Summer Outlook

Helping the electricity industry prepare for summer

April 2026

NESO
National Energy
System Operator

Welcome

Welcome to the National Energy System Operator (NESO) *Summer Outlook 2026* report. This report, at this volatile time geopolitically and in the energy markets, details our electricity security of supply assessment and operational expectations for the period from April to October 2026. It summarises our view of supply adequacy at peak demand, system flexibility at minimum demand and the wider energy market context. It is designed to support industry to prepare for summer.

Summer Outlook 2026 has been produced in the most volatile market context since 2022, with the closure of the Strait of Hormuz affecting energy prices around the world. This serves as a reminder that energy security, at a time when threats around the world are growing, remains front and centre in NESO's priorities. We are working closely with strategic partners to assess and monitor risks to the energy system for summer, and we have already begun our preparations for winter. We will publish our *Early View of Winter 2026/27* in June.

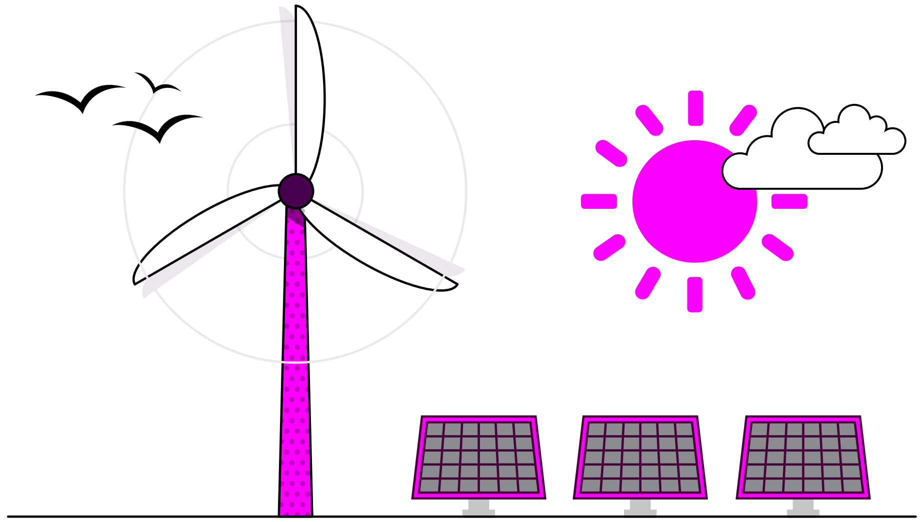
In summer, our attention turns to the challenge of managing minimum demand on the transmission system, when much of the demand is met by embedded generation. The complexity of operating the system at low demand is increasing, and we may need to use more of our tools, and use them more often, than in previous summers. Our analysis shows that low demand is increasingly driven by weather patterns – most notably solar photovoltaic (PV) generation – rather than underlying consumer behaviour. This has a range of consequences, including when the seasonal minimum is likely to occur and what time of day. This in turn affects the volume and type of actions we must take to balance supply, demand and system needs.

As the system evolves, we are continually developing and enhancing our capabilities. In recent years, we have transformed our tools to ensure we can reliably operate a zero-carbon network. We have delivered major new systems and world-first products and services to reduce balancing costs, cut carbon and support safe, reliable and efficient operations. We are confident we have the right tools to enable the safe, reliable and efficient operation of the system. This summer, we have taken further steps to develop our operational toolkit, including changes to the Demand Flexibility Service (DFS) to encourage consumers and industry to shift their energy use to times when weather conditions result in excess supply. This will enable households and businesses to support system flexibility by shifting demand, increasing the range of everyday actions available to our control room at times of low demand.

The daily operational surplus – that is, the excess supply once peak demand and our reserve requirements have been met - is typically higher in summer. Our assessment for this year is no different, suggesting that Great Britain will regularly be able to support exports to neighbouring countries if required. We will continue to assess margins against a range of possible scenarios and monitor market conditions, available supply and factors influencing interconnector flows throughout the season. National Gas publishes a separate *Gas Summer Outlook report*.

We will keep stakeholders up to date with any changes to our outlook through the NESO Operational Transparency Forum.

Kayte O'Neill
Chief Operating Officer
National Energy System Operator



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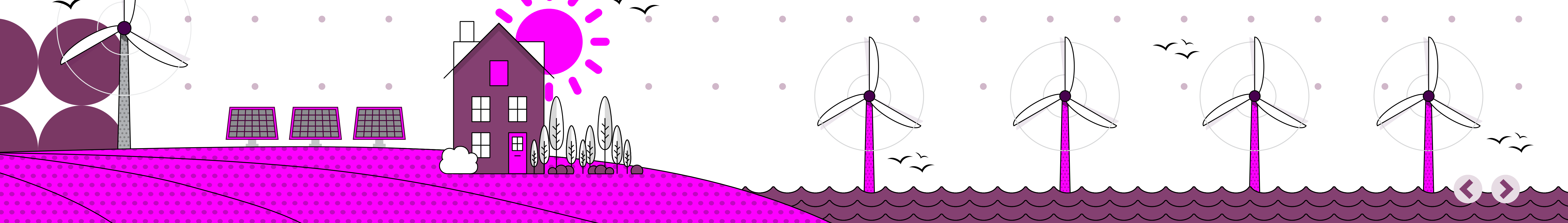


Summer Outlook 2026 at a Glance

1 Security of supply

We expect there to be sufficient supply to meet demand and our reserve requirements at all times this summer.

We expect to be able to support exports to interconnected countries if needed, and will continue to work closely with our neighbouring Transmission System Operators (TSOs), coordinating support and ensuring interconnectors remain mutually beneficial for flexibility and adequacy.

We continue to assess margins against a range of possible scenarios and are working closely with strategic partners to assess and monitor risks to the energy system for the summer. We have already begun our preparations for winter and will share our *Early View of Winter 2026/27* report with industry in June.

2 Managing low demand

We are confident we have the right tools to enable the safe, reliable and efficient operation of the electricity system, but we expect to see an increase in the number of everyday actions required to achieve this, compared with last summer.

Operating the system at low demand is complex – and the challenge is increasing as the drivers of low demand evolve and the duration of low demand periods extends. There may be periods when we need to use our full range of standard operational tools, including issuing a national Negative Reserve Active Power Margin (NRAPM) notice. NRAPM notices, although rare, are part of our standard toolset for managing the system.

3 Electricity markets

Market signals indicate that Great Britain is likely to be a net importer of electricity this summer. We would expect a typical pattern of electricity interconnector imports under both high gas price and low gas price scenarios.

High forecast nuclear generation availability in Continental Europe has resulted in lower wholesale prices – most notably in France – which should mean that Great Britain typically imports at times of peak demand.

The growth in renewable generation in Continental Europe suggests the potential for oversupply, particularly during solar peak hours, in key interconnected markets. This may result in scheduled imports into Great Britain even during low demand periods.

4 Operations and resilience

We continually innovate and adapt our systems and services to maintain the secure and efficient operation of Great Britain's power system.

As part of the ongoing development of our operational toolkit, we have updated the design of the Demand Flexibility Service (DFS) to incentivise consumers and industry to shift their energy use to periods of excess supply. This will increase the range of everyday actions available to our control room at times of low demand.

We continue to collaborate widely, working closely with strategic partners and industry, to ensure Great Britain's electricity system is ready for the coming season and resilient to the various conditions it may face.

Security of Supply

Operational surplus

We expect to have a sufficient operational surplus throughout the summer when considering a wide range of scenarios for demand, wind and solar generation, generator availability and interconnector flows. We expect Great Britain to be able to export to neighbouring countries regularly, if required.

Our analysis indicates that both peak demand and reserve requirements can be met throughout the summer period. Figure 1 shows a central forecast (the pink line) and a forecast range (the shaded pink plume) for the daily operational surplus this summer. To derive this, we simulate 30,000 variations around the central forecast using multiple scenarios for weather, demand, conventional generation availability, wind and solar generation and interconnector availability. This approach produces a forecast distribution of outcomes. Although there may be isolated days when the surplus falls outside this range, our latest analysis shows that a combination of factors – including interconnector exports, high demand, constrained generation or generator availability at the lower end of our modelled range – would be required for a low operational surplus to materialise; that is, for the initial supply provided by the market to approach our reserve requirement. Our advanced modelling shows the likelihood of such combinations of conditions on any given day is low. We plan for such occasions and have a range of operational tools to balance the system should they occur.

Our analysis also indicates that we will be able to export to neighbouring countries if required. However, power prices and capacity auction results suggest that Great Britain will, in aggregate, be a significant net importer across the summer (see page 14). We continue to monitor the wide range of factors that may affect supply in Great Britain or influence prices in neighbouring markets. We will closely monitor generator availability across the season, particularly in the shoulder months of April and October, which can experience higher demand relative to the rest of the summer period due to the credible risk of colder temperatures. While current market submissions indicate an adequate operational surplus during these months, significant downward revisions to generator availability could result in some tighter days. Planned generator outages are scheduled in line with expected seasonal demand patterns, resulting in a broadly stable operational surplus across the summer. Variation in the peak demand forecast is shown on page 7, while planned availability is detailed on page 8 and in the accompanying data workbook.

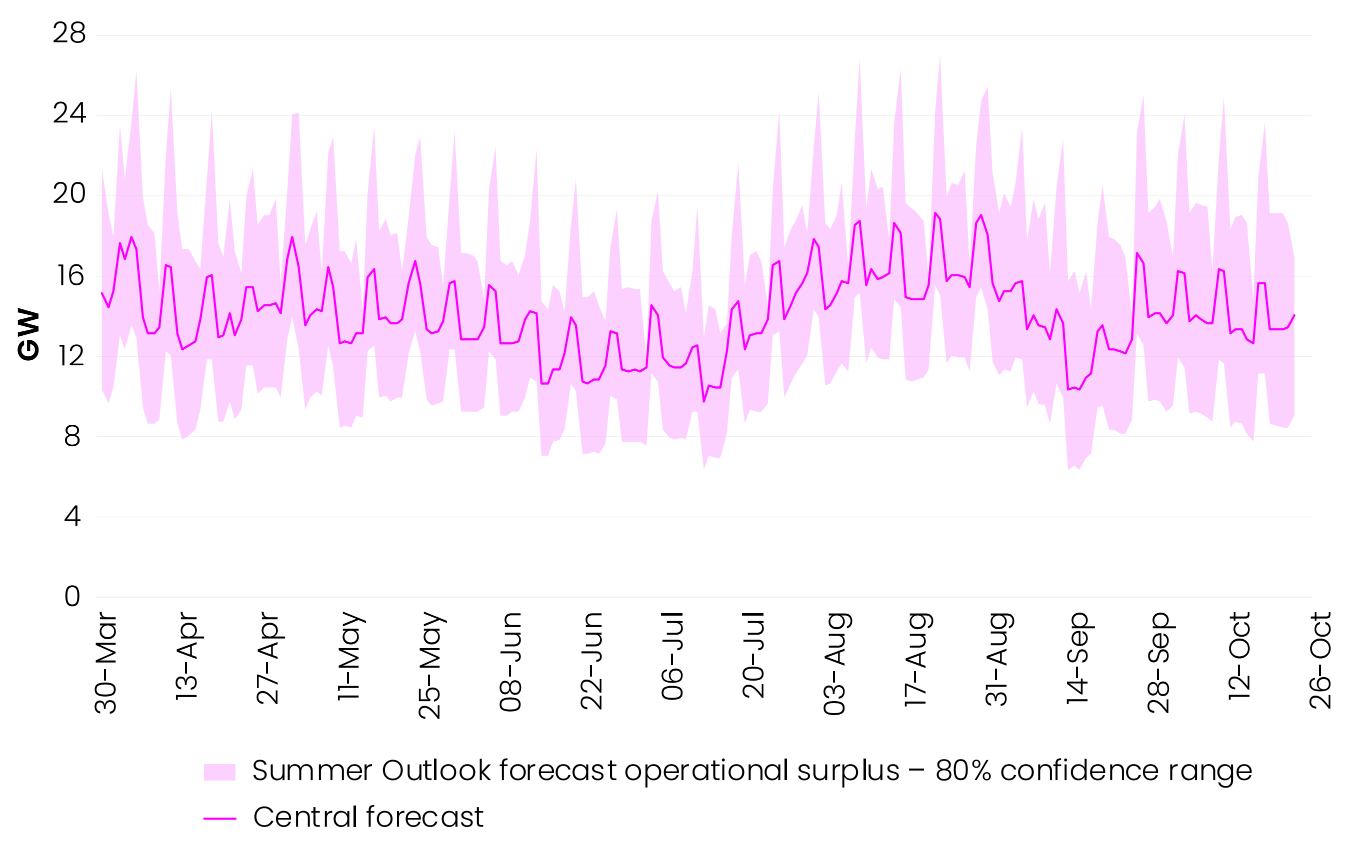


Figure 1: Forecast range for the daily operational surplus under different supply and demand conditions. The confidence bound shows the range between the 10th and 90th percentiles (p10 and p90).

Peak demand

Peak demand for summer 2026 is expected to be comparable to last summer, as increases in underlying demand are forecast to be broadly offset by growth in embedded generation.

Throughout this report, we forecast National Demand. This represents the demand observed on the transmission system, excluding the demand created by pumped storage, transmission-connected battery storage and interconnector exports. As the capacity of solar PV, wind generation and battery storage connected to distribution networks increases, so too does the variability in National Demand. Producing a meaningful demand forecast therefore requires explicit consideration of weather-driven variability. To address this, we simulate a wide range of weather conditions to generate a forecast range of potential outcomes. Figure 2 shows our forecast of peak National Demand and the credible range resulting from weather variation.

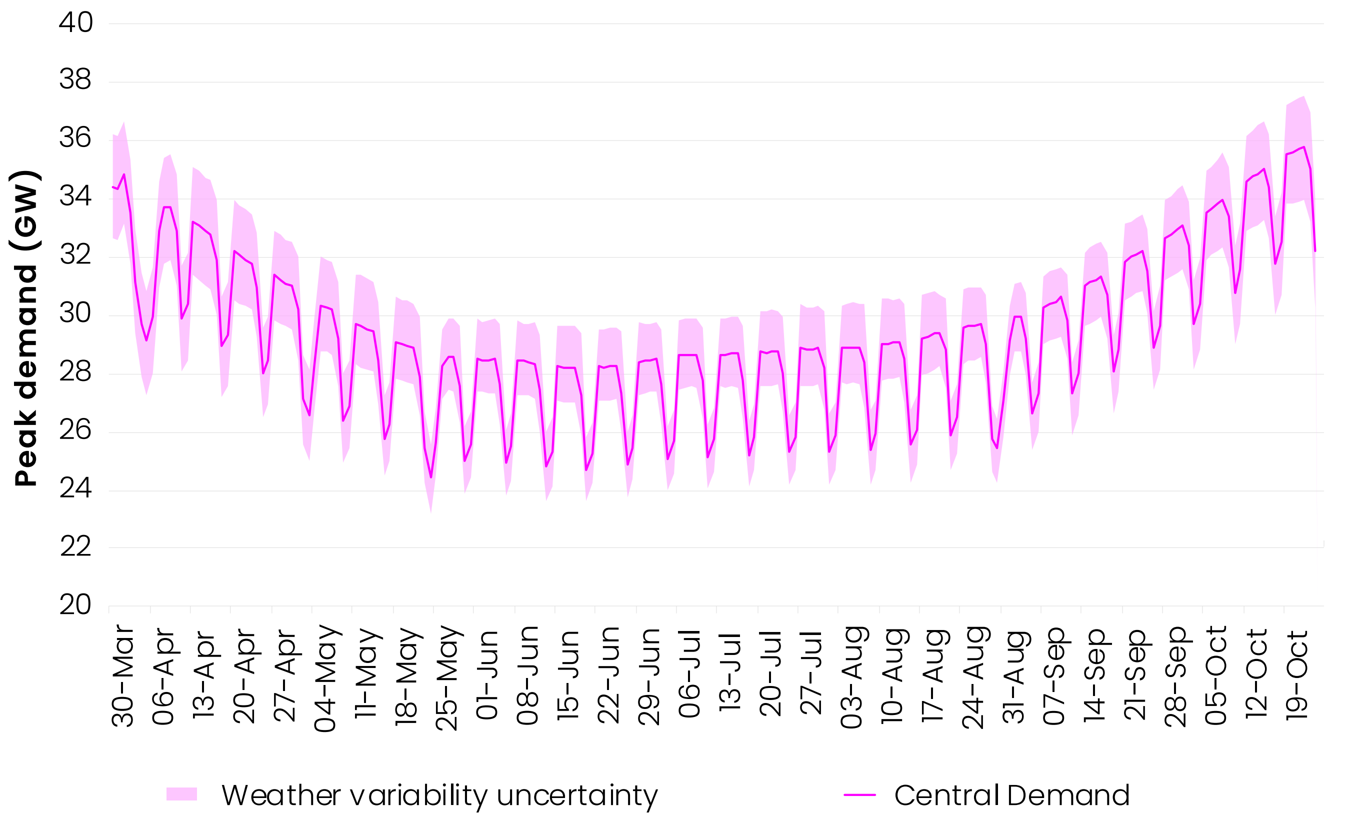


Figure 2: Daily peak National Demand for our central scenario and the impact of weather variation. The confidence bound shows the range between the 10th and 90th percentiles (p10 and p90) and does not include reserve.

