Winter Outlook Report

Helping to inform the electricity industry and prepare for the winter ahead

6 October 2022

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Executive summary

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Since last winter the world has fundamentally changed with the invasion of Ukraine by Russia. With this backdrop the ESO presents the Winter Outlook. Building on the Early View of Winter, this document presents a more detailed view focusing on the upcoming winter in Great Britain. This Winter Outlook covers the period from 31 October 2022 to 31 March 2023. The data freeze date for this outlook was 22 September 2022.

This Winter Outlook is developed in the context of unprecedented turmoil and volatility in energy markets in Europe and beyond and, as we stated earlier in the year, shortfalls of gas in continental Europe could have a range of knock-on impacts in Britain. Therefore, in this Winter Outlook in addition to our Base Case, we also set out scenarios to illustrate the implications should some of those risks to security of energy supplies materialise.

Our central view remains, as set out in the Base Case, that there will be adequate margins (3.7GW / 6.3%) through the winter to ensure Great Britain remains within the reliability standard[1], although we expect there to be days where we will need to utilise many of the tools in our operational toolkit, including use of system notices[2].

Given the scale of uncertainty and risks associated with the current geopolitical situation we have developed a range of new tools, including:

- Publishing an early view of winter to help the market understand risks
- contracting to retain approximately 2GW of coal fired generation that would otherwise have closed
- and introducing an innovative Demand Flexibility Service to incentivise customers to reduce consumption at periods when margins are tight.

Notwithstanding the mitigation measures noted above, it is highly likely that the wholesale price of energy (both gas and electricity) will remain very high throughout the winter outlook period[3].

While our Base Case assumes that capacity across all providers (generation, storage, interconnection etc.) is available in line with commitments secured under the Capacity Market, we have also modelled a scenario whereby the energy crisis in Europe results in electricity not being available to import into Great Britain from continental Europe. This could be due to a combination of factors, including a shortage of gas in Europe (which in turn limits power generation in Europe) and / or generation unavailability (e.g., due to a high level of outages across the French nuclear fleet).

We have also considered the scenario where there is a shortfall of gas available in Great Britain.

1 The reliability standard is 3 hours Loss of Load Expectation (LOLE). Modelling shows the Base Case LOLE to be 0.2 hrs, well within the standard.
2 These would include Electricity Margin Notices (EMNs), Capacity Market Notices (CMNs) etc.
3 This will also lead to higher balancing costs as the costs of each required action are linked to the wholesale price of electricity as bid into the Balancing Mechanism or offered for trades on interconnectors.

Executive summary

Our first illustrative scenario examines what would happen if there were no electricity imports from continental Europe[4]. In this scenario we would deploy our mitigation strategies – dispatching the retained coal units and our Demand Flexibility Service. By securing 4GW[5] through these actions, we would maintain adequate margins and mitigate impacts on customers.

Our Demand Flexibility Service is new and innovative, and we have worked with suppliers, aggregators, industry, Ofgem and BEIS on the design to ensure it is ready for the winter and capable of delivering the required level of participation and response (2 GW+). It will launch on 1 November, and we are encouraging suppliers and aggregators to work with their customers to ensure the highest levels of engagement and participation. We see particular potential from commercial organisations who can shift their load from peak hours and have had positive feedback from British companies on this.

Without the Demand Flexibility Service, we would expect to see a reduction in margins. In this scenario on days when it was cold (therefore likely high demand), with low levels of wind (reduced available generation), there is the potential to need to interrupt supply to some customers for limited periods of time in a managed and controlled manner. However, we expect the mitigations outlined above to be effective.

A second, more extreme scenario, looks at a hypothetical escalation of the energy crisis in Europe such that there is insufficient gas supply available in Great Britain (in addition to no electricity available to import from continental Europe as per above scenario). In the unlikely event that escalation of the situation in Europe means that insufficient gas supply were to be available in Great Britain this would further erode electricity supply margins[6] potentially leading to interruptions to customers for periods. All possible mitigating strategies, including our new measures, would be deployed to minimise the disruption.

Overall, this is likely to be a challenging winter for energy supply throughout Europe. We have taken extensive measures to try to mitigate the impacts for British consumers and expect that, under our base case, margins will be adequate. Nevertheless, there remain scenarios, driven principally by factors outside of Great Britain which could impact upon British electricity supplies. Plans are in place to ensure the impact is minimised and the overall security and integrity of Britain's energy systems are protected.

This document only covers the electricity outlook for the winter ahead; the Gas Winter Outlook can be found here.

For more information, you can email us at marketoutlook@nationalgrideso.com

4 The scenario assumes no electricity imports available from France, Netherlands and Belgium; 1.2 GW imports from Norway; 0.4 GW exports to Northern Ireland & Ireland.
5 We expect the additional coal units to provide 2 GW and therefore the Demand Flexibility Service would need to provide 2 GW.
6 Due to the curtailment of gas supplies to gas fired power stations in GB for example CCGTs etc.

Contents

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Base Case / System margins

System margins are expected to be adequate in our Base Case. Notwithstanding this we expect there may be days when we need to use our operational tools.

The de-rated margin of 3.7GW (6.3%) is similar to both our Early View of Winter and margins that we have had in recent years.

- The Base Case loss of load expectation (LOLE) is around 0.2 hours/year, which is within Reliability Standard of three hours per year set by Government.
- Our base case assumes electricity imports from Europe are available at times when we need them to meet demand, delivering in line with their Capacity Market agreements, and that there is no disruption to gas supplies.
- Our base case does not assume any material reduction of consumer demand due to high energy prices. It does not include any of our mitigation measures such as coal contracts or the Demand Flexibility Service as we would not expect to deploy them here.

The chart in Figure 2 shows the de-rated margins included in previous Winter Outlook Reports and highlights how this year's de-rated margin is similar to those in some recent winters (e.g. 2015/16, 2016/17 and 2021/22).

If there are some tight periods this winter, we may need to use our standard operational tools such as issuing Electricity Margin Notices (EMNs). Capacity Market Notices (CMNs) may also be issued. We expect there to be sufficient available supply to respond to these signals to meet demand.

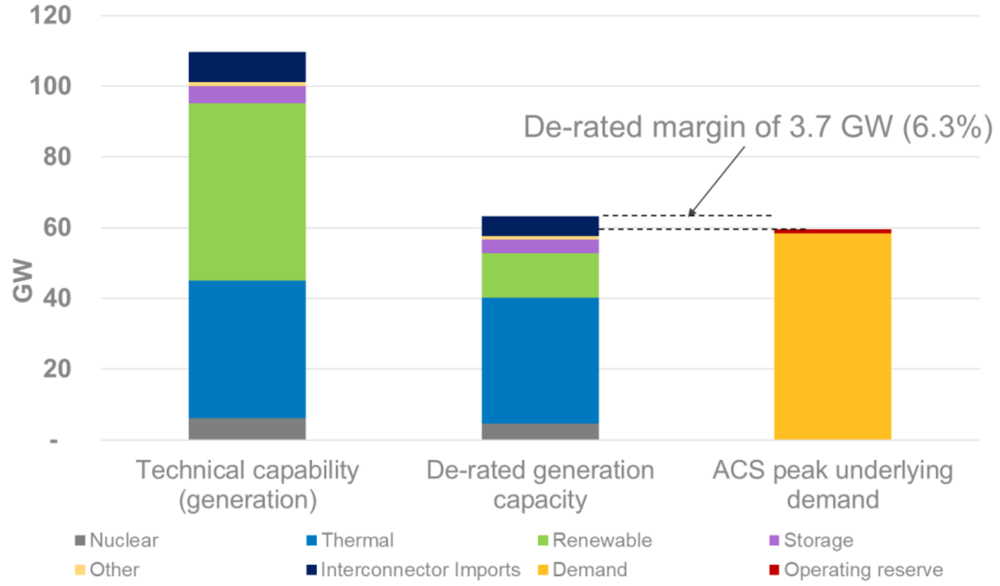

Figure 1. Supply margin in relation to generation capacity and demand

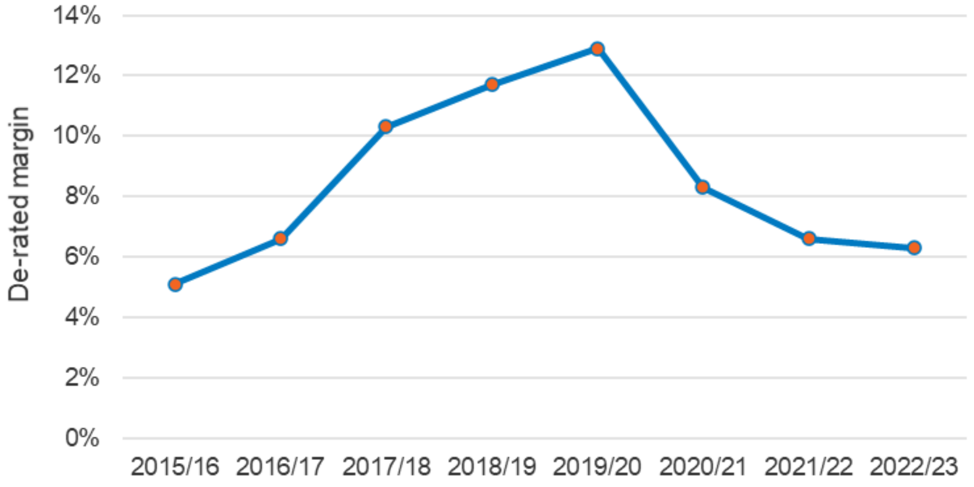

Figure 2. Historic de-rated margin forecasts made ahead of each winter in the Winter Outlook Report (i.e. not out-turns)[1]

[1] Includes additional reserves (Supplemental Balancing Reserve and Demand Side Balancing Reserve – SBR and DSBR) of 2.4 GW and 3.5 GW procured in 2015/16 and 2016/17 respectively.

