of gas sets the price...

...this is almost always LNG

### Marginal pricing

Britain moved to pricing gas on its own terms earlier than the Continent because the UK had indigenous supply, and a more market oriented outlook. Although North Sea gas production began in 1967 and the domestic retail gas market was privatised in 1986, NBP was not set up until 1996, a whole decade later. It took another 10 years for hub pricing to gain traction in Europe. The UK allowed domestic production and domestic demand to clear against each other, forming the price on the basis of the marginal molecule needed to meet demand and the willingness of buyers to pay for it. A market importing all of its gas from a handful of external suppliers under long-term contract has no internal balance to price against; a producing market does.

Liberalisation supplied the institutional machinery that enabled hub pricing to emerge. Unbundling, third-party network access and a virtual trading point at which title could transfer across the whole system gave the emerging price somewhere to be quoted and something to settle against. Regulated third-party access was the step that broke the hold of the monopoly suppliers who had operated the oil-linked system. By the late 1990s NBP was a functioning gas-on-gas market. The Interconnector UK ("IUK") to Belgium, commissioned in 1998, then did something novel: delivering gas from a market where price was formed by gas fundamentals into markets where price was formed by oil indexation, making the difference between the two visible and tradeable.

"At the moment, when gas prices are high, we end up paying more for our electricity, even though the cost of producing it doesn't change. And so myself and Ed Miliband are now working to come up with a practical way that we can delink those prices.

It is quite a big change but is absolutely the right thing to do, especially as electricity makes up an increasing part of our energy mix, and we hope, within the next sort of few days, weeks, to be able to give more details on what that looks like,"

- Rachel Reeves MP, then Chancellor of the Exchequer

LNG is not uniformly priced...

...there is not a single "international" price for gas or LNG...

...the price of LNG depends on a range of factors

Today most major gas markets use marginal pricing. A view has developed that marginal pricing is a bizarre quirk of the British electricity market – this is not the case. All freely traded commodities markets in the world use marginal pricing, whether that is wheat, pork bellies, copper, silver, oil or gas. That means the British wholesale gas price is driven by the most expensive source of supply needed to meet demand, which today is typically an LNG cargo.

This means that NBP typically varies based on the source of the marginal LNG cargo. The common assumption is that LNG arrives at a single "international price", and that the diversity of sources of LNG is irrelevant to the price Britain pays for gas. In fact the opposite is closer to the truth: cargoes landing at the Isle of Grain, South Hook or Dragon in any given month are priced by several quite different mechanisms, with origin being a poor guide to which one applies.

A cargo may be delivered under a legacy long-term contract indexed to Brent, in which case its price is a function of the oil market and moves independently of any gas hub. It may come from a United States liquefaction facility under a tolling arrangement, where the buyer pays a Henry Hub-referenced commodity cost plus a fixed liquefaction fee and freight, and where the delivered economics turn on the transatlantic arbitrage rather than on any European assessment. Or it may be a spot or portfolio cargo, priced at the netback value of whichever destination market bid highest – that is to say, priced off a hub rather than setting one. Cargoes

from the same country routinely arrive under all three arrangements, and cargoes from different countries routinely arrive under the same one: a Norwegian cargo from Hammerfest and a West African spot cargo delivered into the same terminal in the same week are likely to be priced far more alike than two Qatari cargoes, one contracted in 2010 and one bought in the last month.

The practical consequence is that there is no single international price of LNG, and no mechanism by which one is transmitted to Britain. There is a set of contractual structures, of varying vintage and varying index, whose common feature is that the divertible ones settle by reference to the destination hub. Origin determines which seller captures the margin between the cost of production and the delivered value; it does not determine what Britain pays. That is set at the point of delivery, by the price required to attract the marginal cargo away from its next-best market, and, as the following section sets out, only in those periods when a marginal cargo is required at all.

### Europe's shift to hub pricing

Continental Europe took two decades to transition to hub pricing, ultimately driven by regulation and a commercial crisis. The regulatory strand began with the EU's First Energy Package between 1996 and 1998, which was intended to liberalise national energy markets along lines closer to the US model<sup>15</sup>. Successive packages, the EU gas target model and the introduction of entry and exit pricing then created the conditions in which NBP and TTF could build liquidity, and in which national hubs could exist at all.

The commercial element was more decisive. In 2004 gas indexation accounted for less than 5% of European long-term contract pricing<sup>16</sup>, but the share was growing. In 2008 spot (hub) prices fell while oil prices rose, creating a gap that became untenable for utilities holding oil-indexed supply contracts with Russian state gas company Gazprom but selling at hub prices. By 2009, oil-indexed contract prices were roughly double the level of UK spot prices. A wave of arbitration and renegotiation followed.

A tribunal required Gazprom to adjust its contract with RWE, a ruling seen at the time as potentially ending the decades-long practice of linking long-term gas prices to oil<sup>17</sup>. Oil indexation stopped being the dominant mechanism for European gas pricing between 2012 and 2015, although many import contracts retained blended oil and hub components. The International Energy Agency estimated that gas-on-gas competition rose from 30% of total EU gas imports in 2010 to over 80% by 2020, saving an estimated \$70 billion in import costs over the decade. However, in 2021 alone, the same exposure cost the EU around \$30 billion more than oil indexation would have<sup>18</sup>.

Gazprom resisted this transition more strongly than other major suppliers. Oil indexation priced its gas against a benchmark that no competing gas seller influenced, insulating its volumes from price competition, whereas hub indexation exposes every supplier to gas-on-gas competition at the delivery point, which is why oil indexation and destination clauses featured together in the arbitration, rather than separately. The structure reinforced this: oil-indexed formulae typically referenced a moving average of gasoil and fuel oil prices over six months, so the contract price moved slowly and with a lag even when the underlying moved sharply, while a hub price reflects the balance of the market as it stands. It is also likely that oil indexation suited the wider alignment of Russian state revenues and fiscal planning with oil prices<sup>19</sup>.

<sup>15</sup> <https://www.sciencedirect.com/science/article/pii/S0954349X25000542>

<sup>16</sup> <https://www.oxfordenergy.org/publications/is-there-a-rationale-for-the-continuing-link-to-oil-product-prices-in-continental-european-long-term-gas-contracts-2/>

<sup>17</sup> [https://www.europarl.europa.eu/doceo/document/E-7-2013-011258\\_EN.html](https://www.europarl.europa.eu/doceo/document/E-7-2013-011258_EN.html)

<sup>18</sup> <https://www.iea.org/commentaries/despite-short-term-pain-the-eus-liberalised-gas-markets-have-brought-long-term-financial-gains>

<sup>19</sup> <https://cdr.lib.unc.edu/concern/dissertations/9s161717m>





Henry Hub and JKM

North America reached gas-on-gas pricing by a different route and much earlier, through regulatory reform that separated pipeline transport from pipeline sales and left the commodity to trade competitively. Of the three main world gas markets, the United States is the only one to have moved substantially away from long-term contracting toward short-term trading (although this is also prevalent in Britain). By the end of the 1990s, almost all major hubs in the United States had developed into spot markets where gas was traded continuously. The most important spot gas market in the US is Henry Hub. This highly liquid and efficient spot market determines gas prices on a continuous basis. Henry Hub was the basis for the first financial gas contract, the New York Mercantile Exchange (“NYMEX”) natural gas futures contract<sup>20</sup>. The shale expansion from the mid-2000s drove Henry Hub structurally low and severed any residual relationship with oil.

Asia retained oil indexation for much longer. Almost all Asian supply was transacted under twenty-year contracts indexed to crude, typically priced as a percentage slope on the average monthly price of crude oil imported into Japan. This benchmark was known as Japan Crude Cocktail (“JCC”). In 2009, Platts launched the Japan Korea Marker to assess the spot value of cargoes delivered ex-ship into Japan, South Korea, China and Taiwan<sup>21</sup>. JKM swaps are now traded on the ICE and CME exchanges. JKM quickly became the main pricing measure used in the Asian spot market, as LNG demand in Asia grew<sup>22</sup>, particularly in Japan after the nuclear closures following the Fukushima incident saw a large increase in gas imports for electricity generation.

As a result of the way these different regional markets have evolved, an LNG cargo may be priced against any of several unrelated indices, and increasingly against more than one. Asian buyers often hold portfolios of oil-indexed term contracts topped up with JKM-priced spot cargoes, with the ratio between the two shifting according to which is cheaper. Contracts blending Henry Hub, hub and oil components in a single formula are commonplace, as are optionality clauses under which the applicable index depends on where the cargo ultimately discharges. The JKM-to-TTF spread now functions as the routing signal determining whether flexible Atlantic-basin cargoes sail east or west. The two markers have become increasingly correlated as a result<sup>23</sup>.

20 <https://documents1.worldbank.org/curated/en/177061468761435889/pdf/17897-Replace-ment-file-141JURIS.pdf>

21 [https://uk.practicallaw.thomsonreuters.com/Glossary/PracticalLaw/I3d5e52dc38d611ebbea4f0dc9fb69570?transitionTy pe=Default&contextData=\(sc.Default\)&firstPage=true](https://uk.practicallaw.thomsonreuters.com/Glossary/PracticalLaw/I3d5e52dc38d611ebbea4f0dc9fb69570?transitionTy pe=Default&contextData=(sc.Default)&firstPage=true)

22 <https://www.anz.com/institutional/insights/articles/archive/jkm-the-future-of-the-LNG-market/>

23 <https://offshoreindustry.co.uk/lng-spot-trading-and-the-jkm-ttf-spread-how-asian-and-european-gas-markets-are-increasingly-linked/>

The GB gas market

The British gas balance

UK gas demand has fallen substantially over the past two decades, from 1,124 TWh in 2000 to 680 TWh in 2025. Demand in 2025 fell to its lowest level since 1992, driven principally by a fall in gas burn for electricity generation<sup>24</sup>.

It is important to note a few things. Firstly, Great Britain supplies gas to both Northern Ireland and the Republic of Ireland as well as the Isle of Man over the Moffat pipeline (see later). Government data treat the flows to the Irish Republic and Isle of Man as exports, and in one sense they are, but they are not really optional in the normal way that exports are optional.

Secondly, the Irish Government expects substantially all of Irish gas demand to be supplied by the UK by 2030 as the Corrib gas field declines (indigenous Irish supply, primarily Corrib, met 17% of Irish demand in 2025<sup>25</sup>). In a 2023 risk assessment it concluded that were supplies over Moffat to be disrupted, Irish gas security would be at risk, and that Ireland was not fully compliant with the EU Infrastructure Standard relating to gas security<sup>26</sup>.

The Irish Government also acknowledges that in the event of a domestic gas emergency in GB, gas supplies to both Northern Ireland and the Irish Republic would be curtailed in line with regional domestic supply restrictions in Britain. This reflects the situation in the electricity market and implicitly treats the whole of Ireland as load on the British grid<sup>27</sup>.

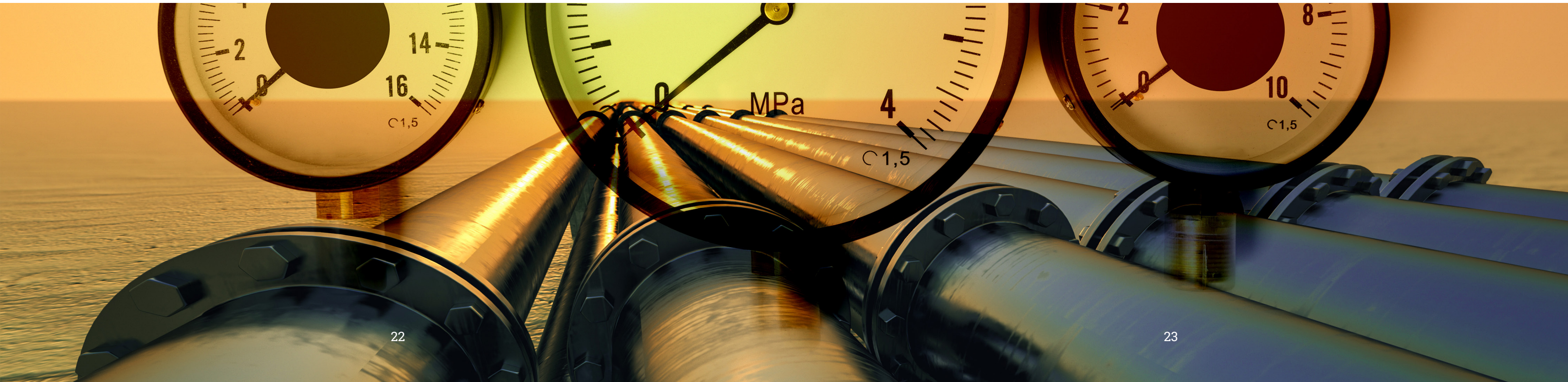
So while the UK reports exports to the Republic of Ireland and the Isle of Man in its export data, these are not exports in the true sense. Although Moffat could import as well as export, it has never carried a reverse flow. Ireland has no alternative source of pipeline gas, no LNG import terminal and plans to install a floating regasification plant are not close to materialising. For this reason, Ireland behaves like, and should be treated as, a source of demand in the GB system, and these export flows should be treated as part of GB demand rather than as exports to a third country.

24 <https://www.gov.uk/government/statistics/natural-gas-chapter-4-digest-of-united-kingdom-energy-statistics-dukes>

25 <https://data.cso.ie/>

26 <https://www.gov.ie/en/department-of-climate-energy-and-the-environment/publications/energy-security-in-ireland-to-2030/>

27 <https://www.irishtimes.com/business/2022/08/03/british-gas-shortage-could-hit-ireland-government-admits/>

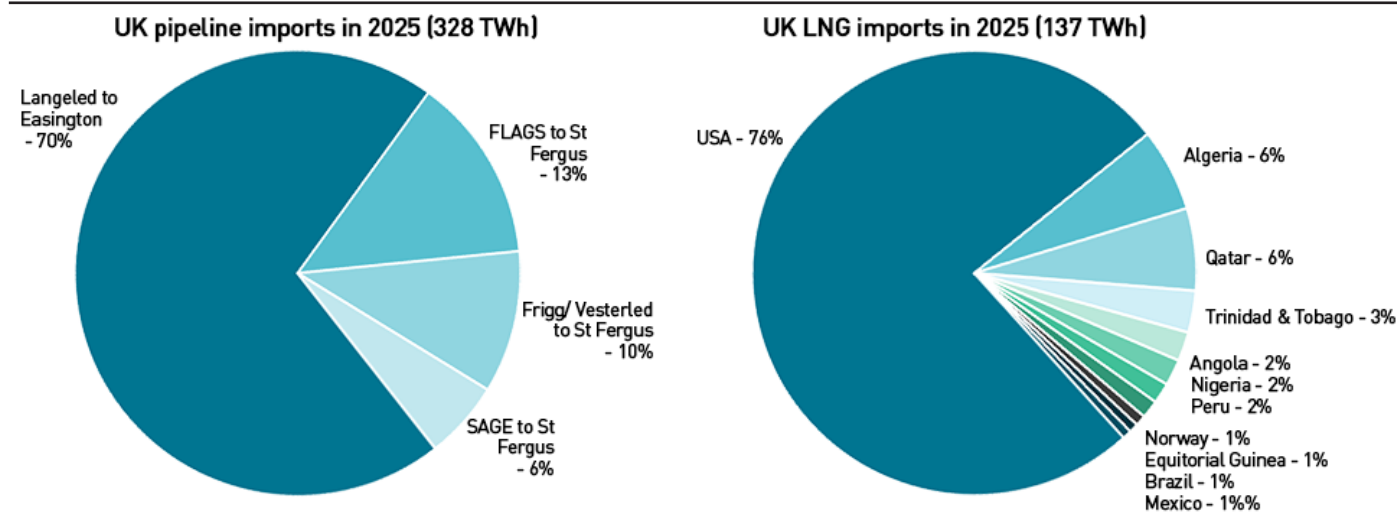




In 2025 the UK exported 47 TWh of gas to the Republic of Ireland and Isle of Man – including this in UK demand figures raises it to 727 TWh in 2025.

Against this demand, UKCS production was around 332 TWh in 2025 roughly a quarter of the 2000 level of 1,260 TWh<sup>28</sup>. Pipeline imports from Norway, arriving via Langeled into Easington and Vesterled into St Fergus, supply a broadly comparable volume: Norway delivered 322 TWh in 2025, equivalent to 47% of total UK consumption, of which over 99% came by pipeline<sup>29</sup>, and in 2025 Norwegian gas accounted for 69% of all UK imports.

## UK gas imports 2025



In addition there were pipeline imports from:  
Interconnector UK (IUK) - 1.2%  
Bacton Balgzand Line (BBL) - 0.6%  
and a very small amount through CATS to Teeside (53 GWh)

Source: DESNZ, Energy Trends UK: natural gas

Norwegian pipeline imports have increased as a share of UK gas demand from 35% in 2019 to 47% in 2025 (a small reduction from 50% in 2024) while LNG imports varied between 16% (2024) and 35% (2022) over the same period. UKCS production has been around 50-55% during this period except for 2021 when it was 43% of gas demand.

Gross exports from the UK totalled 133 TWh in 2025, but the headline figure conflates two different things. Some 45,712 GWh went to the Republic of Ireland and a further 1,400 GWh to the Isle of Man, both over the Moffat interconnector, together 35% of gross exports.

## UK gas balance



Source: DESNZ, Energy Trends UK: natural gas

<sup>28</sup> <https://www.gov.uk/government/statistics/digest-of-uk-energy-statistics-dukes-2026>

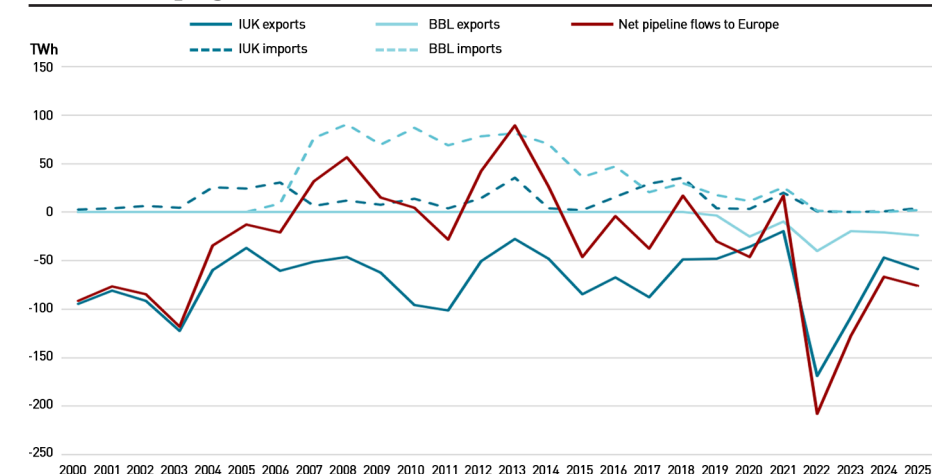
<sup>29</sup> <https://www.gov.uk/government/statistics/gas-section-4-energy-trends>

(It is worth noting that Moffat is a small pipeline system rather than a single pipe. Originating from the Moffat interconnection point in Scotland, one pipe runs to Northern Ireland while two run to the Republic of Ireland, one of which carries a short spur to the Isle of Man.)

Irish and Manx volumes have also been considerably more variable than their status as captive load might suggest, moving with Irish weather, power sector gas burn and the availability of indigenous Corrib production. That variability is a call on GB supply which GB does not control and cannot decline.

Setting those volumes aside leaves 85,996 GWh in 2025 as the whole of Britain's export to the wider European market: 58,390 GWh over the Interconnector to Zeebrugge, 23,907 GWh over BBL to Balgzand, and 3,699 GWh of direct exports from a handful of UK-sector fields tied back into Dutch off-shore infrastructure. Flows in the opposite direction were negligible: 4,076 GWh over IUK and 2,004 GWh over BBL, barely 1% of total imports.

## UK – Europe gas flows



Source: Energy Trends UK: natural gas

That near-absence of return flow is a recent development, and a significant one. The interconnectors have passed through three distinct phases. From 2000 to 2006 the position was consistently one of net export, peaking at 118,264 GWh in 2003, when IUK was the only route and had been built to move UK gas to the Continent.

From 2007 to 2021 the link was genuinely bidirectional: GB was a net importer in nine of those fifteen years, taking in 89,428 GWh net in 2013 and 56,788 GWh in 2008, with the balance switching direction repeatedly as relative prices and continental supply conditions changed. Since 2022 the position has been one-way, and on a scale without precedent in the series: net exports of 207,676 GWh in 2022, 127,221 GWh in 2023, 66,500 GWh in 2024 and 76,218 GWh in 2025. The 2022 figure is nearly two and a half times the largest net import year ever recorded. What had been a genuinely bidirectional link has become, in practice, an export route with a vestigial return leg.

## The UKCS production outlook: a moving and disputed target

The gas balance described above is not a fixed picture. UKCS production was 332 TWh in 2025, just a quarter of the 2000 level. In 2019, the then-Oil and Gas Authority projected that 6.5 billion barrels of oil equivalent (a combined oil and gas measure) could be recovered from the UKCS between 2025 and 2050, with a near-term challenge of reaching 1.3 million boe/d of production by 2030. NSTA's current position, as of its November 2025 projections, puts total 2025-2050 recovery at just 3.8 billion boe, a fall of more than 40% from the 2019 figure, with the 2030 production target now more than halved, to 0.6 million boe/d<sup>30</sup>. Every intervening revision has pointed the same way – downwards, driven by a hostile fiscal regime and a ban on new exploration drilling.

<sup>30</sup> <https://oeuk.org.uk/product/business-outlook-report-2026/>



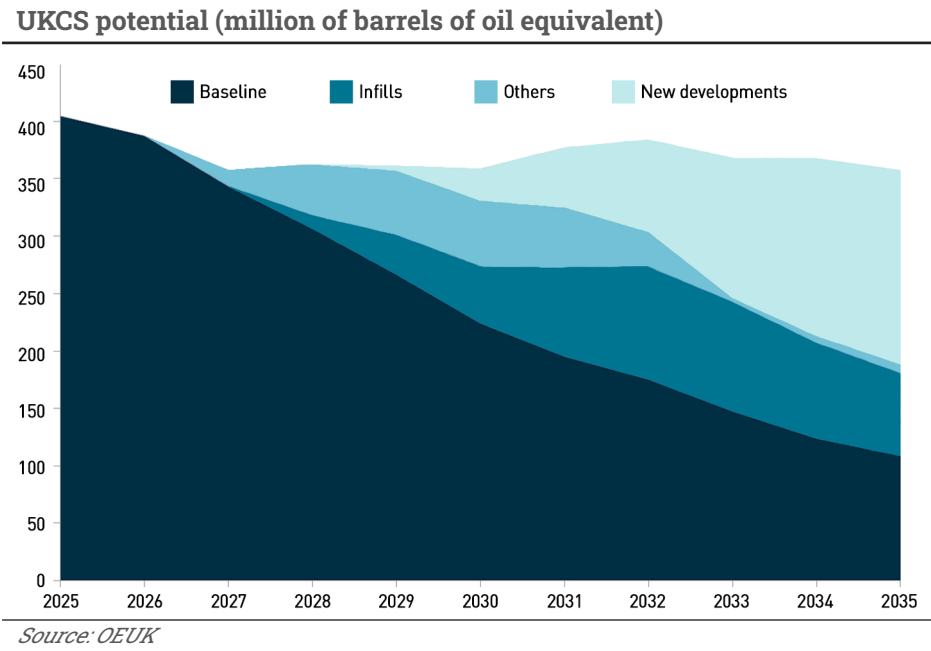
The GB gas balance is not a fixed picture...

...production forecasts reflect economically recoverable gas...

...this reflects both geology AND the fiscal regime...

...production forecasts can rise or fall based on changes in the fiscal regime with no changes to the geological outlook

These forecasts are often used as “proof” that the UK’s gas resources are rapidly declining and that approving new production is largely futile. But this is to misunderstand what lies behind these forecasts – they are not a representation of total available gas, but a forecast of economically recoverable gas. If policy changes restrict drilling and make production less profitable, the amount of economically recoverable gas will fall regardless of the actual volume of gas reserves.

