Summer Outlook

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

April 2023

ESO

Foreword

Welcome to our 2023 Summer Outlook Report. This report contains our view of the electricity system for the summer ahead and is designed to support the industry in its preparations for the period.

With winter 2022/23 now concluded we look ahead to the coming summer months. This report considers the period from April to October. As with last summer our operational view now changes focus from managing winter margins and peak demands to managing minimum demand periods.

This summer we expect that operations will be similar to last year. We expect to deliver our world-leading reliability standards across summer 2023 and we continue to have the right tools in place to manage low demand periods and other operational issues over this summer.

We expect that summer minimum demands will be slightly lower than those seen across summer 2022, continuing the trend of lower demands over the last couple of years. Peak transmission demand is also expected to be lower this summer compared to recent years, as new embedded generation on the Distribution Networks are expected to suppress electricity demand at the transmission level.

Looking beyond this summer is obviously of importance this year, as we head into next winter. We have already begun preparations for winter 2023/2024 and will be looking to share our analysis with industry over the coming months.

By June we intend to publish a joint report reviewing the 2022/23 winter, as well as an early view of our expectations for winter 23/24.

In September/early October we will publish the full Winter Outlook report.

As ever, we will continue to monitor the situation and outlook for the electricity system and keep stakeholders up to date with any changes via the ESO Operational Transparency Forum.

National Gas Transmission have published a separate Gas Summer Outlook which can be found here. You can join the conversation at our weekly ESO Operational Transparency Forum, by email at marketoutlook@nationalgrideso.com or by following us on Twitter (@NationalGridESO).

Fintan Slye

Director, Electricity System Operator

Contents

Executive summary / Key messages

Russia's illegal invasion of Ukraine continues to impact global energy markets.

We continue to monitor its impact on both global and UK markets, working closely with Government, Ofgem and National Gas Transmission.

1. Security of supply

We will meet our world-leading reliability standards throughout summer 2023.

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 from last summer and winter.

2. Managing the system

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

Periods of low demand typically represent the more challenging operational events during summer. We already have operational tools and services in place to manage these, including our stability services and Dynamic Containment.

3. Market prices and balancing costs

We expect balancing costs to be lower than last summer due to lower wholesale prices and activities implemented by the ESO.

While wholesale prices remain high, they have fallen since last summer. This will reduce the cost of our balancing actions. The ESO has undertaken an extensive number of activities to reduce costs to consumers. This includes our recommendation to reduce the existing minimum inertia requirement under our Frequency Risk and Control Report policy; delivery of the Voltage Mersey and Stability Phase 1 pathfinders; and the Constraint Management Intertrip Service. Overall, we forecast that balancing costs could be around 30% lower than last summer.

Executive summary / Overview

We are confident there will be sufficient supply to meet electricity demands over the summer and we will be able to meet operability challenges.

Demand

Weather corrected summer minimum demand is expected to be slightly lower than last summer. Increasing generation connected to the distribution networks continues to reduce daytime minimum and peak **transmission system demands** year on year. The forecasts for demand in the table and graph are for transmission demand, consistent with previous Outlook reports[1].

Supply

We are confident that there will be sufficient available supply to meet demand and our reserve requirement throughout summer accounting for variation of both weather and interconnector flows. We expect lower levels of exports to continental Europe than last summer, but they are likely to be higher than typical summers. We expect to have sufficient operational surplus to support some exports to Europe throughout summer if needed. We do not expect high interconnector exports when demand in Great Britain is high as current peak forward prices are higher here than in Europe.

Operability

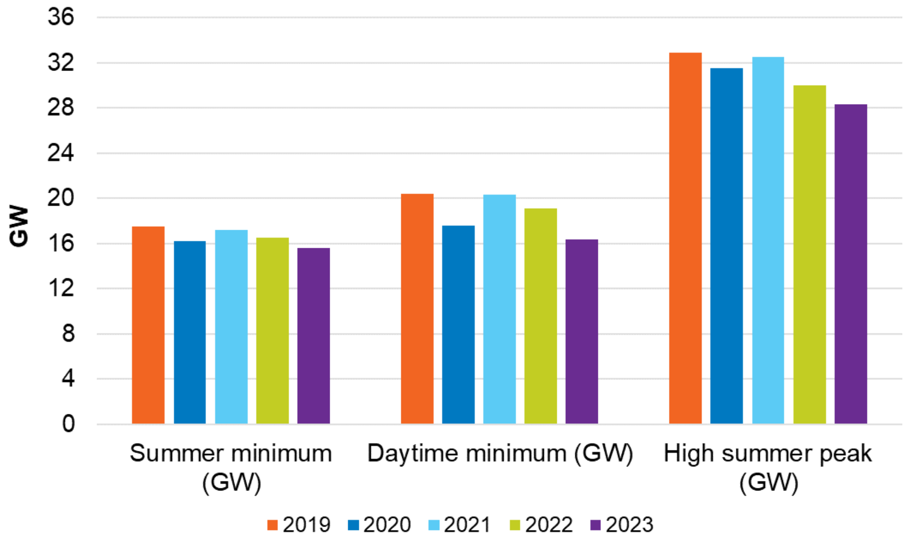
We are confident that we have tools and actions available to manage operability challenges around periods of low demand over the summer. We will have to take actions on the system when demand is low, but these will mainly be everyday actions such as trading on interconnectors and increasing demand by pumping. If high wind generation occurs at periods of low demand, we may need to use the enhanced actions within our existing toolkit, such as issuing a Negative Reserve Active Power Margin (NRAPM). We do not anticipate requiring emergency instructions. Our analysis also shows that we do not need to reintroduce a downward flexibility management service similar to the Optional Downward Flexibility Management (ODFM) service used in 2020 and 2021.

The ESO has taken a number of measures to reduce costs to consumers through the use of balancing tools and capabilities to manage the system effectively. Combined with a reduction in wholesale prices, we expect balancing costs could be around 30% lower than last summer. We recognise the importance of proactive, regular, quality engagement with industry and will continue to use our weekly Operational Transparency Forum as a key forum for engagement.

Key statistics

Summer 2023 forecasts (weather corrected)	GW
Electricity transmission **high summer** peak demand	28.3
Electricity transmission minimum demand	15.6
Electricity transmission daytime minimum demand	16.4
Minimum available generation	31.1

Figure 1: Weather corrected summer overnight and daytime minimum demand outturns for previous years and the summer 2023 forecast



Glossary: Definitions for the terms in bold purple text can be found in the glossary on page 26

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1. See Appendix C for more information on different demand types

Demand / Overview

Weather corrected minimum transmission system demands for summer 2023 are expected to be slightly lower than last summer, with daytime minimums and high summer peak demands also falling.

This summer we expect…

- summer minimum demands to be slightly lower than the outturn in summer 2022
- weather corrected **minimum demand** to be 15.6 GW and to occur overnight
- weather corrected high summer peak **transmission system demand (TSD)** to be 28.3 GW

Did you know?

Demands presented for previous years are the weather corrected outturn for demand on the electricity transmission system. These figures are for total demand after any actions taken by the ESO, so include actions to increase demand for pumping and electricity trading. Forecast demands do not include these, as they will depend on prevailing market conditions at the time.

These demands are all at transmission level. This means that it does not include demand that is met by generators connected below the transmission boundary and therefore, increased levels of this type of embedded generation effectively reduce transmission demand.

When we forecast demand in this section, it is **Transmission System Demand** (TSD), which includes the demand from power stations and interconnector exports. This forecast is based on historical data and current market conditions. In the Appendix, we have included a table of different demand definitions on page 23.

We base our peak 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).

Table 1: Forecast and historic summer peak and minimum demands (weather corrected)

Year	Summer minimum (GW)	Daytime minimum (GW)	High summer peak (GW)
2019	17.5	20.4	32.9
2020	16.2	17.6	31.5
2021	17.2	20.3	32.5
2022	16.1	19.0	29.9
2023 (central case)	15.6	16.4	28.3

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. These are normal occurrences, typically for maintenance, and are scheduled for summer as demand is lower than in winter and so do not impact security of supply.

Demand / Day-by-day view

Weather corrected minimum transmission system demands are expected to be slightly lower than last summer and occur on a weekend between late May and the end of August. High summer peak demands are expected to be lower than last year and could occur at anytime in the high summer period.

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 2 shows forecast minimum demands compared to last year's weather corrected outturns. This year's minimum is expected to be slightly lower than last summer in our central forecast, at 15.6 GW compared to last summer's 16.1 GW. This is weather corrected and will vary according to real weather conditions as discussed on the following page. The minimum demand is expected to occur on a weekend between late May and late August. We also expect lower than usual demand early in the season on the bank holiday for the coronation on the 8th May. Weekday daily minimums are expected to be lower than in our modelling last year.

Figure 3 shows the daily peak demand for summer 2022 against our forecast for 2023. Our peak demand for the high summer period between June and the end of August is 28.3 GW, 1.6 GW lower than last summer. Generally our peak demand forecast is lower than last summer's **outturn** throughout the summer, although there is some variation, particularly at the beginning of the high summer period.

