Summer Outlook

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

April 2021

nationalgridESO

Foreword

Welcome to our 2021 Summer Outlook Report. This contains our view of the electricity system for the summer ahead and is designed to support the industry in its preparations for the period.

This summer we will again be dealing with challenges and uncertainties caused by the COVID-19 pandemic. Last spring and summer, with the country in lockdown, we saw record low demands on the electricity transmission system. We implemented measures to ensure GB consumers continued to receive secure and reliable electricity supplies and are well prepared if similar steps are necessary this summer.

Throughout this document we present forecast electricity demands assuming a general relaxation of COVID-19 restrictions through the period April to June, in line with the road map recently announced by the Prime Minister. We have also prepared for other higher and lower demand sensitivities and present some discussion of these. We have retained the ODFM (Optional Downward Flexibility Management) service we introduced last summer to help manage particularly low demands on the system.

We will continue to keep stakeholders up to date on the situation as it changes by holding our weekly webinars run by the Electricity National Control Centre (ENCC).

National Grid 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 (@ngeso).

Fintan Slye

Executive Director, Electricity System Operator

Executive summary / Key messages

As the ESO we continue to evolve and refine our approach to short term operability, building on our early response to COVID-19 in Spring 2020.

While there remains a degree of uncertainty around COVID-19 and the associated impact on demand, this is not expected to pose the same level of operability challenges in summer 2021 as in spring / summer 2020. Nevertheless, we are considering a range of weather and COVID-19 sensitivities for the summer ahead.

1. Electricity demands

We expect electricity demands to be less suppressed than summer 2020 and more in line with previous years.

We expect some continued impact on demand patterns due to COVID-19, with minimum demands forecast to be low again in 2021 but not as low as during the national lockdown of April and May 2020.

2. Managing the system

Managing low demand is one of the most complex scenarios our control rooms have to face and can require a greater number of actions to protect the network.

We have the right tools and services available to manage system operability for the summer, including services introduced last summer such as ODFM and Dynamic Containment.

3. Risk reduction

Our new Frequency Risk & Control Report provides industry with greater visibility of the risks we currently manage on the network, so we can work together to further minimise these risks in future.

The risk posed by vector shift protections was challenging last Summer. Working together with industry on the Accelerated Loss of Mains Change Programme (ALoMCP) we have been able to reduce the volume of generation using vector shift protection by half.

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 demand seen on the transmission system at a peak and minimum level will be higher than last summer, as reduced impact is seen from COVID-19 on electricity demands, but lower than summer 2019. Increasing generation connected to the distribution networks also continues to drive down **transmission system demands**. The forecasts for demand in the table and graph are for transmission demand, consistent with the approach in previous Outlook reports.

Our sensitivity analysis shows minimum demand could go as low as 14.7 GW under 1-in-10 year weather conditions and assuming higher COVID-19 impacts. This minimum demand is quoted assuming zero exports and this means there is scope for the ESO to take actions to increase demand using exports over the interconnectors.

Supply and Operability

We will be able to meet demand and our reserve requirement at all times throughout summer 2021 under all interconnector scenarios. We will have to take actions on the system when demand is low.

We have retained the **Optional Downward Flexibility Management (ODFM)** service we introduced last summer to help manage periods of low demand. Under our central case we are not currently forecasting any requirement to use the service, however we may call on it should it be necessary due to weather conditions or COVID-19 impacts on demand.

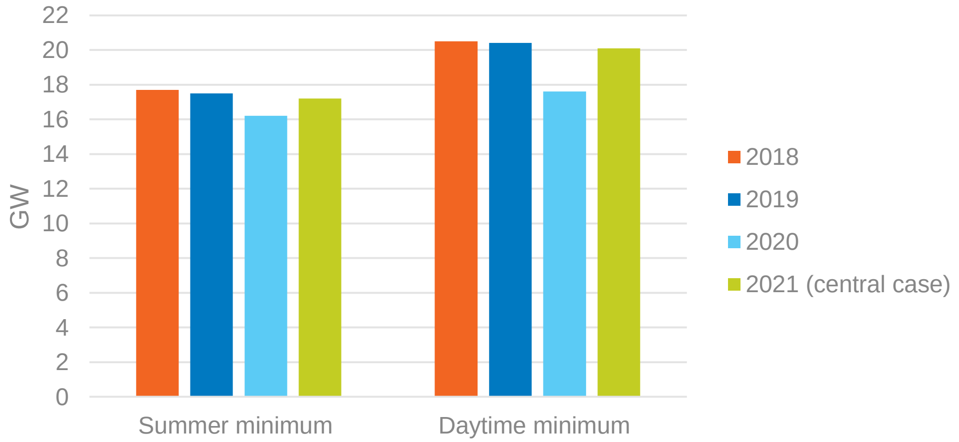
Weather and system conditions could also lead to more expensive days over the summer at times of high or low demand if they mean we need to make more use of our balancing tools and capabilities to manage the system effectively.

Proactive, regular, quality engagement was key to our approach to summer operability in 2020 and we aim to continue this, primarily through our weekly ESO Operational Transparency Forum.

Key statistics

Key statistics, Summer 2021	GW
Electricity transmission high summer peak demand	32.0
Electricity transmission minimum demand	17.2
Electricity transmission daytime minimum demand	20.1
Minimum available generation	38.4

Figure 1. Weather corrected summer overnight and daytime minimum demand outturns for previous years and the summer 2021 forecast



Glossary: Definitions for the terms in bold purple text can be found in the glossary on page 25

Contents

Demand / Overview

Weather corrected minimum transmission system demands for summer 2021 are expected to be higher than last summer, while peak demands are similar with lower impact expected from COVID-19 on demand in general.

This summer we expect…

- Lower impact from COVID-19 on demand than last summer with minimum demands to be closer to 2019 outturn than 2020
- weather corrected high summer peak **transmission system demand (TSD)** to be 32.0 GW,
- weather corrected **minimum demand** to be 17.2 GW and to occur overnight rather than in the afternoon (when embedded solar output is highest)

Table 1. Forecast and historic summer peak and minimum transmission system demands (weather corrected)

Year	Summer minimum (GW)	Daytime minimum (GW)	High summer peak (GW)
2018	17.7	20.5	34.0
2019	17.5	20.4	32.9
2020	16.2	17.6	31.5
2021 (central forecast)	17.2	20.1	32.0

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 demand for pumping and electricity trading. Forecast demands do not include these, as these will depend on prevailing market conditions at the time.

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. As an Appendix we have included a table of different demand definitions on page 23 and discussion of how these are related on page 12.

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).

Last summer's well publicised record low demand excluding pumping demand and without weather correction is substantially lower at 13.4 GW (**National Demand**), this was increased to 16.6 GW of Transmission System Demand by ESO actions on the system including pumping and electricity trading.

More information on the record demands last summer can be found on page 12.

Demand / Week-by-week view

Weather corrected minimum transmission system demand for summer 2021 is expected to be higher than last summer, with lower impact expected from COVID-19 on demands. Weather corrected peak demands are also expected to be higher than last summer.

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 are higher than last summer in our central forecast at 17.2 GW compared to last summer's 16.2 GW. This is weather corrected and will vary according to real weather conditions as discussed on the following page.

Figure 2: Weekly minimum transmission system demands for summer 2020 against our summer 2021 minimum demand central forecasts (all weather corrected)

