Winter Review and Consultation 2024/25

June 2025

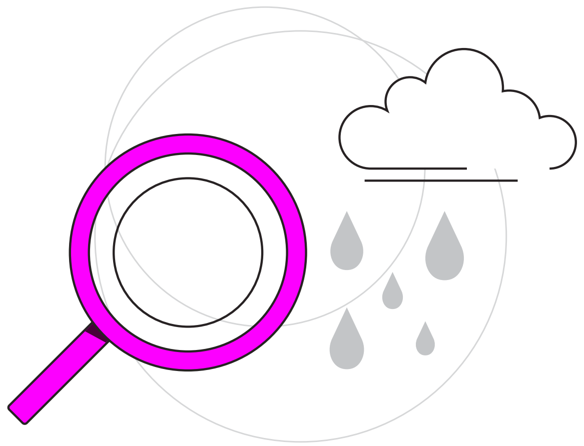
NESO
National Energy
System Operator

Welcome

Welcome to our *Winter Review and consultation 2024/25* report.

This annual report reviews the modelling and analysis detailed in the *Winter Outlook 2024/25* report against the actual events during the season.

Kayte O'Neill
Chief Operating Officer
National Electricity System Operator



At NESO (formerly ESO) we have a long history of ensuring that electricity flows safely and reliably from where it is generated to where it is needed. We operate Great Britain's evolving electricity transmission network to one of the highest standards of safety and reliability anywhere in the world.

We work year-round with Government, Ofgem, National Gas and other parts of the energy industry to assess emerging risks and build resilience ahead of winter. This includes ongoing engagement with neighbouring Transmission System Operators (TSOs) across Europe and Transmission Owners (TOs) across Great Britain. Each year, we produce an *Early View* of winter followed by a full *Winter Outlook* report, setting out our assessment of the electricity margin available to manage customer supply and demand.

This document reviews the forecasts and analysis in our *Winter Outlook 2024/25* report, comparing what we expected, to what actually occurred. Alongside this report, we have published the *Winter Outlook 2025/26: Early View*, providing an early assessment of the year-on-year changes to the security of supply outlook. Together, these reports support effective planning and preparation for the coming winter.

As in previous years, the consultation section of this report focuses on the *Winter Review 2024/25* and the upcoming *Winter Outlook 2025/26*. However, we welcome feedback on all aspects of our winter planning and preparation and will make sure any comments and information received are passed to the relevant teams across NESO.

If you would like to share your views, or if you have any general queries or comments, please email us at marketoutlook@neso.energy, join us for a discussion at our Operational Transparency Forum (OTF), or contact us via LinkedIn or on X @neso_energy.

Please note that National Gas has published a separate *Gas Winter Review and Consultation*.

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Winter Review at a Glance

1

Operational surplus

Winter margins were broadly within the expected range of the *Winter Outlook* report and there was no interruption to customer demand due to unavailable supply.

Our control room engineers continually monitor supply and demand across Great Britain utilising a range of operational tools to ensure a sufficient operational surplus is maintained. These tools includes the use of system notices.

Capacity Market Notices were automatically issued on 14 October, 3 December and 8 January. An Electricity Market Notice (EMN) was issued for 8 January. These notices operated efficiently and as expected – producing the required market response. Adequate margins were maintained at all times across winter.

2

Demand and supply

Our plans, preparations and balancing tools were sufficient to enable the reliable operation of the system under varied supply and demand conditions.

Demand was largely within the forecast range published in the *Winter Outlook* report. There were a few notable cold spells in January and February that saw demand consistently move towards, or above the higher end of our forecast range.

Supply was generally within the range forecast in the *Winter Outlook* report. There was a prolonged period in December and January when conventional generation availability was lower than our forecast as several generators extended outages or scheduled outages during a period of anticipated low demand.

3

Electricity markets

Reciprocal support and close coordination with neighbouring system operators ensured interconnectors remained mutually beneficial.

The pattern of interconnector flows was consistent with our expectations ahead of winter. Great Britain's power prices were typically higher than those in interconnected markets, leading to net imports during peak and off-peak periods. In line with expectations, Great Britain typically exported to Ireland and Northern Ireland.

A summary of how the Gas Network responded to the demand of last winter is available in the *National Gas Winter Review and Consultation*.

01

Margins

How did the operational surplus compare to our expectations in the Winter Outlook 2024/25 report?

What we said in the *Winter Outlook 2024/25* report	What happened
Our analysis also indicates that our operational surplus will be sufficient across winter…	Sufficient margins were maintained throughout winter. All operational, system and balancing requirements were met at all times.
…there may be periods where we need our standard operational tools, including the use of system notices.	If our forecasts suggest that our control room may not be able to meet our normal margin for operating the system through the normal mechanisms, we'll issue a formal message to the electricity market. These messages are known as system notices. They are standard operational tools and do not indicate that electricity supply is at risk. There were a small number of days where system notices were issued. This included automated Capacity Market Notices (CMNs) on 14 October, 3 December and 8 January and an Electricity Margin Notice (EMN) for 8 January. Further details on the different types of system notice can be found in Appendix B.
There could be days where the operational surplus falls below our forecast range – up to 5% of days.	The outturn operational surplus was broadly consistent with our forecast range. The surplus fell below the forecast range on 13% of days. Three periods (3 to 9 November, 8 to 11 January and 13 to 15 March) saw consecutive days where the surplus was at, or below, forecast levels. Full details on the performance of our demand and supply modelling, which in turn impacts the performance of our operational surplus forecasting, can be found on pages 8-12.

Operational surplus

A sufficient operational surplus was maintained at all points this winter, with a small number of days for which system notices were issued. This included one Electricity Margin Notice (EMN) for 8 January.

Figure 1 shows the actual operational surplus for winter (the blue line) compared with the expected range (90% confidence level) presented in the *Winter Outlook 2024/25* report. As expected, there was considerable variation in the operational surplus, driven by variations in demand, wind output, interconnector flows and generator availability. In general, this variability was well captured, with our central projection closely aligned to the actual trend. The forecast overestimated the operational surplus at the lower bound more frequently than expected (on 13% of days against an expected value of 5%). Most notably this occurred between 3–9 November, 8–11 January and 13–15 March. We will utilise weather-corrected data to determine if this was a result of atypical weather conditions or, if not, how our models could be enhanced to better capture the variability of the surplus at both the upper and lower ends of the forecast range.

On 8 January, several generators were on maintenance outages and approximately 3 GW of interconnector capacity with Continental Europe was unavailable. Widespread low temperatures led to weather warnings across large parts of the country, with demand at the higher end of our forecast range. An Electricity Market Notice (EMN) was issued for the period from 16:00 to 19:00. Several actions were taken to improve margins including the use of the Demand Flexibility Service (DFS) and engagement with interconnector owners and neighbouring Transmission System Operators to increase available import capacity. In January we produced a review (available here) of the actions we took to ensure that operational, reserve and balancing requirements were met at all times.