Figure 2: Daily minimum transmission system demands for summer 2022 (outturn) against our summer 2023 minimum demand central forecasts (all weather corrected)

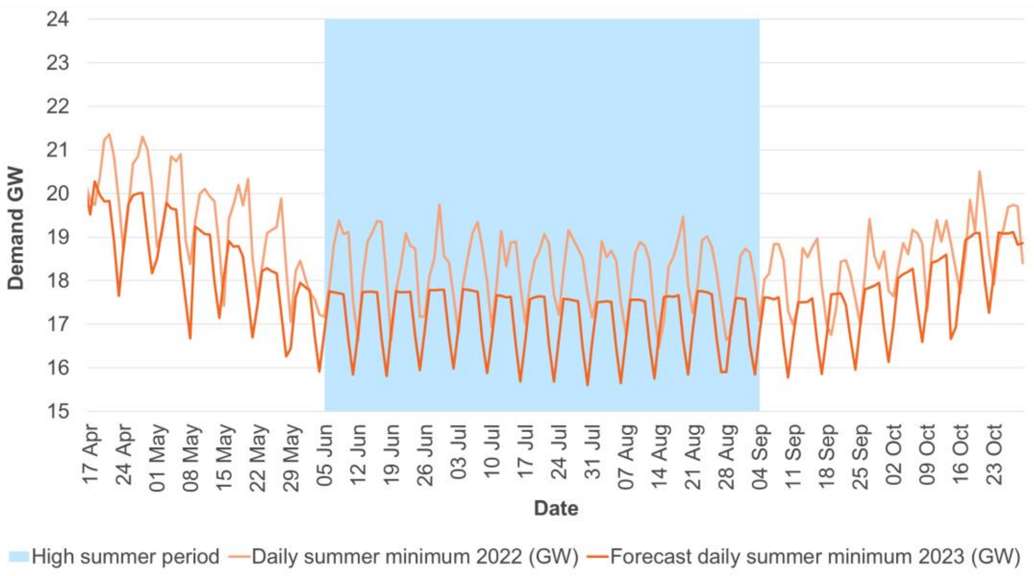
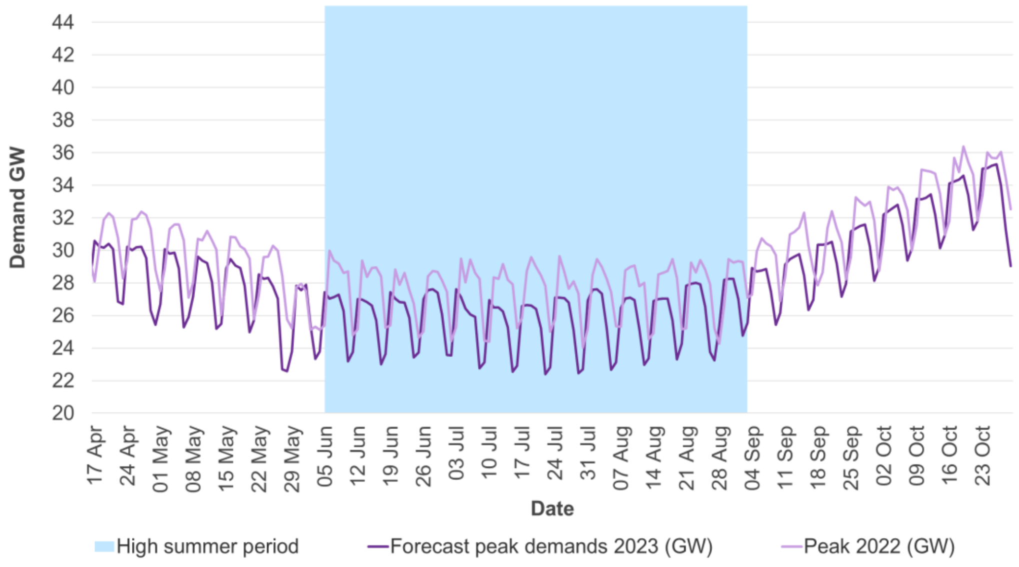


Figure 3: Daily peak transmission system demand for summer 2022 (outturn) against our summer 2023 peak demand central forecast (both weather corrected)



Demand / Demand variability

Weather variability will have an effect on demands over the summer. The demands presented on the previous page use seasonal normal weather conditions for the time of year, but weather variations can cause fluctuations around the central case.

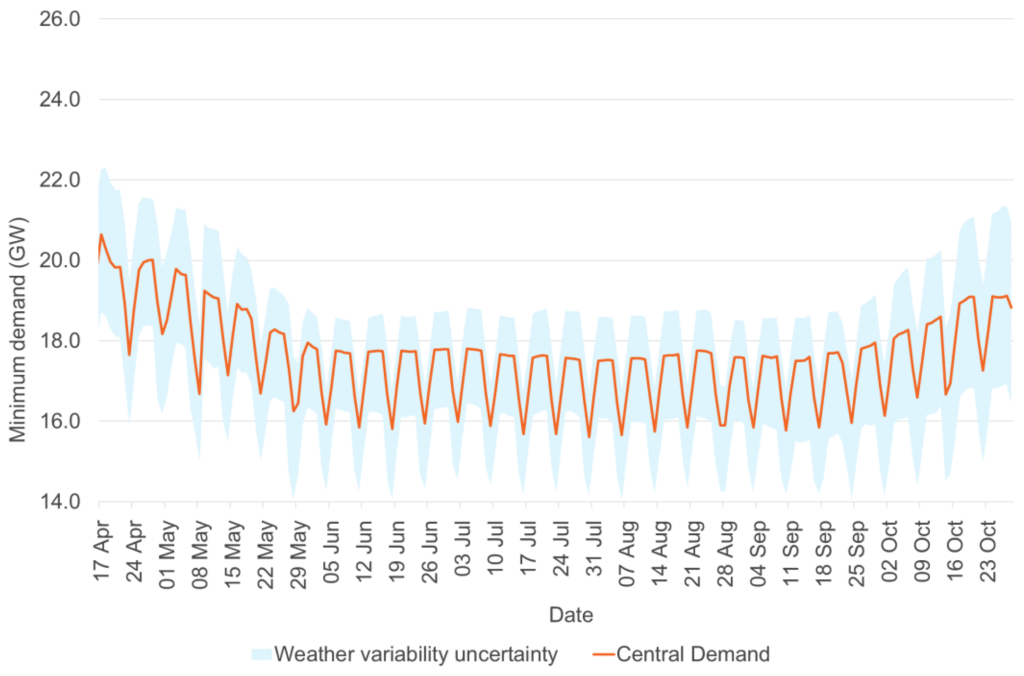
The demand values used in this report assume **seasonal normal weather conditions** and so are, in effect, average minimum demands. However, weather conditions are rarely at their average values. Figure 4 shows for each day the credible variation that can exist (to a 1 in 10-year risk level) because 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 that, under a 1 in 10-year weather risk level, **transmission system demand** could go as low as 14.0 GW over the late May bank holiday weekend, because of weather variation alone. 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 will be when there is a lot of embedded wind and the lowest daytime minimum demand will be at times of high solar output.

This minimum demand is before any actions have been taken by the ESO and is 0.6 GW higher than the lowest equivalent minimum demand ever seen, which was 13.4 GW and occurred in 2020 (see Appendix B, p24).

We will typically use everyday actions, such as instructing pumped storage, reducing flexible wind and trading on the interconnectors, to increase demand if needed. See page 11 for the full range of actions available to us to manage low demand.

Figure 4: Daily minimum transmission system demands for our central scenario and the impact of weather variation



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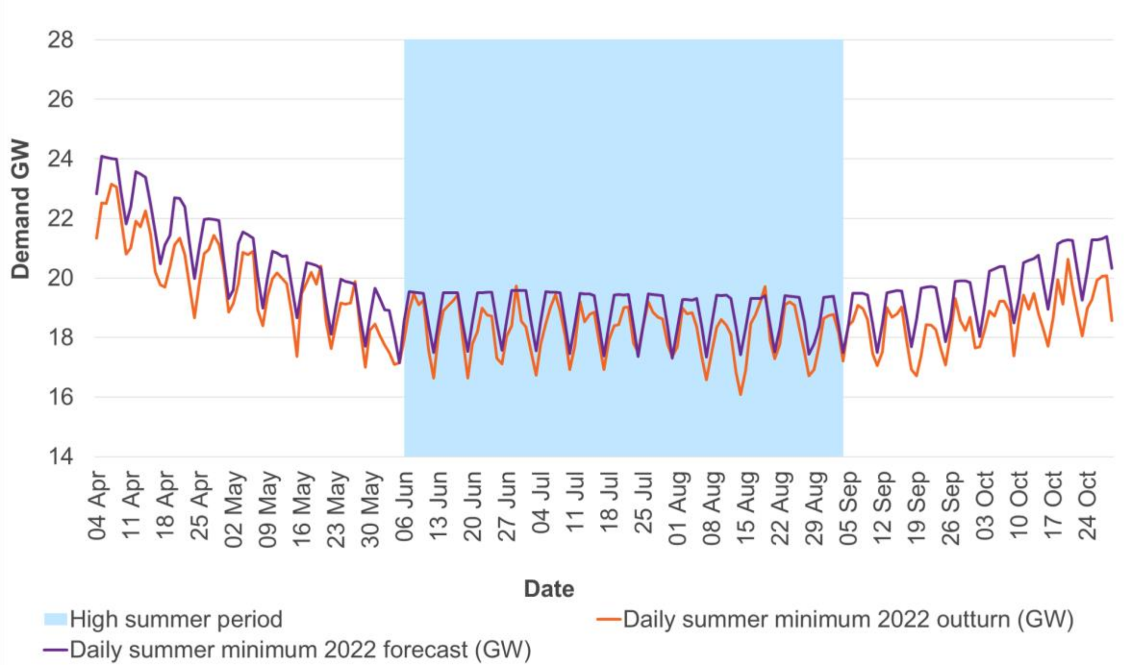
Demand / Summer 2022 retrospective