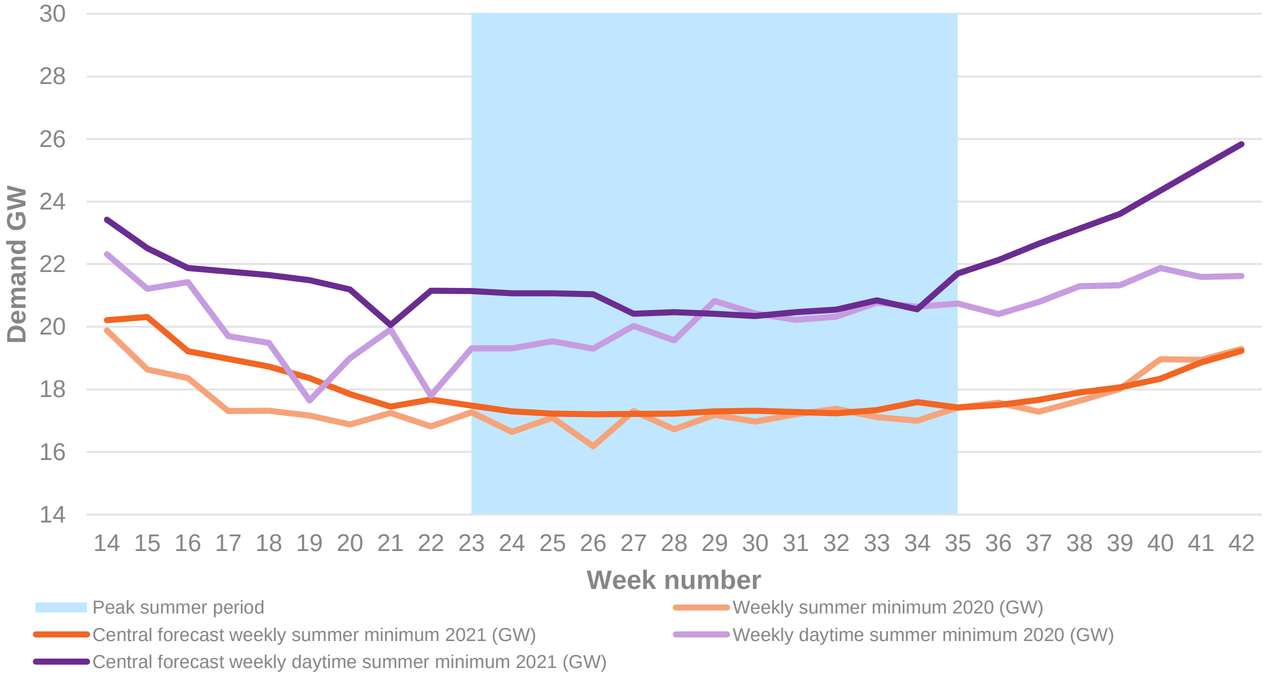
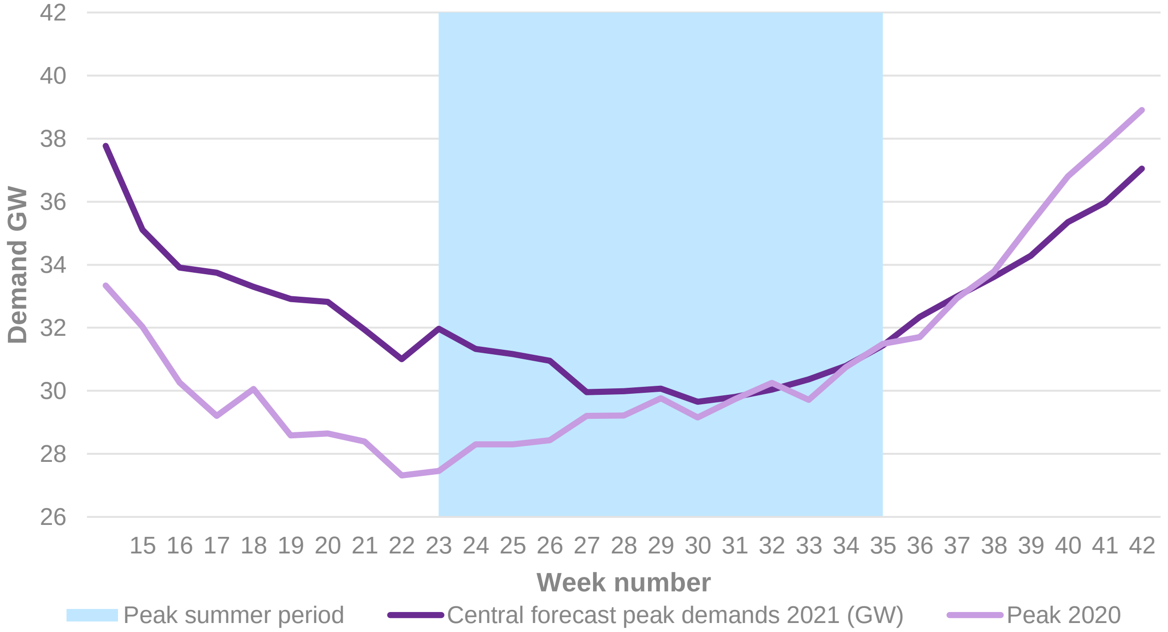


Figure 3 shows the weekly peak demand for summer 2020 against our forecast for 2021. Our peak demand for the high summer period between June and the end of August is 32.0 GW, 500 MW higher than last summer. While our peak demand forecast is higher than last summer's **outturn** through most of the summer, it is slightly lower right at the end of the forecast period.

Figure 3: Weekly peak transmission system demand for summer 2020 against our summer 2021 peak demand central forecast (both weather corrected)



Demand / COVID-19 impact and weather 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, however weather variations can cause fluctuations around the central case.

Our central forecast for COVID-19 effects on demand is for a general relaxation of restrictions through the period April to June, in line with the road map recently announced by the Prime Minister. Our forecasts are then calculated using **seasonal normal weather conditions** for the time of year.

However, weather conditions are rarely at their average values. Figure 4 shows for each week 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 attain the 1-in-10 year level for every week over summer.

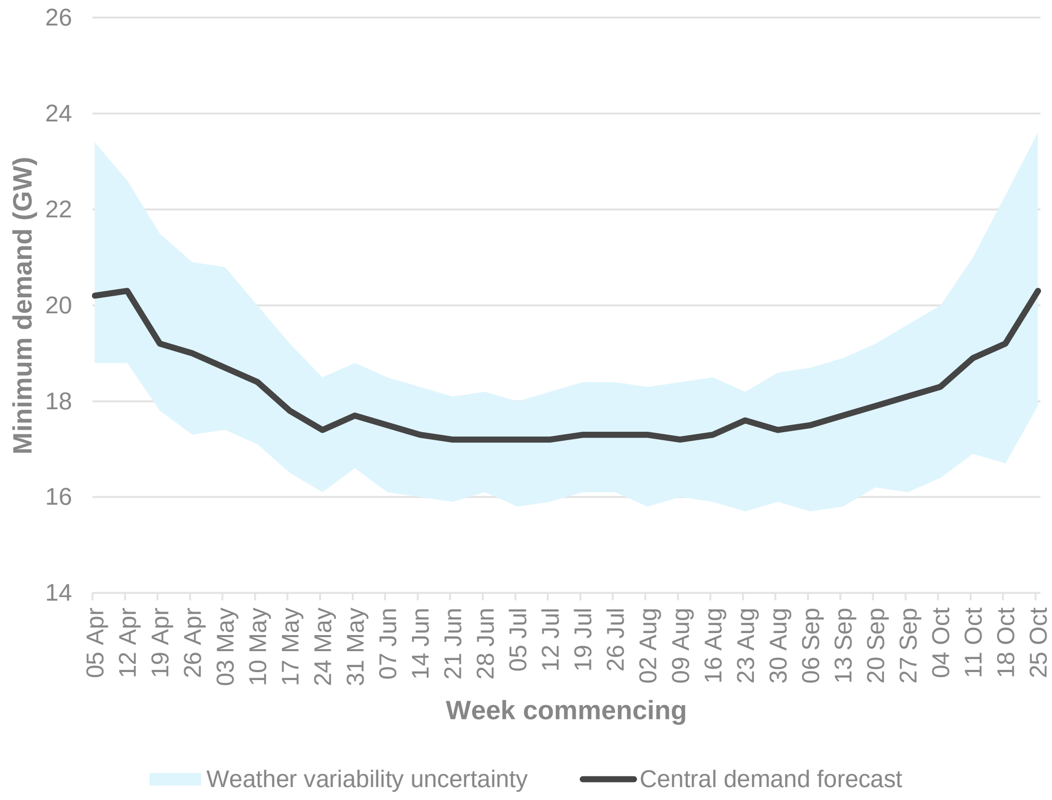
The graph shows it is possible that, in the central COVID-19 forecast, **transmission system demand** could go as low as 15.7 GW during one week this summer because of weather variation alone. The impact of weather is seen in the level of renewable generation output as well as through consumer behaviour (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.

We have considered two further COVID-19 sensitivities:

The high impact sensitivity is one in which the country has to re-enter lockdown with similar effects to the lockdown which began after Christmas. In this sensitivity, the 1-in-10 year weather risk drives transmission system demands as low as 14.7 GW.

In the low impact sensitivity, after June 21st, demands return to the level predicted in the ‘pre-COVID’ period, with no subsequent economic impacts from COVID-19 disruption. We consider this sensitivity unlikely, but include it in order to give an upper bound for the maximum demand. In this sensitivity the maximum credible transmission system demand using our 1-in-10 weather risk over the period April to October during BST is 41.7 GW. The maximum demand in high summer (June to August) is 32.2 GW.

