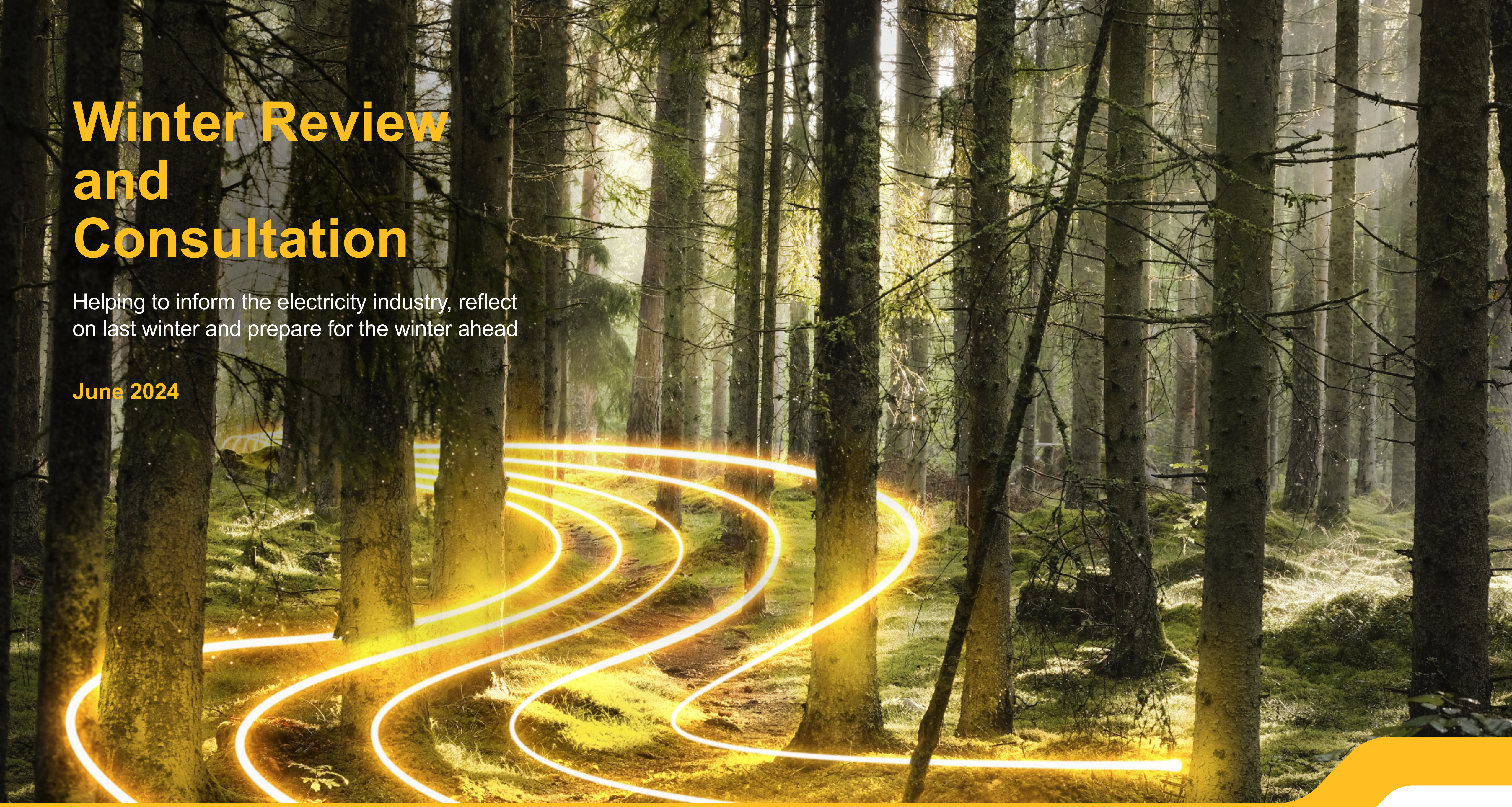
Winter Review and Consultation

Helping to inform the electricity industry, reflect on last winter and prepare for the winter ahead

June 2024



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Welcome

Welcome to our 2023/24 *Winter Review and Consultation* Report.

This annual document provides a review of what we said in the 2023/24 *Winter Outlook Report* and how it compared to what actually happened.

This document includes a review of the analysis from the 2023/24 *Winter Outlook Report* including how the prevailing weather conditions, demand levels, generator availability and interconnector flows which determine the operational surplus compared to our forecasts.

We have published an early view of winter 2024/25 alongside this report, to give early assessment of the security of supply outlook to help industry prepare for the coming winter.

As with previous years, the consultation section of this report focuses on the winter review for 2023/24 and the upcoming *Winter Outlook Report* for 2024/25.

However, we welcome feedback on all our potential plans and preparations for the upcoming winter, so we will make sure any comments and information received via this document are passed to the relevant teams within the ESO.

If you would like to share your views, or if you have any general queries or comments, please don't hesitate to email us at marketoutlook@nationalgrideso.com, join us for a discussion at our Operational Transparency Forum (OTF), or get in touch **via LinkedIn or on X (previously Twitter) @NationalGridESO**.

National Gas Transmission (NGT) has published a similar document, the 2024 *Gas Transmission Winter Review and Consultation report*.

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List of Figures and Tables

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Tables

1. Key Messages

Winter Review 2023/24

1. Margins

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.

Winter 2023/24 was milder than average with two notable cold spells in November, December and January. There were no Electricity Margin Notices (EMNs) or Capacity Market Notices (CMNs) issued during winter 2023/24.

There were a small number of days over winter where the outturn surplus fell below the range presented in the *Winter Outlook Report*. In late winter unplanned nuclear outages led to reduced generation and therefore a prolonged period when the operational surplus was below the *Winter Outlook Report's* forecast.

Interconnector capacity across the winter was sufficient to support the flows forecast in the *Winter Outlook Report*. Reciprocal support between European system operators helped maintain an efficient position across all markets, delivering benefits for us and our European neighbours. Great Britain was a net importer across interconnectors over the period but was able to support net exports when needed, including over peak periods.

2. Demand

Outturn demand was generally lower than the central forecast published in the *Winter Outlook Report* due to generally mild weather conditions throughout most of winter.

Daily weather corrected peak demand was broadly in line with the central forecast in the *Winter Outlook Report*, remaining within the assessed range presented in the winter outlook.

The highest observed peak demand of the winter was close to our average cold spell (ACS) peak forecast, whilst outturn demand during cold spells in November, December and January also remained within the expected range.

3. Balancing Costs

Balancing costs over winter 2023/24 have fallen by over 40% year-on-year, principally driven by lower wholesale costs and activities undertaken by the ESO to minimise cost to consumers.

In Spring 2024, we published our first annual balancing costs report. As well as offering projections on balancing costs over the next decade, it also details the impact of the wide range of the ESO's activities to minimise costs. The report, along with further information can be found on our balancing costs webpage.

2. Surplus Review

Margins were adequate throughout winter. Daily operational surpluses were, on average, lower than forecast in the Base Case of the *Winter Outlook Report* but largely remained within the credible range.

We observed a small number of days when margins were tight in early winter.

Demand

The daily peak demand was generally lower than the *Winter Outlook Report's* central forecast, as shown in Figure 1. However, periods of cold weather in late November, early December and mid-January led to a few periods of higher than forecast demand.

The actual winter peak demand including reserve was slightly lower than the ACS peak including reserve (47.6 GW vs 48.2 GW) and occurred during the cold spell in January.