Figure 5 shows that last summer minimum (overnight) demand outturn was typically lower than the forecast throughout the summer period, with the outturn of 16.1 GW being 1 GW lower than forecasted. This was due to a combination of factors, in particular a fall in overall electricity demands of up to 8% with a knock on effect on both peaks and minimums. This was partly driven by increasing prices starting to play a role in suppressing electricity demands.

Minimum daytime demand outturn (Figure 6) was significantly more variable than forecast. This is due to our forecast being based on average conditions, whereas real conditions have more variation, even after weather correction. The minimum forecast daytime demand of 20.6 GW was also higher than the actual minimum daytime demand of 19.0 GW.

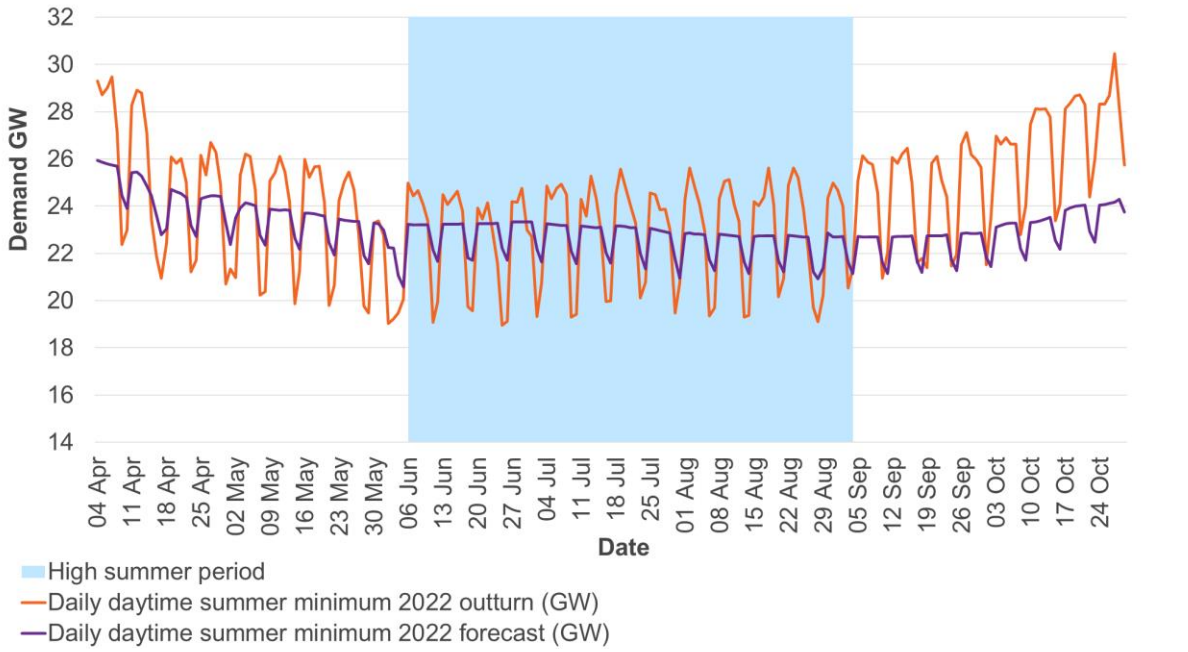
Figure 5: Daily minimum transmission system demand scenario forecasts for summer 2022 in purple against our summer 2022 minimum demand outturn in orange (weather corrected)



We always look for opportunities to continuously improve our modelling. This year this includes taking steps to better reflect the contribution from embedded generation, which will help improve the accuracy of our forecasts.

The charts on this page present weather corrected forecasts and **transmission system demand outturns,** which is useful for year-on-year comparison, but doesn't match exactly with actual demands on the system, which include real weather variations.

Figure 6: Daily daytime minimum transmission system demand scenario forecasts for summer 2022 in purple against our summer 2022 minimum demand outturn in orange (weather corrected)



Supply / Day-by-day view

We expect to be able to meet normalised transmission demand and our positive reserve requirement at all times throughout the summer.

This summer we expect…

- to be able to meet demand without imports throughout the summer
- minimum available generation to be 31.1 GW and occur around mid-July (no continental interconnector flow scenario) based on current operational data
- **maximum demand** on this day to be up to 23.1 GW under our central demand forecast (assuming full export on Irish interconnectors)
- to be able to support **net exports** over the interconnectors at times, as we continue to coordinate with and provide reciprocal support to neighbouring TSOs

Did you know?

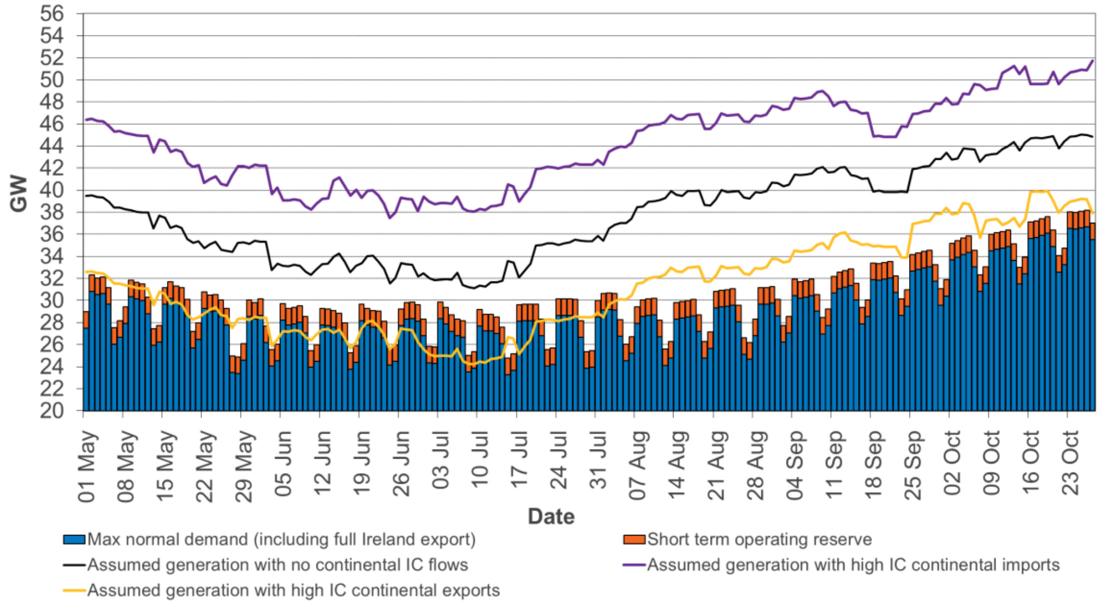
In the summer months, power stations often carry out planned maintenance as there is typically lower demand and lower electricity prices than in the winter.

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, updated each Friday. This data is dynamic and changes throughout the summer. This analysis is based on market submissions as of 12/04/2023.

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, NSL** and **Eleclink**. For more detail see the "Assumptions" tab in the Data Workbook.

Figure 7: Day-by-day generation and demand forecast for summer 2023



Supply / Managing low demands

We may need to take actions to maintain operability of the network. The graphic below shows the hierarchy of these actions. We expect to use our everyday actions to manage low demand. There may also be times when we need our enhanced actions if there is high wind generation at times of low demand. These actions are available to us as part of our existing operational toolkit.

At times of low demand and high levels of renewable generation it is important to be able to reduce generation output or increase demand to ensure the system is balanced and frequency remains within operational limits. We do this using ‘everyday actions’ shown in the graphic on the right.

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 this summer and so we will not be reintroducing this.

Enhanced tools include the use of local or national **Negative Reserve Active Power Margin (NRAPM).** To date, a limited number of local NRAPMs have been issued, but none at a national level. You can read more about this tool on our website.

The graphic on the right also highlights the ‘emergency actions’ we can take over and above this to secure the system. However, our analysis does not suggest anything more than enhanced actions is likely to be required.

