Summer Outlook

Helping to inform the electricity industry and support preparations for the summer ahead

April 2024

ESO

Foreword

Welcome to our 2024 Summer Outlook.

This report contains our view of the electricity system for the coming season and is designed to support the industry in its preparations for the period.

In recent years, our Summer Outlook reports have sought to highlight our response to significant unfolding events, including the record-low demands resulting from unprecedented societal changes during the COVID-19 pandemic and the dramatic reshaping of global energy supply caused by Russia's illegal invasion of Ukraine.

For summer 2024, energy markets show signs of finding a new equilibrium. Wholesale prices have fallen significantly, reflecting high scheduled French nuclear availability, and robust European gas storage. While volatility in the energy markets shows signs of subsiding, the electricity system continues to change at pace.

The ongoing growth of **embedded generation** on the distribution networks continues to lower peak summer transmission demands and increase the significant variability in daily demand patterns.

New **interconnectors** and the rapid growth in grid scale battery storage provide significant additional flexibility with new opportunities to reliably and efficiently operate the system.

During the summer, our operational focus moves from managing winter margins and peak demands to the challenges of managing **minimum demand**. We expect that summer minimum demands will be similar to those seen in summer 2023 and are confident we continue to have the right tools in place to manage low demand periods.

We are confident of delivering our world-leading reliability standards throughout summer 2024.

Looking ahead, we have already begun our preparations for winter 2024/25 and will be looking to share our analysis with the industry over the coming months. By June, we intend to publish an early view of winter 2024/25. In September, we will publish the full Winter Outlook report.

As the ESO, we continue to adapt to meet the challenges of efficiently operating a rapidly changing electricity system and accelerate progress towards our net-zero ambition. As ever, we will continue to monitor risks to the electricity system and keep stakeholders up to date with any changes via the ESO Operational Transparency Forum.

National Gas Transmission has published a separate *Gas Summer Outlook Report 2024*.

You can join the conversation at our weekly ESO Operational Transparency Forum by emailing *marketoutlook@nationalgrideso.com* or by following us on X (previously Twitter) @NationalGridESO.

Kayte O'Neill
Chief Operating Officer
Electricity System Operator

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Executive Summary

We are confident we have the operational tools available to manage our rapidly changing electricity system, delivering a resilient, reliable and efficient network.

1. Security of Supply

We are confident of meeting our world-leading reliability standards throughout summer 2024.

We expect there to be sufficient available supply to meet demand at all times this summer. We expect to be able to support exports to neighbouring European countries if needed, continuing the close-working and coordinated support with our neighbouring transmission system operators.

2. Managing the System

We are confident that we can use our existing tools to manage system operability this summer.

Managing low demand is one of the most complex scenarios we face and can require a greater number of everyday actions to protect the network. These everyday actions include trading on the interconnectors to reduce imports, or pumping and charging storage to increase demand.

We will continue to derive significant operability and efficiency benefits from the pathfinder projects, our suite of dynamic frequency services, new balancing products, new systems and the delivery and implementation of the *Frequency Risk and Control Report 2023 (FRCR)* recommendations. These measures reduce cost, save carbon and provide significant additional flexibility at times of low demand.

3. Market Prices and Balancing Costs

We expect balancing costs for summer 2024 to be lower than those incurred in summer 2023.

This summer, although we expect a minor increase in the volume of balancing actions, the cost of these will be offset by a combination of falling wholesale prices and activities undertaken by the ESO to minimise costs to consumers as outlined in our *Balancing Costs Portfolio*. The forecast cost of our balancing actions for summer 2024 is prepared based on seasonal average conditions.

In Spring 2024, we will be publishing our first *Annual Balancing costs report* which will offer projections on balancing costs over the next decade and detail the impact of the wide range of the ESO's activities to minimise these costs.

Executive Summary

We are confident there will be sufficient supply to meet electricity demand over the summer and we will be able to meet the operational challenges associated with managing periods of minimum demand.

Demand

Seasonal normal summer minimum demand is expected to be marginally higher than last summer's **weather corrected outturn**, due to an increase in the installed capacity of battery storage connected to the distribution networks. However, the magnitude of the increase is lower than the level of uncertainty in our demand models. We expect that peak transmission system demand will continue to fall due to an increase in solar generation connected to the distribution networks. Historically minimum demand periods have occurred overnight, but this is showing signs of changing. In late April and early May, we consider the probability that the daily minimum demand will occur during the afternoon to approach 50%. The forecasts for demand throughout this report are for **Transmission System Demand (TSD)**, with interconnector flows, **pumped storage** and battery charging assumed to be zero. This is consistent with previous outlook reports[1].

Supply

Daily surpluses are typically greater during the summer due to lower peak demands. Minimum forecast generation is expected to be comfortably above summer peak demand.

As a prudent system operator, we continue to assess the daily surplus against a range of possible scenarios to ensure our ability to meet our world-leading reliability standards. We are confident that there will be sufficient available supply to meet demand, and our reserve requirement, throughout the summer accounting for variation in weather patterns and interconnector flows. We anticipate being a net importer from Europe across the period. We continue to expect interconnectors to be mutually beneficial at times of high and low demand and anticipate being able to support exports to neighbouring European countries if required.

Operability

We are confident that we have tools and actions available to manage operability challenges during periods of low demand. In order to balance supply and demand we will have to take actions on the system when demand is low, but these will mainly be everyday actions such as trading on interconnectors, or issuing everyday control room instructions to increasing demand through pumping or charging storage[2]. Scheduled pump storage availability is marginally higher than last year's forecast, but expected to be higher than last year's outturn availability. The ongoing growth of grid scale battery storage continues to provide additional flexibility at minimum demands. Should we exhaust our everyday actions, we have a further range of enhanced actions which afford further downward flexibility, such as issuing a **Negative Reserve Active Power Margin (NRAPM)**. For more information on the everyday, enhanced and emergency actions available to us see page 12.

Table 1: Key statistics

Summer 2024 forecasts (weather normal conditions)	GW
Electricity transmission high summer peak demand	29.2
Electricity transmission minimum demand	16.2
Electricity transmission daytime minimum demand	17.0
Minimum available generation	34.4

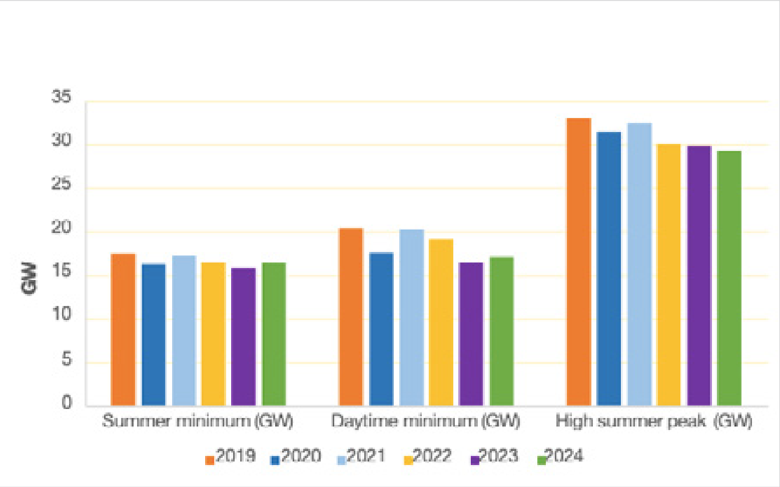

Figure 1: Weather corrected summer overnight and daytime minimum demand outturns for previous years and the summer 2024 forecast

1 See Appendix A for more information on different demand types

2 You can find out more information on *Balancing Mechanism (BM)* actions on our website

1. Demand Overview

Seasonal normal minimum transmission system demand for summer 2024 is expected to be marginally higher than last summer's weather corrected outturn, with high summer peak demand falling slightly.

This summer we expect:

- seasonal normal minimum demand to be 16.2 GW and to occur overnight
- the observed minimum demand could be as low as 13.5 GW under a 1 in 10-year weather pattern (see page 9)
- seasonal normal high summer peak demand to be 29.2 GW.

Unless otherwise stated, the demand values used in this report assume seasonal normal weather conditions and so are, in effect, average minimum demands.

Demands presented for previous years are the weather corrected outturn for National Demand plus Power Station Demand (station load) unless otherwise stated. They therefore does not take into account pumping, charging or interconnector flows. Likewise, when we forecast demand, it is National Demand plus Power Station Demand (station load) only. These demands are all at transmission level and therefore do not include demand that is met by generators connected below the transmission boundary. Increased levels of embedded generation appear as a reduction in transmission demand.

Appendix A and B provide more information on different demand definitions. We base our demand forecasts on seasonal normal weather, applying regression models to the average of various weather variables for the past 30 years. We then adjust our forecast to account for a standardised daily amount of embedded wind and solar generation (based on the seasonal normal weather and historical **load factors**).