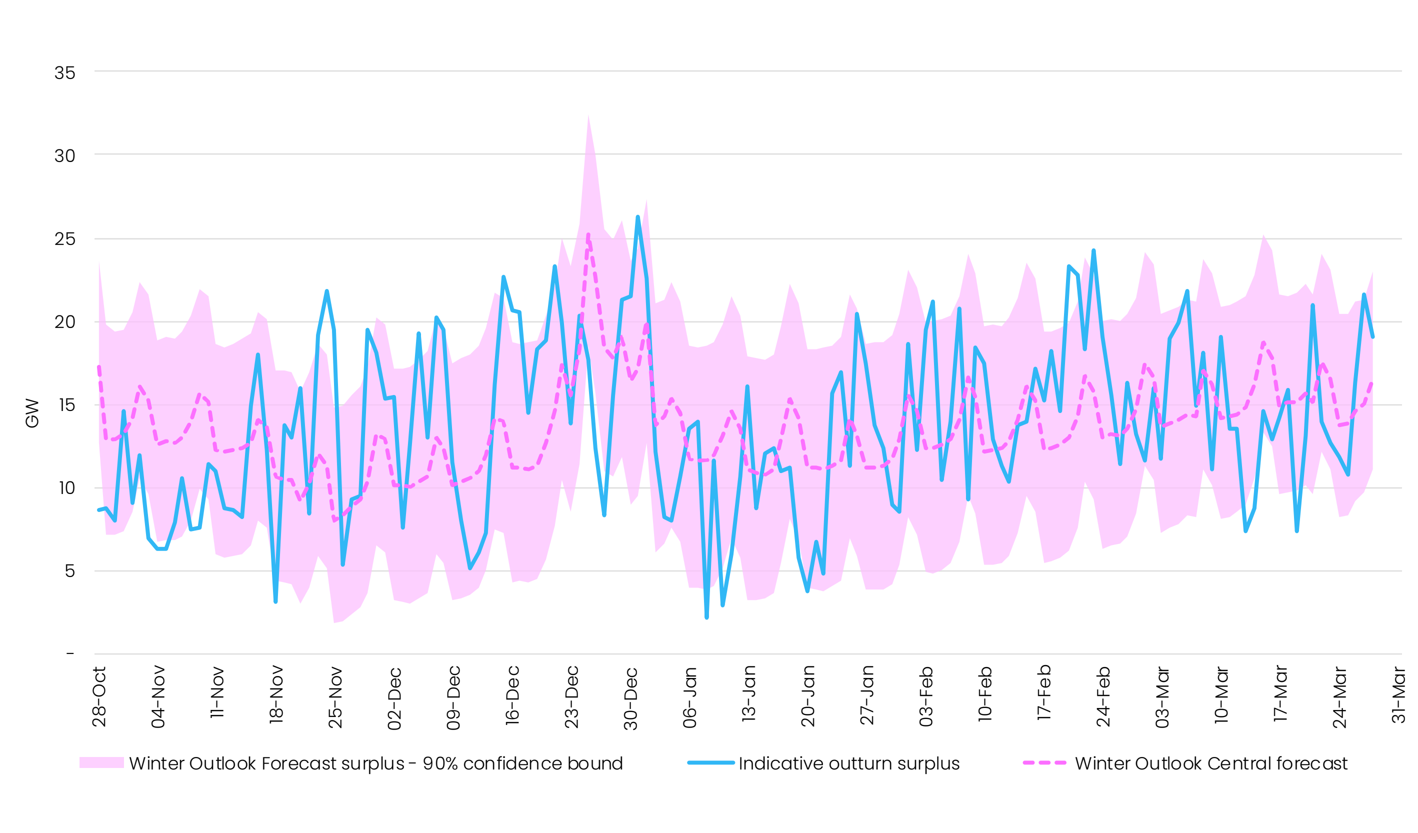


Figure 1: Forecast and actual operational surplus for winter 2024/25

Interpreting this chart: Figure 1 shows the credible range of the operational surplus at the time of peak demand, throughout winter as published in the *Winter Outlook 2024/25* report. The shaded region represents the 90% confidence bound, reflecting day-to-day variations in weather and available generation. We would expect to see days (approximately 5%) where the operational surplus is below this range.

Demand and Supply

How did demand and supply compare to our expectations in the *Winter Outlook 2024/25* report?

What we said in the *Winter Outlook 2024/25* report	What happened	For more details
Weather corrected peak demand is expected to be slightly lower than recent winters due to continued growth in generation connected to the distribution network. **We predict that weather corrected peak National Demand would be 43.0 GW and occur in early to mid-January.**	Weather corrected peak demand was comparable to recent winters. Weather corrected peak National Demand was 44.2 GW and occurred on 9 January. An explanation of different definitions of demand is available in Appendix A.	Page 10
Late October to mid-December will see the lowest available generator capacity. **Generator unavailability across the season was assumed to be comparable to the average of recent years.**	Low generator capacity was observed at the start of winter, as expected. We also observed low generator availability from mid-December to early-January as several generators extended outages or scheduled new planned outages during a period of relatively low demand, driven by mild weather and the Christmas period. The season's weighted average generator unavailability was in line with our forecast. All fuel types were within 5% of their respective unavailability factor.	Page 12

Demand review

Demand observed during winter 2024/25 was well captured by the credible range published in the *Winter Outlook 2024/25* report.

Daily peak demand was broadly within the forecast range throughout the season (see Figure 2). Winter 2024/25 was generally milder than average, with approximately 60% of days warmer than seasonal normal. However, several short-lived cold spells led to relatively high demand. These occurred in mid-November, early-January, mid-February and mid-March. While our modelling captured seasonal effects well, we saw occasional underestimations of weekend peak demand – particularly in early January and towards the end of the season. Figure 3 shows that weather corrected peak demand was largely in line with our forecast range. The actual peak weather corrected National Demand was 44.2 GW on 9 January compared to a forecast of 43.0 GW.