Figure 4: Weekly minimum transmission system demands for our central COVID-19 forecast highlighting the impact of weather variation



Demand / COVID-19 impact and weather variability

COVID-19 impact on demand

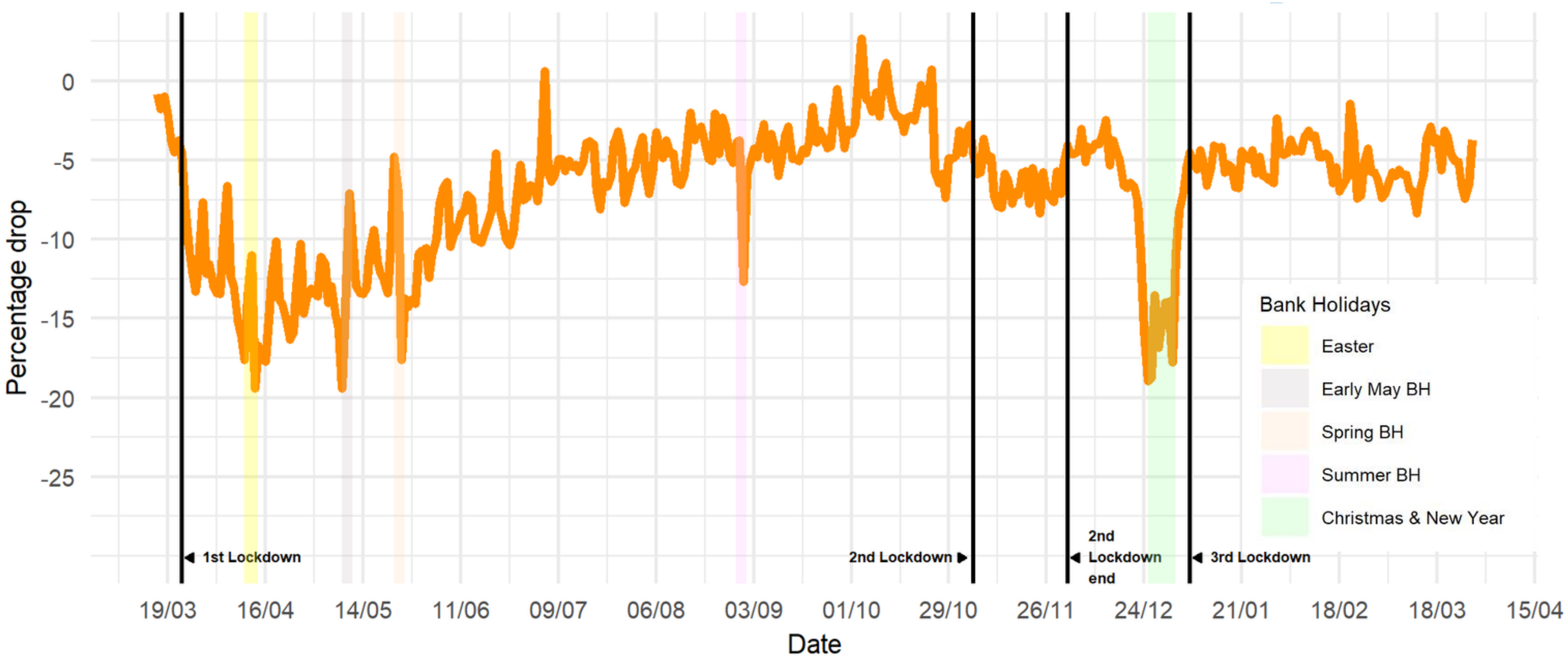
Figure 5 presents the latest view of demand relative to 'pre-COVID' expectations. It shows how electricity demand has varied against expected demand without the pandemic and how this has changed over the past 12 months. The impact of the pandemic on demand has waxed and waned with the advent of different levels of restrictions on the economy.

Demand suppression in the most recent lockdown since Christmas was substantially less than the suppression seen in the first COVID-19 lockdown. Record low **National Demand** of 13.4 GW was seen in June 2020 when background demands were low and suppression was between 10% and 15%, however because industry and businesses have adapted to work within lockdown restrictions we don't expect to see more demand suppression than the current level of 5-7% this summer even if re-entering another lockdown as in our high COVID-19 impact sensitivity. We therefore don't expect to see minimum demands as low as summer 2020 over the summer ahead.

Bank holidays usually see a demand drop, and are not accounted for in the pre-COVID expectation figures, but are highlighted on the chart to show these demand drops are not directly related to COVID-19.

We will continue to monitor this situation and discuss changes in our forecasts at our weekly ESO Operational Transparency Forum.

Figure 5: ESO % change in demand relative to pre-COVID expectation March 2020 to March 2021.



Demand / Summer 2020 retrospective

In spring and early summer with the country under strict lockdown, we saw the biggest impact on minimum demands, with demands falling up to 17% against pre-COVID expectations, and a gradual recovery as shown in the charts below. While overnight minimum demands recovered to our pre-COVID expectation by the end of the summer, daytime minimum demands remained substantially lower due to continued restrictions on the economy.

The charts on this page present weather corrected forecasts and **transmission system demand outturns** which is useful for comparison, but doesn't match exactly with actual demands on the system, which include real weather variations. This is discussed in more detail on page 12. Over Easter 2020 we saw extremely low **national demand** on the system of 14.7 GW. This was a combination of lower demand as usually experienced on a bank holiday, reduced demand due to COVID-19 associated demand impacts and especially the impact of unseasonably high output from embedded wind and solar generation.

Figure 6. Weekly minimum transmission system demand scenario forecasts for summer 2020 in purple against our summer 2020 minimum demand outturn in orange (weather corrected)

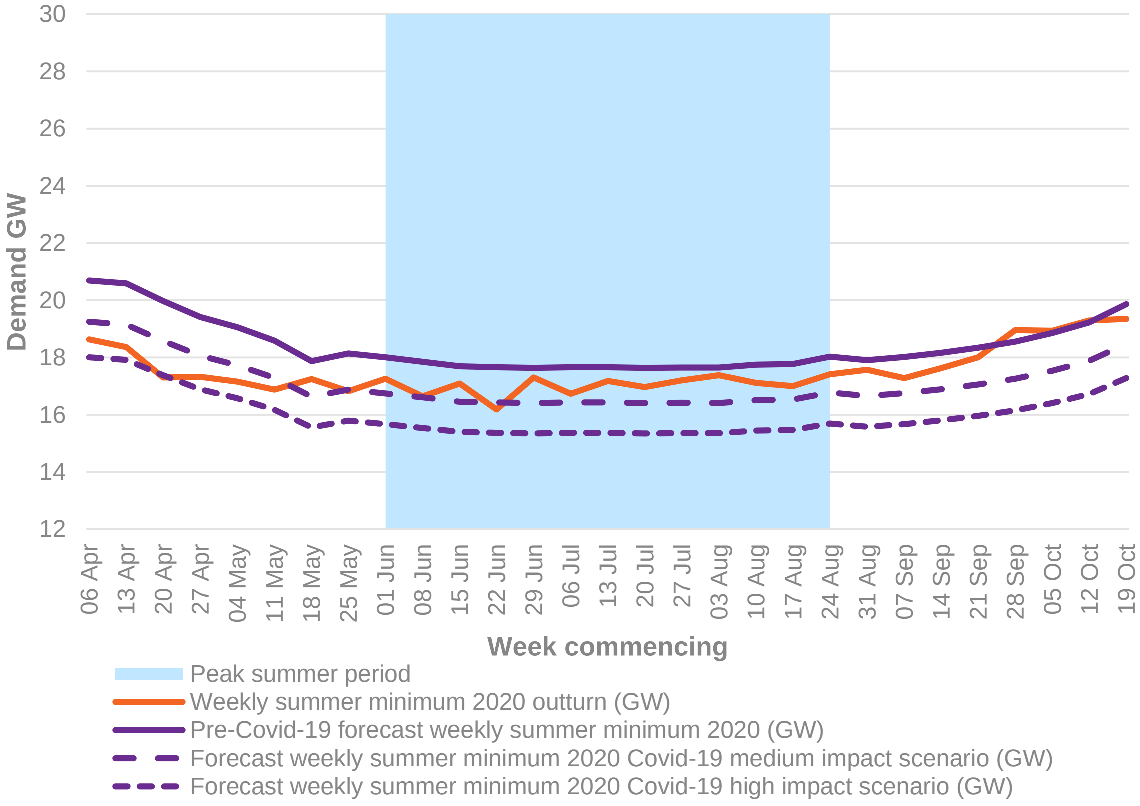
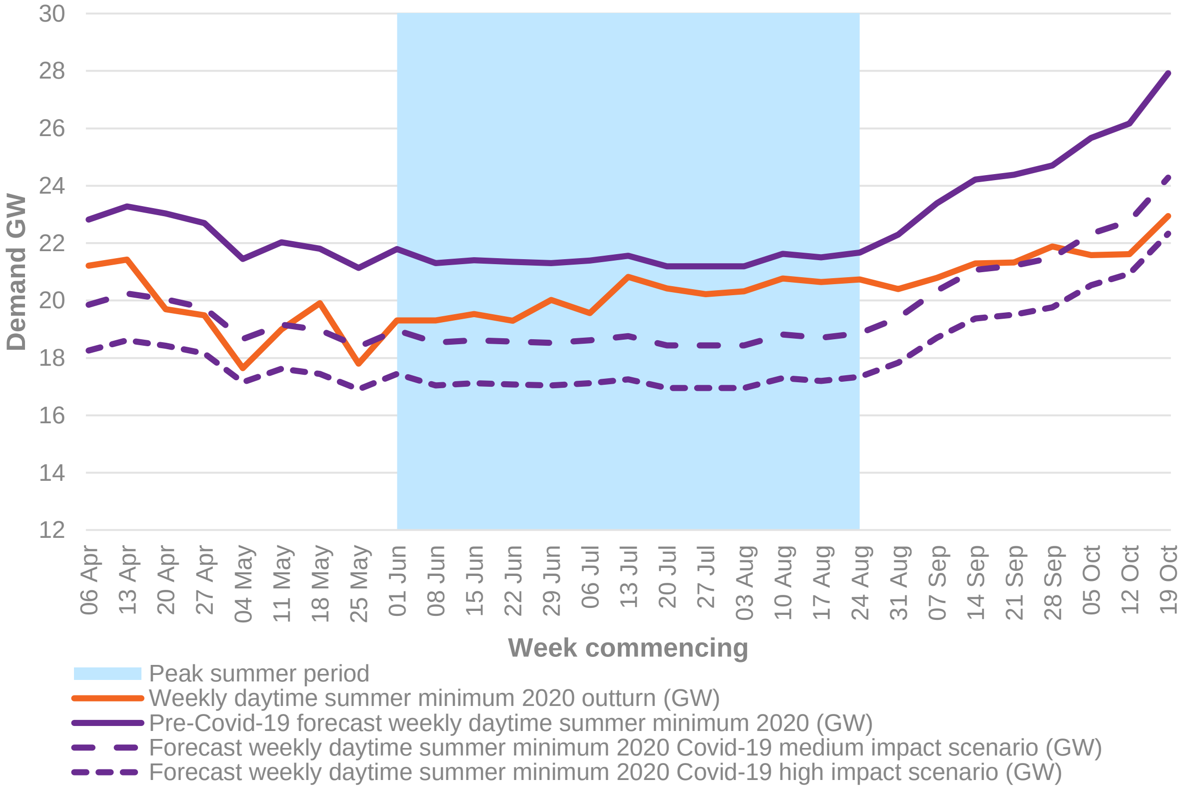