Base Case / Operational Surplus

Our base case operational view shows sufficient operational surplus for each week of winter.

This winter we expect

- normalised weather corrected transmission system demand to be met in the Base Case before using any operational tools
- Average Cold Spell (ACS) transmission demand to be met under our base case with utilisation of our operational tools (e.g. system notices)
- normalised peak transmission demand to occur in mid December or early January, based on our latest forecasts
- the minimum operational surplus is currently projected to be lowest in mid-December when these forecasts are combined with current generator submissions.

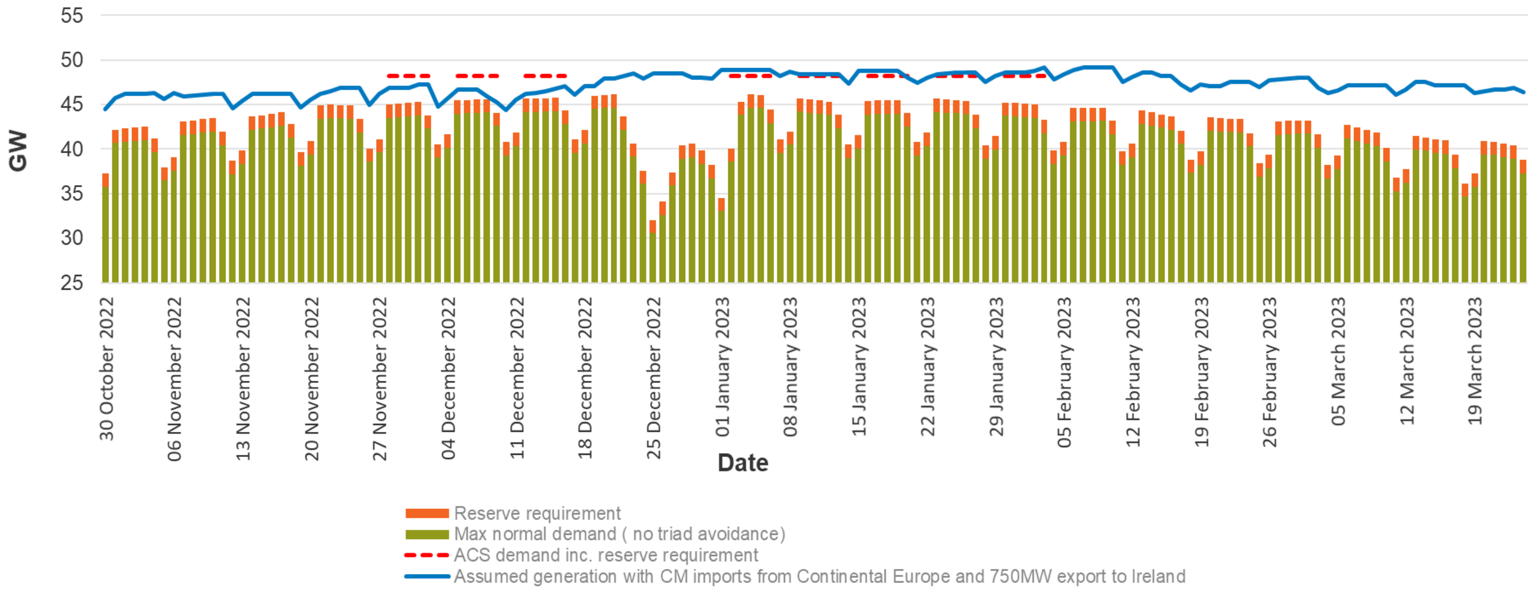

Figure 3. Day-by-day view of operational surplus for winter 2022/23 (based on market data submissions from 22 September)

How our assessments are developed

As we get closer to winter, we move from an assessment that considers the winter as a whole, to one where we consider much greater temporal granularity on a week-by-week and day-by-day basis. This is our operational modelling. It includes actual plant outages, current weather patterns and price differentials that drive interconnector flows. It is based on transmission demand and generation, and therefore represents the perspective from our control room based on what the market is currently intending to provide (i.e. before use of our operational tools). Our operational modelling helps to identify when tight periods are most likely to occur, and to indicate when we may need to use our operational tools to manage margins. These periods do not necessarily occur at times of peak demand. This view will change throughout winter, based on weather and changes to plant outages.

Our Base Case operational view assumes imports from Continental Europe in line with Capacity Market agreements. It also assumes 750MW exports to Ireland, which is based on long-term historic flows. However, we have observed that the flows on Irish interconnectors have become much more variable in recent years (see page 17) and could reverse direction in the event of tight periods in Great Britain, responding to market signals. Our Base Case operational view does not include potential market responses to higher demand or tighter conditions, such as power stations increasing their output levels for short periods. Nor does it include our mitigation measures for winter (i.e. the contingency coal contracts or the Demand Flexibility Service). During periods of low operational surplus, generators may be incentivised to reschedule planned outages by Capacity Market obligations or through revenue opportunity from higher market prices. ACS demand has historically always occurred between the first week in December and the first week in February, but never during the Christmas fortnight or on a weekend.

Base Case / Credible range

We expect to have sufficient operational surplus throughout winter in our Base Case, even when we consider the expected natural variation of demand, wind and outages.

This winter we expect

- to have sufficient operational surplus throughout winter when routine tools such as margin notices are used
- tight margins to be likely throughout December to mid-January (excluding the Christmas period).

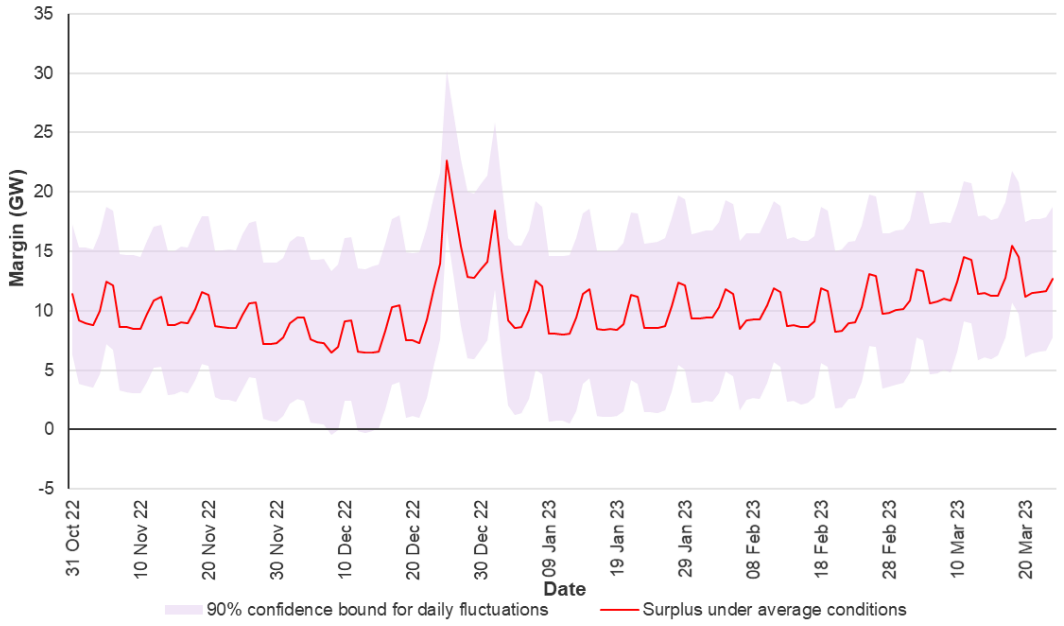

Figure 4. Range of outcomes for the daily operational surplus in our Base Case under different supply and demand conditions

Did you know?

