June 2021

Winter Review and Consultation

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

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Welcome

Welcome to our *2021 Winter Review and Consultation Report*. This annual document provides a review of how the forecasts in the *2020/21 Winter Outlook Report* compared to what actually happened – as well as an opportunity to share your views on the winter ahead and any potential changes to our *Winter Outlook Report* approach.

This document includes a review of all the standard analysis from the *2020/21 Winter Outlook Report* in relation to elements such as demand levels, performance of generators and any operability challenges faced. However, in light of the Electricity Margin Notices (EMNs) issued, we are also including a more detailed review of our existing approach to margin analysis, including deep dives of the days when EMNs were issued to ensure that our approach to the *Winter Outlook Report* remains appropriate as the electricity system evolves.

We would appreciate feedback on our potential plans and on preparations for the upcoming winter. If you would like to share your views, please refer to the consultation section in this publication, or join us for a discussion at our Operational Transparency Forum (OTF) on 30 June.

As in the *2020 Winter Review and Consultation Report*, the 2021 document will only cover the electricity perspective. We will continue to engage with National Grid Gas Transmission to ensure consistency of approach. The Gas *2021 Winter Review and Consultation Report* can be found here.

If you have any general queries or comments, don't hesitate to email us at marketoutlook@nationalgrideso.com , join the conversation at our weekly OTF webinars or use social media via LinkedIn, Facebook and Twitter.

Contents

Key Messages / winter 2020-21

Did you know? Electricity Margin Notices (EMNs) and Capacity Margin Notices (CMNs) are tools we use to manage the National Electricity Transmission System. These notices are issued to inform the market that our normal operating margin is lower than we'd like for a future period and to help avoid potential system issues. To find out more visit our website.

1 Margin notices

Winter 2020/21 had tighter margins than the previous winter, as reflected in the issuing of six Electricity Margin Notices (EMNs) and two Capacity Market Notices (CMNs) between November 2020 and January 2021.

Overall margins were forecast to be lower than previous winters in the *Winter Outlook Report*. While EMNs and CMNs reflect the normal working processes of the market, these were the first EMNs issued since 2016. All EMNs were cancelled before the settlement periods they concerned, without any erosion of key operational reserves, and the power system was secured at all times.

2 Supply

Margin levels were influenced to an extent by demand and wind output but the greatest driver was thermal generation availability which did not meet the expectations from the *Winter Outlook Report*.

There was a shortfall in available supply capacity in real time compared to expected levels which were determined ahead of winter based on generator submissions, planned outages and historic performance. Unplanned interconnector outages were also a factor.

3 Market prices

This winter, especially on days when EMNs were issued, saw the highest System Prices since 2001 which translated into spikes in wholesale prices.

System Prices, which are used to settle imbalance volumes in the GB power market, reached a high of £4,000/MWh on 8th January. Wholesale day-ahead power prices exceeded £1,000/MWh on several occasions in January, with the market cap of £1,500MWh for the day ahead auction reached twice.

Description of Winter 2020/21

Despite near average temperatures, winter 2020-21 was a season of variable weather. Wind patterns were particularly extreme, with periods of very high wind regularly followed by spells of unusually low wind. On top of this, the winter included transitions in and out of national and regional COVID-19 lockdowns, presenting a changing impact on national demand patterns.

Lessons Learned

Although operating conditions were complex, we continued to operate the system securely and reliably over the winter period. However, as part of our standard continual improvement approach, we are using lessons learnt from last winter as an opportunity to review a number of elements regarding how we provide our Winter Outlook analysis. We are also seeking your views on potential changes to how we most effectively manage system challenges which may occur over the upcoming winter period.

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Review / margins

Operational surplus: a look back at our *Winter Outlook Report* forecasts

The *2020/21 Winter Outlook Report* contained a week-by-week view of operational margin (also referred to as surplus) and this is shown in Figure 1.

This week-by-week chart showed that, although the highest demand was expected in the first week of January, under average weather conditions the tightest parts of winter were expected to be in the latter part of November and the first half of December. Electricity Margin Notices (EMNs) were issued during these periods. The chart highlighted that the expected tight system margins were driven by a combination of lower generation and/or interconnector imports in the higher demand periods of the winter.

The green bars represent the transmission system demand forecast (under average weather conditions, with average embedded wind generation and assumed 4% demand suppression due to the COVID-19 effect).

Demand is then combined with the expected reserve requirement (in orange). The red dotted line represents where demand and reserve could be, should average cold temperature conditions be experienced thereby raising demand levels. This is referred to as ACS (Average Cold Spell) conditions.

Finally, the light and dark blue and purple lines represent the forecast of generation supply when combined with low, medium and high imports from interconnectors.

Note that generation supply is made up of Balancing Mechanism generation availability submissions (de-rated using historic data to take account of breakdowns) plus an assumption of expected wind generation. Other forms of distribution connected generation are excluded as quoted demands are at transmission level.

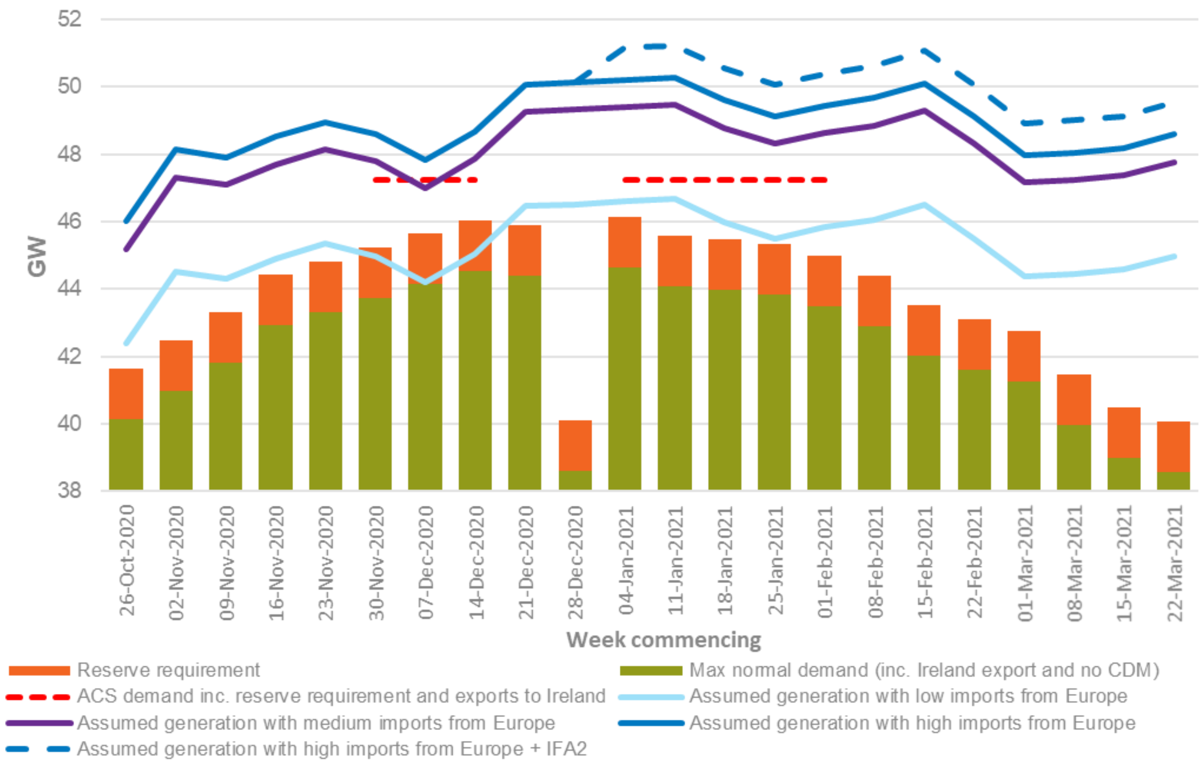

Figure 1. Week-by-week forecast view of operational surplus for winter 2020/21 (Figure 3 from *Winter Outlook Report 2020/21*)

Review / margins

How did the winter compare to the forecast in the *Winter Outlook Report*?

Figure 2 overlays the forecast from the *Winter Outlook Report* with the actual out-turns from the winter for both demand and plant availability and is designed to be comparable with Figure 1.

Demand

- green and orange bars respectively show the forecas weekly normal demand and reserve requirements as in the *Winter Outlook Report* (exact same values)
- solid black line indicates daily out-turn total of "demand plus reserve" (and corresponds to the dotted "forecast" above the bars).
- dotted red line represents the forecast Average Cold Spell (ACS) peak demand at transmission level as in the *Winter Outlook Report* (exact same values).

The actual winter peak demand was close to the forecast ACS.

Supply

- dotted purple line shows the weekly expected plant availability under the base case interconnector scenario from the *Winter Outlook Report* (exact same values).
- solid purple line shows the actual daily plant availability, including wind output and interconnector flows.

Tight margin days, like those that produced EMNs, occur when the solid black out-turn demand is close to the solid blue out-turn supply.