Figure 7. Weekly daytime minimum transmission system demand scenario forecasts for summer 2020 in purple against our summer 2020 minimum demand outturn in orange (weather corrected)



Spotlight / Changing times of low demand periods

Increasingly we are seeing periods where the lowest demands on the transmission system in a day occur during the afternoon rather than in the traditionally lowest demand periods in the early hours of the morning.

Spring and summer 2020 saw record low demands on the electricity system and at times saw lower demands during the afternoon (13:30-16:30) than in the traditionally lowest demand periods overnight in the early hours of the morning (04:30-07:30).

This occurred on a number of days through last spring and summer, with the largest difference being 1.7 GW on 19th April (see Figure 8), where daytime demand fell to 17.2 GW compared to 18.9 GW overnight.

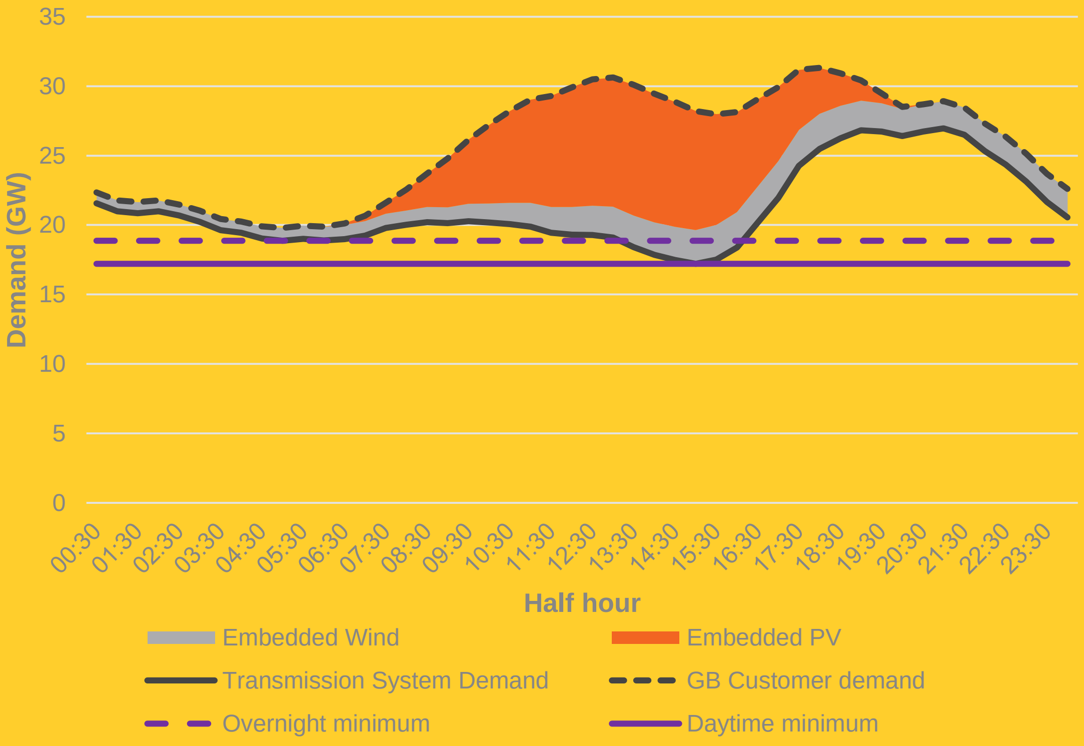
Under **normal weather conditions** we are not forecasting any periods where this will occur over summer 2021, however there are periods where minimum overnight and daytime demands are expected to be close, and where higher renewable generation output could lead to lower daytime transmission system demands. This occurred over the Easter 2021 weekend.

When demand is at its lowest values over the entire summer, the minimum for those days still occurs overnight.

The weekend of 29-30 May 2021 is currently forecast to be challenging, with daytime minimum demand only 1.6 GW higher than overnight minimum on 29/05, and morning peak demand 4.4 GW higher than overnight demand on 30/05.

Figure 8 shows the difference between **GB Customer demand** and **Transmission System Demand**, and the effect that embedded renewable generation can have on the difference between these figures (see definitions on page 23).

Figure 8: Transmission system demand outturn (not weather corrected) and impact of embedded generation on 19 April 2020



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Spotlight / Record minimum electricity demands in 2020

What was the lowest electricity demand in the summer of 2020? It sounds like a simple question, but the answer is not as straightforward as it seems.

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 occurred on 28 June at 05:30. This demand of **13.4 GW** was by far the lowest ever seen (the lowest National demand prior to 2020 was 15.8 GW).

In addition to the customer demand component, there was approximately 500MW 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**.[1]

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, the Sunday of the Early May 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.

[1] See pages 23 and 24 in the Appendix for full definitions and a diagram showing the relationship between National Demand and Transmission System Demand

Supply / Week-by-week view

We expect to be able to meet normalised transmission demand and our positive reserve requirement at all times throughout the summer, including throughout the shoulder months of April and September.

This summer we expect…

- Minimum available generation to be 38.4 GW in the week commencing 14 June (no continental interconnector flow scenario) based on current operational data
- **Maximum demand** in this week to be up to 32.1 GW under our central demand forecast (assuming full export on Irish interconnectors).