Everyday actions

- Bid actions on all other flexibility in the Balancing Mechansism, including **super-SEL**
- Selling power to the continent to create exports on the interconnectors
- Creating demand through pumping demand at pumped storage sites

Enhanced actions

- Issuing a local or national **NRAPM** and flag as alert status on the Balancing Mechanism Reporting Service.
- Taking additional actions obtained through NRAPM

Emergency actions

- Emergency Instruction to Transmission connected generation
- Emergency Instruction to DNO to disconnect distributed energy resources
- Emergency Instruction to Interconnector

Supply / Day-by-day view

Based on current data we expect to be managing periods where inflexible generation output plus flexible wind output exceeds minimum demand and, therefore, will need to take actions to manage this. Under higher wind conditions, we could also see a small number of periods where inflexible generation output alone may exceed minimum demand.

This summer we expect…

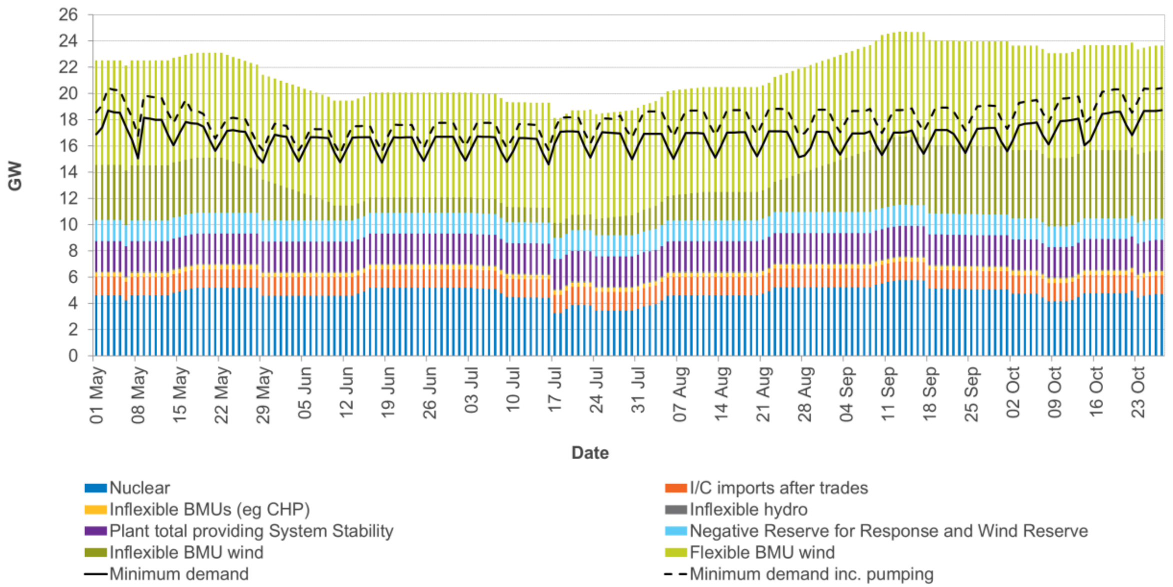
- periods where pumping is required to manage low demand to occur a similar number of times to last year.
- that there could be a small number of days if wind generation is high on which inflexible generation output may exceed minimum demand including pumping

Figure 8 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 the 70th percentile of wind output). We also assumed a cap on flexible wind capacity of 8 GW due to the number of actions required by the control room, with anything above this added to the inflexible volume.

In Figure 8 we see periods where **transmission system demand**, without pumping, is close to the level that can be achieved by reducing the flexible wind. In most instances, when action is taken to increase demand by instructing pumping storage, the system can be managed by reduction in flexible wind and/or by trading on the interconnectors.

There are several weekend days in September where, if wind generation is high, inflexible generation output alone may exceed minimum demand even with pumping. During these periods, a local or national **Negative Reserve Active Power Margin (NRAPM)** can be issued. A NRAPM warning is a tool that the ESO has had available to encourage more flexible parameters from generators and inform participants of a risk of emergency instructions. It should be noted this only occurs under the very high wind scenario.

Figure 8: Day-by-day forecast generation and minimum demand scenarios for summer 2023



Supply / Forward price comparison

Forward electricity prices for summer 2023 are below those ahead of summer 2022 but remain much higher than those for summer 2021, driven by high gas prices

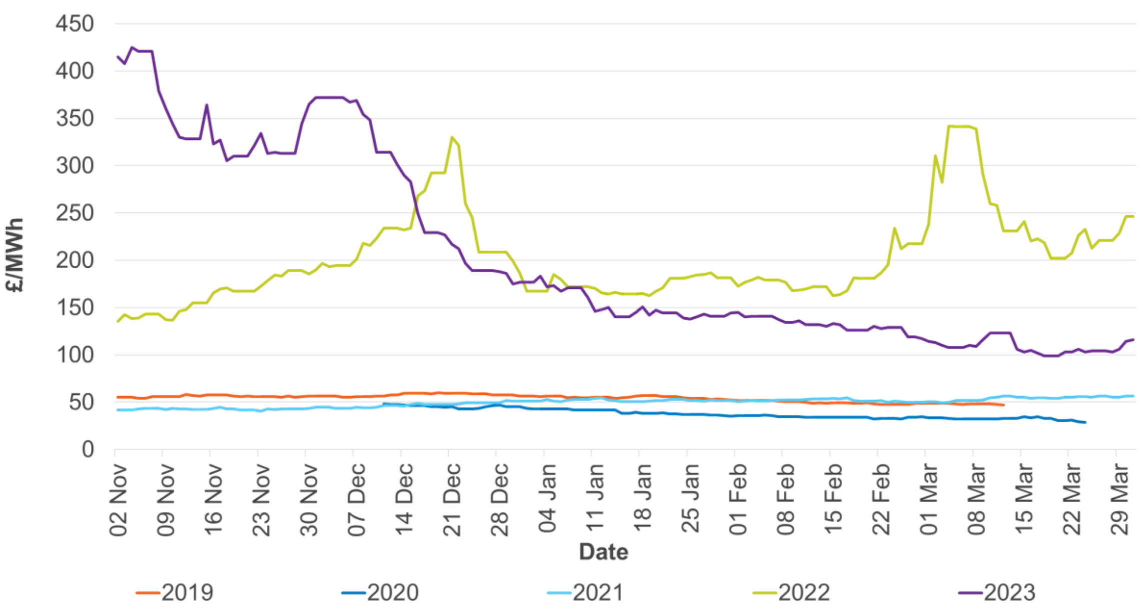
Figure 9 shows the GB forward electricity prices for summer 2023 compared to those of summer 2021 and 2022. Those for summer 2023 have dropped significantly in recent months, and are now below where they sat ahead of summer 2022, but still significantly higher than prices ahead of summer 2021, which were around £55/MWh and similar to previous years.

Electricity prices are expected to continue to be higher than 2021 due to pressure on global gas supplies driven by the Russian invasion of Ukraine. The recent falls reflect the position of European gas storage levels after winter 2022/23.

While this does not impact GB security of supply of electricity, it does increase the cost of the balancing actions the ESO carries out to operate the network reliably and efficiently. Although the ESO has taken measures to reduce the actions required and therefore the cost to consumers, the high energy prices will result in continued high operability costs, but higher volatility in prices than in years prior to 2022 also add additional uncertainty to our forecasts. More detail on this summer's expected trajectory for these operability costs are given on page 21.

We will continue to monitor market prices and their impact on the network and report back to industry through our Operational Transparency Forum as required.

Figure 9: GB forward electricity prices for summer



Europe and interconnected markets / Overview

We expect lower levels of exports to continental Europe than seen in summer 2022, but higher levels than was typical in previous summers. However, high prices and uncertainty related to the situation in Ukraine means the import/export pattern across the interconnectors to continental Europe remains uncertain.

This summer we expect…

- convergence of **forward baseload prices** in GB with those in Belgium, the Netherlands and France to lead to variability in interconnector flows.
- to see imports into GB at peak times based on current forward prices, subject to weather variations.
- to see greater exports over our continental interconnectors at times of low demand.
- **Moyle** and **EWIC** interconnectors to continue to be driven by weather conditions which could lead to imports or exports during peak times

There is significant spare capacity on the system during the summer (Figure 7). We are therefore well equipped for potential uncertainty over interconnector imports and exports, and this will not have an impact on security of supply. We will continue the close-working and coordinated approach with our neighbouring TSOs to offer reciprocal support where appropriate.

Did you know?

The insights on this page and page 15 are based on forward prices as of the 12th April (see Figures 11 and 12 on page 15).

Since the last Summer Outlook Report we have seen the successful commissioning of the **ElecLink** interconnector in May 2022. The 1 GW cable laid in the channel tunnel continues the growth in connection between GB and France to make a total of 4 GW alongside the **IFA** (2 GW) and **IFA2** (1 GW) interconnectors.

We will continue to monitor the development of new connections as they move through the commissioning process, but don't expect any new projects to come online in summer 2023.