Table 1 presents historic peak National Demand. A table showing minimum National Demand is provided on page 11. To support consistent year-on-year comparisons, we also calculate weather-corrected values by adjusting the observed data to remove the estimated effects of weather. A summary of the weather-corrected demand data is included in the accompanying data workbook.

Table 1: Historic peak National Demand between 1 June and 31 August

Year	Observed High Summer Peak Demand (GW)
2026 (forecast)	29.7
2025	29.7
2024	30.3
2023	29.9
2022	31.3
2021	32.9
2020	32.9
2019	34.9

Transmission System Demand (TSD) includes the additional demand contribution – for example, from storage assets or interconnector exports – that depends on prevailing weather and market conditions. Our use of National Demand not only removes effects that are challenging to forecast several months in advance but also enables direct year-on-year comparisons. Appendix C shows the relationship between different demand definitions.

Peak supply

Our analysis shows that there will be sufficient supply to meet peak demand – and our positive reserve requirement – at all times throughout the summer.

During the summer months, power stations typically undertake planned maintenance, as lower demand usually results in lower electricity prices. Figure 3 presents the current availability of conventional generation alongside the upper bound of our peak demand forecast range (defined in Figure 2) plus our reserve requirement. Our analysis indicates that, throughout the summer, there will be sufficient capacity to support exports during peak periods if required.

To assess the availability of supply throughout the summer, we need to consider both planned and unplanned generator outages. Planned outages are included in our supply assessment using the latest market submissions from generators. Actual availability may deviate from this schedule because of the rescheduling of existing outages, or because new planned or unplanned outages arise during the season. We use historic variation from expected availability to inform our forecast of how available supply is likely to change from our initial assessment. We undertake this analysis by fuel type to derive an unavailability factor. Currently, the lowest scheduled availability (and wind generation under average conditions) is 36.0 GW, occurring on 11 July, when peak demand is expected to be in the range 24.1 GW to 26.2 GW.

As a prudent system operator, we plan and prepare for a wide range of potential scenarios, working closely with the government, Ofgem and National Gas. We will continue to monitor generator availability and evolving risks in global energy markets that could affect available supply.

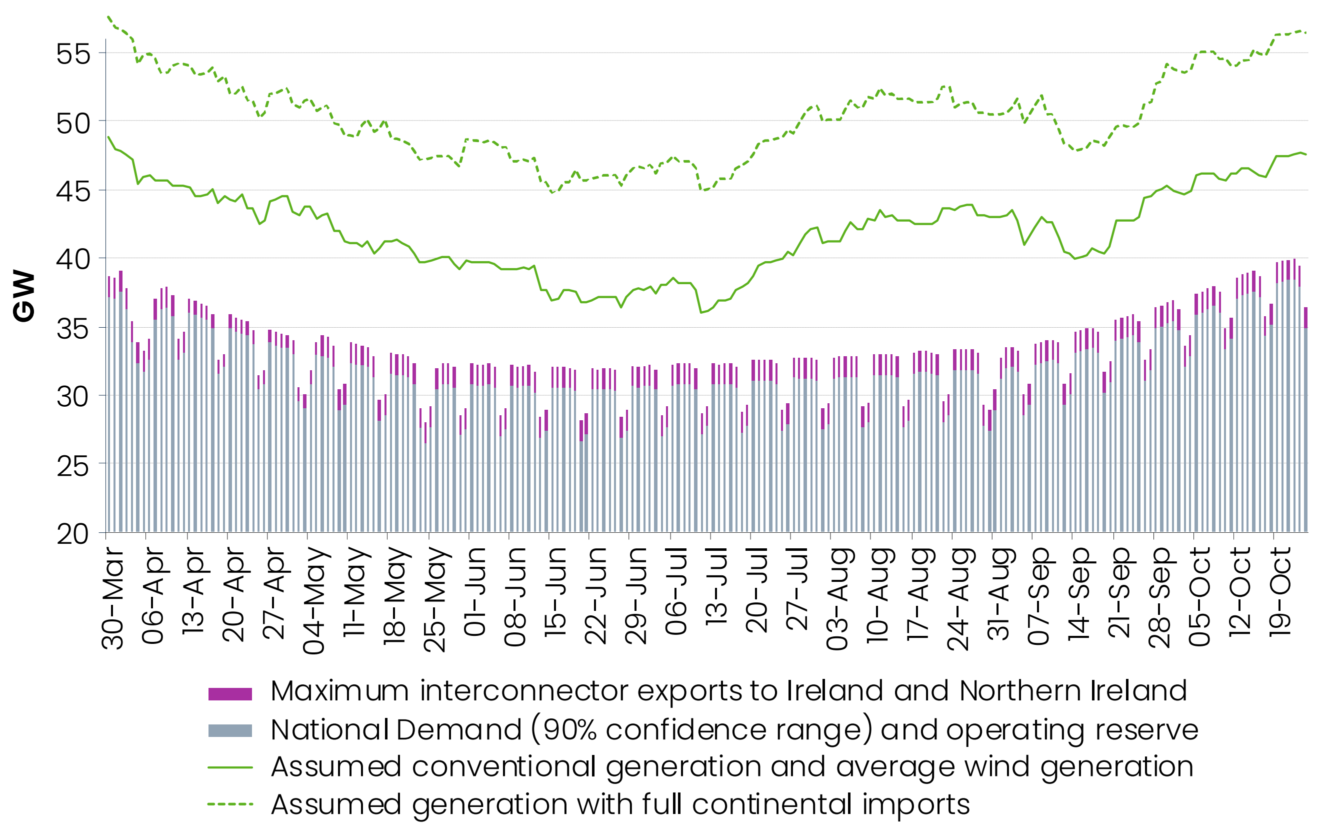


Figure 3: Day-by-day generation forecast for summer 2026 compared with the upper bound of the peak demand forecast range. Information on electricity market prices, and our expectation for the typical pattern of flows across the Summer, can be found on pages 14–15.

Managing Low Demand

The changing nature of demand

Low demand is increasingly driven by weather patterns. Solar irradiance is the main driver, overtaking low consumer use and wind generation, meaning there is potential for low demand days throughout the summer.

The growth in embedded renewable generation is increasing demand variability and broadening the range of weather patterns that lead to low demand on the transmission system. Figure 4 shows our forecast of the variation in daily minimum demand due to weather variation alone. As the role of weather-dependent embedded generation grows, the number of days on which the seasonal minimum could credibly occur also increases. It is credible that the seasonal minimum demand this summer could occur on any weekend or bank holiday between April and August. This means there is a greater likelihood (around a 75% chance) that National Demand will be lower than the current record low of 12.8 GW observed in May 2025.

Figure 5 separates the potential range of minimum demand for the overnight (which has historically seen the lowest demand) and afternoon periods. Growth in solar PV is increasing the range of possible daytime minimum demand throughout summer, leading to a growing probability that the lowest daily demand will occur in the afternoon. This occurred 37 times in 2025, compared with 12 in 2024, with 16 of these afternoon daily minimums occurring on a weekday. We expect the weekday minimum demand to occur increasingly in the afternoon. On any given day, there is a 10% probability that demand will fall below the forecast range shown in Figures 4 and 5.

What do we mean by 'low demand'?

The electricity transmission system is the physical infrastructure - includes towers, pylons and cables- used to move electricity nationally and regionally. Some generation connects to the National Electricity Transmission System (NETS), while others are connected to the regional or Distribution Networks. In this report, generation connected to the Distribution Networks is referred to as "embedded". Low demand on the NETS does not necessarily mean low underlying consumer use of electricity. When a high proportion of consumer demand is met by embedded generation – closer to the point of use – less electricity needs to move across the national transmission network. The lowest demand periods in Figures 4 and 5 occur when low consumer demand, such as at weekends and on bank holidays, coincides with high embedded generation.

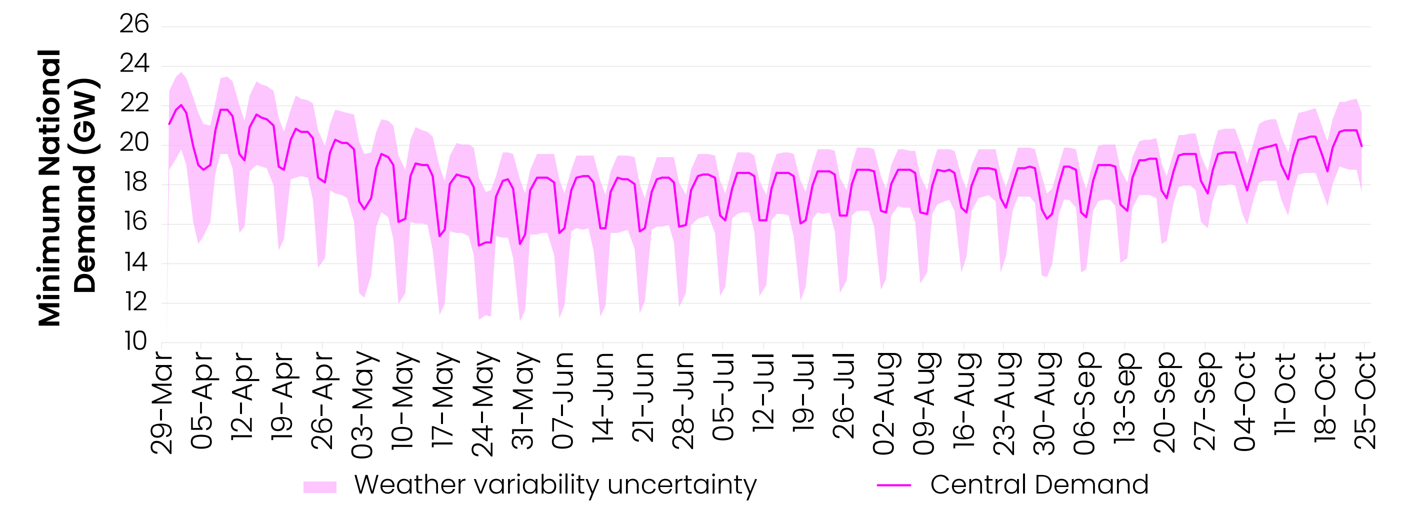


Figure 4: Daily minimum National Demand forecast. The confidence bound shows the range between the 10th and 90th percentiles (p10 and p90).

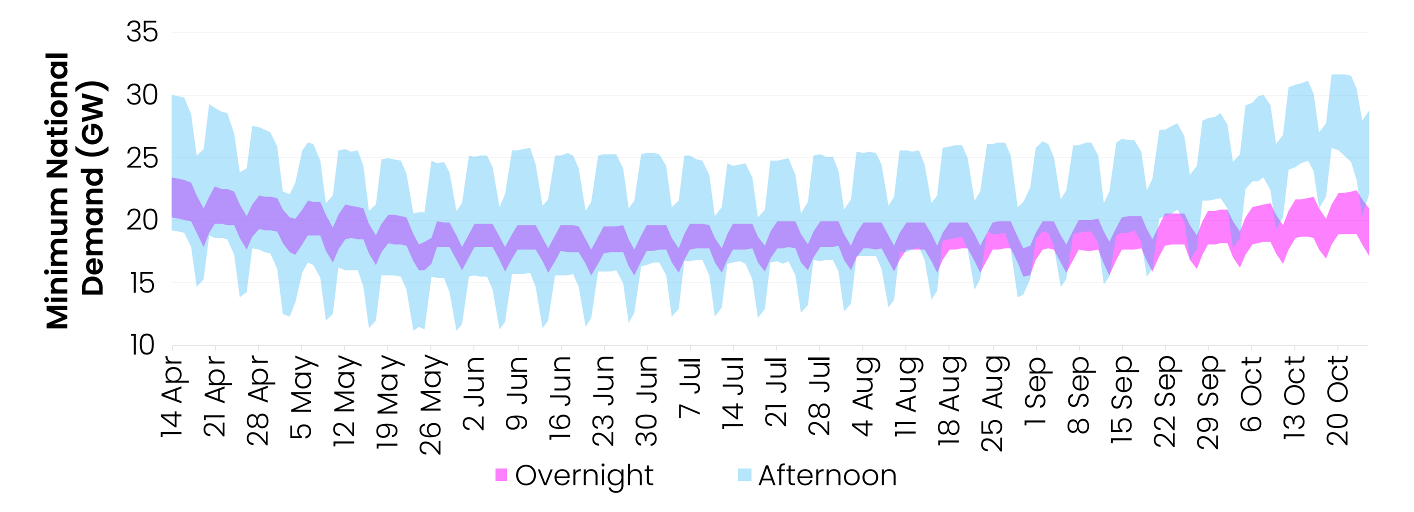


Figure 5: Daily minimum National Demand forecast by time of day. The confidence bound shows the range between the 10th and 90th percentiles (p10 and p90).

Operating the system at low demand

We are confident that we have the tools required to operate the system safely and reliably, but we anticipate an increase in the number of everyday actions required to do so. There may be periods when balancing supply, demand and system needs will require us to use our full range of operational tools, including system notices.

Operating the system safely and securely requires us to balance supply and demand, while meeting wider system needs, for example, maintaining stability, thermal constraints and voltage requirements. We have a range of standard operational tools at our disposal to achieve this. Figure 6 shows the lower bound of the forecast demand range (as defined in Figure 4) against high wind generation, scheduled inflexible generation, illustrative interconnector imports and an illustrative requirement for additional units to support system stability or provide reactive power.

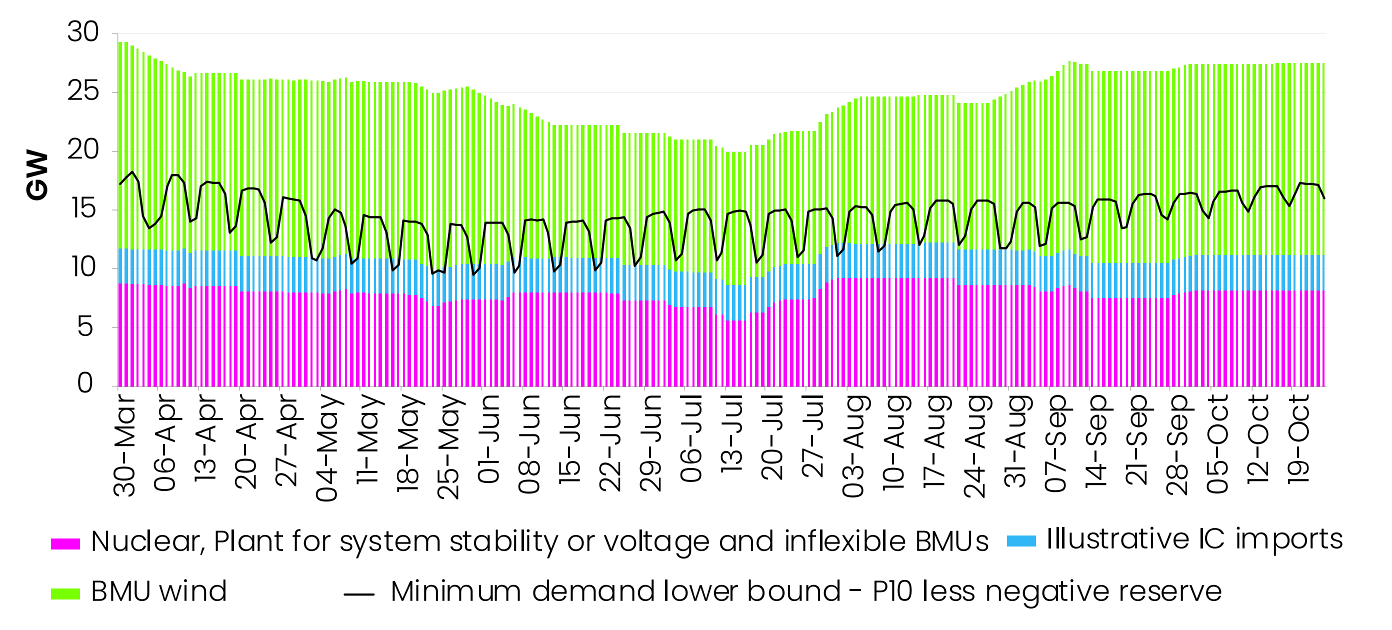


Figure 6: The lower bound (10% confidence level) of the forecast minimum National Demand against inflexible generation and illustrative wind and interconnectors. While it is not credible to expect demand at the 10% confidence level to occur every day throughout the summer, it may occur on individual days across the period.