Figure 3 shows a particular view of generation and demand from which you can extract a single view of operational surplus. However, a single view is not appropriate in assessing the potential risk due to natural variation in demand, wind, outages etc.

The analysis behind Figure 4 considers a situation under typical conditions, using average weather conditions for demand, average availability for conventional generation and average wind conditions when margin is tight.

To explore the variation around this central view, we simulate many possible scenarios for weather, demand, conventional generation availability, wind generation output and interconnector availability and, for each of these scenarios, we calculate the daily surplus time series across the entire winter for that scenario. We do not include any actions that could be taken by the ESO.

Figure 4 shows the forecast of daily surplus under our Base Case, with the shaded region representing the credible region within which the surplus can fluctuate. It is important to note that, although on any given day the fluctuation can reach the lower bound (or dip below it), it is not credible that surplus will remain at the lower bound level for the entirety of the winter.

We look at a day-by-day analysis, finding the daily credible range of values for the surplus. By "credible" we mean a 90% confidence bound for the day-by-day fluctuations in surplus between 5% and 95%

The modelling here considers the natural variation of forced outages. Planned outages are assumed to be in line with those declared through REMIT at the time of the data freeze for this report. This modelling also assumes that, for continental interconnectors, market forces will allow flow into GB of whatever interconnector capacity is available after unplanned outages.

Winter scenarios

In addition to our Base Case, we have set out two scenarios to illustrate the risks and uncertainties for winter. These scenarios are not forecasts and they do not indicate an expectation or likelihood of these situations materialising.

Scenario 1: Reduced electricity imports from Europe

Due to risks created by the invasion of Ukraine by Russia, we have modelled a scenario where the energy crisis in Europe results in electricity not being available to import into Great Britain from continental Europe at times when we need it.

This could be due to a combination of factors, including a shortage of gas in Europe (which in turn may limit power generation in Europe) and / or generation availability (e.g. due to a high level of outages across the French nuclear fleet).

This scenario assumes no electricity imports from France, Belgium and the Netherlands for the whole winter. We continue to assume 1.2GW imports from Norway, with a total of 0.4GW sustained exports to Northern Ireland and Ireland.

In this scenario we would need to deploy our mitigation strategies, and so we assume the additional coal units (around 2GW) are available to dispatch by the ESO and the Demand Flexibility Service is deployed (delivering around 2GW).

Scenario 2: Reduced electricity imports from Europe combined with insufficient available gas supply in Great Britain

We have also considered a situation where there is a shortfall of gas supply available in Great Britain.

In addition to the assumptions of Scenario 1, we have chosen to model a two-week period in January in which around 10GW CCGTs are unavailable due to a gas shortage. We continue to assume the additional coal units (around 2GW) are available to dispatch by the ESO and the Demand Flexibility Service is deployed (delivering around 2GW).

We have modelled this scenario to illustrate the impact on the electricity system if there is insufficient gas supply available in GB. For further details on the Gas Winter Outlook, please refer National Grid Gas Transmission’s 2022/23 Winter Outlook Report.

Scenario 1 / Reduced electricity imports from Europe

We expect to use coal contracts and our Demand Flexibility Service to maintain adequate margins if imports from Europe are not available when we need.

In this scenario we assume that we have no electricity interconnector imports from France, Belgium and the Netherlands (these are assumed to provide a de-rated capacity of 3.9GW in the Base Case). It is assumed that we import 1.2GW from Norway and export 0.4GW to Northern Ireland and Ireland.

In this situation we would deploy both the contingency coal contracts (around 2GW) and the Demand Flexibility Service (assumed around 2GW). This would result in a de-rated margin of 3.3GW (5.7%) with an LOLE of 0.5 hours/year, broadly similar to our Base Case.

Without sufficient take-up of the Demand Flexibility Service, we would still expect margins[1] to be within the Reliability Standard of three hours LOLE per year. In this case, there may be days when it was cold (therefore likely high demand), with low levels of wind (reduced available generation), where there is the potential to need to interrupt supply to some customers for limited periods of time in a managed and controlled manner. However, our expectation is that our mitigation measures will be effective.

Credible range for surplus

Figure 6 shows the variation in operational surplus for Scenario 1. It uses the same approach as outlined on page 8 to reflect the natural variation of demand, wind and outages, for the assumptions set out for this scenario. It assumes contingency coal contracts and the Demand Flexibility Service are deployed.

The tightest periods are from late November to January, where the daily margin often drops below zero. This does not mean that there will be interruption to supply. It means that it is more likely we will need to use our operational tools at these times (e.g. system notices). In deploying both the contingency coal contracts and the Demand Flexibility Service, we would expect to mitigate the risk of supply disruption to customers.

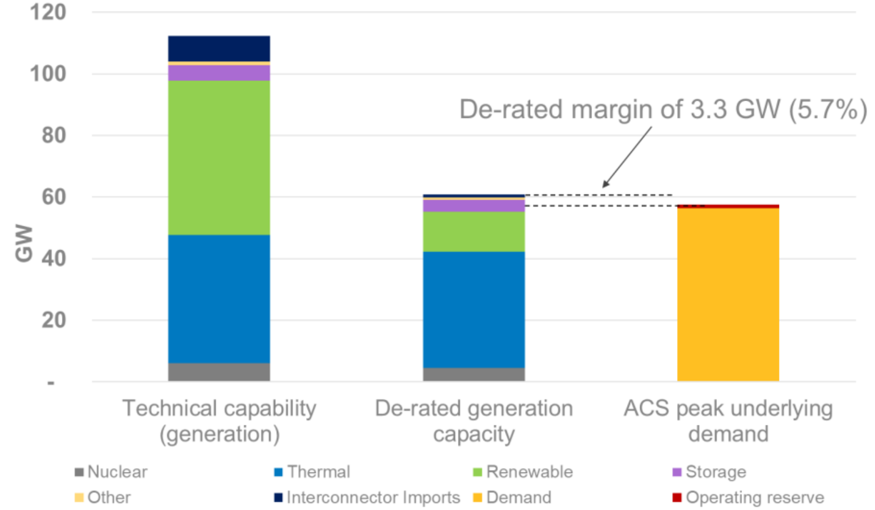

Figure 5. Supply margin in relation to generation capacity and demand for Scenario 1

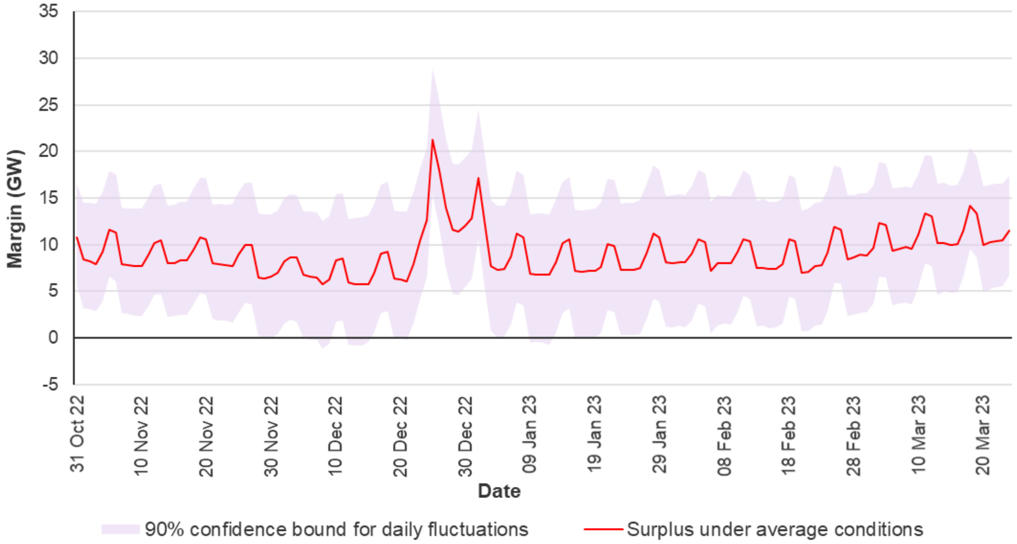

Figure 6. Range of outcomes for the daily operational surplus in Scenario 1 under different supply and demand conditions

[1] Assuming 0GW from the Demand Flexibility Service results in a de-rated margin of 2GW / 3.3% with an LOLE of 2.4 hours/year. The shift in margin is less than the 2GW from DFS due to the way wind (which is variable) is represented as a single number through its Equivalent Firm Capacity (EFC) in the margin. The EFC value changes with system tightness even though we model its full variability in the LOLE calculation in the same way.