High Summer Period

The period between 1 June and 31 August, or weeks 23 to 35, is when we expect the greatest number of planned generator **outages**. These are normal occurrences, typically for maintenance, and so are scheduled for summer as demand is lower than in winter and so do not impact security of supply.

Table 2: Forecast and historic minimum demands and high summer peak demand

Year	Observed summer minimum National Demand (GW)	Weather corrected summer minimum (GW)	Weather corrected daytime minimum (GW)	Weather Corrected high summer peak (GW)
2019	15.9	17.5	20.4	32.9
2020	13.4	16.2	17.6	31.5
2021	16.3	17.2	20.3	32.5
2022	14.9	16.5	19.1	30
2023	13.6	15.8	16.4	29.8
2024 forecast (central case)	–	16.2	17.0	29.2

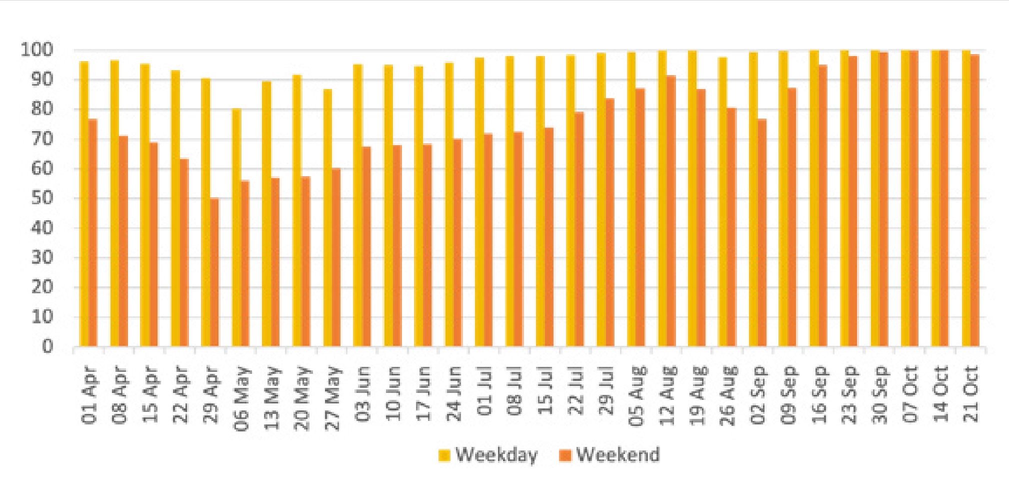

Figure 2: Probability that the daily minimum demand occurs overnight

Demand – Day-by-Day View

Minimum demand, under seasonal normal conditions, is expected to be marginally higher than last summer's outturn and occur on a weekend between late May and the end of August. High summer peak demands are expected to be slightly lower than last summer's outturn during the high summer period due to increased solar generation connected to the distribution networks.

Periods of low demand can have an impact on how we operate the transmission system. As a result, it is important that we understand the minimum levels of demand along with the peak demand that we can expect to see during the summer months.

Figure 3 shows forecast minimum demand for summer 2024 compared to last year's forecast and last year's weather corrected outturn. This year's minimum demand is expected to be marginally higher than last summer's weather corrected outturn.

Our forecast is in seasonal normal weather conditions and will vary according to actual weather conditions as discussed on page 8.

Figure 4 shows the daily peak demand for summer 2024 compared to last year's forecast and weather corrected outturn. Our peak demand for the high summer period between June and the end of August is 29.2 GW, 0.6 GW lower than last summer's outturn.

The forecast for summer 2024 is lower than last summer's outturn due to an increase in assumed solar generation reducing daytime demand, with significant further growth in installed solar capacity anticipated by the end of the year.

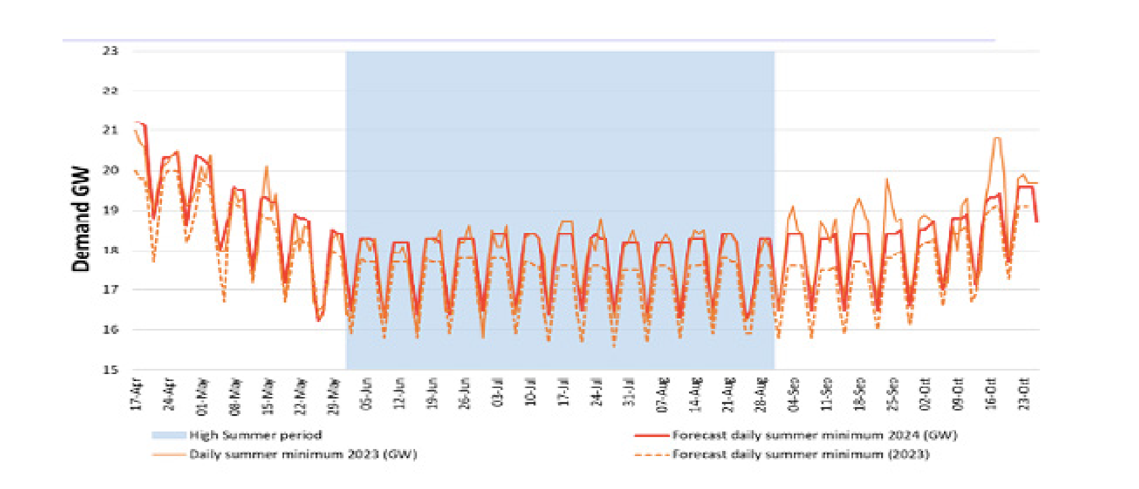

Figure 3: Daily minimum system demands (transmission system demand) for summer 2023 (outturn) against our summer 2024 minimum demand central forecast (all weather corrected)

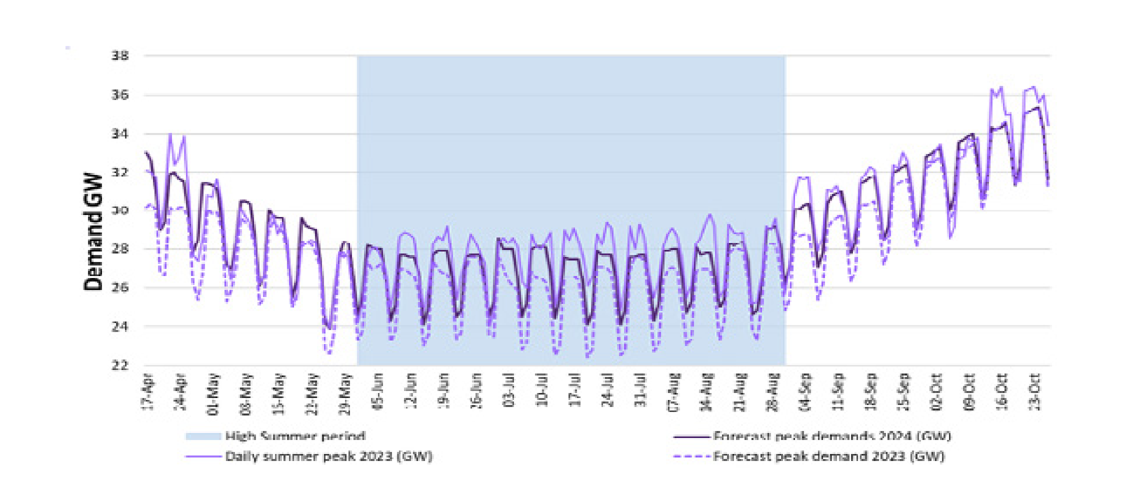

Figure 4: Daily peak system demands (transmission system demand) for summer 2023 (outturn) against our summer 2024 peak demand central forecast (all weather corrected)

Demand – Variability

The demands presented on the previous pages use average weather conditions, but weather variations can cause wide fluctuations around the average. We expect outturn minimum demand could be as low as 13.5 GW under a 1 in 10-year weather pattern.

The demand values used in this report assume seasonal normal weather conditions and so are, in effect, average minimum demands. However, weather conditions are rarely at their average values. Figure 5 shows for each day the credible variation that can exist (to a 1 in 10-year risk level) because of weather variation alone. It would not be credible to expect the 1 in 10-year level for every day over summer, although it may occur on individual days over the summer period.

The graph shows it is possible, under a 1 in 10-year weather risk level, demand could go as low as 13.5 GW over the late May bank holiday weekend. The impact of weather is seen in the level of **renewable generation** output as well as through consumer behaviour (e.g. heating and cooling demand). For instance, the lowest overnight minimum demand would coincide with high embedded wind output, and the lowest daytime minimum demand with high solar output.

The minimum demand is before any actions have been taken by the ESO and is 0.1 GW higher than the lowest equivalent minimum demand ever seen, which was 13.4 GW and occurred in 2020. However, this is without assuming any interconnector exports, pumping or charging storage.