Further analysis on the demand can be found on page 8.

Supply

Generator and interconnector availability was generally in-line with the *Winter Outlook Report's* expectations, with the notable exceptions of unplanned, extended nuclear outages in February and March. IFA2 also had a long-term unplanned outage from mid-November to late February.

Further analysis on the generator availability can be found on page 9. Further analysis on interconnector flows can be found on pages 12–15.

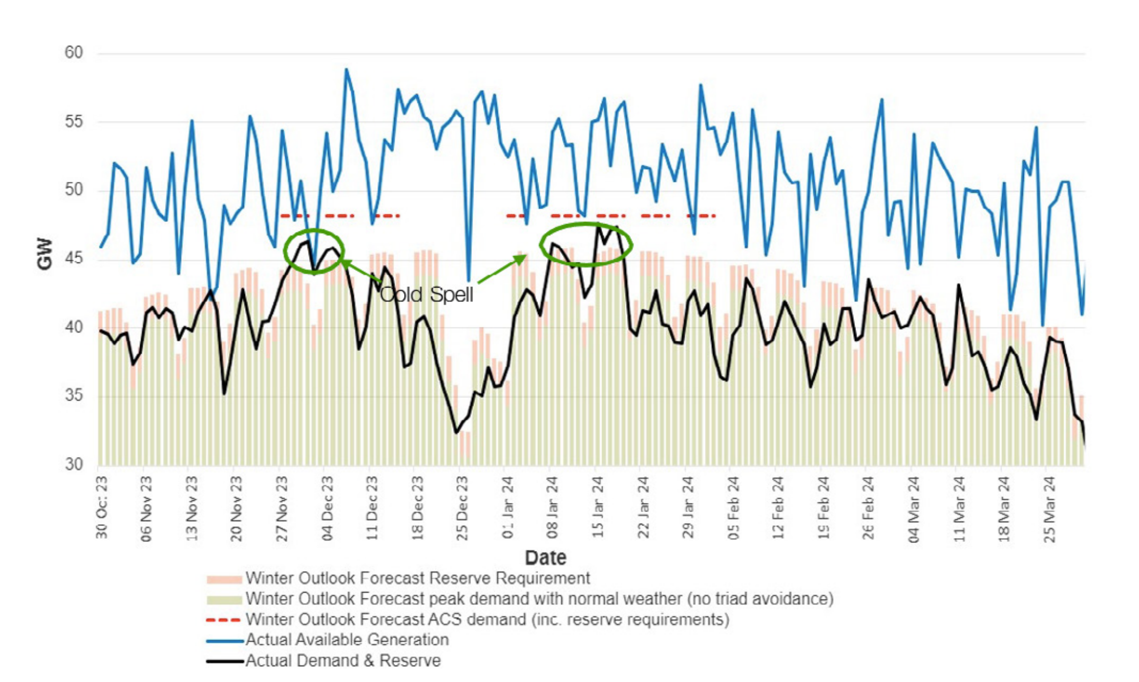

Figure 1: Winter 2023/24 day-by-day view of operational surplus. Forecasts from the *Winter Outlook Report* of demand are compared to the actual available generation and demand.

Interpreting this chart: Figure 1 shows our forecasted day-by-day peak demand under normal weather conditions (green bars) and an indicative reserve requirement (orange bars) from the 2023/24 *Winter Outlook Report*. It also shows the forecasted peak demand under average cold spell conditions (dashed red line) also from the 2023/24 *Winter Outlook Report*. The solid black line shows the actual peak demand for each day during winter. The solid blue line shows the actual available supply at peak for each day during winter. Margins were tighter on days when the solid blue and black lines were closer together.

Surplus Review Cont.

The daily operational surplus varied throughout winter but was largely in line with the credible range set out in our Base Case. Late season generator unavailability, and wind generation below our assessed range, led to instances of a lower-than-expected operational surplus.

Figure 2 shows how the indicative outturn surplus (solid blue line) was generally within the expected credible range (shaded region) set out in the *Winter Outlook Report*.

The outturn surplus was generally below the central forecast for large parts of winter. This was due to:

- low wind generation on individual days in mid-November led to lower operational surpluses
- cold spells observed in late November, early December and mid-January led to increased demand
- unplanned, extended nuclear outages in February and March, and an unplanned outage on IFA2, leading to lower-than-expected generation.

The surplus shown in Figure 2 shows our assumed reserve requirement of 1.8 GW (dotted red line on Figure 2). The actual reserve requirement on each day varies, depending on a variety of factors including the prevailing weather conditions. There was no requirement to issue system notices due to insufficient margins during the period as sufficient reserves were maintained.

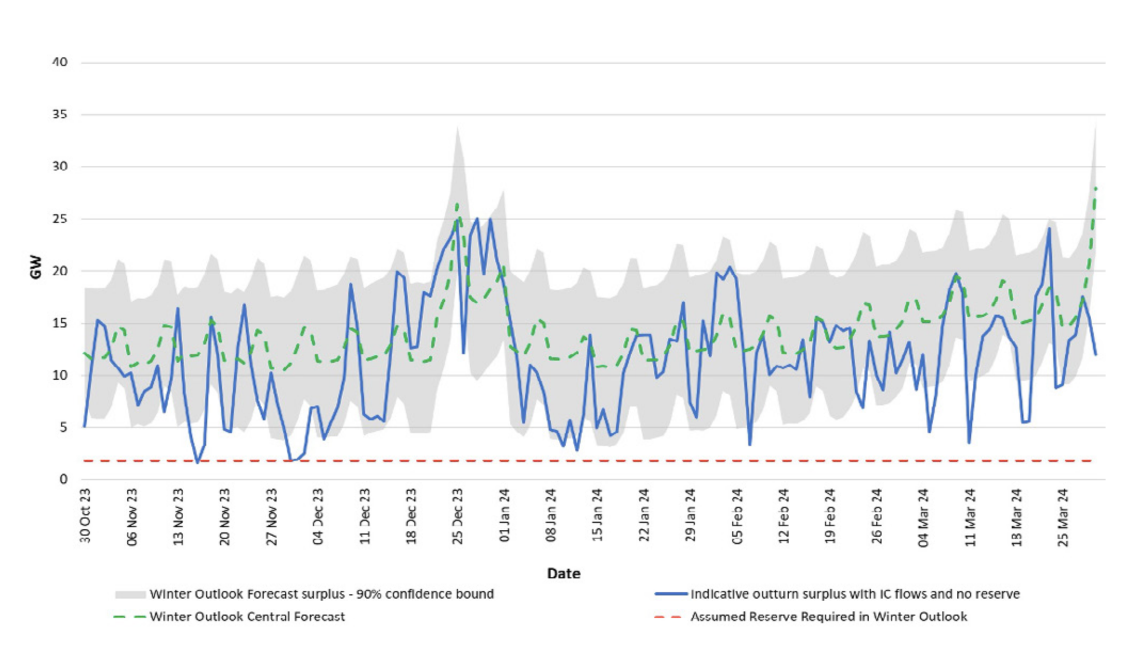

Figure 2: Day-by-day view of the operational surplus for winter 2023/24 against the forecast surplus and credible range sensitivity from the *Winter Outlook Report*.

Interpreting this chart: Figure 2 shows the forecast range of operational surplus that we expected on each day's demand peak throughout winter as published in the 2023/24 *Winter Outlook Report*. This range (shaded region) represents the 90% confidence bound reflecting day-to-day variations in weather and available generation as such we would expect to see instances of individual days where the operational surplus is outside of this range. A central view (dashed green line) was also published in the *Winter Outlook Report*. The solid blue line shows an indicative view of the outturn operational surplus on each day.