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Scenario 2 / Reduced electricity imports from Europe combined with insufficient gas supply in Great Britain

If there is insufficient gas in GB for power generation combined with reduced electricity imports from Europe then this could erode security of supply margins.

In this scenario we assume the same assumptions as Scenario 1, but with an additional 10GW CCGTs unavailable for a two-week period in January[1]. These assumptions have been chosen to illustrate the potential impact on the electricity system if there was insufficient gas supply in Great Britain.

As this scenario only considers a specific, limited time period within the winter, we can only consider it using the modelling for our operational view. We are unable to provide a de-rated margin or LOLE value for this scenario.

<u>**Credible range for surplus**</u>

Figure 7 shows the variation in operational surplus for Scenario 2. Coal contingency contracts (around 2GW) and the Demand Flexibility Service (around 2GW) are both assumed to be deployed.

The impact of this is evident from the large negative surplus on the chart. The magnitude of this surplus is such that we would not expect there to be a sufficient response from the rest of the market to prevent interruptions to consumer supplies.

Should this scenario happen, it may be necessary to initiate the planned, controlled and temporary rota load shedding scheme under the Electricity Supply Emergency Code (ESEC). In the unlikely event we were in this situation, it would mean that some customers could be without power for pre-defined periods during a day – generally this is assumed to be for 3 hour blocks. This would be necessary to ensure the overall security and integrity of the electricity system across Great Britain. All possible mitigating strategies would be deployed to minimise the disruption.

The extent of rota load shedding would depend on the number of CCGTs that are unavailable and the duration for which there is insufficient gas to meet power station demand.

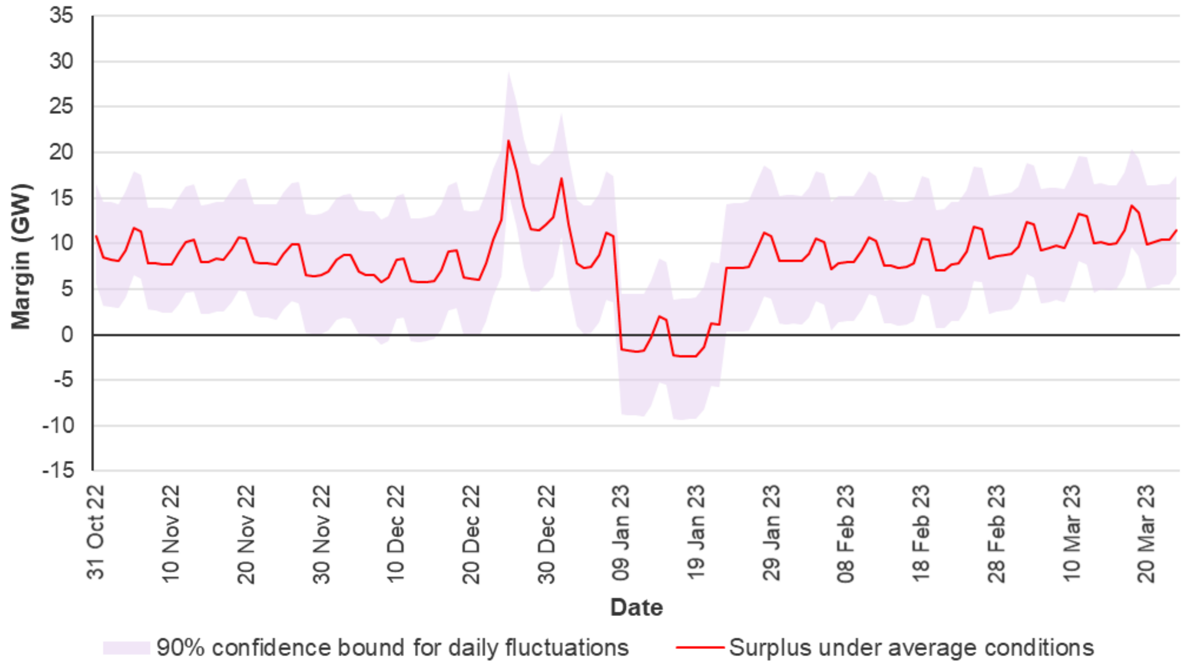

Figure 7. Range of outcomes for the daily operational surplus in Scenario 2 under different supply and demand conditions

[1] We have arbitrarily assumed 9 – 23 January 2023

Demand / Normal peak demand

Weather corrected peak demand for winter 2022/23 is expected to be lower than the previous winter, but higher than winter 2020/21 which was affected by COVID-19 restrictions. Weather corrected minimum demand is expected to be greater than last winter.

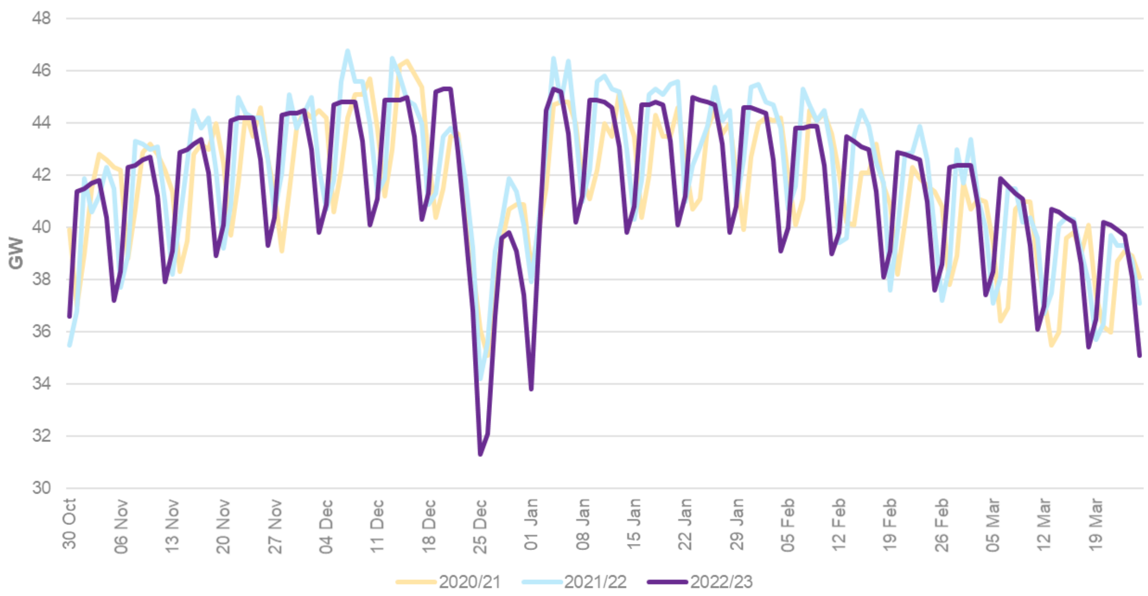

Figure 8. Historical and forecast normalised weekly peak winter demand[1]

This winter we expect

- weather corrected peak transmission system demand (TSD) to be 45.3GW, based on assumptions in Table 1.
- minimum demand under normal weather conditions to be 20.7GW (assuming no interconnector exports overnight).
- triad avoidance of up to 0.8GW

Transmission connected power station demand	600MW
Base case interconnector exports to Ireland (at time of peak)	750MW
Embedded wind capacity	6.5GW
Embedded solar capacity	13.1GW
Pumped storage (at time of peak)	0GW

Table 1. Assumptions for weather corrected peak TSD demand

Did you know?

The ESO is currently consulting with the energy industry on proposals for a new Demand Flexibility Service to run between November 2022 and March 2023. This service will incentivise consumers and businesses to reduce or reschedule their electricity use away from peak times. The service will be offered by suppliers and aggregators to their customers.

This could reduce peak demand below levels shown in the forecast in Figure 8 by up to around 2GW.

[1] Data is adjusted for interconnector export, historical data is weather corrected, forecast uses normal weather.

Supply / Overview

We currently expect sufficient levels of generation and interconnector imports to meet demand throughout the winter under our base case.

This winter we expect

- lower available generator capacity than last year, driven by reductions in nuclear and coal capacity available over the winter
- generator reliability to be broadly in line with recent winters (Table 2)
- remaining coal-fired generation to potentially run more frequently due to high gas prices (but for overall levels of coal generation to remain low due to continued reductions in capacity levels)

Additional coal fired generation

At the request of the Department for Business, Energy and Industrial Strategy the ESO has signed three contracts with EDF, DRAX and Uniper to provide additional coal generation this winter. Note, Figure 9 excludes this additional coal capacity.