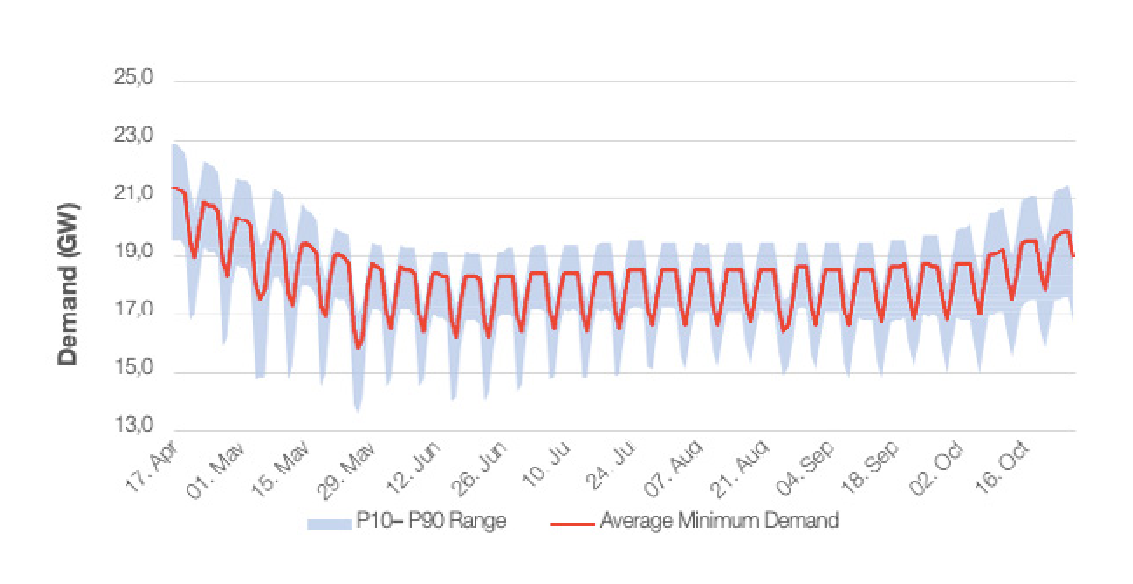

Figure 5: Daily minimum demands (National Demand plus station load) for our central scenario and the impact of weather variation

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Demand – Summer 2023 Retrospective

Summer 2023 saw higher demand than forecast across most of the period as warmer weather supported minimum demand, most notably in June and September.

Figure 6 shows there were several periods over the summer where minimum demand outturn was greater than the upper range of our forecast, the largest period being in early September. This was largely due to warm weather conditions, with temperatures peaking at 33.5°C on 10th September.

Minimum daily demand outturn was 14.1 GW (on 16 July). Periods of minimum demand were largely within our forecast range.

Last summer we saw weather corrected daily minimum outturn's were generally higher than our forecast going into summer (see Figure 7). There was a large amount of uncertainty around customer behaviour and demand levels going into summer 2023, following high energy prices in winter 2022/23 and the impact of the COVID-19 pandemic in the preceding summers. We continually look for opportunities to improve our modelling and have updated our demand forecast for 2024 to reflect last year's outturn.

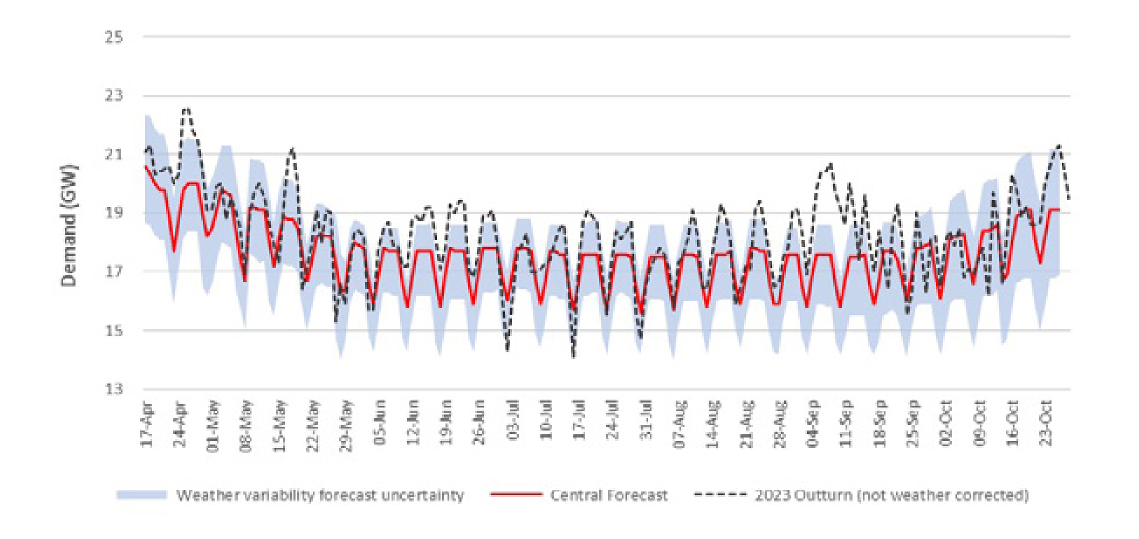

Figure 6: Daily minimum demand (transmission system demand) scenario forecast for summer 2023 against our summer 2023 minimum outturn (actual outturn has not been weather corrected)

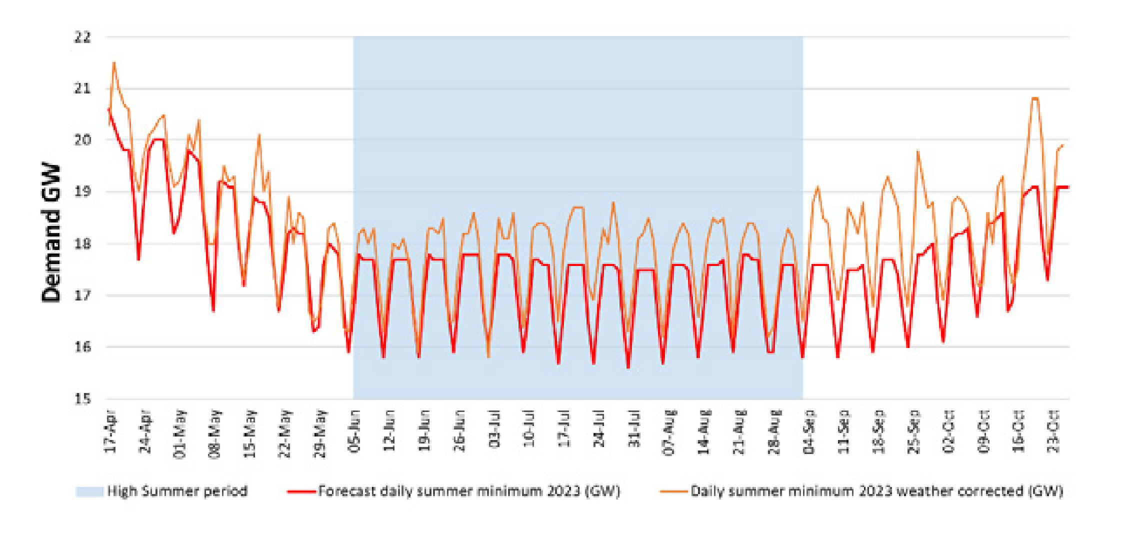

Figure 7: Daily minimum demand (transmission system demand) scenario forecast for summer 2023 against our summer 2023 minimum outturn (weather corrected)

2. Supply – Day-by-Day View

We are confident there will be sufficient supply to meet peak demand and our positive reserve requirement at all times throughout the summer.

This summer we expect:

- minimum available generation to be 34.1 GW and occur around early June (no continental interconnector flow scenario) based on current operational data
- Peak Transmission System Demand on this day to be 25.1 GW under our central demand forecast
- to be able to support exports over the interconnectors during peak periods if needed, as we continue to coordinate with, and provide reciprocal support to, neighbouring TSOs.

Figure 8 shows our ability to meet positive reserve requirements under a range of scenarios. Pages 14 and 16 include more information on why we anticipate to be a significant net importer over the summer, particularly during periods of peak demand. As part of our everyday actions the ESO has the ability increase imports to meet our positive reserve requirement, through trading on the interconnectors if required.

Did You Know?

In the summer months, power stations often carry out planned maintenance as there is typically lower demand and lower electricity prices than in the winter.

Our generation forecasts are based on published **OC2 data**, to which we apply a breakdown rate for each fuel type, to account for unexpected generator breakdowns and restrictions or losses close to real-time. For the latest OC2 data and operational view, see the BM reports website. This data is dynamic and changes throughout the summer. This analysis is based on market submissions as of 21 March 2024.

For wind, the average wind level as a load factor for each week is used – this is based on the last 30 years of wind data.

Our continental interconnector flow assumptions for the summer include **IFA**, **BritNed**, **Nemo Link**, **IFA2**, **North Sea Link (NSL)**, **ElecLink and Viking Link**. For more details see the "Assumptions" tab in the data workbook.