3. Demand Review

The outturn demand observed during winter was well captured by the credible range published in the *Winter Outlook Report*. Outturn demand throughout winter was generally lower than the central forecast of the *Winter Outlook Report* due to mild temperatures. There were two prolonged periods where temperatures remained below seasonal normal for multiple days, leading to high demands. However, this was still largely within the published credible range.

Figure 3 shows that weather corrected demand observed over winter was broadly in line with the forecast in the *Winter Outlook Report*.

Figure 4 shows that, in general, the outturn demand (solid purple line) was lower than our central forecast (dashed green line). However, periods of cold weather in late November, early December and in mid-January led to relatively high demands (close to the top of the credible range (red shaded region) from the *Winter Outlook Report*.

The actual peak transmission system demand was 45.8 GW on 15 January with a weather corrected peak demand of 44.7 GW.

See Appendix A for more information on the different demand definitions.

Table 1: Peak transmission system demands (TSD)* for winter 2023/24

2023/24 *Winter Outlook Report* forecast peak (normal weather) (GW)	Actual 2023/24 peak (weather corrected) (GW)	Actual 2023/24 peak (GW)
44.1	44.7	45.8

* For the purpose of the outlook and review reports, TSD includes national demand, 600 MW of station load and 750 MW export to Ireland on interconnectors (over the peak only).

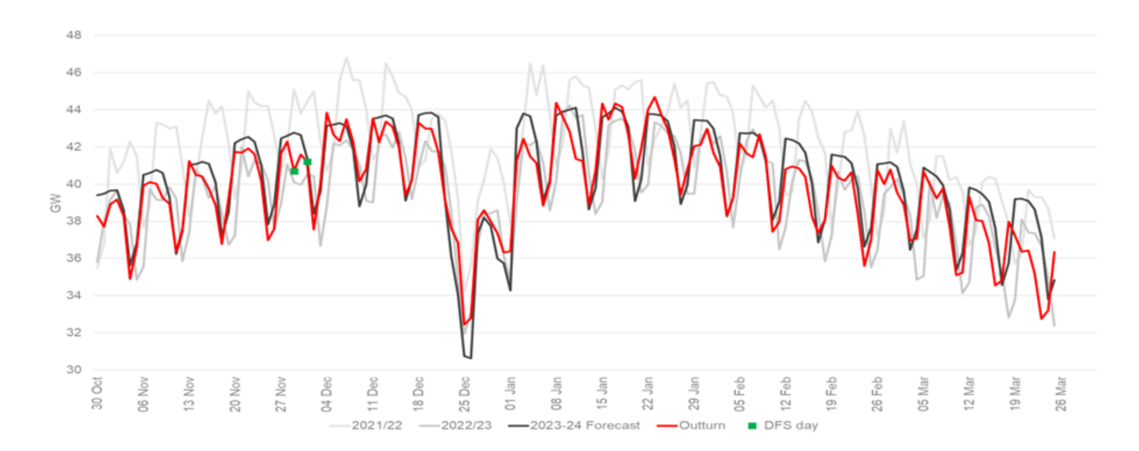

Figure 3: Peak Transmission System Demand (TSD) outturn (weather corrected) for winter 2023/24 compared to the *Winter Outlook Report's* forecast.

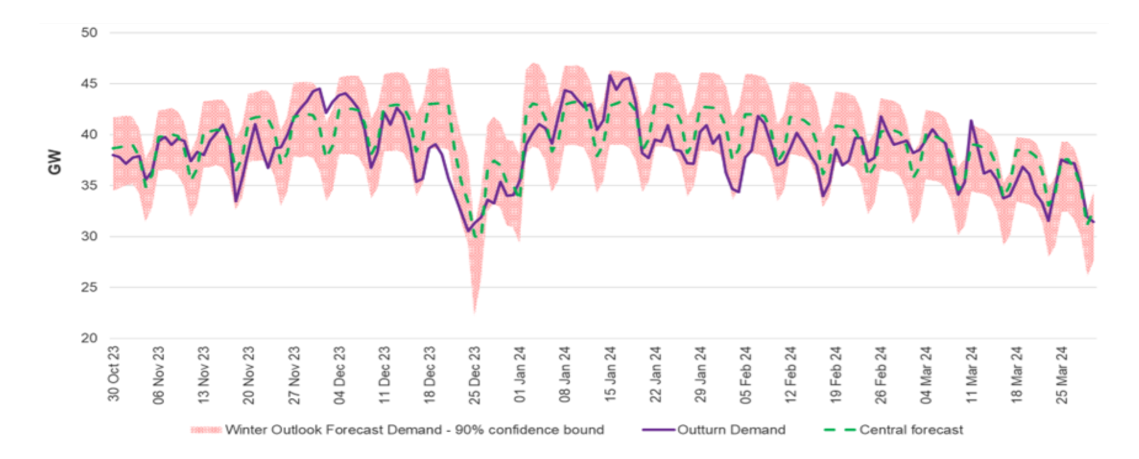

Figure 4: Comparison between the daily outturn peak demand and our forecasts from the *Winter Outlook Report*. The dashed green line shows our central forecast, while the red-shaded region represented a credible range for our forecast reflecting natural variation in weather.

4. Supply Review

The proportions of electricity provided by wind and interconnectors increased compared to winter 2022/23, displacing gas generation and replacing lower nuclear generation.

	What did we say in the *Winter Outlook Report*?	What actually happened?	Why was there a difference?
Capacity and the percentage of electricity provided by fuel type.	Based on market submissions, we expected higher generator capacity than last year, driven primarily by small increases to the contribution from wind, additional coal availability and additional capacity from CCGT units.	While capacity additions were in line with expectations, we saw an increase in the proportion of electricity from wind generators and interconnectors year-on-year. This was offset by a reduction in the proportion of electricity from CCGTs and nuclear generators.	Extended, unplanned nuclear outages in February and March led to a reduced proportion of electricity coming from nuclear sources. The commissioning of Viking Link in December 2023 enabled imports from Denmark, which were not available in the previous winter and was not included in the *Winter Outlook Report's* modelling.
Breakdown rates (this term covers all aspects of plant reliability, including restrictions and unplanned generator breakdowns, but not planned unavailability known ahead of winter).	The assumed breakdown rates are based on historic data, reflecting generator performance over the last three winters. The assumed breakdown rates were generally similar to the previous winter.	Nuclear breakdown rates were significantly higher than forecast in the *Winter Outlook Report* as shown in Table 2.	We saw extended, unplanned outages in February and March which were not included in our forecast.