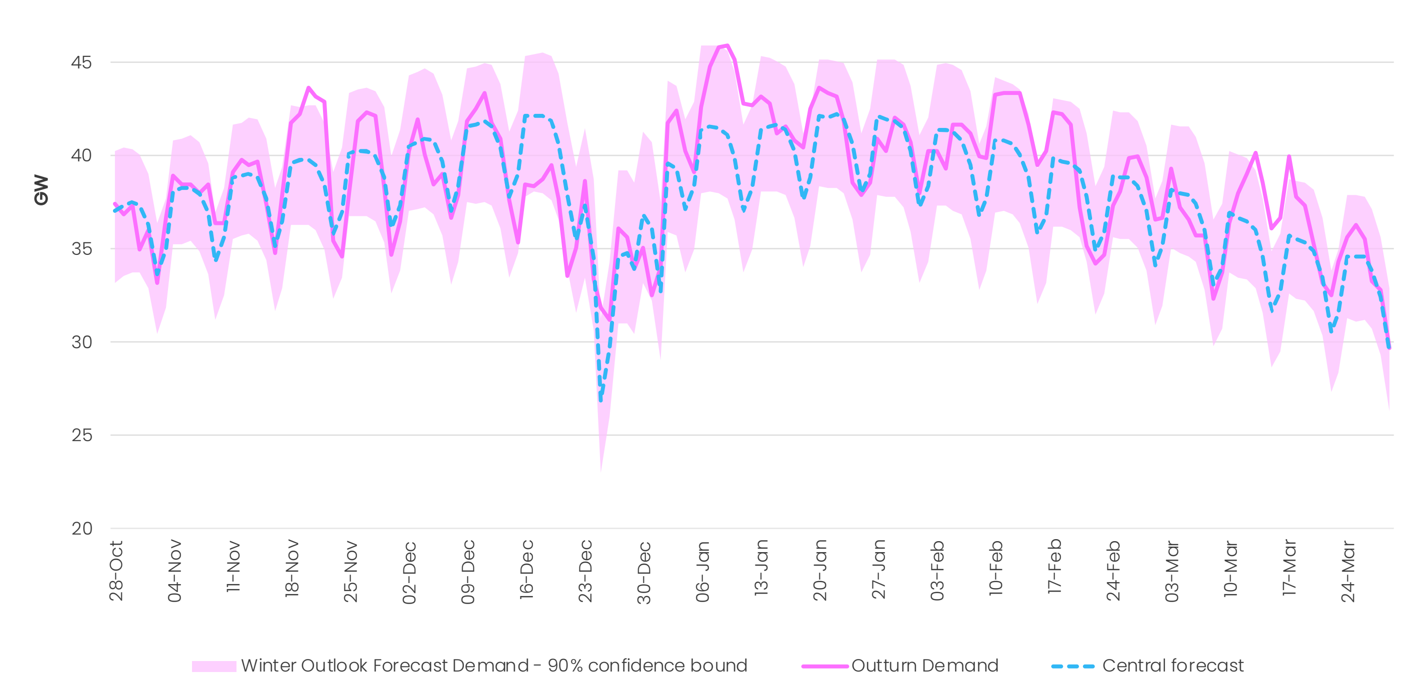


Figure 2: National Demand during winter 2024/25

Spotlight:

The Demand Flexibility Service (DFS) helps households and businesses participate in the electricity market by providing incentives, through suppliers and aggregators, for reducing or shifting demand. DFS was introduced during the winter of 2022/23 as part of the winter contingency toolkit to act as an enhanced action for use on days when the system could have been under stress.

During 2024, we made changes to the design of DFS, evolving the service from an enhanced action to an in-merit based margin tool.

Across winter 2024/25 we saw 25 registered DFS providers representing more than 1.7m customers, with a large proportion of this volume coming from domestic demand reduction. NESO procured volume on 18 occasions, with a peak delivered volume of 188 MW. More information on DFS use this winter is available here.

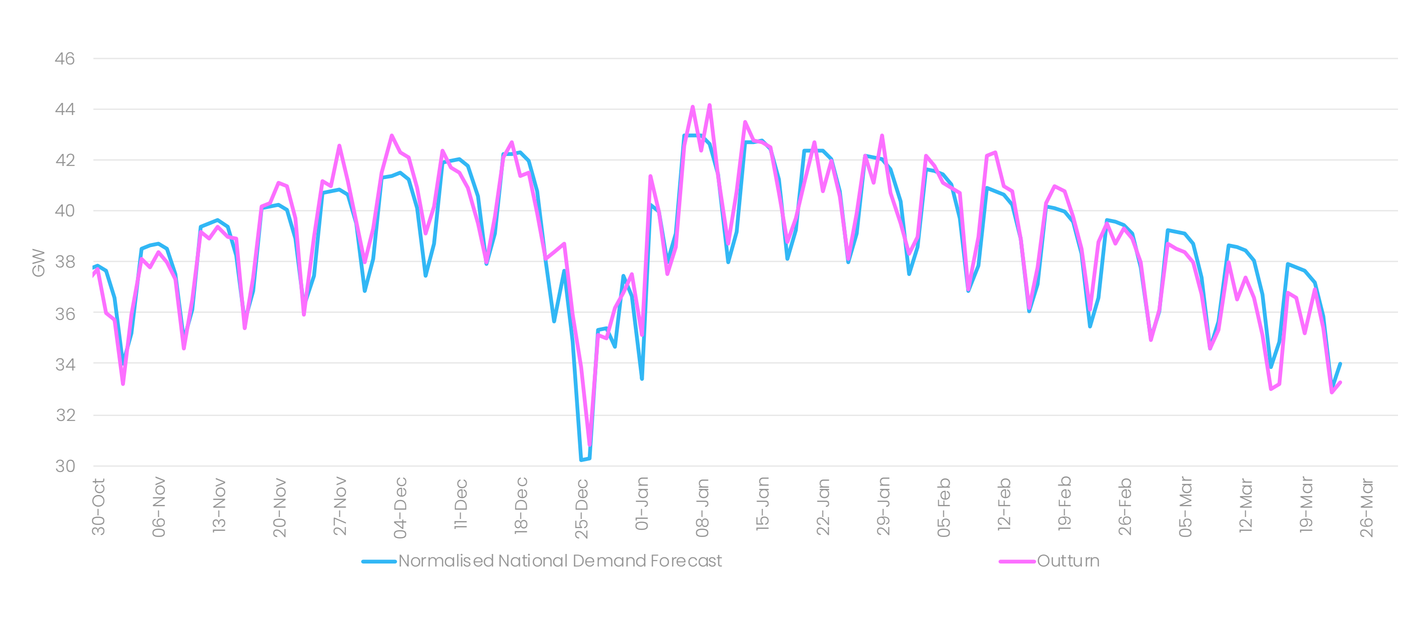


Figure 3: Actual and forecast weather corrected daily peak demand for winter 2024/25

Supply review: wind variability and demand interactions

Wind generation

Effectively predicting weather-dependent variables over extended timelines requires the production of a confidence range. The pink plume in Figure 4 shows the modelled variability of wind generation (90% confidence level) against actual wind output during peak hours. While the central forecast was reasonably well calibrated, actual wind output fell below the forecast range on 14% of days (higher than the expected value of 5%). This is partially a result of the anomalously high number of low wind speed days during the winter.

Demand net wind

The wide range of weather patterns experienced throughout winter leads to large variability in the requirement for non-wind generation. The cold, calm conditions in early January led to a prolonged period of high demand net wind with higher levels of non-wind generation required to meet demand. Figure 5 shows the forecast range (90% confidence level) of demand required to be sourced from non-wind generation (net of wind output). The magnitude and frequency of these periods was well captured by our modelling with 7% of days exceeding the forecast range (against an expected 5%).