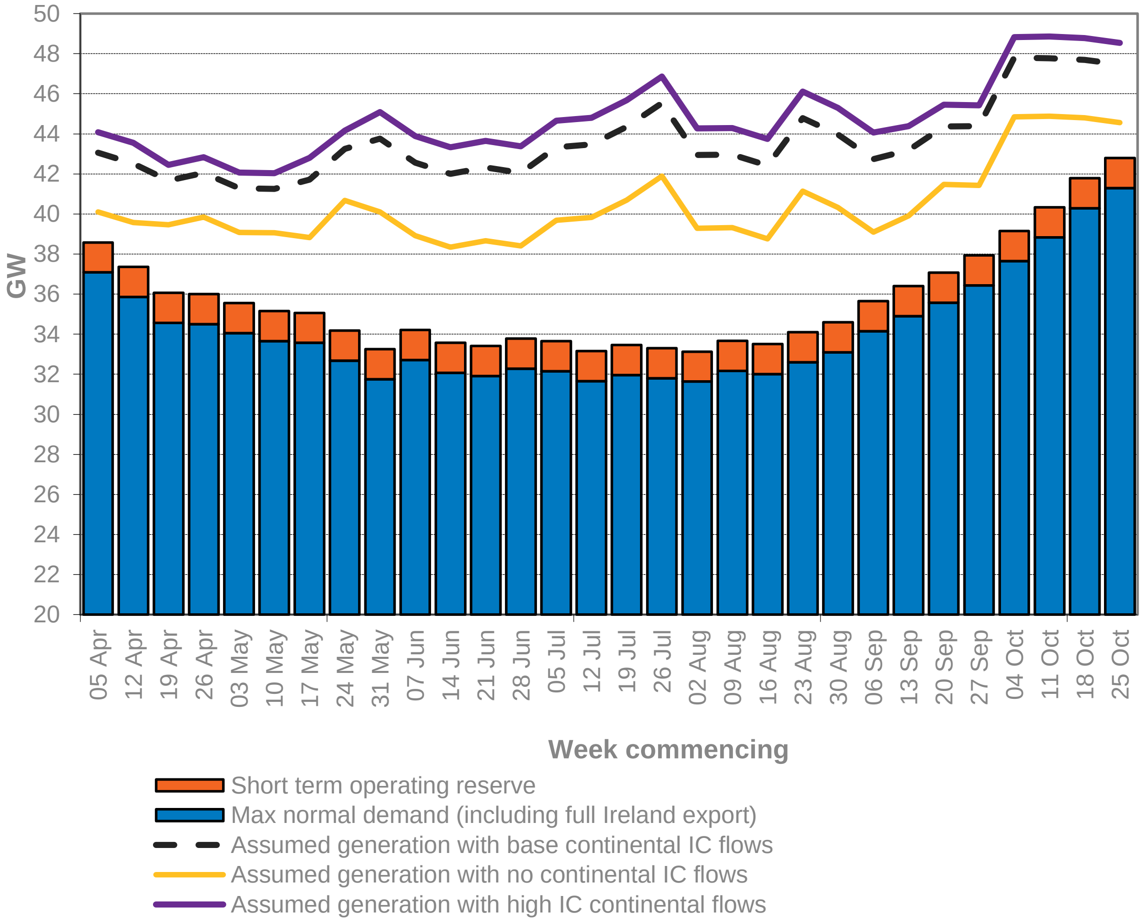
Did you know?

In the summer months, power stations typically 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, restrictions or losses close to real-time. For the latest OC2 data and operational view, see the BM reports website, updated each Friday.

Our continental interconnector flow assumptions include use of IFA, BritNed, NEMO and IFA2 over the summer.

Figure 9. Week-by-week generation and demand forecast for summer 2021



Supply / Week-by-week view

Based on current data we expect to be managing periods where inflexible generation output plus flexible wind output exceeds minimum demand and to take actions to manage this including requesting pumped storage units to increase demand, curtailing flexible wind and trading to reduce levels of interconnector imports.

This summer we expect…

- periods where pumping is required to manage low demand to occur more often than in a usual summer but less often than last summer
- Increased likelihood of periods where inflexible generation output alone may exceed minimum demand between mid-June and early August.
- no additional requirement for services beyond our everyday actions to manage the low demand points in our central forecast

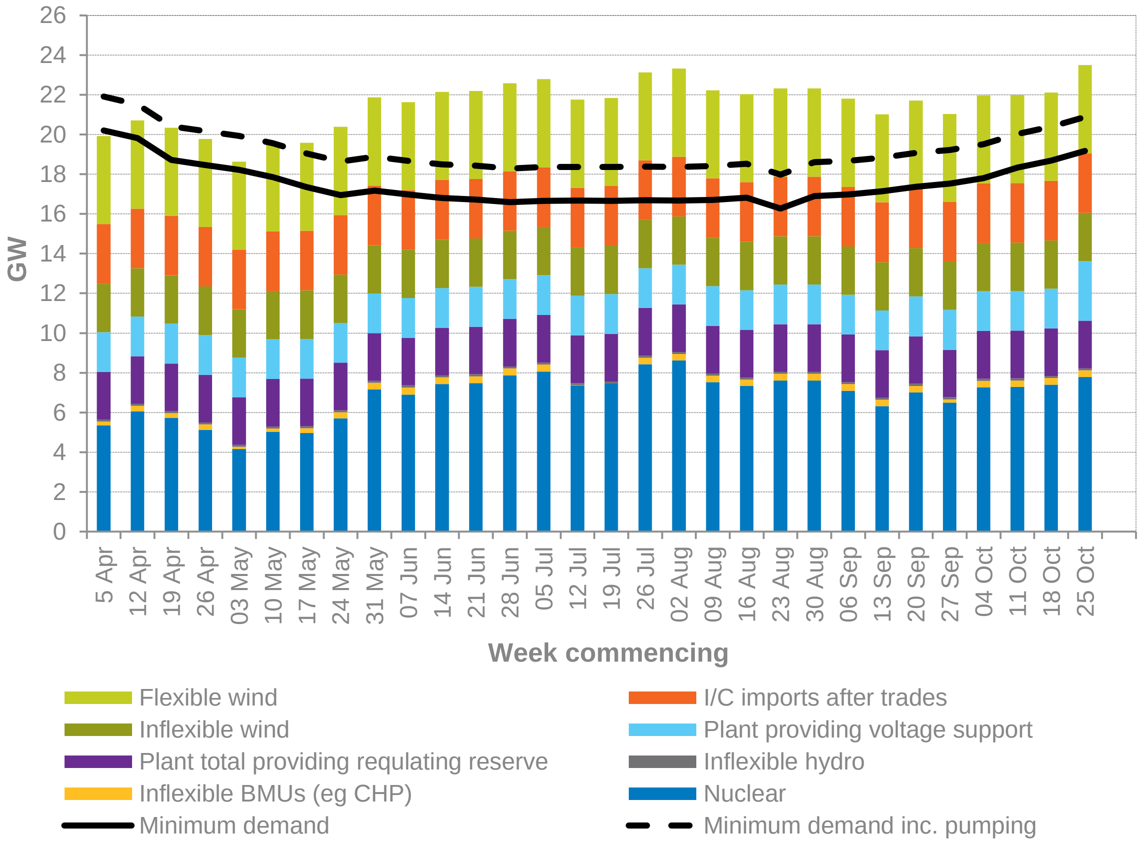
In Figure 10 we see periods where transmission system demand, without pumping, is below the level that can be achieved by reducing the flexible wind. When action is taken to increase demand by instructing pumping storage, the demand can be managed by reduction in flexible wind and/or by trading on the interconnectors.

As a prudent system operator, we are ensuring that if required we still have access to the other services developed in 2020 to manage the low demand points in terms of the **Optional Downward Flexibility Management (ODFM)** ancillary service and the last resort Grid Code disconnection scheme. Both options are being developed with industry through March and April.

In 2020 the additional gas fired plants that were required on the system to manage inertia, combined with power from other sources that are considered inflexible, created an issue where the ESO required more demand to effectively manage the network. This capability was increased by the launch of the ODFM product and changes to codes to ensure emergency actions were available.

Due to the reduction in the **vector shift** risk (discussed on page 21), and in turn the reduction in requirement to add additional gas fired plants, our current forecasts indicate that there is no additional requirement for services to manage low demand points in our central case. The next slide shows the hierarchy of different actions available to us as the ESO.

Figure 10. Forecast generation and minimum demand scenarios by week, summer 2021



Supply / Managing low demands

As National Grid ESO we may need to take actions to maintain operability of the network. The figure below shows the hierarchy of these actions and how our new Optional Downward Flexibility Management (ODFM) service fits in. Our expectation as part of our central case for this summer is to use only everyday actions.

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 figure on the right.

We also have some additional actions we can use if everyday actions are insufficient. We have retained the ODFM service we introduced last summer to help manage periods of low demand. Under our central case we are not currently forecasting any requirement to use the service, however we may call on it should it be necessary due to weather conditions or COVID-19 impacts on demand.