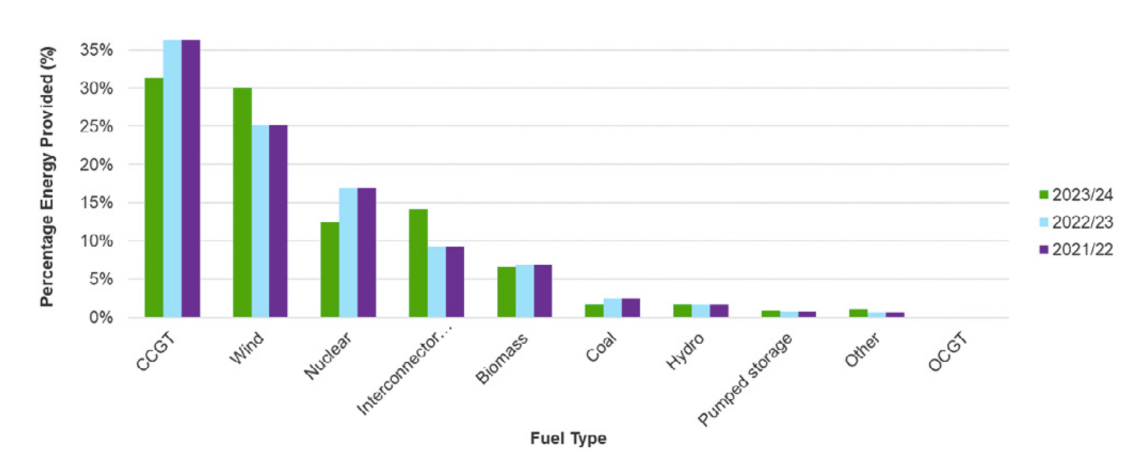

Figure 5: Percentage of electricity provided by each fuel type over winters 2021/22, 2022/23 and 2023/24 (transmission connected generation only).

Table 2: Breakdown rates by fuel type for winter forecast and actual winter. Weighted average is calculated based on derated capacity.

Fuel type	Forecast	Actual
Coal	9%	25%
CCGT	6%	7%
Nuclear	14%	39%
OCGT	7%	11%
Pumped storage	3%	3%
Biomass	5%	3%
Hydro	9%	9%
Weighted average	7%	12%

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Supply Review Cont.

Generator Availability

Generation availability fluctuated around our expectations in our *Winter Outlook Report*.

Figure 6 shows the how the actual available generation at real time (including actual wind output) compared with the expected available generation. This includes availability notified at the time of publication and wind at its Equivalent Firm Capacity (EFC) as forecast in the *Winter Outlook Report*.

In early winter, until the end of January, availability was generally above that estimated in the *Winter Outlook Report*. There were a few periods with low generator availability, mostly due to lower wind generation. However, these periods were not prolonged. From February onwards we saw a greater number of days where generator availability was below the forecast in the *Winter Outlook Report*. This was caused by unplanned, extended nuclear outages.

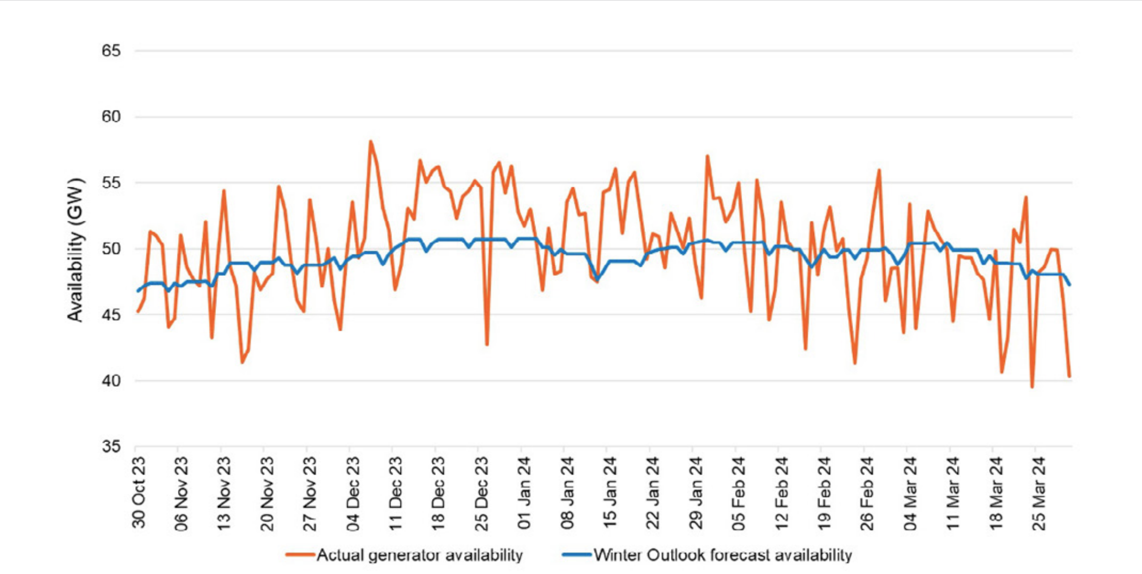

Figure 6: Shortfall between generation availability notified in the *Winter Outlook Report* and actual generator availability (including wind generation).

Wind Generation Output

Wind generation during peak demand was highly variable throughout winter but generally higher than the Equivalent Firm Capacity level.

For wind generation, we consider a shortfall to be the gap between actual wind generation on a given day and the level assumed in the *Winter Outlook Report*, which is based on a statistical consideration of the contribution of wind to capacity adequacy (i.e. not its average annual load factor).

Figure 7 shows this Equivalent Firm Capacity (EFC) for wind and the actual availability throughout the winter at peak periods. Wind generation output was generally higher than the EFC level, however there were a number of days over winter where the output was below the EFC level. An increasing number of these days fell in February and March and would have contributed to the low surplus on those days, where outturn surplus fell below the forecast range (see page 7).

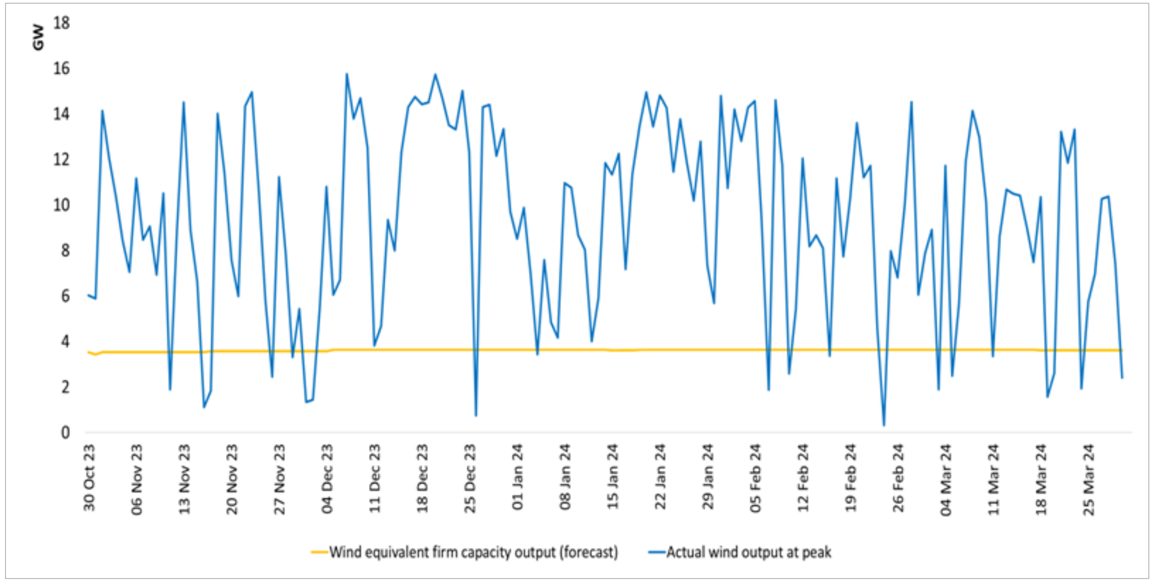

Figure 7: Wind output at peak against equivalent firm capacity.