The ongoing growth of battery storage, and year-on-year improvement in the availability of pumped storage, will enhance the potential to increase transmission system demand. Despite this greater flexibility, we forecast an increase in the number of hours when inflexible generation, units meeting system requirements, scheduled imports and wind output will exceed demand.

Our analysis suggests there may be some days this summer when we need to use our full range of standard operational tools, including issuing Negative Reserve Active Power Margin (NRAPM) notices.

Table 2: Historic minimum National Demand

Year	Overnight Minimum Demand (GW)	Daytime Minimum Demand (GW)
2025	13.8	12.8
2024	15.1	15.3
2023	13.6	14.8
2022	14.9	16.4
2021	16.3	17.4
2020	13.4	15.3
2019	15.8	18.3

What is a Negative Reserve Active Power Margin Notice?

At times of low demand, or in periods where less controllable generation connected directly to distribution networks makes up more of the supply, we might identify that we need some additional flexibility on the system. We may issue what we call a Negative Reserve Active Power Margin (NRAPM) notice. It's a way to tell power stations that we might need them to turn down output to retain our safety margin, and we'd expect them to respond. NRAPM notices are rare – a small number of local NRAPMs have been issued, and none at a national level. A local NRAPM signifies that inflexible generation will exceed demand, and the constraint limit, on a portion of the network. A national NRAPM would be issued if we forecast insufficient flexibility across the system. While rare, system notices are standard operational tools and do not indicate that supply or the system is at risk.

Extended low demand periods

The increasing role of weather in determining low demand periods is extending the duration of low demand events.

If high solar irradiance coincides with high wind generation, mild temperatures and low underlying consumer demand, it can result in extended periods of low demand. Figure 7 shows the expected National Demand if the weather conditions of the late May bank holiday in 2025 were repeated during the late May bank holiday in summer 2026. Under these conditions, we could see a minimum afternoon demand of 11 GW, with a prolonged period of low demand below 15 GW for approximately 12 hours.

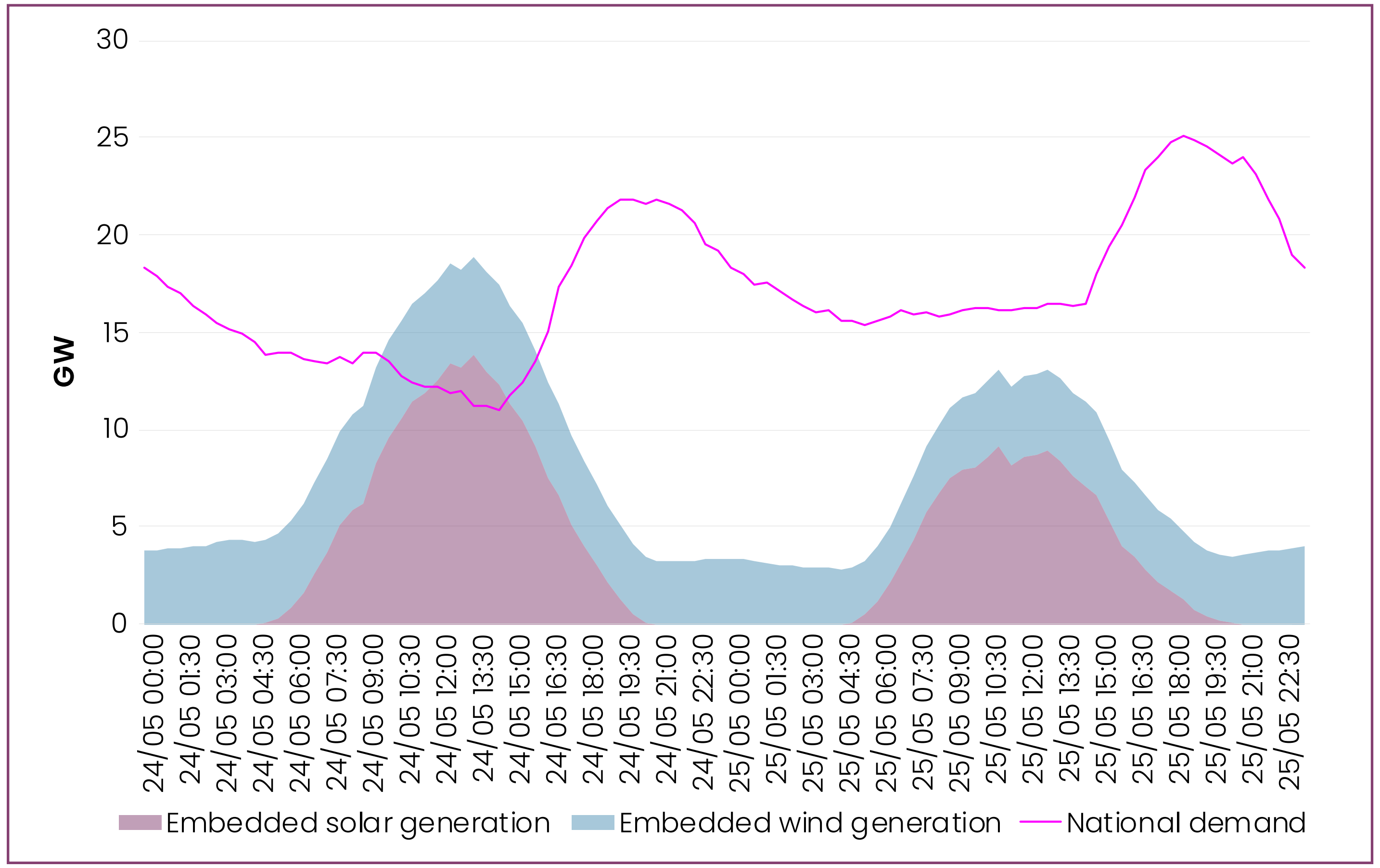


Figure 7: Example profile of National Demand over a weekend in May 2026 during a credible weather event

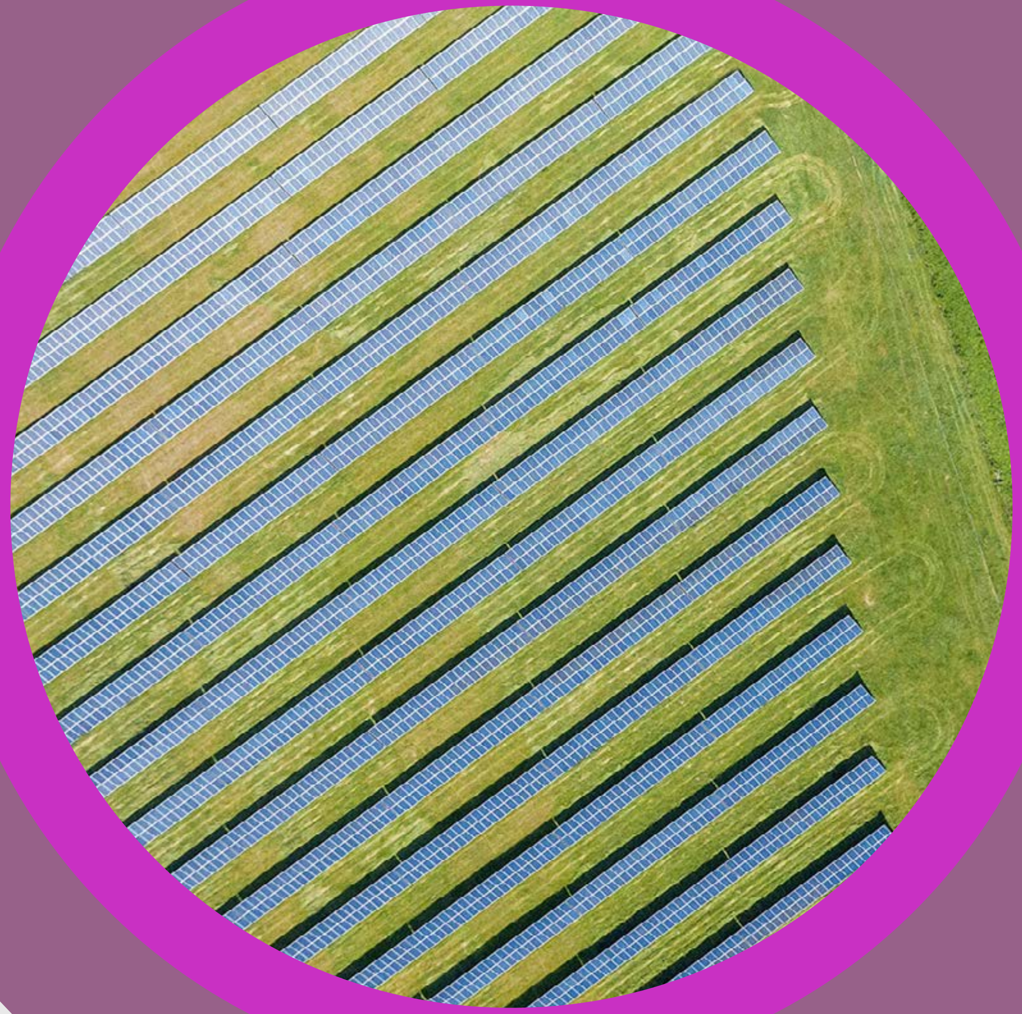
During these periods, we expect the growing battery storage fleet to provide significant within-day flexibility - both through regular cycling to help match supply and demand, and through the provision of vital system services such as fast-acting frequency response. During extended low demand periods, pumped storage and interconnector exports will be key sources of increased transmission system demand. As part of the ongoing development of our operational toolkit, we have updated the Demand Flexibility Service (DFS). Several changes to the service design – including the introduction of a negative margin element and lower capacity thresholds - will enable households and businesses to support system flexibility by shifting demand, while removing barriers to entry for smaller resources and renewable assets. The updated service will increase the range of actions available to our control room at times of low demand.

Why managing low demand periods is complex

The complexity of managing the electricity system increases at low demand. Balancing Mechanism (BM) actions to balance supply and demand (for example, reducing wind generation) changes network flows, which in turn alter voltage profiles and increase the need for support from reactive power providers. Lower prices mean fewer conventional generators self-dispatching, leading to lower system inertia.

To meet these needs, we may instruct additional generators in the BM. These units become functionally inflexible, creating a need for further reductions in generation elsewhere (for example through interconnector trading) to maintain the balance between supply and demand. Forecast uncertainty may require us to increase reserve and response holdings during these periods. The systems, operational tools, balancing services and network service procurements delivered by NESO in support of our zero-carbon ambition provide significant additional flexibility during these periods, resulting in cost savings for consumers and operational benefits for our control room (see our ‘Operational view’ on pages 28–31 for more details on these services).

Markets



Interconnected markets overview

Market signals suggest that Great Britain is likely to be a significant net importer from France and will typically import from other Continental European markets.

Electricity flows across interconnectors are primarily driven by price differentials, with electricity flowing to markets with higher prices. Baseload electricity prices in Great Britain for summer 2026 are £13–£70/MWh higher than in Continental Europe. The recent rise in gas prices has increased Great Britain's premium to neighbouring markets, reflecting the different role of gas-fired power generation in these markets. Prior to the start of the Middle East conflict on 28 February, prices suggested a typical pattern of interconnector imports. As such, we anticipate that Great Britain will be a net importer under both high and low gas price scenarios. Recent trends in the spread between Great Britain and neighbouring markets are provided in the accompanying *Summer Outlook 2026* data workbook.

Figure 8 shows how the premium in wholesale electricity prices has been reflected in interconnector capacity auction results, with import prices clearing significantly higher than export prices. While actual interconnector flows will be determined by prevailing conditions on the day, the capacity auction results indicate the premium that market participants are willing to pay for the right to flow power to Great Britain, on average, across the season. Prices for import capacity from France have risen since summer 2025, driven by stable French prices supported by strong nuclear generation. Meanwhile, the spreads across other markets have slightly reduced year-on-year. As such, we expect particularly strong net imports from France, while imports from the Netherlands, Denmark and Belgium may be more variable than last summer. Current prices suggest a typical pattern of exports to Ireland and Northern Ireland.

Our operational surplus analysis (see page 6) suggests that Great Britain has the ability to regularly support exports, leaving the system well placed to manage potential uncertainty.

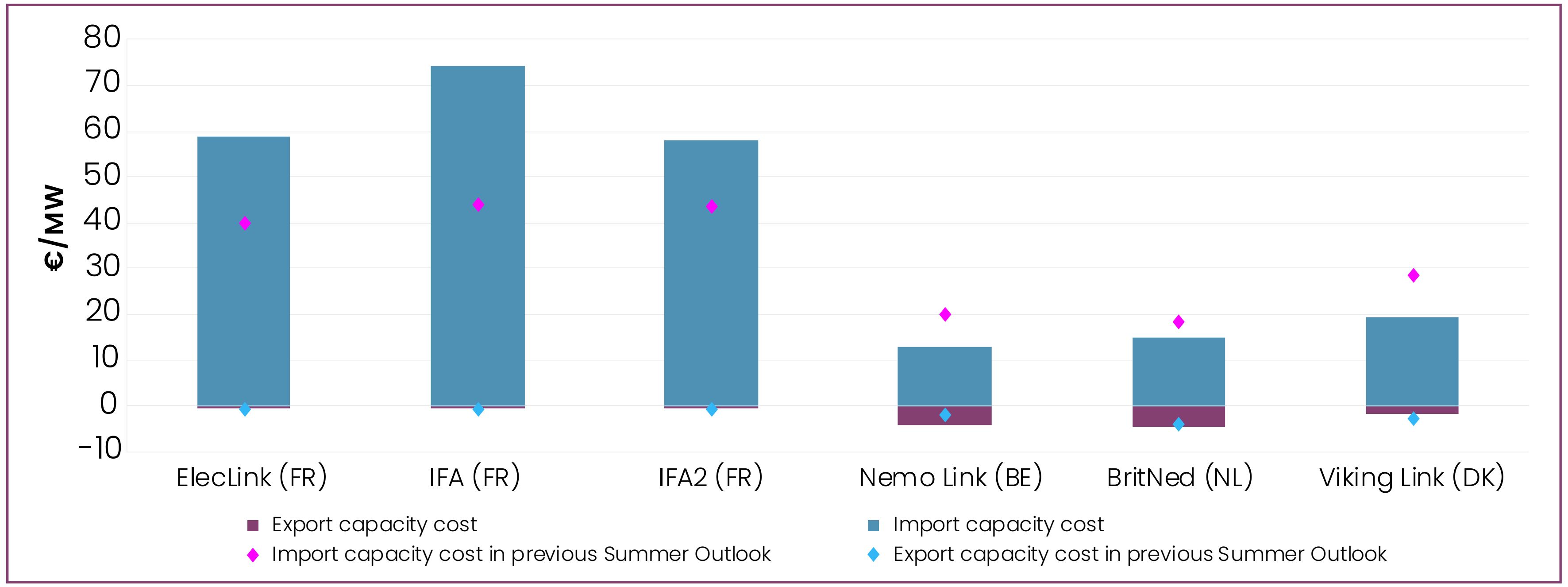


Figure 8: Summer 2026 interconnection capacity auction prices for interconnectors holding long-term auctions, compared with import and export capacity prices from summer 2025 (Source: JAO, Empire)