The ODFM service will only be instructed in the event that such challenging conditions occur and will therefore be in place to insure against the need for emergency disconnections.

Our enhanced actions include the use of local or national **Negative Reserve Active Power Margin (NRAPM)** notification. 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 sensitivity analysis does not suggest anything more than ODFM usage as one of our 'additional actions'

Everyday actions

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

Additional actions

- Usage of **Optional Downward Flexibility Management (ODFM),** a commercial service we can call on

Enhanced Actions

- Issuing a local or national **NRAPM** and flag as alert status on the ENTSO-E transparency platform.
- Taking additional actions obtained through NRAPM

Emergency actions

- Emergency Instruction to Transmission connected generation
- Emergency Instruction to DNO to disconnect DER

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Europe and interconnected markets / Overview

We expect the usual summer pattern of net imports of electricity through interconnectors from continental Europe to GB for most of this summer. We also continually expect to typically export from GB to Northern Ireland and Ireland during peak times.

This summer we expect…

- **forward baseload prices** in GB to be ahead of those in continental Europe for the majority of the summer
- imports into GB at peak times via the **IFA**, **IFA2**, **BritNed** and **Nemo Link** interconnectors, although occasionally not at full import and subject to weather variations
- **Moyle** and **EWIC** interconnectors typically to be exporting from GB to Northern Ireland and Ireland during peak times

Did you know?

Throughout the summer we will be working with our customers to commission two new interconnectors. The North Sea Link (NSL) a 1400 MW connection between Blyth and Stavanger will allow British consumers to benefit from the considerable renewable energy sources in Norway, although additional operability challenges will need to be managed as it will become the largest single loss on the system. The 1000 MW ElecLink cable laid in the channel tunnel will continue the growth in connection between Great Britain and France to make a total of 4 GW following the successful commissioning of IFA2 (1000 MW) at the start of 2021.

We will continue to monitor the development of these new connections as they move through the commissioning process.

Figure 11. Current and planned interconnectors ahead of summer 2021

Europe and interconnected markets / Expected flows

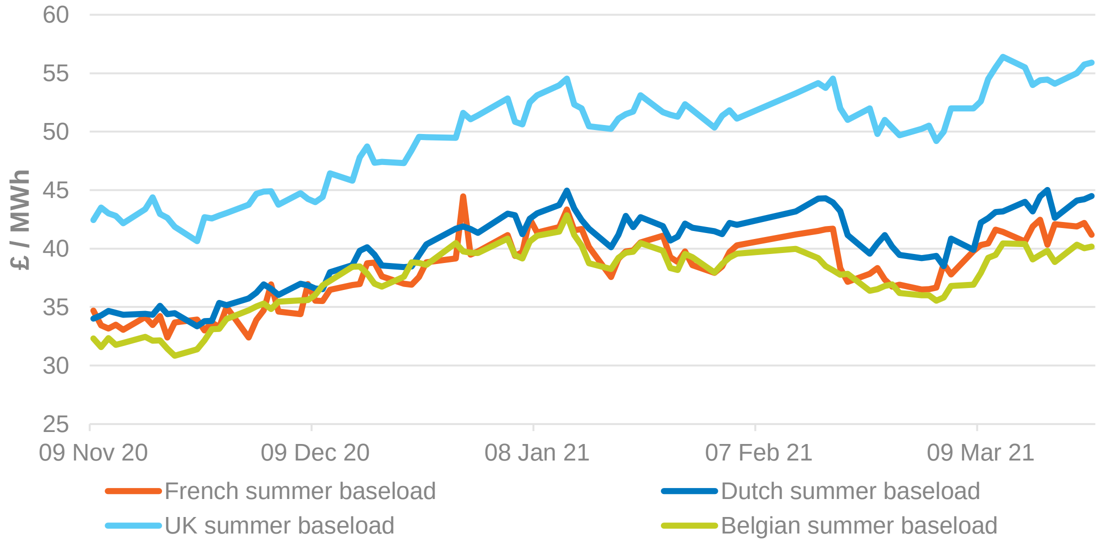
European forward prices

Electricity flows through the interconnectors are primarily driven by the price differentials between the markets.

Forward prices for **baseload electricity** during summer 2021 in GB are higher than those in the French, Dutch and Belgian markets (see Figure 11), with a larger price spread than previous years, and therefore we expect to see similar import/export patterns over these interconnectors as in a typical summer. **IFA2** connects the GB and French markets and is expected to behave similarly to the current **IFA** interconnector.

In previous years, there were some periods when IFA exported from GB to France driven by lower available French generation due to nuclear outages. Planned French nuclear outages for this year are lower than previous summers, so are not expected to significantly affect interconnector flows. Further detail can be found in the data workbook.

Figure 12: Summer 2021 electricity baseload forward prices



Physical capabilities

Since last summer a new interconnector **IFA2** has come into service between GB and France, providing an additional 1 GW capability.

Interconnectors may undertake planned outages over the summer, or experience fault outages. A table of current fault outages and planned outages for each interconnector is shown below.

Table 2. Interconnector outage schedule

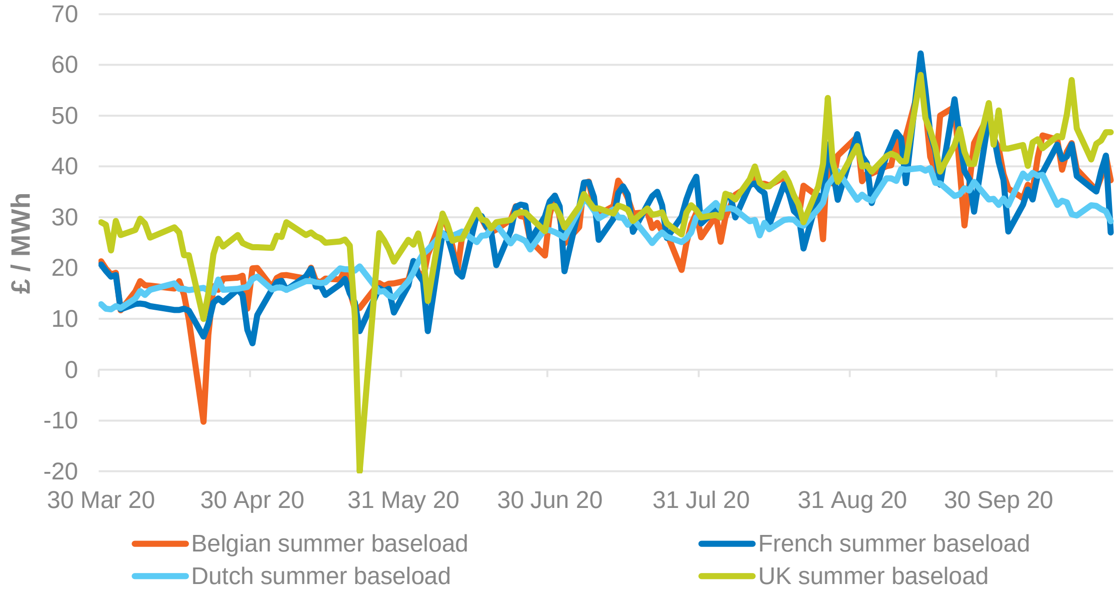
Interconnector	Planned outages (resulting capacity)	Current outages
IFA (2 GW)	16 May - 21 May (1.5 GW) 05 Sep - 17 Sep (1.5 GW)	None
IFA 2 (1 GW)	11 Apr –12 May (0 GW)	None
BritNed (1 GW)	None	09 Mar – 08 May (0 GW)
Nemo (1 GW)	None	None
EWIC (500 MW)	26 May - 27 May (0 GW) 23 Aug –12 Oct (0 GW)	None
Moyle (500 MW)	12 Jul - 19 Jul (0 GW)	None

Europe and interconnected markets / Summer 2020 interconnector flows

Baseload prices

Figure 13 shows historical GB and European day ahead electricity baseload prices for summer 2020. As can be seen here these were mostly higher in GB than in the Netherlands, leading to net imports into GB. The price differential with France and Belgium varied more, with French baseload prices occasionally higher than GB prices. This led to slightly lower average imports over IFA in the daytime however, as shown in Figure 14, imports at peak remained very high at over 97%.