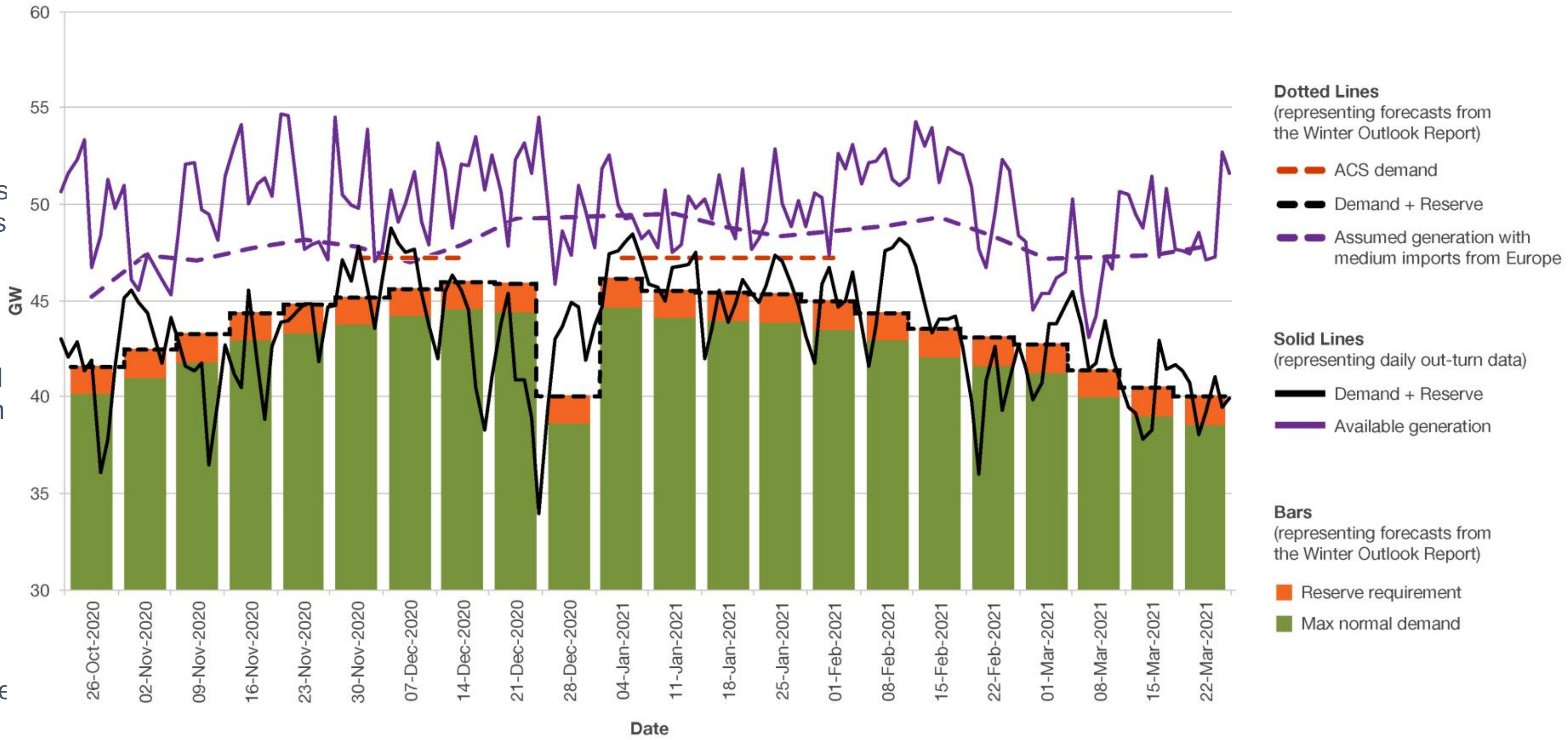

Figure 2. Week-by-week actual view of operational surplus for winter 2020/21

The graph in Figure 2 clearly demonstrates the variability in both demand and generation, which are hidden when focussing on average values and weekly peaks.

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Review / margins

How did the winter compare to the forecast in the *Winter Outlook Report*?

Overall, winter 2020/21 was close to the average for windiness over the past five years, but significantly less windy than winter 2019/20. However, the main driver for lower margins came from thermal plant being less available than had been notified at the time of the *Winter Outlook Report*.

What we said in the *Winter Outlook Report*	What actually happened	Why was there a difference?
Average Cold Spell (ACS) transmission demand to be met in all weeks under the high import interconnector scenario and all but one week in the base import scenario	ACS demand (calculated proxy rather than metered figure) would not have been met in all weeks but there was sufficient generation and interconnector imports to meet demand throughout the winter period.	The *Winter Outlook Report* considers what would happen under different average conditions whilst the out-turn fluctuates around the average level. Had cold spells fallen on different days a market response would be expected (i.e. comparison has to be hypothetical).
The operational surplus will be lower than last year due to generation outages and plant closures of up to 2.25 GW, bringing a reduction in maximum technical generation capacity.	In addition to the lower than expected availability of thermal plant, demand was higher than expected during some periods of the winter, and weather variability and interconnector outages meant that we were at times tighter than the average values suggested.	The margin calculated on average, or typical, values did not capture the effects of natural variability around the average value. We plan to address this by explicitly producing studies of the credible range of margin on a daily basis.

Table 1. Margins commentary for winter 2020/21

Table 2 below shows the days when Electricity Margin Notices (EMNs) and Capacity Market Notices (CMNs) were issued over the winter period.

These dates are referred to throughout the report including on charts, in a deep dive on p10 as well as individual EMN case studies in the Appendix.

Date	EMN	CMN
4 November	Yes	No
5 November	Yes	No
3 December	No	Yes
6 December	Yes	No
6 January	Yes	No
8 January	Yes	Yes
13 January	Yes	No

Table 2. Days of EMNs and CMNs over Winter 2020/21

Review / margins

Generation shortfall by fuel type

Figure 3 shows the shortfall between generation notified at the time of the *Winter Outlook Report*, published in October 2020, and what was actually available throughout the winter. By shortfall we mean the gap between generation assumed in the *Winter Outlook Report* and what was available in real time. This includes both breakdowns and commercial unavailability.

The analysis is on a weekly basis, with the period of the lowest margin that week used as the quoted value. We have excluded the Christmas period from the chart, as well as any weeks in which margins were more than c.3 GW.

The main drivers for lower margins came from coal and CCGT plant being less available than had been notified at the time of the *Winter Outlook Report*. As a percentage of total capacity, coal capacity had the largest shortfall. Although generally lower than anticipated, wind generation provided a contribution on most of the days with EMNs issued (as per Table 4 on the next page) and was not the main factor in tight margins. Nuclear generation prior to Christmas met or exceeded the notified availability but availability was lower post-Christmas. There was also reduced interconnector availability across the whole winter due to unplanned outages (e.g. BritNed).

The shortfall between the forecast availability and the out-turn availability highlights a potential requirement for a different approach in the *2021/22 Winter Outlook Report*.

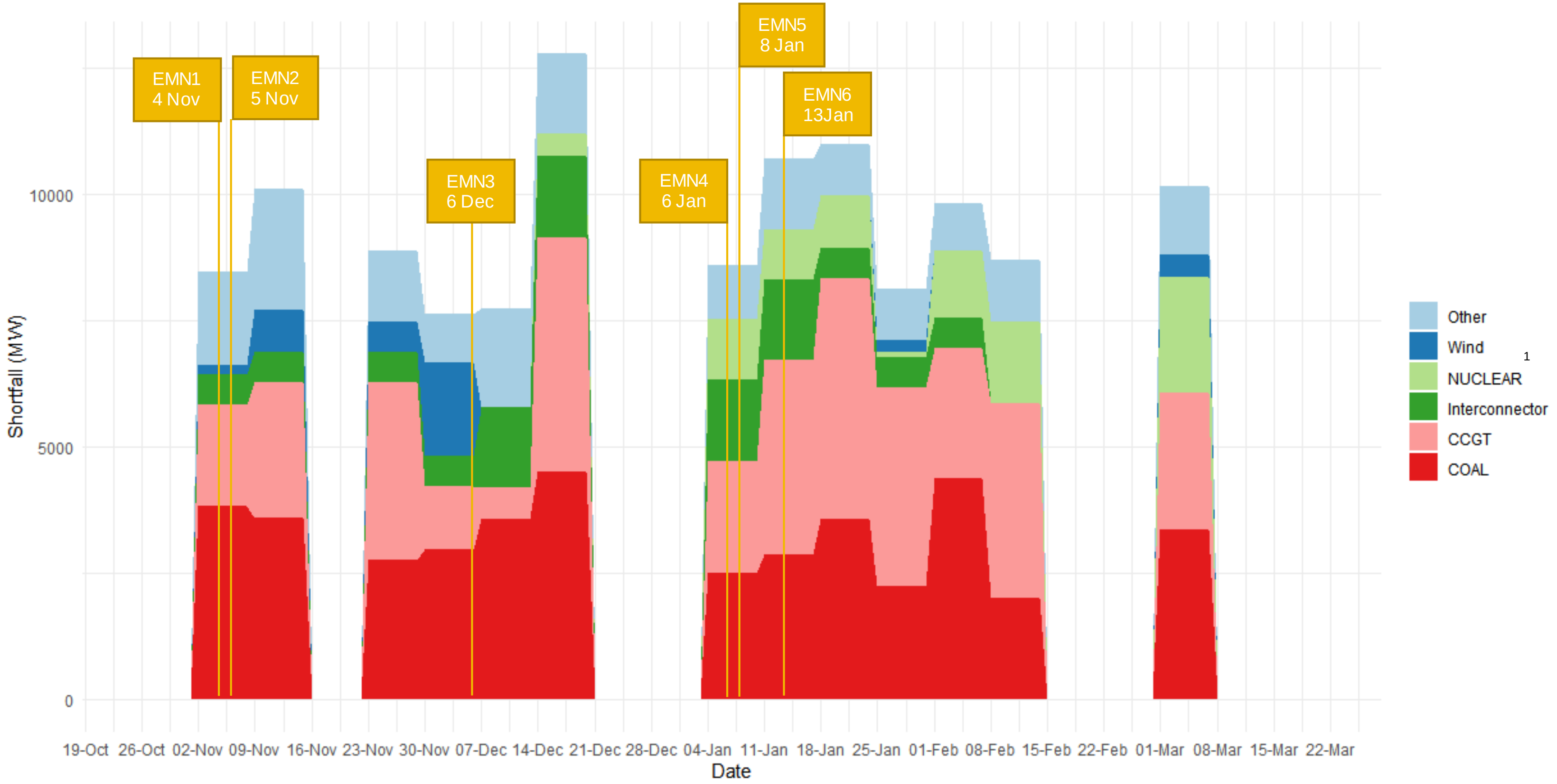

Figure 3. Week-by-week view of generation capacity shortfall over the winter

- For wind generation, we consider a shortfall to be the gap between actual wind generation on a given day and the level assumed in the *Winter Outlook Report* which is based on a statistical consideration of the contribution of wind to capacity adequacy (i.e. not its average annual load factor).
- For Continental interconnectors, we treat it as the gap between actual availability and our high import scenario in the *Winter Outlook Report*.
- For all other generators, it is the difference from the de-rated weekly expectations of the *Winter Outlook Report* and the actual available generation on the day.

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[1] Other includes: Combined heat and power (CHP), hydro, biomass and mixed fuel sources.

Review / margins

Generation and interconnector background to margins

Figure 4 shows the difference or shortfall between generation availability notified when the *Winter Outlook Report* was published, and the prevailing view of availability at real time. There are a number of different reasons for the lower than anticipated availability of generators and no common theme. This chart excludes wind and solar generation assets. There is no impact of a large shortfall between expectations and out-turns when demands are lower, typically at weekends and over Christmas.

When forecasting interconnector flows in the *Winter Outlook Report*, we expect imports from the continent to GB at time of peak, and exports from GB to Ireland. We model both a high import case based on outage plans and price spreads and a more conservative base case which includes some unavailability as well as lower levels of import. This winter, interconnector availability was at times lower than either of these scenarios (see Figure 5). No outages were planned for the winter period but there were several unplanned outages (see Table 3).

During the EMN periods the level of wind played only a limited role in the reduced margins, as shown by Table 4. There was only one day on which an EMN was issued where wind output was significantly below the level assumed in the Winter Outlook Report.