Figure 10: Interconnectors expected to be operational in summer 2023

Europe and interconnected markets / Expected flows

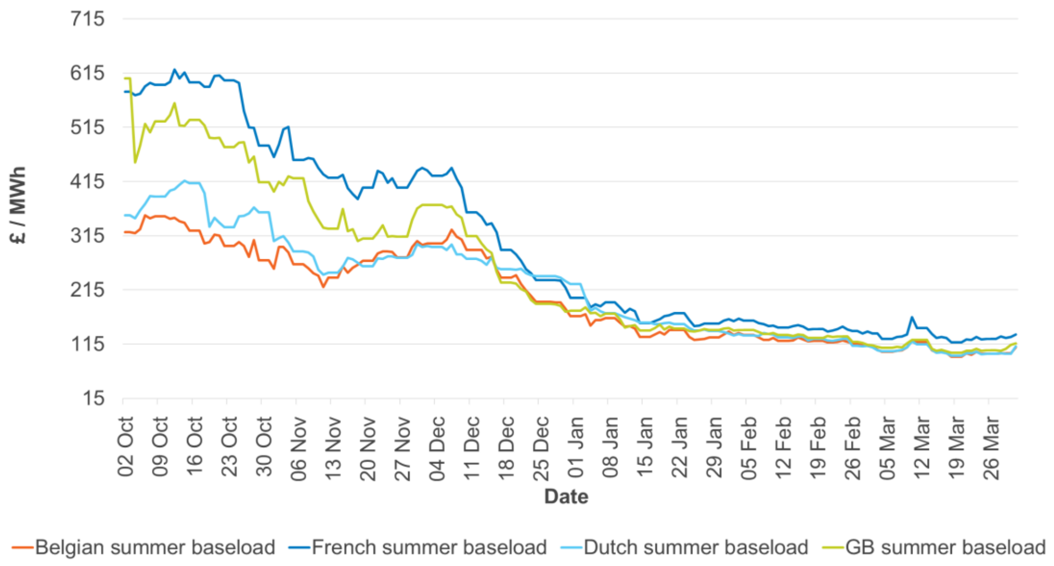
European forward prices

Electricity flows through the interconnectors are primarily driven by the price differentials between the markets. Typically during the summer, GB prices are higher than those in European markets leading to interconnector imports. However, the situation in Ukraine is continuing to have a significant impact on prices across Europe and GB.

Forward prices for electricity during summer 2023 are relatively high across all markets compared to previous years. Baseload forward prices are close across all GB and European markets, but French baseload forward prices are ahead of those in GB. The price spread between GB and the markets in Belgium and the Netherlands has also shrunk significantly[1].

The convergence in forward baseload prices could mean flows are likely to be more variable, driven increasingly by events on the day such as wind or solar generation.

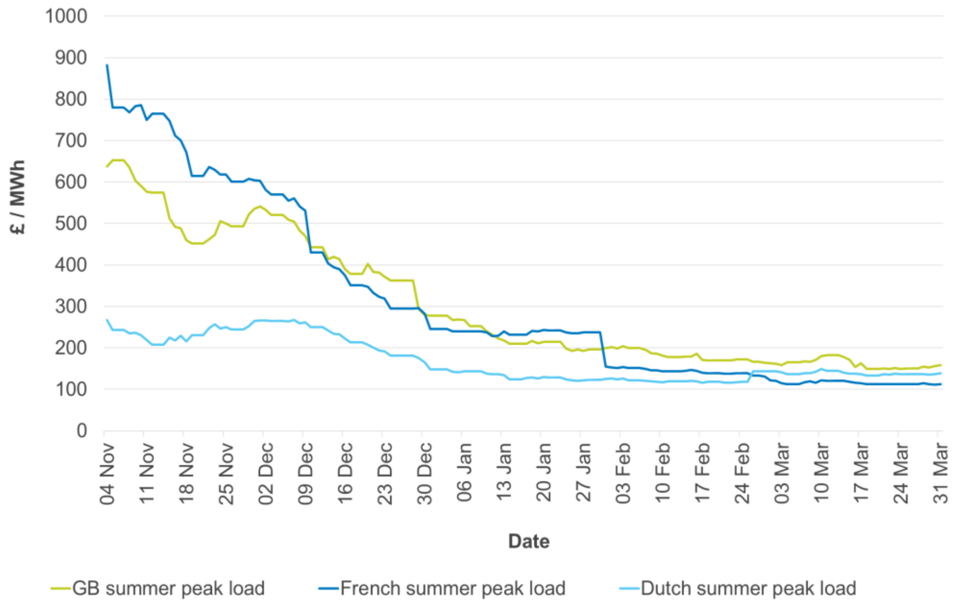
Figure 11: Summer 2023 electricity baseload forward prices (quarter ahead)



We expect to be able to support some exports to the continent, including at times over our peak. However the spread between peak forward prices has also shrunk, as shown in Figure 12. We now see GB's peak prices ahead of those in France and the Netherlands, indicating we are likely to see more imports at peak, particularly if we have tighter periods in GB. We also have a range of measures as part of our normal operating toolkit which we can use to manage interconnector flows.

Operability challenges over the summer are usually due to low demand, and so continued high exports over the summer are unlikely to present an operability challenge. This is covered in more detail in the Operability section from page 19.

Figure 12: Summer 2023 electricity peak forward prices (quarter ahead)



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1. Forward prices for Norway are not included but Norwegian market prices are typically much lower than the UK.

Europe and interconnected markets / Expected outages

Physical capabilities

Recent years have seen new interconnector capacity come online, with **NSL, IFA2** and **Eleclink** interconnectors providing 3.4 GW of additional capacity since 2021. Interconnectors may undertake planned outages over the summer, or experience fault outages. Table 2 shows current fault outages and 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.

Last summer, there were extensive periods of export from GB to continental Europe. This was driven by a combination of factors including availability of thermal generators, periods of drought affecting hydroelectricity generation and reduced availability of French generation due to nuclear outages. The availability of the French nuclear fleet can have a big impact on European electricity markets. Planned French nuclear outages are currently higher at the start of the summer, with units expected to return as we move through summer, increasing the availability of the fleet.

Figure 13: Summer outages for French nuclear plants: 2017-2022 and planned for 2023

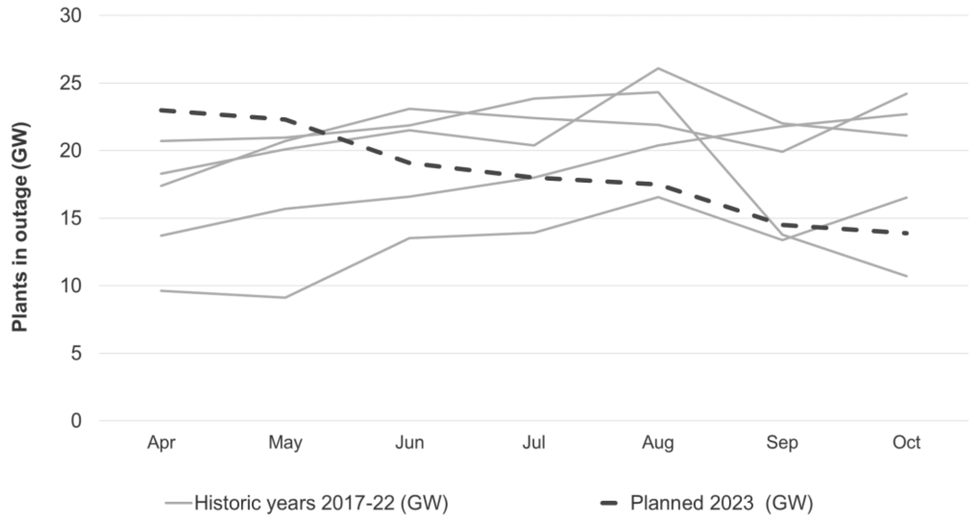


Table 2: Interconnector outage schedule for summer 2023

Interconnector (capacity)	Planned outages (resulting capacity)	Current outages (resulting capacity)
IFA (2 GW)	2023-06-05 to 2023-06-14 (1 GW) 2023-06-26 to 2023-06-26 (1 GW) 2023-09-11 to 2023-10-06 (1 GW) 2023-10-16 to 2023-10-20 (1 GW)	
BRITNED (1 GW)	2023-05-22 to 2023-05-26 (0 GW) 2023-09-18 to 2023-09-22 (0 GW)	
IFA2 (2 GW)	2023-06-19 to 2023-06-30 (0 GW)	
NEMO (1 GW)	2023-09-25 to 2023-10-06 (0 GW)	
Eleclink (1 GW)	2023-10-08 to 2023-10-08 (0 GW) 2023-10-08 to 2023-10-09 (0 GW) 2023-10-09 to 2023-10-10 (0 GW) 2023-10-10 to 2023-10-11 (0 GW)	
MOYLE (0.5 GW)	2023-08-21 to 2023-09-01 (0.25 GW)	
EWIC (0.5 GW)		
NSL (1.4 GW)		