Figure 13: Day ahead baseload prices during summer 2020



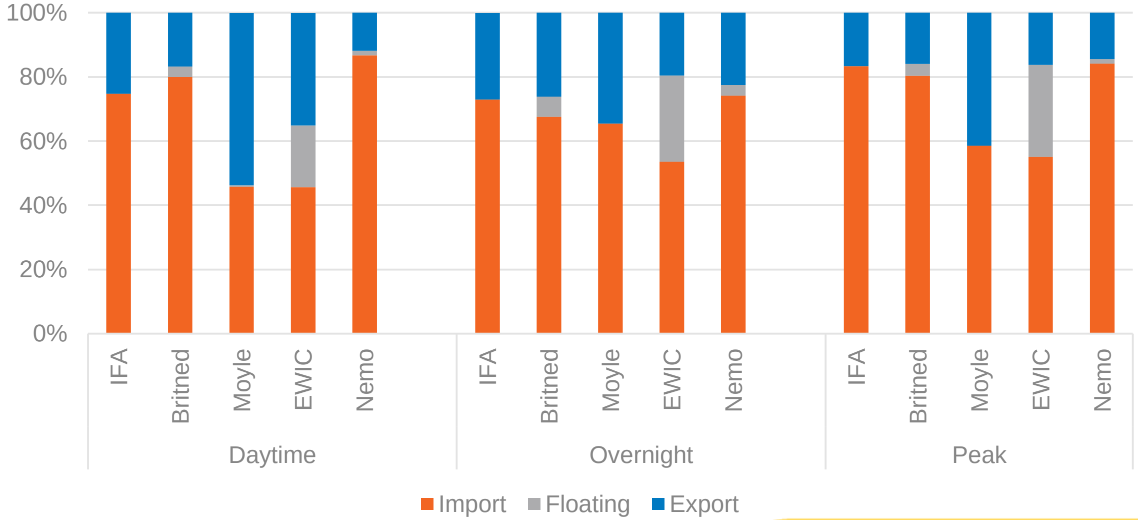
Interconnector flows

Figure 14 shows interconnector flows during the daytime, overnight and at peak times (5pm to 8pm) for summer 2020 (IFA2 is not shown as it was not operational).

Continental European interconnectors saw the highest level of imports at peak times, importing power for almost all peak hours, however this differed for the Irish interconnectors, which predominantly exported during these times.

All interconnectors were importing more than exporting during most of the overnight periods, particularly those connected to continental Europe. In the daytime, the Moyle and EWIC interconnector flows remained similar while continental European interconnectors saw slightly higher levels of exports.

Figure 14: Proportion of import and export for continental and Irish interconnectors in summer 2020



Operational view / Summer 2021

While there remains a degree of uncertainty around COVID-19 and the associated impact on demand, summer 2021 is not expected to be as operationally challenging as spring / summer 2020 and we expect that the necessary tools will be in place to enable safe, reliable, efficient system operation.

The ESO continues to evolve and refine its approach to short term operability, building on our early response to COVID-19 in Spring 2020 and ensuring ongoing monitoring and forecasting of system needs, defining requirements and ensuring the correct tools are in place for system operation. While there remains a degree of uncertainty around COVID-19 and the associated impact on demand, summer 2021 is not expected to be as operationally challenging as spring / summer 2020 and we expect that the necessary tools will be in place to enable safe, reliable, efficient system operation.

Further progress on the Accelerated Loss of Mains Change Program (ALoMCP), and the launch of a new fast acting response product 'Dynamic Containment' (DC), have reduced the impact of frequency risks being managed on the system. Against this improving backdrop, the control room will be required to take fewer actions to increase system inertia, which in turn will reduce the key downward flexibility requirement experienced in 2020. While we do not expect to need them in 2021, we will have an 'Optional Downward Flexibility Management' tool (ODFM) available to create foot-room to manage exceptionally low demands, along with the requisite emergency disconnection powers.

Our latest view on operability across our five core areas for summer 2021 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 ESO Operational Transparency Forum.

Thermal

All Transmission Owners have submitted outage plans to deliver new connections or reinforce and maintain parts of their existing networks. These plans are subject to change as faults occur and new urgent work is identified. We continue to work with the Transmissions Owners to optimise these outage plans and find ways to increase capacity on their networks to mitigate (outage related) constraint costs.

We are building a new team to develop constraint cost forecasts using outage information provided to us by the Transmission Owners. Forecasting of constraint costs can be uncertain as they are highly dependent on demand and generation background, as well as changes to the outage plan.

Costs are forecast to increase in 2021/22 with existent limits to network capacity, increased outages needed to deliver TO plans and more generation connecting in constrained areas. We are aiming to move away from a central forecast to providing a range of constraint costs and will be publishing these improved constraint cost forecasts in future.

Restoration

No significant issues have been identified currently but we will be monitoring how assurance activities will be affected/ progressed this year. We will continue to work with providers, TOs and DNOs to carry out these activities safely and efficiently. Providers' summer availability monitoring will also continue to ensure we meet compliance to Black Start Strategy.

Costs are likely to increase in 2021/22 compared to current year as we will incur an increase in capital contributions.

Operational view / Summer 2021

Frequency and stability

The frequency risks on the system for 2021 have recently been reviewed as part of the first Frequency Risk and Control Report. An overall recommendation of the cost versus risk balance of the system was made in the Report and consulted on with industry in March. This is pending approval by Ofgem, but once approved will result in an updated Frequency Control Policy.

The combined impact of the recommendations, delivery of the **Accelerated Loss of Mains Change Programme** and the introduction of **Dynamic Containment** is a reduction in frequency risk.

The ALoMCP has seen the maximum 'vector shift only loss' risk reduce from 1000MW (last summer) to below 700 MW and as such 'vector shift only loss' risks are fully covered by our minimum inertia policy. This removes the risk of RoCoF protection being triggered due to a Vector Shift loss alone and so we do not anticipate the need to take actions to manage this risk this summer. The work we have done here is discussed in more detail in a spotlight on page 21. The impact of this is a reduction in the requirement for the ESO to intervene in the market dispatch of power stations in order to raise the inertia of the system, and as such will lead to a reduction in balancing costs currently attributed to RoCoF constraint management. Indicative costs for frequency control are projected to be lower than in previous years, due to lower frequency risk.

The new fast acting service, Dynamic Containment (low) launched in October 2020, with volumes anticipated to grow throughout the summer. The FRCR assessed the value of the growth in Dynamic Containment pipelines and demonstrated that the service enables a significant risk reduction in 2021.

This is because, as the supply of Dynamic Containment increases and adds to the existing supply of Primary, Secondary and High-frequency response, the overall frequency response holding can begin to cover risks associated with consequential Loss of Mains losses.

Increasing volumes of Dynamic Containment will reduce in the scale of intervention the ESO must take in market dispatch through trades and Balancing Mechanism actions to reduce individual loss risks, moving those to the system-wide response and inertia controls and competitive markets.

The introduction of Dynamic Containment has increased the overall volume of response the ESO is seeking to procure. A consequence of this is that costs associated to system-wide controls (frequency response, inertia) may increase, but this increase will be offset by a decrease in the cost of individual loss risk controls due to fewer targeted actions being taken on large BMUs.

Spotlight / Accelerated Loss of Mains Change Programme

Removal of Vector Shift protection through the Accelerated Loss of Mains Change Programme (ALoMCP) will help to make the system cheaper to operate and more secure this summer.

The ALoMCP is an industry-led project to accelerate compliance with Loss of Mains (LoM) protection requirements in the Distribution Code which will come into force in September 2022. The programme offers funding for updating **Vector Shift** and **Rate of Change of Frequency** (RoCoF) protection. It is delivered by National Grid ESO (NGESO), distribution network operators (DNOs), independent distribution network operators (IDNOs) and the Energy Networks Association (ENA).

The programme has led to a reduction of nearly half the volume of generation using Vector Shift protection. As Vector Shift protection will only be affected by network faults close to the distributed generation, this progress in the programme has substantially lowered the risk on the system.

Previously, the volume at risk of disconnection by Vector Shift protection could be large enough to cause the rate of change of frequency to be so fast that RoCoF protection could also be triggered and more generation could be lost. As we could not curtail the volume of generation which could be disconnected due to Vector Shift, we needed to take actions to ensure that there was enough inertia on the system to prevent the RoCoF being too fast and disconnecting more generation. Through this programme of protection changes the Vector Shift levels are now such that this action to manage more inertia is no longer required.

Before making the protection changes, this issue was most challenging over summer as a large proportion of generators with Vector Shift relays are solar powered and therefore reach their maximum output during the summer months. With lower volumes of Vector Shift, the risk of RoCoF protection being triggered due to a Vector Shift loss alone is removed and we do not anticipate the need to take actions to manage this risk this summer.