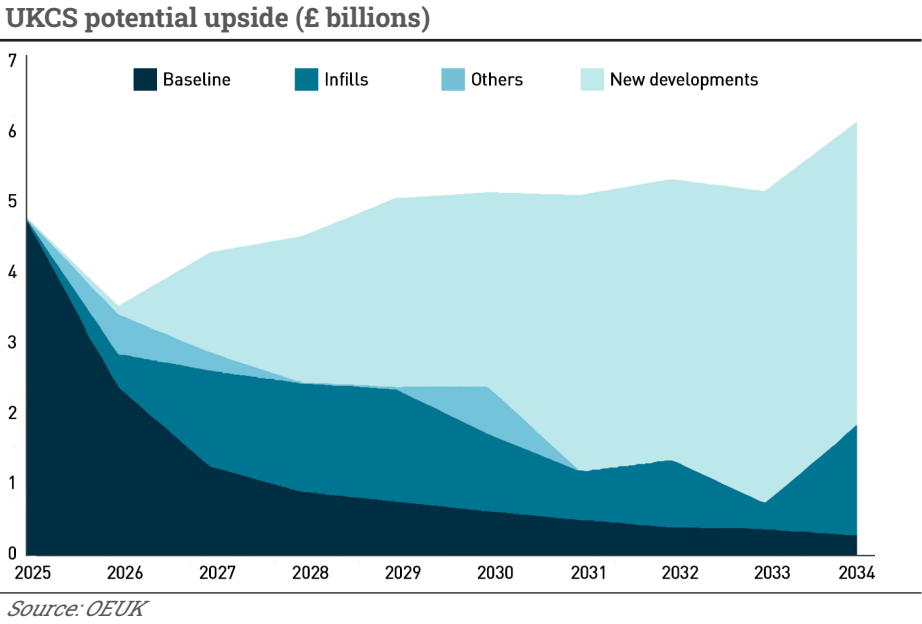


OEUK believes, based on analysis it commissioned from Westwood Global Energy Group, that recovery under a supportive fiscal and licensing regime could reach 7.5 billion boe, almost double the NSTA’s current projection, while under continued deterioration in investor sentiment it could fall as low as 2.6 billion boe. The equivalent range expressed in gas volumes specifically, rather than combined oil and gas, is comparably wide: OEUK’s modelling puts the NSTA’s November 2025 gas production projection for 2025-2035 at 176 bcm, against an OEUK “upside potential” of 288 bcm for the same period, rising to a cumulative 2025-2050 gap of 226 bcm (NSTA) against 456 bcm (OEUK upside)<sup>31</sup>.

31 [https://oeuk.org.uk/wp-content/uploads/2026/03/OEUK\\_Gas\\_Security\\_of\\_Supply\\_Consultation\\_Submission.pdf](https://oeuk.org.uk/wp-content/uploads/2026/03/OEUK_Gas_Security_of_Supply_Consultation_Submission.pdf)

OEUK analysis indicates significant upside potential in a more favourable policy environment

Exploiting this upside potential would reduce Britain's reliance on imports



OEUK frames the gap between its high and low production scenarios explicitly as a policy artefact rather than a geological one, arguing that the sharp downward revision in official projections since 2019 “reflects investor confidence, not a reassessment of the basin’s geological potential”. The evidence for that claim is concrete - 2025 was the first year since the UKCS was first explored, in which no exploration wells were spudded at all, down from eight in 2018, the last full year before the current fiscal regime. Appraisal drilling fell to two wells, from a recent high of 16 in 2019.

Rates of return for UKCS operators have been negative for seven consecutive quarters to mid-2025, averaging -2.6% over the twelve months to June 2025 which is the longest sustained period of negative returns on record for the basin, exceeding even the five-quarter run triggered by negative oil prices and record-low gas prices at the start of the pandemic.

For a British gas balance that depends on Norwegian pipeline imports for 47% of demand and LNG for a further share that varies year to year with global cargo availability, the difference between the top and bottom of that range is the difference between UKCS production continuing to supply roughly half of GB gas demand, as it has for most of the past five years, and Britain becoming import-dependent on a scale not seen in the history of the series.





NSTA's UKCS production forecasts for 2026 are c10% lower than the pre-windfall-tax forecasts of 2022

The windfall tax is driving significant job losses in the North Sea...

...these are not being replaced with new green jobs

Stifel's analysis, submitted as written evidence to a parliamentary committee in January 2026, quantifies this - NSTA's UK North Sea production forecasts for 2026 have already been cut by around 10% versus the pre-windfall-tax forecasts of 2022, and Stifel's base case projects cumulative UKCS output of 2025-2050 falling to around 2.1 billion barrels of oil equivalent, down 40% from the roughly 3.6 billion boe that would have been expected absent the tax<sup>32</sup>.

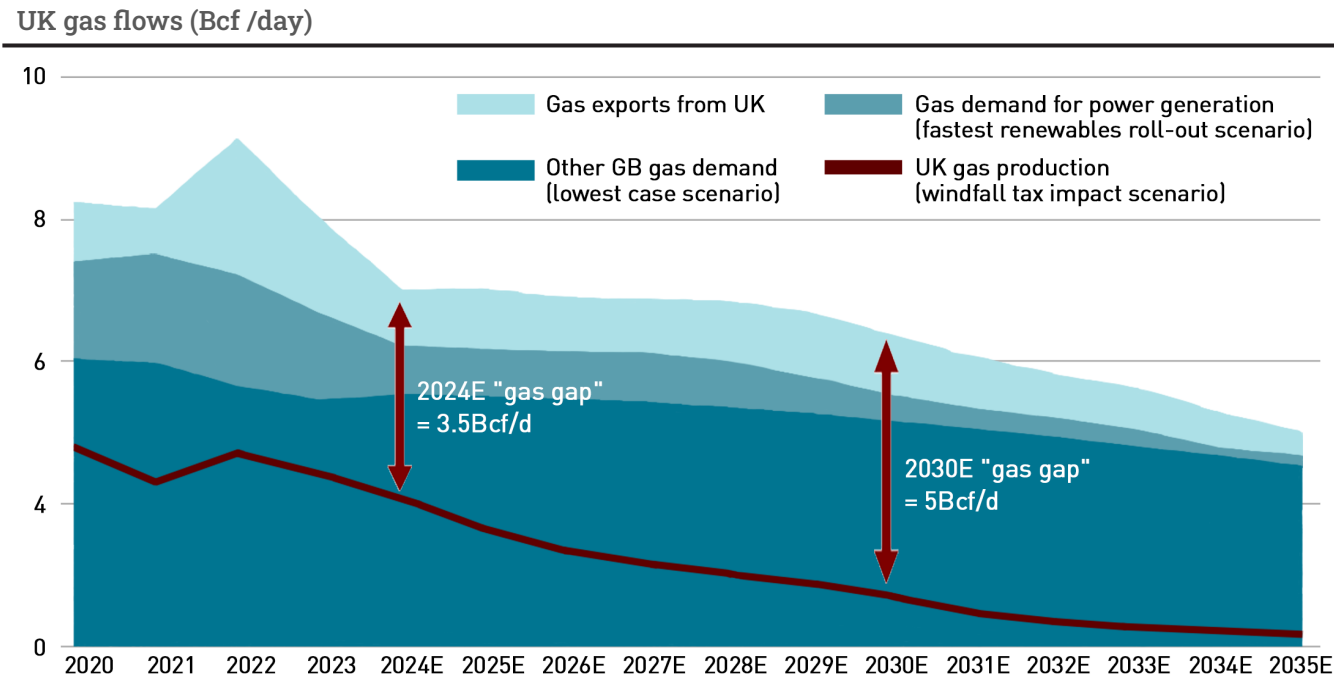
"This political decision is turning a natural and controlled rate of decline in UK North Sea production into an uncontrolled collapse of the industry. Decline is inevitable – catastrophic collapse is not.

The "Windfall" tax impact is now causing both an unjust transition – North Sea jobs are being destroyed at a much faster rate than "green" jobs are being created (and oil and gas jobs are c.1.6-2x more valuable to the UK economy than green jobs...) – and also both increasing emissions whilst making the UK's energy security worse,"

- Stifel Europe written evidence to Parliament

Stifel separately estimates the UK's "gas gap", that is the shortfall between domestic production and demand, including exports to Ireland, widening from 3.5 Bcf/d in 2024 to 5 Bcf/d by 2030, even under National Grid's fastest renewables rollout scenario, and notes that UK gas storage of around 12 days of peak consumption compares with 65-70 days across Europe as a whole. This is not simply a production-decline story, it also threatens the viability of offshore pipeline infrastructure. Stifel also notes that UK gas production is essential in meeting peak gas consumption in winter, when residential demand is around half of total gas demand

Whichever end of this range materialises has a direct and immediate bearing on the rest of Britain's gas balance, because the two things that would otherwise absorb any shortfall – Norwegian pipeline imports and LNG – are each subject to constraints of their own, addressed later in this report.



Source: National Grid, Stifel estimates

<sup>32</sup> <https://committees.parliament.uk/writtenevidence/161078/pdf/>

A UKCS trajectory closer to OEUK's downside case does not simply mean lower domestic output on paper; it means a materially larger and faster-growing call on import routes whose physical capacity, as the following section sets out, is itself bounded well below the level Britain's own balance can require of it.

### True import/export pipeline capacity

The physical pipes connecting GB to Continental Europe are substantial. Interconnector's published technical capacities give 651.7 GWh/d in the Bacton-to-Zeebrugge direction and 667.9 GWh/d in the reverse – roughly 238 TWh a year of export capability and 244 TWh of import, if run continuously<sup>33</sup>. The hardware is oriented very slightly towards import - the return direction is 16.2 GWh/d, or 2.5%, larger, reflecting larger compression capability at Zeebrugge. Ofgem, implementing the EU capacity allocation network code, put the combined maximum technical capacity of the two gas interconnectors at 1,302 GWh/d<sup>34</sup>.

The binding constraint, however, lies upstream of the pipes, in the exit capacity available on the National Transmission System at Bacton. Until 2022, National Grid (now National Gas) was obliged to offer 651.68 GWh/d of Licence Baseline Exit Capacity at Bacton (IUK) and nothing at all at Bacton (BBL): BBL could access only interruptible and non-obligated capacity, and had no entitlement to obligated exit capacity to flow gas to the Netherlands<sup>35</sup>.

Ofgem concluded the arrangement was not sufficiently competitive, noting that interruptible off-peak capacity is not a firm product, can be curtailed, and that National Grid might have to scale it back or find itself unable to offer non-obligated firm capacity at all. The remedy, implemented through UNC Modification 0785 in March 2022, merged the two into a single Bacton (exit) interconnection point, with a combined licence baseline of 651.68 GWh/d. The entitlement was made contestable between the two pipes, and was not enlarged<sup>36</sup>.

Britain's firm export entitlement therefore stands at roughly 652 GWh/day, or some 238 TWh a year if run flat out every day, against interconnectors physically capable of close to twice that. Anything above the baseline depends on interruptible capacity released at the transporter's discretion, which by definition cannot be relied upon.

The precise reason for the limit, whether it originates in the compression at Bacton, in the licence baseline, in downstream capacity on the Belgian and Dutch networks, or in the commercial availability of firm bookings, matters less than the fact of it. What matters analytically is that Britain's capability to move surplus gas to the Continent is bounded, and bounded well below what the domestic system can be long by. The consequences of that boundedness for price formation, and in particular for the persistence of differentials between NBP and continental hubs, are addressed below.

As an aside, there is a small amount of gas that is produced in UK waters that is exported directly into the Dutch offshore pipeline infrastructure and counts in the UK's gas export data. These are the UK fields of the Greater Markham Area (Chiswick, Grove and Kew), processed across the Spirit Energy-operated J6A platform and exported by the 160 km WGT pipeline system to the Den Helder terminal<sup>37</sup>, together with the Block 44 fields Minke, Orca, Sillimanite and Wingate, which straddle or lie close to the median line and whose gas has been routed to the Netherlands since 2007.

Markham ceased production in 2019 and J6A now serves purely as a pro-

<sup>33</sup> <https://www.fluxys.com/en/about-us/interconnector-uk/infrastructure>

<sup>34</sup> <https://www.ofgem.gov.uk/consultation/options-great-britains-implementation-european-union-network-code-capacity-allocation-mechanisms-gas-transmission-systems-regulation-9842013-bacton-entry-point>

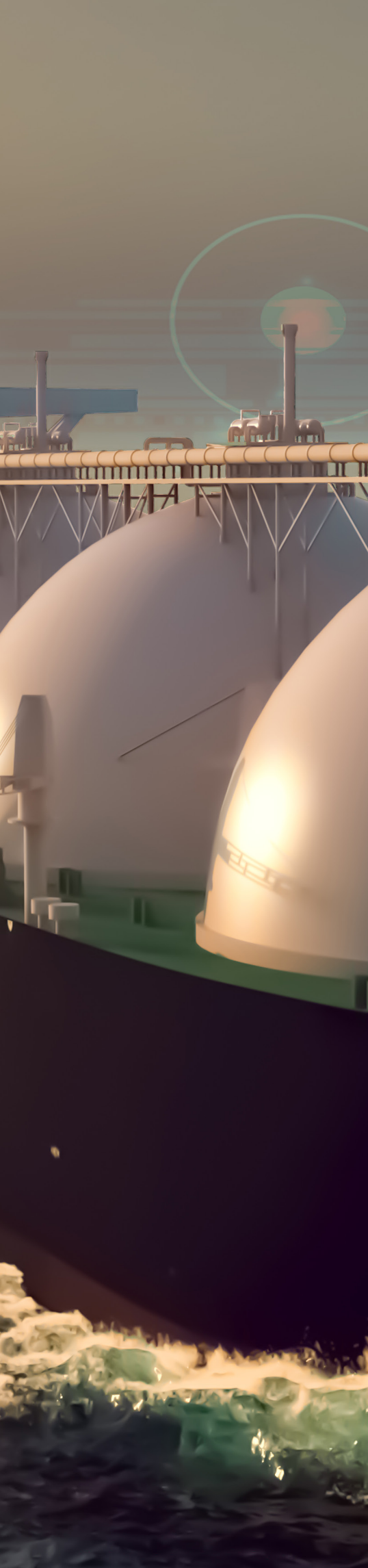
<sup>35</sup> <https://www.ofgem.gov.uk/sites/default/files/2021-07/IUK%20-%20CEPA%20-%20Economic%20Assessment.pdf>

<sup>36</sup> <https://www.ofgem.gov.uk/publications/decision-approve-uniform-network-code-unc-0785-application-unc-processes-aggregated-bacton-exit-interconnection-point>

<sup>37</sup> <https://www.spirit-energy.com/our-operations/netherlands/producing-fields/>







cessing hub for its neighbours; Windermere, which produced to Markham and hence to the Netherlands, has likewise ceased. The Minke and Wingate fields are also now decommissioning. Collectively, the fields still feeding gas into the Dutch system produced 3.7 GWh in 2025 (3% of total UK gas exports, or 4% of the volumes to Ireland and the Isle of Man are excluded). Every other producing UKCS gas field lands its gas into the GB National Transmission System.

UKCS production comes ashore at a small number of terminals: primarily St Fergus, Teesside, Easington and Bacton, feeding the National Transmission System (“NTS”) which is the high pressure pipeline system. Norwegian pipeline gas enters on the same footing at Easington and St Fergus.

## LNG import capacity

Gas is imported by ship through three LNG import terminals: Isle of Grain, South Hook and Dragon (the latter two both located at Milford Haven in Wales). The Isle of Grain and South Hook expanded their daily deliverability over late 2025 and early 2026.

Britain’s three LNG terminals have a combined maximum send-out of approximately 1,740 GWh/d. South Hook has a maximum daily regasification capacity of 812.5 GWh/d and a process capacity of 19.5 mtpa<sup>38</sup>. It has five storage tanks of 155,000 m<sup>3</sup> each<sup>39</sup>. Grain has an annual regasification capacity equivalent to approximately 649 GWh/d and 1,000,000m<sup>3</sup> of storage, with a planned expansion that would add some 159 GWh/d and 200,000m<sup>3</sup> of tankage<sup>40</sup>. Dragon has a sendout capacity of around 278 GWh/d, with two storage tanks totalling 320,000 m<sup>3</sup> and a deep-water jetty able to accommodate vessels up to 217,500 m<sup>3</sup><sup>41</sup>.

Send-out capacity is an appropriate measure of the contribution these terminals make to Britain’s energy security because the binding constraint on a cold winter day is the rate at which gas can be delivered into the NTS, rather than the volume that can be landed over a year. The rate of send-out at the three terminals collectively is almost three times the rate at which Britain can export over IUK and BBL. South Hook alone can send out more gas in a day than the entire firm export entitlement at Bacton of 651.68 GWh/d

Send-out capacity is not, however, a measure of annual throughput, and it should not be annualised. Sustaining maximum send-out requires a corresponding rate of cargo arrivals, and the storage between them is limited: at full rate, Grain holds roughly ten days of send-out, Dragon around seven and South Hook around six. A terminal running flat out consumes a full cargo every day or two, a rate that no single jetty could sustain. Actual throughput is therefore determined by how frequently cargoes arrive, which is both a commercial and physical question.

Three factors drive throughput. The first is relative price: a divertible cargo will go to whichever market offers the highest netback, so British import volumes depend on the NBP price relative to TTF and JKM net of freight. The second is contractual: capacity at these terminals is held under long-term agreements rather than being freely available, with South Hook’s regasification capacity wholly held by South Hook Gas under twenty-five year arrangements while Grain is fully contracted until 2029 with commitments extending to 2045<sup>42</sup>. Uncontracted parties access the terminals only through secondary capacity release. The third is seasonal demand, which dominates the observed usage pattern: LNG imports ran at over 20,000 GWh a month in the first quarter of 2025 and fell to 759 GWh in August<sup>43</sup>.

38 <https://www.southhooklng.com/about/incremental-capacity-project/>

39 <https://www.nsenenergybusiness.com/projects/south-hook-lng-terminal-uk/>

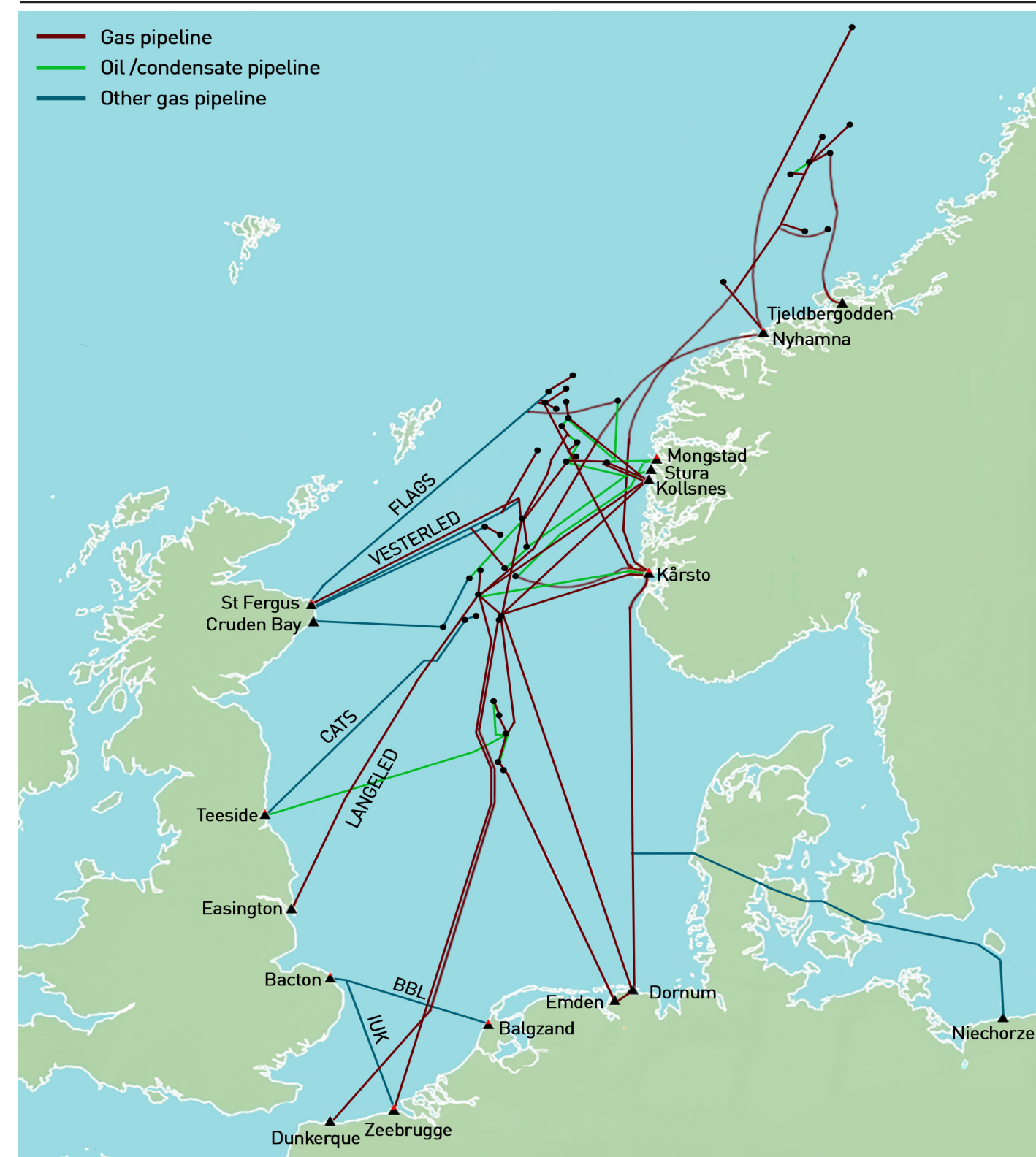
40 <https://www.ecpgp.com/equity/portfolio/grain-lng>

41 <https://lngprime.com/europe/uks-dragon-lng-terminal-offers-capacity-from-september-2029/112483/>

42 <https://finance.yahoo.com/news/centrica-acquire-isle-grain-lng-094219202.html>

43 [https://assets.publishing.service.gov.uk/media/6a6a08d41bcde42205706015/ET\\_4.3\\_JUL\\_26.xlsx](https://assets.publishing.service.gov.uk/media/6a6a08d41bcde42205706015/ET_4.3_JUL_26.xlsx)

## North Sea gas pipes



Source: Norwegian Petroleum, Watt-Logic

Both South Hook and Grain state that full send-out is subject to available pipeline capacity - South Hook notes that sending out at full capacity alongside the other terminals would require modification of the NTS. The three terminals cannot all run at nameplate simultaneously. Import capability, like export capability, is constrained not by the terminals themselves but by the network they feed.

In terms of the contribution LNG can make to Britain’s gas supplies, LNG supplied 137,364 GWh in 2025, just over 20% of UK demand (just under 19% if Irish exports are included), against combined terminal send-out capacity of approximately 1,740 GWh/d. On an annualised basis that capacity



would represent some 635,000 GWh, so headline utilisation is around 22%. However, peak-month utilisation is closer to 60% - even at the height of the 2022 gas crisis when Britain was importing at record volumes and acting as a transit route into Europe, the terminals were running at roughly two thirds of send-out.

It is also worth noting that the UK has no liquefaction capacity of any kind: none onshore, and none floating or fixed in UK waters. Gas that enters the GB system cannot be loaded onto a ship - it can leave only by pipe.

### Seasonal gas balances

With both UKCS and Norwegian piped gas imports each meeting about half of UK gas demand it's tempting to say that the UK imports LNG purely to export it to Europe. There have been times when Britain acted as a transit route for gas supplies into Europe, notably during the gas crisis when access to Russian gas was suddenly lost. However, in order to understand the actual sources and uses of gas, it is necessary to look at monthly gas flows.

The two flows are almost exactly out of phase. In 2025, LNG imports were 20,639 GWh in January, 24,292 GWh in February and 21,713 GWh in March, falling to 4,421 GWh in May and 759 GWh in August - a factor of thirty between the high and the low. Exports over IUK and BBL had the opposite behaviour: nothing at all in January, 192 GWh in February, rising to 13,596 GWh in June and 17,147 GWh in July. Britain does not import LNG and export to the Continent simultaneously - it imports LNG in winter and exports pipeline gas in summer, with little overlap.