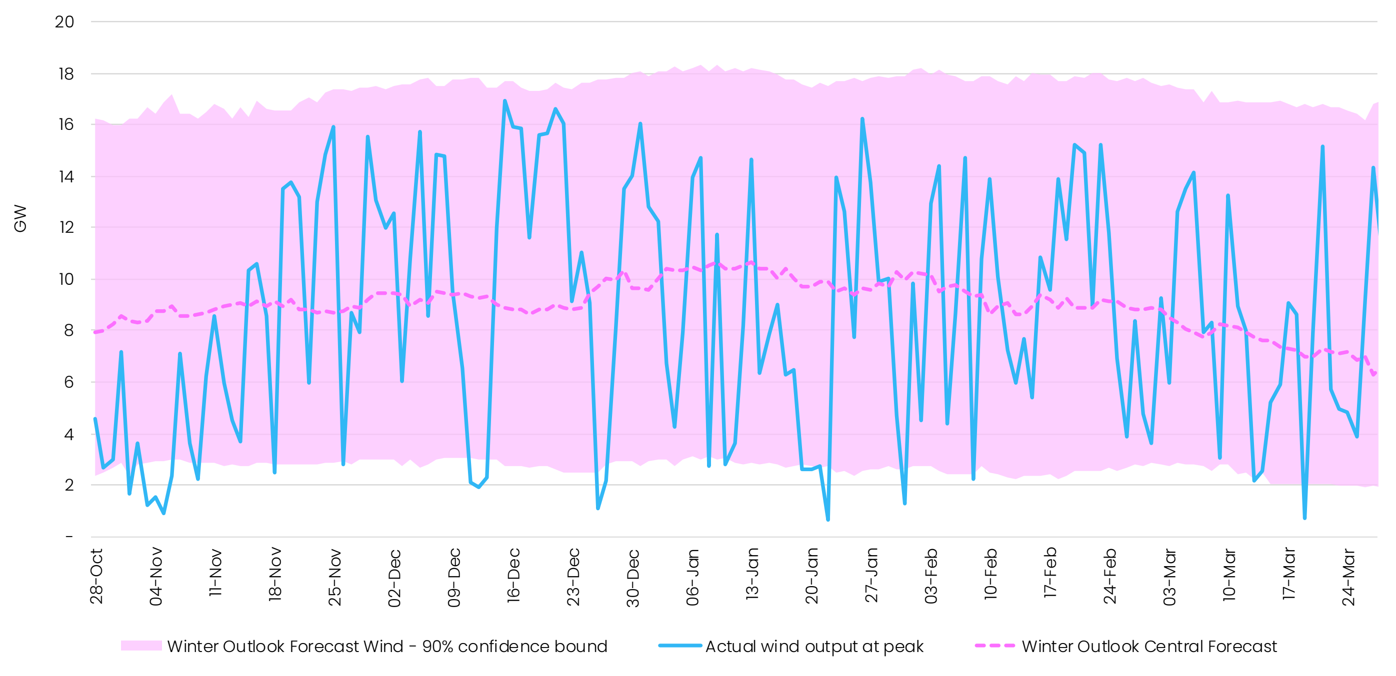


Figure 4: National wind generation during winter 2024/25 at the 90% confidence range against actual wind output during peak hours

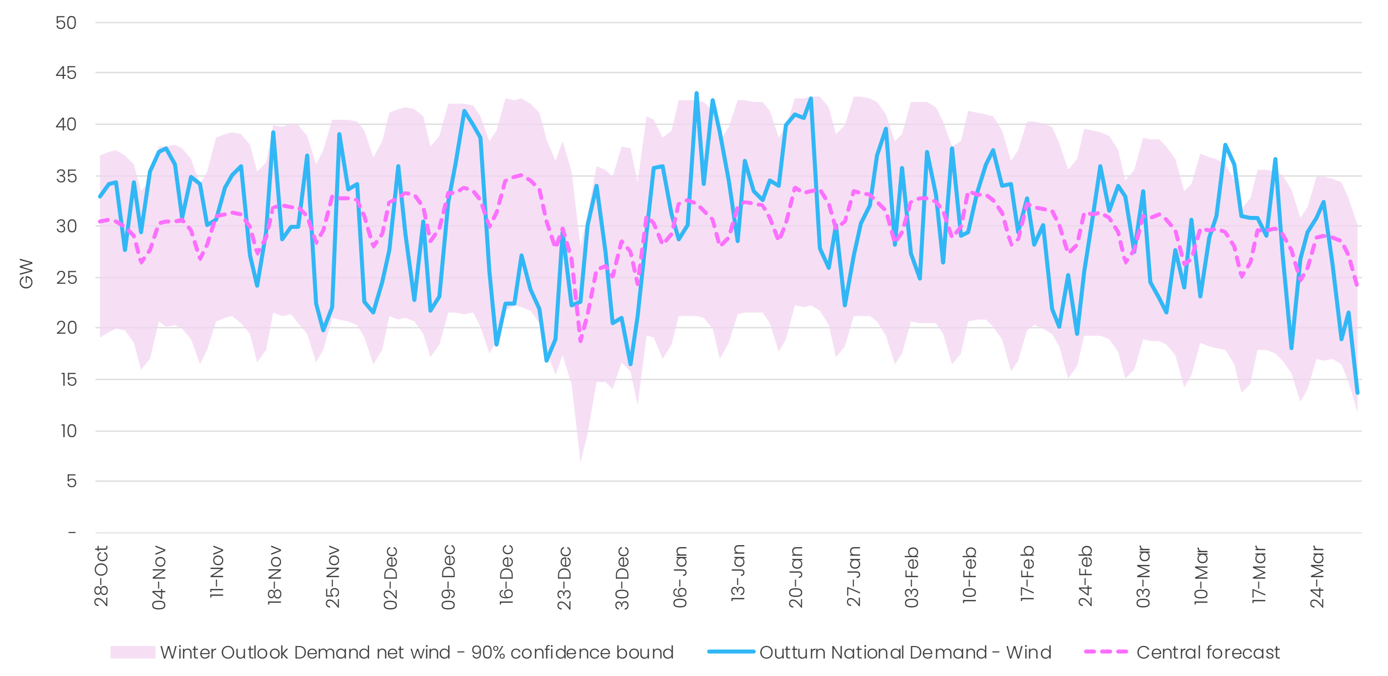


Figure 5: Forecast and actual National Demand net of wind generation during winter 2024/25 at the 90% confidence range

Supply review: conventional generation

Conventional generator availability

Available generation was largely within the forecast range of the *Winter Outlook 2024/25* report. However, for a prolonged period from early December to early January conventional generation availability fell below this range (see Figure 6). This was driven by several generators extending outages or scheduling new planned outages during a period of relatively low demand, associated with mild weather and the Christmas period. Availability recovered strongly from late January to mid-February.