These contracts will enable the ESO to directly instruct units at West Burton A, Ratcliffe and Drax to provide around 2GW additional de-rated capacity to support the system this winter if required.

These contracts are only intended to be used after all other commercial options. This could be in response to a generation shortfall over an extended period of time or a short-term margin issue.

Breakdown rates

The assumed breakdown rates are based on historic data to reflect how generators performed against their planned availability during peak demand periods over the last three winters (see Table 2).

For nuclear and biomass, the three-year rolling average has increased when last winter was accounted for. For wind generation, we assume an Equivalent Firm Capacity (EFC) of 16%.

	Assumed Breakdown Rate	
Power Station Fuel Type	**21/22**	**22/23**
Coal	11%	10%
CCGT	6%	6%
Nuclear	9%	10%
OCGT	5%	7%
Biomass	5%	6%
Hydro	9%	8%
Wind (EFC)	17%	16%
Pumped storage	3%	3%

Table 2. Breakdown rates by fuel type (based on a 3-year rolling average)

Supply / Daily view

We currently expect sufficient levels of generation and interconnector imports to meet demand throughout the winter under our base case.

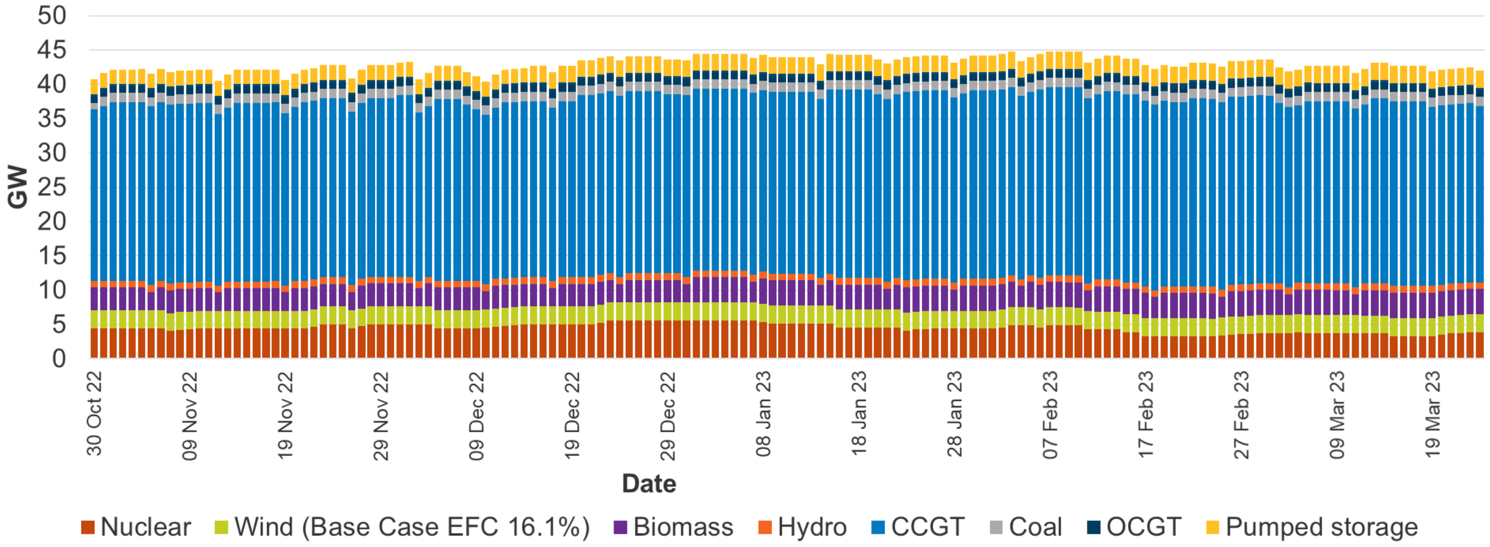

Figure 9. Daily generation availability by fuel type (based on market submissions and including breakdown rates)

Did you know?

Figure 9 shows a daily view of generation based on generator submissions of availability which is different to our calculation of de-rated margin for the winter on page 5.

Our generation forecasts are based on published availability data broken down to a half-hourly profile, to which we apply a breakdown rate for each fuel type, to account for unexpected generator breakdowns, restrictions or losses close to real-time.

Europe and interconnected markets / Overview

We expect more exports across the interconnectors to continental Europe from GB than in past winters.

This winter we expect

- forward prices, including peak prices, in GB to be below some of those in continental Europe across parts of the winter period
- increased exports to Continental Europe across much of the winter period driven by price differentials outside of times of system stress
- net imports from Norway across the NSL interconnector across the winter period, particularly at peak
- imports into GB at peak times of tight margins or stress on the GB system. We don’t expect interconnectors to be exporting to Europe if this would mean we were unable to meet GB demand
- Moyle and EWIC typically export from GB to Northern Ireland and Ireland during peak times, although at substantially less than maximum capacity due to high demand on the GB system. When operational surplus is particularly tight, exports to Northern Ireland and Ireland are expected to reduce to zero, and could even provide imports to GB.

Did you know?

Figure 10 shows last year's average interconnector flows at peak times, and during periods when operational surplus was below 2GW. These, alongside the expected prices (see page 16) are used to help inform our expectations for interconnector flows this year.

The new NSL interconnector was operating at restricted capacity for part of last winter, but is now running at full capacity and is expected to import to GB – especially at times of tight margins. Since last winter the ElecLink interconnector between GB and France has also come into service.

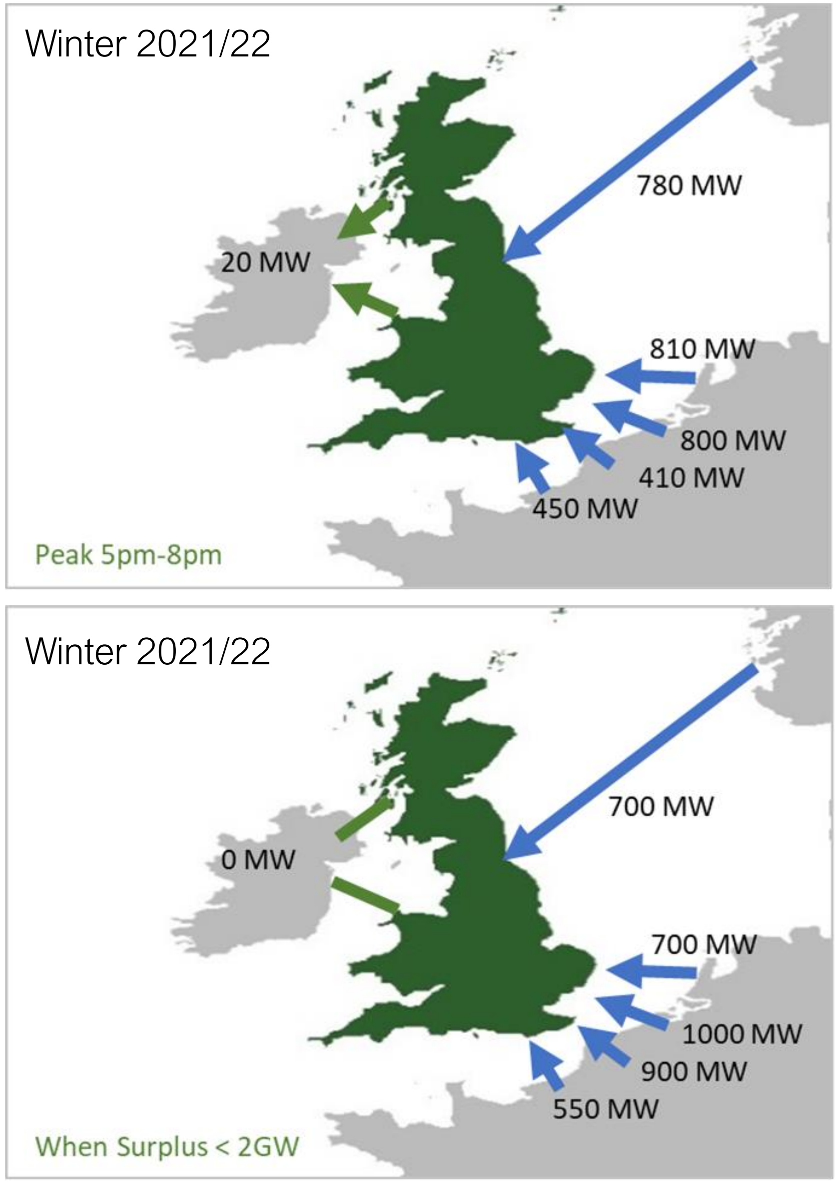

Figure 10. Historical flows on the interconnectors for winter 2021/22

Europe and interconnected markets / Peak flows analysis

Our assumptions around peak flow of electricity on the interconnectors depend on a number of factors.