Interconnector	Outage start	No. of days	Capacity available
Moyle	24/11/20	1	250 MW
Moyle	01/12/20	1	250 MW
BritNed	08/12/20	64	0 MW
EWIC	02/01/21	1	0 MW
IFA	18/01/21	1	0 MW
IFA	29/01/21	1	0 MW
IFA	30/01/21	1	0 MW
IFA	02/02/21	1	1014 MW
IFA	14/02/21	1	0 MW
BritNed	09/03/21	23*	0 MW
EWIC	14/03/21	1	0 MW

Table 3: Unplanned interconnector outages

EMN date	Wind output
4 November	14.2%
5 November	14.2%
6 December	**3.8%**
6 January	20.4%
8 January	11.4%
13 January	15.5%

Table 4: Out-turn wind load factors at the tightest point on days with EMNs issued

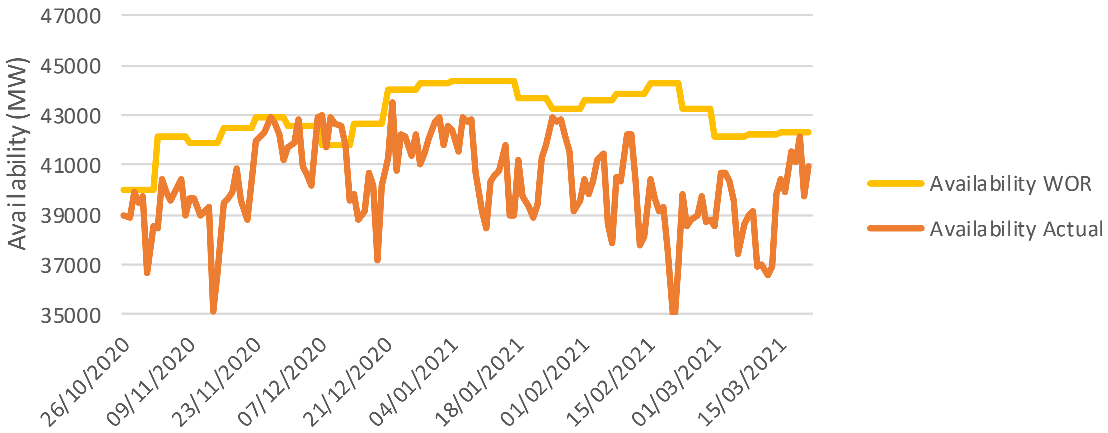

Figure 4. Shortfall between generation availability notified in the *Winter Outlook Report* and actual generator availability (excluding wind and solar)

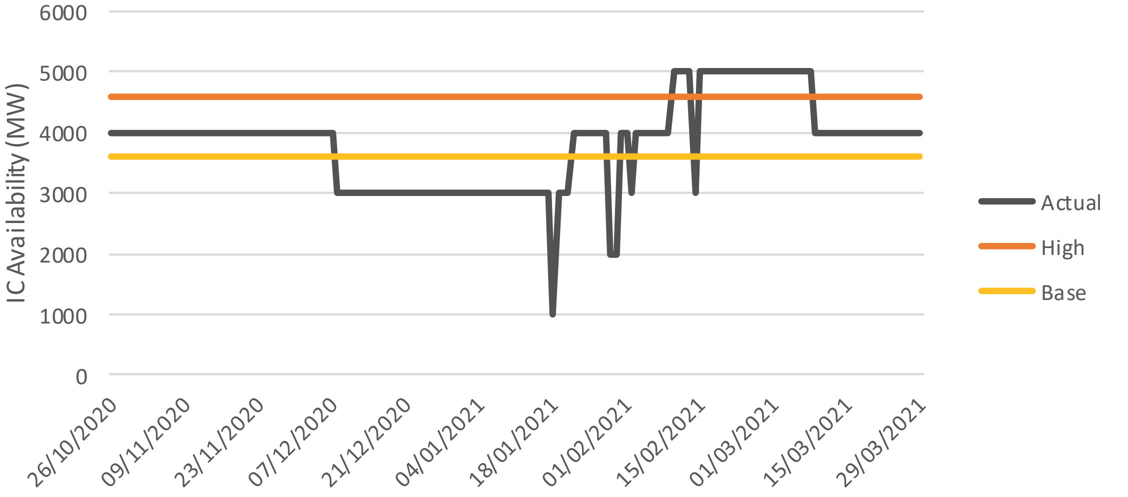

Figure 5. Interconnector scenarios in the *Winter Outlook Report* and actual availability during peak times

* Outage continues beyond the winter period

Review / margins

Transmission demand

Peak actual weather-corrected Transmission System Demand (TSD) was higher by 1.7 GW than forecast but was not a key driver during days when EMNs were issued.

The highest normalised demand was expected (from the *Winter Outlook Report*) in the first week of January, the actual one occurred in the third week of December (see Figure 6).

There was a one-week period in December when demand spiked (see Figure 7). This was between Thursday 10th and Wednesday 16th December, and was part of a lead up towards Christmas with reduced COVID-19 restrictions in place.

2020/21 Winter Outlook Report forecast (normal weather used) (GW)		Actual 2020/21 (weather corrected) (GW)		Actual 2020/21 (not weather corrected) (GW)	
Peak	Minimum	Peak	Minimum	Peak	Minimum
44.7	19.6	46.4	18.7	47.4	20.3

Table 5. Peak and minimum transmission system demands for winter 2020/21

EMN date	Day of week	Actual Peak TSD at time of EMN (GW)
4 Nov 2020	Wed	44.1
5 Nov 2020	Thu	43.5
6 Dec 2020	**Sun**	44.6
6 Jan 2021	Wed	46.7
8 Jan 2021	**Fri**	45.7
13 Jan 2021	Wed	45.4

Table 6. Actual Transmission System Demand at times of EMNs (not weather corrected)

On all 6 occasions when EMNs were issued, actual TSD (as opposed to weather-corrected as in the forecast) was lower than the actual winter peak TSD (47.4GW) in Table 5.

This, as well as how EMNs were issued on a Sunday and Friday (see Table 6), highlights how EMNs do not necessarily occur on the days with the highest demand but on the days with the biggest shortfall of generation.

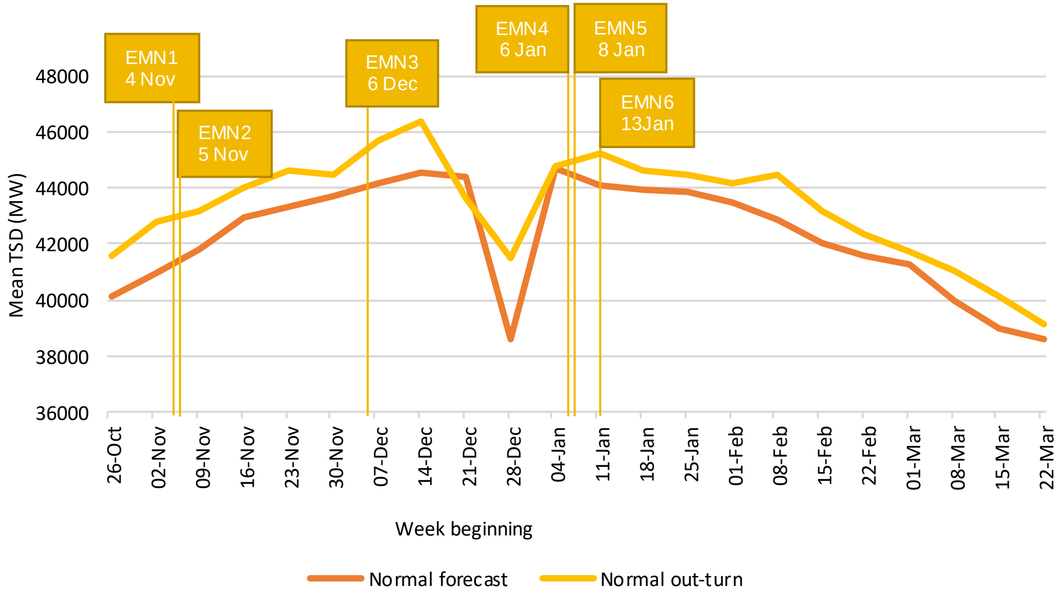

Figure 6. Peak Transmission System Demand (TSD) forecast and outturn for winter 2020/21 (weather corrected)

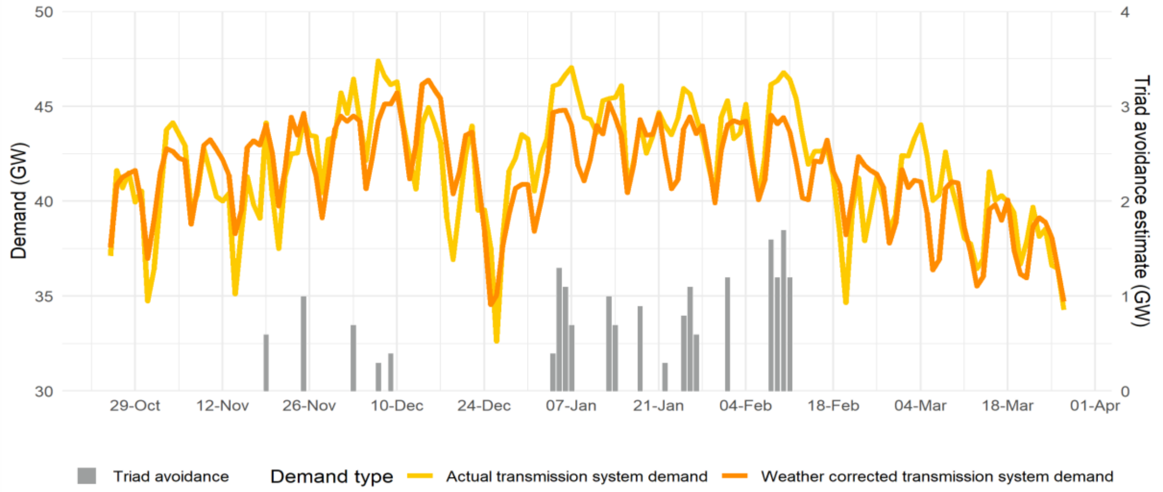

Figure 7. Daily actual and weather corrected peak demands including triad avoidance

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* For the purpose of the Outlook and Review Reports, TSD includes national demand, 600MW of station load and 750MW export on interconnectors (over the peak only).

Deep dive / Electricity Margin Notices

Electricity Margin Notices (EMNs) are used as a normal operational tool to highlight when margins are looking tight ahead of real time – they don't indicate that demand will not be met. The first EMNs since 2016 were issued this winter, with six EMNs having been issued in total between November 2020 and February 2021. Each one was cancelled ahead of real time.

While these EMNs reflect normal ESO operational process, there has been a significant rise this year which is primarily due to two main factors:

- The forecast supply margin this year, while well within the security of supply standard of 3 hours loss of load expectation (LOLE), was tighter than the last three years ; and
- Elements of the generation portfolio under-performed with the overall supply availability at times below that indicated by generators, and below historic performance levels (see Figure 8).

There were some specific generation and interconnector outages at the times of the EMNs, and while wind was generally low, it was within the range of what could be expected. In all cases when an EMN was issued, there was an appropriate market response – prices rose, generation made itself available, interconnection flowed into GB – such that security of supply was always maintained through the peak periods (we had enough to cover demand, frequency response with reserves) and EMNs could be cancelled before real time. Demand was never shed and the next level of system notice \ warning "High Risk of Demand Reduction" was never required.