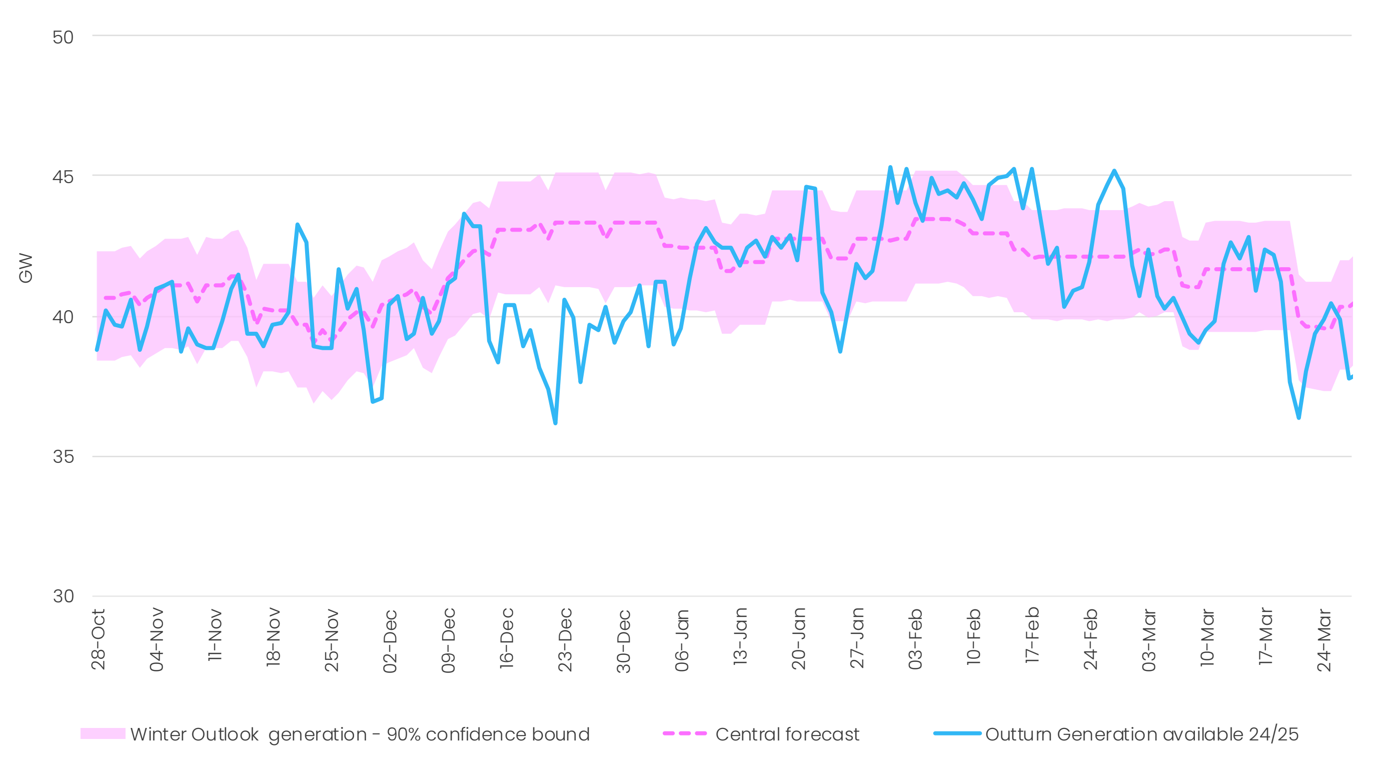


Figure 6: Forecast and actual conventional generation availability for winter 2024/25

Unavailability factor methodology

Planned outages are included in our supply assessment using the latest market submissions provided to us by generators. Actual availability may deviate from this schedule due to the re-scheduling or extension of existing outages, or due to new planned or unplanned outages occurring during the season. We use historic variation from expected availability to inform our forecast of how available supply is likely to change across winter.

Under our previous methodology, we compared each generator's maximum technical capacity against the maximum export limit (MEL) observed during the peak on days the unit was expected to be operational. Under our new methodology, a generator's maximum capacity is calculated as the highest output achieved for two consecutive half-hour periods over the past year. This is consistent with the approach used in our operational surplus modelling.

Table 1: Forecast and actual unavailability during winter 2024/25 and a revised forecast using the updated methodology

Fuel Type	Forecast Rate in Winter Outlook Report	Revised Forecast Rate (New Methodology)	Actual Unavailability Rate for Winter 2024/25 (New Methodology)
CCGT	5%	5%	8%
Nuclear	24%	12%	7%
OCGT	11%	8%	4%
Storage	3%	3%	2%
Biomass	5%	9%	12%
Hydro	7%	10%	14%
Weighted average	8%	7%	8%

Interconnectors and Energy Markets

How did interconnector flows compare to expectations in the Winter Outlook 2024/25 report?

What we said in the *Winter Outlook 2024/25* report	What happened
We expect close cooperation between European System Operators to play an important role in helping maintain secure supplies for customers in GB and Europe.	Throughout the winter NESO took a collaborative approach to managing margins, working closely with neighbouring Transmission System Operators to provide reciprocal support.
There will be imports into GB at times of tight margins or stress on the GB system, provided by the market and/or NESO actions.	On selected days (for example 6 December and 12 January) prevailing conditions in Europe led to insufficient scheduled imports at the day-ahead stage. NESO has a range of operational tools to manage peak demands including the ability to trade on the interconnectors to secure the flows. Where required sufficient interconnector trading volumes were available to meet reserve requirements.
There will be periods when exports flow from GB to Europe, including over some peak periods, when we have sufficient operational surplus.	As expected, isolated days such as 17 February saw high wind generation result in a sufficient operational surplus to enable net exports to Continental Europe.
There is minimal planned maintenance during winter 2024/25. We currently expect full availability of the interconnectors, providing key flexibility and security of supply for GB and Europe. Unplanned outages can also occur. We account for this by considering breakdown rates, which are factored into our modelling.	Interconnectors experienced more outages than initially scheduled at the start of winter. However, unplanned or short notice outages were broadly consistent with the assumed interconnector unavailability factor.
Wholesale prices for Great Britain are trading at a slight premium to other major European markets, which, along with interconnector auction results, indicate an import bias this winter.	Great Britain was a net importer from Continental Europe during winter 2024/25. This reflected high generation availability in Europe, including strong nuclear availability in France, which led to lower wholesale prices in interconnected markets.

Interconnector review

Adequate supply in interconnected markets resulted in interconnector imports into Great Britain during winter. Reciprocal support between European TSOs maintained an efficient and mutually beneficial position across markets.

At the time of publishing the *Winter Outlook 2024/25* report, the power price differential between Great Britain and interconnected countries was narrow, giving a limited signal of expected flow directions. The high levels of nuclear generation and relatively full hydro reservoirs identified in our analysis, combined with milder than normal weather, resulted in lower wholesale prices in interconnected markets. The daily baseload power price in Great Britain, the Integrated Single Electricity Market (ISEM) for Ireland and Northern Ireland, and Continental European markets is shown in Figure 7.

Figure 8 shows how this typical premium impacted interconnector flows during winter, with Great Britain a net importer from Continental Europe across all periods. As anticipated in our operational surplus modelling, Great Britain was a strong exporter to Ireland and Northern Ireland.