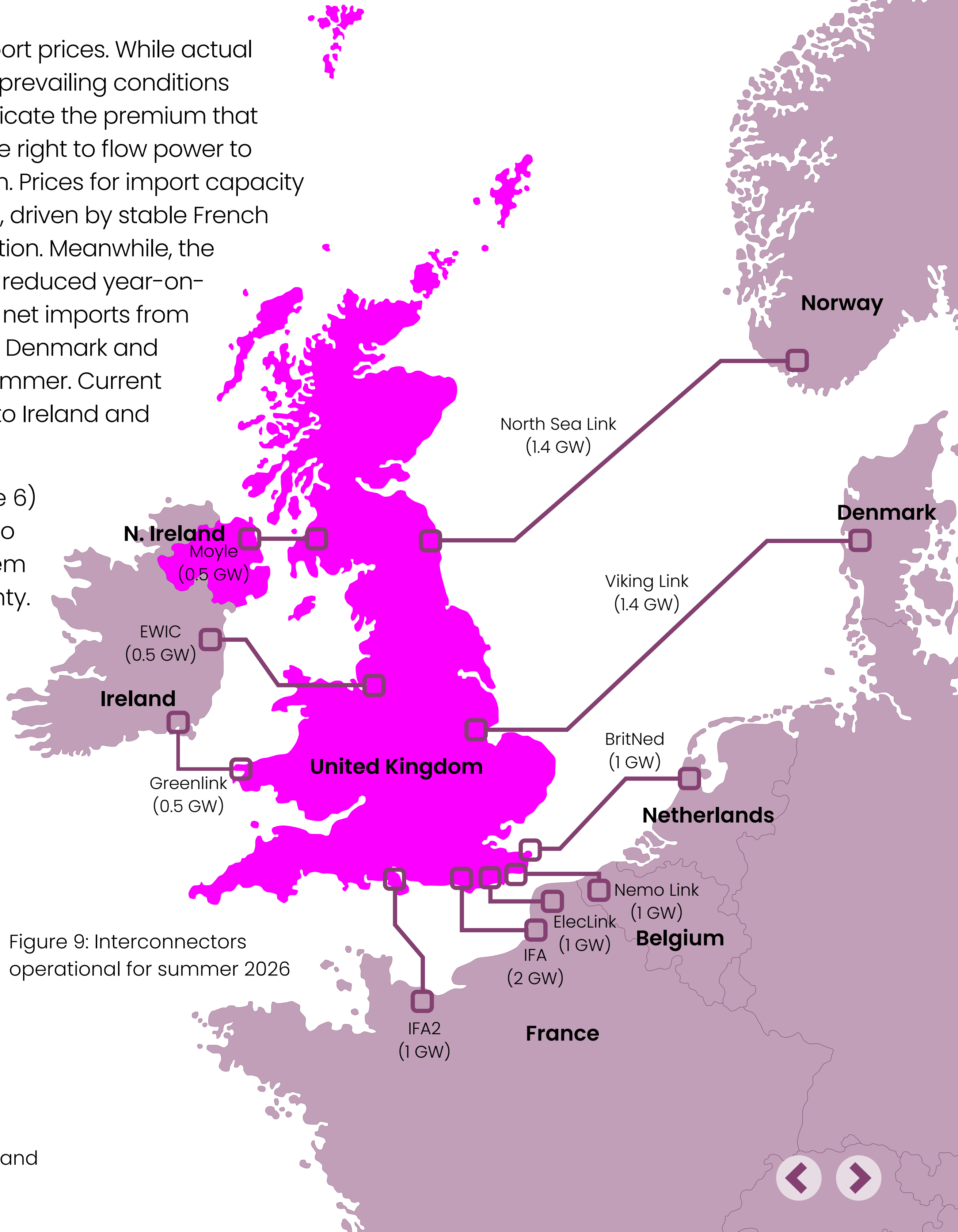


Figure 9: Interconnectors operational for summer 2026

Power markets

Significant growth in renewable generation, and high scheduled nuclear availability, suggest a growing potential for negative prices as a result of oversupply during solar peak hours.

Electricity prices in Continental Europe reflect high forecast generation availability, including strong nuclear availability in France. Figure 10 shows scheduled French nuclear availability for this summer compared with summer 2025 and the historic range. Allowing for revisions to this schedule, we still expect French nuclear production to be towards the upper end of the recent range. As a result, we expect France to be able to support a high level of exports to neighbouring markets, including Great Britain, throughout the summer.

Ongoing structural changes in European supply and demand, driven by growing renewable capacity, are reflected in prices. Figure 11 highlights the growing discount of peak contracts (7am–7pm) relative to baseload contracts (24 hours). This suggests a growing potential for negative-priced periods, particularly during solar peak hours. Periods of high solar irradiance in Great Britain are highly correlated with neighbouring markets. As a result, we expect to regularly observe scheduled imports on the interconnectors, even when demand is low. We will continue to work closely with our neighbouring TSOs, coordinating support to ensure interconnectors remain mutually beneficial for flexibility and adequacy.

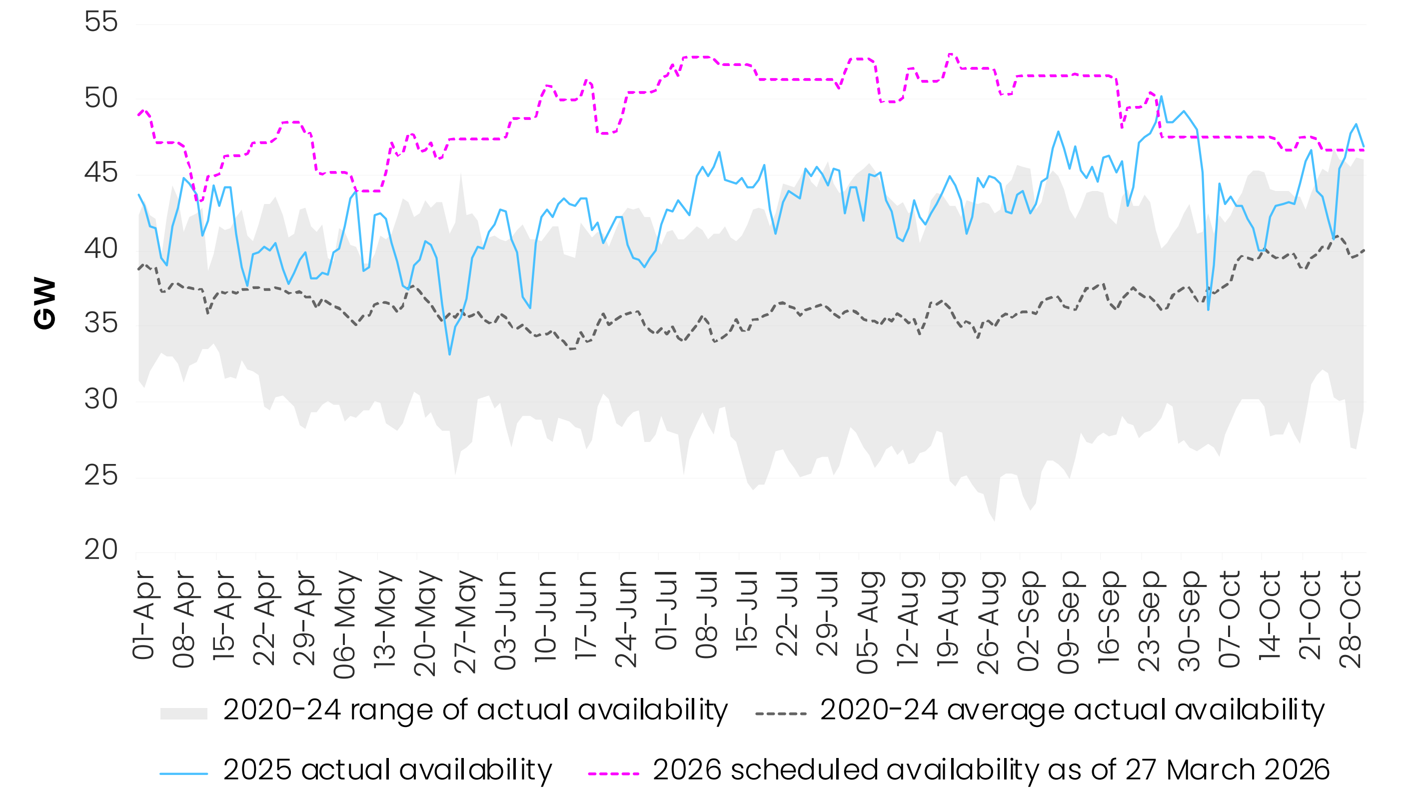


Figure 10: Scheduled French nuclear availability for 2026 against actual availability for 2020–2025 (Source: RTE)

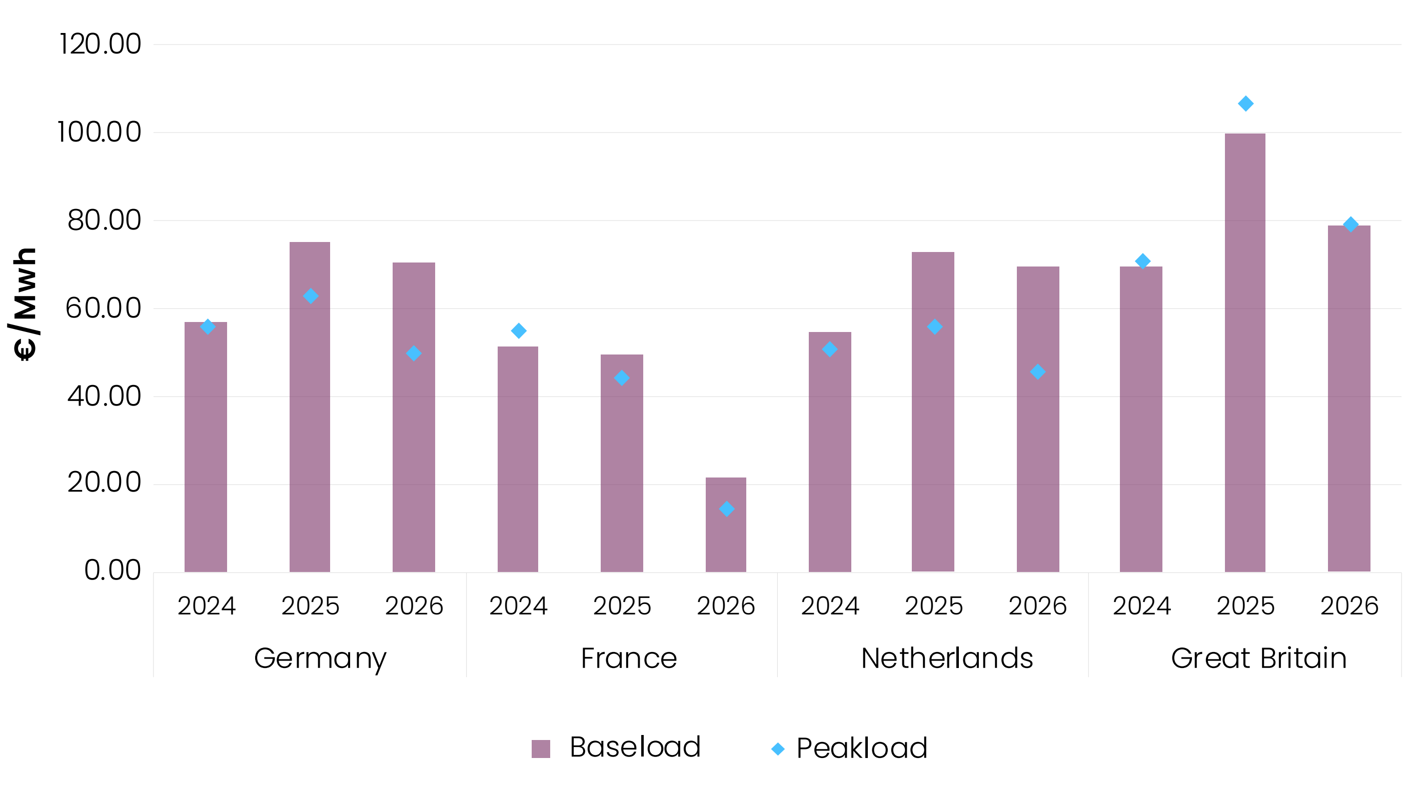


Figure 11: Q2 baseload and peak load prices for recent years, as of 1 March in each respective year (Source: Argus Media)

Gas markets

Compared with recent summers, there is a higher injection requirement to meet EU storage targets. We continue to work closely with strategic partners to monitor risks in global energy markets.

European gas storage was 28% full on 27 March. This is 6 percentage points below 2025 levels and 31 percentage points below 2024 levels. EU member states can meet the 90% filling target at any point between 1 October and 1 December, with allowances to deviate by up to 10 percentage points in difficult conditions.

Europe's reliance on liquefied natural gas (LNG) has grown in recent years. High LNG imports will be necessary to refill European gas storage this summer. This means that European gas, and therefore power prices, will remain sensitive to supply-side disruptions in the global LNG market.

Gas prices for summer 2026 in both Great Britain (National Balancing Point (NBP)) and Europe (Title Transfer Facility (TTF)) rose significantly at the start of March following the effective closure of the Strait of Hormuz, affecting around 20% of global LNG production, with most of these volumes usually flowing to Asia. We will continue to work closely with the government, Ofgem and National Gas to monitor energy markets, assessing how geopolitical events, evolving policy mandates and price signals may affect available supply. An assessment of gas security of supply this summer can be found in National Gas' separate *Gas Summer Outlook* report.

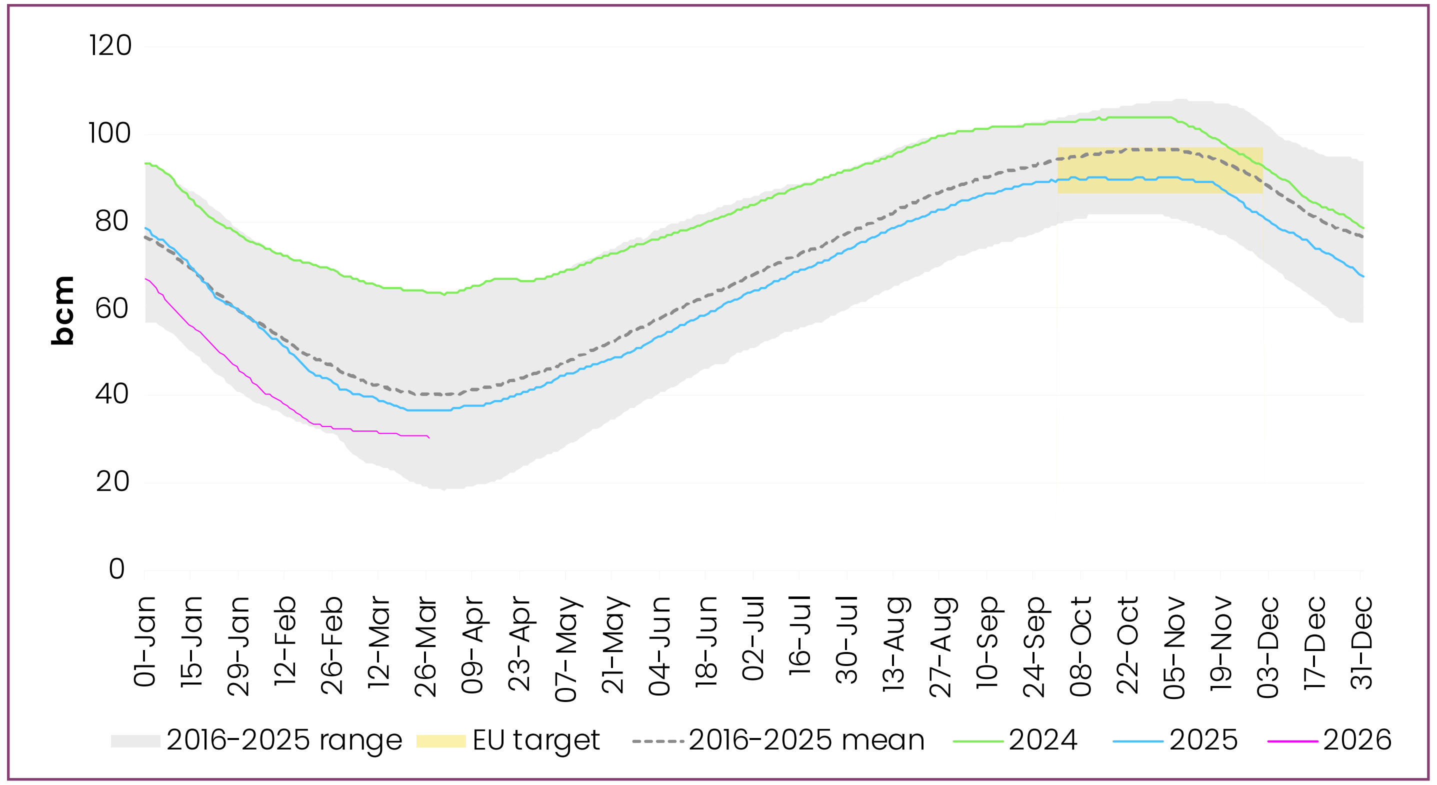


Figure 12: Aggregated EU gas storage (Source: GIE)