1. Physical capabilities

Interconnector capability will be affected by the outages set out in the table below. The ongoing IFA outage is a result of a fire last autumn that led to reduced capacity, it is expected to come back to full capacity by mid-December.

Since last winter the ElecLink interconnector between GB and France has also come into service.

Interconnector	Maximum capacity	Planned outages	Available capacity during outage
IFA	2GW	21/10/21 – 30/10/22	1GW
		31/10/22 – 15/12/22	1.5GW
IFA2	1GW	n/a	
BritNed	1GW	n/a	
Nemo Link	1GW	n/a	
EWIC	500MW	n/a	
Moyle	500MW	n/a	
NSL	1.4GW	n/a	
ElecLink	1GW	n/a	

Table 3. Planned interconnector outages at time of analysis

2. Capacity Market

Interconnectors have secured agreements in the Capacity Market (CM) in the T-3[1] auction for 2022/23 as set out in Figure 11 below. While we expect increased exports this winter to continental Europe, at times of tight margins or stress in GB (e.g., when a Capacity Market Notice was issued) we would expect to see flows into GB.

Our Base Case assumes interconnectors deliver in line with their CM obligations. We have also assessed the risks and uncertainties of reduced imports from Continental Europe through our first scenario.

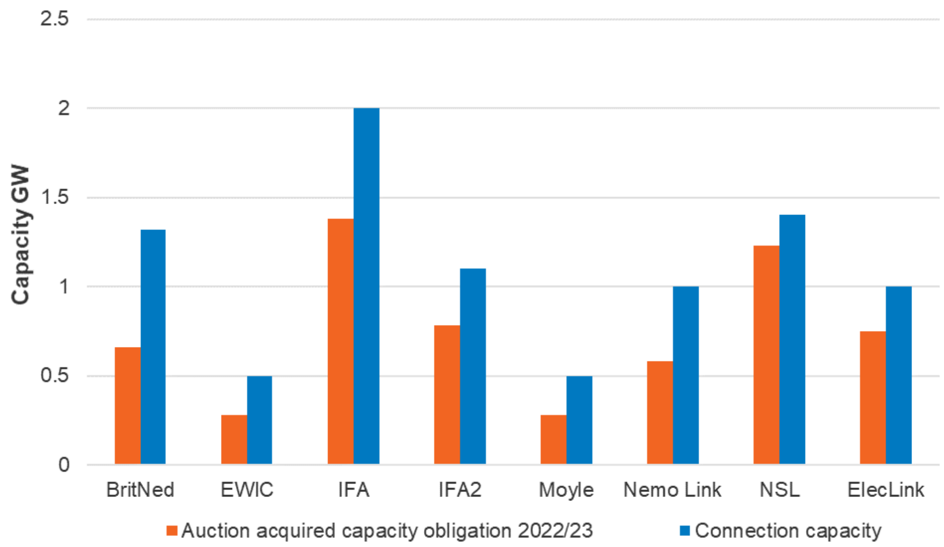

Figure 11. Capacity Market agreements for interconnectors in Delivery Year 2022/23

[1] Due to the suspension of the Capacity Market, a T-3 auction was run for delivery in 2022/23 rather than a T-4 auction

Europe and interconnected markets / Peak flows analysis

3. European forward prices

- Electricity flows through the interconnectors are primarily driven by the price differentials between the markets.
- Quarter ahead forward prices for baseload electricity during winter 2022/23 in GB are below those in the French and Dutch, but above those in the Belgian markets (see Figure 12). We therefore expect exports across the interconnectors to France and the Netherlands at times across the winter.
- Figure 13 shows forward prices for peakload electricity during winter 2022/23, in which GB prices are ahead of those in the Dutch market but significantly below prices in France. This indicates we may see exports to France at peak times over the winter. However, should GB experience some tight/stress periods, we would expect GB prices to escalate and interconnectors to import in line with Capacity Market obligations.
- We don't expect interconnectors to export to Europe if this would mean we were unable to meet GB demand; they would import or float in this situation.

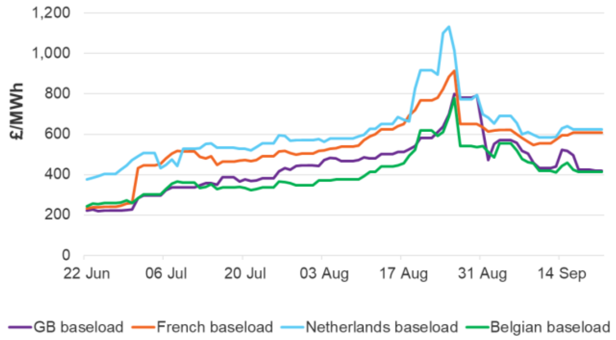

Figure 12. Winter 2022/23 electricity baseload

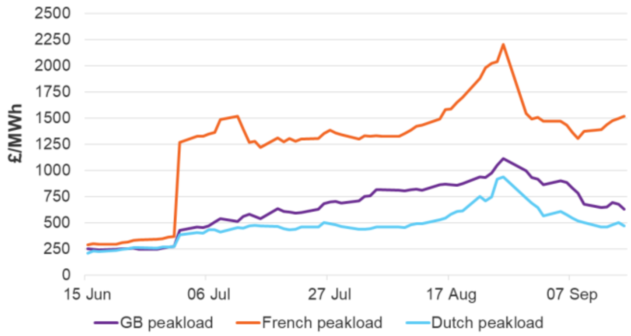

Figure 13. Winter 2022/23 electricity peak forward prices[1]

4. Network access constraints

- Transmission outages in the regions with interconnectors could cause power flow constraints resulting in disruption to interconnector flows, particularly in the South East. This has already been challenging to manage over the summer.

5. Nuclear availability in France

- Figure 14 shows French nuclear outages for the winter ahead against historical outages. While outages are high at the beginning of the winter period they are expected to drop to around 5GW (around 8% of capacity[2]) by January 2023.
- We expect these outage levels, combined with high French market prices, to lead to exports to France across much of the winter.

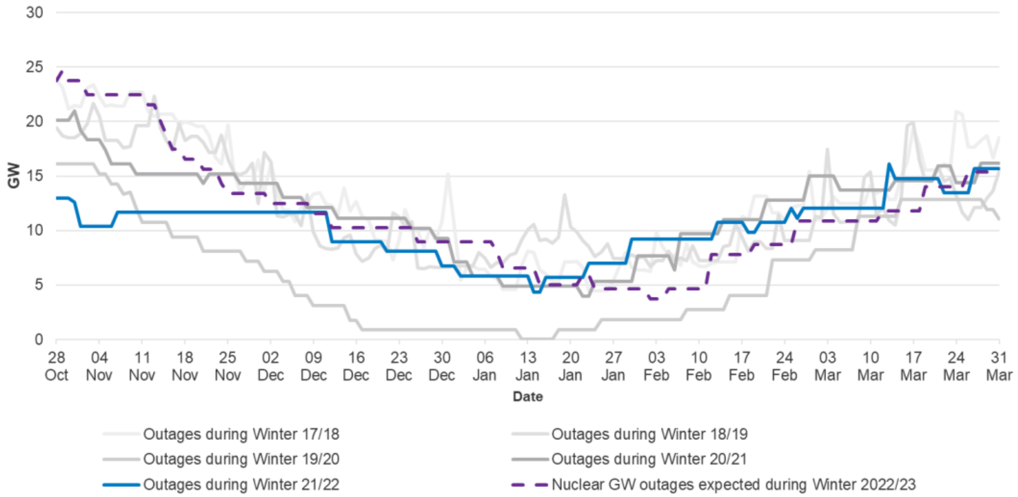

Figure 14. The impact on French nuclear capacity from planned outages in 2022/23 and actual outages in recent years[3]

[1] Figure 12 uses data from Bloomberg. Peak forward prices were only given for GB and France in Bloomberg, therefore Figure 13 uses data taken from Argus, which includes prices for the Netherlands. Lower liquidity means no peakload forward prices were available for Belgium.

[2] Total French nuclear capacity is 61.4GW this winter.

[3] https://www.edf.fr/en/the-edf-group/who-we-are/activities/optimisation-and-trading/list-of-outages-and-messages/list-of-outages

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Europe and interconnected markets / Historic flows

Overview of European interconnectors

Based on forward prices for the 2022/23 winter products, we expect imports into GB at peak times from Norway, the Netherlands and Belgium under normal network operating conditions. We may see greater levels of export to France at peak times than in previous years. Despite day ahead baseload prices in France exceeding GB prices on a number of occasions last winter we saw only limited exports to France at peak last winter, as shown in Figure 15.