5. Spotlight: Demand Flexibility Service

Our Demand Flexibility Service (DFS) demonstrated that demand flexibility can be provided at national scale, allowing customers to benefit from shifting electricity usage away from specific periods. Participation grew over winter 2023/24 highlighting the potential for further growth of such services.

The Demand Flexibility Service (DFS) allows consumers, as well as some industrial and commercial users, to be incentivised for voluntarily reducing their electricity demand when we need them to. The DFS tool has been an enhanced action available to us and was used as part of a range of tools designed by the ESO to help manage the electricity system.

The DFS tool was first introduced in winter 2022/23 in response to the threat of global gas supply shortages following Russia's illegal invasion of Ukraine. We continued to include the service within our operational toolkit for winter 2023/24, refining and developing the service.

2.6 million reach

c.450 MW submitted capacity

48 DFS registered providers

14 onboarding & regular tests

2.7 GWh delivered in test events

2 Live events

1.0 GWh delivered in live events

For more information on the live DFS events, please visit our Operational Transparency Forum webpage where you can find a recording of the webinar and slides from 13 December 2023.

During winter 2023/24 we introduced within-day procurement windows, allowing us to gain a better understanding of the how delivery and performance of the service changes when procured closer to real time.

Competitive bidding was introduced to test events for the first time and allowed us to gain insights into different scenarios. These tests have been an important development of the service and will allow us greater clarity and insight as we consider how we might develop and evolve the service.

Insights and data from DFS tests and live events will be used to update the Consumer Building Blocks, which will be used by the ESO as one of the tools to model how consumers may adapt their energy consumption in different conditions. We opened a feedback questionnaire to industry on their thoughts for the evolution of DFS going forward. This closed on 24 April and will help us shape any future iteration of the service.

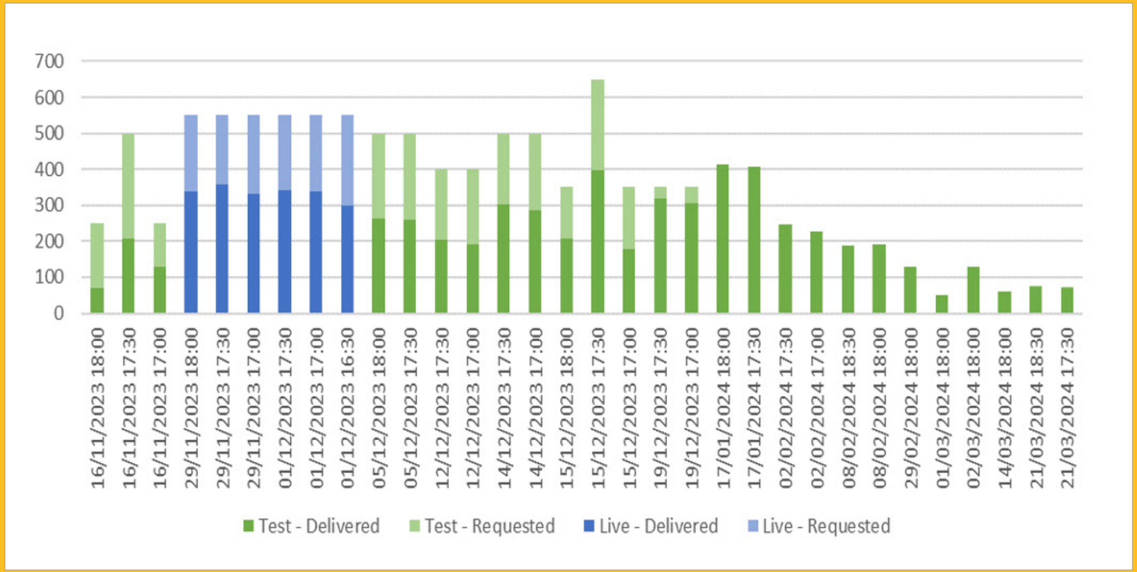

Figure 8: The volume of generation requested in our test and live events along with the generation delivered. In a few test events slightly more generation was delivered than requested, which is not shown on the graph.

6. Europe and Interconnected Markets Review

Continental Interconnector Flows

Across the winter, interconnectors with continental Europe were generally importing to Great Britain over peak periods, following the direction of the price spreads over winter.

Interconnectors continued to be mutually beneficial for Great Britain and connected countries over winter 2023/24. At the time of publishing the *Winter Outlook Report*, price spreads between Great Britain and some interconnected countries were narrow, giving a limited signal of expected flow directions over interconnectors.

	What did we say in the *Winter Outlook Report?*	What actually happened?	Why was there a difference?
Overview of continental European interconnectors (BritNed, IFA, IFA2, Nemo Link, NSL and Viking Link).	We expected to see periods when exports flow from Great Britain to Europe, including over some peak periods.	Over winter we saw Great Britain being an importer of electricity from continental Europe over peak periods on the vast majority of days (see Figure 9). We did see exports to Europe over peak periods on a small number of days. This included 7 December when wind generation remained above 15 GW across the peak.	Electricity prices in continental Europe were generally lower than those in Great Britain over winter.
	We expected to see net imports from Norway across the NSL interconnector across the winter period, particularly over peak periods.	For the vast majority of days, we saw imports of electricity across NSL at peak.	Imports were seen over NSL on over 90% of peak periods. Imports were at, or near, maximum capacity on over 70% of peak periods. This was in line with our expectation.

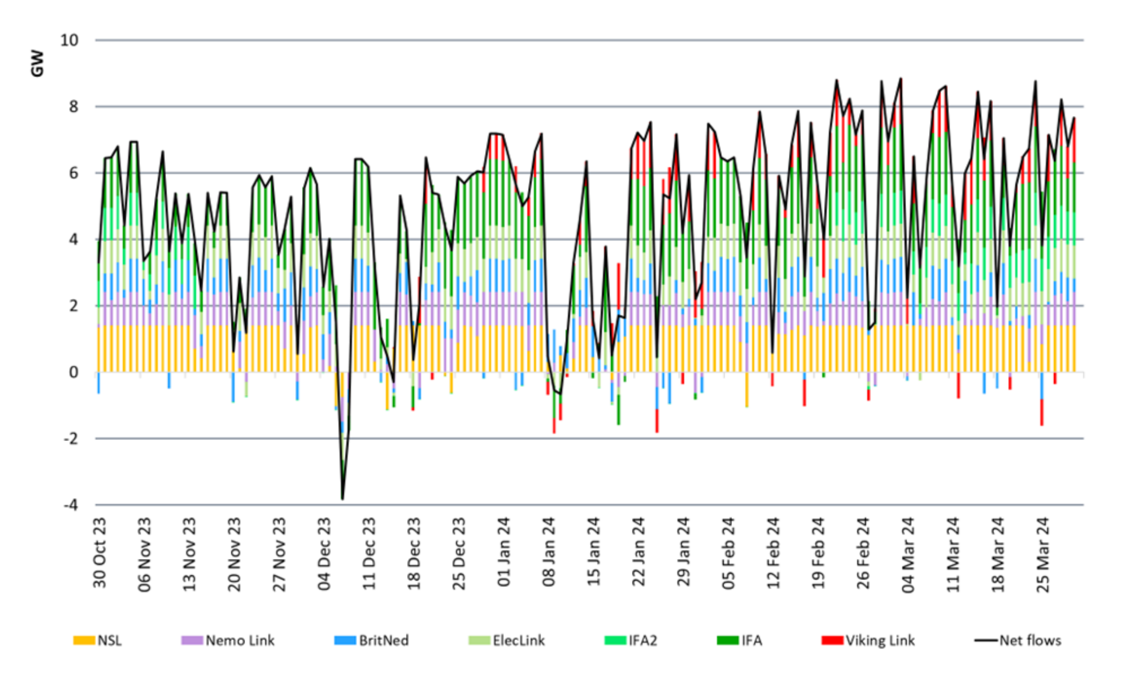

Figure 9: Continental interconnector flow at peak times.