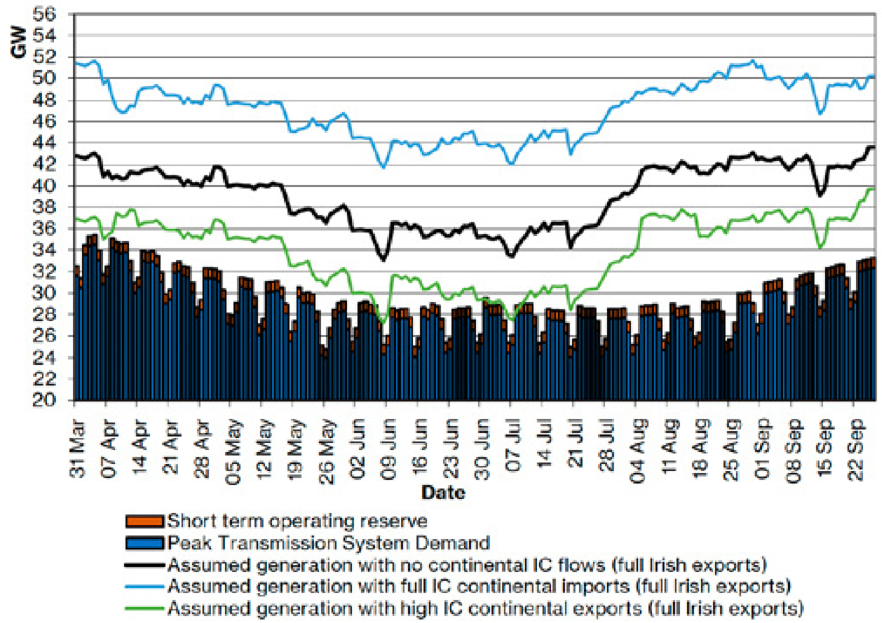

Figure 8: Day-by-day generation and demand forecast for summer 2024

Supply – Flexibility

We expect to be managing periods where inflexible generation, interconnector imports and wind output exceed minimum demand. We will therefore need to take action to manage this including pumping or charging storage, curtailing wind and trading on the interconnectors to reduce imports.

This summer we expect:

- minimum demand will exceed inflexible generation
- periods where meeting our negative reserve requirement will require the pumping and charging of storage assets, or trading on the interconnectors to reduce imports or increase exports.

Figure 9 shows how high wind generation can contribute to generation exceeding demand. To take a risk averse view in our analysis, we use a credible high wind generation scenario (equivalent to 70th percentile of wind output).

Across the summer we forecast a number of periods where meeting our negative reserve requirement will require actions to increase demand through pumping or charging storage and by trading on the interconnectors to reduce imports or increase exports.

Beyond our everyday actions the ESO has enhanced actions available for encouraging more flexible parameters from generators. Should inflexible generation alone exceed minimum demand, even after our everyday actions, we are able issue a local or national Negative Reserve Active Power Margin (NRAPM). In addition to securing more flexibility, a NRAPM informs market participants of a risk of emergency instructions. To date a number of local NRAPMs have been issued, but none at the national level.

Over and above our enhanced actions we can take emergency actions to secure the system. These include emergency instructions to transmission connected generation, emergency instructions to Distribution Network Operators (DNOs) to disconnect distributed energy resources or emergency instructions to interconnectors.

Our analysis indicates that we will not require a downward flexibility management service similar to the **Optional Downward Flexibility Management (ODFM)** service used during 2020 and 2021.

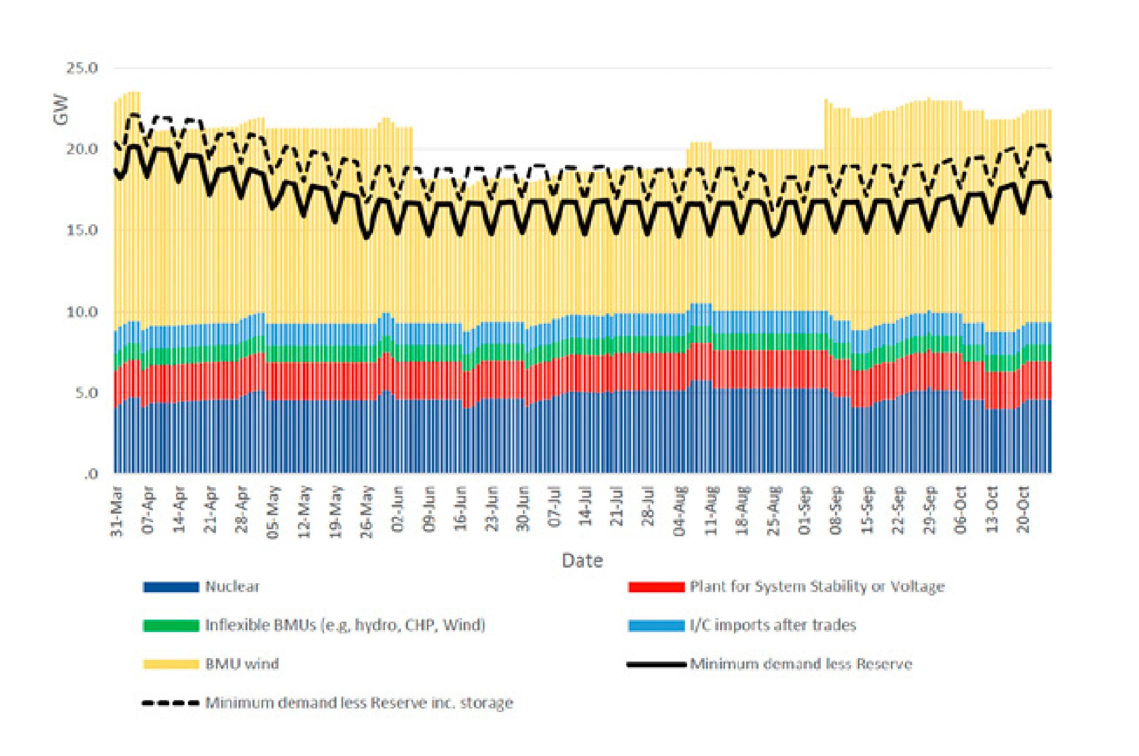

Figure 9: Day-by-day generation and minimum demand scenarios for summer 2024

3. Europe and Interconnected Markets Overview

Interconnectors will continue to be mutually beneficial for flexibility across the summer. We expect Great Britain will be a net importer from continental Europe over the summer, however weather conditions and on-the-day events in each country will impact interconnector flows.

This summer we expect:

- to see net imports into Great Britain from the Continent as both **baseload** and **peak forward electricity prices** are higher than those on the Continent
- weather conditions and events on the day to impact the pattern and levels of imports or exports seen over the interconnectors.

There is significant spare capacity on the system during summer. We are therefore well equipped for potential uncertainty over interconnector imports and exports. We will continue the close-working and coordinated approach with our neighbouring TSOs to offer reciprocal support where appropriate.

Note: The insights on this page and page 13 are based on forward prices as at 25 March.

Did You Know?

Since the last Summer Outlook report, we have seen the successful commissioning of the Viking Link interconnector between Great Britain and Denmark. The interconnector went live in December 2023 with a maximum capacity of 1.4 GW.

Interconnector flows over Viking Link have typically been limited to 800 MW at day-ahead stage, with up to 600 MW of additional intraday import capacity released when conditions allow. Scheduled network improvements should see the full import capacity available at the day-ahead stage.