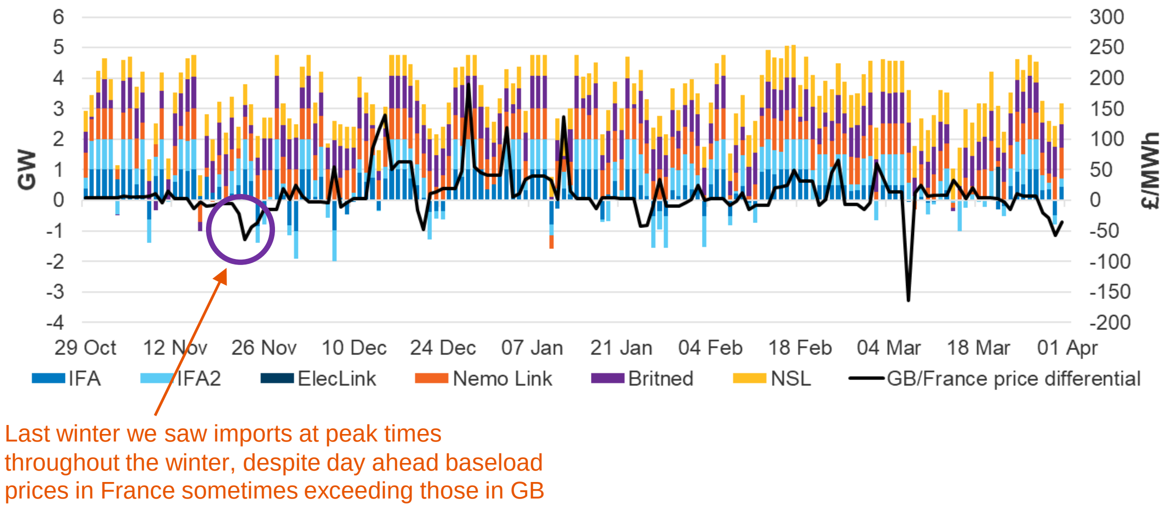

Figure 15. Daily peak time flows across the continental interconnectors in winter 2021/22 (positive MW values mean imports into GB)[1]

Overview of Irish interconnectors

During peak times through winter 2022/23, we expect a similar proportion of exports to imports across the Moyle and EWIC interconnectors to Ireland. This may, however, be reversed during periods of high wind and system stress. Figure 16 shows examples of where market conditions and weather variance affected flows last winter.

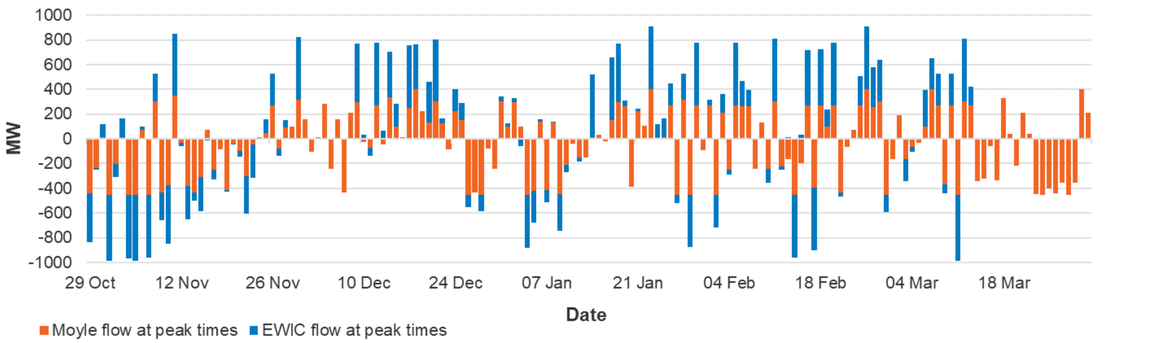

Figure 16. Daily peak time flows across the Irish interconnectors in winter 2020/21 (positive MW values mean imports into GB)

[1] Figure 15 peak forward prices were not provided for weekend days so interpolation was used to predict these values. Flows are out-turn values.

Market prices / Winter view

Forward wholesale electricity prices are significantly higher than last year. In addition, tight margin days are likely to see significant price spikes in the Balancing Mechanism.

This winter we expect

- forward prices in GB to be higher than last year across the winter period (Figure 17). This is due to external pressures, particularly very high gas prices.
- days with tight margins to see spikes in the balancing mechanism. During periods of tight system margins, energy prices increase to reflect the scarcity of the resource, particularly when margin notices are issued.

Did you know?

Traditionally power plants have bid into the Balancing Mechanism at prices which largely reflected the marginal cost of running the plant over that period. Capital and operational costs are generally recouped over a longer period through forward markets and/or long-term contracts.

Last winter saw significantly increased prices over the year before and this winter has much higher market prices still, with baseload prices several times higher than last winter, although having dropped by a third from a peak of over £800/MWh at the end of August.

We commissioned an independent review of the balancing market and have provided the report to Ofgem. This is available here. We are also enhancing our market monitoring activities this Winter.

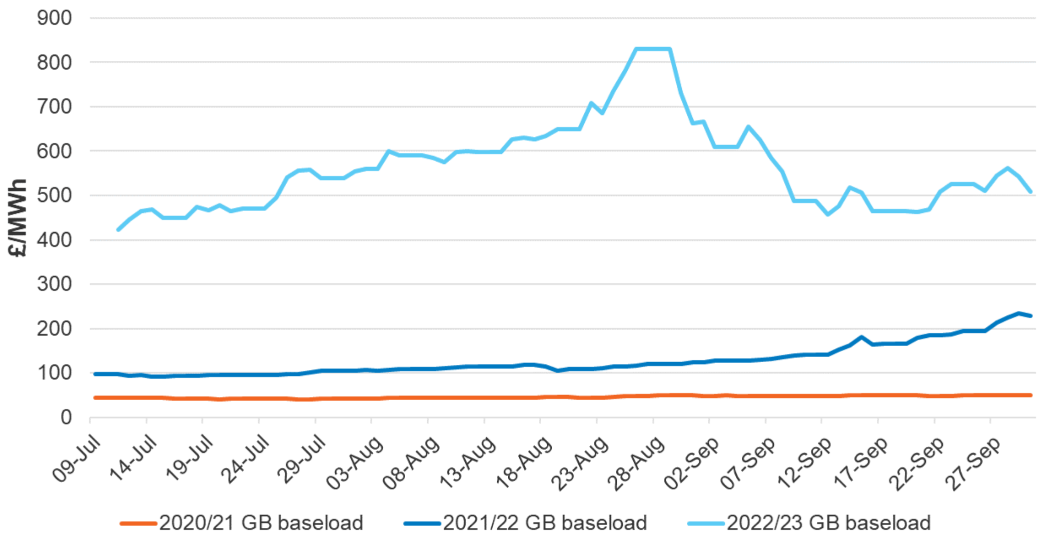

Figure 17 Historically traded quarter-ahead GB winter ahead forward electricity baseload prices for Winter 2020/21, Winter 2021/22 and Winter 2022/23 taken from Argus[1]

[1] The numbers shown in Figure 17 are historical traded prices not forecasts. Trading does not take place on weekends or bank holidays so these values have been interpolated.

Appendix / Margin notices

Electricity Margin Notices (EMNs) and Capacity Market Notices (CMNs) are used to highlight to market participants when margins are looking tight ahead of real-time. They are intended to stimulate a market response through, for example, additional generation being made available. They don't indicate that demand will not be met.

- **Electricity Margin Notices (EMNs)** are one of our operational tools to manage margins. They are based on operational margins which are calculated from transmission system demand and transmission system capacity.

- **Capacity Market Notices (CMNs)** are issued automatically. They act as a notice for providers with Capacity Market agreements to deliver in line with their CM obligations for the indicated settlement period(s). If the CMN remains in place, the providers who do not deliver in line with their obligations may be subject to penalties in accordance with the CM Rules. They are issued automatically and are not considered as one of our operational tools. They are based on Capacity Market margins which are calculated from whole system demand and whole system capacity (including Distributed Energy Resources (DER)).

While having similar intentions in stimulating a market response for tight periods, EMNs and CMNs should be considered as being part of two separate processes: the operational processes used by our control room to operate the system in real-time, and the CM penalty process. They serve different purposes, and are not part of the same sequential process.

The ESO is working with Ofgem to improve the communication of system notices. This is an ongoing process and more detail will be published in due course.

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

1. **Trigger** - Capacity Market Notices are issued based on an automated system margin calculation using data provided by market participants, whereas System Warnings are manually issued by the ESO control room using engineering judgement based on experience and knowledge of managing the electricity transmission system.