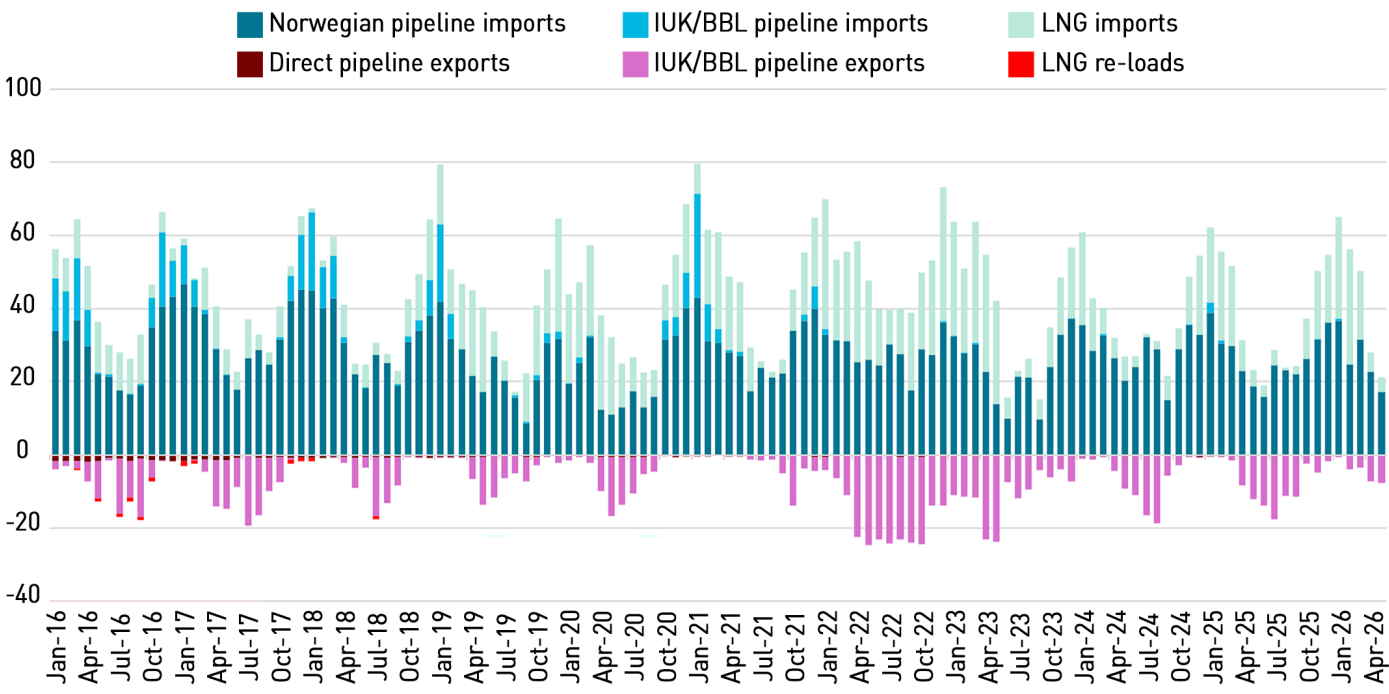
In the summer, Britain exports more gas than it imports as LNG, so the exported volume is not dominated by LNG – in fact LNG summer imports are tiny compared with IUK and BBL exports. What is exported in summer is UKCS production and Norwegian pipeline gas surplus to a system with low seasonal demand. Conversely, in winter, exports fall to almost nothing and LNG imports are consumed domestically.

Britain's seasonal reversal has often been characterised as the use of Continental storage in place of domestic storage with gas being sent into Europe in summer then to return in winter.

**Britains imports significant amounts of LNG in winter when piped exports to the EU are lower...**

**...Britain does not currently import LNG in order to export it to Europe**

Monthly gas flows



**Britain has exported gas to the EU almost continuously since the summer of 2021 with almost no imports...**

**...this is because UK gas prices have generally been lower than European gas prices...**

**...following the loss of cheap Russian piped gas, the cost structure of European gas has increased**

This was never backed by any storage agreements but for decades the interconnectors served as a type of synthetic storage. However, this trend completely broke down in 2022 with the gas crisis and Britain became a net exporter of gas to the EU all year. Since then, despite the EU securing alternatives to Russian gas, in particular increased piped gas imports from Norway and a significant increase in LNG from the US, using rapidly deployed floating regas terminals, particularly in Germany, GB exports to the EU have continued.

The data show an increase in export activity following the closure of the Rough storage facility in 2017. This was the UK's only large domestic seasonal gas storage facility. Its closure removed a natural destination for surplus summer gas, forcing it to be exported where previously some was stored. There is not a similar increase in winter imports, because unlike the export of the summer surplus which was not discretionary, the UK can choose from different sources of supply in winter, with LNG being an obvious alternative to IUK and BBL imports.

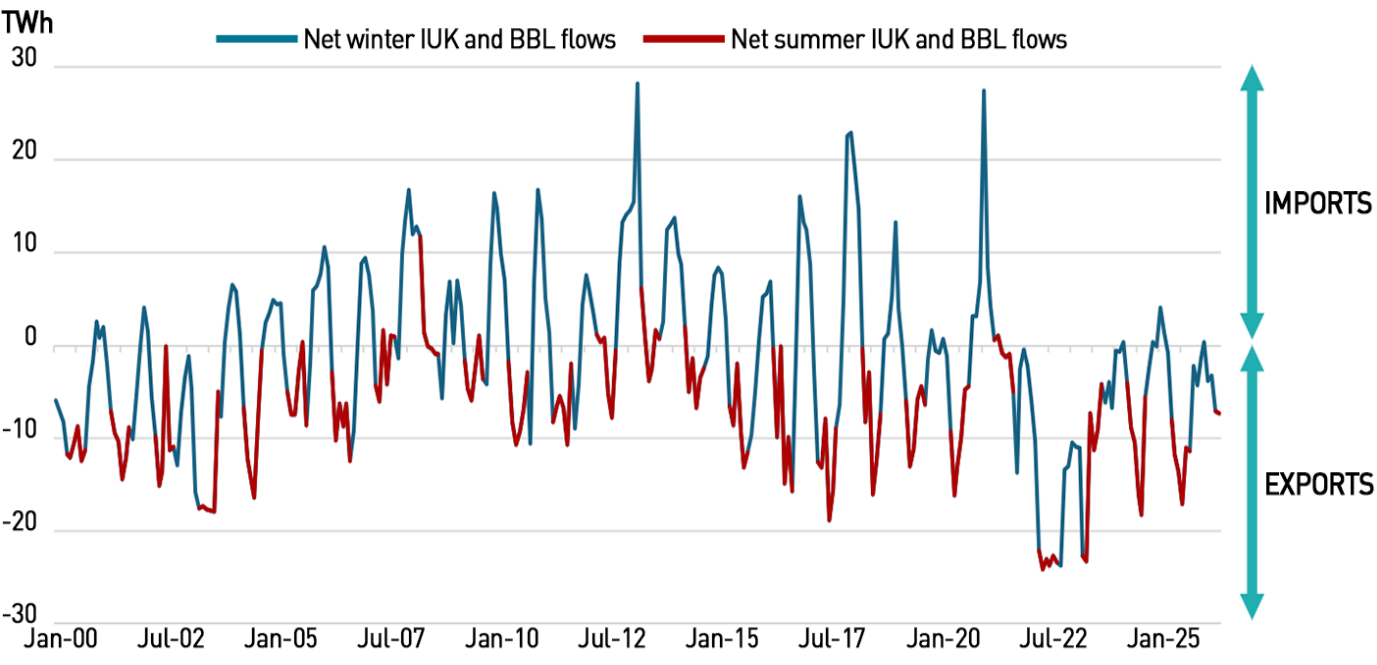
The UK is likely to continue to be a significant exporter of gas to Europe for the short to medium term. Although the EU materially cut piped gas imports from Russia, it has continued to buy Russian LNG and there is significant pressure to end this trade. This, rather than the current disruptions to Qatari gas supplies is more likely to ensure that the status quo is maintained in relation to IUK and BBL flows. The EU has struggled to maintain gas security since 2022, and heads into this winter with much lower inventories than policymakers would like (see later).

### GB's gas storage capability is far lower than on the Continent

Following the closure of Rough, the UK has almost no seasonal storage, now having only a few days' of supply. Although Rough did re-open in 2022, there have been no injections since November 2024 (except for one day in April 2025 and a few tiny (under 1 MWh) injections in early 2026 which might just be metering artefacts)<sup>44</sup>, and Centrica has indicated it will close again. However it is important to note that when it re-opened it was not the same asset as before its closure. There are two features of storage that matter for gas security: capacity and deliverability ie how much gas can be stored and how quickly it can be withdrawn and delivered to the market.

The UK has eight active gas storage facilities of varying size, duration (the time a facility takes to deplete from full at the maximum withdrawal rate)

Summer vs winter flows on IUK and BBL



44 <https://data.nationalgas.com/find-gas-data/view>

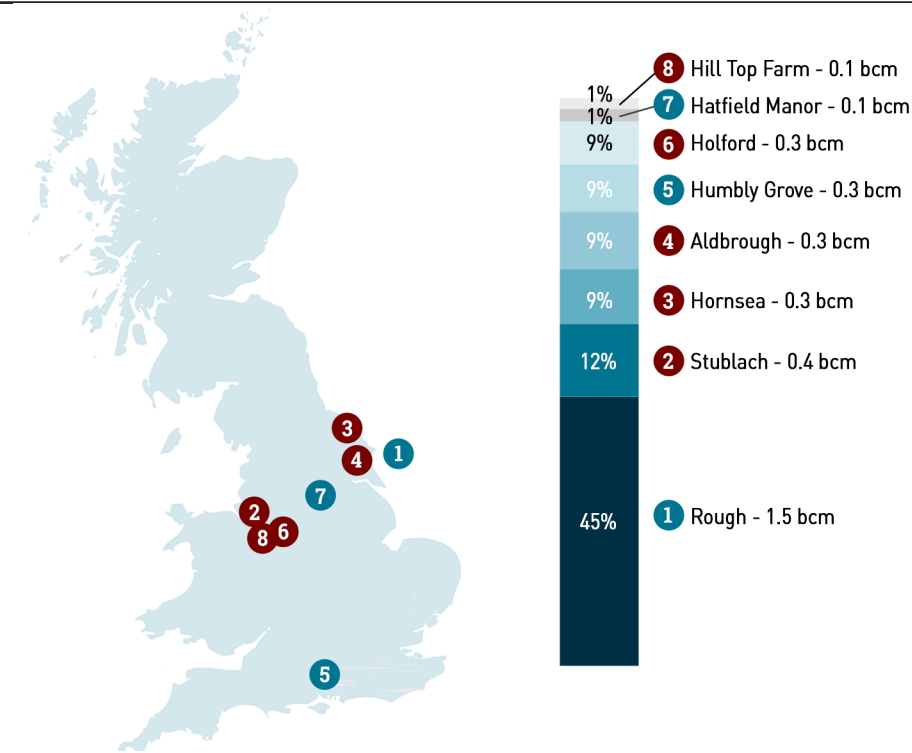




and form. The largest is Rough a depleted gas field capable of storing 1.5 bcm, with a duration of around 115 days. Two other depleted fields, Humbly Grove and Hatfield, provide a further 8.2% and 2.2% of total gas storage, respectively. Britain also has five salt cavern gas storage facilities located across Cheshire and Lancashire. These are man-made storage facilities created by solution mining - a process where rock salt deposits are drilled and injected with high-pressure water to dissolve the salt and create an airtight space.

Total GB gas storage capacity is around 3.3 bcm which equates to around 16 days' of national gas demand (annual average), compared with total EU gas storage capacity of around 102 bcm.

**GB gas storage capabilities**



Source: Westwood Global Energy Group

When Rough re-opened the capacity opened for use was smaller, but the deliverability rate was much smaller. This was because gas exits Rough under the reservoir pressure, and after closure, Centrica withdrew all of the cushion gas and then began producing the tail gas – reserves held in the field from when it was a regular producing field before it was converted to storage in the first place<sup>45</sup>. (Cushion gas is gas that is used to support pressure in the reservoir and normally remains untouched during normal storage operations.) This radically reduced the reservoir pressure, drastically cutting the deliverability rate, making Rough a much less useful storage asset than it had been. When the media became concerned in winter 2025 that there was “only six days’ of gas” in storage, it was largely missing the point because it would not be possible to withdraw the gas over six days. In fact, the deliverability rate was far too slow for any withdrawals from Rough to make any meaningful impact on Britain’s gas security.

Stifel believes that the low level of gas storage in the UK has been “one of the drivers of UK gas prices (and therefore electricity prices) remaining higher and more volatile than before the invasion of Ukraine, despite the normalisation of the European gas market”.

**Summer displacement of LNG**

It is often claimed that increasing North Sea gas production would do little to improve UK gas security and would not lower prices. Neither of these claims is true. It is obvious that increasing domestic production lowers re-

45 <https://watt-logic.com/2022/08/08/re-opening-rough-gas-storage/>

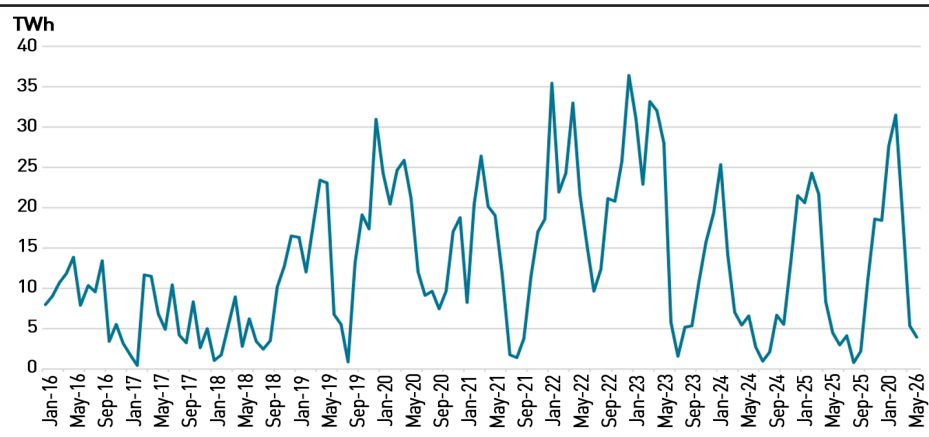
**Any increase in UK gas production will displace the most expensive supplies of gas and lower British gas prices**

liance on imports and is therefore beneficial for energy security, as well as supporting jobs and delivering tax income.

The argument on prices is also clear once the marginal pricing mechanism described above is understood – **any increase in domestic production displaces LNG imports which are the most expensive supplies of gas into the British market**. And, as noted above, other than a couple of small fields delivering into the Dutch offshore pipeline system, all of the gas produced in the UKCS comes directly to the GB NTS and only to the NTS – there is no other physical route available for this gas.

Looking at LNG flows it’s interesting how little we import in the summer, which makes fully displacing it entirely feasible, and would make pricing over those months entirely based on pipeline gas from the UKCS and Norway, which has a real cost advantage over LNG.

**Monthly LNG imports**



Source: UK Energy Trends: gas

**Jackdaw alone could displace price-setting LNG for 2-4 months of the year...**

**...this could have a meaningful impact on prices during those months**

**The imminent decline in UK gas production is not inevitable...**

**...it is driven by policy choices not geology**

Given the ongoing controversy over the potential approval of the Jackdaw gas field, this is a useful test case. It would be the largest new gas development to reach production in the UKCS for some years, and its output would be almost entirely gas rather than oil.

At peak, Shell expects the field to deliver around 6.5% of UKCS gas production, or roughly 40,000 barrels of oil equivalent per day, with first production before the end of 2026 depending on the timing of any permit to proceed, with peak output in 2027<sup>46, 47</sup>. Converted to energy terms, and netting off the condensate fraction, this equates to approximately 60 GWh/d of gas, or around 1,800 GWh a month and 21,600 GWh a year.

**“The decline in domestic gas production is not inevitable; under a supportive fiscal and regulatory regime the UK could reduce its reliance on LNG imports,”**

- Offshore Energies UK, Business Outlook Report 2026

Set that against monthly LNG imports and the result is striking. In each of the past three years there has been at least one month in which Jackdaw alone, at constant peak output, would have covered the entire LNG import volume: July 2023, when imports were 1,584 GWh, July 2024, at 937 GWh, and August 2025, at 759 GWh.

Several further months came close: August 2024 at 2,110 GWh, September 2025 at 2,188 GWh, June 2024 at 2,716 GWh and June 2025 at 2,985 GWh, each of which could have been covered by between 60% and 85% by the addition of Jackdaw alone. The summer LNG requirement has fallen to a lev-

46 <https://www.offshore-mag.com/regional-reports/north-sea-europe/article/14280168/shell-commits-to-north-seas-jackdaw-gas-project>

47 <https://www.pressandjournal.co.uk/fp/news/aberdeen-aberdeenshire/7079437/jackdaw-aberdeen-energy-expert/>



el at which one new field is of comparable magnitude to the entire monthly import meaning that if Jackdaw is allowed to go ahead, LNG would no longer be required in some summer months.

The UK's lack of storage capability means that surplus gas must be exported using spare capacity on IUK and BBL. While some LNG cargos may still arrive, these would be less likely to be sent out onto the NTS until the pricing became more attractive unless they were delivered under contractual agreements and therefore not marginal price-setters in the first place. LNG cargo scheduling and terminal send-out would adjust in advance of any physical surplus, as they already do since British summer weakness is well understood in the LNG sector and cargoes are diverted to higher-net-back markets when GB demand falls away.

In practice, no price-setting LNG cargoes would arrive in the low months of GB gas demand, with the surplus UKCS production being exported. There is very limited surplus firm export capacity available on IUK and BBL in July and August, but there is plenty of interruptible capacity since only about half of the technical capacity of the pipes is offered to the market as firm.

In the worst case where the surplus gas can neither be exported nor stored (including storage as linepack – the storage capacity of the NTS itself which can be accessed by varying the pipeline pressure within certain limits), the gas would have to be consumed. This is typically done by firing up gas power stations and implies negative wholesale gas prices, a rare but not unprecedented phenomenon on the GB gas grid, which would create a brief but significant reduction in wholesale electricity prices (the most notable example of negative NBP prices was in 2006 when the Langeled pipeline was being commissioned and an unexpectedly large volume of gas was delivered to the NTS requiring the surplus to be burned in gas power stations in order to keep the NTS in balance<sup>48</sup>.)

In other words, increasing domestic gas production is very likely to displace any price-setting LNG imports in the summer – July and August would be

**Whether incremental UK gas production displaces imports or leaves as an export, the effect on the UK's external accounts is broadly similar and broadly positive**

**Not only is there no global price for gas, there is not even a single European price for gas**

highly likely to be LNG-free (aside from non-price setting cargoes meeting contractual or operational needs) with June and September quite often becoming LNG-free. This means that between a sixth and a third of the year which is not insignificant, even if it is in the cheaper summer months, and this would translate to lower prices since pipeline gas is cheaper than LNG.

Finally, whether the incremental gas displaces an import or leaves as an export, the effect on the UK's external accounts is broadly similar and broadly positive. Jackdaw's 21,600 GWh a year, valued at a wholesale price of £25 to £35 /MWh represents around £540 million to £760 million annually in gross value, either as imports not made or as exports earned. Against an external deficit measured in tens of £billions this is not transformative, but neither is it negligible. The benefit that accrues to the UK exists whether the gas is consumed domestically or sold to the Continent. The same cannot be said of a cargo of American LNG.

## The NBP–TTF differential

There is a wider question about price and the issue of “international prices”. In Northwest Europe there are now three main sources of gas – UK and Norwegian piped gas and LNG from the rest of the world. If there was an international price at which British producers had to sell their gas, that would also apply to Norwegian sellers, and all three sources of gas would have the same price. But this is not how the market works.

Stepping back, one can always ask the question “what is the value of X?” For example, my house has a different value depending on who is asking and for what purpose. The insurance valuation is the rebuild cost, whereas the value for mortgage purposes would be the purchase price. At any given time, the value of something could be either the cost of replacing/rebuilding it, or the amount a third party would be willing to pay to acquire it.

This creates different pricing dynamics for the three sources of gas into Europe. Norway has almost no domestic requirement for its gas, so could sell for cost plus some margin. However, why should it if Europeans are

48 <https://www.energyintel.com/0000017b-a7ad-de4c-a17b-e7ef18940000>





Price differentials between regions persist because there is not enough physical capacity to move gas between markets to smooth out these differences

Britain has been a net exporter to the Continent in every year since 2022, including across the winter half of each year...

...this is because UK prices tend to be cheaper than European prices...

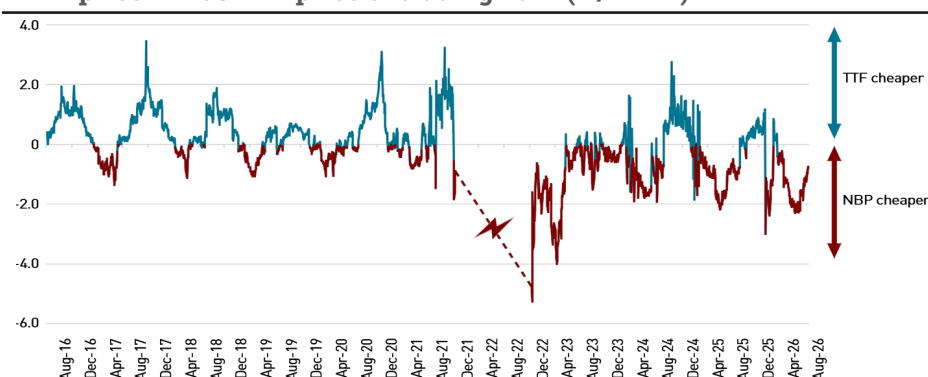
...Britain is persistently the cheaper market and gas persistently flows east

willing to pay the price for LNG? Norway could always sell its gas at a small discount to the cheapest available LNG delivered into NW Europe. The UK producers have both a domestic use for gas and a limit on export capacity. Therefore, different dynamics apply.

In that sense Norway is a more captive seller than Britain, which at least consumes its own output. But Norway has five or six delivery points across four countries, plus Hammerfest LNG, and the Gassco pipeline system which optimises across them. Norway is a forced seller with destination choice, so it realises the best available netback.

UKCS gas has no such choice. It lands in the NTS and its only alternative realisation is Bacton, which is both narrow and, in the summer months when the surplus arises, already carrying substantial flow. UK producers are forced sellers into a single market – when that market is long the price falls until domestic demand absorbs it, which is why October 2006 produced minus 5 p/th with National Grid paying people to take gas away.

NBP price minus TTF price excluding 2022 (£ /MWh)



Source: Trading Economics, ECB

It is often asserted that NBP and TTF trade within a narrow band representing the cost of transport between them, and that this proves the GB price is set on a European rather than a domestic basis. The band does exist, and the chart above of the NBP-TTF price shows it.

Excluding 2022, the NBP/TTF differential has spent almost the whole of the past decade within a range of roughly -£4 to +£3 /MWh, and for most of that period within a much narrower band than that. Taken in isolation this looks like strong evidence for the proposition: two hubs, closely coupled, differing by something of the order of the cost of moving gas between them.

It is worth establishing what that cost actually is. IUK publishes “through the pipe” tariffs covering combined entry and exit capacity for each direction, fixed at 2.10 p/th for annual capacity (£0.72 /MWh) for gas years 2025-26 to 2039-40, rising to 2.50 p/th for seasonal, 2.80 p/th quarterly, 4.00 p/th monthly and 6.00 p/th, (£2.05 /MWh) for daily capacity<sup>49</sup>.

To this must be added IUK’s commodity charge, a fixed element of 0.0103 p/kWh plus a small multiple of the prevailing NBP day-ahead price, amounting to between £0.12 and £0.14 /MWh across any realistic price level, and the NTS exit capacity charge at the Bacton interconnection point, set by National Gas at 0.0356 p/kWh/day for gas year 2026-27 (equivalent to £0.36 /MWh) at full utilisation<sup>50</sup>. With the Fluxys system charge at the Belgian end, the full cost of moving a megawatt hour of gas from NBP into the Belgian system is somewhat over £1.20 /MWh for a shipper booking annual capacity.

The marginal cost is far lower. Capacity charges are incurred whether or not gas flows, so for a shipper already holding capacity the cost of moving an additional unit is only the commodity charge, around £0.13 /MWh. This

asymmetry matters because a shipper who booked in advance can profitably export at spreads which would not justify a fresh booking, while one responding to a differential that has opened unexpectedly faces the daily tariff of £2.05 /MWh for capacity alone, if any remains available.