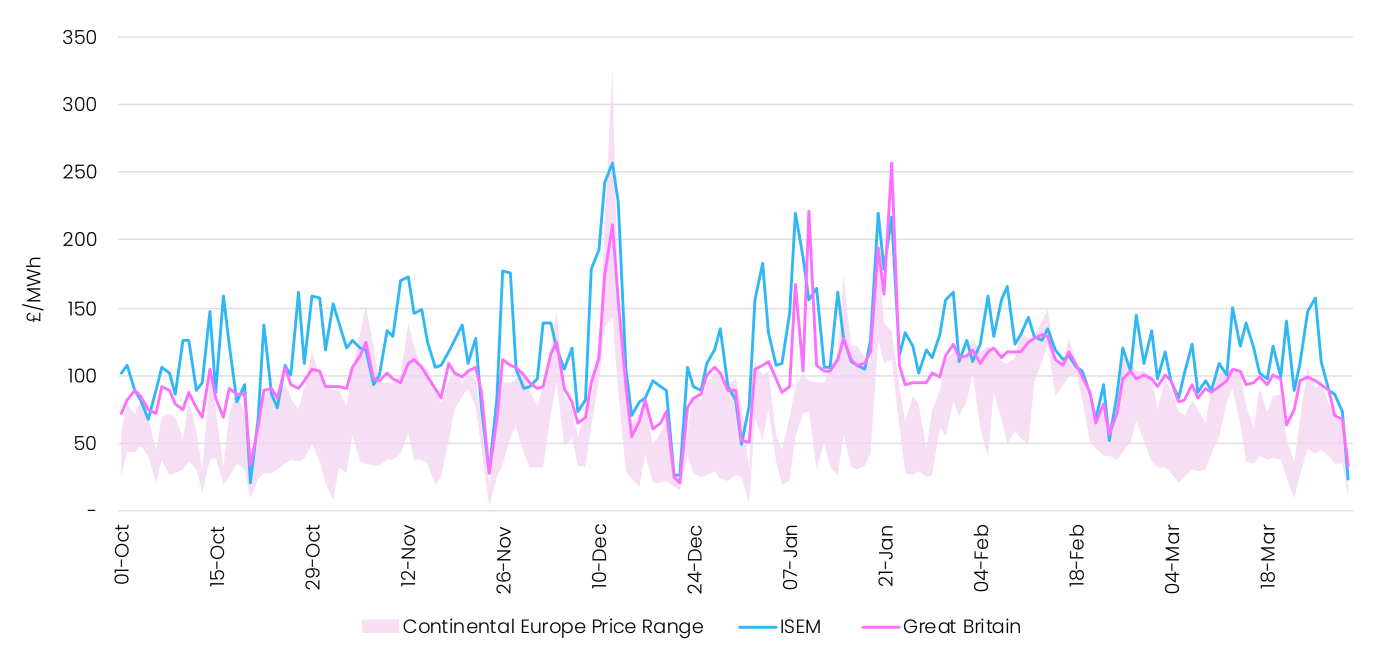


Figure 7: Daily range of baseload power prices in Great Britain and interconnected markets during winter 2024/25

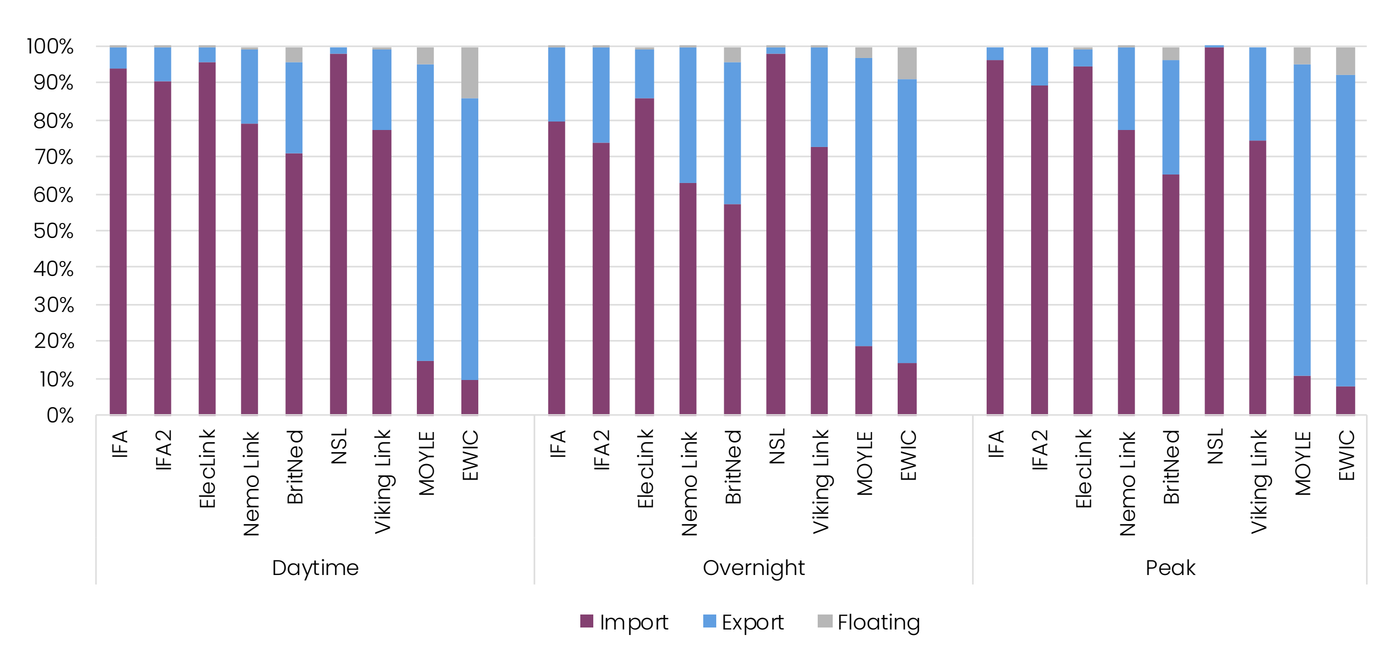


Figure 8: Proportion of imports and exports (by interconnector) by time of day for winter 2024/25

04

Consultation

Winter review and outlook consultation

The purpose of this annual consultation is to gather feedback on our outlook documents and engage with stakeholders to inform our analysis for the upcoming *Winter Outlook 2025/26* report.

Your views on market conditions, and your reflections on our plans and preparations, help provide us with a more complete picture of the challenges and opportunities facing the electricity system in the coming winter. This consultation also enables us to test the usefulness of the outlook documents and identify areas for improvement in how we engage.

We will ensure that any comments or information received in response to this consultation are shared with relevant teams across NESO.

Consultation questions

Winter Review

1. What do you use the *Winter Review and Consultation* report for? What information in the report is most useful to you?
2. Is there anything else that could be included in the *Winter Review and Consultation* report?
3. How could the *Winter Review and Consultation* report be improved to increase its value?
4. Do you have any other feedback on this report or the wider suite of outlook documents?