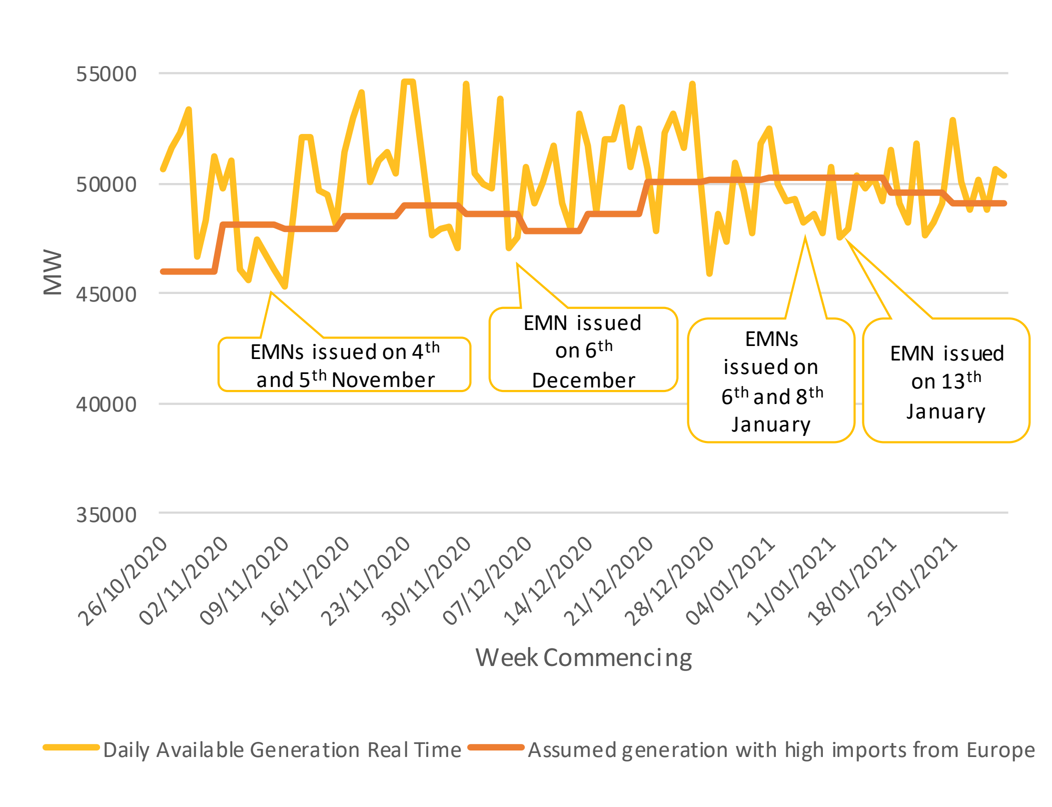


Figure 8. Generation portfolio availability

Six EMNs were issued for the darkness peaks on Wednesday 4th November, Thursday 5th November, Sunday 6th December, Wednesday 6th January, Friday 8th January and Wednesday 13th January. The fact that an EMN was issued on a Sunday in particular highlights the varying impact of demand levels on margins. Further details of these EMNs can be found in the appendix.

Find out more on the differences between Electricity Margin Notices (EMNs) and Capacity Margin Notices (CMNs) here.

Did you know? / Capacity Market Notices and Electricity Margin Notices

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

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

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

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

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

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

We'd like to hear what you think about this. Head to the Consultation section of this report to find out how you can provide feedback.

Proposed changes / operational margins

We're constantly looking for ways to improve our methodologies at the ESO. This year, we're looking at a number of potential changes:

1. Operational margin calculations

While still reporting average values as we have in the past to allow consistent year on year comparison, we want to focus more on periods of lower margins, and reporting the effects of natural variability. We want to give credible ranges for the operational margin on a daily basis around the average value, and report on the daily risk of tight margin conditions. This will allow for better risk planning, and is more appropriate for a system with less generous overall margin levels.

To report credible ranges and risks most appropriately, it is not possible to present the information in a component manner, giving values for demand and generation separately. Instead the focus has to be on the value of the operational margin itself – which is a factor of demand and supply combined. We propose to trial this new approach whilst continuing to provide the existing "average view", which does allow for a component breakdown.

2. New approach to reserve setting for winter 2021/22

In addition to business as usual development work, we are also prototyping newer modelling techniques for reserve setting. This includes trialling a Monte Carlo simulator.

Alongside this, we are running two innovation projects:

- Innovation 1: Dynamic Reserve Setting project, to create a Machine Learning Probabilistic Model for reserve setting
- Innovation 2: REACT project, to create a Stochastic Probabilistic Model for reserve setting.

The deployment and integration of the prototypes are dependent on a performance comparison of the predictive effectiveness of the new models in comparison to existing methodologies. It is likely that any use in winter 2021/22 would be in parallel to existing methods.

Monte Carlo: Runs repeated loops using a random number generator to generate a spread of different possible outcomes, allowing potential reserve level from the tail-ends of these outcomes.
- Pro: Established technique in other industries at predicting product demand vs supply
- Con: Difficult to apply to a complex power system outcome with multiple partially interacting/coupled drivers and many different types of demand and supply being impacted in varying amounts by the drivers.
For example, an unexpectedly sunny day has a direct impact on PV generation compared to, say, gas generation. However, gas generation responds to lower prices caused by surprising excess PV generation. Then, if it's sunny do people go out (lower demand) or stay in and turn up the air con (higher demand)?

Machine Learning Probabilistic: Trains an algorithm to associate outcomes with complex input drivers (e.g. a day with an unexpectedly large imbalance might be driven by a mix of market forces, weather forces, and uncertainties)
- Pro: Can account for many complex and interacting drivers and outcomes
- Cons: Can be a "black box", which in turn can undermine confidence of decision makers in using outputs (i.e. if it's not possible to explain where they came from). Also, bias is inherent in chosen training dataset.

Stochastic Probabilistic: Driving the reserve requirement directly from the uncertainty bounds of probabilistic forecasts themselves
- Pro: Provides a more direct link to uncertainty of forecast, rather than trying to predict forecast error
- Con: There is a need to have true productionised probabilistic forecasts driven by ensemble data embedded in decision making, it is difficult to merge separate forecasts (PV generation, wind, demand, traditional generation) into one overall uncertainty, and so bias is then pushed back into forecasting model designs.

We'd like to hear what you think about this. Head to the Consultation section of this report to find out how you can provide feedback.

Proposed changes / margins

We're constantly looking for ways to improve our methodologies at the ESO. This year, we're looking at a number of potential changes:

1. System level Margin calculations

In the *Winter Outlook Report* we present an overall whole system margin, based on an assessment of the winter as a single snapshot using assumptions informed by long-term averages. This is the 4.8GW / 8.3% "Capacity Market" margin quoted for last winter.

We then also assess the winter on a week-by-week transmission-level view that allows for greater granularity, which becomes more important in how we operate the system throughout the winter. This is the "Operational Margin".

One of the questions we would like to consider is how useful the single snapshot view in the *Winter Outlook Report* is, given it is presented alongside the more granular weekly view.

2. Market engagement on margins for winter ahead

An alternative option we think may be of merit, would be to present the single snapshot view earlier in the year instead (e.g. in summer, possibly via the Operational Transparency Forum).

This could potentially support industry better in their preparations for winter. The *Winter Outlook Report* would then focus solely on the more granular weekly view as we approach winter.

If we get feedback that the margin number in October is still very useful, then we will keep doing it. If not, then we move to earlier in the year, provide the signal and just consider the week by week view in the *Winter Outlook Report*.

3. Market margin signals (De-rated Margins, Capacity Market Notices, Electricity Margin Notices)

We are currently working with the ELEXON Issue Group 92 to decide whether the current De-rated Margin (DRM) calculation, Reserve Scarcity Price Mechanism and the link to cash-out prices are still appropriate. This is due to how rarely there has been any impact on prices in recent years and to reflect other changes such as the new Day Ahead Short Term Operating Reserve (STOR) market.

The Issue was published for industry consultation in April and a decision is expected in summer 2021.

From last winter's experience and feedback, where possible we are aiming to make our margin signals more consistent. We are looking at different options which could include: combining the DRM and CMN margin calculations into a single calculation and updating the methodologies to reflect known issues and changes since the two calculations were introduced 5-6 years ago.

We expect to retain the EMN signal as a separate manually derived margin view that can incorporate engineering judgement and experience from the control room, to complement the automatic DRM and CMN processes which are purely automatic based on market submitted data, latest forecasts and fixed formulae, thresholds or trigger levels.

Review / impact of COVID-19

In preparing the demand forecast for the *Winter Outlook Report*, one of the critical inputs into the calculation of the demands was the assessment of the expected demand suppression over the daily peak during the winter due to COVID-19. The level of demand suppression varies according to time of day and day of week. As the peak of the year historically tends to occur on Monday-Thursday, we focused on these days when deciding on the suppression value.

We matched the relative Darkness Peak (DP) suppression to the few days evidence we had in March 2020 in the calculations. The first national lockdown was announced on 23 March 2020, which meant we had only 3 relevant weekdays (not counting Friday) to use.

To adapt our pre-COVID forecasts to our base case COVID-19 effect, we used a 4% suppression over the peak as the input into the models. Looking back at the assumption applied to the demand suppression over the Darkness Peak (DP) forecasting period*, the average overall drop over the winter over the DP* was 4.25% (see Figure 9 and Table 7).

As noted on p9, there was a period in December in the lead up to Christmas when restrictions were lifted and we saw a spike in demands.

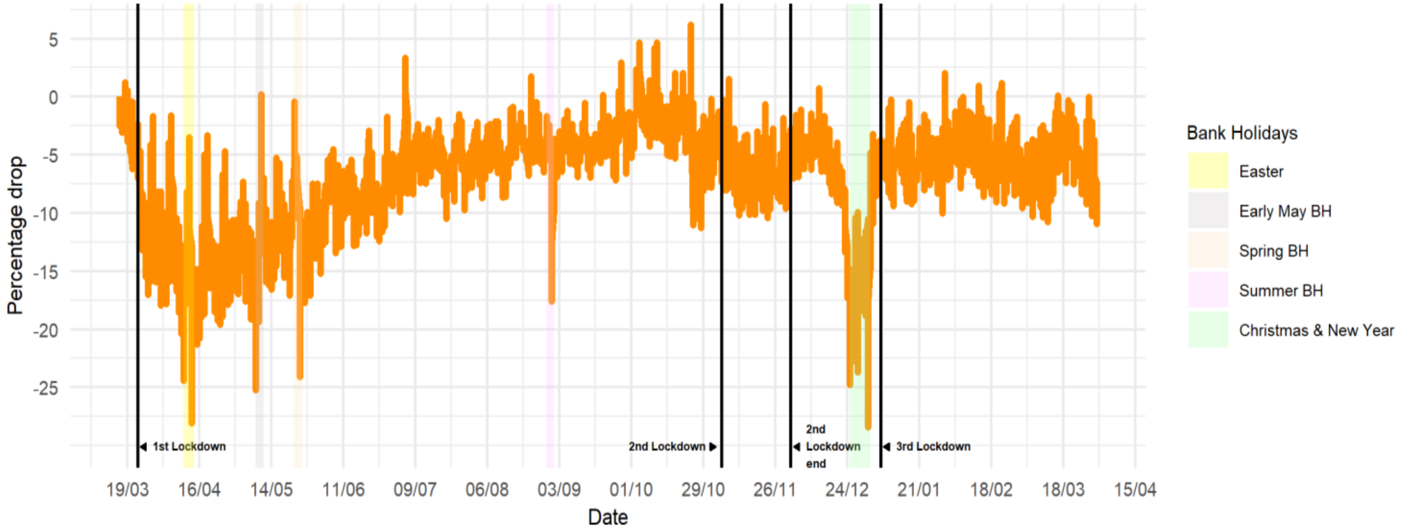


Figure 9. Percentage change in daily average demand relative to pre-COVID forecast (March 2020 to March 2021)

Month	Average demand suppression over DP (%)
Nov-20	4.1
Dec-20	3.9
Jan-21	4.6
Feb-21	3.3
Mar-21	5.2

Table 7. Assessment of the COVID-related demand suppression in winter 2020/21

* November to March, Monday to Thursday only and excluding Christmas and New Year period (from 22 Dec 2020 to 3 Jan 2021)

Review / triad avoidance

Triad avoidance occurs when industrial and commercial users alter their pattern of energy use during peak periods to avoid transmission charges. The three half-hourly periods with the highest demand over the winter, separated by 10 calendar days, are known as triads.