But the structure of the spread tells a different story from its width. The differential is not constant, nor does it fluctuate randomly. It oscillates seasonally, and it does so in tandem with the direction of physical flow. NBP trades at a premium to TTF through the winter months, when Britain is drawing gas in, and at a discount through the summer, when Britain is pushing gas out.

The spread flips sign as the interconnectors reverse. That is not a toll being levied on a fixed route but the price of a scarce and directional service, rising and falling with the direction in which the capacity is needed. A transport cost does not change sign twice a year.

The second feature of the chart is a shift in level. Before 2022 the differential oscillated broadly symmetrically about zero, with winter premia of £2-3 /MWh offset by summer discounts of £1-2 /MWh. Since 2022 the entire distribution has moved down by something on the order of £0.71, and NBP now trades at a discount to TTF through much of the year, including in winter months, when the historical pattern would have produced a premium.

This is the price counterpart of the flow data set out above: **Britain has been a net exporter to the Continent in every year since 2022, including across the winter half of each year, and the reason is visible here. Nothing pulls the spread back into positive territory, because Britain is persistently the cheaper market and the gas persistently flows east.**

Since 2022 NBP has averaged £0.71 /MWh below TTF, less than the fully-costed round trip of somewhat over £1.20 /MWh, but roughly five times the marginal cost facing a shipper who already holds capacity. That is exactly what one would expect of a functioning arbitrage - the spread settles between the two, wide enough to keep booked capacity flowing east but not wide enough to justify fresh bookings. The band is not evidence that transport cost sets the price, it is evidence that, in normal conditions, capacity is available and the arbitrage works. The question is what happens when it is not.

The explanation for both regimes is the same. Before 2022, Europe took around two fifths of its gas by pipeline from Russia, a supply that flowed regardless of price. Although by 2022 this was largely hub rather than oil-indexed and received TTF like any other seller, its sheer volume meant continental Europe rarely needed to bid in a marginal LNG cargo to balance. TTF therefore cleared at low prices.

Britain, with declining indigenous production and no equivalent block of cheap infra-marginal supply, was the tighter of the two markets and more frequently required the marginal cargo, meaning that NBP priced above TTF on average and gas flowed west in winter. After 2022 that position was inverted - Europe lost its access to cheap Russian gas and became the market that had to attract LNG cargoes, while Britain retained its Norwegian pipeline volumes and substantial spare regasification capacity. The direction of the average spread reversed accordingly, and with it the direction of physical flow.

But this second chart including 2022 tells a very different story which discounts the transport-cost explanation altogether. This chart shows TTF-NBP, and includes 2022 when the differential reached more than £80 /MWh in NBP’s favour – ie TTF was more expensive by an amount similar to the entire absolute price of gas under normal market conditions, sustained for the better part of a year. No construction of transport cost, capacity charge, commodity charge and fuel comes within an order of magnitude of that number. Whatever was happening to the price differential in 2022, it had little to do with the cost of moving gas from Bacton to Zeebrugge.

<sup>49</sup> [https://www.fluxys.com/en/natural-gas-and-biomethane/empowering-you/tariffs/tariff\\_interconnector](https://www.fluxys.com/en/natural-gas-and-biomethane/empowering-you/tariffs/tariff_interconnector)

<sup>50</sup> <https://www.nationalgas.com/sites/default/files/documents/Notice%20of%20Final%20NTS%20Exit%20Capacity%20Charges%20effective%201%20October%202026.pdf>



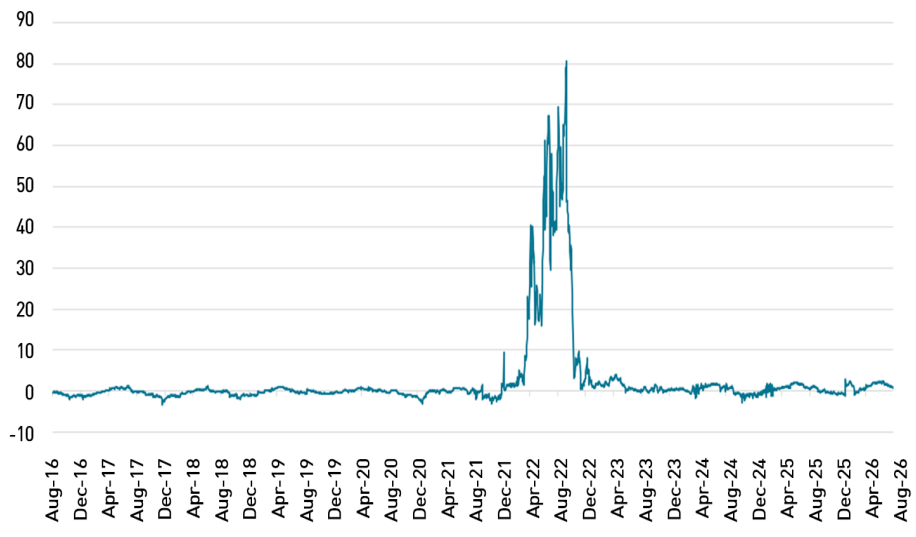


2022 illustrates the point very well - TTF remained materially higher than NBP for month...

...Europe lost Russian piped gas and had limited LNG import capacity...

...GB had spare LNG import capacity but not enough pipeline capacity to export additional gas to Europe

TTF price minus NBP price (£ /MWh)



Source: Trading Economics, ECB

Instead it was the market signalling an arbitrage that could not be executed - Britain had substantial spare regasification capacity while Continental terminals were saturated. Divertible cargoes landed in the UK but the gas could not be moved on because the export route was already running at capacity and there is no other way out of the country. Monthly exports over IUK and BBL averaged between 731 and 781 GWh/d for seven consecutive months of 2022, some 12-20% above the firm entitlement at Bacton of 651.68 GWh/d, sustained only by drawing on interruptible capacity.

The pipes were full, the discount was enormous, and it stayed open for months. That combination is not consistent with a market in which the GB price is disciplined by the ability to export. This period broke the typical convention that Britain does not generally import LNG while exporting gas via IUK and BBL because Europe needed to get gas by any means, including using the UK as a transit market. By the end of 2022 Germany had begun to open floating regasification terminals allowing a more typical pattern to return.

As a result British gas consumers paid less than European neighbours for gas despite record high prices

Similar effects were seen in Spain which has high LNG import capacity but limited pipelines to the rest of Europe

Who benefited from this position? It was British gas consumers - households, and in particular energy-intensive industry paid substantially less than their German, Dutch and Belgian counterparts throughout that period, which at a time of acute energy stress was a material advantage.

The dominating narrative in this period was one of expensive gas but the UK experienced a material and entirely overlooked cost advantage during this period when its access to UK and Norwegian gas insulated it from the worst of the market shock experienced in Europe. It wasn't simply that the UK did not previously rely on Russian gas which was important, it was that the UK had access to both relatively cheap pipeline gas and enough LNG import capacity to balance the market and for much of the year, produce a surplus.

Producers selling into NBP realised less than they would have if they could sell into TTF, with the shippers holding export capacity capturing the difference on the volumes that could be exported. The benefit of a constrained export route, therefore, accrues to the demand side of the domestic market, which is the exact mechanism by which additional domestic UK production would be expected to reduce the price paid by British consumers, and the exact mechanism which the contrary argument assumes away.

Britain is not the only European market to demonstrate this mechanism, and it is not even the clearest case. Spain provides a more controlled test, because it lacks almost every complicating factor that a critic might invoke to explain the British discount away.

Spain holds around 34% of Europe's regasification capacity and 44% of its LNG storage. Together with Portugal, Iberian regasification amounts to some 68 bcm a year, roughly a third of Europe's total<sup>51</sup>. Its physical connection to the rest of Europe consists of two pipelines through the western Pyrenees, at Larrau in Navarre and Irun in the Basque country, with a combined capacity of 7 bcm a year, increased to 8.5 bcm from November 2022<sup>52</sup>. S&P Global assessed the interconnection as equivalent to about 10% of Spain's theoretical re-export capacity. A third pipeline, MidCat, was refused permits by the French and Spanish regulators in 2019 on grounds of

51 <https://www.spglobal.com/market-intelligence/en/news-insights/articles/2022/9/energy-crunch-reignites-interest-in-disputed-spain-france-gas-pipeline-71937638>

52 [https://www.lamoncloa.gob.es/lang/en/gobierno/news/Paginas/2022/20220922\\_gas-supply.aspx](https://www.lamoncloa.gob.es/lang/en/gobierno/news/Paginas/2022/20220922_gas-supply.aspx)







necessity and cost, and formally abandoned. France continued to resist its revival through the crisis, arguing that the existing lines were under-utilised<sup>53</sup>.

The consequences were visible in 2022 when Spain had spare import capacity when the rest of Europe was desperate for gas, and could do almost nothing with it. Deliveries to France across the Pyrenees reached only 1.7 bcm in the first ten months of the year - four times the previous year's volume, but still negligible against a continental deficit measured in tens of bcm<sup>54</sup>. The Spanish hub, PVB, opened a discount of more than €20 /MWh to TTF<sup>55</sup>. Gas in Spain was worth substantially less than identical gas in the Netherlands, and remained so for months, because there was no way to move it.

What makes Spain the cleaner case is the absence of alternative explanations for this differential. Spain has no indigenous production of any size, so the discount cannot be attributed to domestic supply. It had no Russian pipeline exposure, so it cannot be attributed to the loss of that supply. It has no equivalent of Britain's Norwegian imports, no seasonal swing of its own, and no meaningful export route other than the two Pyrenean pipelines. The discount can only be attributed to one thing - a market with abundant import capacity, negligible export capacity, and no means of arbitraging the difference away.

Two markets in the same year, having the same structural characteristics and the same outcome. Both had surplus regasification capacity while Continental terminals were full. Both had onward pipeline capacity an order of magnitude smaller than their import capability. Both traded at large and sustained discounts to TTF. And in both cases the discount persisted for months, at levels far beyond any plausible cost of transport, exactly when the arbitrage would have been most profitable to exploit.

The lesson can be generalised - hub prices converge when the physical route between them has spare capacity, and diverge when it does not. This is not a defect of European gas markets requiring correction, nor evidence that the markets are somehow failing - it is simply the result of locational pricing in physical markets with limited interconnecting infrastructure. A price at a point in a network is a price at that point, and the difference between two such prices measures the cost and availability of the capacity linking them. Where that capacity is exhausted, the prices are free to move apart, and they do.

**This is why arguments that UK gas prices are set internationally lack merit. If the UK increased its domestic gas production it could lower the price that UK gas consumers pay.**

### The EU Methane Regulation will complicate European LNG procurement

A further complication for European gas procurement will arise from the EU Methane Regulation, Regulation (EU) 2024/1787, which progressively imposes requirements relating to the methane emissions associated with imported oil, gas and coal<sup>56</sup>. From 1 January 2027, for supply contracts concluded or renewed on or after 4 August 2024, importers must demonstrate that gas produced outside the EU is subject at producer level to monitoring, reporting and verification ("MRV") measures equivalent to those required within the EU. The European Commission states that compliance can also be demonstrated through meeting specified standards with independent verification<sup>57</sup>.

From August 2028, importers will also have to report the methane intensity of production, while from August 2030 new or renewed contracts will be

subject to maximum methane-intensity thresholds which have yet to be determined. The UK does not currently have an equivalent regulation, nor is one currently seriously under consideration.

These EU methane requirements are likely to have major consequences for LNG procurement in the bloc. Compliance depends on information about the producer itself and not just the liquefaction plant or country from which a cargo is shipped. Importers are required to identify both the exporter and, where different, the producer, with requirements around MRV equivalence and methane intensity apply at producer level. This creates challenges for complex LNG supply chains in which gas from different producers may be commingled prior to liquefaction. The Commission has explicitly recognised cases in which importers cannot identify the production origin associated with their contracts and has been developing contractual mechanisms intended to address these problems.

This could have a significant impact on the spot LNG market - that is cargoes that are not contracted to a particular destination and are traded on a short-term basis. Spot trading depends on the ability to redirect cargoes rapidly between markets in response to changes in prices and demand. An EU buyer which must establish the upstream provenance and MRV status of the gas it purchases will likely have a smaller pool of suitable cargoes than a buyer without those requirements.

The Regulation recognises the potential implications for security of supply, so the Commission is required to consider energy security when establishing the methodology and maximum methane-intensity thresholds. The practical effect could be to push EU buyers towards established, traceable supply chains and longer-term contracts, reducing some of the flexibility traditionally provided by the global spot LNG market.

The implications for Britain are unclear at this point. Since the UK has not adopted equivalent import requirements, British buyers should in principle retain access to a wider range of LNG cargoes, including supplies for which the producer-level information required by EU buyers is unavailable. This may well provide an advantage in the spot market, particularly where a cargo cannot demonstrate compliance with the EU regime. At the same time, overall access to LNG may be reduced if EU buyers lock in volumes under long-term contracts. Depending on the number of sellers willing to co-operate with the EU methane regulations, Britain may have regulatory access to a wider range of suppliers, while having to compete for a smaller pool of uncommitted LNG.

This could increase the strategic value of Britain's LNG infrastructure since cargoes unable to enter the EU could be delivered into GB, increasing gas availability within the British system and potentially freeing other supplies for export to Continental Europe. The extent to which this creates a genuine advantage will depend on how the methane regulation is implemented in practice, particularly the treatment of complex and commingled supply chains. It will also depend on the extent to which sellers are willing to co-operate with EU buyers, and whether security of supply concerns weaken the force of the Regulation<sup>58</sup>.

While Norway has indicated that it expects to comply with the Regulation, key LNG suppliers in the US, Qatar, Algeria and Nigeria have pushed back. On 24 June 2026, the US Energy Secretary and the energy ministers of Qatar, Algeria and Nigeria jointly wrote<sup>59</sup> to EU leaders asking for a "stop-the-clock" mechanism, grandfathering of new contracts signed while changes are negotiated, removal of penalties during the transition and targeted amendments to the Regulation.

They said that a large share of EU gas imports would not be capable of complying on the current timetable and stated that "as of now there is no viable path to compliance with the regulation." They also explicitly reject-

<sup>53</sup> <https://www.euronews.com/next/2022/09/23/eu-energy-spain-france>

<sup>54</sup> <https://www.rystadenergy.com/news/iberia-a-new-european-energy-powerhouse-emerges>

<sup>55</sup> <https://timera-energy.com/blog/prices-across-europes-gas-hubs-diverge/>

<sup>56</sup> <https://eur-lex.europa.eu/eli/reg/2024/1787/oj/eng?>

<sup>57</sup> [https://energy.ec.europa.eu/topics/carbon-management-and-fossil-fuels/methane-emissions\\_en?](https://energy.ec.europa.eu/topics/carbon-management-and-fossil-fuels/methane-emissions_en?)



<sup>58</sup> [https://energy.ec.europa.eu/document/download/b545c5a6-03c9-4cfa-805a-0411de927ce6\\_en?file-name=Methane+regulation+import+requirements+Q%26A.pdf&](https://energy.ec.europa.eu/document/download/b545c5a6-03c9-4cfa-805a-0411de927ce6_en?file-name=Methane+regulation+import+requirements+Q%26A.pdf&)

<sup>59</sup> <https://www.energy.gov/articles/us-qatar-nigeria-and-algeria-warn-proposed-eu-methane-regulations-could-disrupt-europes?>



ed the idea that informal non-enforcement was enough, arguing that exporters and importers would be unwilling to enter contracts that knowingly breached EU law merely because penalties might not be applied.

The European Commission subsequently introduced significant enforcement flexibility. In July 2026 it recommended that Member States refrain from imposing penalties for breaches of the importer requirements relating to 2027, 2028 and 2029, except in cases of fraud, citing global supply shortages, competition for available cargoes and the importance of preserving the flexibility of global gas markets.

This was not a formal suspension of the Regulation but the three-year penalty grace period materially reduces the immediate commercial consequences of non-compliance. The practical effect may be a two-tier market in which some suppliers, notably Norway and some US producers with low emission operations, work towards full compliance while others continue supplying Europe under the enforcement flexibility provided on security-of-supply grounds.

Whether the Regulation ultimately reshapes global LNG trade will probably depend less on the legal requirements than on market conditions. The EU's leverage to impose methane (or any other) standards on imported LNG weakens as the global gas market tightens. If exporters can easily sell into Asian or other markets, the EU may have little choice but to continue accommodating supplies that do not satisfy its preferred regulatory framework.

For Britain, the EU Methane Regulation is therefore unlikely to represent a significant gas security risk before the end of the decade. The position will become more important from 2030 assuming there are no further changes. By then, European buyers may have secured a greater proportion of demonstrably compliant LNG through longer-term contracts, potentially changing the composition and liquidity of the residual spot market.

This timing will be challenging for the British gas market as UKCS production will fall to critical levels during this period unless new licences are approved, progressively increasing Britain's dependence on imported gas. GB will become more exposed to the global LNG market at around the same time that the EU's methane rules begin to bite. Assuming no equivalent regulations are introduced in the UK, Britain will remain free to buy cargoes which do not meet EU requirements, but the availability of such cargoes remains to be seen.

Britain should use this window to secure its own long-term access to LNG supplies. There is a significant opportunity to contract with producers which are reluctant to accept the costs, reporting requirements and future uncertainty associated with the EU Methane Regulation. While European buyers will increasingly favour suppliers willing and able to demonstrate compliance, Britain can offer long-term market access without imposing equivalent requirements.

Securing part of these supplies under long-term contracts before the EU rules begin to bite more meaningfully towards the end of the decade would reduce Britain's exposure to an increasingly competitive spot market at the same time as declining UKCS production increases its dependence on imports. This would turn Britain's regulatory independence into a tangible energy-security advantage rather than simply leaving British buyers to compete for whatever LNG remains available on the spot market.

## Gas infrastructure and energy security

In the past year, NESO and National Gas have begun to warn that Britain may run short of gas on the coldest winter days. Typically this concern relates to the potential gap between what Britain can receive through pipelines from the UKCS and Norway and from LNG. A related concern that gets less attention is the risk that the UKCS pipelines themselves may close, forcing the premature closure of any producing fields that tie back to them.

Unfortunately, while these risks of pipeline closures have been discussed by market participants and consultants such as Westwood Global Energy Group, their impact on UKCS production has not been factored into any official UKCS projections, which continue to show smooth decline, when closing pipelines will lead to a more stepped profile.

## Gas Supply Security Assessment confirms the risk

In November 2025, NESO published its first annual Gas Supply Security Assessment covering the five- and ten-year horizons to the winters of 2030/31 and 2035/36<sup>60</sup>. The assessment applies a "de-rating" methodology (as used in electricity security-of-supply analysis) recognising that the gas supply that is realised in practice on any day is generally only a fraction of the technical maximum capacity of that supply.

NESO expects that Britain's import dependency during periods of peak winter demand in the 2030s "could rise above 90%". The contribution of UKCS production to peak-day supply is forecast to fall from around 86 mcm/d in winter 2024/25 to around 30 mcm/d by 2030/31 and just 15 mcm/d by 2035/36, a fall of 65% and then 83% from today's level, driven by an assumed ongoing decline of 12-13% winter-on-winter.

Under NESO's base case (its Ten Year Forecast pathway), and assuming the entire gas supply network remains fully intact, the margin between de-rated supply and 1-in-20-year peak demand in winter 2030/31 is just 23 mcm against total demand of 461 mcm on that day. The report notes that "outages exceeding 23 mcm have occurred during previous winters". Under NESO's slowest-decarbonisation scenario (Falling Behind), the margin is already negative at minus 20 mcm even before any infrastructure loss is considered.

When NESO applies the industry-standard N-1 test (the loss of the single largest piece of gas supply infrastructure, a standard derived from retained EU law), Britain fails to meet 1-in-20-year peak demand in every single Future Energy Scenarios pathway in winter 2030/31, with a shortfall of 76 mcm under the base case alone. By 2035/36, the base case and Falling Behind pathways still fail the N-1 standard; only the three fastest-decarbonisation pathways pass.

NESO's treatment of storage and interconnectors independently corroborates concerns raised elsewhere in this report. On Rough, NESO states that it has assumed the facility will be "unavailable over the assessment period on the basis that it has not refilled during summer 2025 ahead of winter 2025/26", meaning GB's official gas system planner is modelling the country's largest storage asset as contributing nothing at all to security of supply for the rest of this decade.

On interconnectors, NESO records that annual imports to GB via IUK and BBL have fallen 89% since 2022, and that both pipelines' technical import capacity has been reduced ahead of winter 2025/26. BBL was cut twice, from 45 mcm/d to 22 mcm/d, and IUK from 73 mcm/d to 60 mcm/d, reductions NESO assumes will persist throughout the assessment period.

What NESO's assessment does not fully engage with, however, is why this shift has persisted through every season rather than easing outside the summer refill window. NESO attributes reduced imports to European gas balances and lower technical bookings, and frames the interconnectors' recent use for exports as linked to summer storage-refill demand on the Continent, which is only part of the story.

The underlying cause is not a seasonal European buying pattern but a structural repricing that followed the loss of Russian piped gas in 2022 - with continental Europe's supply of cheap, infra-marginal pipeline gas gone, Europe rather than Britain became the tighter market that must attract the marginal LNG cargo, and the NBP-TTF spread has moved from a historical winter premium to a discount for much of the year as a result.

<sup>60</sup> <https://www.neso.energy/what-we-do/resilience-emergency-management/gas-supply-security-assessment>



**The loss of cheap Russian piped gas changed the cost structure of European gas, possibly permanently...**

**...this change does not appear to have been recognised by the Government**

**Increasing the capacity of gas pipelines to Europe would likely increase Britain's gas exports to Europe...**

**...it would not be likely to secure piped gas imports from Europe...**

**The UK Government recognises that some intervention in the gas market is likely to be necessary to support energy security**

The loss of cheap Russian piped gas has changed the cost structure of European gas, possibly permanently.

That is a European-fundamentals story that operates continuously through the price mechanism rather than only in the months when European storage happens to need filling, which is why GB has remained a net exporter over IUK and BBL through every winter since 2022, and not just every summer. NESO's proposed mitigation of working with Fluxys and BBL Company "to reinstate and maintain maximum technical import capacity" treats availability as the binding constraint. But if flow direction is set by a structural price relationship rather than by capacity, restoring technical capacity to its pre-2022 level would not by itself restore historical import volumes – it would simply result in larger exports from Britain to Europe.

NESO's assessment recognises that UKCS terminals will close as throughput declines, noting that Burton Point was decommissioned in 2023 with flows into two further terminals forecast to end over the coming decade. Its methodology, however, treats this as a planned, gradual withdrawal consistent with the smooth NSTA decline curve, rather than modelling the threshold-driven, cascading closure dynamic described in the next section.

NESO's modelling establishes that the margin for absorbing any additional, unmodelled shock is now negligibly small. The pipeline viability risk described below is the type of shock its central case does not yet account for.

In August 2026, the Government published its interim response to its Gas System in Transition: Security of Supply consultation<sup>61</sup>. It is largely non-committal, saying that the Government has not yet taken a position on which interventions to pursue, citing the need for further analysis of costs, interdependencies and unintended consequences, with a full response promised only "in due course."

However, the consultation responses themselves point the same way as this report's own analysis - three-quarters of respondents agreed that supply-demand imbalances become possible in low-probability, high-stress scenarios as UKCS production continues to deplete, and a majority judged that the market would not address this without government intervention, since commercial incentives are weighted toward day-to-day utilisation rather than insurance against rare but high-impact events.

The Government's language reflects the scale of that conclusion: it describes any intervention in a market that "has operated freely" until now as "unprecedented," to be pursued only where "targeted to a specific and impactful risk." The interim document signals intent to explore regulatory easing, commercial support schemes for existing capacity, and the potential for a Floating Storage and Regasification Unit and/or a strategic gas storage reserve, without committing to any of them. It also ignores the potentially more useful approach which would be to slow the decline of UKCS production, which has been accelerated by a hostile policy environment.