Europe and Interconnected Markets Review Cont.

Continental Europe Prices

Day-ahead peak prices in Great Britain were generally higher than those in continental Europe across the period. Early winter saw the highest price spreads between Great Britain and continental European markets.

	What did we say in the *Winter Outlook Report*?	What actually happened?
European forward prices.	At the time of publishing the *Winter Outlook Report*, price spreads between Great Britain and continental European countries were narrow, providing a limited signal for the direction of flows.	Over winter we saw that day-ahead peak prices in Great Britain were generally higher than those of connected European countries, leading to Great Britain being a net importer during peak periods on the vast majority of days.

Table 3: Market wholesale electricity prices, comparing the forward market data published in the *Winter Outlook Report* (sourced from Bloomberg and Argus) to the average day-ahead prices across the winter. Note: forward prices were not available for all European markets.

Market	*Winter Outlook Report* peak prices (£/MWh)	Average day-ahead peak prices (£/MWh)
GB	£134	£83
France	£139	£68
Netherlands	£118	£74
Belgium	N/A	£72
Norway	N/A	£64
Denmark	N/A	£66

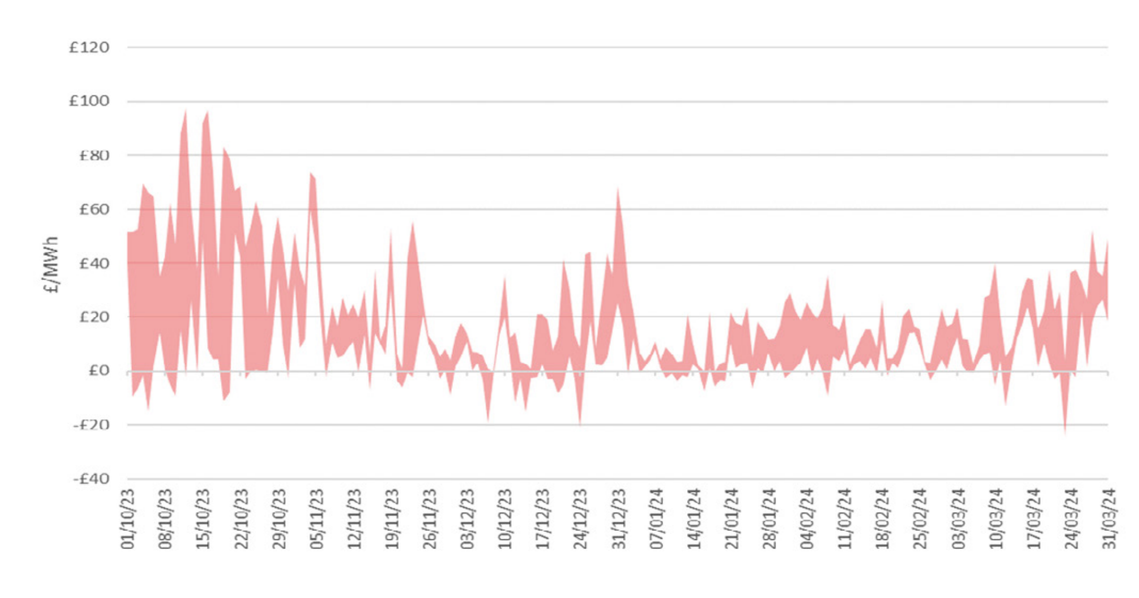

Figure 10: Winter 2023/24 day-ahead peak price spreads between Great Britain and the interconnected European countries in Table 3.

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Europe and Interconnected Markets Review Cont.

Continental Interconnector Availability

Available interconnector capacity was more than sufficient throughout winter to support the flows assumed in the Base Case of the *Winter Outlook Report*.

In the *Winter Outlook Report*, we assumed continental interconnectors would deliver imports in line with capacity market agreements over peak periods and that Irish interconnectors would export 750 MW.

What did we say in the *Winter Outlook Report*?	What actually happened?	Why was there a difference?
There were no planned winter outages for any interconnectors at the time of publication of the *Winter Outlook Report*.	Available interconnector availability was at, or near, full capacity for the majority of winter, as shown in Figure 11.	Interconnectors were largely operating at full capacity throughout winter with the exception of IFA2, which had an extended unplanned outage from mid-November to late February resulting in no capacity over the interconnector during this period. Despite the IFA2 outage, interconnector capacity was more than sufficient throughout winter to support the flows assumed in the *Winter Outlook Report*. Viking Link, a new interconnector connecting Great Britain to Denmark, commissioned on 29 December 2023, providing additional capacity of 800 MW, increasing to 1.4 GW over time. The *Winter Outlook Report* did not include this interconnector in its analysis as it had no capacity market contract in place for winter 2023/24.

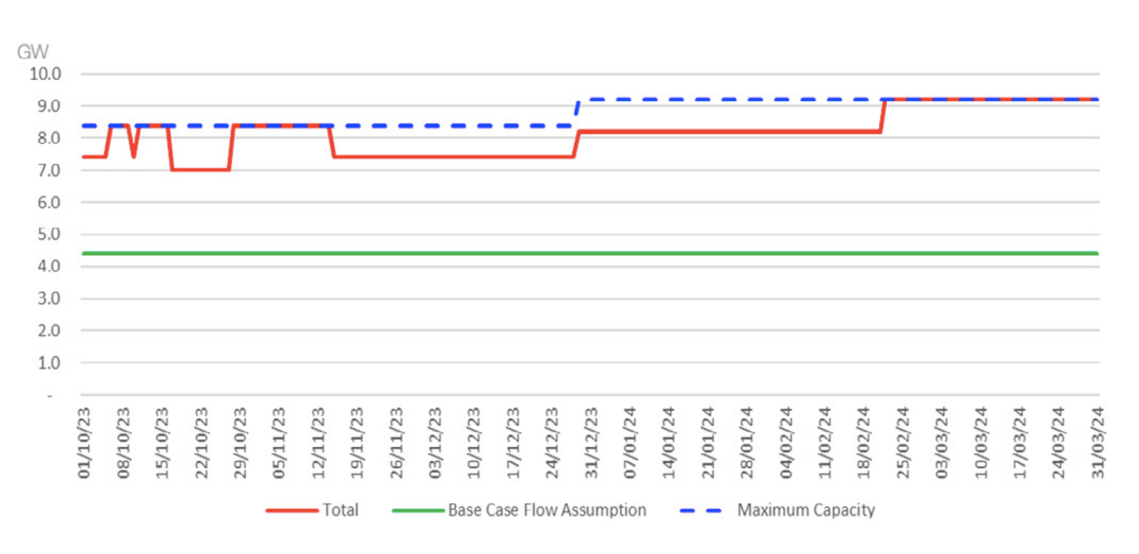

Figure 11: Actual interconnector availability compared to the availability known in the *Winter Outlook Report* (in each case continental Europe availability is netted off with Irish interconnector availability). The *Winter Outlook Report's* Base Case flow assumptions are also shown for context (Capacity Market levels for continental interconnectors and 750 MW export to Ireland).