Ahead of the winter, it was uncertain how COVID-19 restrictions would impact demand levels which added to the uncertainty around how changes to the Embedded Benefits regime would alter the triad avoidance volumes and/or historical triad "behaviour". Triad avoidance levels were lower than in previous years (maximum estimated avoidance level stands at 1.7GW) and they occurred over a tighter time window, e.g. two settlement periods rather than 4 to 5 settlement periods. As shown in Figure 10, the three triad dates for winter 2020/21 strongly correlated with the days when there were low temperatures over the winter.

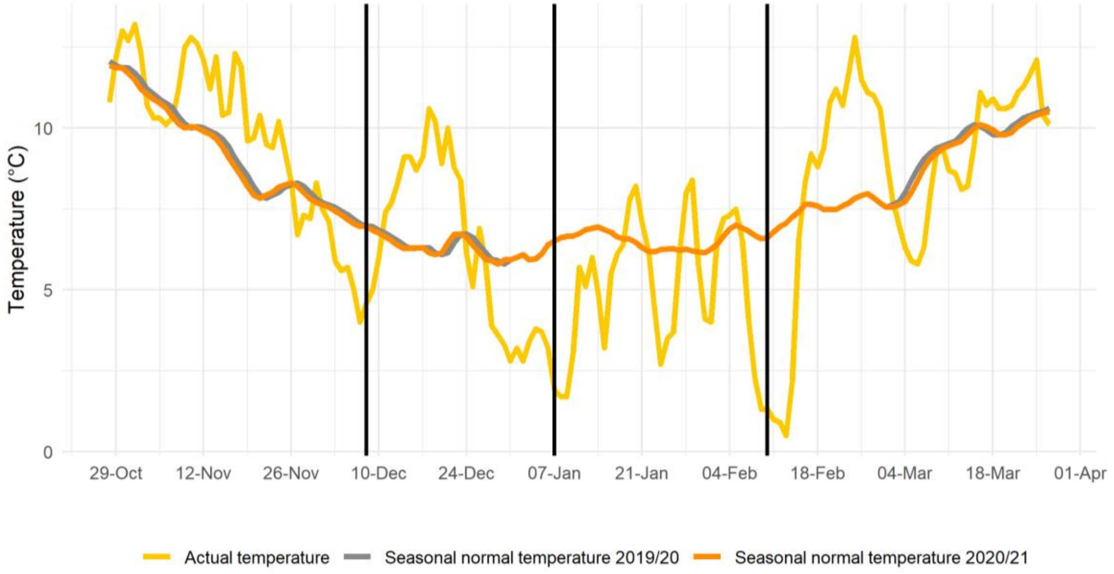


Figure 10. Daily actual and seasonal normal temperature for winter 2019/2020 and 2020/21 alongside the date of the three triads (three vertical black lines)

What we said in the *Winter Outlook Report*	What triad avoidance occurred (estimation)	Why was there a difference?
Maximum forecast triad avoidance: 2.2 GW	The values corresponding to the three triad dates (operational view) were 0 GW, 0.6 GW and 1.7 GW (see Table 9). The values corresponding to the three triad Demand dates (settlement view) were 0 GW, 0.3 GW and 1.3 GW (see Table 10).	Demands were suppressed due to the pandemic - and it was unknown at the beginning of November if there was going to be future lockdowns and if so, what type would they be. These are likely to have influenced the triad activity levels. In relation to the 7th & 8th December, our assessment of the triad avoidance shows that there was a limited activity in December, with the majority of the avoidance and the highest volume of it occurring in January and February. This could indicate that the triad avoidance providers were initially expecting higher demands in January and February (after Christmas period) as they were not anticipating another lockdown.

Table 8. Triad avoidance commentary for winter 2020/21

Date	Time Half hour ending	National Demand (MW)	Estimated* triad avoidance (HH corresponding with the peak) (MW)
08/12/20	1730	45986	0
07/01/21	1730	46433	600
10/02/21	1800	46179	1700

Table 9. Details of triads for winter 2020/21 (Uses **operational metering** and **national demand** definition)

Date	Time Half hour beginning	Settlement Demand (MW)	Estimated* triad avoidance (HH corresponding with the peak) (MW)
07/12/20	1700	44353	0
07/01/21	1730	45328	300
10/02/21	1800	44914	1300

Table 10. Details of **triad demands** for winter 2020/21(**settlement metering**)

* The triad avoidance estimate is not based on demand reduction data provided to us by suppliers, customers or aggregators.

Review / electricity supply

	What we said in the *Winter Outlook Report*	What actually happened	Why was there a difference?
Clean spark spreads vs. clean dark spreads*	Gas to be ahead of coal in generation running order, based on current forward prices.	Outturn was generally in line with expectations, but the difference between clean dark and clean spark spreads was tighter than the previous winter (see Figure 11).	Periods of system stress, and resulting high electricity prices, influenced the relative tightness between the clean dark and spark spreads this winter. We saw spikes of up to £253/MWh for coal on 13/01 for example.
Breakdown rates (this term covers all aspects of plant reliability, including restrictions and unplanned generator breakdowns).	Generator reliability to be in line with recent winters – we have not been made aware of significant impacts on maintenance due to COVID. Breakdown rates are expected to range from 2% for pumped storage to 8% for hydropower, 5% for CCGT and 9% for both coal and nuclear.	Breakdown rates (where by breakdown we mean outages that were not notified in advance of the outage, and does not include planned unavailability) on average across the winter as a whole were largely in line with expectations – deviating from a small range of between 1 and 4% in most cases (see Table 12). However, the breakdown rate for coal was much higher than forecast, at 14%. Nuclear was as anticipated, at 9% breakdown rate overall (although availability was lower in the post-Christmas period).	The difference between forecast and actual breakdown rates for coal and thermal units is not fully known, but may be related to changed usage patterns over the preceding summer.

Table 11. Electricity supply commentary for winter 2020/21

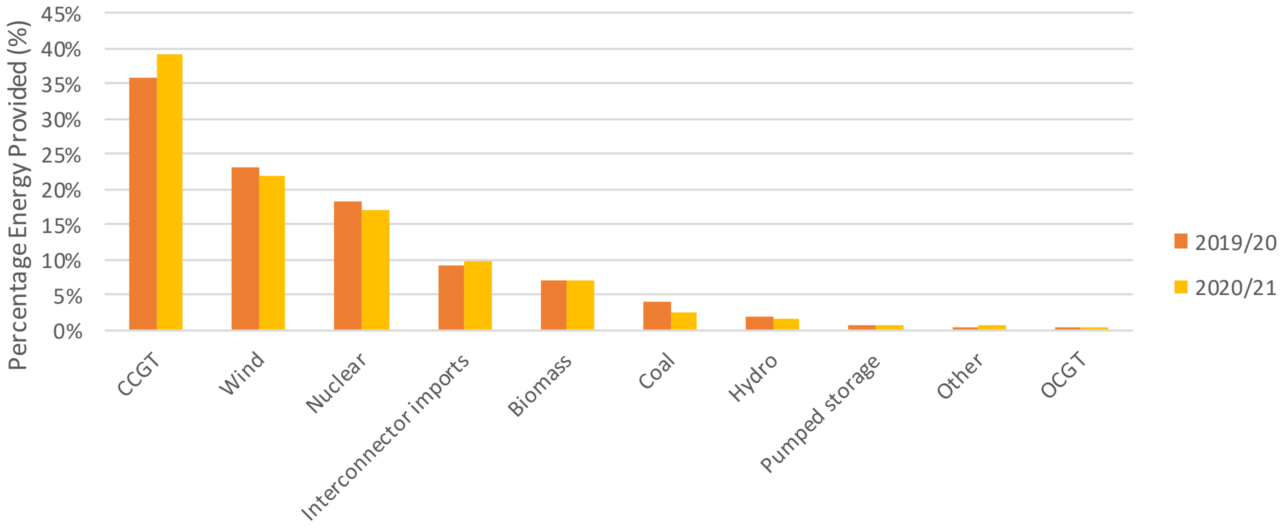


Figure 11. Percentage energy provided by each fuel type over Winter 2019/20 and Winter 2020/21 (transmission connected)

Fuel Type	Forecast	Actual
Coal	9%	14%
CCGT	5%	8%
Nuclear	9%	9%
OCGT	5%	6%
Pumped Storage	2%	5%
Biomass	3%	7%
Hydro	8%	11%

Table 12. Breakdown rates by fuel type for winter forecast and actual winter.