2. **Threshold** - Capacity Market Notices are triggered where the buffer between available generation and the total of forecast demand and Operating Margin falls below a threshold. The threshold is taken from the Capacity Market Rules. System Warnings are triggered by varying volumes, for example an EMN may be issued where ESO expects to utilise a certain amount of its Operating Margin.

3. **Constraints** - The Capacity Market Notice calculation does not take account of any transmission system constraints that may be preventing capacity from accessing the network. System Warnings however do take such constraints into account.

4. **Lead time** - Capacity Market Notices are initially issued four hours ahead of when the challenge is foreseen. System Warnings can be issued at any time but we would generally expect to issue a first EMN at the day ahead stage.

For more information about margins and margin notices

https://www.nationalgrideso.com/news/everything-you-need-know-about-electricity-system-margins

Appendix / Operational surplus analysis

Our operational surplus analysis represents the market's current intentions (i.e. based on market submissions before we take actions). This analysis is based on market submissions as of 22nd September.

It is a dynamic view that changes throughout winter and, as such, we will be providing regular updates at the ESO Operational Transparency Forum. It provides insight on the periods when we may need to send market signals / use tools to ensure there is enough generation on the system to meet demand and contingency requirements. The periods of tightest margins do not necessarily occur at times of peak demand but rather when supply is lowest relative to demand.

How the operational surplus is calculated and used

- For the operational surplus analysis, we plan based on the operational data submitted to us. We are not just looking at the capacity provided via the Capacity Market (a market tool that helps to set us up for winter), but also at the supply that is forecast to be available on a day-by-day basis. To do this we need to consider a more granular view of the winter.
- We consider a daily view as we get closer to real-time and start assessing the daily views in August ahead of the Winter Outlook Report publication in October. The Winter Outlook Report includes a daily view of margins for the winter, as well as information on the effects of variability and the likelihood of tight operational margins.
- The operational data includes information relating to planned plant outages, the impact of weather (e.g. on wind and demand) and flows on interconnectors. As generators can also have unplanned outages, we also apply breakdown rates based on averages of the last 3 winters. In addition, we study the effects of variability of all relevant factors, particularly weather, renewable resource and unplanned outages. The operational data may be different from the assumptions based on historic data / long-term averages used for the winter view of margin.
- The operational surplus also considers grid constraints and largest loss requirements. In the central daily view we use a low wind scenario, so the grid constraints play only a small part in the calculation. When we consider the credible range of values, grid constraints become more significant.
- The operational surplus helps us to identify when we might have tight periods. However, the operational data provided to us changes throughout the winter. There may be some tight periods that are apparent a week in advance; others may not become apparent until much closer to real-time (e.g. day ahead or on the day itself).
- These assessments of security of supply are used to support decisions taken in operational timescales (e.g. whether to issue an EMN).

Glossary

Average Cold Spell (ACS)

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

Balancing Mechanism

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

Balancing Mechanism Unit (BMU)

A unit which participates in the Balancing Mechanism.

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 close to real time. Forecast breakdown rates are applied to the operational data provided to the ESO by generators. Rates are based on how generators performed on average by fuel type during peak demand periods (7am to 7pm) over the last three winters.

BritNed

BritNed Development Limited is a joint venture between Dutch TenneT and British National Grid that operates the electricity link between Great Britain and the Netherlands. It is a bi-directional interconnector with a capacity of 1,000MW. 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.

Capacity Market Notice (CMN)

Based on Capacity Market margins which are calculated from whole system demand and whole system capacity. For more information about margins and margin notices see: https://www.nationalgrideso.com/news/everything-you-need-know-about-electricity-system-margins

Combined Cycle Gas Turbine (CCGT)

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

Contingency coal contracts

At the request of the Department for Business, Energy and Industrial Strategy the ESO has signed three contracts with EDF, DRAX and Uniper to provide additional coal generation this winter. More details can be found here: https://www.nationalgrideso.com/winter-operations

Demand flexibility service

The ESO is currently consulting with the energy industry on proposals for a new Demand Flexibility Service to run between November 2022 and March 2023. This service will incentivise consumers and businesses to reduce or reschedule their electricity use away from peak times. The service will be offered by suppliers and aggregators to their customers. More details can be found here: https://www.nationalgrideso.com/industry-information/balancing-services/demand-flexibility

Demand suppression

The difference between our pre-Covid forecast demand levels and the actual demand seen on the system. We have not included any Covid-related demand suppression this winter.

Glossary

De-rated margin for electricity

The sum of de-rated supply sources considered as being available during the time of peak demand plus support from interconnection, minus the expected demand at that time and basic reserve requirement. This can be presented as either an absolute GW value or a percentage of demand (demand plus reserve). The formula was revised in winter 2017/18 to include distribution system demand, and in winter 18/19 to better account for interconnection. See our previous publications for further details (https://www.nationalgrideso.com/research-publications/winter-outlook).

Distributed Energy Resources (DER)

Resources connected to the distribution network which can generate or offtake electricity.

East West Interconnector (EWIC)

A 500MW interconnector that links the electricity transmission systems of Ireland and Great Britain. You can find out more at www.eirgridgroup.com/customer-and-industry/.

ElecLink

A 1000MW interconnector that links the electricity transmission systems of France and Great Britain. You can find out more at https://www.eleclink.co.uk/.

Embedded generation

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

Electricity Margin Notice (EMN)

Based on operational margins which are calculated from transmission system demand and transmission system capacity. For more information about margins and margin notices see:

https://www.nationalgrideso.com/news/everything-you-need-know-about-electricity-system-margins.

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.

Float / Floating

When an interconnector is neither importing nor exporting electricity.

Forward prices

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

Grid Code

The Grid Code details the technical requirements for connecting to and using the National Electricity Transmission System (NETS).

GW Gigawatt (GW)

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

Interconnector

Electricity interconnectors are transmission assets that connect the GB market to Continental Europe and Ireland. They allow suppliers to trade electricity between these markets.

Interconnexion France–Angleterre (IFA)

A 2,000MW link between the French and British transmission systems. Ownership is shared between National Grid and Réseau de Transport d'Electricité (RTE). See more at https://www.ifa1interconnector.com/.

Interconnexion France–Angleterre 2 (IFA2)

A 1,000MW link between the French and British transmission systems commissioned in 2020. Ownership is shared between National Grid and Réseau de Transport d'Electricité (RTE). See more at https://www.ifa1interconnector.com/.

Glossary

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.

Loss of Load Expectation (LOLE)

LOLE is the expected number of hours when demand is higher than available generation during the year before any mitigating /emergency actions are taken but after all system warnings and System Operator (SO) balancing contracts have been exhausted. It is important to note when interpreting this metric that a certain level of loss of load is not equivalent to the same amount of blackouts; in most cases, loss of load would be managed by actions without significant impacts on consumers. The Reliability Standard set by the Government is an LOLE of 3 hours/year

Minimum demand

The lowest demand on the transmission system. This typically occurs overnight.

Moyle

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

MW Megawatt (MW)

A measure of power. 1MW = 1,000,000 watts.

Nemo Link

A 1GW HVDC sub-sea link between GB and Belgium. See more at https://www.nemolink.co.uk/.

North Sea Link (NSL)

A 1.4GW HVDC sub-sea link from Norway to GB commissioned this October. See more at https://www.northsealink.com/.

Normalised transmission demand

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

Normalised peak transmission demand

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

Operational surplus

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

Outage

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

Peakload electricity

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

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.

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.

REMIT

REMIT data is information provided by market participants to comply with Article 4 of Regulation on Wholesale Energy Market Integrity and Transparency (REMIT) Regulation (EU) 1227/2011.

Glossary

Renewables

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

Reserve requirement

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

Rota load shedding

Scheduled disconnection and reconnection of electricity supplies in an electricity supply emergency, as set out in the government's Electricity Supply Emergency Code (ESEC).

Seasonal normal weather

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.

Short Term Operating Reserve (STOR)

At certain times of the day, we may need access to sources of extra power to help manage actual demand on the system being greater than forecast or unforeseen generation unavailability. STOR provides this reserve.

System Operator Transmission Code (STC)

The System Operator Transmission Owner Code defines the relationship between the Transmission Owners (TOs) and the ESO.

Technical capability

The capacity of connected plant expected to be generating in the market, based on the Capacity Market auctions and 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 distributed generation sources, using on-site generation or reducing their energy consumption. This is sometimes referred to as customer demand management but we refer here to 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 (WLHVDC)

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.

Winter period

The winter period is defined as 1 October to 31 March.

Electricity System Operator legal notice

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

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

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