Europe and Interconnected Markets Review Cont.

Irish Interconnector Flows

Exports across the EWIC and Moyle interconnectors to the Republic of Ireland and Northern Ireland were in line with expectations in the *Winter Outlook Report*.

In the *Winter Outlook Report*, we assumed continental interconnectors would deliver imports in line with capacity market agreements over peak periods and that Irish interconnectors would export 750 MW.

	What did we say in the *Winter Outlook Report*?	What actually happened?	Why was there a difference?
Overview of Irish interconnectors (Moyle and EWIC).	In our *Winter Outlook Report*, we stated that we expected to see net exports from Great Britain to Northern Ireland and Ireland during peak periods across the winter.	We did observe this, with net exports seen over the majority of peak periods and often at, or near, full capacity. There were times when we saw net imports across these interconnectors during peak periods.	Interconnector flows were generally in line with our expectations in the *Winter Outlook Report*.

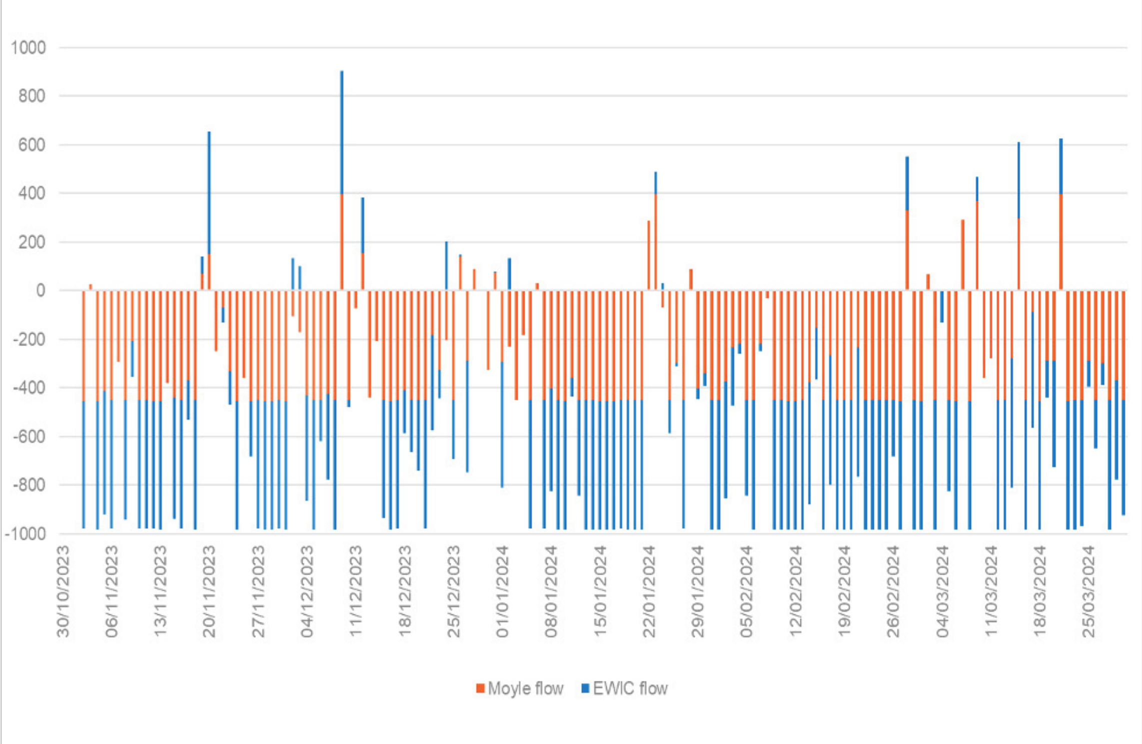

Figure 12: Moyle and EWIC flows at peak times (positive MW values mean flows into Great Britain).

7. Consultation Introduction

The purpose of this annual consultation is to gather feedback on our outlook documents and stakeholder insights each year to inform our analysis for the upcoming *Winter Outlook Report*, which will be published in autumn 2024.

Your views on the market and related issues are always important to provide a comprehensive picture of the challenges and opportunities for the forthcoming winter.

This consultation also allows us to test how useful the suite of outlook documents is and to identify areas for improvement in our engagement.

Feedback on our potential plans and preparations for the upcoming winter remains extremely important. We will ensure that any comments and information received via this document are passed to the relevant teams within the ESO.

This year's consultation closes on

5 July 2024.

Please refer to the next page for questions. You can send us your views via email: marketoutlook@nationalgrideso.com.

The ENCC Operational Transparency Forum will also provide an opportunity for you to share your views on the winter ahead and ask us questions.

Register for ENCC Operational Transparency Forum

Consultation Questions

Winter Review and Consultation

1. What do you use the *Winter Review and Consultation* Report for? What information in the report is most useful to you for this?

2. Is there anything else that could be included in the *Winter Review and Consultation* Report?

3. How do you think the *Winter Review and Consultation* Report could be improved more generally to increase its benefit to you?

4. Do you have any other feedback on this report or the other outlook documents?

Winter Outlook Report

5. What would you like to see in the 2024/25 *Winter Outlook Report*, in terms of content or modelling?

6. Do you have any general queries or concerns in relation to winter 2024/25?

Appendices

Contains extra information on demand definitions and margin notifications

Appendix A: Relationship between types of demand

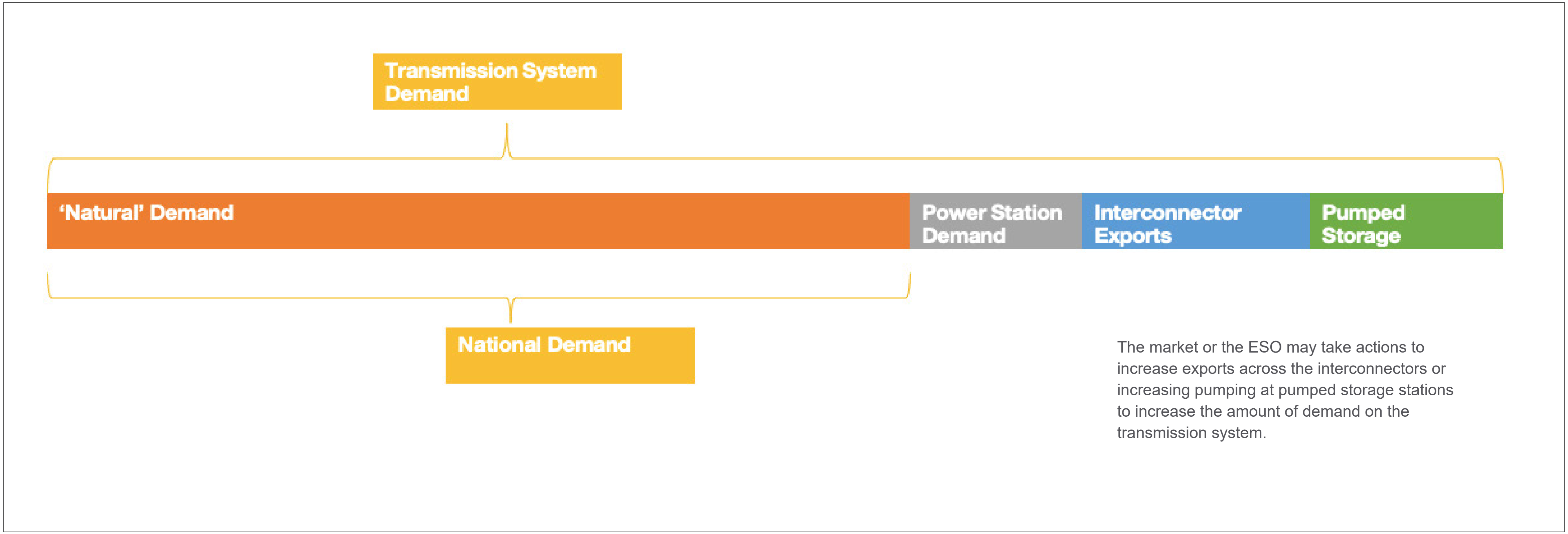

Figure 13: This figure shows the relationship between some of the different types of demand.