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

Review / Europe and interconnected markets

	What we said in the *Winter Outlook Report*	What actually happened	Why was there a difference?
Physical capabilities	There are no planned outages for any of the interconnectors connected to Great Britain over the winter. These cover: IFA, BritNed, Nemo, EWIC and Moyle.	BritNed was offline for significant periods – December to February and again from early March. Other than minor issues, the other interconnectors ran as planned. IFA2 was not included in margin calculations but became available over the winter.	Unplanned outages impacted interconnector availability.
European forward prices	Forward prices in GB to be ahead of those in continental Europe for the majority of the winter period. There may be some occasions when we see exports to continental Europe, however this is unlikely during peak times and should GB experience some stress periods, we would expect GB prices to escalate and interconnectors to import.	For most of the winter, forward prices in Continental Europe were lower than GB (see Figure 12), meaning that we saw a net flow of electricity from the Continent to GB as expected. There are some notable instances, particularly in January 2021, where GB baseload prices were particularly high.	N/A
Network access constraints	Planned French nuclear outages for this year are higher than the previous winter, however with GB forward prices ahead of those in France we expect imports to continue, particularly during peak times.	This was in line with expectations.	N/A

Table 13. Europe and interconnected markets commentary for winter 2020/21

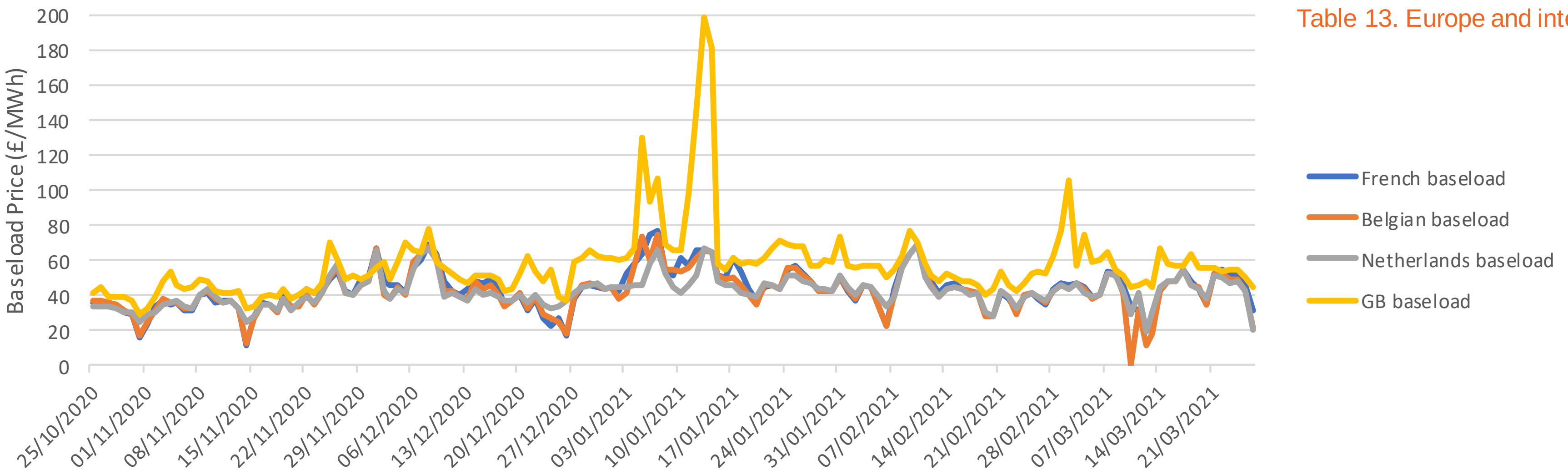


Figure 12. GB and European baseload prices for winter 2020/21

The Data Workbook contains further detail on:

- Interconnector outages;
- specific interconnector behaviour; and
- French nuclear outages.

Review / Europe and interconnected markets

	What we said in the *Winter Outlook Report*	What actually happened	Why was there a difference?
Overview of continental European interconnectors (BritNed, IFA, IFA2, NEMO Link)	We expect imports into GB at peak times from France, the Netherlands and Belgium under normal network operating conditions. Occasionally, these may not be at full import due to weather variations, which could push demands higher during cold spells or affect renewable generation.	Peak flows were largely as expected –IFA, BritNed and Nemo Link imported to the extent that they were available throughout the winter (see Figure 13).	N/A
	The flow over the new IFA2 is expected to be similar to the IFA interconnector, depending on the outcome of the planned commissioning work. Once in service, it's expected to provide an additional 1 GW of capacity between GB and French markets.	IFA2 began running on 23/01/21.	N/A
Overview of Irish interconnectors (Moyle and EWIC)	We expect GB to export to Northern Ireland and Ireland during peak times on Moyle and EWIC interconnectors. They may be reversed during periods of high wind and system stress.	Both Moyle and EWIC exported electricity to Northern Ireland at peak times for the majority of the winter (see Figure 14). On days with EMNs, with the exception of 4 November, flows were generally towards GB, driven by higher GB prices.	N/A

Table 14. Europe and interconnected markets commentary for winter 2020/21

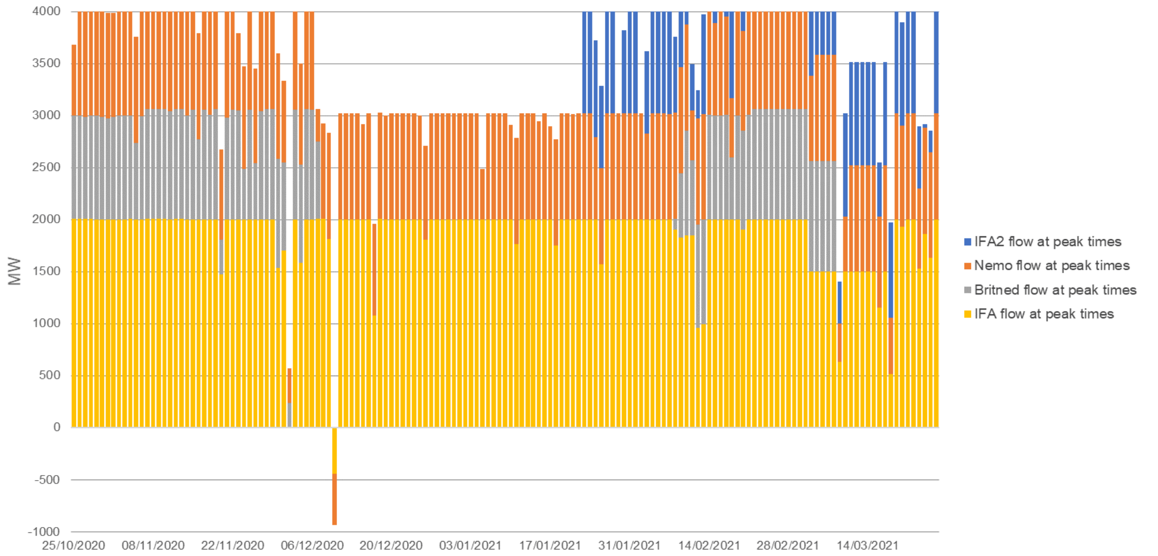


Figure 13. IFA, IFA2, BritNed, and Nemo Link flow at peak times

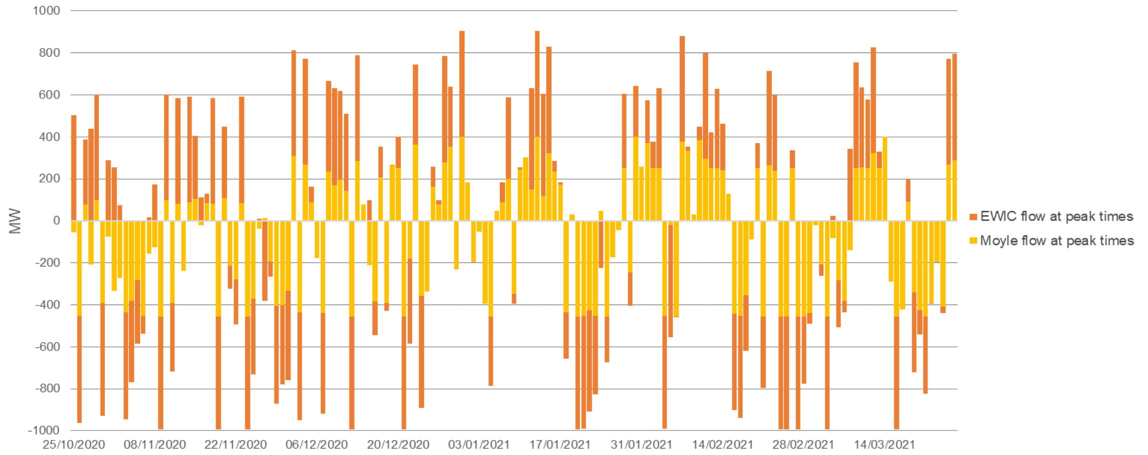


Figure 14. Moyle and EWIC flows at peak times

Review / Operational view – transmission system

Demand suppression due to the COVID-19 pandemic persisted over the Winter months. However the lowest level of suppression is seen at the peak demand of the day which resulted in tight margin conditions for instances where high demand coincided with low wind and solar output. We took action across the five core areas to ensure operational security over the winter period.

Thermal

There were high volumes of planned outages required over the Winter period following delays to a high volume of works during the COVID-19 lockdown. This was managed in an agile manner alongside the operability of the network during Winter.

The full capability of the Western High Voltage (HVDC) link (2.25GW) was not able to be utilised due to the delayed return of the Hunterston power station, however, no operability issues relating to the import of energy into Scotland were experienced due to the network configuration and generation outturn. The Western HVDC link itself was available for the majority of the Winter period except for a 4 week period in February/ March.

IFA2 has now commissioned and connected and offered commercial capacity to the market. However, BritNed remained unavailable for the majority of the Winter period.

Stability

We continued to experience low inertia periods on the system, albeit to a lesser extent during the traditionally higher demand months, and we took bids and offers as required to manage these. Critical work continued to be accelerated by the Distribution Network Owners to move smaller generation to new protections settings. This reduces the need and cost to manage system stability using operational tools. Find out more here. Over the last few months we have experienced a growing number of instances whereby generation or network licensees' assets have failed to 'ride through' faults on the National Electricity Transmission System (NETS). We have issued an open letter to industry detailing our next steps.

Frequency

Dynamic Containment went live in the early part of Winter and is a key service to contain frequency within statutory limits in a range of system conditions and for a range of loss-sizes. The service has been further developed through the Winter and this will continue over the coming months.

We have consulted on our Frequency Risk and Control Report (FRCR) which will now be implemented through the coming months.

Restoration

Our Restoration capability was maintained over the Winter period as per our requirement.

Voltage

Actions required to synchronise machines to manage reactive power and voltage levels continued to be required, particularly during lower demand periods over the winter.

Contracting units to be generating (and therefore providing reactive power) ahead of time alongside trading and Balancing Mechanism actions were the main approaches used to manage voltage over the winter.

Review / Operational view

Services

We are currently transitioning our frequency market, introducing both new products and moving our procurement closer to real time. This will ensure we have the right tools in place to operate a low carbon system with procurement mechanisms that maximise competition and maximise consumer value.

In October 2020 we introduced the first of our enduring response products with the launch of Dynamic Containment (DC) Low Frequency (LF). Launching this fast acting response product also gave the opportunity to move our procurement closer to real time. To enable a soft launch for DC, 24 hour contract windows were initially implemented as part of day ahead procurement, whereby providers can offer a fixed volume at a single availability price for the entire period.

Volumes of DC grew throughout the Winter with 80% of the volume offered being accepted for 92% of the time. There were 9 instances where a significant proportion of the market withdrew and was rejected due to price from DC LF (more than 100 MW). The highest recorded volume withdrawn was 403 MW on 3rd March which coincided with tight margin conditions (caused by very low winds and lower temperature). This was likely due to providers optimising their assets in markets offering better prices for periods of that day.

Procuring DC in 24 hour contract windows limits the ESO's ability to signal the value of DC across a day, as system conditions such as demand, inertia and largest loss risks may change across a day, and risks increasing the cost to consumers as providers price in lost opportunity costs due to locking themselves out of other markets for an entire day. We are seeking to implement more granular procurement to address this and have recently consulted on our plans to implement EFA block contract lengths later this summer.

Constraints

The volume of system access required and the operability challenges with allowing access to some key areas of the network have increasingly meant that outages are being planned year round rather than focusing on the Summer outage season.