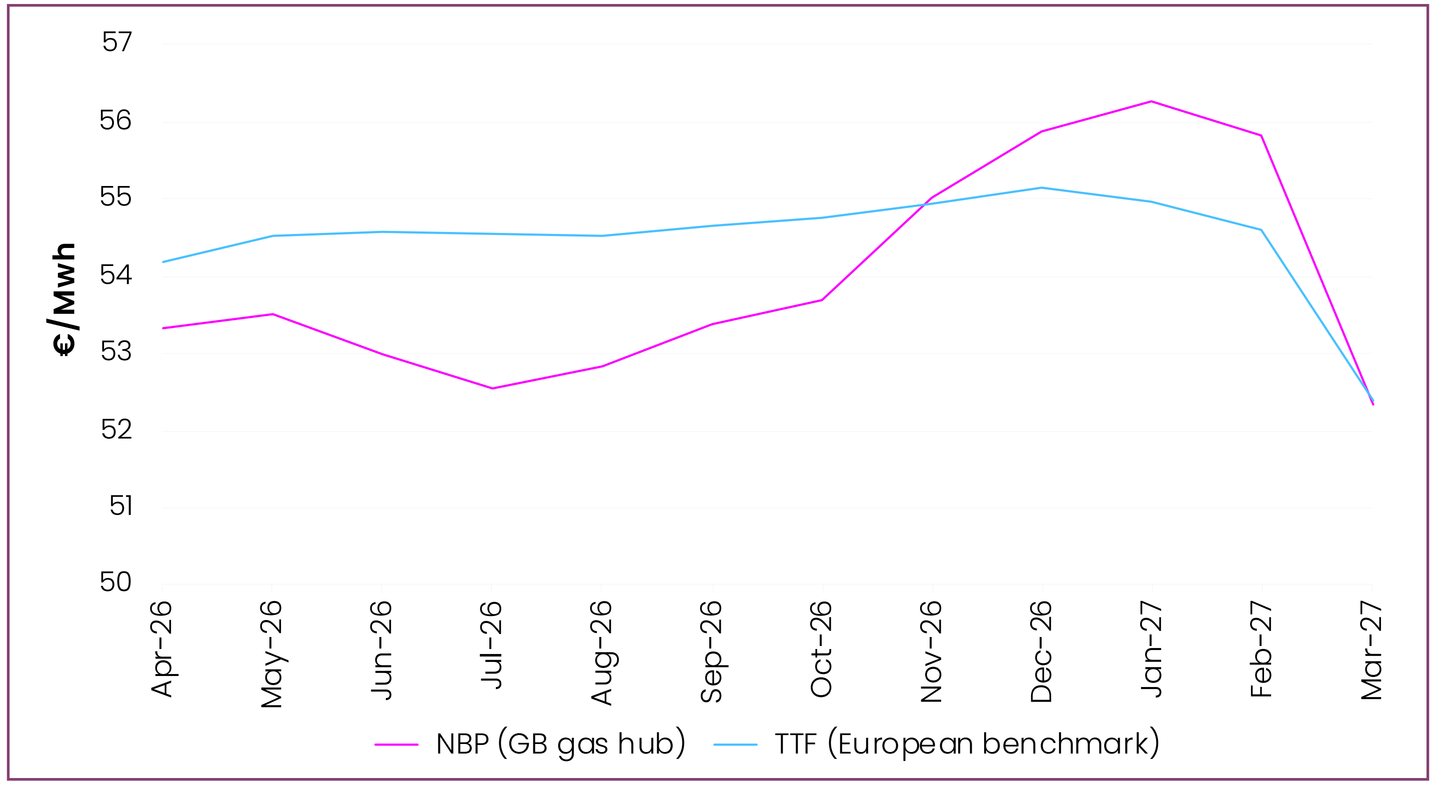


Figure 13: Forward gas prices in Great Britain (NBP) and the equivalent European benchmark (TTF) as of 27 March 2026 (Source: ICE)

Operations and Resilience

Resilience and industry readiness

We continue to collaborate widely, working closely with strategic partners and engaging across the industry to ensure Great Britain's electricity system is ready for the coming season, and resilient to the various conditions it may face.

As NESO, we have a critical role in strengthening the resilience of the whole energy system, turning insight into coordinated, prioritised action that reduces risk and builds capability across the system. We deliver this through analysis, assessments, reviews, emergency exercises, and plans that drive tangible improvements with our partners, catalysing change through an enhanced understanding of risks within an increasingly complex and interconnected energy system. Identifying, understanding and mitigating the possible risks facing all parts of the energy system requires us to collaborate widely across the energy sector and beyond.

Our work involves:

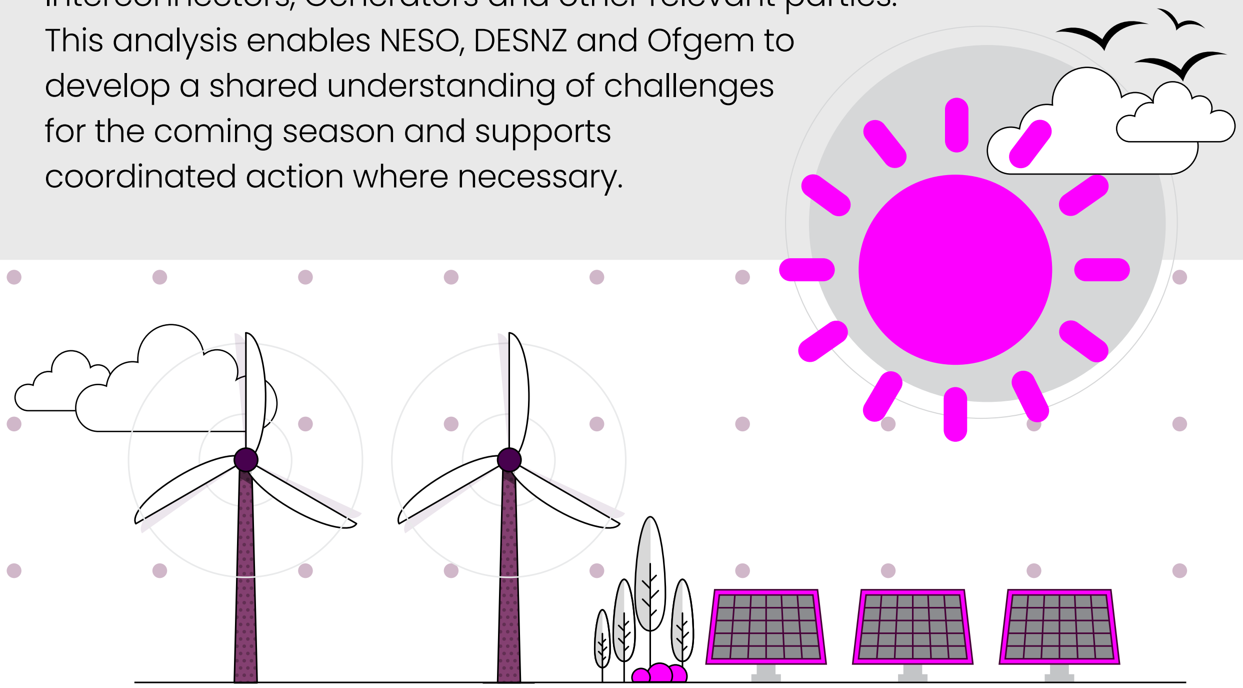
- undertaking whole energy risk assessments to identify vulnerabilities in the energy system
- conducting whole energy resilience assessments with industry partners, taking account of multiple energy vector interactions
- coordinating preparation for emergency response across the energy sector and investigating specific events and emergencies across the system
- providing insight and recommendations on security of supply through seasonal outlook reports, Capacity Market modelling, Gas Security of Supply Assessments and Resource Adequacy Studies
- continuing to lead industry activities to ensure all stakeholders are on track to meet the new Electricity System Restoration Standard (ESRS), which goes live on 31 December 2026

Seasonal readiness

To provide comprehensive whole energy reviews, analysis and insight, we collaborate with stakeholders and strategic partners to ensure industry readiness and preparedness for a range of potential incidents and emergencies which could impact the whole energy system.

The Electricity System Operator Licence (C7 Part E) and the Gas System Planner Licence (C6 Part E) require NESO to assess whole energy industry readiness ahead of each season, in cooperation with electricity and gas stakeholders.

Our engagement process provides insight and analysis considering the National Electricity Transmission System, National Gas Transmission System, Distribution Systems and Networks, Gas and Electricity Interconnectors, Generators and other relevant parties. This analysis enables NESO, DESNZ and Ofgem to develop a shared understanding of challenges for the coming season and supports coordinated action where necessary.



Future readiness

We continue to innovate and adapt to operate a rapidly changing electricity system safely and efficiently. The *Operability Strategy Report* defines future system needs, while the *Markets Roadmap* sets out how market-based solutions will meet these needs in the most efficient way.

Operability Strategy Report

The electricity system is undergoing a fundamental transformation, requiring a corresponding shift in how it is operated. As the generation mix continues to evolve, we monitor and forecast system needs, define requirements and ensure the correct tools are in place for system operation. From large-scale offshore wind to domestic solar panels and increasing demand-side participation, integrating newer technologies is critical to ensuring safety, reliability, lower consumer bills and reduced carbon emissions.

To help forecast requirements and develop solutions for future operational challenges, NESO publishes an annual *Operability Strategy Report*.

We have already delivered a range of new systems, products and services. Our stability and voltage pathfinders have reduced reliance on fossil-fuelled generation for critical transmission system services. We have also delivered new frequency response services fit for operating a clean power system and are developing groundbreaking system operability solutions for within-day flexibility to help balance the system.

Electricity Markets Roadmap

NESO's balancing services markets are crucial to facilitate the government's Clean Power 2030 ambition and ensure the capabilities and market design needed for secure, low-cost and low-carbon system operation. Efficient design and operation of balancing services markets are essential to reduce costs for consumers while maintaining system security.

Reforming markets to be more efficient, accessible and liquid is crucial to meeting future system needs in the most cost-effective way. This requires NESO to provide a clear view of how these markets will develop.

The *Markets Roadmap*, published in March 2026, sets out plans for the markets owned and operated by NESO. It explains what NESO is doing to reform its markets and why. The roadmap details our objectives, design principles and plans to reform and evolve our markets. It consolidates and presents information clearly to support investment and build stakeholder confidence. The report also sets out the vision for response, reserve, thermal, voltage, stability and restoration markets, revenue stacking and the Balancing Mechanism.

Market Facilitator

As part of ongoing work across the industry to better align flexibility markets and reduce barriers to participation across NESO and Distribution Network Operators (DNOs), Elexon has been appointed as the Market Facilitator. The Market Facilitator is intended to be a single expert entity responsible for aligning local and national markets and reducing friction for providers seeking to access them.

Elexon's Market Facilitator went live on 12 December 2025, and published a delivery plan covering 2026 to 2028, focused on simplifying access and improving coordination and stacking opportunities across electricity networks. NESO will continue to engage with Elexon, DNOs and wider market participants to support the development and delivery of these activities in the interests of consumers and system benefits.

Summer 2025 Retrospective

How demand compared with our expectations in the *Summer Outlook 2025*

What we said in the *Summer Outlook 2025* report	What happened
Peak demand for summer 2025 is expected to be slightly lower than last summer's weather-corrected outturn, due to the growth of embedded generation.	Peak demand for summer 2025 was, on average, lower than summer 2024 and was well captured by our forecast range. Peak demand across the summer was generally lower than our central forecast due to warmer-than-average weather conditions. See Figure 14 for details.
The late May bank holiday has the greatest probability of extremely low demand (below 14 GW). The lowest daily demand could credibly occur on any weekend between May and late August.	The minimum demand over summer 2025 occurred during the afternoon on the Sunday of the late May bank holiday weekend. A National Demand below 14 GW was also observed on Saturday 9 August (13.2 GW) and Monday 25 August (13.8 GW), showing that the potential for extremely low demand days persisted throughout the season
Year on year, there is a growing probability that the lowest daily demand will occur in the afternoon. The minimum demand forecast range by time of day (Figure 5 in the *Summer Outlook 2025* report) suggested that weekends were significantly more likely to observe afternoon minimum demands.	Minimum demand occurred in the afternoon 37 times in 2025 compared with 12 times in 2024. This was not limited to weekends; minimum demand also occurred in the afternoon on 16 weekdays.
The wider range of weather patterns that result in low demand has increased the probability (to approximately 50%) that we will observe a new record low National Demand (below 13.4 GW) this summer. A combination of high solar irradiance, high wind and mild temperatures – can lead to extremely low demand and extended low demand events.	Great Britain recorded a new record minimum National Demand of 12.8 GW on Sunday 25 May. National Demand on this day remained below 15 GW for over 6 hours between 8:30am and 3pm.

Peak demand

The wide range of weather patterns experienced throughout the summer leads to large variability in daily peak demand. Predicting weather-dependent variables over extended time horizons requires the use of a confidence range. The pink plume in Figure 14 reflects the modelled variability of daily peak demand. Outturn peak demand was broadly within this range throughout the season. While the modelling captured seasonal effects well, there were occasional overestimations of both weekend and weekday peak demand across the high summer period.

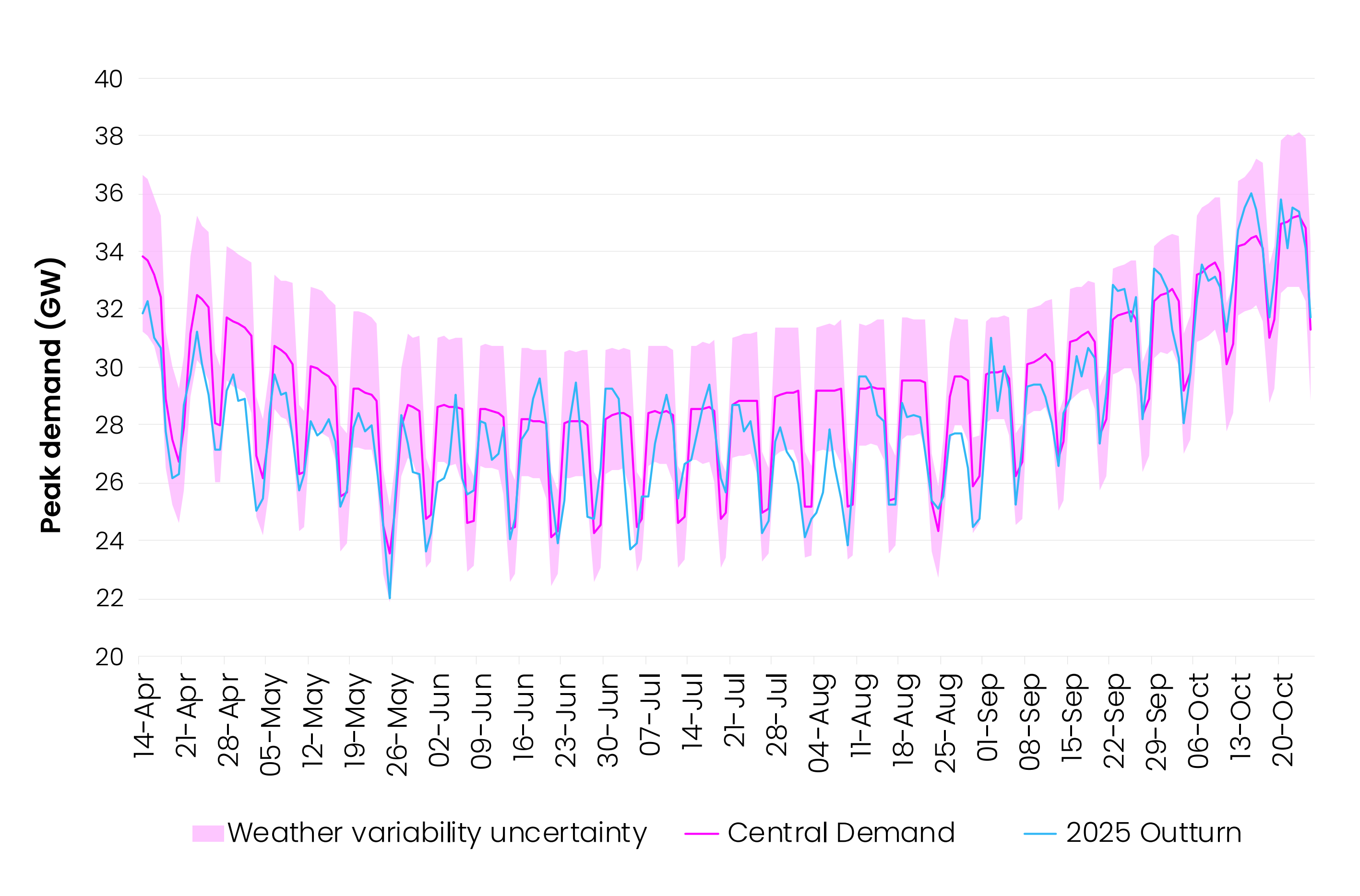


Figure 14: Peak demand forecast for summer 2025 compared with peak outturn (actual outturn has not been weather-corrected)

Minimum demand

The pink plume in Figure 15 shows the modelled variability of daily minimum demand against the outturn. The central forecast was well calibrated, and the magnitude and frequency of low demand periods were well captured by the modelling, with 10% of days falling below the forecast range and 18% above the forecast range (compared with an expected 10%). The modelling accurately assessed the potential for record minimum National Demand and the year-on-year increase in afternoon minimum demand periods.