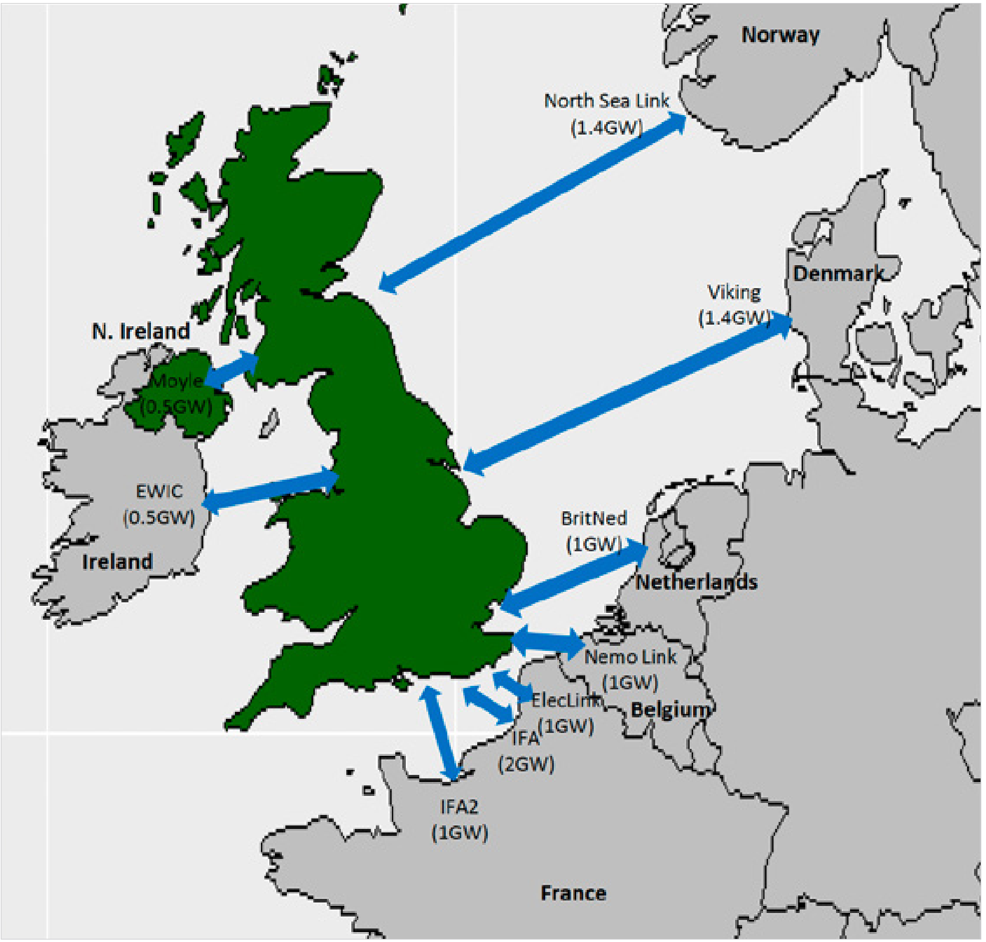

Figure 10: Interconnectors expected to be operational in summer 2024

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Europe and Interconnected Markets – Expected Flows

Both baseload and peak forward electricity prices are higher in Great Britain than those on the Continent. This spread is reflected in interconnector capacity auction results, suggesting Great Britain will be a net importer over the summer.

Electricity flows through the interconnectors are primarily driven by the price differentials between markets. Typically, during the summer, prices in Great Britain are higher than those in European markets, leading to interconnector imports.

Forward prices for electricity during summer 2024 have fallen across all markets compared to previous years. Both baseload forward prices (Figure 11) and peak forward prices (Figure 12) in Great Britain are higher than those in continental Europe, with France and the Netherlands included as an illustration.

Interconnector auctions for the second quarter of 2024 (Q2) and summer have higher clearing prices for imports than exports. This supports our view that we typically expect Great Britain to be a net importer over the summer period (see Figure 13).

The higher price in Great Britain means imports to Great Britain are more likely to occur over the summer period, however interconnector flow directions are highly dependent on prevailing weather conditions and supply availability on the day.

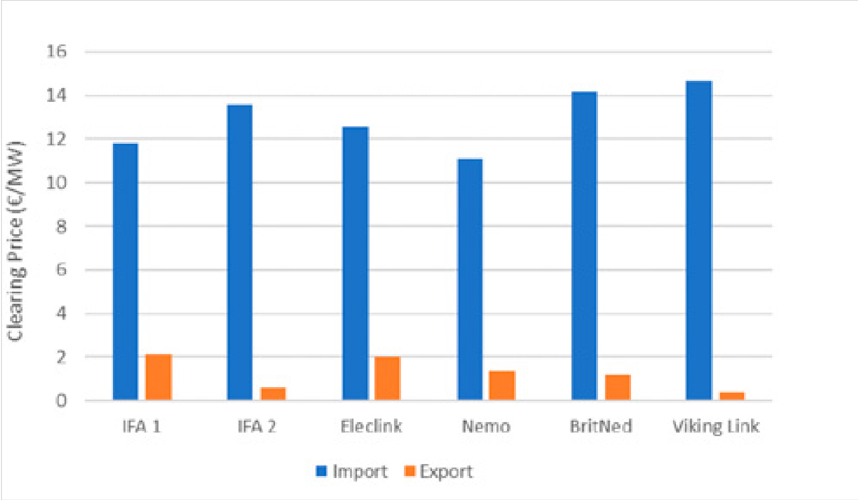

Figure 13: Q2/summer 2024 interconnector auction results

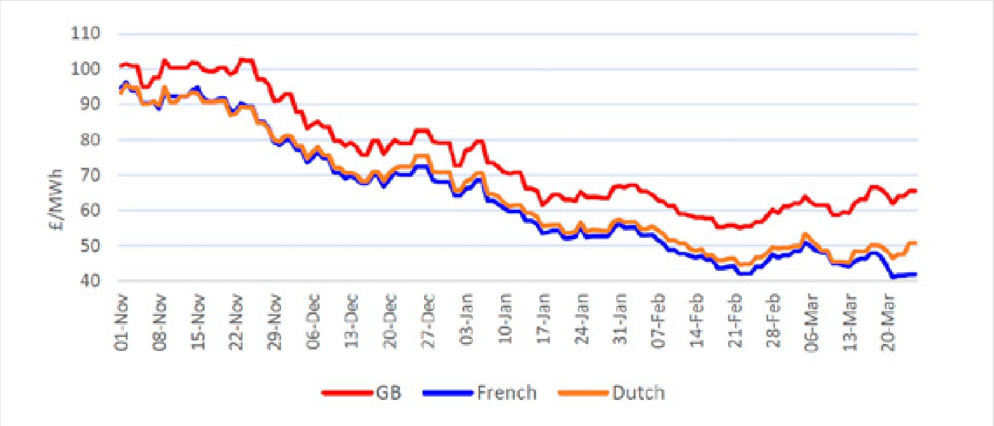

Figure 11: Summer 2024 electricity baseload forward prices

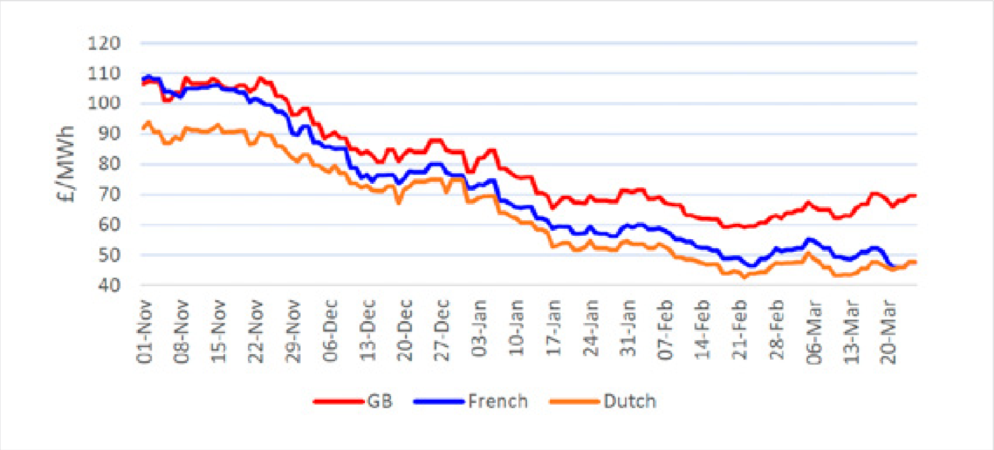

Figure 12: Summer 2024 electricity peak forward prices

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Europe and Interconnected Markets – Expected Outages

It is common for routine maintenance of interconnectors to be planned during the summer when demand is lower. We do not expect planned outages to cause an issue in meeting demand.

Recent years have seen new interconnector capacity come online, with the IFA2, NSL, ElecLink and Viking Link interconnectors providing 4.8 GW of additional capacity since 2021.

Interconnectors may take planned outages over the summer, or experience fault outages. Table 3 shows planned outages for each interconnector.

In addition to the planned outages, the ESO can control the flow of interconnectors or take actions to adjust flows to manage operational constraints, as part of our everyday processes.

Figure 14 shows that, even with planned outages, we expect to have over 6 GW of interconnector capacity throughout the summer.