The outage plan for the year included a number of schemes to facilitate new generation connections and network upgrades. The B7a boundary was particularly impacted due to a long programme of outages to install Smartwires technology which significantly reduced the boundary capacity. High wind levels, particularly at the end of October and through November, with the reduced boundary capacity, resulted in very large volumes of constraint management action being taken.

The Western Link HVDC fault in mid February resulted in a much larger volume of constraint management action being required to manage the B6 boundary. The fault was coincident with a high wind period and lasted until mid March.

Review / Operational view

Day Ahead and Within Day prices

During periods of tight system margins, energy prices increase to reflect the scarcity of the resource. Over the winter, Day Ahead and In Day prices were high for the peak of the day whenever margins were tight, and particularly when we had issued an Electricity Margin Notice (EMN). Figure 15 shows an example of this happening on a day when an EMN was issued (6 December) in comparison with the same day the following week (13 December).

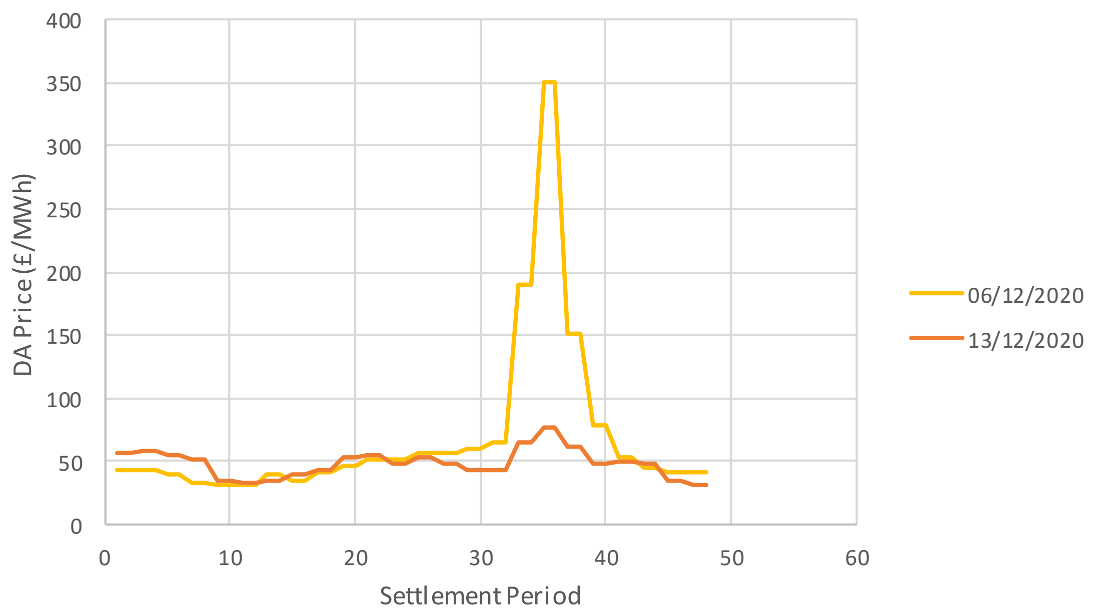


Figure 15. Day ahead price comparison for 6 December (EMN) and 13 December

Margin cost

During the Winter period, we experienced a number of tight margin days and we issued six EMNs. As expected, the high energy prices resulted in high offer prices available to the ESO to synchronise generation. Therefore, operating reserve costs rose significantly over the winter due to the tight margins experienced. Figure 16 shows the £/MWh cost for the ESO to buy margin for each month of the year.

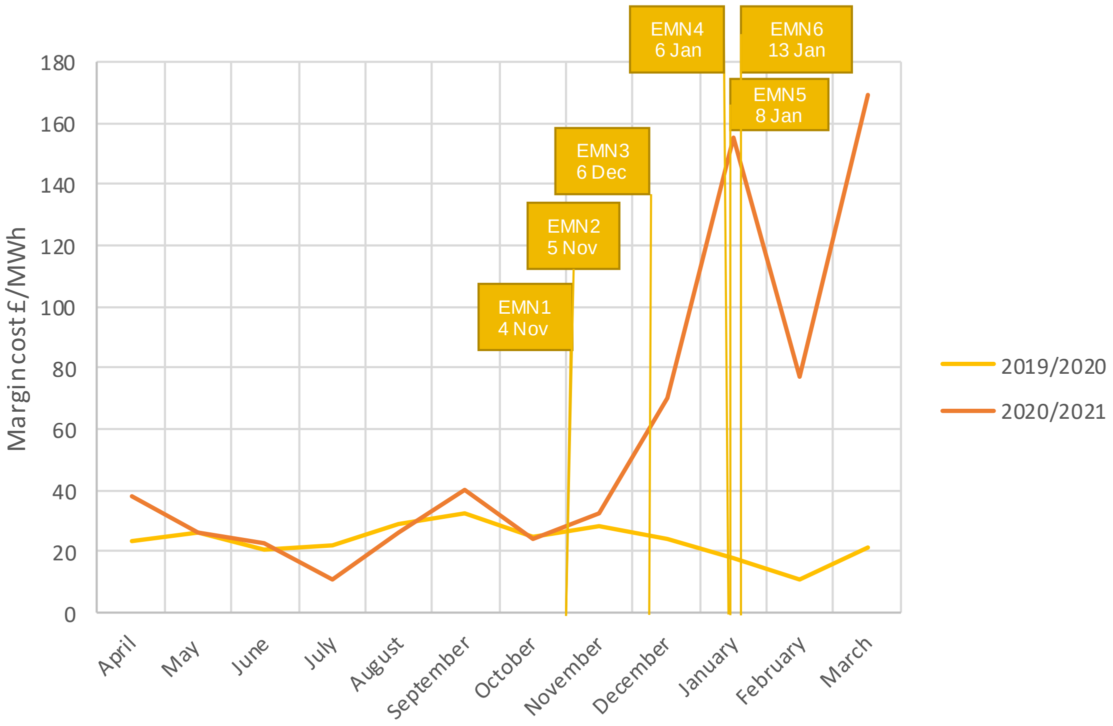


Figure 16. Cost for the ESO to buy margin over the winter

nationalgridESO

Review / Operational view

Wholesale market prices

The chart below shows the electricity wholesale market prices during the winter period. Days of particularly high prices tended to align with the days when EMNs were issued, although this is not the case for the whole winter period, as shown by price spikes from late January to March (see Figure 17). This was linked to the high System Prices on these days caused by high offer prices having to be taken in the Balancing Mechanism.

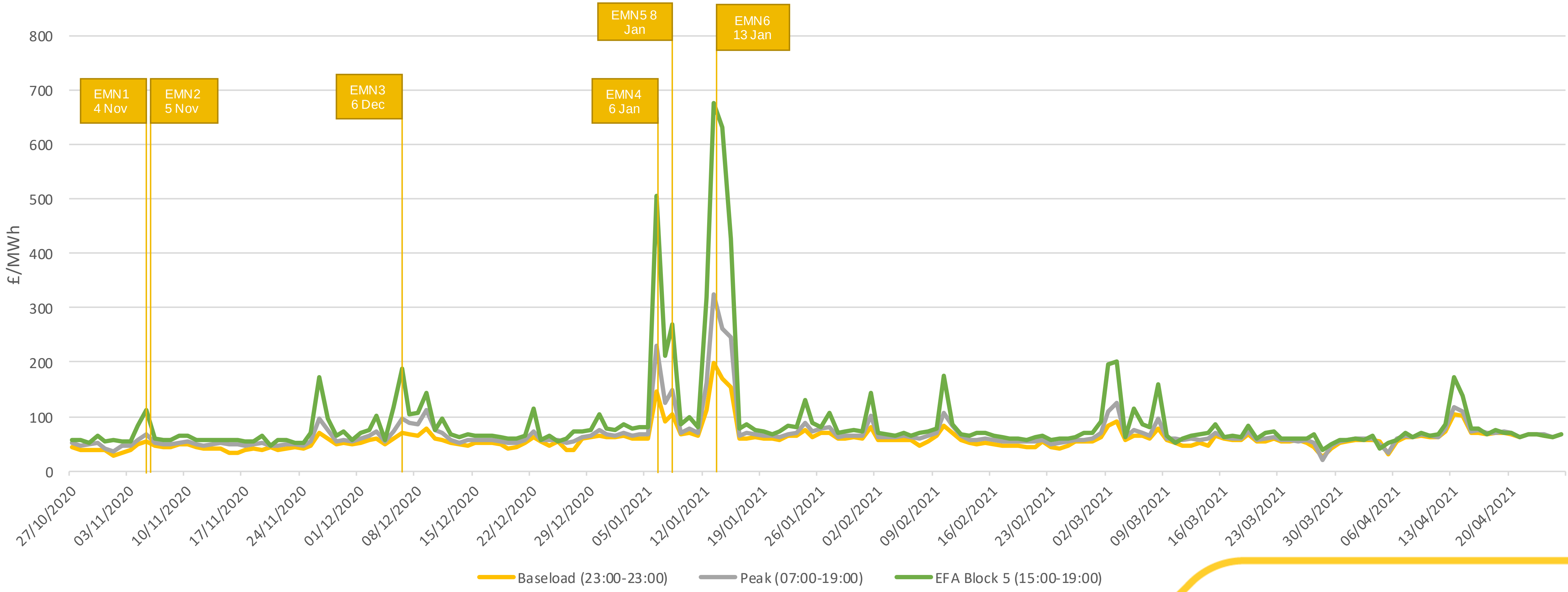


Figure 17. N2EX Wholesale market prices on days when EMNs issued

Consultation / Introduction

The purpose of this annual consultation is to gather stakeholder insight each year to inform our analysis for the upcoming *Winter Outlook Report*, to be published in October 2021.

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

This year, we have also included questions on proposed new ESO approaches to winter outlook processes to ensure that any potentially relevant impacts are reflected in our planning.

It also allows us to test how useful the suite of Outlook documents are and to identify areas for improvement with our engagement.

This year's consultation closes on 30 July 2021.

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

On 30 June, the ENCC Operational Transparency Forum will feature the topic of 'winter readiness', where you can also share your views on the winter ahead and ask us questions. Please register here.

Consultation / Questions

Winter 2021/22 preparations

1. Is there anything you would like to share with us on your preparations for the forthcoming winter period? For instance, to what extent have your preparations been impacted by COVID-19 and related restrictions?

2. Do you foresee any challenges in fulfilling your role in the energy system this winter, for example, in relation to:
   - plant reliability;
   - outage planning;
   - European price spreads;
   - COVID-19;
   - delays to commissioning new capacity; or
   - the UK's exit from the European Union?

3. Do you have any other comments in relation to winter 2021/22 in relation to electricity demand, supply or operability?

Triad avoidance

4. Did you or your customers participate in triad avoidance over the winter 2020/21, and what were your primary reasons for doing so?

5. Do you think that the peak level of triad avoidance will increase or decrease in winter 2021/22, and what do you think the reason will be for this change (e.g. COVID-19)?