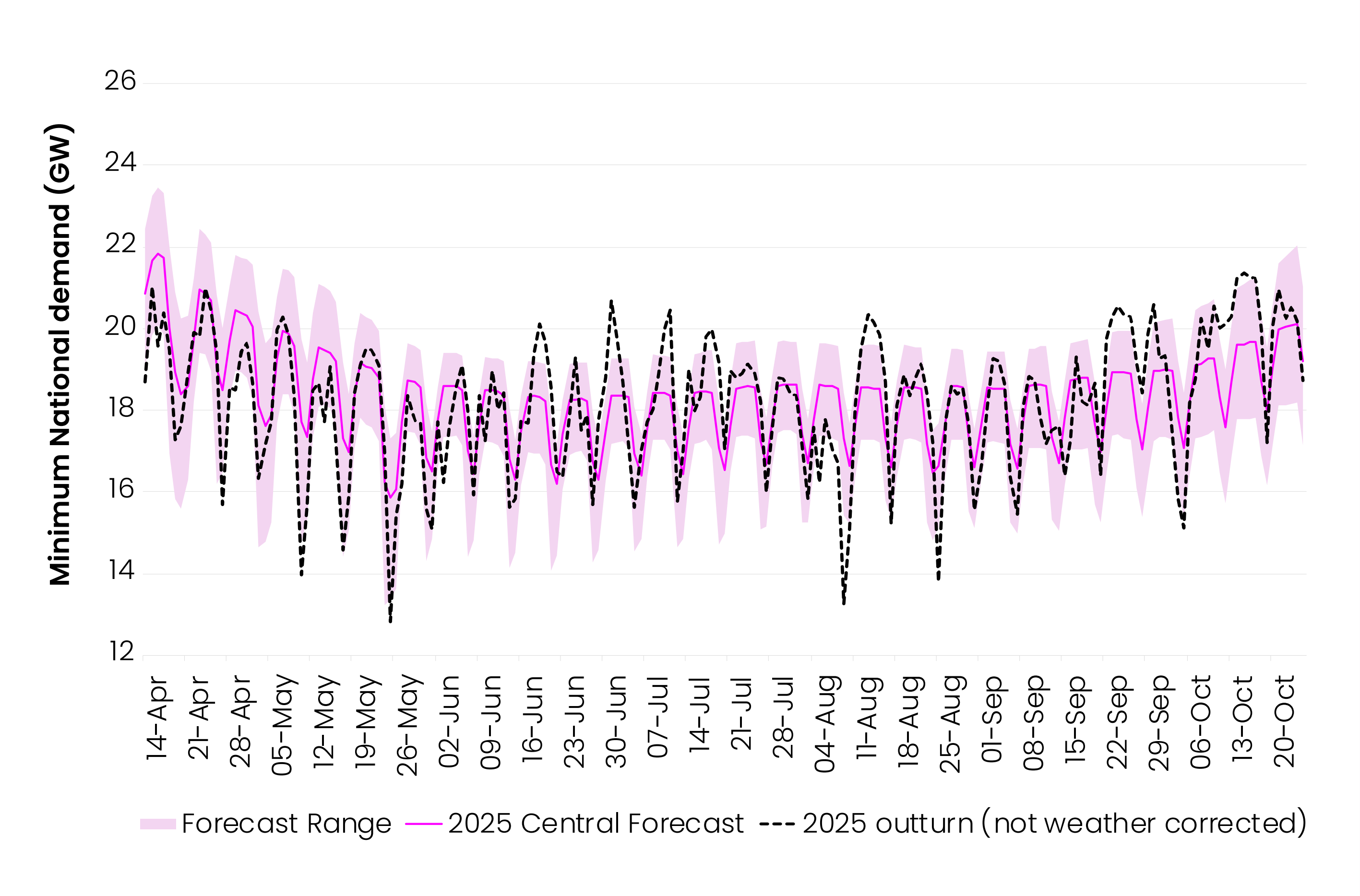


Figure 15: Daily minimum demand forecast for summer 2025 against the summer 2025 minimum outturn (actual outturn has not been weather-corrected)

How market behaviours compared with our expectations in the *Summer Outlook 2025*

What we said in the *Summer Outlook 2025* report	What happened
We expect to see strong net imports into Great Britain. Baseload electricity prices in Great Britain for summer 2025 were £15–£40/MWh higher than in Continental Europe at the time of publication of the Outlook.	Great Britain was a significant net importer from Continental Europe over the summer and a significant net exporter to Ireland.
Oversupply in neighbouring markets may result in interconnector imports, even when demand in Great Britain is low.	High wind generation in Great Britain, coupled with low irradiance across Europe, resulted in scheduled exports at the time of the record minimum National Demand of 12.8 GW. Day-ahead scheduled interconnector imports were observed on Saturday 9 August and Monday 25 August when demand was below 14 GW.

Interconnector flows

Adequate supply in interconnected markets resulted in interconnector imports into Great Britain throughout the summer. Reciprocal support between European TSOs maintained an efficient and mutually beneficial position across markets. In line with our assessment, Great Britain remained a strong net importer from France and Norway – and a significant net exporter to the Integrated Single Electricity Market (ISEM) for Ireland and Northern Ireland – in all periods. Overnight (7:30pm to 7am) and peak (5pm to 7:30pm) flows to Belgium, the Netherlands and Denmark were more variable.

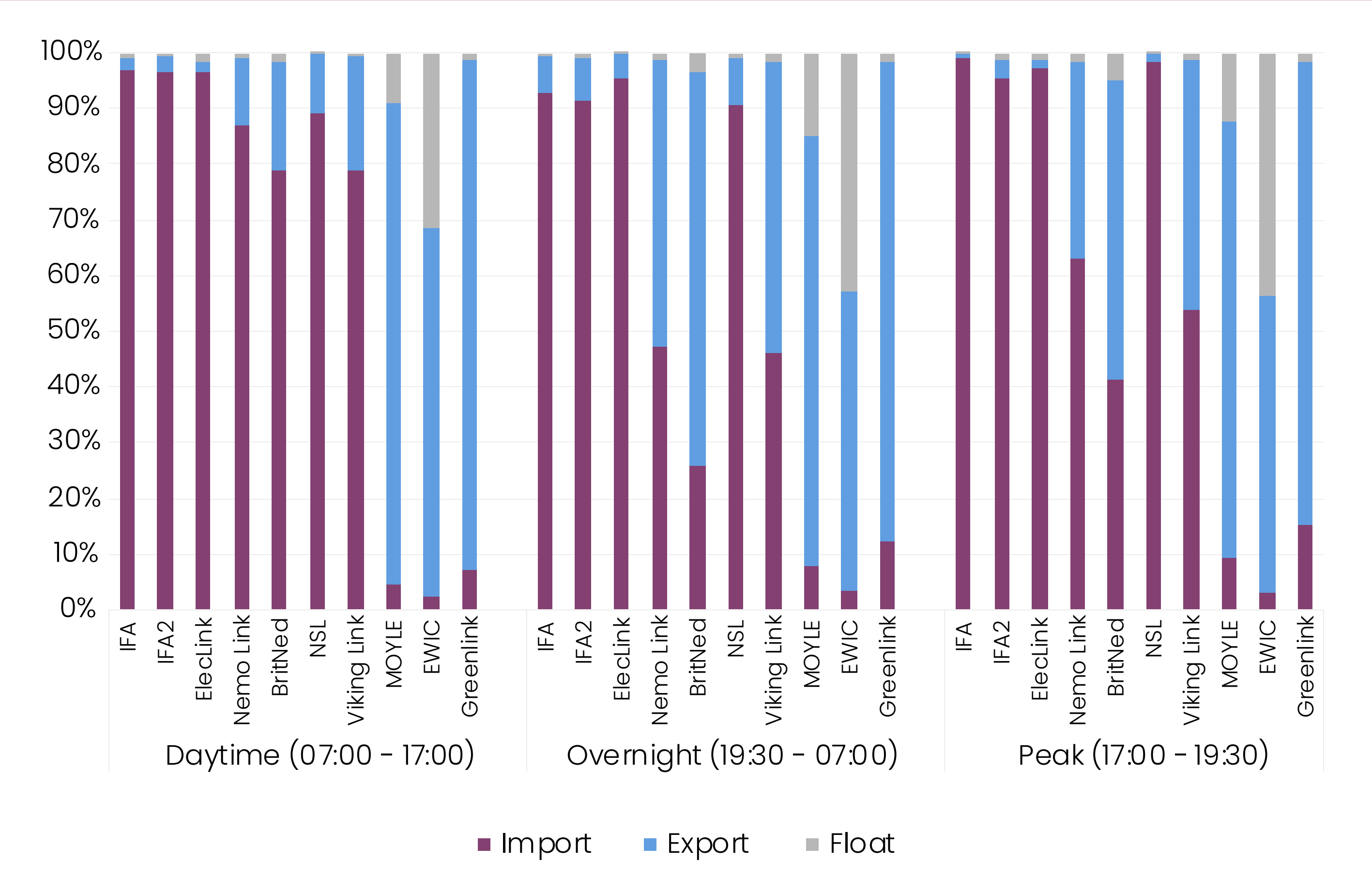


Figure 16: Proportion of periods interconnectors were importing and exporting during summer 2025

Prices

The high levels of nuclear generation identified in our analysis, combined with growth in renewable generation, resulted in lower wholesale prices in interconnected markets. This led to the typical pattern of daytime imports identified in Figure 16. The daily baseload power price in Great Britain, the ISEM for Ireland and Northern Ireland, and Continental European markets is shown in Figure 17.

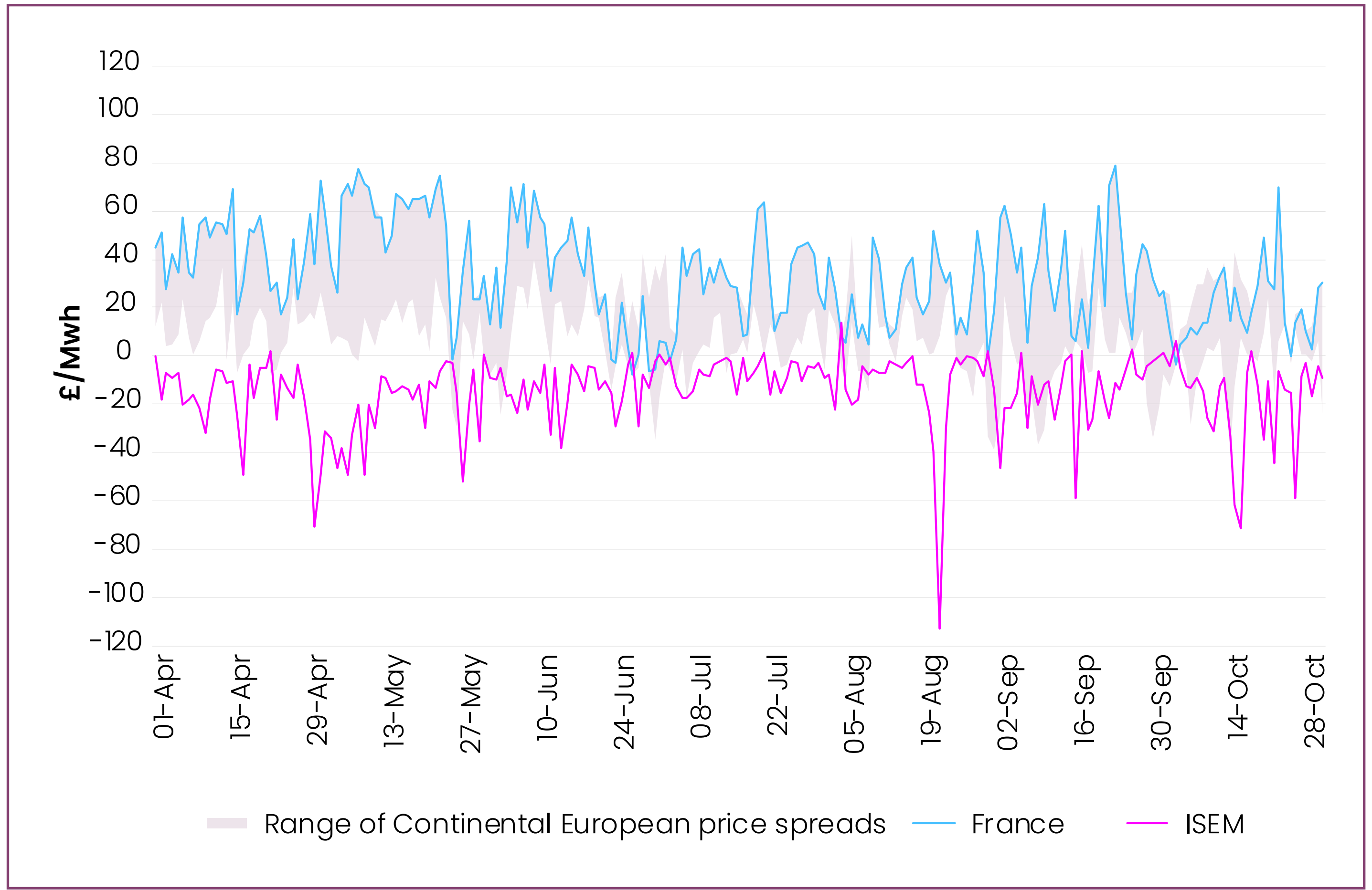


Figure 17: Day-ahead price spread for Great Britain vs border countries in summer 2025 (+ve indicates Great Britain was more expensive)

Looking Beyond Summer

Winter 2026/27

Winter 2026/27

As a prudent system operator, we never stop planning and preparing. We have already begun working with stakeholders to prepare for winter 2026/27 and will share our analysis with industry in the coming months through our winter publications.

We will continue to work closely with our stakeholders and strategic partners as we prepare for the season. This includes the government, Ofgem, National Gas, Transmission Owners, Distribution Network Operators and neighbouring electricity Transmission System Operators in Europe.

We also continue to monitor developments in global energy markets to identify and assess any risks to electricity system margins or winter operations. We work closely with DESNZ, Ofgem and National Gas to develop a shared understanding of potential risks and challenges for the season ahead, and to enable coordinated action where necessary.

In Great Britain, the T-1 Capacity Market auction for delivery in winter 2026/27 concluded on 4 March 2026, securing 7.2 GW of capacity. As the Delivery Body for the Capacity Market, NESO delivers the T-1 auction process from prequalification through to auction delivery and is also responsible for ongoing Capacity Market Agreement management.