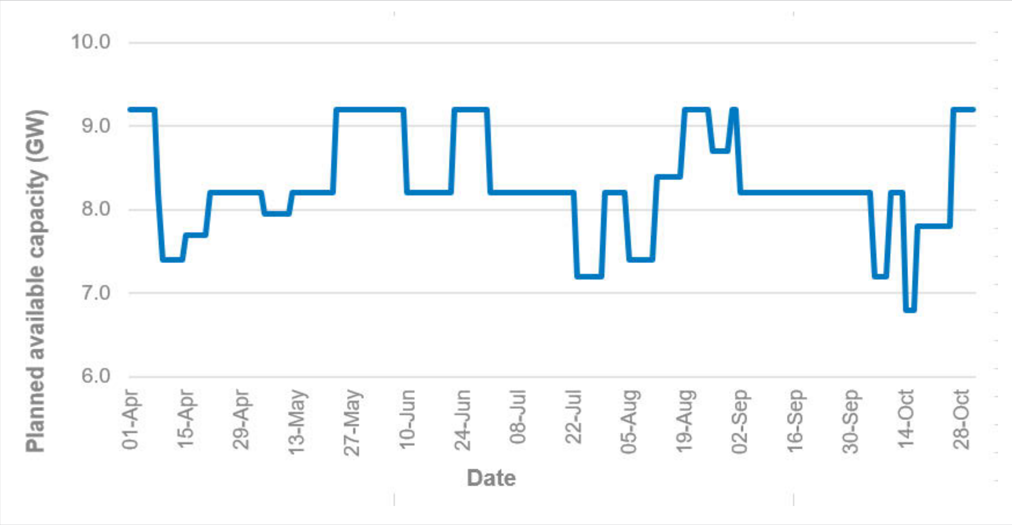

Figure 14: Interconnector capacity available with planned outages

Table 3: Interconnector outage schedule for summer 2024

Interconnector (capacity)	Connects to	Planned outages (resulting capacity)
IFA (2 GW)	France	08/04/24–22/05/24 (1 GW) 02/09/24–16/10/24 (1 GW)
Moyle (0.5 GW)	Northern Ireland	05/05/24–11/05/24 (0.25GW) 26/08/24–30/08/24 (0 GW)
BritNed (1 GW)	Netherlands	01/07/24–11/08/24(0 GW))
EWIC (0.5 GW)	Ireland	15/04/24–20/04/24 (0 GW)
Nemo Link (1 GW)	Belgium	23/09/24–29/09/24 (0 GW)
IFA2 (1 GW)	France	10/06/24–21/06/24 (0 GW)
NSL (1.4 GW)	Norway	14/10/24–25/10/24 (0 GW)
Eleclink (1 GW)	France	06/10/24–09/10/24 (0 GW)
Viking Link (1.4 GW)	Denmark	09/04/24 - 14/04/24 (0 GW) 05/08/24–18/08/24 (0 GW)

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Europe and Interconnected Markets – Summer 2023 Retrospective

Great Britain was a net importer of electricity from continental Europe during summer 2023. This was largely driven by lower electricity prices in continental Europe.

Interconnectors with continental Europe saw high levels of imports during summer 2023, with 74% of total periods over the summer seeing imports. This was significantly different to summer 2022 where we were a net exporter. For most of the Continental interconnectors, the highest levels of imports were seen during daytime, with imports over the peak generally lower and the overnight lower still. The NSL to Norway was the exception with high levels of imports in all periods.

Conversely, the **EWIC** and **Moyle** interconnectors saw high levels of exports during all periods over summer 2023.

Interconnector exports were driven by lower electricity prices in Europe. Figure 16 shows the day ahead electricity baseload spread (converted to GBP) for Great Britain and European countries during summer 2023. A positive price spread indicates Great Britain electricity prices were higher than its European counterpart. Day ahead prices in France were generally lower than those in Great Britain throughout the summer. It was a more balanced story in Belgium and Netherlands, with day ahead prices being higher in Great Britain around 55% of the time.

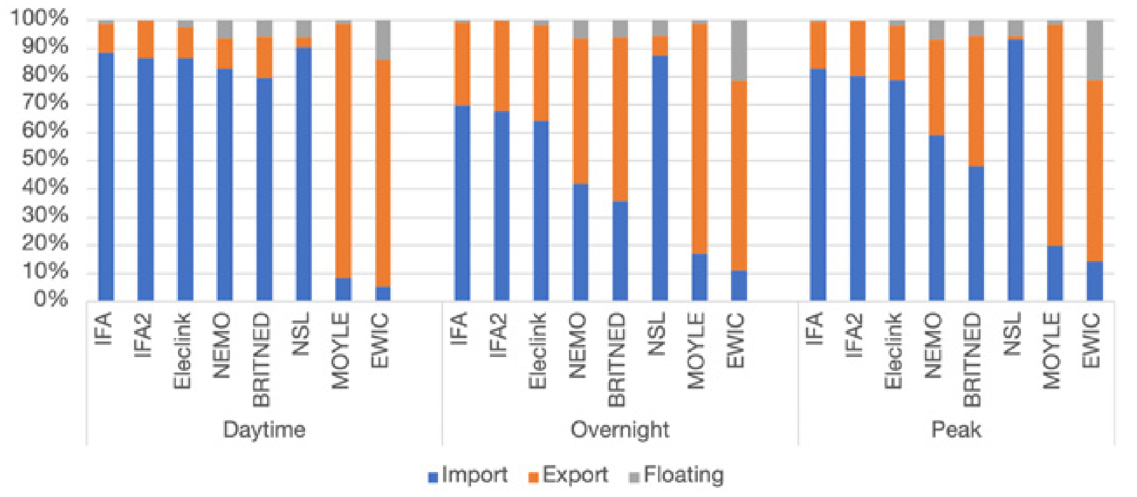

Figure 15: Proportion of import and export for continental and Irish interconnectors in summer 2023

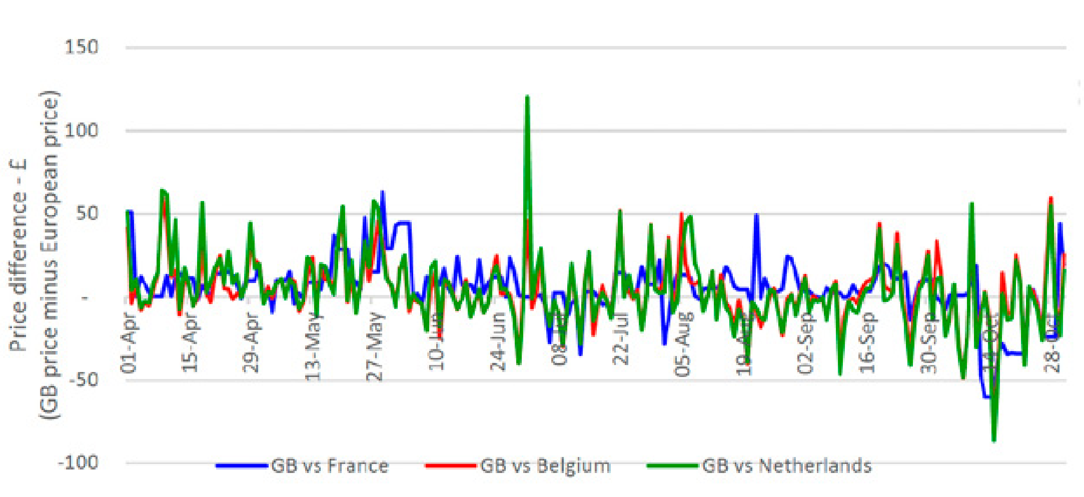

Figure 16: Day ahead baseload price spread for Great Britain vs France, Belgium and Netherlands (+ve indicates Great Britain was more expensive)

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4. Operational View – Summer 2024

Summer 2024 is expected to present similar operational challenges as summer 2023. We have the necessary tools in place to enable safe, reliable and efficient system operation.

As the generation mix continues to evolve, we are monitoring and forecasting system needs, defining requirements and ensuring the correct tools are in place for system operation as we move towards our 2025 zero carbon ambition[1]. This section includes our operational view for the summer across several key areas. Summer 2024 is expected to present similar operational challenges as summer 2023 and we have the necessary tools in place to enable safe, reliable and efficient system operation. A more in depth explanation of the challenges associated with operating the system can be found in our *Operability Strategy Report*.

Thermal

There is a comprehensive transmission network outage plan for the summer to connect new generation and to improve system capacity. These outages will impact the capacity of the network resulting in constraints. All major constraint boundaries in Scotland have continual outages throughout summer. Work is continuing across Northern Scotland to upgrade the 275 kV circuits on the boundary between SSEN-T and SPT to 400 kV. The outages have been aligned with major generator outages where possible, but due to the volume of works the B2 and B4, constraint costs associated with this boundary are likely to be the similar to or higher than those incurred last summer. There are also a number of outages across these boundaries to connect large wind farms, or new synchronous compensators as part of the ESO Stability Pathfinder projects. In order to alleviate constraint volumes and costs during high wind periods, we have secured commercial intertrip services on the B6 boundary with roughly 1.7 GW of generation contracted.

There will be constraint costs associated with the GMSNOW boundary. In addition work will commence at Lackenby 400 kV to connect Dogger Bank windfarm by early 2025, with ongoing works scheduled to allow the commissioning of the Greenlink interconnector.

Voltage

When demands are lower, the ESO needs to ensure there is enough voltage support from reactive power providers in local areas. This is typically more expensive in the summer when fewer generators self-dispatch to meet the lower demand.