Europe and interconnected markets / Summer 2022 interconnector flows

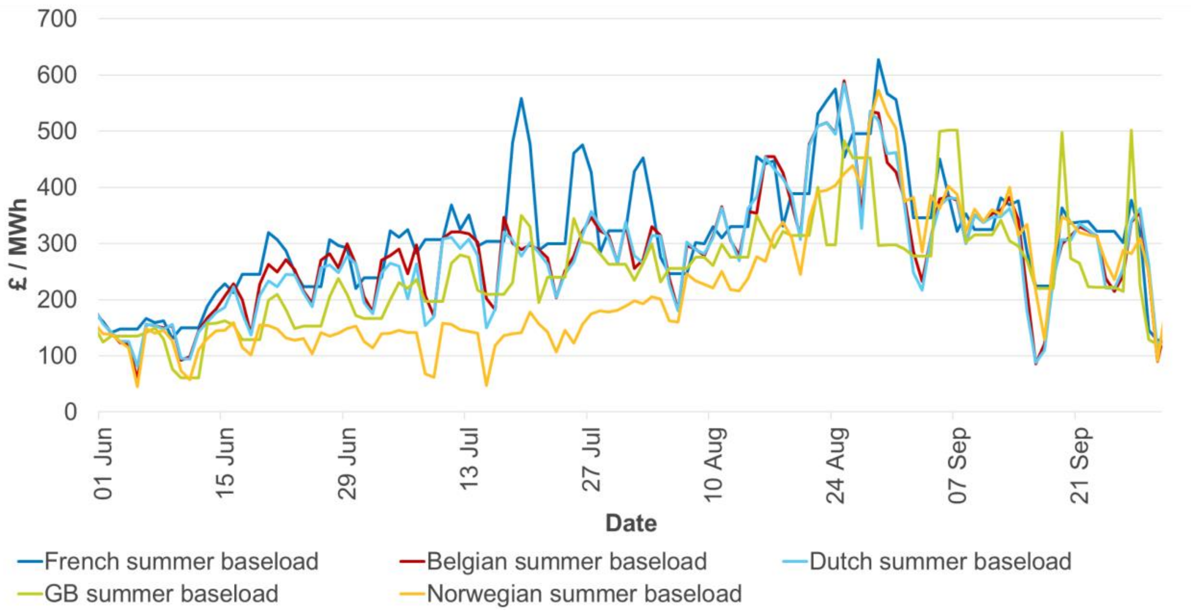
Baseload prices

Figure 14 shows GB and European day ahead electricity baseload prices for summer 2022. As shown, these were mostly **lower** in GB than in the Netherlands, France and Belgium, leading to net exports from GB to continental Europe (Figure 15).

Norwegian prices were below GB prices for much of the summer period, leading to a more mixed picture, with imports and exports seen over NSL for much of the summer.

These flows are explored in greater detail in the spotlight on the following page.

Figure 14: Day ahead baseload prices during summer 2022



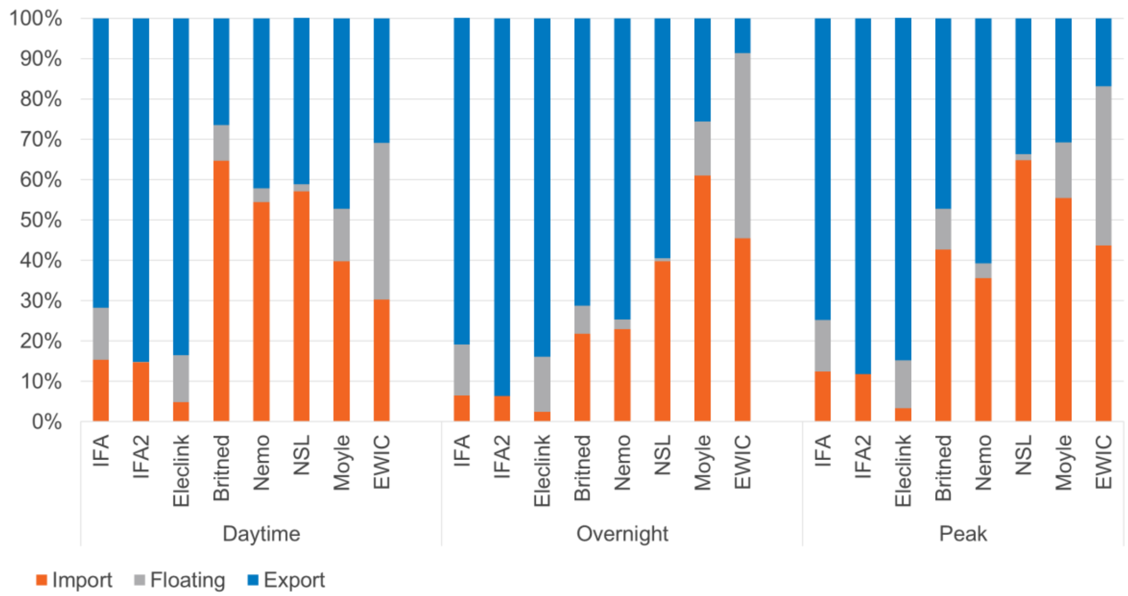
Interconnector flows

Figure 15 shows interconnector flows during the daytime, overnight and at peak times (5pm to 8pm) for summer 2022.

French interconnectors saw high levels of export throughout all periods, while Belgian and Dutch interconnectors saw more import during daytime and peak periods, with export overnight. **NSL** provided higher levels of import to GB particularly at peak.

Irish interconnectors provided more import to GB than in previous years, particularly during peak periods.

Figure 15: Proportion of import and export for continental and Irish interconnectors in summer 2022



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Spotlight / Summer 2022 interconnector exports

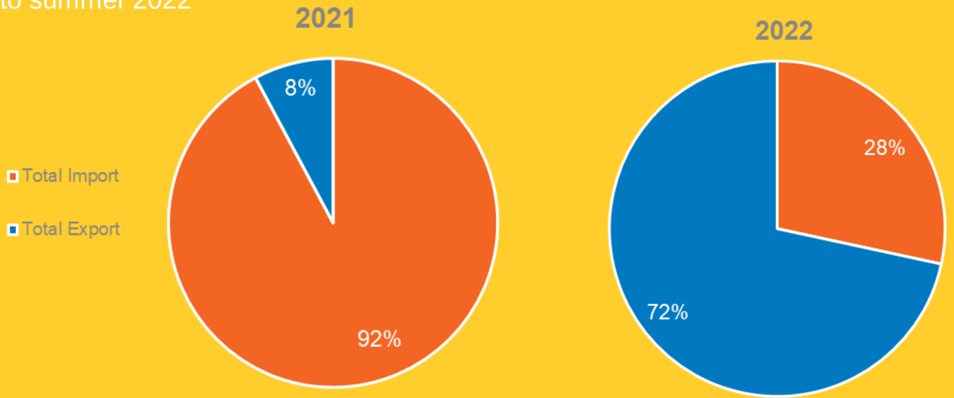
The ESO continues to work closely with our neighbouring TSOs, providing a coordinated approach and reciprocal support. In summer 2022 high electricity prices driven by the invasion of Ukraine led to higher levels of exports to continental Europe.

Electricity prices for summer 2022 led to a very different picture of interconnector flows compared to previous years where GB prices were typically higher than connected continental European markets. Market prices in summer 2022 in GB and Europe were significantly affected by the Russian invasion of Ukraine. This led to much higher prices with continental European prices also moving ahead of those in GB. This led to much higher levels of exports from GB, particularly to France.

Figure 16a shows the proportion of total import and export over GB interconnectors in 2021 and 2022. From this you can see that while in 2021 GB was importing significantly more electricity than it exported, in 2022 this trend reversed completely. Figure 16b shows the volumes of import and export across each interconnector, highlighting the varying pictures for each market.

In 2021 prices in the Netherlands and Belgium were typically below GB prices, leading to consistent levels of interconnector import. In 2022 the picture was more mixed, with significant flows seen in both directions, but with a majority of export.