61 <https://www.gov.uk/government/consultations/gas-system-in-transition-security-of-supply>

**UKCS production forecasts tend to show smooth decline...**

**...this is unrealistic. The closure of offshore pipelines will create a stepped profile...**

**...when a pipeline system is forced to close due to lack of throughput any fields relying on it will be forced into early closure**

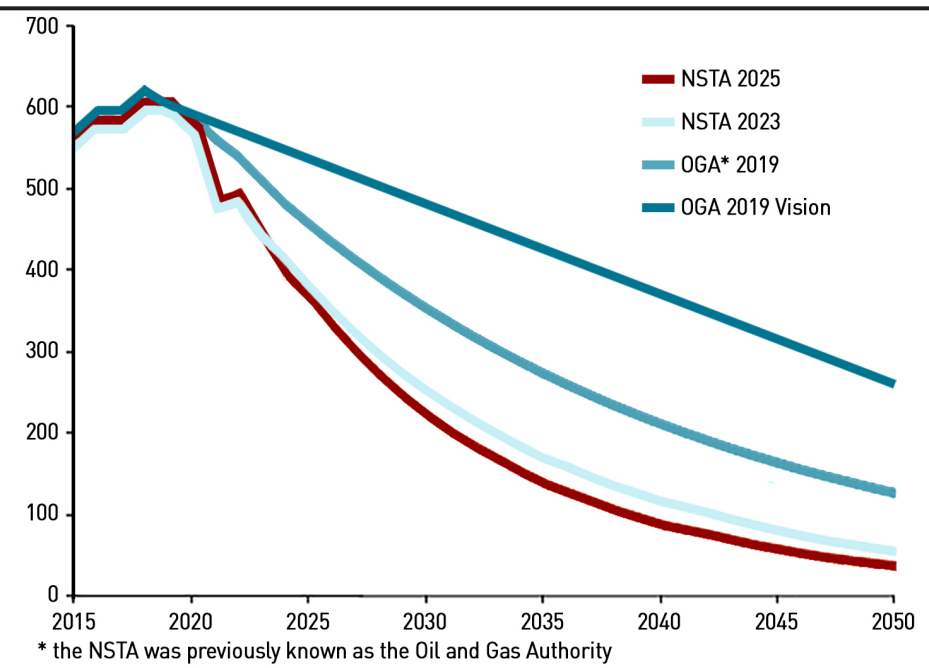
**The UKCS pipeline infrastructure is critical to gas security**

It is possible that issues with offshore gas pipeline viability could emerge as early as the winter of 2026/27. The North Sea Transition Authority's ("NSTA's") latest projections show accelerating UKCS decline through the 2020s<sup>62</sup>.

The key issue isn't simply that UKCS output is declining, but that the offshore gathering and transmission system has fixed costs and physical interdependencies - as throughput falls, it becomes progressively harder to maintain and justify these assets.

Pipelines such as the Central Area Transmission System ("CATS"), the Scottish Area Gas Evacuation ("SAGE") system and the Far North Liquids and Associated Gas System ("FLAGS") were designed for high throughput and depend on tariffs from producers. As volumes decline, unit tariffs rise to recover fixed costs. At some point, remaining producers face uncompetitive transportation tariffs, which accelerates field decommissioning, leading to a "death spiral" where loss of one anchor field undermines the economics of the whole system.

**Forecast UKCS oil and gas production (millions of barrels of oil equivalent)**



Offshore gas lines require a minimum flow to maintain stable pressure, gas velocity, and to prevent liquids (water, condensate) from pooling. If flows

62 <https://oeuk.org.uk/product/impact-of-fiscal-policy-on-the-uk-continental-shelf/>







drop too low hydrates can form, liquids can accumulate, increasing corrosion risk, and compression and dehydration systems become inefficient. Below a certain threshold, the system cannot safely operate without costly reconfiguration. So, a sudden production fall can force early shutdowns of gathering systems, even if some reserves remain in place.

This is not a hypothetical mechanism. In 2018, the closure of the Theddlethorpe Terminal triggered the early closure of several Southern North Sea fields whose export route it had provided which demonstrated the exact cascading closure dynamic described above<sup>63</sup>.

Issues with offshore gas pipeline viability could emerge as early as the winter of 2026/27 with an accelerated decline in UKCS production. However, sustained domestic throughput underpins system resilience and peak day deliverability through the 2030s and beyond, putting security at risk if UKCS pipelines close prematurely.

According to Westwood Global Energy Group, the Reserves/Production (R/P) ratio, a measure of how long an asset could continue to produce at current rates, given remaining reserves and 2025 production estimates, for four pipeline systems is <6, two of these are critical for the UK with a high number of field entrants.

**Flotta Pipeline System:** relies on production throughput from three hubs (seven producing fields). Although infill drilling and workover activity is ongoing at the hubs, the R/P ratio is 5.5. The progression of the Marigold discovery as a tieback to the Piper hub would change the current outlook. Roughly 40% of the resource upside within 50 km is unlicensed.

**Forties Pipeline System:** a critical liquids pipeline system for the UK, with 71 field entrants via 17 hubs, accounting for around 23% of UK liquids throughput in 2025. Seven hubs, could cease before 2030, including the namesake Forties. There is one tieback under development and infill drilling at some hubs, but due to the relatively high current throughput rates versus the reserves replacement the R/P ratio is 5.5. Three hubs are expected to contribute 45% of 2025 throughput. Delivery of upside opportunities, such as an infill well at Elgin, additional drilling at ETAP and progression of new developments such as Birgitta, Fotla and Leverett, would improve the outlook for this system. Over half of the resource upside within 50 km is unlicensed.

**CATS Pipeline System:** a critical gas pipeline system for the UK, with around 42 field entrants via nine hubs, contributing roughly 25% of UK gas throughput in 2025 but due to the relatively high current throughput rates compared with the reserves replacement, the R/P ratio is 5.0. Two hub entrants account for 68% of 2025 forecast throughput. Strong performance from a development well being drilled at Culzean (largest entrant), the progression of ongoing drilling opportunities at J-Block and ETAP, and development of tieback opportunities at Birgitta will be important to the outlook. There is high upside potential within proximity of the hub entrants.

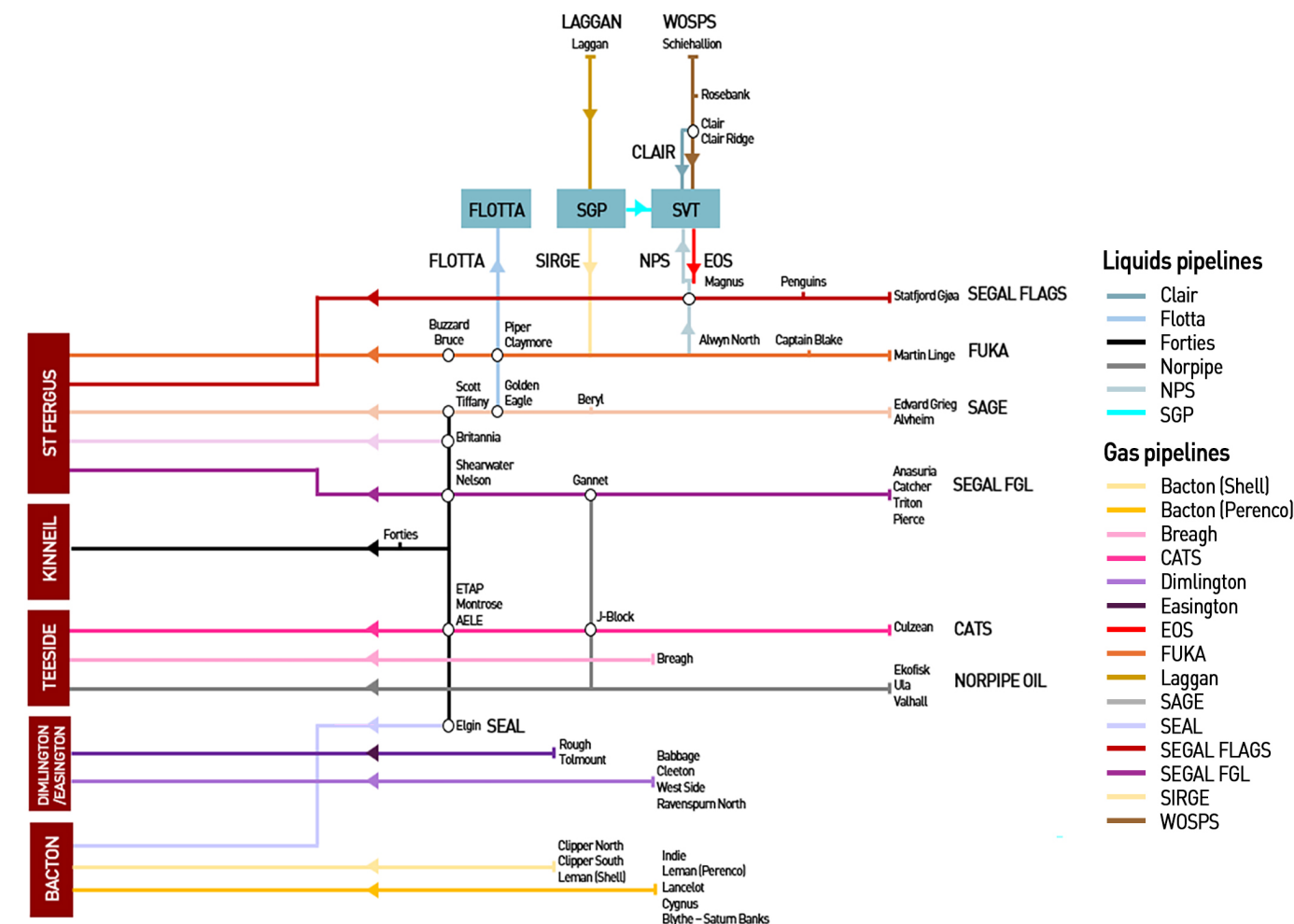
**Ninian Pipeline System:** the most northerly pipeline system in the UK feeds liquids production from three hubs via 12 fields. The Ninian hub has commenced decommissioning activities, with only one of the three original platforms still operating. The pipeline, however, feeds into the Sullom Voe terminal which also receives oil from Clair and Clair Ridge and therefore supports economics. Over 80% of the resource upside within 50 km of the Ninian Pipeline System is unlicensed.

Liquids and gas export routes are intrinsically linked - changes to one export route can impact many other export routes. This interdependency means that if one system becomes uneconomic, it could lead to a cascading effect forcing the closure of other systems, stranding potentially viable fields and leaving some areas of the North Sea inaccessible for future development.

When an offshore trunkline is decommissioned, all connected satellites

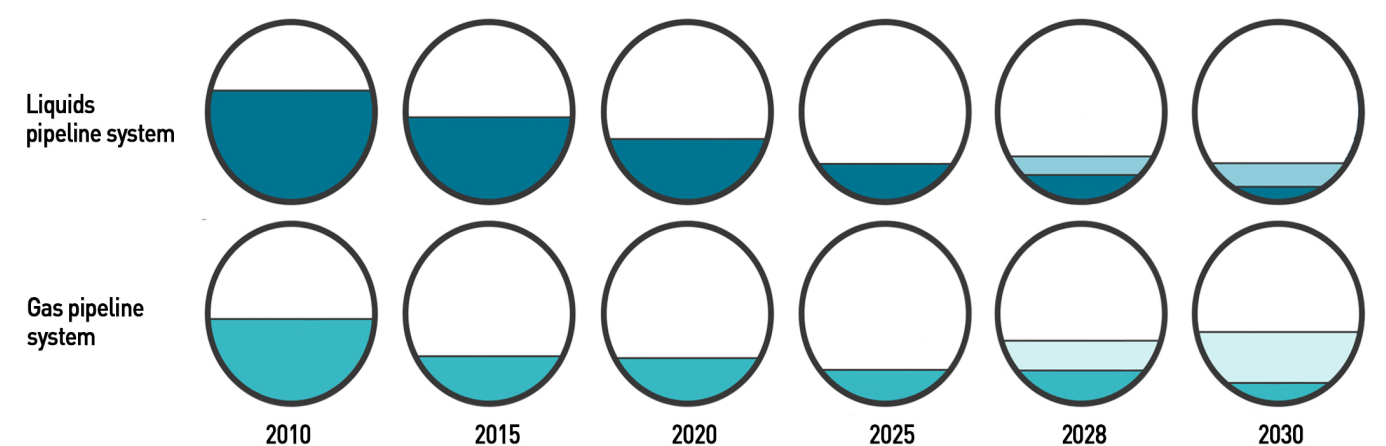
lose evacuation routes<sup>64</sup>. For example, closure of the SAGE or FLAGS system would strand several smaller tiebacks. Once a trunk is gone, re-establishing offshore transport to shore would require new infrastructure which would be uneconomic for tail-end volumes. With each major offshore system that shuts down, the steady baseload flow into the NTS diminishes, which has several system-level implications:

#### Infrastructure schematic (not geographically accurate, excludes hubs closing before 2028)



Source: Westwood Global Energy Group

#### North Sea gas pipeline infrastructure outlook



These circular diagrams represent throughput for selected pipeline systems. Historic years (2010 - 2020) show actual throughput levels. Forecast years (2025 - 2030) include two projections: Base case (dark fill) and Upside case (pale fill). Each circle is filled proportionally to indicate throughput relative to peak capacity, eg a half-filled circle represents 50% of peak throughput

Source: Westwood Global Energy Group

<sup>64</sup> <https://oeuk.org.uk/product/licensing-and-infrastructure-report-2025/>

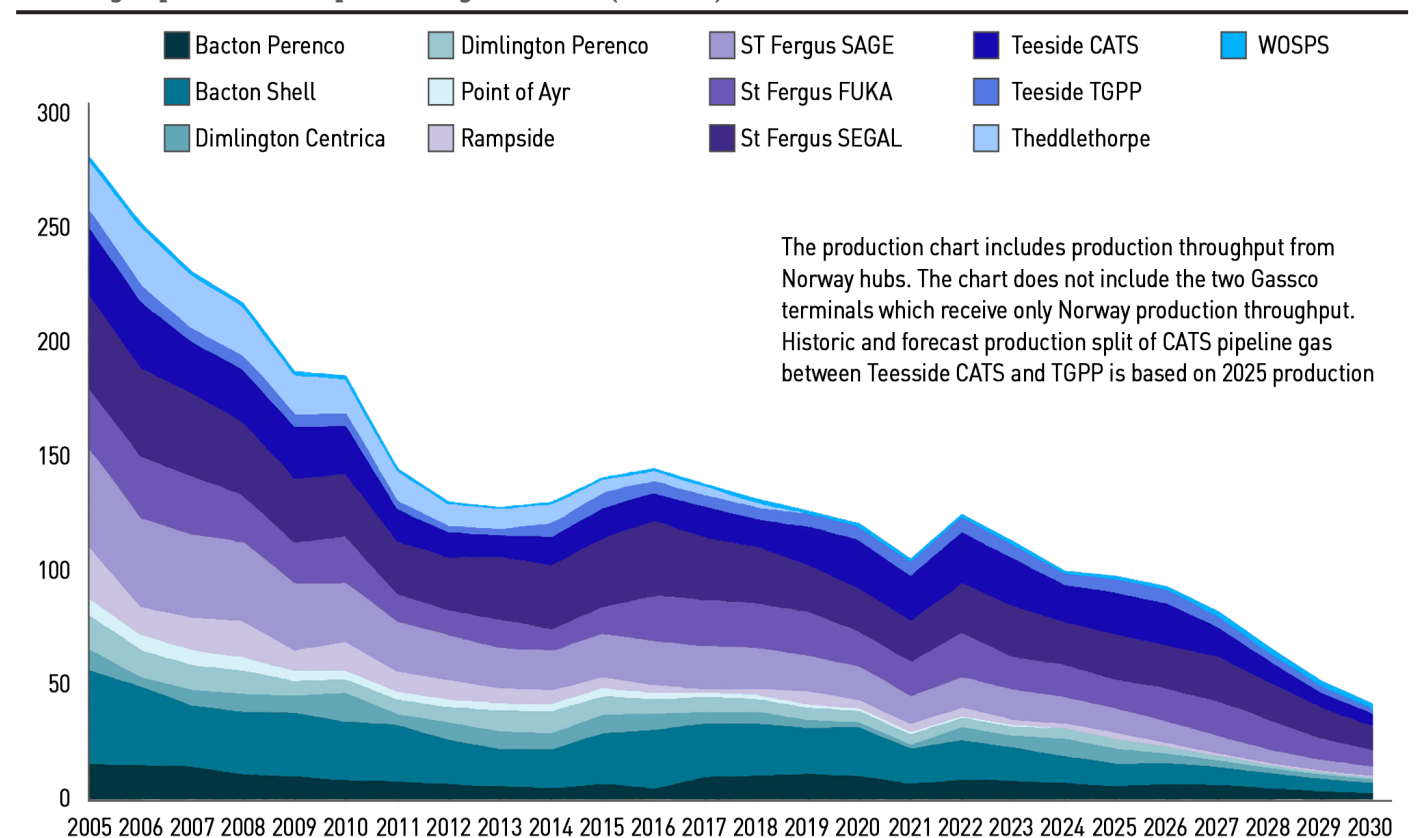
<sup>63</sup> <https://www.westwoodenergy.com/news/westwood-insight/westwood-insight-ukcs-pipeline-inter-connectivity-demonstrates-the-importance-of-a-managed-transition>



- (a) Reduced baseline inflow capacity: St Fergus, historically a high-pressure feed point, is already seeing declining flows. As these terminals wind down, the NTS loses one of its few north-to-south supply anchors, increasing reliance on southern entry points (Easington, Bacton, LNG). This complicates linepack management and reduces network flexibility under high demand.
- (b) Greater dependence on LNG: LNG can physically fill the gap on paper, but it is price sensitive as cargoes may divert to Asia, and vulnerable to weather and shipping delays. They are also logistically constrained due to availability of shipping and regas throughput limitations, and they are not instantly dispatchable as tank inventories must be pre-positioned. This means that during cold snaps or high continental demand, the GB system may struggle to ramp LNG send-out quickly enough to cover both power station and heating loads (which are higher in cold weather).
- (c) Interconnector reversal uncertainty: Continental gas systems are structurally net importers, especially after the closure of the Groningen field in the Netherlands. During European cold spells, they are unlikely to export to GB. Recent investments in IUK /BBL reversibility help, but molecule availability is the limiting factor.
- (d) Power-sector rationing: gas-fired power plants are classified as interruptible customers under the emergency supply hierarchy. If total inflows (UKCS + LNG + Norway + IUK/BBL) cannot meet domestic heating and firm industrial loads, supplies of gas to power generators may be curtailed to preserve household supply (although this is not necessarily rational since most heating systems require power to operate, so supplying gas but not electricity to households would be counterproductive).

In an orderly decline, UKCS production falls predictably, pipelines are rationalised, and alternative import capacity is scaled up. In fact, most production forecasts indicate a smooth decline profile over the coming years. This is unlikely in practice because forced decommissioning of offshore pipeline infrastructure would lead to a cliff-edge loss of capacity. This would reduce maximum NTS entry capacity by tens of mcm /day overnight, and shift pressure management southwards changing the utilisation of key compressor stations such as that at Peterborough.

UKCS gas production to processing terminals (mcm /d)



Source: Westwood Global Energy Group, DESNZ analysis of DESNZ (2025) 'Energy Trends: UK gas'

It would also force higher LNG and interconnector reliance without time to build redundancy, or sufficient NTS capacity – there are currently constraints that limit the volumes of gas that can be transported from Dragon and South Hook eastwards to consumers in England. Because offshore decommissioning is irreversible, the risk is asymmetric - once a trunkline or







compressor is removed, it cannot be reinstated in winter emergency conditions.

This risk is compounded by a further layer of interdependency. Outside the Southern North Sea, which predominantly produces dry gas requiring only a single export route, most North Sea hubs export via two separate systems – one for gas, one for liquids.

Because a field commonly shares both routes with other fields at the same hub, the early closure of a liquids pipeline can force the premature cessation of gas production that depends on the same platform infrastructure, even where the gas export route itself remains perfectly viable. Westwood Global Energy Group's analysis for OEUK finds that six UK gas terminals currently receive gas from field entrants also reliant on the Forties (liquids) Pipeline System for their oil export route, with three of those terminals additionally exposed to Norpipe<sup>65</sup>.

St Fergus alone handles between 25% and 50% of total UK gas flows depending on operating conditions, processing gas from five separate systems (FLAGS, FGL, SAGE, Vesterled and FUKA). A failure, outage, or closure for economic reasons at St Fergus would simultaneously remove multiple feed streams at once, creating a significant single point of failure. Nor has this argument gone unmade to government.

OEUK's submission to the DESNZ Gas System in Transition: Security of Supply consultation, informed by this same Westwood analysis, states plainly that "the loss of key infrastructure such as the Forties Pipeline System... should be treated as a critical system risk," and that throughput at UK terminals "has fallen by almost 40 percent since 2020 and, without a change in policy conditions, is forecast to halve again by 2030."

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**"The loss of key infrastructure such as the Forties Pipeline System, or any major offshore corridor that supports multiple hubs, should be treated as a critical system risk. These assets are not merely volume conduits but regional arteries whose failure would remove entire catchment areas from the network, reducing flow diversity and sharply increasing exposure during peak day or N 1 events,"**

- Offshore Energies UK Consultation Response,

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OEUK makes it clear in its submission that UKCS pipeline infrastructure is far more important than the interconnectors, answering the question on whether strategic support for interconnectors should be provided with a simple "N/A". The trade body for the UK's offshore energy industry was firmly of the view that UKCS pipelines are far more critical than the interconnectors, but DESNZ was silent on these assets in its interim response to the consultation.

At current decline rates, UKCS inflows to the NTS could fall from around 30 bcm in 2024 to 20 bcm by 2030, with much of the loss concentrated in the north and east coast terminals. This progressively reduces the steady baseload inflow that underpins pressure and linepack flexibility in winter. This will lead to rising import dependence, as GB will rely more on LNG (up to half of peak-day supply) and Norwegian imports (Langeled, Vesterled). From 2028 risks of structural reduction in Norwegian deliveries will also begin to manifest - before then, Norwegian offshore pipeline operator, Gassco, projects stable or slightly higher export capability, although maintenance outages will present some short-term risk.

As UKCS production falls, even if overall gas availability remains adequate on paper, North Sea gas flows will reduce baseload pressure support, increase reliance on LNG logistics, and heighten the risk of generator curtail-

<sup>65</sup> <https://oeuk.org.uk/product/uk-produced-gas-and-its-role-in-future-security-of-supply/>

ment on extreme-demand days, beginning as early as winter 2026/27, and increasing year-on-year into the 2030s unless policy change reverses the accelerating decline in UKCS production.

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**"We think Neso forecasts are too optimistic. We forecast gas production to decline by 70pc by 2030 due to the impact of the windfall tax. That suggests the UK will run out of LNG import capacity as early as 2031, as the current import terminals reach the maximum rate they can deliver gas into the UK grid during winter. The best way to ensure security of gas supply is to maximise domestic gas production,"**

- Chris Wheaton, analyst at Stifel

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In November 2025, NESO warned<sup>66</sup> that by 2030, there could be insufficient gas entering the UK to meet demand on cold days, however, these forecasts are seen by industry insiders as optimistic and there is an expectation the risk will manifest earlier.

## UKCS infrastructure risk mitigation strategies

### Halt the decline in UKCS production

There are several mitigation strategies that could be employed. The best option would be to remove the fiscal headwinds that are making North Sea gas production uncompetitive, and to allow new drilling to optimise the gas resources owned by the UK.

### Provide strategic state support to critical offshore pipelines

The Government should also consider providing financial support to key pipelines that would support their economics even under lower throughput conditions, essentially removing the economic drivers for decommissioning. This would be analogous to the Capacity Market that ensures lower utilisation of gas power stations due to the use of wind and solar generation does not force their premature closure.

The Government has signalled openness to this kind of intervention, but not yet for this specific infrastructure. In its interim consultation response, published in August 2026, DESNZ confirms that the Government "recognises that changes are needed to help build a commercial landscape that provides sufficient incentives for existing gas supply infrastructure," and that "a long-term commercial model in the form of financial or revenue support may be required".

But it says that such a scheme "is most likely to be of benefit to GB's gas storage operators and two bi-directional gas interconnectors, where profit margins and forward bookings are in long-term decline", meaning the subsidy conversation currently underway is scoped to storage and to IUK/BBL specifically, rather than to the offshore gathering and transmission pipeline systems (CATS, SAGE, FLAGS, and the liquids systems) most exposed to the R/P-ratio risk described above.