Various pathfinder projects (both voltage and stability) are now available across the transmission system, which will help with high voltage management. These help to reduce the cost of synchronising generation specifically for voltage management. In addition, the replacement of a large shunt reactor in the South of Scotland is expected in the early summer which will be effective for voltage support, with a new substation in the North of Scotland connecting two reactive compensation devices, further supporting the network. This, along with the connection of a new synchronous compensator, should assist with voltage management and reduce the dependency on large synchronous generators for voltage support. New reactive equipment is also scheduled to commission as part of the ESO Pennine pathfinder project.

Restoration

We have contracts in place to meet all restoration requirements. We will continue to work with contracted restoration service providers, TOs and DNOs to carry out relevant assurance activities safely and efficiently. Providers' summer availability monitoring will also continue to ensure we meet compliance with the Assurance Framework.

[1] Visit *net zero explained* on our website

Operational view – Balancing the System

Continued development of new services and products has allowed us to reduce our minimum inertia requirement, with a forecast reduction in operational costs of approximately £65m per year, while maintaining our risk profile in frequency control.

The Great Britain electricity system operates at close to 50 Hz. This is a measure of balance between energy supply and demand which is fundamental to safe and reliable system operation. The balance of energy supply to meet demand is mostly met by the wholesale market. The ESO balances any residual difference between supply and demand, in real time, to maintain the frequency of the system at or near to 50 Hz.

We are confident we have the necessary tools in place to operate the electricity system over the summer period. We are continually developing new tools to enable the development of a robust electricity system as the industry continues to decarbonise.

Frequency

The Security and Quality of Supply Standard (SQSS) requires us to produce a **Frequency Risk and Control Report (FRCR)** and submit to Ofgem every year. FRCR aims to set out the right balance between risk and cost to the consumer when managing frequency on the electricity system. FRCR 2023 recommended a reduction in the existing minimum inertia requirement from 140 GVAs to 120 GVAs with a forecast reduction in operational costs of approximately £65m per year, while maintaining our risk profile in frequency control. This change was made possible by new services and projects such as the continuous growth in **Dynamic Containment (DC)** and the reduction in loss of mains risk volumes delivered through the **Accelerated Loss of Mains Change Programme (ALoMCP)**.

An initial reduction in minimum inertia requirements to 130 GVAs was implemented in late February. Our intention is for the next phase of implementation, reducing requirements to 120 GVAs, to occur this summer following an extended period of operating at 130 GVAs. This phased implementation gives us and industry time to adapt to the lower inertia and puts us on a glide path to meet our 2025 zero carbon ambition.

Dynamic Containment (DC), Dynamic Moderation (DM) and **Dynamic Regulation (DR)** make up our suite of Dynamic Response Services. Together they work to control system frequency and keep it within our licence obligations. DM provides fast acting pre-fault delivery for particularly volatile periods, and DR is our slower pre-fault service. DC is our post-fault service that arrests sudden, large changes in frequency such as the loss of a generator on the system.

During low demand periods there is less generation on the system to provide inertia making the frequency more sensitive to changes in circumstances that might result in frequency variations. Therefore, in low demand periods these products are vital in maintaining the frequency standards.

Operational view – Developing our Systems and Tools

We continue to adapt to meet the challenges of efficiently operating a rapidly changing electricity system, and accelerate progress towards our zero carbon ambition, through the development of new systems and tools. These measures save carbon, reduce costs and provide additional flexibility during periods of low demand.

The Balancing Programme

The aim of the Balancing Programme is to support Control Room operations, whilst we transform to new balancing capabilities that we need to deliver reliable and secure system operation, facilitate competition for the benefit of consumers, and meet our zero carbon ambition.

On 12 December the Balancing Programme went live with Release 1 of the **Open Balancing Platform (OBP**). This first release of OBP provides bulk dispatch capability within the control room for two zones - Batteries and Small Balancing Mechanism Units (BMUs). The ability to send bulk instruction to smaller BMUs, combined with the recently implemented 30-minute rule, enhances the use of storage assets in our balancing activities, allowing these assets to play a more active role in balancing the network.

Through the Operational Transparency Forum (OTF) we will continue to provide updates on the benefits associated with OBP. Further releases will happen throughout 2024 and we will continue to engage with industry on future developments and our delivery roadmap. Sign up to get the latest from the ESO's *Balancing Programme*.

Operational Metering

As part of our ongoing commitment to remove barriers to participation for distributed flexibility, the ESO is reviewing **operational metering** requirements applied to small-scale aggregated assets. This review aims to allow for greater consumer, industrial and commercial participation in flexibility, enabling capacity from small scale assets, such as EV chargers and electric heating systems, to be used to balance the system.

This year, the ESO is admitting up to 300 MW of aggregated assets into the **Balancing Mechanism (BM)** via a derogation that relaxes operational metering requirements whilst an independent expert study is commissioned to determine the exact changes necessary for to allow similar assets to participate in the BM in long term. Opening up ESO markets, including the BM, to flexible assets is vital in achieving our zero carbon ambition and delivering the clean, fair and affordable energy system of the future.

Enduring Auction Capability

The **Enduring Auction Capability (EAC)** was designed to deliver co-optimised procurement for our day-ahead Frequency Response and Reserve products. It is envisioned that this method of procurement will allow us to meet our needs in the most efficient way, while enabling providers to participate in multiple markets. Currently the EAC is used to procure the Dynamic Response Services and **Balancing Reserve** with future products to be added as they are developed.

The **EAC** offers introduced a number of features:

- Co-optimisation: The auction clearing algorithm allows for selection between alternative provider offers and alternate ESO requirements to better optimise the overall market clearing.
- Splitting: Participants may offer to delivery more than one service simultaneously from the same market unit.
- Negative Prices: Provider offer prices, ESO bid prices, and market clearing prices may be less than zero, to enable providers to offer to pay the ESO for offering an ancillary service.
- Overholding: The auction clearing algorithm may clear a quantity of service in excess of ESO requirements if this better optimises the market.

Since the introduction of EAC we have seen greater liquidity and lower prices on the products procured on the platform as well as securing all, or close to all, of our requirements.

5. Balancing Costs

We expect balancing costs for summer 2024 to be lower than those incurred in summer 2023. We anticipate that an anticipated increase in the volume of balancing actions will be offset by falling prices.

Summer 2023 saw a reduced volume of actions required to balance the system as warmer temperatures supported minimum demands. This summer although we anticipate an increase in the volume of balancing actions, the cost of these will be offset by a combination of falling wholesale prices and cost savings measures *(Balancing Costs Portfolio)* undertaken by the ESO.

Falling wholesale prices

Electricity prices impact the cost of the balancing actions the ESO carries out to operate the network reliably and efficiently. Forecasted summer 2024 electricity prices have dropped significantly compared to 2022 and 2023 prices, and are now more inline with prices ahead of summer 2021, which were around £55/MWh.

The fall in electricity prices reflects reduced pressure on global gas supplies and high French nuclear availability. Figure 17 shows the forward electricity prices for the front summer contract compared to front summer contract for previous summers.

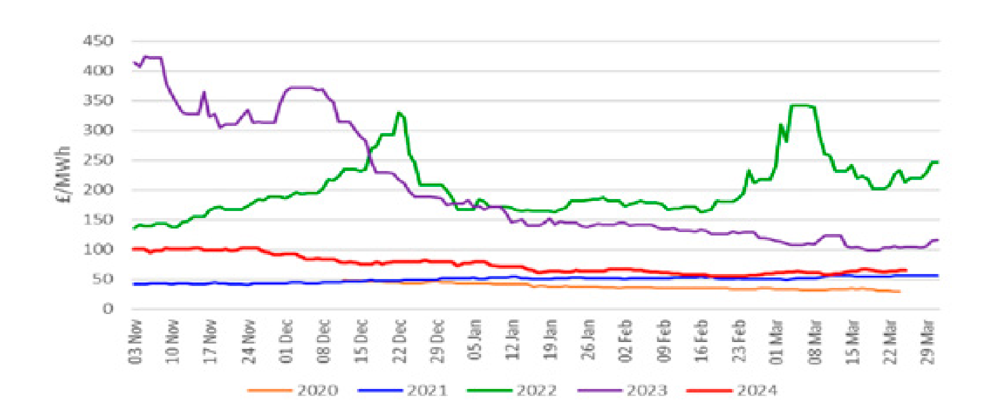


Figure 17: GB baseload forward electricity prices for the front summer contract

Table 4: Balancing costs for summer 2023 and 2024 (April–October £m)

	2024 forecast	2023 actuals
Energy Imbalance, Reserve and Response	428	429
Constraints, Voltage, Stability, Restoration and Other	891	983
Total Balancing Costs	1,319	1,413

A forward projection of savings from the ESO's activities will be shared in our first *Annual Balancing Costs Report* due to be published in the coming months.

6. Looking Beyond Summer and Winter 2024/25

We have already begun working with stakeholders to prepare for winter 2024/25. We will publish an Early View for winter 2024/25 in June, alongside our review of last winter. We expect the Winter Outlook report to be published by late September. We are continuing to work closely with our stakeholders as we undertake our winter preparations. This includes Government, Ofgem, National Gas Transmission and our neighbouring electricity transmission system operators in Europe.