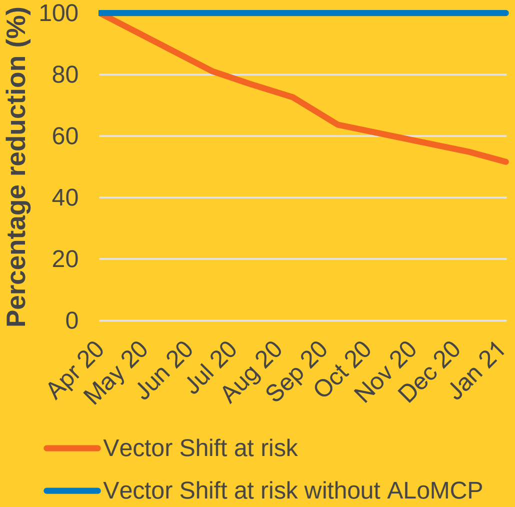
This has removed one aspect of the risk related to LoM protection. There is still work to do to change the remaining Vector Shift and RoCoF protection to achieve more cost savings and improve security of supply. We continue to encourage owners and operators of affected embedded generation to participate in the programme.

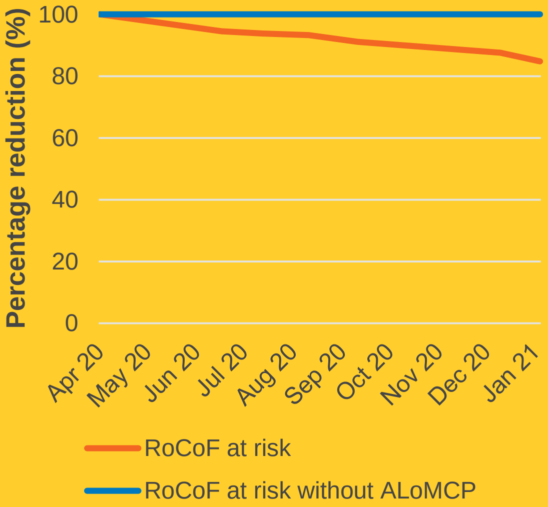
For more information…

You can find out more about how to apply here:

https://www.nationalgrideso.com/industry-information/accelerated-loss-mains-change-programme-alomcp

Figure 15: ALoMCP programme impact on volume of generation at risk of disconnection by vector shift protection (left) and volume at risk of disconnection due to RoCoF protection being triggered (right)





Operational view / Summer 2021

Voltage

When demands are lower, the ESO needs to ensure there is enough voltage support from reactive power providers in the local areas. This is typically more expensive in the summer where fewer generators self dispatch to meet the lower demand. The forecasted demand level is in line with the demand last year, so we would anticipate that the cost for voltage will be in line with previous years.

The outage pattern of reactive power providers through early May indicates that there will be a deficit in reactive power on the network across the north of London, exacerbating voltage management challenges. We will be running a tender covering this area to gain access to additional sources of reactive power. At the current time no other areas of concern have been identified for the summer, though we will keep the outage patterns of reactive power providers under review to identify any other areas of concern.

We have committed to providing more transparency on our trading decisions and as part of that, to provide more information on our reactive power requirements for voltage management. We have now started publishing overnight voltage requirement at week ahead. We have also published a document explaining how we manage the voltage requirement to help the industry understand this better.

Costs

Last summer we saw high balancing costs, we expect costs overall to be lower this summer. The table below gives a current indication of likely trajectories for the different balancing and constraint costs we expect over summer 2021 relative to last summer.

Area	
Thermal ⬆	Costs are likely to increase in 2021/22 with existent limits to network capacity, increased outages needed to deliver TO plans and more generation connecting in constrained areas. We are aiming to move away from a central forecast to providing a range of constraint costs and will be publishing these improved constraint cost forecasts in future.
Restoration ⬆	Costs are likely to increase in 2021/22 compared to current year as we will incur an increase in capital contributions.
Frequency ⬇	Indicative costs for frequency control are projected to be lower than in previous years, with recommendations in the Frequency Risk and Control Report and ALoMCP and RoCoF changes leading to a reduction in frequency risk.
Stability ⬇	The impact of ALoMCP changes is a reduction in the requirement for the ESO to intervene in the market dispatch of power stations in order to raise the inertia of the system, and as such we expect to see a reduction in balancing costs currently attributed to ROCOF constraint management.
Voltage ➡	Ensuring there is enough voltage support from reactive power providers in the local areas at times of low demand is typically more expensive in the summer, where fewer generators self-dispatch to meet the lower demand. Forecast demand level is in line with the demand last year, so we anticipate that the cost for voltage will be in-line with previous years.
Overall ⬇	Our current view is that cost reductions associated with frequency and stability should outweigh cost increases in other areas and for overall costs to be lower this summer than last summer.

Appendix / 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 FES.
	Transmission system 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.
	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 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.
	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 for peak demand forecasting when considering capacity available to meet peak demands during low temperatures.

Appendix / Demand definitions

This figure shows the relationship between different types of demand

The lowest overnight **Transmission demand** occurred on 10 May, the Sunday of the Early Bank Holiday weekend. The Transmission demand was 16.9 GW, 0.3 GW higher than the lowest Transmission demand.

Transmission System Demand

The lowest daytime **Transmission demand** was 16.6 GW at 15:00 in the afternoon on 31 May

'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 13.4 GW was by far the lowest ever seen (the lowest National demand prior to 2020 was 15.8 GW).

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.

Glossary

Active Notification System (ANS)
A system for sharing short notifications with the industry via text message or email.

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
Breakdown rates for generation over the summer are calculated using historic summer breakdown rates. These are taken from a units output against capacity, for demand peaks higher than the 80th percentile, for the last 3 years. This excludes planned outages notified to the ESO. For wind, a median load factor is calculated, meaning that there is a 50% chance of wind being higher or lower than this.

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 1,000MW. 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.

Carbon intensity
A calculation of how much carbon dioxide is emitted in different processes. It is usually expressed as the amount of carbon dioxide emitted per kilometre travelled, per unit of heat created or per kilowatt hour of electricity produced.

Clean dark spread
The revenue that a coal fired generation plant receives from selling electricity once fuel and carbon costs have been accounted for.

Clean spark spread
The revenue that a gas fired generation plant receives from selling electricity once fuel and carbon costs have been accounted for.

CMP264/265
Changes to the Charging and Use of System Code (CUSC). These changes were phased in from 1 April 2018 and reduce the value of avoided network charges over Triad periods.

CO2 equivalent/kWh
The units 'gCO2eq/kWh' are grams of carbon dioxide equivalent per kilowatt-hour of electricity generated. Carbon dioxide is the most significant greenhouse gas (GHG). GHGs other than carbon dioxide, such as methane, are quantified as equivalent amounts of carbon dioxide. This is done by calculating their global warming potential relative to carbon dioxide over a specified timescale, usually 100 years

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

Demand side response (DSR)
when demand side customers reduce the amount of energy they draw from the transmission network, either by switching to distribution generation sources, using on-site generation or reducing their energy consumption. We observe this behaviour as a reduction in transmission demand.

Demand suppression
The difference between out pre-COVID forecast demand levels and the actual demand seen on the system. We have considered a range of potential outcomes for demand suppression this winter.

Glossary

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 and battery units. This form of generation is not usually directly visible to National Grid as the system operator and reduces demand on the transmission system.

Dynamic Containment
This is a new fast-acting post-fault service to contain frequency within the statutory range of +/- 0.5Hz 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 (+/- 0.2Hz).

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/

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.

European Union Emissions Trading System (EU ETS)
An EU-wide system for trading greenhouse gas emission allowances. The scheme covers more than 11,000 power stations and industrial plants in 31 countries.

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.

GB Customer demand
Sum of all demand used within GB. Total demand requirement for GB.

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 2,000 MW 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 1,000 MW 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.

Glossary

Margins Notice Issued
If forecast demand for the day ahead exceeds a pre-defined forecast of supply.

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

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

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

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).

Nemo Link
A 1000 MW 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.

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 basis. It includes both notified planned outages and assumed breakdown rates for each power station type.

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.

RoCoF limit
The maximum loss we can allow on the system. A loss of generation larger than this limit has a high risk of resulting in a RoCoF of 0.125Hz/s.

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.

Station load
Electricity demand for power stations connected to the transmission system, this is considered separately to customer demand.

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.

TNUoS demand charges
Transmission Network Use of System charges recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and offshore. Generators are charged according to TEC (Transmission Entry Capacity). Suppliers are charged based on actual demand.

Transmission system demand (TSD)
Sum of all generation that flows through the GB Electricity Transmission network to meet internal GB demand or exports out of GB. This is the 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.

Vector shift
The sudden change in voltage phase angle in a part of the network. When this happens a generator’s protection settings may disconnect it from the network to protect the equipment.

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.

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

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.

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