### Provide state support for UK gas suppliers to enter into long-term LNG contracts

The Government should consider a scheme to encourage gas suppliers and traders to secure a greater share of its LNG supply through long-term contracts rather than relying on the spot market. The case for this has strengthened considerably as a result of the EU Methane Regulation. The three-year enforcement grace period the Commission introduced in July 2026 provides a window for European buyers to secure compliant long-

<sup>66</sup> <https://www.neso.energy/news/mitigations-protect-future-security-gas-supply-identified>





term LNG contracts – Britain should act to ensure it does not lose out, particularly as an increase in committed gas would reduce the residual spot market GB relies on. This is expected to coincide with the time that UKCS production is forecast to fall toward critical levels absent new licensing.

Beyond the specific opportunity created by the methane regulation, there is a wider case for an increase in long-term LNG contracts. Long-term contracts provide price certainty over the contract horizon – generally now 20 years for newbuild US LNG contracts, insulating buyers from the kind of short-term volatility that characterised the spot market during 2021–22, when GB’s heavy reliance on spot and short-term cargoes left it fully exposed to the price spikes that followed reduced Russian pipeline flows to Europe. They also provide volume certainty: a buyer with contracted cargoes is not competing for supply against every other spot buyer during a system-wide stress event, which is when spot cargoes are scarcest and most expensive.

This matters disproportionately for GB given its position at the end of Europe’s pipeline network – in a tight global market, NBP must rise above Continental hubs to make diverting a cargo to GB worth more than delivering it to a Continental buyer, meaning GB is structurally the buyer most exposed to being priced out of the spot market when supply is tightest and every seller has a higher-netback alternative on its doorstep.

Long-term contracts also support the commercial viability of LNG import infrastructure itself as terminal operators and shippers can plan capacity investment around anticipated utilisation. A greater proportion of contracted throughput improves the investment case for maintaining and expanding infrastructure, addressing one of the concerns raised in DESNZ’s gas security consultation about weak commercial incentives for capacity that isn’t reliably utilised.

The trade-off is reduced flexibility as a long-term contract commits volume regardless of whether prices later fall or demand patterns shift. The Government intends for UK gas demand to fall under its net zero targets. However, as discussed elsewhere in this report, gas demand for domestic heating is expected to continue for around half a century, well beyond the expiry of long-term contracts signed this decade. The Government should recognise this and take a pragmatic approach to securing gas supplies.

#### Provide strategic state support to gas storage facilities

In fact, the main focus of the discussions on support are around storage – which makes sense versus the interconnectors which already operate with high levels of utilisation and do not seem to require support. This is likely to be a more expensive, and less viable option than simply arresting the decline of the UKCS. To make Rough a meaningful source of gas during cold weather it would be necessary to either drill new wells and re-inject cushion gas to raise the reservoir pressure – which would require a significant investment – or to install pumps on the production wells (which may not be a safe option given concerns over well integrity). Either option would require new capital expenditure, but the result would not solve the problems caused by a decline in gas from the UKCS.

Centrica puts the scale of that investment at £2 billion, for which it has asked for a guaranteed return such as a cap and floor arrangement. In a public LinkedIn exchange on 26 August 2026, Centrica CEO Chris O’Shea confirmed the company “stand[s] ready to invest £2bn of shareholders’ money to redevelop the Rough gas storage facility with the right regulatory support framework, but time is rapidly running out”<sup>67</sup>. On cushion gas, O’Shea confirmed that as much cushion gas as can be economically produced “will have been extracted by the end of the first quarter, which is the envisaged long-stop for closing the facility in the absence of a cap and floor”.

Reintroducing a cushion could take several forms, including treating it as a strategic reserve added to Centrica’s capital base as an asset and drawn only when the government instructs. O’Shea also flagged, as “a longer shot,”

the possibility of using injected CO<sub>2</sub> as a cushion, but noted that Centrica is unsure if that would work effectively.

An interesting prospect emerged in the discussion around the design of any re-built facility at Rough. O’Shea indicated that there was flexibility in the design, so it would not have to be the same as it was before it closed. This could include faster injection and withdrawal speeds for example, which would be a major benefit to the market – faster withdrawal would mean that more stored gas could be used to meet demand on any given day. Of course it would accelerate depletion of the working gas but having access to this trade-off would certainly have value to the market.

Separately, O’Shea noted the asymmetry in strategic reserve policies. While the IEA requires countries to hold strategic oil reserves equivalent to at least 90 days of their net imports from the previous calendar year, there is no equivalent recommendation for gas. Given the criticality of gas to the economy, this is surprising. It is difficult to justify a strategic reserve for oil but not for gas when there is no material difference in ability to secure cargoes.

#### Deploy floating storage and regasification capabilities

Beyond storage, Britain could also consider installing floating storage and regasification units (“FSRUs”) to increase the amount of LNG GB could accept as another means of increasing gas security. Spare NTS entry capacity at Easington and St Fergus would make these the most likely sites, but ship docking facilities as well as storage tanks would need to be built. Depending on the extent of works needed to accommodate large LNG tankers, this is likely to be part of the solution to the eventual decline of the UKCS.

FSRUs can provide rapid, relocatable regasification capacity and have been used in the UK (Teeside Gasport between 2007 and 2015) and elsewhere in Europe as short-notice tools – Germany deployed its first FSRU after the Russian invasion of Ukraine after 10 months. However, evidence from OEUK’s modelling and the Westwood Global Energy Group’s infrastructure study shows that the main emerging resilience risk is falling throughput in the UKCS pipelines rather than insufficient import-capacity. If the production and delivery of gas from the UKCS to the NTS was maintained then there would be no requirement for additional import capacity.

This approach is not as straightforward as it looks at first glance. FSRUs cannot replicate the distributed balancing capability provided by the UKCS pipeline network as each vessel is a single point source rather than a geographically dispersed one. FSRUs do not substitute for domestic entry point diversity unless sited specifically to address it, which is a function of location rather than capacity – to replicate the diversity provided by the UKCS pipeline infrastructure, multiple FSRUs would be needed at the UKCS terminals. By definition, the deployment of FSRUs would deepen Britain’s reliance on LNG, a supply that has higher carbon intensity, higher-cost, and greater exposure to global competition than domestic or Norwegian pipeline gas.

The Government has proposed that it could directly charter and operate an FSRU. It is not clear why this would be desirable as it would introduce market distortions, putting the government in competition with commercial LNG terminals for cargoes. Commercial LNG importers would face a higher risk premium as they would not know when or how the government intended to fill, dispatch or otherwise use the vessel. The fact that a government-operated FSRU would need periodic refilling regardless of prevailing market conditions would distort the price signals that would otherwise govern that decision.

Similar strategic interventions in EU gas markets suppressed ordinary merchant trading behaviour and increasing rather than reducing price volatility, and at times creating perverse pricing behaviours such as the inversion of the winter-summer spread driven by the storage mandate. Care would be needed to avoid distorting an LNG market that currently works well to deliver gas in line with demand requirements.

<sup>67</sup> <https://lnkd.in/p/dnsRmuYk>



## Winter energy security

There are several risk factors building that might adversely impact Britain's gas balances this winter.

### European gas storage levels are unusually low

EU gas storage stood at approximately 61% of capacity in mid-August 2026, against a seasonal norm closer to 80%<sup>68</sup>. European storage emerged from the 2025-26 winter at roughly 27% against a more typical level of 40%. Since the Russian invasion of Ukraine, and the near total disappearance of Russian piped gas in the European market, the EU has been sensitive to gas security and introduced mandates to ensure sufficient storage is in place for the heating season.

The EU's Gas Storage Regulation, adopted in 2022, requires member states to fill underground storage to 90% of capacity by 1 November each year, with binding intermediate targets set in February, May, July and September<sup>69</sup>. Unfortunately this target has had perverse effects. Under normal circumstances, gas is cheaper in summer than in winter, reflecting lower demand. As long as the cost of buying gas in summer, financing it, and renting space to store it is lower than the winter price, it is profitable as well as prudent for utilities to take advantage of cheaper summer gas to build stocks for winter use.

Unfortunately, the creation of a storage mandate distorts this dynamic by artificially creating demand for gas in summer that would not otherwise be there. Since the mandate is designed to be binding, it forces utilities to buy summer gas for storage even if the economics do not justify it. The very nature of the mandate and the size of the filling requirement in 2026 caused the winter-summer price spread to invert, turning a normally profitable storage strategy loss-making. Naturally European utilities demanded to know who was going to pay for this loss, imposed by the EU's desire to create an informal strategic reserve.

<sup>68</sup> <https://agsi.gie.eu/>

<sup>69</sup> <https://eur-lex.europa.eu/eli/reg/2022/1032/oj/eng>

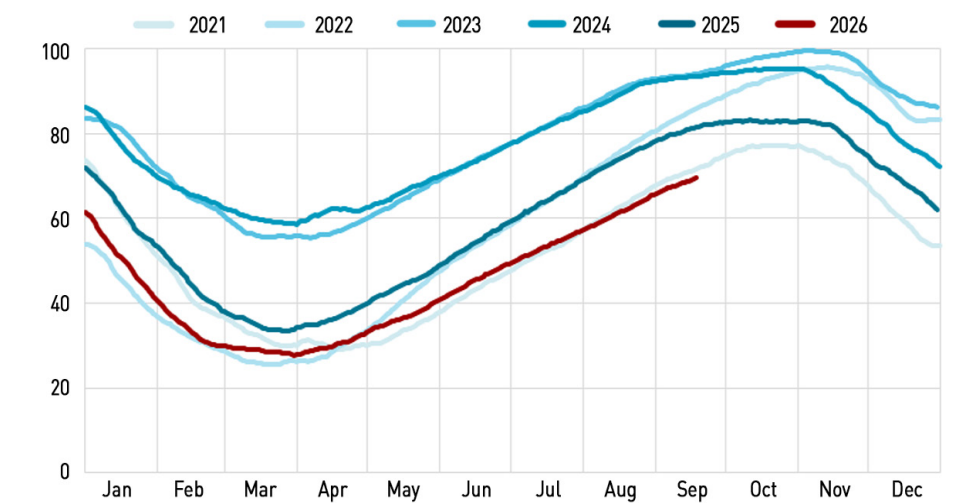
EU gas inventories are unusually low for the time of year

The gas storage mandate is unlikely to be met and has been relaxed to avoid distorting the market too much

Gas inventories were low at the beginning of the year...

...and fell further when the summer heatwave saw low wind output increasing gas demand for electricity generation

EU gas inventory levels (% full)



Source: Gas Infrastructure Europe

Compounding the low starting point has been higher than normal gas burn in the summer as low wind output and higher cooling requirements during the heatwave stimulated gas demand for power generation. This coincided with the closure of the Strait of Hormuz at the end of February which removed around a fifth of global LNG supply from the market, raising prices and causing US cargoes which would otherwise have come to Europe to be diverted to Asia.

The winter-summer gas spread inverted in 2025 as well, causing the EU to amend the storage Regulation. The headline 90% target was retained, but the obligation was loosened considerably, allowing the target to be met at any point between 1 October and 1 December rather than on just on 1 November with intermediate targets becoming indicative rather than binding. Member states are now able to deviate from the target by up to 10% where filling conditions are difficult, and the Commission may also allow a further 5% reduction in persistently unfavourable market conditions, lowering the filling level to 75% against the original 90% target<sup>70</sup>. Separately, Germany has lowered its national target to 70%<sup>71</sup>.

<sup>70</sup> <https://www.consilium.europa.eu/en/press/press-releases/2025/07/18/gas-storage-council-greenlights-2-year-extension-of-reserves-filling-rules-to-safeguard-winter-supply/>

<sup>71</sup> <https://www.argusmedia.com/en/news-and-insights/latest-market-news/2683696-germany-ap-proves-decree-to-lower-gas-storage-target>





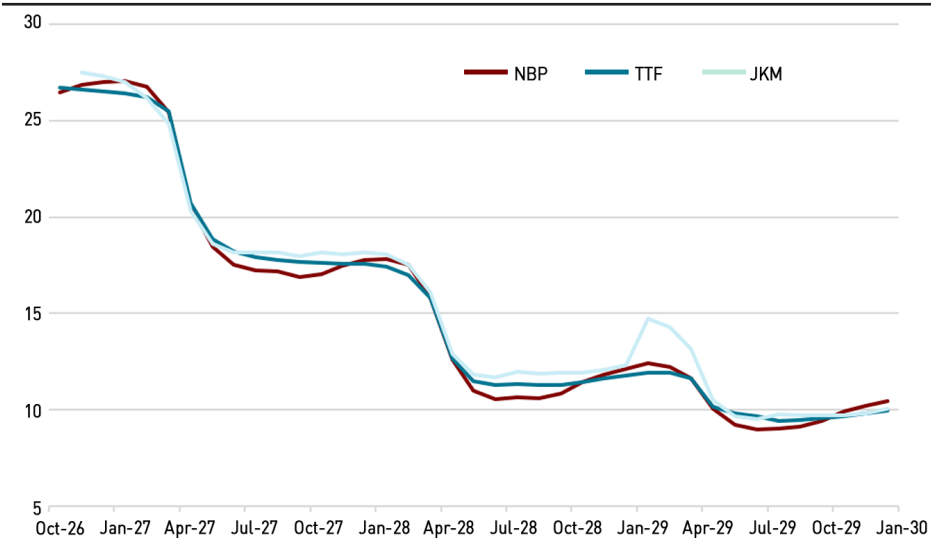
These revisions were an admission that the original design of the mandate was self-defeating, creating a market distortion that was unaffordable, and arguably creating the very problem it was trying to solve – expensive gas. Europe has, in effect, decided that the cost of guaranteeing storage exceeded what it was willing to impose on the parties obliged to provide it, the same question Britain has failed to answer about Rough, arrived at from the opposite direction.

(While from 2022 onwards various commentators have claimed that the UK's unwillingness to invest in gas storage contributed to high prices during the gas crisis, no analysis was brought forward to demonstrate such investments would have been cost-effective. In 2016 Centrica said it would cost £1 billion to bring Rough to an adequate safety standard, but there does not appear to have been any retrospective cost-benefit analysis that clearly demonstrates the benefits of having Rough fully operational since 2022 would have exceeded this £1 billion cost.)

It now seems safe to conclude that Europe will enter Winter 2026 with levels of gas stored that are both lower than the Commission would like and lower than they have been historically. Ongoing hostilities in the Middle East would mean that competition with Asia for US and African LNG cargoes will continue, elevating prices and creating potential scarcity. The question is what this might mean for Britain.

Prior to 2022, Britain typically exported gas to the Continent in the summer and imported in the winter. In 2022 this pattern was broken with Britain exporting much of the time, although far less in winter than in summer. The current EU gas balance suggests that Winter 2026 might be similar to that of 2022 and 2023 when Britain exported over IUK and BBL consistently. When British demand was at its highest those exports were lower, but nevertheless, exports continued from June 2021 to March 2024 without break.

NBP, TTF and JKM forward prices (US\$ /mmbtu)



Source: Platts via CME

The current forward curves are interesting. First of all the macro shape is consistent with forecasts of increased LNG supply normalising global prices before the end of the decade. However the forward curve for the coming winter tells a different story, and one which is difficult to reconcile with the fundamentals. The strip prices NBP above TTF from November 2026 through February 2027, peaking at around £1.36 /MWh in January, and JKM only US\$ 0.31 to US\$ 0.57/mmbtu above TTF across the same months.

The first of these implies a return to the pre-2022 seasonal pattern, in which Britain draws gas in from the Continent over the winter and pays a premium of roughly the cost of transport to do so. That pattern has not occurred since 2022 with Britain being a net exporter to the Continent in every year since, including across the winter half of each year. There is no obvious reason for four years of one-way flow to reverse in a winter when European storage is some 15% below normal.

The second aspect is even harder to justify. If Britain and Continental Europe are competing with Asia for the same marginal cargoes, and those cargoes are predominantly American given ongoing disruption in Hormuz, then the freight differential must be overcome before any gas moves east. A voyage from the US Gulf Coast to north-west Europe takes roughly 12 to 14 days, while to north-east Asia it takes 24 to 28 days via the Panama Canal, 34 to 36 days via Suez, and 37 to 38 days around the Cape of Good Hope. Europe is closer by a factor of two even on Asia's shortest routing, and by a factor of three if Panama is unavailable. A JKM premium of under US \$0.60 does not cover that gap other than in an exceptionally weak freight market.

Perhaps the market expects the disruption to Middle Eastern supply to be resolved, and for Qatari cargoes to resume reaching Asia on short haul, with the competition for Atlantic volumes easing accordingly. Nothing in the current position appears to justify that assumption. On the fundamentals as they stand, both JKM and TTF should sit above NBP this winter, and JKM should sit above TTF by enough to compensate for the additional voyage, which is considerably more than the forward market is currently pricing.

The biggest risks to Britain's gas position this winter relate to further supply disruption whether in the Middle East, to Norwegian production or to US liquefaction. Weather is the second most significant risk factor. Cold raises heating demand directly, while the accompanying still weather depresses wind generation, so gas demand rises in both the heating and power generation sectors. A sustained cold, still period in January is the scenario the entire European system is least equipped for, and it is the scenario in which Britain, Germany and the Netherlands would all be bidding for the same cargoes simultaneously. A repeat of this summer's blocking high pressure weather would be very challenging in the winter, when there is minimal contribution from solar generation to ease the pressure.

Not only would such weather raise gas demand in Britain, it raises demand in Europe, which may pull more gas through IUK and BBL. It may also raise European electricity prices above British ones, reducing or even reversing electricity imports from the Continent. As Britain relies heavily on electricity imports in winter, this would be particularly difficult to manage.

### Britain's reliance on electricity imports creates risks to its gas market

Britain's electricity system has grown structurally more reliant on interconnection at precisely the moment its interconnectors have become more constrained, and the two developments are connected rather than coincidental. GB electricity interconnector capacity with Continental Europe now stands at roughly 8.8 GW with a Government target of at least 18 GW by 2030<sup>72</sup>. That capacity has been built on the presumption that interconnectors are beneficial to energy security and support net zero goals (they are treated as zero carbon regardless of the generation technology used to generate the electricity crossing the border).

However, in its 2021 *Interconnector Policy Review: Decision*, Ofgem noted that "the net welfare impact of future GB interconnection is likely to be positive. However, we expect a shift in the allocation of some welfare benefits from consumers to producers, and between GB and the connecting countries", effectively suggesting that as a country becomes a net exporter, which Britain is expected to become as its wind fleet grows, interconnectors can disadvantage consumers due to expected increases in wholesale electricity prices in the exporting market<sup>73</sup>. As a result, Ofgem declined to approve most of the new interconnector projects in Window 3 of the cap and floor mechanism<sup>74</sup>.

To date, interconnectors have been considered to be both a cheap source of

<sup>72</sup> <https://www.gov.uk/government/publications/energy-security-bill-factsheets/energy-security-bill-factsheet-multi-purpose-interconnectors>

<sup>73</sup> <https://www.ofgem.gov.uk/decision/interconnector-policy-review-decision>

<sup>74</sup> <https://www.ofgem.gov.uk/decision/initial-project-assessment-window-3-interconnectors-decision>



**Britain has become increasingly reliant on electricity imports from Europe**

**The European regulator has prevented European system operators from cutting cross-border capacity to solve internal grid congestion**

**However NESO announced it would impose these types of restrictions on electricity exports from GB to Europe**

electricity and an important component of security of supply. Interconnectors are generally counted as being equivalent to domestic generation, but they are fundamentally different: they do not create energy, they simply allow it to flow between markets. In a stress event, the UK can restrict exports, but it cannot compel imports, and if neighbouring markets are themselves tight, which is entirely possible given the high weather correlation with most of these markets, then the assumption that interconnectors will deliver power into Britain becomes highly questionable. Yet interconnectors accounted for 20% of the capacity awarded in the most recent T-4 auction<sup>75</sup>.

So far, the picture on interconnector usage has been mixed. Until this year, Britain had not been affected by or involved in the problems, which were predominantly experienced elsewhere in Europe. For example, in the early years of market coupling, system operators were frequently restricting cross-border capacity in order to protect their domestic markets from high prices or local grid challenges by declaring local grid constraints. The European regulator, Acer, determined that these were abusive actions and banned them. Regulation (EU) 2019/943 of the European Parliament and of the Council, which was translated into English law, specifically states that “cross-zonal capacity should not be reduced in order to resolve internal congestion”<sup>76</sup>.

Despite these rules, in July, NESO announced that it will use Day-Ahead Net Transfer Capacity (“NTC”) restrictions on interconnectors more regularly from 23 July 2026<sup>77</sup>. The mechanism is currently available only on North Sea Link, Viking Link, Nemo and ElecLink. IFA, IFA2 and BritNed pick up equivalent restrictions later, at the intraday stage, through Intraday Trading Limits (“ITLs”), although NESO is negotiating with the French and Dutch system operators to try and secure day ahead restrictions as well.

NESO says these restrictions will be applied “equitably” that is spread across whichever interconnectors are capable of delivering the required security margin, based on capability declared at the two-day-ahead stage, and that all restrictions will be published on NESO’s Data Portal, with compensation governed by the published Methodology for GB Commercial Arrangements relating to Interconnector Capacity Calculation.

**NESO confirmed this action was not driven solely by security concerns...**

**...this means NESO is using tools designed for security for regular operational planning**

**There is a risk that European system operators impose similar restrictions on their electricity exports to GB...**

**...this would be a major threat to winter energy security**

In the 22 July Operational Transparency Forum webinar<sup>78</sup>, NESO confirmed that NTCs have always been part of its operational toolkit and their use would now be expanded. NESO was asked whether EU system operators had been informed about these changes, and if they were in agreement, since they do not use NTCs in this way. The answer was that they were informed and are “on board”. NESO was also asked whether the security concerns that would prompt the use of NTCs related to margin or operational issues. The response was that the use of NTCs had always been part of the operational plan and **are wider than just security concerns**.

That is a materially different justification from the one the OTF slide itself leads with that “DA NTC restrictions may be required to guarantee the security of the GB system”. This is important because the narrower, security-of-supply framing is the only one that sits comfortably within GB’s retained EU congestion-management law. An admission that restriction is also, or primarily, an operational planning tool, used, on NESO’s own account, more broadly than to meet genuine system emergencies, is functionally an admission that NESO is doing at least some of what recital (30) of Regulation (EU) 2019/943 was written to prevent: resolving internal congestion by reducing cross-zonal capacity rather than by managing the domestic grid.

That cross-zonal capacity should not be reduced in order to resolve internal congestion is the animating principle behind the EU’s binding minimum-availability rule set out in Article 16(8) of the Regulation - the “70% rule” - which requires transmission system operators (“TSOs”) to make at least 70% of cross-zonal capacity available for cross-border trade to stop TSOs from exporting the cost of internal congestion management onto interconnector users<sup>79</sup>. However, Article 16(8) is the one provision of the Regulation that did not survive transposition into English law - the UK’s EU Exit Regulations of 2020 expressly omitted it from the retained text.

What remains in GB law is the general principle at Article 16(1) that congestion should be addressed through non-discriminatory, market-based solutions, and that a TSO “must consider, so far as possible,” the effect of its measures on neighbouring control areas, and the general statement at Article 16(4) that “the maximum level of capacity of the interconnections... shall be made available to market participants.” Neither carries a quantified floor, and neither is backed by an external regulator empowered to test

<sup>75</sup> <https://watt-logic.com/2026/03/29/gb-capacity-market-is-broken/>

<sup>76</sup> <https://www.legislation.gov.uk/eur/2019/943>

<sup>77</sup> <https://www.neso.energy/document/384776/download>

<sup>78</sup> <https://www.youtube.com/watch?v=HItluU-D7gs>

<sup>79</sup> <https://eur-lex.europa.eu/eli/reg/2019/943/oj/eng>



compliance the way ACER tests EU TSOs against the 70% target.

ACER's own monitoring found that, across the EU generally, TSOs were making only around half of technical interconnector capacity available for trade before the 70% rule was introduced<sup>80</sup>. This is the exact pattern the rule was designed to correct, which GB's retained law no longer has a binding mechanism to prevent, and now NESO is planning to engage in on a more regular basis.

That may sound like a get-out-of-jail-free card except that the UK Government intends to rejoin European electricity market coupling. The UK-EU Trade and Cooperation Agreement's energy provisions were set to expire on 30 June 2026, but have been extended. Negotiations on possible UK re-entry in the EU's Internal Energy Market have yet to begin<sup>81</sup>, but the Government's draft explanatory memorandum on the European Commission's negotiating mandate confirms that the EU is seeking "timely dynamic alignment of wholesale and retail electricity market rules"<sup>82</sup>. This would include oversight by ENTSO-E and ACER, noting that the UK would retain the ability to adopt policy measures on affordable prices, security of supply, and grid stability "in the same way as EU Member States."