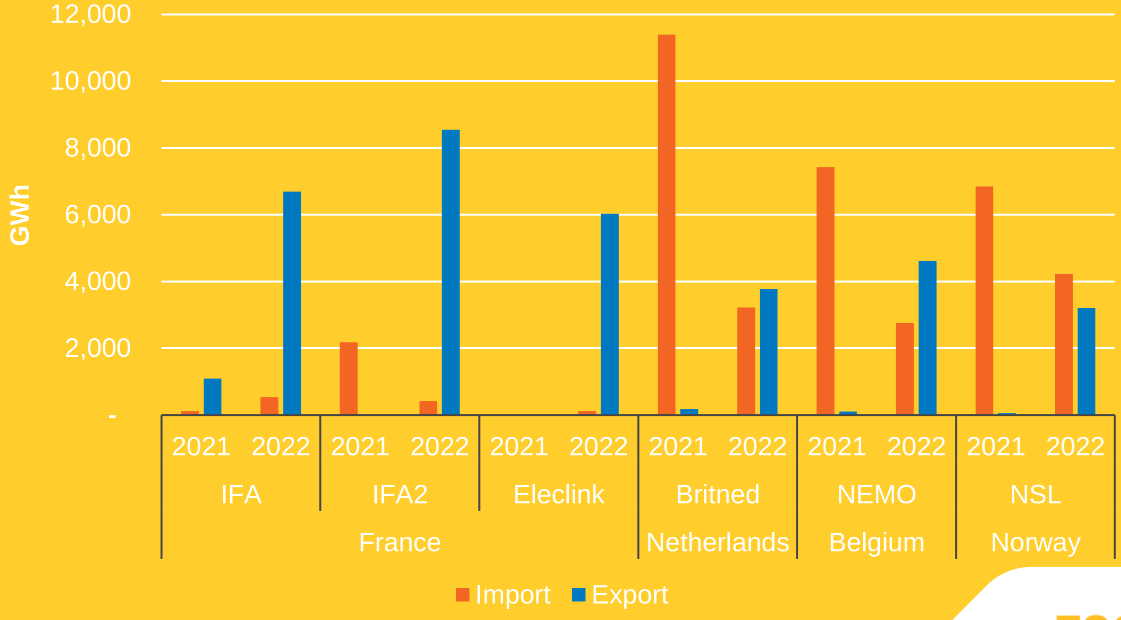
Figure 16a: Total mix of GB imports and exports over interconnectors summer 2021 compared to summer 2022



In France in 2021 the picture was mixed. Prices were often close between GB and France, with low levels of both import and export, biased slightly towards imports. In 2022, the situation was very different leading to 95% of volumes being exports, even with IFA being limited to 1 GW over the period.

In Norway we saw consistent imports throughout 2021, and a more mixed picture in 2022, as the situation elsewhere in Europe led to greater demand for Norwegian power exports to other markets.

Figure 16b: GB total imports and exports per interconnector in summer 2021 compared to summer 2022



ESO

Operational view / Summer 2023

Summer 2023 is expected to present similar operational challenges to summer 2022. We have the necessary tools in place to enable safe, reliable, 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. Summer 2023 is expected to present similar operational challenges as summer 2022 and we have the necessary tools in place to enable safe, reliable, efficient system operation.

Our latest view on operability across our five core areas for summer 2023 is set out in the following section. Beyond this, we will continue to engage stakeholders and industry on the challenges and costs of operability through the weekly Operational Transparency Forum.

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. There will be constraint costs associated with all the major system boundaries: B4/5, B6, B7, B9 and GMSNOW [1]. Forecasts for this summer indicate that the European interconnectors are likely to be importing to GB more than last summer, easing the LE15 constraint. However, under this scenario higher constraint costs than last year on the B15 boundary are likely to occur. Work continues at Bicker Fen substation prior to the connection of Viking Link interconnector in early 2024. Likewise, work is ongoing at Pembroke substation for the connection of Greenlink Interconnector. Work is continuing in northern Scotland for the longer-term upgrade to 400kV circuits, although the outages align with a major generator outage where possible.

Constraint volumes are likely to be the same or higher in summer 2023 than 2022, although the overall outturn constraint cost may be lower if the gas price continues to fall in 2023. We are providing a 24 month ahead forecast of constraint limits and costs on our data portal.

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. The forecast demand level for summer 2023 is slightly lower than the demand out-turn from the same period last year, so we would anticipate that the actions required for voltage management will be broadly like previous years.

However, during the summer of 2022 we experienced high interconnector flows to Europe, which increased flows on the GB transmission system and therefore reduced the overall need. There will be a level of uncertainty around interconnector flows and therefore the requirements are based on a worst case position.

Where there are outage patterns that result in periods where there are deficits in regional reactive power, the ESO may need to intervene through a tender to secure the requirement. This will be communicated via our website and account managers.

There are major planned or ongoing outages of Sizewell and Dinorwig for parts of the summer which require operational options and other actions to secure for certain periods, which are being explored.

Various pathfinder projects (both voltage and stability) are now available across the transmission system, which will help with high voltage management where they are connected. These will help to reduce the cost of synchronising generation specifically for voltage management.

To provide transparency on our trading decisions for reactive power requirements for voltage management, we continue to publish overnight voltage requirements for voltage management at the week-ahead stage. We have also published a document at the same link explaining how we manage the voltage requirement to help the industry understand this better.

[1] More details on boundary locations can be found here: https://www.nationalgrideso.com/research-and-publications/electricity-ten-year-statement-etys/electricity-transmission-network

Operational view / Summer 2023

Frequency and stability

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 GB electricity system. FRCR 2023 recommends we reduce our existing minimum inertia requirement from 140 GVAs to 120 GVAs. This will reduce operational costs by approximately £65m per year whilst maintaining our risk profile in frequency control. This is mainly driven by 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). The final report can be found from ESO website[1].

Once approved by Ofgem, we will implement the policy change in two stages. Initially we will reduce to 130 GVAs and operate at this level for 1 – 2 months and then we will reduce further to 120 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. We will provide advanced notice to industry prior to the change once the timing has been clarified.

Phasing out Dynamic Firm Frequency Response (DFFR):

We communicated in our monthly Market Information Report (MIR) that a key milestone in frequency response reform is the phasing-out of monthly Dynamic FFR (DFFR). This will happen gradually as we develop and establish the new pre-fault dynamic frequency response product **Dynamic Regulation** (DR).

We have met criteria to increase the volume of DR and since March 2023, we have been seeking to procure up to 200 MW of DR. As such we will be reducing our requirement for primary, secondary and high dynamic frequency response, to reflect the contribution of DR to managing the system. We intend to reduce our DFFR requirements by no more than 50 MW for each EFA block per month since March. We will continue to procure up to 100 MW of **Dynamic Moderation** (DM) and will keep monitoring frequency performance and communicate our further requirements of DM to industry.

Day Ahead Procurement of Static Frequency Response (SFFR):

Ofgem approved the new service terms and procurement rules of Day ahead Static Firm Frequency Response (SFFR) in Feb 2023. The service is not materially changing but changes the procurement timescale from monthly to daily. The service launched on the 31st March . More information can be found on our website.

We publish our short term frequency response requirements via the data portal.

Reserve

We have communicated to industry on our website our Short Term Operating Reserve (STOR) requirement for summer 2023. The required volume for service windows is 100 MW less than in summer 2022 due to the increased reliability from STOR units from past year. This puts the summer STOR requirement for the day ahead auction at 1210 MW. Other reserve requirements remain mostly the same as last summer.

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. See here for more information on restoration services.

Costs are likely to remain relatively high as a consequence of work we are doing in this area. We have three live Restoration Tenders where the ESO will be contributing (capped contribution) to the detailed engineering studies that will underpin the technical offers from potential providers.

[1] https://www.nationalgrideso.com/industry-information/codes/security-and-quality-supply-standards/frequency-risk-control-report

Operational view / Summer 2023 costs

The table below gives a current indication of likely trajectories for the different balancing and constraint costs in terms of volume of actions, cost per action and total cost we expect over summer 2023 relative to last summer. Overall, we forecast that balancing costs could be around 30% lower than summer 2022.

Area	Volume of actions	Cost per action	Total cost	
Thermal	↑	↓	→	An increased volume of connected generation, particularly renewable generation located at the extremities of the transmission network is likely to drive a higher volume of action required to manage thermal issues on the network. Cost per action is forecast to fall if gas prices continue to decrease through 2023.
Restoration	→	→	→	Volume of actions and the cost of these actions are forecast to remain stable. The ESO will be contributing to three live Restoration tenders to support the detailed engineering studies underpinning technical offers from providers.
Frequency	↑	↓	↓	We've further developed our new suite of frequency response services and will be growing these markets over summer 2023. The volume of actions will increase as we look to grow the markets and implement a lower minimum inertia policy, but the cost per action is forecast to fall with increased competition in each market.
Stability	↓	→	↓	We now have access to the majority of volume delivered from our phase 1 stability pathfinders (12.5 GVAs) which reduces the volume of actions needed. The lower inertia level introduced through the FRCR 2023 will result in a lower volume of actions required to operate the system for stability.
Voltage	→	↓	↓	Requirements are similar to last year, so with a decrease in gas prices, the total cost should fall, though there is some uncertainty around interconnector flows.
Overall	↑	↓	↓	Despite the expectation for a higher volume of actions to be needed, reduced wholesale prices and the ESO's ongoing work on reducing balancing costs will help minimise cost per action and reduce total balancing costs compared to summer 2022.

Looking beyond summer / Winter 2023/24

We have already working closely with stakeholders to prepare for winter 2023/24. We will publish an Early View for winter 2023/24 by June, alongside our review of last winter. We expect the Winter Outlook Report to be published by early October.

Looking beyond this summer is of obvious importance this year. We have already started our preparations for winter and expect to share this with industry stakeholders in the coming months.

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 work with industry stakeholders on what's next for our innovative Demand Flexibility Service (DFS) that we launched last winter[1].