Upcoming publications

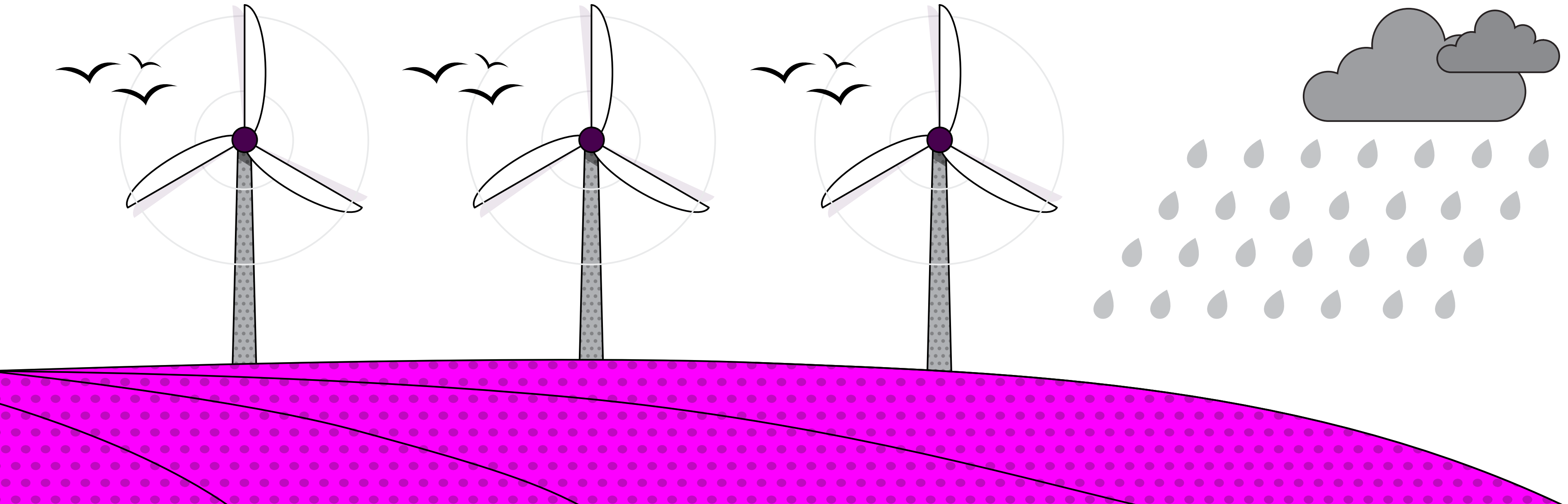
Early View 2026/27

The *Early View for Winter 2026/27* report will be published in June, alongside our review of last winter. The *Early View* will set out our developing assessment of system margin and the daily operational surplus for the coming winter.

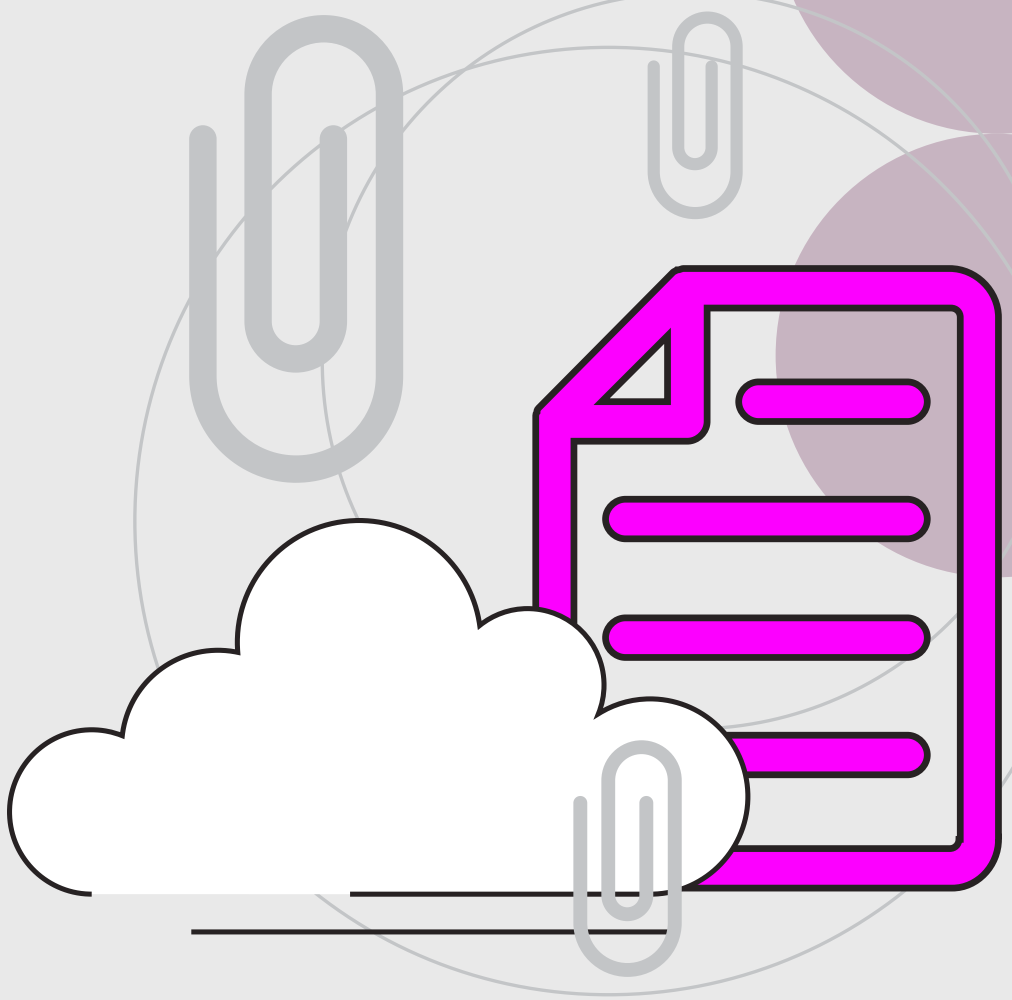
Winter Outlook report

The full *Winter Outlook 2026/27* report is expected to be published by October. It will set out our final view of system margin for winter and an updated view of the daily operational surplus throughout winter. It will be accompanied by a data workbook and more detailed information on demand, supply and potential flows on electricity interconnectors, compared with the *Early View*.

National Gas will publish a separate *Gas Winter Outlook* report.



Appendices



Appendix A: Operational View

To decarbonise Great Britain's electricity system and operate a zero carbon network, we are delivering new systems and world-first products and services that will reduce balancing costs, cut carbon and support safe, reliable and efficient operations this summer.

In 2019, NESO set an ambition[1] to be able to run Great Britain's electricity system carbon free for one 30-minute settlement period in 2025, if the market provided us with electricity purely from renewable sources. In 2025, we ran the system with 97% zero carbon generation for a settlement period.

Frequency

The Security and Quality of Supply Standard (SQSS) requires NESO to produce a *Frequency Risk and Control Report (FRCR)* every year. The FRCR sets out the balance between risk and cost to consumers when managing frequency on the electricity system. For summer 2026, system frequency will continue to be managed through a combination of holding sufficient system inertia and procuring appropriate frequency response products.

In line with the current FRCR 2024 policy, the minimum system inertia requirement remains at 120 GVA·s, and sufficient response is secured to cover the largest credible infeed and outfeed risks. In parallel, we are working with Ofgem on the development of FRCR 2025, which proposes a reduction in the minimum inertia requirement from 120 GVA·s to 102 GVA·s. Until FRCR 2025 is approved and implemented, the minimum system inertia requirement will remain at 120 GVA·s. Any future changes or implementation details will be communicated to the industry at the Operational Transparency Forum (OTF) and other relevant events.

Response

As there is less inertia on the system, maintaining system frequency close to 50 Hz requires a faster response to balance real-time supply and demand. Our suite of dynamic response services – including Dynamic Containment (DC), Dynamic Moderation (DM) and Dynamic Regulation (DR) – enables us to manage system changes effectively under lower inertia conditions.

DC is our post-fault service that arrests sudden, large changes in frequency, such as the loss of a generator. DM provides fast-acting pre-fault delivery during volatile periods. DR is our slower pre-fault service. The roles of DR and DM are to suppress pre-fault frequency movements and support system stability ahead of potential disturbances.

The DC requirement is set in line with the FRCR minimum inertia policy and is intended to secure the largest loss on the system. In response to emerging operational challenges and increased system volatility, we have increased DR service volumes for both high and low frequency response by 150 MW, bringing the current procurement level to 480 MW.

We have also increased DM Low and DM High service volumes, with procurement reflecting forecasts of system volatility. These adjustments reflect our commitment to maintaining sufficient pre-fault resilience as the system conditions change. To minimise costs, while ensuring security, we are trialling a pre-fault policy and its supporting methodology.

How inertia supports system stability

Inertia acts to stabilise the system instantaneously by resisting changes in frequency during sudden power imbalances. Our minimum inertia requirement ensures that, in the event of the largest loss on the system, the rate of change of frequency remains within 0.5 Hz/s, allowing response services and our control room to restore balance. This is because the 'stored' energy slows the rate at which frequency changes. In such circumstances, when renewable generation is high and demand is low, fewer generators self-dispatch due to low power prices, reducing system inertia.

1 Zero Carbon Operation | National Energy System Operator

Reserve

In 2025, we introduced reforms to Quick Reserve (QR) and Balancing Reserve (BR) services. Quick Reserve has replaced Fast Reserve as our fast-acting reserve service to manage sudden imbalances between supply and demand. Quick Reserve Phase 2 has enabled QR instructions to be issued outside the Balancing Mechanism, making the service open to non-BM units.

Balancing Reserve (BR) provides a day-ahead price signal to secure volume ahead of the real-time procurement of operating reserve. We have brought forward the BR auction to allow co-optimisation on the Enduring Auction Capability (EAC) platform with other reserve services, reducing procurement costs.

On 1 April we launched our new Slow Reserve (SR) service, which will replace Short Term Operating Reserve (STOR). SR is designed to manage energy imbalances on the electricity transmission system. It is primarily focused on restoring frequency within operational limits (±0.2 Hz from 50 Hz) within 15 minutes of a loss event, whether due to generation or demand. The service is essential for frequency management and acts as a backup to frequency response, which automatically responds to changes in system frequency. We aim to procure 1,800 MW positive and negative Slow Reserve.

Demand Flexibility Service

For summer 2026, we are expanding the Demand Flexibility Service (DFS), which is currently a merit-based action used to secure additional megawatts (MW) during times of high demand, into a bi-directional service by introducing the ability to increase demand. Further changes to the service design – including lower capacity thresholds and primacy rules - will enable participation from smaller generators and renewable assets and support whole-system coordination with DNOs.

We expect DFS to expand the range of tools available to balance supply and demand, complementing existing balancing services such as the Balancing Mechanism. We aim to implement these changes in April 2026.

What is the Demand Flexibility Service?

The Demand Flexibility Service (DFS) was introduced during the winter of 2022/23 as an enhanced action used to access additional megawatts (MW) at times of high National Demand. In November 2024, DFS transitioned to a merit-based margin tool used year-round when demand is high. DFS volumes are assessed alongside Balancing Mechanism actions and interconnector trades to meet the demand margin requirement issued by the Electricity National Control Centre (ENCC).

We are introducing several changes from April 2026. These include expanding it to a bi-directional service, introducing the ability to procure negative margin. We are also introducing locational procurement and embedding primacy rules. Other changes include reducing the eligibility criteria from a minimum threshold of 1 MW to 0.1 MW. This is a positive step in removing barriers to entry. We are also introducing an optional self-nominated baseline methodology for industrial and commercial (I&C) participants and renewable assets. These changes were approved by Ofgem on 25 March 2026, and we plan to go live with the evolved service on 14 April 2026.

Thermal and transmission network outages

There are times when the network's physical capacity cannot transfer the required amount of electricity. When this happens, generation output on one side must be reduced. This is known as a 'constraint'. Network diagrams showing the location, limits and flows of relevant boundaries are available on our Day Ahead Constraint Flows and Limits webpage. Summer is a key period for network reinforcements and new connections, as lower peak demand and generator outages enable network upgrades. This can lead to more constraints. There is a comprehensive transmission network outage plan for the summer to connect new generation and improve system capacity.

In Scotland, significant network outages are continuing across the B2 and B4 constraint boundaries. This includes projects such as the East Coast Upgrade Project (ECUP), the Tealing – Kincardine Upgrade Project (TKUP) and Northeast 400 kV upgrades as part of wider works for the Eastern Greenlink HVDC. Multiple outages are scheduled across Scotland to connect new Battery Energy Storage Systems (BESS) and synchronous compensators which, once commissioned, will provide additional stability services.

There are six schemes for customer connections and system reinforcement that will reduce the capacity of several parts of the network in the south of England over the summer period. Careful replanning and coordination of these outages will be required as NESO assesses the impact of system faults and unplanned outages. In the north of England, there is the continuation of major National Grid Electricity Transmission (NGET) schemes, asset replacement work and several new battery connections. These will all reduce the capacity of parts of the network.

Where possible, we work with Transmission Owners (TOs) to align network outages with planned generator outages to minimise constraint costs. We also have commercial arrangements (known as intertrips) with generators that can be used to manage constraints. These automatic control arrangements reduce or disconnect generation following a system fault. This reduces the number of pre-fault actions, lowering curtailment costs and enabling a greater volume of renewable generation to meet demand.

A new set of contracts will go live this summer, including an upgrade to the East Anglia tripping scheme. Reducing the trip time of generators to 200 ms, from the current 10 seconds, provides greater operational flexibility for the control room and will deliver balancing cost savings.

Stability

To ensure the system can securely and reliably withstand unplanned events, there must be sufficient inertia and short circuit level (SCL). Stability Network Services enhance stability and reduce operability risk, unlocking opportunities to secure the future resilience of the network. These initiatives achieve this through the procurement of inertia and SCL from a range of technologies.

Seven units under Phase 2 Stability Pathfinder are now live, including the connection of Great Britain's first grid-forming battery site. We expect all remaining Phase 2 units, and our first Phase 3 units, to be operational by the end of the year. This will reduce the reliance on conventional generators to meet stability needs while lowering costs for consumers.

In 2024, NESO launched its first enduring stability market, the mid-term (Y-1) market. This sought to competitively procure inertia at a lower cost than previous approaches. In November 2024, contracts were announced with five units to provide 5 GVA·s of inertia. Two of these contracts are now live, with the remaining three expected to follow later this year. These agreements are projected to deliver approximately £47 million in consumer benefits.

The second tender has now been completed, with delivery from October 2026. The availability and utilisation data related to these assets can be found on our Stability Pathfinder service information webpage.

Understanding grid-forming technology

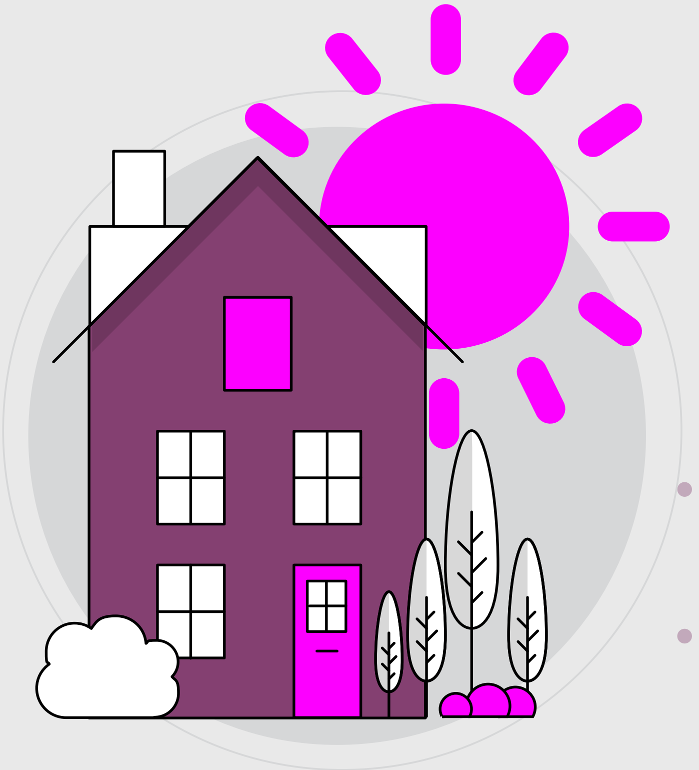
Renewable generation technologies such as batteries and wind are connected to the grid through power electronics, commonly known as inverters. Grid-forming inverters are a new control technology that alters the current and voltage of renewables to control fluctuations, behaving in the same way as synchronous power stations in response to network disturbances. For example, grid-forming inverters can respond more directly to a sudden change in frequency, providing synthetic inertia.