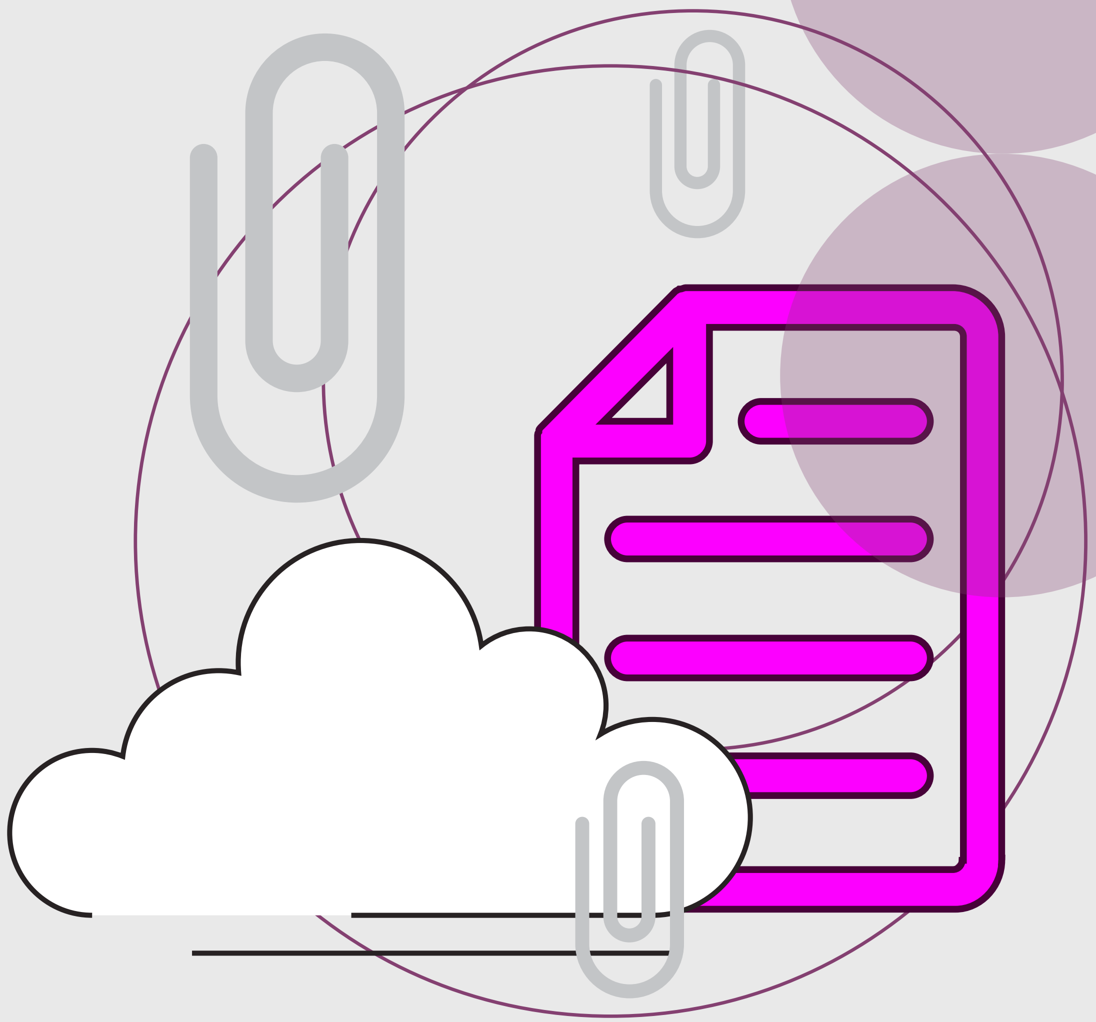
Winter Outlook

5. What would you like to see included in the *Winter Outlook 2025/26* report, in terms of content or modelling?
6. Do you have any general queries or concerns relating to winter 2025/26?

Please send your views and responses to:
marketoutlook@neso.energy

The Operational Transparency Forum (OTF) also provides an opportunity for you to share your views on the winter ahead and ask us questions.

Appendices and Glossary



Appendix A: How operational tools impact demand

The operational tools available for use can impact the demand observed by our control room, as demonstrated in Figure 9 below. The definition of Transmission System Demand (TSD) does not currently include battery storage.

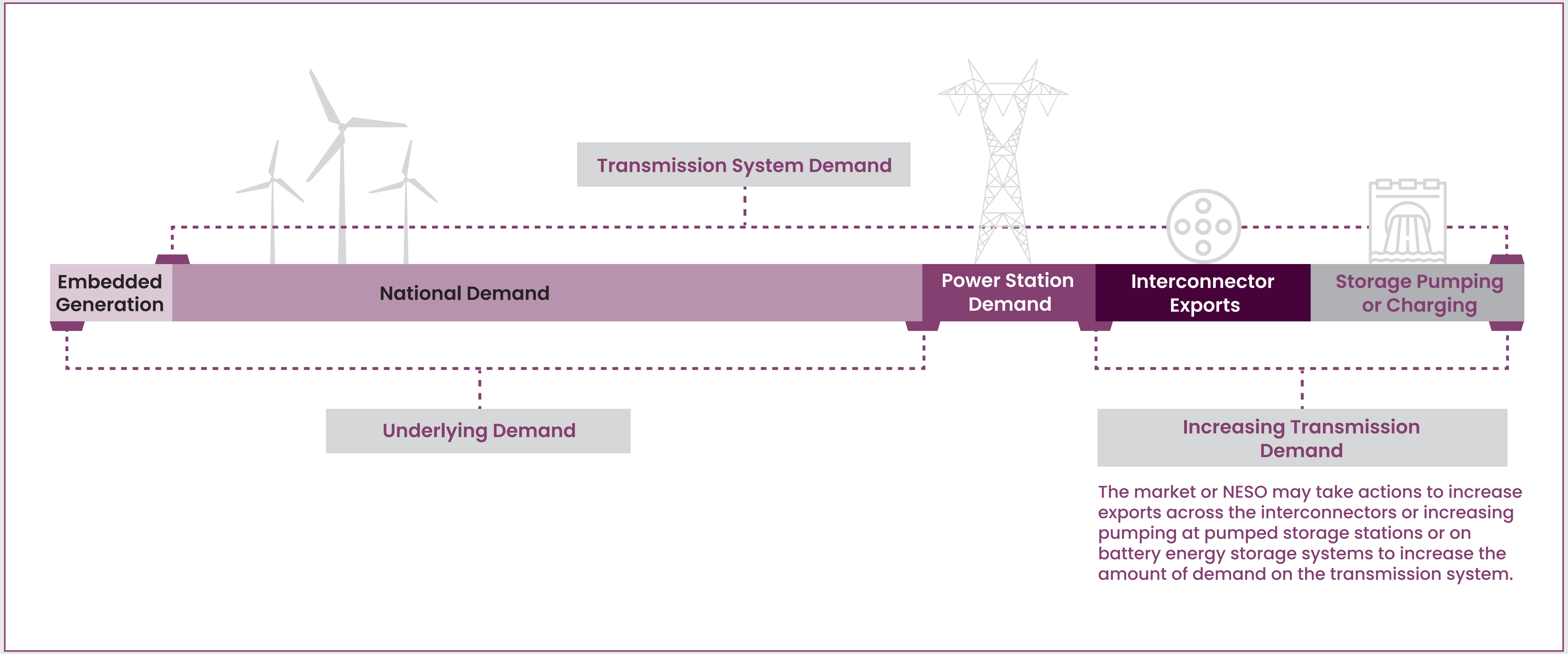


Figure 9: Shows the relationship between types of demand (this is not to scale)

Appendix B: Capacity Market Notices (CMNs) and Electricity Margin Notices (EMNs)

As NESO, one of our key roles is to reliably operate the electricity transmission system, enabling the flow of electricity around the country from where it is generated to where it is needed. To do this, we ensure the supply of electricity from the market always matches demand. This process is known as 'balancing' the system, and it is managed by our national control room.

Our control room experts have a range of operational tools at their disposal to maintain this balance – the primary one being the Balancing Mechanism (BM). Balancing effectively and efficiently requires continuous communication with the electricity market.

On rare occasions, when supply and demand cannot be balanced through the normal mechanisms, we issue formal communications to the market. These messages are known as system notices and include both CMNs and EMNs. A CMN is an indication to all market parties with a capacity market obligation that they should be ready to supply their committed capacity.