That last caveat appears to allow EU member states to retain security-of-supply discretion in setting cross-border trading capacity, but it has not stopped ACER from constraining how, and how transparently, that discretion can be exercised through capacity restrictions. If GB re-enters a coupled arrangement on terms genuinely equivalent to an EU member state's, NESO's current freedom to restrict interconnector capacity without reference to any binding minimum-availability rule, and without ACER-style external monitoring, is unlikely to survive in its current form. Dynamic alignment itself would import something functionally close to the 70% rule and the transparency-and-justification obligations that go with it. Whether the eventual agreement delivers that in substance, or produces a looser form of "volume coupling" arrangement of the kind previously floated for UK-EU trading (distinct from full EU market coupling, using a different algorithm, with GB TSOs excluded from ACER and ENTSO-E membership), remains to be seen<sup>83</sup>.

It would be a mistake to assume the Government will necessarily resist ceding ground on energy security in order to secure what it perceives as the trade and market-access benefits of the wider deal. The pattern in the parallel sanitary and phytosanitary ("SPS") negotiation is instructive - there "dynamic alignment" is the Government's proposed mechanism, meaning the "vast majority of movements of animals, animal products, plants, and plant products between Great Britain and the Union being undertaken without the certificates or controls that are currently required or expected".

This would expose the UK to various animal diseases such as African Swine Fever ("ASF")<sup>84</sup>. The UK has never had an outbreak of ASF, however ASF outbreaks have been ongoing in the EU since 2017, when they first appeared in domestic pigs in Romania. Other EU countries with ASF outbreaks since 2023 include Bulgaria, Croatia, the Czech Republic, Estonia, Germany, Greece, Hungary, Italy, Latvia, Lithuania, Poland, Spain and Sweden.

The Dover Port Health Authority was reported to have confiscated 100 tonnes of diseased meat in 868 separate consignments in 2024<sup>85</sup>, when the UK required any meat, dairy, fish or eggs from the EU to have full third-country SPS paperwork. Had the UK had dynamic alignment and certificate free trade with the EU much of this diseased meat would have entered the UK and UK food chains. The risk of such diseases entering the UK would then restrict the UK's ability to export food and animals to certain trade partners such as Australia and New Zealand, which restrict imports from the EU in

<sup>80</sup> <https://www.tandfonline.com/doi/full/10.1080/02646811.2019.1707441>

<sup>81</sup> <https://publications.parliament.uk/pa/cm5902/cmselect/cmbeis/126/report.html>

<sup>82</sup> <https://www.gov.uk/government/publications/em-for-uk-participation-in-eu-electricity-market-com2025804>

<sup>83</sup> [https://energy.ec.europa.eu/topics/international-cooperation/key-partner-countries-and-regions/unit-ed-kingdom\\_en](https://energy.ec.europa.eu/topics/international-cooperation/key-partner-countries-and-regions/unit-ed-kingdom_en)

<sup>84</sup> <https://committees.parliament.uk/writtenevidence/168029/html/>

<sup>85</sup> <https://www.bbc.com/news/articles/c74m3dke3pwo>

order to prevent the introduction of such diseases.

A government prepared to accept dynamic alignment with associated loss of domestic discretion in food and agriculture is not obviously one that would hold a harder line to preserve NESO's unilateral discretion over interconnector capacity restrictions.

The difficulties do not end there. The chances of the UK re-entering the EU internal energy market before this coming winter are very slim, but NESO's recent actions on interconnectors including the increased use of NTCs, create risks of retaliation by European TSOs. There are two other areas of concern.

The first is NESO's approach to the EU's new restrictions on intraday interconnector trading by TSOs. In May, the EU introduced limits of 300 MW on any one interconnector and 1,500 MW collectively for intraday system operator trading by NESO on interconnectors in any settlement period<sup>86</sup>. However, since this restriction was introduced, NESO has breached the limit on multiple occasions. This is apparently done with the agreement of the EU TSOs (according to the 22 July Operational Transparency Forum), but the frequency of these violations over the short time since the restrictions were introduced is unlikely to be well received by the European TSOs.

The second was NESO's actions on 23 June 2026 when NESO issued an Emergency Instruction ("EI") to the Netherlands cutting exports from GB to the Netherlands on the BritNed interconnector. An EI is a mandatory instruction, meaning GB's exports to the Netherlands were cut without the agreement of TenneT, the Dutch TSO. Shortly afterwards, NESO issued a request for Emergency Assistance ("EA") to France, requesting a reduction in GB exports to France. French TSO, RTE agreed to provide the EA, accepting lower imports from Britain. These actions were taken despite GB not issuing any market warnings indicating the existence of system security concerns, as would normally be expected before such actions are taken.

The response of European TSOs to these events has been that they are "irritated" with Britain increasingly seen as a poor trading partner for electricity<sup>87</sup>. Goodwill is reportedly declining. Britain has repeatedly exported its problems to its neighbours, exposing them to its security problems and price volatility. On 23 June, all our connected markets with the possible exception of Norway were themselves short of electricity.

Although the heatwave resulted in high solar generation, that had significantly declined by the evening when the EI and EA were undertaken, and wind output was low. Hot and dry weather had also depressed hydro generation across the Continent and reduced the availability of cooling water for nuclear reactors, lowering nuclear availability. Meanwhile demand was high as air-conditioning use rose across Europe.

Flows that evening were repointed towards GB despite those tensions, and despite the lack of prior warning. By failing to issue an Electricity Margin Notice on 23 June NESO effectively signalled that it considers EI and EA to be part of its normal operational toolkit alongside NTC and ITL actions. Yet at the same time it considers electricity imports to be essential to maintaining security of supply in Britain in the winter<sup>88</sup>.

European TSOs may decide to do the same - if the UK does not consider interconnector trading limits to be binding, and treats curtailment of cross-border capacity as an ordinary operational tool, at times cutting exports without warning or agreement, then European TSOs may do the same with their exports to Britain when it suits them. European regulators are unlikely to hold them to a different standard than the UK follows in the circumstances.

And if Britain cannot import electricity then it will be forced to generate more itself, with gas-fired generation being the only viable flexible means of replacing lost imports.

<sup>86</sup> [https://www.neso.energy/data-portal/interconnector-requirement-and-auction-summary-data/interconnector\\_trading\\_restrictions\\_for\\_neso](https://www.neso.energy/data-portal/interconnector-requirement-and-auction-summary-data/interconnector_trading_restrictions_for_neso)

<sup>87</sup> <https://dispatches.kilowatts.io/p/a-midsummer-nights-near-miss>

<sup>88</sup> <https://www.neso.energy/publications/winter-watch>



Britain consistently imports electricity from Norway

The Norwegian electricity system is dominated by hydro

With minimal pumping capability, Norwegian reservoirs rely on rain and snow-melt for filling

Stressed Norwegian hydro levels may put British electricity imports at risk

Reservoir levels in NO2, the southern Norwegian bidding zone that hosts the Kviteseid converter station at the Norwegian end of North Sea Link electricity interconnector to GB have fallen below the twenty-year range for the time of year. Filling bottomed at around 27% in April, just about within the historical band, but the summer refill has been unusually weak. By early August the zone stood at roughly 48%, below the lowest level recorded in the preceding two decades for that week<sup>89</sup>.

The near-term outlook offers little relief - the Norwegian Meteorological Institute's seasonal forecast does not provide confidence that the autumn will be wetter than normal leading to increased levels of filling<sup>90</sup>. The reservoirs serving NO2 sit largely on the southern Norwegian highlands, at elevations where precipitation increasingly falls as snow from October onwards. Snow locks the water up until the spring melt and contributes nothing to reservoir inflow in the interim, so the autumn filling season effectively ends in late October or early November.

Whatever level NO2 has reached by then is broadly the water available to generate electricity in the region through the winter. On the current trajectory, that level will be the lowest in twenty years.

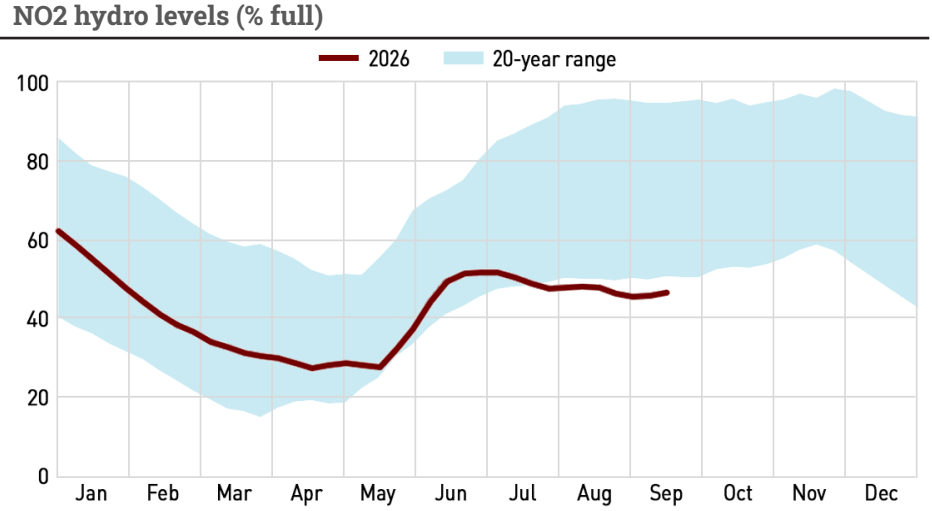
Many people in Europe either do not know, or forget that the Norwegian hydro system is not a pumped system. This means that when the water runs out it is no longer available to serve domestic customers until the reservoirs are refilled by rain or snow-melt. The lack of pumping (only 1.4 GW of the 33 GW system has any pumps, and none in NO2<sup>91</sup>) means there is no way of replacing the water. Imports can only serve to displace water use, but the very short-term nature of the pricing means that Norwegian prices will generally only rise once shortages actually hit (scarcity pricing), and by then it would be too late to preserve the water levels.

This matters for Britain because the legal and political framework governing Norwegian exports has changed materially in recent years. Norway has twice amended its Energy Act to strengthen the authorities' powers to restrict exports, and the trigger is now a risk of domestic shortage rather than an actual one, a much lower threshold, and one which a reservoir position below the twenty-year minimum could plausibly satisfy<sup>92</sup>. The ex-

Reservoirs in the south of Norway where the interconnector to GB lands are below 20-year lows...

...this may limit Norway's ability to export electricity

ercise of these powers has not been tested, but their existence changes the risk profile of relying on Norwegian imports.



Source: Norwegian Water Resources and Energy Directorate

There is a precedent for this. In December 2021, shortly after both NSL and NordLink began operating, Swedish system operator Svenska Kraftnät reduced its cross-border capacity to Norway, and Norway retaliated by reducing its exports to Sweden<sup>93</sup>.

The Swedish action was prompted by Norway increasing its imports from Sweden during periods when it was exporting to Britain and Germany - in effect, Swedish power was transiting Norway to reach the higher-priced markets, and Svenska Kraftnät reduced export capacity by as much as half over the following year to keep its own system secure. Finland and Denmark, both of which rely on imports, saw their electricity prices rise materially as a result, and both pressured the European Union to end the exemption that allows TSOs to make such reductions.

The episode illustrates two things relevant to this winter. The first is that curtailment is not a hypothetical response to extreme scarcity but an established operational behaviour, adopted within weeks of the new interconnectors opening, by a system operator in a well-supplied Nordic market. The second is that it propagates - a reduction on one border prompted

styringsmekanisme-for-aa-sikre-forsyningssikkerheten-trer-i-kraft-1-juli

93 <http://web.archive.org/web/20211206115438/https://www.bloombergquint.com/technology/europe-s-thirst-for-electricity-spurs-nordic-grid-blockade#bypass-sw>





There is political pressure in Norway to restrict electricity exports

Even without political pressure, water shortages in Norway might push up Norwegian electricity prices to a level that attracts imports including from Britain

a reciprocal reduction on another, and the effects were felt in two further countries that were party to neither decision. Britain sits at the end of a chain of interconnected systems, and a Norwegian restriction would not be confined to the 1.4 GW of North Sea Link.

Indeed, the prospect of export restrictions this winter is no longer hypothetical. In March 2026 the Red Party tabled a motion proposing a strengthened control mechanism, giving Statnett the responsibility and authority to reduce export capacity whenever filling in the principal reservoirs falls below the seasonal median<sup>94</sup>.

The Energy Minister rejected it in a reply of 10 April 2026, arguing that the existing mechanism was a more targeted and appropriate instrument than a new arrangement. In early June he declined to use the existing mechanism. On 3 August the Red Party's deputy leader, Sofie Marhaug, submitted a further written question to the Storting asking whether the minister would now use the control mechanism to limit generation for export, and what other concrete measures the government was considering to prevent further drawdown of the reservoirs ahead of winter.

“It is absolutely crazy that we have come to this situation. Norway does not have nearly enough export restrictions to secure the industry. We fear shock prices for the winter and a number of bankruptcies. We must have a responsible minimum level for filling ratio. The Minister of Energy must start doing his job,”

- Kristoffer Sivertsen, Progress Party Energy Spokesman

So far the government is resisting. Energy Minister Terje Aasland has attributed the low filling to weather stating that Norway has a weather-based power system in which filling naturally varies, following a cold winter with little snow, high consumption and high production, and more

94 <https://www.stortinget.no/no/Saker-og-publikasjoner/Sporsmal/Skriftlige-sporsmal-og-svar/Skriftlig-sporsmal/?qnid=126887>

Norway is no longer willing to act as the “battery of Europe”...

...saying it will not build any new interconnectors

Norway believes its integration with European power markets has left it more exposed to Continental price volatility than it planned for...

...and Europe should be self-reliant in electricity rather than relying on Norwegian flexibility

recently low precipitation and low inflow in southern Norway<sup>95</sup>.

He cited NVE's (the Norwegian Water Resources and Energy Directorate's) assessment that it is not concerned about energy security for the coming winter. Aasland has said he has no plans to use the mechanism, although NVE's Director General, Kjetil Lund, has indicated he is considering intervening in respect of hydropower producers<sup>96</sup>.

The pressure is not confined to one party. The Progress Party's energy spokesman, Kristoffer Sivertsen, has said that Norway does not have anywhere near enough export restrictions to secure its industry, that a responsible minimum filling level is needed, and that Norway cannot be a net exporter of power when defence and industry are not getting the power they need, adding that it is easier for Germany to obtain power from southern Norway than it is for northern Norway.

“In a situation of great instability in the European power markets, the government does not want to tie Norway more strongly to the European power system. Therefore, we are saying no to new foreign cables and are not introducing the controversial market regulations”

- Terje Aasland, Norwegian Energy Minister

The party's longstanding position is that arrangements with Germany and Britain should provide for power exchange rather than power export, and that both countries should be responsible for their own security of supply. More recently Sivertsen has said he worried the shortages in NO2 will lead to price spikes that could lead to business failures<sup>97</sup>.

NO2 reservoir levels are at 20 year lows despite the fact that Norway has

95 <https://www.nettavisen.no/nyheter/rekordlav-fyllingsgrad-frp-frykter-stromsjokk-etter-mas-siv-krafteksport/s/5-95-3178055>  
96 <https://www.nettavisen.no/okonomi/nve-sjef-kjetil-lund-vurderer-a-gripe-inn-mot-vannkraftproducentene/s/5-95-3181595>  
97 <https://borsen.dagbladet.no/nyheter/kan-gi-prissjokk-sterkt-bekymret/85028302>





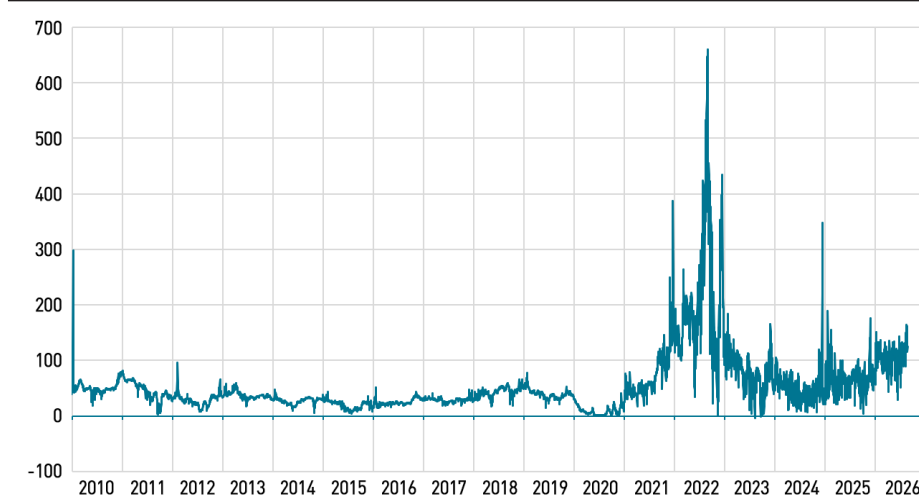
been importing power in the middle of the day, when solar generation is high in neighbouring countries, only exporting for the remainder of the day. That daily import window closes in winter, when northern European solar output falls to a fraction of its summer level, accelerating hydro withdrawals.

The political context in Norway is unambiguous - almost every party in the Storting is now opposed to new interconnection. The governing Labour Party committed not to approve any new interconnectors during the current or the next parliamentary term, and to instruct Statnett not to begin planning new submarine connections until 2029<sup>98</sup>.

The immediate expression of this is the Skagerrak cables to Denmark. SK1 and SK2, commissioned in 1976 and 1977 and totalling 500 MW of the 1,632 MW Skagerrak system, reach the end of their technical lives in 2026 and 2027 respectively. Labour campaigned on not replacing them, which would cut cross-border capacity with Denmark by roughly 30%. Statnett submitted a notification to NVE in 2024 and NVE issued a study programme in April 2025, but no formal licence application has followed; even if one were made and approved, replacement capacity would not be available for years<sup>99</sup>.

The politics of this were visible this summer when SK2 failed on 2 June, with the fault located some 30 km off the Danish coast. Statnett attributed the fault to wear and tear consistent with a cable approaching fifty years of service. Statnett and Energinet decided to repair it at a cost of NOK 130–160 million (£10 – 12.6 million), with restoration expected by 2 September 2026, prompting the Centre Party's Erling Sande to describe spending public money repairing cables the government has promised to scrap as "madness" and saying this would be a good opportunity to start limiting exports from Norway<sup>100</sup>. Whatever the merits, the direction of Norwegian policy is toward less interconnection, not more.

#### NO2 day ahead prices (€ /MWh)



Source: NordPool

Underlying this is a price grievance. Prices in Southern Norway have risen considerably since 2021, the year in which the interconnectors with Britain and Germany opened<sup>101</sup>. The widespread view in Norway is that the interconnectors to Germany and Great Britain import continental price volatility into a system that would otherwise be insulated from it, and that German nuclear closures and British coal closures have made both countries more dependent on Norwegian flexibility while making Norwegian consumers pay for it.

The policy response has been to support Norwegian consumers with high

<sup>98</sup> <https://www.regjeringen.no/en/whats-new/new-steps-to-reduce-electricity-bills-and-maintain-control-over-national-energy-resources/id3085960/>

<sup>99</sup> <https://www.statnett.no/vare-prosjekter/region-sor/skagerak-1-og-2/>

<sup>100</sup> <https://www.document.news/news-brief/2026/07/norway-to-spend-us16-6-million-repairing-a-power-cable-it-plans-to-retire>

<sup>101</sup> <https://watt-logic.com/2025/02/21/norway-turning-away-from-electricity-interconnection/>

prices, through the Norgespris<sup>102</sup>, a subsidised consumer price covering the great majority of household consumption that is costing the government NOK billions.

That political direction hardened further on 24 August 2026, when Energy Minister Terje Aasland told Reuters that Norway's framing of itself as Europe's "green battery" was "a flawed idea" that is now "outdated," on the grounds that Norway alone cannot balance the European power market<sup>103</sup>. Aasland confirmed explicitly that Norway will not build new interconnectors, while stating the country remains committed to "strong power sector cooperation" with Europe in more general terms.

He said that deeper integration with the European power system left Norway more exposed to continental price volatility than the country had planned for, and that Europe should be self-reliant in electricity rather than relying on Norwegian flexibility. He urged countries on the Continent to strengthen their domestic firm power supplies which were weakened by coal and nuclear closures and insufficient investment in new gas-fired generation, rather than looking to Norway to make up the difference.

The consequences of this for Britain are a risk that its imports from Norway are put at risk. NSL has a capacity of 1.4 GW and almost always flows from Norway to GB. If NO2 scarcity results either in explicit export curtailment or simply in Norwegian prices rising above British prices, Britain will lose up to 1.4 GW of expected winter import capability, and worse, could find itself exporting, meaning a reduction of the expected British winter margin of 2.8 GW.

A simple loss of 1.4 GW of imports that had to be replaced with increased gas generation would imply around 67 GWh/d of additional gas burn, or roughly 2 TWh over a winter month (assuming a CCGT efficiency of 50%). This is about 5% of GB winter gas demand. Were Britain to export gas-fired electricity to Norway at the full rate of 1.4 GW, that would increase British winter gas demand by 10%.

Reduced Norwegian exports could also affect the ability of other countries such as Denmark, the Netherlands and even Belgium to export to Britain due to the connectedness of the European power grids and the extent to which these countries themselves rely on Norwegian imports. This could put up to another 3.4 GW of imports at risk. This becomes significantly less manageable than a simple reduction in Norwegian imports, particularly if it coincides with the other pressures on this winter's gas system.

#### Risks to the French nuclear system

Britain's growing reliance on electricity imports creates additional risks for the gas balance because availability of electricity from neighbouring countries cannot be assumed during periods of system stress. This is particularly relevant to France, which has historically been an important source of winter electricity imports to Britain for two reasons – one is that it is the largest single source of imports to Britain with 4 GW of capacity across three interconnectors (IFA, IFA2 and Eleclink), and because like Norway, the French electricity grid is not reliant on intermittent generation such as wind and solar.

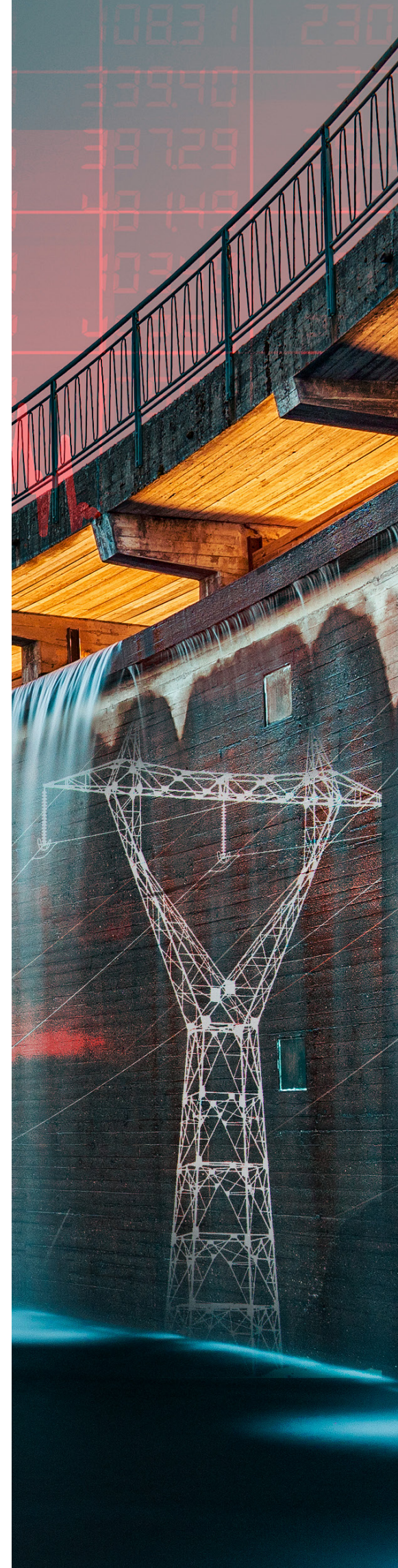
Given high weather correlation between Britain and most of its connected markets, shortages linked to low wind and solar generation can affect all these countries at the same time, reducing their export capabilities.