Appendix B: Capacity Market Notices and Electricity Margin Notices

Margins on the electricity system can vary throughout the winter. This will depend on actual weather patterns and outages taken by generators. The *Winter Outlook Report* also considers how margins could change on a week-by-week basis throughout winter for the transmission system only.

There are two views of margins which the ESO works with. **Capacity Market Margins** are based on whole system demand and whole system capacity (including Distributed Energy Resources (DERs)).

As the majority of DERs are not visible to the ESO, Operational Margins are based on transmission system demand and transmission system capacity. The EMN process is based around the **Operational Margins** and the CMN process is based around the Capacity Market Margins.

The EMN and CMN processes both rely on the visible generation as that is the data provided to the ESO. The *Winter Outlook Report* provides both margin views, the overall **Capacity Market Margin** for the winter as a whole and the weekly **Operational Margin**.

There are a number of significant differences between the operational System Warning messages (such as EMN) and Capacity Market Notices:

1. **Trigger** – Capacity Market Notices are issued based on an automated system margin calculation using data provided by market participants, whereas System Warnings are manually issued by the National Grid ESO control room using engineering judgement based on experience and knowledge of managing the electricity transmission system.
2. **Threshold** – Capacity Market Notices are triggered where the volume of available generation above the sum of forecast demand and Operating Margin, is less than 500 MW. The 500 MW threshold is taken from the Capacity Market Rules. System Warnings are triggered by varying volumes, for example a EMN may be issued where National Grid ESO expects to utilise 500 MW of its Operating Margin. There is therefore a 1,000 MW+ variance between these two discrete alerts.
3. **Constraints** – The Capacity Market Notice calculation does not take account of any transmission system constraints that may be preventing capacity from accessing the network. System Warnings however do take such constraints into account.
4. **Lead time** – Capacity Market Notices are initially issued four hours ahead of when the challenge is foreseen, whereas System Warnings can be issued at any time, but we would expect to issue a first EMN at the day-ahead stage.

Glossary

Average cold spell (ACS)
ACS methodology takes into consideration people's changing behaviour due to the variability in weather, e.g. more heating demand when it is colder and the variability in weather dependent distributed generation, e.g. wind generation. These two elements combined have a significant effect on peak electricity demand.

Balancing Mechanism
The Balancing Mechanism is a tool which we use to balance electricity supply and demand. It allows participants to set prices for which they will increase or decrease their output if requested by the ESO. All large generators must participate in the BM, whereas it is optional for smaller generators.

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, like nuclear.

Breakdown rates
A calculated value to account for unexpected generator unit breakdowns, restrictions or losses. Forecast breakdown rates are applied to the operational data provided to the ESO by generators. They account for restrictions and unplanned generator breakdowns or losses close to real time. Rates are based on how generators performed on average by fuel type during peak demand periods (7am to 7pm) over the last three winters.

BritNed
BritNed Development Limited is a joint venture between Dutch TenneT and British National Grid that operates the electricity interconnector between Great Britain and the Netherlands. It is a bi-directional interconnector with a capacity of 1 GW. You can find out more at britned.com.

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.

Capacity Market Notice (CMN)
Based on Capacity Market margins, which are calculated from whole system demand and whole system capacity. For more information about margins and system notices, see here.

Combined Cycle Gas Turbine (CCGT)
A power station that uses the combustion of natural gas or liquid fuel to drive a gas turbine generator to produce electricity. The exhaust gas from this process is used to produce steam in a heat recovery boiler. This steam then drives a turbine generator to produce more electricity.

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.

Demand Flexibility Service (DFS)
The Demand Flexibility Service (DFS) has been developed to allow the ESO to access additional flexibility when national demand is at its highest - during peak winter days - which is not currently accessible to the ESO in real time. This service incentivised consumers and businesses to reduce or reschedule their electricity use away from peak times. More details can be found here.

Demand suppression
The difference between out pre-COVID forecast demand levels and the actual demand seen on the system.

De-rated margin for electricity
The difference between out pre-COVID forecast demand levels and the actual demand seen on the system. The sum of de-rated supply sources considered as being available during the time of peak demand plus support from interconnection, minus the expected demand at that time and basic reserve requirement. This can be presented as either an absolute GW value or a percentage of demand (demand plus reserve). The formula was revised in winter 2017/18 to include distribution system demand, and in winter 18/19 to better account for interconnection. See our previous publications on our Winter Outlook webpage for further details

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

Glossary cont.

East West Interconnector (EWIC)
A 500 MW interconnector that links the electricity transmission systems of Ireland and Great Britain. You can find out more by visiting Interconnection on the EirGrid website.

ElecLink
A power interconnector through the Channel Tunnel to provide a transmission link between the UK and France with a capacity of 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.

Enhanced Actions
Enhanced actions are part of the ESO's order of actions for managing security of supply and are used if everyday actions are insufficient. For winter 2022/23, two additional enhanced services were developed: the Demand Flexibility Service and contingency coal contracts. Download Order of action – winter 2022 for more details.

Electricity Margin Notice (EMN)
Based on operational margins which are calculated from transmission system demand and transmission system capacity. For more information about margins and system notices, see here.

Equivalent firm capacity (EFC)
An assessment of the entire wind fleet's contribution to capacity adequacy. It represents how much of 100 per cent available conventional plant could theoretically replace the entire wind fleet and leave security of supply unchanged.

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.

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

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

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 (IFA 2)
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).

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

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.

Moyle
A 500 MW interconnector between Northern Ireland and Scotland. Find out more at *mutual-energy.com*.

MW Megawatt (MW)
A measure of power. 1 MW = 1,000,000 watts.

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

Glossary cont.

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.

North Sea Link (NSL)
A 1.4 GW HVDC sub-sea link from Norway to Great Britain commissioned in October 2021.

Operational surplus
The difference between the level of demand (plus the reserve requirement) and generation expected to be available, modelled on a week-by-week or day-by-day basis. It includes both notified planned outages and assumed breakdown rates for each power station type.

Outage
The annual planned maintenance period, which requires a complete shutdown, during which essential maintenance is carried out.

Outturn
Actual historic operational demand from real time metering

Peak electricity
A market product for a volume of energy for delivery between 7am and 7pm on weekdays.

Positive and negative reserve
The ESO maintains positive and negative reserve to increase or decrease supply and demand in response to manage system frequency as required.

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

Reserve requirement
To manage system frequency and to respond to sudden changes in demand and supply, the ESO maintains positive and negative to increase or decrease supply and demand and provides head room (positive reserve) and foot room (negative reserve) across all generators synchronised to the system.

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.

Transmission system demand (TSD)
Demand that the ESO sees at grid supply points, which are the connections to the distribution networks.

Viking Link
Viking Link is a 1400 MW high voltage direct current (DC) electricity link between the British and Danish transmission systems, commissioned in December 2023.

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.

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