While CMNs and EMNs are based on the same fundamental data (such as generator availability and demand forecasts) they differ in how they are triggered, the thresholds at which they are issued, the treatment of constraints and their lead times.

Table 2: Differences between CMNs and EMNs

Aspect	Capacity Market Notices (CMNs)	Electricity Margin Notices (EMNs)
Trigger	Automatically issued four hours ahead of real time based on specific market data relating to the system's operating margin.	Issued manually by the control room based on operational and engineering judgment.
Threshold	Triggered when the volume of available generation above the sum of forecast demand and the Operating Margin is less than 500 MW. This threshold is set in the Capacity Market Rules.	No fixed threshold; issued based on expert assessment, which can result in some variance compared to CMNs.
Constraints	Do not account for transmission system constraints that may prevent capacity from being delivered.	Account for transmission system constraints and operational conditions.
Lead time	Issued four hours ahead of the anticipated shortfall.	Can be issued at any time, typically from the day-ahead stage onwards.

Appendix C: Unavailability factor methodology

To assess the availability of supply throughout the winter, we need to consider both planned and unplanned generator outages.

Planned outages are included in our supply assessment using the latest market submissions provided to us by generators. Actual availability may deviate from this schedule due to the re-scheduling or extension of existing outages, or due to new planned or unplanned outages occurring during the season. We use historic variation from expected availability to inform our forecast of how available supply is likely to change across winter.

Unavailability factors are derived, per fuel type, based on historic data using the following methodology:

1. Estimate the maximum capacity of each unit as a benchmark for actual availability. The maximum capacity of each generator is calculated as the highest output achieved for two consecutive half hour periods over the past year.
2. Identify the periods of high demand over the last three winters. Periods when half hourly demand is greater than the 80th percentile for the season are considered a peak demand period. We utilise weekday data between settlement period 20 and 40.
3. Determine the availability of generators for each of the peak demand periods over the last 3 winters. Availability is provided by the Maximum Export Limit via operational data.
4. For each generator exclude any periods when there is a planned outage (submitted prior to the start of the season).
5. Find the availability rate of each generator. This is the average of the availability across all peak demand periods divided by the maximum capacity of the unit.
6. Determine the average availability rate per fuel type.
7. Convert the availability rate to unavailability rate.

How does the methodology differ to previous years?

Under our previous methodology we compared each generator's maximum technical capacity against the maximum export limit (MEL). Under our new methodology, the maximum capacity of each generator is calculated as the highest output achieved for two consecutive half hour periods over the past year.

Glossary

Average cold spell (ACS) peak demand
The ACS peak demand is the estimated peak electricity demand during winter under cold weather conditions. As this figure is the average there is a 50% chance (in any given winter) that actual demand will the ACS peak demand. The ACS methodology accounts for changes in consumer behaviour due to weather variability – for example more heating demand when it is colder - and the variability in weather dependent distributed generation, such as wind. These two elements together have a significant effect on peak electricity demand.

Baseload electricity
A market product for a volume of energy across the whole day (the full 24hrs) or a running pattern of being on all the time for power sources that are inflexible and operate continuously, such as nuclear generation.

BritNed
BritNed Development Limited is a joint venture between Dutch TenneT and National Grid in the UK that operates the 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 a 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.

Distribution connected generation
Any generation or storage connected directly to the local distribution network, as opposed to the 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.

East West Interconnector (EWIC)
A 500 MW 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 a 1 GW in either direction of flow.

Embedded generation
Power generating stations/units that are not directly connected to the National Grid electricity transmission network for which we do not have metering data/information. They have the effect of reducing the electricity demand on the transmission system.

Floating
When an interconnector is neither importing nor exporting electricity.

Forward prices
The predetermined delivery price for a commodity, such as electricity or gas, as decided by the buyer and the seller of the forward contract, to be paid at a predetermined date in the future.

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

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

Interconnexion France – Angleterre (IFA)
A 2 GW interconnector between the French and British transmission systems. Ownership is shared between National Grid and Réseau de Transport d'Electricité (RTE).

Interconnexion France–Angleterre 2 (IFA2)
A 1 GW interconnector between the French and British transmission systems commissioned early 2021. Ownership is shared between National Grid and Réseau de Transport d'Electricité (RTE).

Interconnector (electricity)
A transmission assets that connects the electricity market in Great Britain to other markets including Continental Europe, Norway, Ireland and Northern Ireland. By purchasing capacity, market participants are able 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. These are 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 500 MW interconnector between Northern Ireland and Scotland.

National electricity transmission system (NETS)
The high-voltage system that transports electricity from where it is produced to where it is used. It consists of high voltage electricity wires that extend across Britain and nearby offshore waters. It is owned and maintained by regional transmission companies and operated by NESO.

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 the 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.

Normalised peak transmission demand
The peak demand seen on the transmission system, forecast using long-term trends and calculated with the effects of the 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
The annual planned maintenance period, which requires a complete shutdown, during which essential maintenance 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 in response to manage system frequency as required.

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 sources of extra power (in the form of increased generation or demand reduction), enable us to correct energy imbalances and respond to errors in forecasts. The technical features of each service are designed to ensure the reliable delivery of active power at different timescales, depending on the underlying system need they address.

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.

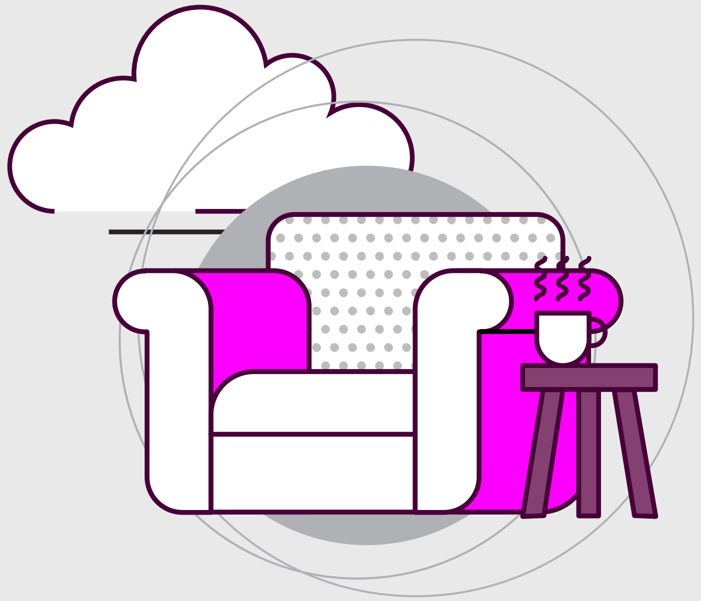
Transmission system demand (TSD)
Demand that NESO sees at Grid Supply Points, which are the connections to the distribution networks.

Underlying demand
Demand varies from day to day, depending on the weather and the day of 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 demand expected or outturned with the impact of the weather removed. A 30-year average of each relevant weather variable is constructed 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

We welcome your views on the *Winter Review and Consultation 2025/26*.
You can email us at marketoutlook@neso.energy and we will get back to you.

You can write to us at: **Energy Security Modelling**

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The *Winter Review and Consultation 2025/26* is part of a suite of documents published by NESO.

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Registered in England and Wales

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