French nuclear availability has recovered significantly since the severe stress corrosion problems experienced in 2022, and EDF currently expects nuclear generation of 350–370 TWh in both 2026 and 2027<sup>104</sup>. However, the

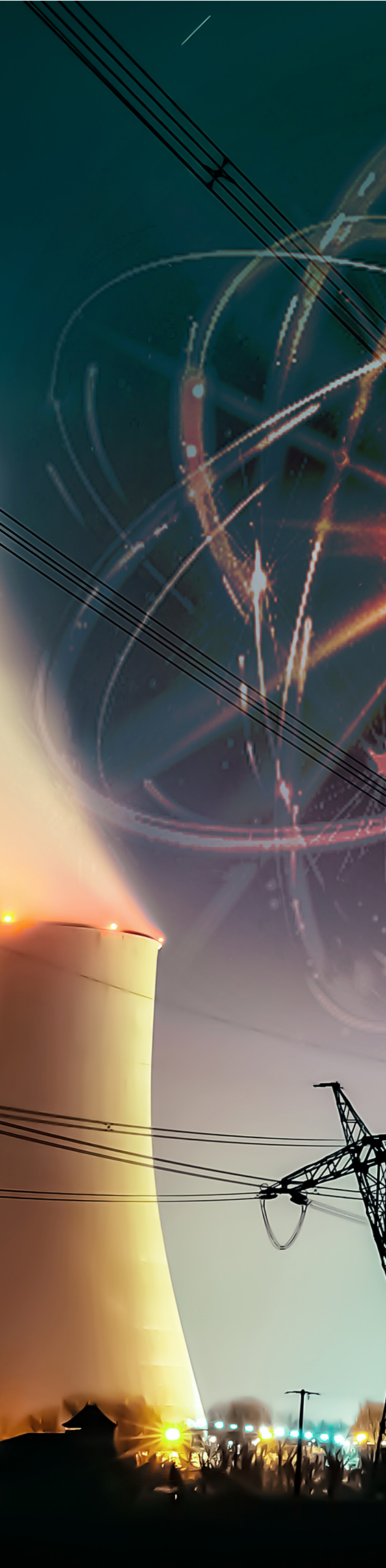
<sup>102</sup> <https://www.regjeringen.no/no/aktuelt/nye-grep-for-lavere-stromregninger-og-kontroll-over-kraftressursene/id3085960/>

<sup>103</sup> <https://www.reuters.com/business/energy/norway-will-drill-arctic-regardless-eus-position-says-energy-minister-2026-08-24/>

<sup>104</sup> [https://www.edf.fr/sites/groupe/files/epresspack/12308/CP-EDF\\_Production-nucleaire-en-France-12.2025.pdf](https://www.edf.fr/sites/groupe/files/epresspack/12308/CP-EDF_Production-nucleaire-en-France-12.2025.pdf)







French fleet is ageing - at the beginning of 2026, 25 of its 56 reactors excluding Flamanville 3 were more than 40 years old<sup>105</sup>. EDF is now undertaking the final fourth ten-year inspections of its 900 MW reactors while beginning the equivalent programme for its 1,300 MW fleet.

The experience of 2022 demonstrates an important vulnerability arising from the high degree of standardisation of the French nuclear fleet. Stress-corrosion cracking was unexpectedly discovered in 2021 in safety-injection pipework at Civaux 1, one of France's N4 reactors. Because reactors within each French series share common designs, the discovery could not safely be treated as an isolated fault - EDF undertook inspections across the fleet and ultimately replaced affected pipework on reactors in the 900 MW, 1,300 MW and 1,450 MW classes<sup>106</sup>.

The regulator described the stress corrosion cracking as an “unexpected degradation phenomenon” and continues to require EDF both to monitor the affected pipework and to improve its understanding of the conditions in which the cracking develops.

This illustrates both the strength and the weakness of France's decision to construct a highly standardised nuclear fleet. Building successive reactors to established designs delivered substantial benefits in construction, operation and maintenance, but it also creates the possibility of correlated failures as the fleet ages. A previously unknown ageing mechanism discovered on one reactor may have implications for many other reactors of the same or related design.

The French nuclear regulator assesses ageing both generically across reactor classes and at individual reactor level. Continued operation beyond 40 years requires EDF to demonstrate that ageing equipment remains capable of performing its safety functions, or to replace or renovate it where necessary. The fourth periodic review programme for the 1,300 MW fleet has now moved from its generic phase to reactor-specific implementation, with the first associated ten-year inspection beginning at Paluel in January 2026<sup>107</sup>.

There is no reason at this point to expect a repeat of the exceptionally poor French nuclear availability seen in 2022 during winter 2026/27. However, it would be imprudent to assume that another significant common-mode problem will not emerge before the end of the decade. Indeed, the stress corrosion cracking occurred in pipework where such degradation had not been expected<sup>108</sup>.

As an increasingly old and standardised fleet undergoes life-extension work, further previously unforeseen ageing mechanisms or generic defects remain a material tail risk to European electricity security. In 2022, the French nuclear regulator warned that ageing, degradation and corrosion phenomena were tending to increase, and stressed the importance of actively searching for developing anomalies before they caused damage<sup>109</sup>.

Any such issues will have an impact on Britain. In 2022, France switched from being a net exporter of electricity to an importer. Even smaller-scale issues can be problematic on cold days because French electricity demand rises further and faster than in Britain because electric heating is more widespread. On the coldest days GB often exports to France rather than importing<sup>110</sup>. Reduced electricity imports would increase the requirement for domestic gas-fired generation. Reduced nuclear availability in France could potentially reduce export capacity in neighbouring countries such as Belgium and the Netherlands, further affecting GB's electricity and gas market balances.

<sup>105</sup>[https://reglementation-controle.asnr.fr/annual\\_report/2025-fr/](https://reglementation-controle.asnr.fr/annual_report/2025-fr/)

<sup>106</sup>[https://reglementation-controle.asnr.fr/content/download/203125/download\\_file/INS-SN-DEP-2025-0361.pdf](https://reglementation-controle.asnr.fr/content/download/203125/download_file/INS-SN-DEP-2025-0361.pdf)

<sup>107</sup><https://reglementation-controle.asnr.fr/content/download/204744/file/Rapport-instruction-ASNR-phase-generique-VD4-1300MWe.pdf>

<sup>108</sup>[https://www.asnr.fr/sites/asnr/files/2026-02/ASNR\\_AIEA-CSN\\_France-10e-rapport\\_2025.pdf](https://www.asnr.fr/sites/asnr/files/2026-02/ASNR_AIEA-CSN_France-10e-rapport_2025.pdf)

<sup>109</sup>[https://www.senat.fr/compte-rendu-commissions/20220516/opecst\\_bul\\_2022\\_05\\_17.html](https://www.senat.fr/compte-rendu-commissions/20220516/opecst_bul_2022_05_17.html)

<sup>110</sup><https://watt-logic.com/2026/03/29/gb-capacity-market-is-broken/>

**Policies such as the Clean Power 2030 plan give a false impression that Britain will soon not need gas**

**The Government does not have any strategy to secure affordable access to gas, and is planning for a smaller and more uncertain gas market**

**If electricity imports become less dependable gas generation will have to fill the gap**

**It is not feasible to operate the electricity market with renewables and batteries...**

**...the Royal Society says the scale of storage required is “over 1000 times that currently provided by pumped hydro in the UK, and far more than could conceivably be provided by conventional batteries”**

## Britain's long term energy security relies on gas

Policies such as the Clean Power 2030 plan give a false impression that Britain will soon not require gas. The Government does not have any strategy to secure affordable access to gas, and is planning for a smaller and more uncertain gas market<sup>111</sup>. This planning is focusing on ensuring gas infrastructure remains in place to meet the ongoing needs of consumers, but the foundational assumption is that much less gas will be needed on relatively short timeframes. But this under-estimates the ongoing importance of gas.

The clearest illustration of this tendency to understate the importance of gas is in domestic heating. Roughly 23-24 million UK homes are currently heated by natural gas boilers. The government's own installation target, already reduced once, from an original 600,000 heat pumps a year by 2028 to 450,000 a year by 2030, is not being met - the UK installed around 105,000 heat pumps in 2025, itself a record year, and retrofit installations then fell 18% year-on-year in the first quarter of 2026<sup>112</sup>. Even taking the more favourable case and assuming the government's 450,000-a-year target were being hit consistently from now on, replacing the existing stock of gas boilers would take on the order of 50 years. At the pace actually being achieved in practice the true time is considerably longer. Gas will therefore remain the primary heating fuel for the great majority of British homes for decades, regardless of the ambition of the underlying policy.

The same is true in the electricity system. The Clean Power 2030 plan does not eliminate gas from power generation, rather it targets unabated gas providing “less than 5% of Great Britain's generation in a typical weather year”. NESO's hierarchy of flexibility options places demand-side response, short-duration storage and interconnector imports ahead of unabated gas, with gas generation as the mechanism of last resort for periods when other technologies cannot cover the gap<sup>113</sup>.

This report has set out in detail why electricity interconnector imports cannot be assumed to be available during exactly the periods of system stress when they would be most needed, whether because of NESO's more assertive use of NTC and ITL restrictions, because of domestic pressures in Norway and France, or because periods of low wind and high demand tend to be correlated across Britain's connected markets rather than confined to Britain alone. If interconnector imports prove less reliable in practice than NESO's planning assumes, unabated gas generation does not become one flexibility option among several, it becomes the most important flexibility option, because it is the only one that does not depend on conditions outside Britain's control.

The Royal Society's assessment of the wider transition notes that the storage and back-up capacity required to run a renewables-based system through the full range of weather conditions adds a materially higher cost than current plans assume, and that this cost is currently being deferred rather than eliminated. It points out that wind supply can vary over time scales of decades meaning that tens of TWh of very long duration storage will be needed. The scale of which is “over 1000 times that currently provided by pumped hydro in the UK, and far more than could conceivably be provided by conventional batteries”<sup>114</sup>.

Unabated gas absorbs the balancing burden today – in a decarbonised electricity system, something else would need to fulfil that role. Nor does NESO's own analysis extend much beyond 2030. Its longer-term forecast to 2050 shows electricity demand almost doubling, with carbon capture and hydrogen expected to “play a role” in meeting it, but without a fully worked-through account of how the flexibility and balancing functions gas currently performs would be replaced at that scale.

<sup>111</sup> <https://www.gov.uk/government/publications/midstream-gas-system-update-to-the-market/midstream-gas-system-update-to-the-market>

<sup>112</sup> <https://www.pv-magazine.com/2026/06/11/uk-heat-pump-installations-stall-despite-subsidy-boost/>

<sup>113</sup> <https://www.neso.energy/news/our-clean-power-2030-advice-government>

<sup>114</sup> <https://royalsociety.org/news-resources/projects/low-carbon-energy-programme/large-scale-electricity-storage/>



**Gas is still needed in electricity generation, in domestic heating and in industry**

**Britain will continue to need substantial, reliable volumes of gas for decades, not as a residual legacy fuel being wound down, but as a structurally essential component of the system**

**Gas security is impossible to separate from energy security...**

**...it is not a subordinate or transitional concern to be addressed once the more pressing work of decarbonisation is complete**

Industrial gas demand tells a similar story. Hard-to-abate sectors such as the chemicals, refining, ceramics, glass, steel, cement, and food and drink industries do not currently have a commercially proven, at-scale, non-gas substitute for high-temperature process heat, and the hydrogen and CCS routes that are periodically proposed as replacements remain years away from deployment at a scale that would meaningfully displace gas in this role, if they arrive at all.

Taken together, the heating, power and industrial pictures point to the same conclusion, that even under an ambitious and broadly successful decarbonisation pathway, Britain's energy system will continue to require substantial, reliable volumes of methane for decades to come, not as a residual legacy fuel in the process of being wound down, but as a structurally essential component of the system. Gas security is therefore impossible to separate from energy security. It is not a subordinate or transitional concern to be addressed once the more pressing work of decarbonisation is complete.

The risks this report has highlighted - a UKCS production outlook that is both declining and uncertain, offshore pipeline and terminal infrastructure operating closer to the margin than at any point in its history, an interconnector regime whose reliability under stress has not been tested and, on the evidence of this year, cannot be assumed, a storage position left unresolved for the best part of a decade, and neighbouring electricity systems in Norway and France facing their own domestic pressures - do not resolve themselves as renewable capacity is built. Not least because renewables generate electricity which represents only around 20% of the UK's final energy demand<sup>115</sup>.

A credible long-term energy security strategy must treat that reality as a planning assumption, and not as a political inconvenience to be minimised in public messaging. It has to fund and regulate gas infrastructure, storage and production accordingly, both for the coming winter, and for the decades after it in which gas will remain indispensable regardless of how the rest of the transition proceeds.

<sup>115</sup> <https://commonslibrary.parliament.uk/the-uk-energy-system/>





Appendix – Constraint costs

NESO data on constraints are difficult to interpret. When writing my 2025 report *The true affordability of net zero*<sup>116</sup> I found four different datasets described as “constraint costs” on the NESO Portal, none of which was consistent with any other. According to NESO some of the differences may be due to settlement timing differences – final electricity settlement prices can take up to 28 months after the delivery of the electricity to determine, so data can be subject to revisions.

Another source of difference could be the inclusion of ancillary services such as the Obligatory Reactive Power Service in some of the data. This is included in the 2024 Balancing Costs report but not in the 2025 equivalent report covering 2024-25. They may not be included in some of the other datasets. The constraint costs in the BSUoS spreadsheets apparently include the costs of “reducing largest loss cost” and “increasing system inertia cost” as well as thermal and voltage constraints.

NESO has not published an Annual Balancing Costs report since the 2025 report covering 2024-25 so there are no equivalent data for 2025-26 available. These years run from 1 April to 31 March, so the 2025-26 period ended six months ago with the annual cost report typically being published in the July immediately following the year-end. Even within these reports there are inconsistencies. For example in the data workbook for the 2025 report the Projections tab contains outturn data which do not correspond to any of the data elsewhere in the workbook, despite there being various other constraint data presented.

The National Audit Office data in the main body of this report were sourced to NESO but do not correspond to any of these datasets.

The result is conflicting and missing data. It is unclear why NESO does not resolve this confusion.

Thermal and voltage constraints

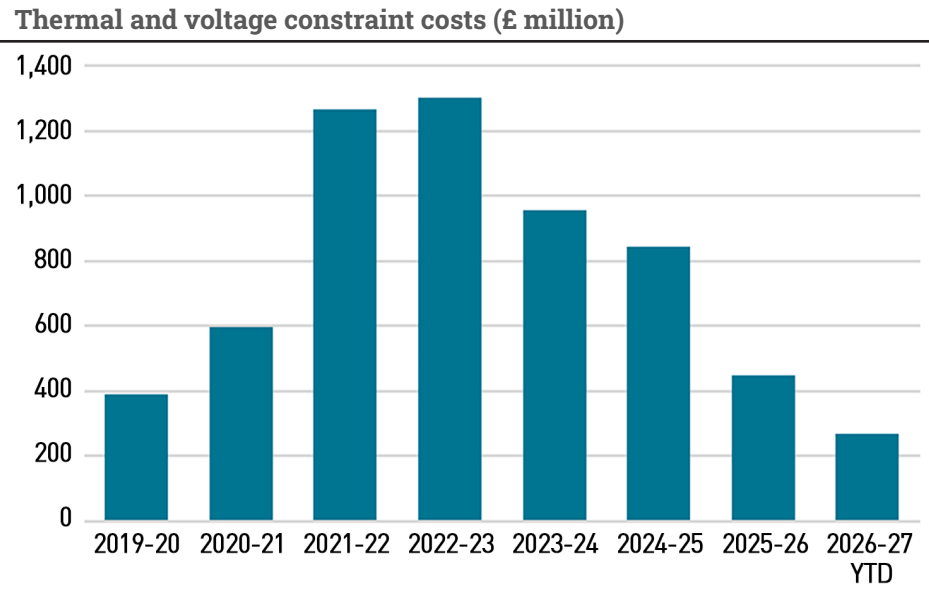
The first type of constraint data are simple thermal<sup>117</sup> and voltage<sup>118</sup> constraints. NESO describes thermal constraints as being “taken when the amount of energy that would flow naturally from one region to another exceeds the capacity of the circuits connecting the two regions. This dataset provides outturn system costs for thermal constraints across a number of

116 <https://watt-logic.com/wp-content/uploads/2025/05/Affordability-of-net-zero-FINAL-SPREAD.pdf>  
117 <https://www.neso.energy/data-portal/thermal-constraint-costs>  
118 <https://www.neso.energy/data-portal/outturn-voltage-costs?page=1>

significant constraint boundaries”.

It describes voltage constraints as “outturn system costs for maintaining voltage levels on the network” and notes that “maintaining the electricity system at the correct voltages enables safe and efficient power transfer across the network. This requires the right balance of reactive power injection and absorption to be maintained in real time”. Publication of voltage constraint costs were paused in May 2025, pending “improvements” and have not yet resumed.

The chart shows the sum of thermal and voltage constraint costs which are available. Voltage constraint costs only run to May 2025 and none are added for 2026-27. Thermal constraints run to 9 September 2026. 2018-19 data are not available for either of these parameters.



Source: NESO

Constraint breakdown costs and volume

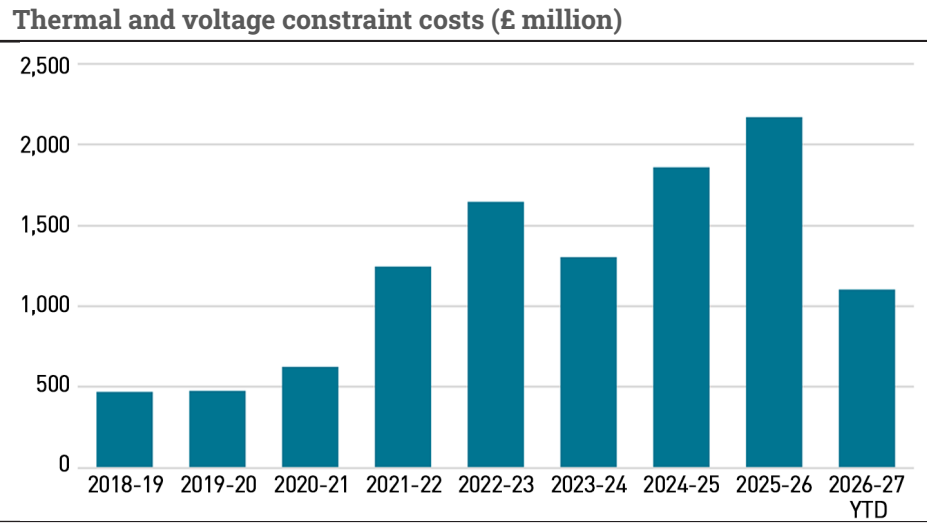
NESO publishes a breakdown of constraint costs and volumes<sup>119</sup> elsewhere on its Portal. It says that “the publication consists of constraint breakdown information to provide additional transparency of why as ESO we are taking actions on the system. Please note that tags applied to actions can occasionally be changed post event and in this instance the information in this dataset would be refreshed to reflect the up to date information”.

119 <https://www.neso.energy/data-portal/constraint-breakdown>





The following chart shows the sum of thermal and voltage constraint costs provided in this breakdown up to 9 September 2026. It can clearly be seen that they are quite different from the thermal and voltage constraints above even before the voltage constraint publication was paused.

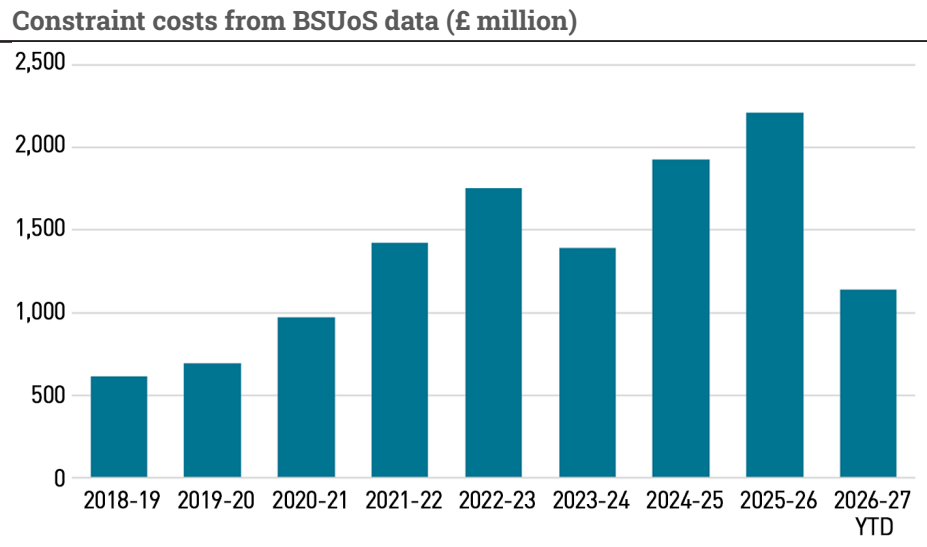


Source: NESO

**Balancing Services Use of System Costs**

According to NESO<sup>120</sup>, “the BSUoS charge recovers the cost of day-to-day operation of the transmission system. Generators and suppliers are liable for these charges, which are calculated daily as a flat tariff for all users. Historical values of these charges, on a daily basis in an annual file, are provided here”.

This chart shows the constraint element of BSUoS costs up to 9 September 2026. They are similar to but not the same as the data published in the previous section.



Source: NESO

**Annual balancing costs report**

Finally, up until 2024-25 NESO issued annual Balancing Costs reports<sup>121</sup> which contained constraint costs. The most recent report dated 2025 covers the period from 2018-29 to 2024-25 and unlike the previous years has removed reactive power costs from constraint costs. Reactive power costs are the costs of managing voltage on the network, but voltage variations are not only attributable to constraints, so their inclusion in constraint costs would not generally be reasonable.

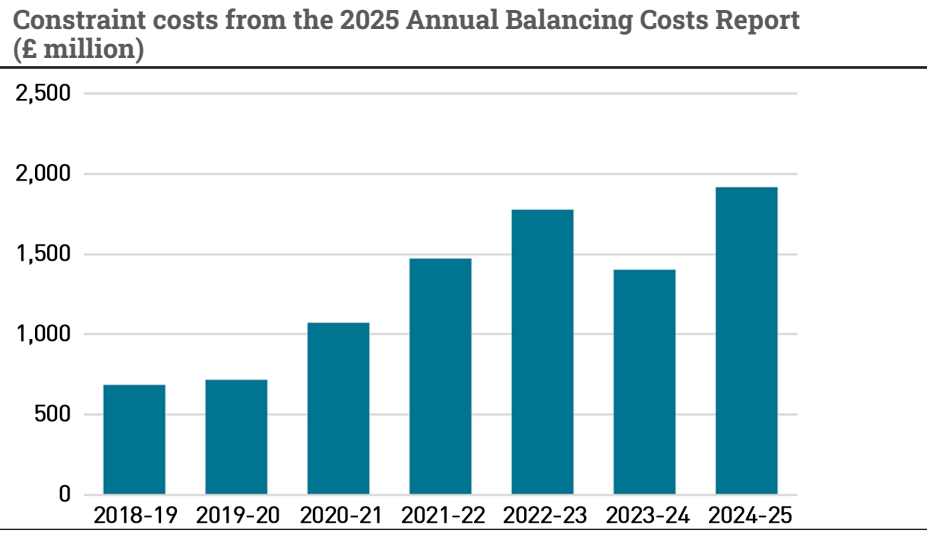
<sup>120</sup><https://www.neso.energy/data-portal/daily-balancing-costs-balancing-services-use-system>

<sup>121</sup> <https://www.neso.energy/industry-information/balancing-costs>

NESO says “this report provides a look back on recent balancing cost trends and drivers and provides a broad view of potential future balancing costs along with NESO’s role in minimising costs”.

No similar report for 2025-2026 exists.

These data are similar to neither the sum of thermal and constraint costs that are published individually nor in the breakdown of constraint costs and is also not similar to the constraint costs published in the BSUoS breakdown.



Source: NESO

It is not credible that these differences relate to the timing of settlement runs – indeed if such large differences were due to timing then it would be expected that the data would be updated once the settlement period is completed with appropriate disclosures to explain such adjustments. Where elements such as reactive power have been removed from some datasets but not others, this should be made clear.

The only area of commonality is the fact that all complete datasets show a consistent upwards trend in constraint costs over the period.



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[www.watt-logic.com](http://www.watt-logic.com) | [kathryn.porter@watt-logic.com](mailto:kathryn.porter@watt-logic.com) | +44 7958 775 745

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