Voltage

System voltage must be kept within acceptable operational limits using reactive power services. Voltage levels on Great Britain's electricity transmission system are continuing to rise, most notably in the South West of England. This overall trend is being driven by increases in embedded renewable generation causing lower transmission demand as well as increasing levels of reactive power export from distribution networks.

In summer 2026, a programme of work is under way to manage the challenges associated with the unavailability of existing, and delays to new, voltage control assets. This work includes accelerated asset commissioning, updated operational strategies and increasing engagement and collaboration to develop a coordinated approach to whole-system voltage management. NESO is developing and progressing voltage control and Mega Volt-Ampere Reactive (MVAr) management trials with National Grid Electricity Distribution (NGED). This includes assessing the feasibility and operational impacts of switching certain high-voltage gain circuits and low voltage reduction and reviewing distributed energy resource power-factor setting changes.

Continued collaboration with TOs, Distribution Network Operators (DNOs), generators, interconnector operators, Ofgem and wider industry stakeholders is critical to maintaining system resilience as the energy transition continues. Various pathfinder projects and TO assets are already available across the transmission system, which, along with a pipeline of further contracted units, including those from Voltage 2026 tender, will support system resilience and provide additional tools for high voltage management. The Medium-Term Reactive Market, covering year ahead and within year requirements, is expected to go live in April.



Appendix B: List of Figures and Tables

Figures

Tables

Appendix C: Relationship between Types of Demand

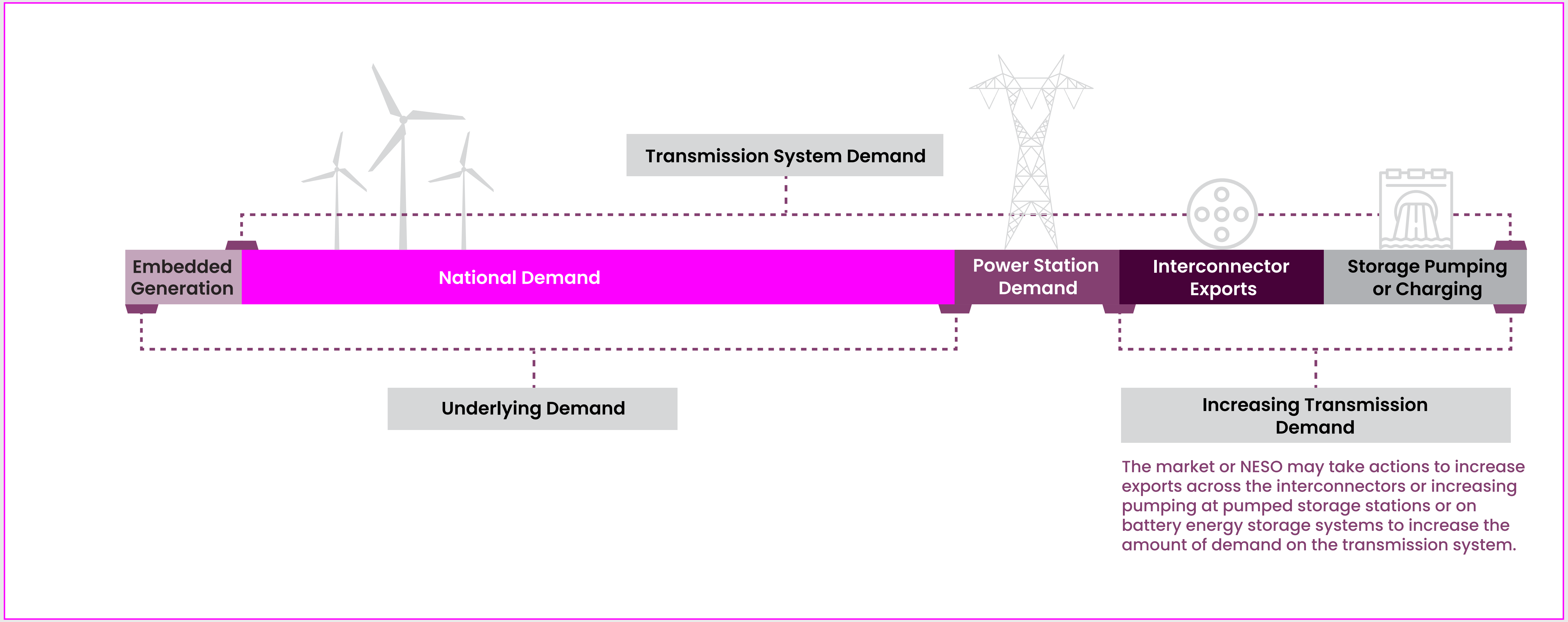
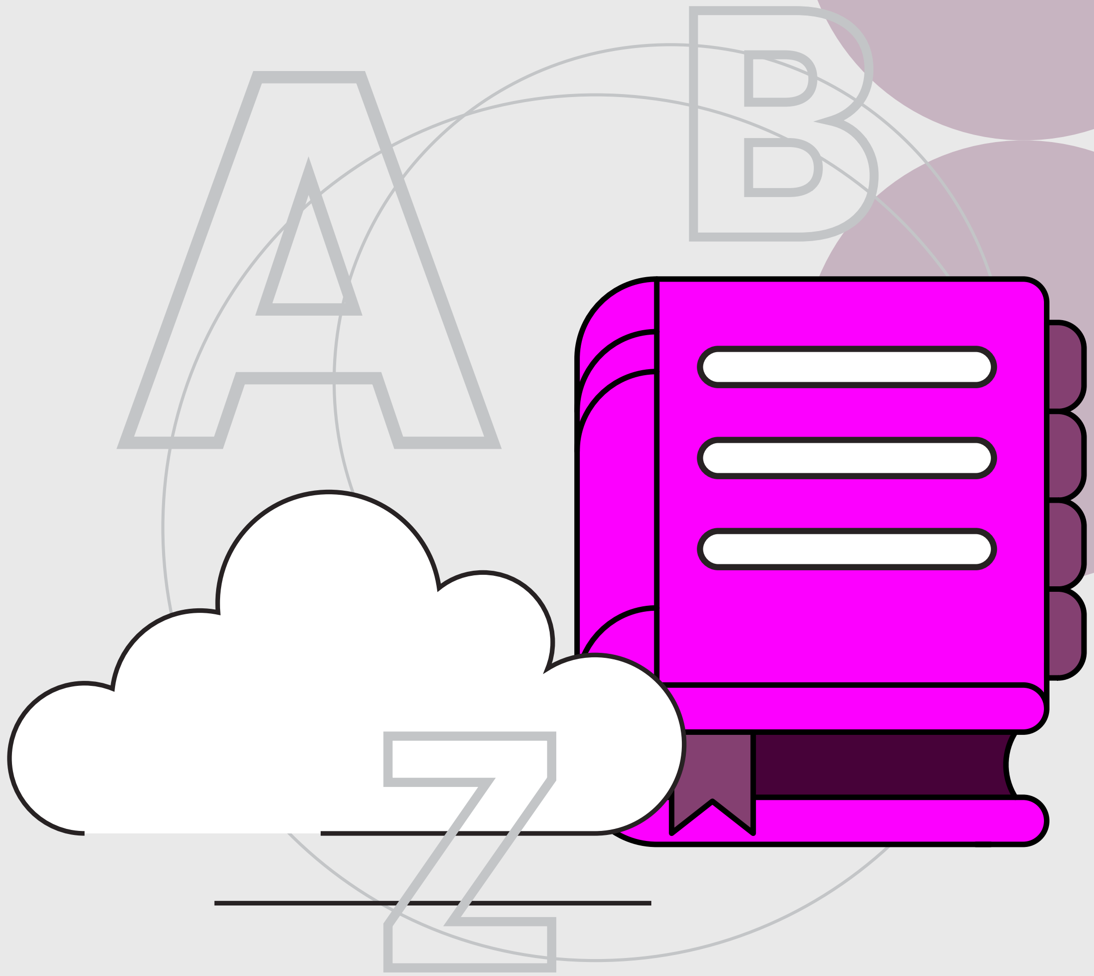


Figure 18: Relationship between types of demand

The published initial transmission system demand outturn (ITSDO) does not currently include charging from battery storage. We are in the process of updating the reporting methodology for ITSDO to include this contribution. We expect this to be completed in spring 2026.

Glossary



Baseload electricity
A market product for a volume of energy across the whole day (the full 24 hours), or a running pattern of continuous operation for inflexible power sources such as nuclear.

BritNed
An electricity interconnector between Great Britain and the Netherlands. It is a bidirectional interconnector with a capacity of 1 GW.

Capacity Market (CM)
The Capacity Market is designed to ensure security of electricity supply. It provides payment for reliable sources of capacity alongside their electricity revenues, ensuring they deliver energy when needed.

Demand side response (DSR)
When demand-side customers reduce the amount of energy they draw from the transmission network, either by switching to distribution generation sources, using on-site generation or reducing their energy consumption. We observe this behaviour as a reduction in transmission demand.

Distributed (embedded) generation
Any generation or storage that is connected directly to the local distribution network, as opposed to the national transmission network. It includes combined heat and power schemes of any scale, including wind generation, solar and battery units. This form of generation is not usually directly visible to NESO and reduces demand on the transmission system.

Dynamic Containment
A fast-acting post-fault service to contain frequency within the statutory range of ±0.5 Hz in the event of a sudden demand or generation loss. The service responds very quickly and proportionally to frequency but is only active when frequency moves outside operational limits (±0.2 Hz).

Dynamic Moderation
A pre-fault frequency service aimed at correcting sudden large imbalances between generation and demand due to, for example, erroneous wind or solar forecasts.

Dynamic Regulation
A pre-fault frequency service designed to correct small, random deviations in frequency around the target of 50 Hz.

East West Interconnector (EWIC)
A 0.5 GW interconnector that links the electricity transmission systems of Ireland and Great Britain.

ElecLink
A power interconnector through the Channel Tunnel providing a transmission link between the UK and France with a capacity of 1 GW in either direction.

Float
When an interconnector is neither importing nor exporting electricity.

Forward prices
The predetermined delivery price for a commodity, such as electricity or gas, agreed between a buyer and seller in a forward contract for delivery at a future date.

Frequency Risk and Control Report (FRCR)
The FRCR is produced at least once annually and sets out the results of an assessment of operational frequency risks on the system.

Greenlink
A 0.5 GW interconnector between Ireland and Wales, commissioned in early 2025.

Gigawatt (GW) and Megawatt (MW)
A measure of power: 1 GW = 1,000MW = 1,000,000,000 watts.

Gigavolt ampere seconds (GVA·s)
Synchronous generators producing electricity rotate at the correct frequency. The kinetic energy 'stored' in these machines is system inertia. If there is a sudden change in system frequency, the stored energy slows the rate of change of frequency while the control room restores balance. Power is measured in MW or GW, but inertia is measured in GVA·s.

High summer period
The period between 1 June and 31 August, or weeks 23 to 35. This is when the greatest number of planned generator outages is expected.

Interconnexion France – Angleterre (IFA)
A 2 GW interconnector between the French and British transmission systems.

Interconnexion France–Angleterre 2 (IFA2)
A 1 GW interconnector between the French and British transmission systems commissioned early 2021.

Inflexible generation
Types of generation that require long notice periods to change output, do not participate in the Balancing Mechanism, or find it expensive to change output for commercial or operational reasons. Examples include nuclear, combined heat and power (CHP) stations, and some hydro generators and wind farms.

Interconnector
Electricity interconnectors are transmission assets that connect the market in Great Britain to other markets, including Continental Europe, Norway, Ireland and Northern Ireland. They allow suppliers to trade electricity between these markets.

Load factors
The amount of electricity generated by a plant or technology type across the year, expressed as a percentage of maximum possible generation. This is calculated by dividing the total electricity output across the year by the maximum possible generation for each plant or technology type.

Minimum demand
The lowest demand on the transmission system.

Maximum demand
The highest demand on the transmission system.

Moyle
A 0.5 GW interconnector between Northern Ireland and Scotland.

National electricity transmission system (NETS)
This transports high-voltage electricity from where it is produced to where it is needed across the country. The system is made up of high-voltage electricity wires that extend across Britain and nearby offshore waters.

Negative reserve active power margin (NRAPM)
An NRAPM notice is a request to encourage more flexible parameters from generators and inform participants of the risk of emergency instructions. A NRAPM may be issued if there is insufficient flexibility available to ensure that generation matches demand during periods of low demand. A localised NRAPM occurs where there is a risk that the combination of demand and inflexible generation within a constraint group can exceed the constraint limit of a portion of the network.

Nemo Link
A 1 GW interconnector between Great Britain and Belgium.

Normalised transmission demand
The demand seen on the transmission system, forecast using long-term trends and calculated with the effects of weather and the day of the week removed as appropriate. This takes into account the power used by generating stations when producing electricity (the 'station load') and interconnector exports.

OC2 data
Power generation operational data provided under Operating Code No. 2 of the Grid Code.

North Sea Link (NSL)
A 1.4 GW HVDC sub-sea link from Norway to Great Britain

Outage
A planned maintenance period requiring a complete shutdown, during which essential work is carried out.

Outturn
Actual historical operational demand as measured by real-time metering.

Positive and negative reserve
NESO maintains positive and negative reserve to increase or decrease supply and demand to help manage system frequency as required.

Pumped storage
A system in which electricity is generated during periods of high demand by using water that has been pumped into a reservoir at a higher altitude during periods of low demand.

Reactive power
The movement of energy across a network, measured in MVAr. Different types of network assets and generators can generate or absorb reactive power. The flows of reactive power on a system affect voltage levels.

Renewable generation
Electricity generation from renewable resources, which are naturally replenished, such as sunlight and wind.

Reserve requirement
To manage system frequency and respond to sudden changes in supply and demand, NESO maintains reserves. These reserves, known as positive and negative reserves, help to increase or decrease supply and demand as needed. Positive reserve, or headroom, allows for additional generation or reduced demand, while negative reserve, or footroom, enables lower generation or increased demand. These reserves are made available across all generators synchronised to the system, ensuring stability and reliability in the power grid.

Restoration
Services used to restore power in the event of a total or partial shutdown of the national electricity transmission system, previously referred to as Black Start services.

Seasonal normal conditions
The average set of conditions we could reasonably expect to occur. We use industry-agreed seasonal normal weather conditions. These reflect recent changes in climate conditions, rather than being a simple average of historic weather.

Technical capability
The capacity of connected plant expected to be generating in the market, based on the Capacity Market auctions and other sources of market intelligence, but does not account for potential breakdowns or outages.

Transmission system demand (TSD)
Demand that NESO sees at Grid Supply Points, which are the connections to the distribution networks.

Unavailability rates
A calculated value to account for unexpected generator unit unavailability including faults, short notice planned outages, restrictions or losses. Forecast unavailability factors rates are applied to the operational data provided to NESO by generators. Rates are based on how generators performed on average by fuel type during peak demand periods (7am to 7pm) over the last three summers.

Underlying demand
Demand varies from day to day, depending on the weather and the day of the week. Underlying demand is a measure of how much demand there is once the effects of the weather, the day of the week and distributed generation have been removed.

Viking Link

Viking Link is a 1.4 GW high voltage direct current (DC) electricity link between the British and Danish transmission systems, connecting at Bicker Fen substation in Lincolnshire and Revsing substation in southern Jutland, Denmark.

Voltage

Unlike system frequency, voltage varies across different locations on the network, depending on supply and demand for electricity, and the amount of reactive power in that area. Broadly, when electricity demand falls, reactive power increases and this increases the likelihood of a high voltage occurrence.

Weather-corrected demand

The outturn demand once the assessed impact of the weather has been removed. This is calculated by constructing a 30-year average of each relevant weather variable for each week of the year. This is then applied to linear regression models to calculate what the demand would have been with this standardised weather.

Get in Touch

Email us with your views on the *Summer Outlook* report at marketoutlook@neso.energy and we will get in touch.

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The *Summer Outlook* report is part of a suite of documents prepared by NESO. Visit neso.energy for more information.

Legal Notice

National Energy System Operator (NESO) legal notice

Pursuant to its licence NESO is, alongside other roles, the system operator of the national electricity transmission system. Throughout this outlook document, the terms “we”, “our”, “us” etc. are used to refer to the licensed entity, the National Energy System Operator.

NESO has prepared this outlook document pursuant to its electricity transmission licence in good faith and has endeavoured to prepare this outlook document in a manner which is, as far as reasonably possible, objective, using information collected and compiled from users of the electricity transmission system together with its own forecasts of the future development of those systems.

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