We are also continuing to closely monitor developments in both global and GB energy markets. This will help us to identify and assess the potential uncertainties that could affect our winter operations. In GB, the T-1 Capacity Market auction for delivery in winter 2023/24 has already concluded, securing 5.8 GW capacity for the upcoming winter[2]. In addition, EDF Energy have also recently announced extensions to the operational lives of two nuclear power stations that had previously been due to close in 2024[3]. In Europe, we are continuing to monitor developments that could influence flows on electricity interconnectors. These include, for example, changes to outages on the nuclear fleet in France, and European gas storage stocks that are currently sitting at over 50% full[4]. This is much higher than this time last year when stocks were below 30% full.

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 email at marketoutlook@nationalgrideso.com or by following us on Twitter (@ngeso).

Upcoming publications for winter 2023/24

- **Early View**

We expect to publish our Early View for winter 2023/24 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. It will also set out further details on some of the steps the ESO is taking to prepare for winter 2023/24.

- **Winter Outlook Report**

The full Winter Outlook Report is expected to be published in September or early October.

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.

1. https://www.nationalgrideso.com/industry-information/balancing-services/demand-flexibility-service-dfs
2. https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-1%20DY%2023-24%20Final%20Auction%20Results%20Report%20v1.0.pdf
3. https://www.edfenergy.com/media-centre/news-releases/edf-confirms-plans-keep-turbines-turning-heysham-1-and-hartlepool-power
4. For example: https://gasdashboard.entsog.eu/#map-storage

Appendix A / Demand definitions

There are a range of different types of electricity demand, the differences between these are presented here.

	Term	Definition	Note
Types of demand	GB Customer demand	Sum of all demand used within GB. Total demand requirement for GB.	This includes demand offset by embedded generation on the distribution networks and is similar to the demands quoted in the Future Energy Scenarios.
	Transmission demand	Sum of all generation that flows through the GB Electricity Transmission network to meet internal GB demand or exports out of GB.	These are the demands typically presented in the Summer and Winter Outlook Reports.
	National demand	Sum of all generation that flows through the GB Electricity Transmission network to meet internal GB demand, excluding electricity used to power large power stations	
	Triad demand	Transmission demand minus exports out of GB. Used to determine the days on which Triads have occurred	
Types of outturn	Operational outturn	Uses all real-time metering feeding into NG 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 plant that participates 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 / Record minimum electricity demands in 2020

There are several different types of demand – each with a different definition. The summer of 2020 saw record low demands – but what was the lowest electricity demand in the summer of 2020? This appendix, first published in 2021, explores this and explains how different types of demand vary.

National demand measures how much generation must be supplied through the transmission network to meet customer demand within GB. Effectively this is the "natural" demand within GB. By this measure the lowest demand in 2020 occurred on 28 June at 05:30. This demand of 13.4 GW was by far the lowest ever seen (the next lowest National demand outside of 2020 was 15.8 GW).

In addition to the customer demand component, there was approximately 500 MW of demand from transmission connected generation, known as **station load**. And there were also exports across the international **interconnectors** and demand from **pumped storage** units, totalling 3.8 GW. This means that the total demand to be met by the transmission network was 17.8 GW; this is known as **transmission demand**.

It is standard practice when summer overnight demands are low, that extra demand can be created by instructing pumped storage units to pump or by trading on the interconnectors. This gives the necessary operational flexibility to the Control Room by increasing the total generation required from the transmission network. The amount of this extra demand that can be created depends on the prevailing market conditions and on the state of the pumped storage reservoirs, and cannot be accurately forecast much ahead of real time.

However, the **transmission demand** on 28 June was not the lowest transmission demand in summer 2020. That occurred on 31 May, the weekend after the late May bank holiday. The lowest **transmission demand** was 16.6 GW at 15:00 in the afternoon. The "natural" customer demand at the time was much higher than the lowest, at 16.0 GW, and only 0.1 GW of extra demand was being created through pumping or interconnectors.

It is normal not to take too much action on pump storage units to create higher transmission demand during the afternoon trough because if the storage reservoirs are filled up during the afternoon trough, the same facility might not be available overnight when the risk is greater.

The lowest overnight transmission demand occurred on 10 May 2020, the Sunday of the early bank holiday weekend. The transmission demand was 16.9 GW, 0.3 GW higher than the lowest transmission demand. But the "natural" demand was lower at 15.3 GW; this is low by normal standards, but not particularly low by the standards of 2020. There was 1.1 GW of "extra" demand created by Control Room instructions.

Additional to **national demand** and **transmission demand**, we also publish **weather corrected outturn demand** (that is, demand as it would have been under average weather conditions), and demand forecasts more than 14 days ahead also use average weather conditions. Weather corrected demands are useful for comparing demands between different years because they strip out the variability of weather conditions, and reflect economic, behavioural and technological changes.

Maximum and minimum weather corrected demands do not necessarily coincide in time or date with the equivalent extremes of the outturn demands, as minimum (or maximum) demands occur on days when we can guarantee that the weather is not average. However, in summer 2020 the minimum weather corrected **transmission demand** of 16.2 GW did occur at the same time as the minimum National demand.

When calculating either weather corrected **transmission demand** or demand forecasts based on average weather conditions we do not apply any assumed value for the "extra" demand that can be created by instructing pumps or interconnectors. The amount that can be instructed is too dependent on prevailing market conditions, and the amount that needs to be instructed depends too much on the actual weather conditions as opposed to the average weather conditions.

This means that caution should be applied when comparing season ahead **transmission demand** forecasts (with zero allowance for "extra" instructed demand) to previous years' outturn **transmission demand** (with the actual amount of "extra" generation included). It is always better to compare the seasonal forecast with the weather corrected outturn, so that they are calculated on the same basis.

In conclusion, what was the lowest summer demand for 2020? It was either 13.4 GW or 16.2 GW or 16.6 GW. Which you choose depends on what you want to use the value for.

Appendix C / Relationship between types of demand

This figure shows the relationship between some of the different types of demand discussed on the previous page, but this time based on minimum demands which occurred over summer 2021

The lowest overnight **Transmission demand** occurred on 27 September. The Transmission demand was 18.4 GW.

Transmission System Demand

The lowest daytime **Transmission demand** was 19.4 GW at 15:00 in the afternoon of 30 May, the Sunday of the late May Bank Holiday weekend

'Natural' Demand

Power Station Demand

Interconnector Exports

Pumped Storage Pumping

National Demand

Increasing Transmission Demand

The lowest **National demand** occurred on 28 June at 05:30. This demand of 16.3 GW was significantly higher than that seen in 2020 (13.4 GW) which due to COVID-19 demand suppression was by far the lowest ever seen.

The market or the ESO may take actions to increase exports across the interconnectors or increasing pumping at pumped storage stations to increase the amount of demand on the transmission system.

ESO

Glossary

Accelerated Loss of Mains Change Programme (ALoMCP)
A joint initiative between the ESO, Energy Networks Association, Distribution Network Operators and independent Distribution Network Operators. 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 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 www.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.

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

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.

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 e.g., 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 at www.eirgridgroup.com/customer-and-industry/

Glossary

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

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.

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.

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 GB market 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 www.mutual-energy.com

Glossary

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).

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 GB and Belgium.

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

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

North Sea Link (NSL)
A 1.4 GW HVDC sub-sea link from Norway to GB commissioned this October. See more at https://www.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 historic demand operational demand from 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 by the use of water that has been pumped into a reservoir at a higher altitude during periods of low demand.

Rate of Change of Frequency (RoCoF)
How quickly system frequency changes on the electricity network. Usually measured in Hertz per second. Some generators have a protection system that will disconnect them from the network if the Rate of Change of Frequency goes above a certain threshold.

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.

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

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. provides head room (positive reserve) and foot room (negative reserve) provided across all generators synchronised to the system.

Glossary

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

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

Super-SEL
A service used to directly decrease the sum of the minimum MW level or Stable Export Limit (SEL) of generators synchronized to the system by lowering the minimum generating level at a generator synchronised.

Technical capability
The capacity of connected plant expected to be generating in the market, based on the Capacity Market auctions another sources of market intelligence, but not taking any account of potential breakdown or outage.

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

Triad avoidance
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. This is sometimes referred to as customer demand management but, in this section, we are considering customer behaviour that occurs close to anticipated Triad periods, usually to reduce exposure to peak time charges.

Triads
The three half-hourly settlement periods with the highest electricity transmission system demand. Triads can occur in any half hour on any day between November and February. They must be separated from each other by at least ten days. Typically, they take place on weekdays around 4.30 to 6pm.

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.

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 out turned 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.

Western High Voltage (HVDC) link
The Western Link uses DC technology to reinforce the UK transmission system and move electricity across the country in very large volumes between Hunterston in Scotland and Deeside in North Wales.

Join our mailing list to receive email updates on our Future of Energy documents.

www.nationalgrideso.com/research-publications/summer-outlook

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

You can write to us at:

Energy Insights
Electricity System Operator
Faraday House
Warwick Technology Park
Gallows Hill
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Electricity System Operator legal notice