We are also continuing to closely monitor developments in global energy markets. This will help us to identify and assess the potential uncertainties that could affect our winter operations. In Great Britain, the T-1 **Capacity Market** auction for delivery in winter 2024/25 has already concluded, securing 7.6 GW[1] capacity. In Europe, we are continuing to monitor developments that could influence flows on electricity interconnectors.

We will share our analysis with industry in the coming months in our winter publications. In addition, you can join the conversation at our weekly ESO Operational Transparency Forum by emailing *marketoutlook@nationalgrideso.com* or by following us on X (previously Twitter) @NationalGridESO.

Upcoming Publications for Winter

2024/25 Early View

We expect to publish our Early View for winter 2024/25 by June. This will be published alongside our review of last winter and invite stakeholder feedback through our annual Winter Outlook consultation. The Early View will set out our developing view of both system margin and daily operational surplus that we expect throughout winter.

Winter Outlook Report

As the ESO transitions into NESO in summer 2024, its responsibilities will expand. As we take on our new roles as NESO, we will continue to publish the *Winter Outlook report*.

The full Winter Outlook report is expected to be published in late September. Our Winter Outlook report will set out our final view of system margin for winter and our latest view of daily operational surplus throughout winter. It will be accompanied by a data workbook and will provide more detailed information on our assessment for demand, supply and potential flows on electricity interconnectors compared with the Early View.

National Gas Transmission will publish a separate *Gas Winter Outlook Report*.

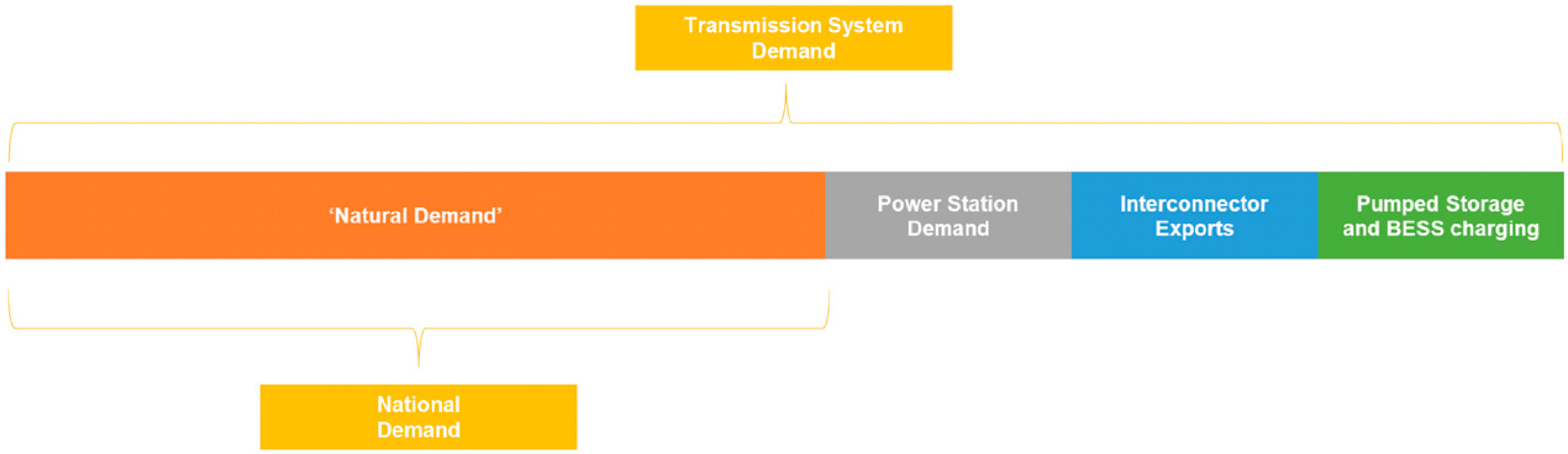
1 *Final Auction Report 2023 One year ahead Capacity Auction (T-1) Delivery year 2024/25*, ESO, 20th February 2024

Appendix A – Demand Definitions

Term	Term	Definition	Note
Types of demand	GB Customer demand	Sum of all demand used within Great Britain. Total demand requirement for Great Britain.	This includes demand offset by embedded generation on the distribution networks and is similar to the demands quoted in the Future Energy Scenarios.
	Transmission System demand	Sum of all generation that flows through the electricity transmission network in Great Britain to meet internal demand or exports.	These are the demands typically presented in the Summer and Winter Outlook reports.
	National Demand	Sum of all generation that flows through the electricity transmission network in Great Britain to meet internal demand, excluding electricity used to power large power stations.	
Types of outturn	Operational outturn	Uses all real-time metering feeding into the ESO live systems.	
	Settlement metering outturn	Uses metering from Elexon settlement metering which is then reviewed by all parties so anomalies can be resolved. For generation this only includes plants that participate in the Balancing Mechanism (BM).	
	Normal or Weather Corrected outturn	Operational outturn adjusted to provide the equivalent demand under average weather conditions.	
	Average Cold Spell (ACS) outturn	A measure of hypothetical maximum demand over some period (usually an entire winter period) based on all the possible weather variation that could have occurred over the period. The ACS outturn is the value that, based on all the hypothetical weather variation, had a 50% chance of being exceeded. It is the average value of the maximum demand.	This is used in the Winter Outlook report when considering supply margins.
Types of forecast	Operational forecasts	Forecasts based on using detailed meteorological forecasts when available (out to 14 days ahead) or average weather conditions (beyond 14 days ahead).	
	Normal or Weather Corrected forecasts	Forecasts based on using average weather conditions (beyond 14 days ahead). All longer-range forecasts are on this basis.	These are the forecasts presented in the Summer and Winter Outlook reports.
	Average Cold Spell (ACS) forecast	A forecast of maximum demand over some period (usually an entire winter period) based on all the possible weather variation that could have occurred over the period. The ACS forecast is the value that, based on all the hypothetical weather variation, has a 50%chance of being exceeded. It is the forecast for the average value of the maximum demand.	Used in the Winter Outlook report for peak demand forecasting when considering capacity available to meet peak demands during low temperatures.

Appendix B – Relationship Between Types of Demand

This diagram shows the relationship between some of the different types of demand discussed on the previous page.



Glossary

Accelerated Loss of Mains Change Programme (ALoMCP)

A joint initiative between the ESO, Energy Networks Association, distribution network operators (DNOs) and independent distribution network operators (IDNOs). It provides funding to non-domestic distributed generators to upgrade their loss of mains protection to be compliant with the Distribution Code by September 2022.

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.

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 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. 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.

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

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 including 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.

Dynamic Containment

This is 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 delivers very quickly and proportionally to frequency but is only active when frequency moves outside of operational limits (+/- 0.2 Hz).

Dynamic Moderation

This pre-fault frequency service is aimed to correct sudden large imbalances between generation and demand due to, for example erroneous wind forecasts.

Dynamic Regulation

This pre-fault frequency service is designed to correct random but small deviations in frequency around the target of 50 Hz.

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 a 1 GW in either direction of flow.

Glossary

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.

Footroom

When a generator can reduce its output without going below minimum output levels.

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.

Frequency risk and control report (FRCR)

The FRCR is produced at least once annually and sets out the results of an assessment of the operational frequency risks on the system.

GW Gigawatt (GW)

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

High summer period

The period between 1 June and 31 August, or weeks 23 to 35. It is when we expect the greatest number of planned generator outages.

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 being 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.

Interconnector (elec)

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.

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. This typically occurs overnight.

Maximum demand

The highest demand on the transmission system.

Moyle

A 500 MW interconnector between Northern Ireland and Scotland. You can find out more at *mutual-energy.com*.

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. It is owned and maintained by regional transmission companies and operated by a single electricity system operator (ESO).

Glossary

Negative reserve active power margin (NRAPM)

The insufficient NRAPM warning is a request to encourage more flexible parameters from generators and inform participants of a 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; in both cases there is a risk that the ESO may need to issue emergency instructions to inflexible and non-BM participating plant. Localised NRAPM are more common in the north of Scotland due to the large volume of wind and water generation and relatively low demand.

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.

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 commissioned this October. See more at *northsealink.com*.

Optional Downward Flexibility Management (ODFM)

Ancillary service introduced in summer 2020 to help manage periods of low demand on the transmission system.

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

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 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 which is 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, the ESO 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.

Glossary

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.

Super-SEL
A service designed to directly reduce the total minimum megawatt (MW) level, also known as the Stable Export Limit (SEL), of generators synchronised to the system. It achieves this by lowering the minimum generation level at a synchronised generator.

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 the ESO 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 1400 MW 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. See more at *viking-link.com*.

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.

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Visit *Research and publications* on our website to view our wide range of publications.

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

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