Winter Review and Consultation

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

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

8. How do you think the *Winter Review and Consultation Report* could be improved to increase benefit for consumers?

9. Do you have any other feedback on this report or the other Outlook documents?

Winter Outlook Report

10. Do you have any comments on the revised methodology for "operational margin" calculations due to be published in the upcoming *Winter Outlook Report*? (see slide 12 for further detail)

11. Do you have any comments on the new approach to reserve setting? (see slide 12 for further detail)

12. Do you have any comments on "CM margin" signals or engagement on winter margins more broadly? (see slide 13 for further detail)

13. Do you have any views on the use of Electricity Margin Notices (EMNs) and Capacity Market Notices (CMNs) as tools to signal potentially tight periods across the winter? (see slide 13 for further detail)

14. Is there anything different you would like to see in the *Winter Outlook Report*, to be published in October 2021?

Appendix – contains extra information on EMNs and demand definitions

EMN Case Studies / 4th & 5th November 2020

On the 4th and 5th November 2020, demands were forecast to be **43.2GW** and **43.1GW** respectively (much higher than can be seen from the green bars in the *Winter Outlook Report* chart – Figure 1 in this publication - which assume average weather conditions). Wind generation was also forecast to be at lower-than-expected levels.

Unplanned generation outages were slightly higher than expected for the time of year, but well within the range of variability for this time of year.

Although network reconfiguration and circuit rating enhancements could alleviate some of the active constraints on the system, there remained some generation constrained by circuit outages on the Scottish network. The tightness of margin for 4th and 5th November were consistently forecast from 30th October onwards. EMNs were cancelled on both days ahead of each darkness peak as the contingency requirement moved to zero as we approached real-time operation.

Day ahead prices reached **£132/MWh** on 4 November and **£192/MWh** on 5 November, with comparable intraday prices. Analysis of the underlying basic demand used by the demand forecast models shows that there was no detectable price response in the distributed generation market. This could either be because distributed generators were not expecting to be called upon, and generation was not ready to run, or because in recent days all available generation had been running over the peak, and there was no extra pool of generation to draw on.

Settlement Period	CET/CEST Time	Price (£/MWh)
00 - 01	23 - 00	36.92
01 - 02	00 - 01	36.67
02 - 03	01 - 02	36.95
03 - 04	02 - 03	34.20
04 - 05	03 - 04	28.93
05 - 06	04 - 05	30.97
06 - 07	05 - 06	38.08
07 - 08	06 - 07	43.29
08 - 09	07 - 08	46.33
09 - 10	08 - 09	50.54
10 - 11	09 - 10	50.90
11 - 12	10 - 11	41.10
12 - 13	11 - 12	40.70
13 - 14	12 - 13	40.50
14 - 15	13 - 14	40.58
15 - 16	14 - 15	41.36
16 - 17	15 - 16	43.09
17 - 18	16 - 17	56.00
18 - 19	17 - 18	132.00
19 - 20	18 - 19	99.91
20 - 21	19 - 20	63.00
21 - 22	20 - 21	46.60
22 - 23	21 - 22	37.00
23 - 00	22 - 23	32.44

Table 15. Day ahead auction prices on 04/11/20 from the N2EX dataset

Settlement Period	CET/CEST Time	Price (£/MWh)
00 - 01	23 - 00	43.27
01 - 02	00 - 01	36.42
02 - 03	01 - 02	34.00
03 - 04	02 - 03	31.89
04 - 05	03 - 04	28.09
05 - 06	04 - 05	30.79
06 - 07	05 - 06	34.40
07 - 08	06 - 07	40.96
08 - 09	07 - 08	43.44
09 - 10	08 - 09	50.00
10 - 11	09 - 10	50.36
11 - 12	10 - 11	44.00
12 - 13	11 - 12	39.66
13 - 14	12 - 13	42.80
14 - 15	13 - 14	42.99
15 - 16	14 - 15	42.00
16 - 17	15 - 16	49.75
17 - 18	16 - 17	60.00
18 - 19	17 - 18	192.25
19 - 20	18 - 19	150.00
20 - 21	19 - 20	66.20
21 - 22	20 - 21	45.10
22 - 23	21 - 22	44.90
23 - 00	22 - 23	39.60

Table 16. Day ahead auction prices on 05/11/20 from the N2EX dataset

EMN Case Study / 6th December 2020

A third EMN was issued for the darkness peak on Sunday 6th December 2020. Historically, it is highly unusual to have tight margins over a weekend. Like the previous two EMNs, higher than expected demand and low wind were drivers but additionally there was lower Balancing Mechanism generation availability too as some power stations continued to take weekend outages. Lower than average temperatures resulted in demand forecasts of **44GW** and wind generation was at extremely low levels.

Unplanned generation outages were at the high end of normal variability for the time of year, but again, within the range of variability we have seen over the past five years.

No generation was constrained on the GB network, there were minimal exports on the Irish interconnectors and continental interconnectors were importing. The tightness of margin was consistently reported from 1st December onwards, with the impact increasing day on day as the wind forecast was consistently revised downwards. The EMN was cancelled ahead of the darkness peak as the situation improved and contingency margin requirement reduced. The demand outturn was in line with forecasts indicating minimal price response from other distribution connected generators and high Balancing Mechanism prices were setting imbalance prices up to **£720/MWh**.

Day ahead prices peaked at **£350/MWh** on 6 December, and intraday prices at **£380/MWh**. Analysis of the underlying basic data showed no evidence of price response from distributed generators, although increased uncertainty in level of Sunday peak demand, coupled with the effects of the recent lifting of the lockdown may have partially masked this. The demand forecast did not factor in any allowance for price response and was 100MW below the outturn. Any under forecast, however slight, does not give any evidence for demand suppression driven by price.

Settlement Period	CET/CEST Time	Price (£/MWh)
00 - 01	23 - 00	44.55
01 - 02	00 - 01	43.05
02 - 03	01 - 02	42.54
03 - 04	02 - 03	39.57
04 - 05	03 - 04	33.00
05 - 06	04 - 05	31.25
06 - 07	05 - 06	31.98
07 - 08	06 - 07	39.53
08 - 09	07 - 08	34.80
09 - 10	08 - 09	41.86
10 - 11	09 - 10	46.27
11 - 12	10 - 11	50.82
12 - 13	11 - 12	51.62
13 - 14	12 - 13	56.92
14 - 15	13 - 14	56.89
15 - 16	14 - 15	60.82
16 - 17	15 - 16	65.00
17 - 18	16 - 17	189.96
18 - 19	17 - 18	350.00
19 - 20	18 - 19	150.49
20 - 21	19 - 20	77.80
21 - 22	20 - 21	53.68
22 - 23	21 - 22	44.73
23 - 00	22 - 23	42.02

Table 17. Day ahead auction prices on 06/12/20 from the N2EX dataset

EMN Case Study / 6th January 2021

A fourth EMN was issued for the darkness peak on Wednesday 6th January 2021. Lower than average temperatures (approx. 2°C) resulted in a high demand forecast of **46.4GW** (including **1.5GW** of customer response demand reduction due to an expected triad) and wind generation was at low levels.

Unplanned generation outages were at the high end of normal variability for the time of year, but again, within the range of variability we have seen over the past five years.

No generation was constrained on the GB network, the Irish interconnectors were partially importing, and the continental interconnectors were fully importing. The tightness of margin was consistently reported from 1st January onwards. The EMN was cancelled ahead of the darkness peak as the situation improved and contingency margin requirements reduced. The demand outturn was in line with forecasts which included approx. **1.5GW** of customer response demand reduction. Analysis of the underlying basic data showed approx. **1.6GW** of customer response demand reduction on 6th January which was close to expected as it was a forecast triad.

Day ahead prices peaked at **£1000/MWh** on 6th January. High Balancing Mechanism prices were setting imbalance prices of up to **£1000/MWh**.

Settlement Period	CET/CEST Time	Price (£/MWh)
00 - 01	23 - 00	46.49
01 - 02	00 - 01	46.41
02 - 03	01 - 02	45.99
03 - 04	02 - 03	42.41
04 - 05	03 - 04	41.55
05 - 06	04 - 05	42.59
06 - 07	05 - 06	48.00
07 - 08	06 - 07	55.03
08 - 09	07 - 08	57.63
09 - 10	08 - 09	75.00
10 - 11	09 - 10	96.60
11 - 12	10 - 11	99.30
12 - 13	11 - 12	97.59
13 - 14	12 - 13	128.47
14 - 15	13 - 14	103.88
15 - 16	14 - 15	90.39
16 - 17	15 - 16	75.00
17 - 18	16 - 17	563.04
18 - 19	17 - 18	1000.04
19 - 20	18 - 19	383.28
20 - 21	19 - 20	156.74
21 - 22	20 - 21	80.30
22 - 23	21 - 22	55.06
23 - 00	22 - 23	51.06

Table 18. Day ahead auction prices on 06/01/21 from the N2EX dataset

EMN Case Study / 8th January 2021

A fifth EMN was issued for the darkness peak on Friday 8th January. Lower than average temperatures (approx. 2°C) resulted in a high demand forecast of **46.2GW** and wind generation was at very low levels.

Unplanned generation outages were at the high end of normal variability for the time of year, but again, within the range of variability we have seen over the past five years.

No generation was constrained on the GB network, the Irish interconnectors were partially importing, and the continental interconnectors were fully importing. The tightness of margin was consistently reported from 1st January onwards. The EMN was cancelled ahead of the darkness peak as the situation improved and contingency margin requirements reduced. The demand outturn was in line with forecasts. The demand forecast from Energy Forecasting did not factor in any allowance for price response and was approx. 700MW below the outturn.

Day ahead prices peaked at **£670/MWh** on 8th January. High Balancing Mechanism prices were setting imbalance prices of up to **£4000/MWh**.

A CMN was also issued for 8th January 2021 (as well as the one on 3rd December 2020).

Settlement Period	CET/CEST Time	Price (£/MWh)
00 - 01	23 - 00	56.62
01 - 02	00 - 01	55.52
02 - 03	01 - 02	51.59
03 - 04	02 - 03	48.75
04 - 05	03 - 04	46.98
05 - 06	04 - 05	46.94
06 - 07	05 - 06	52.45
07 - 08	06 - 07	58.56
08 - 09	07 - 08	78.17
09 - 10	08 - 09	89.73
10 - 11	09 - 10	92.94
11 - 12	10 - 11	93.85
12 - 13	11 - 12	93.14
13 - 14	12 - 13	89.77
14 - 15	13 - 14	87.49
15 - 16	14 - 15	84.22
16 - 17	15 - 16	81.74
17 - 18	16 - 17	163.30
18 - 19	17 - 18	670.39
19 - 20	18 - 19	167.31
20 - 21	19 - 20	90.73
21 - 22	20 - 21	75.68
22 - 23	21 - 22	62.11
23 - 00	22 - 23	59.44

Table 19. Day ahead auction prices on 08/01/21 from the N2EX dataset

EMN Case Study / 13th January 2021

A sixth EMN was issued for the darkness peak on Wednesday 13th January. Lower than average temperatures resulted in a demand forecast of **45.4GW** and wind generation was at very low levels.

Unplanned generation outages were at the high end of normal variability for the time of year, but again, within the range of variability we have seen over the past five years.

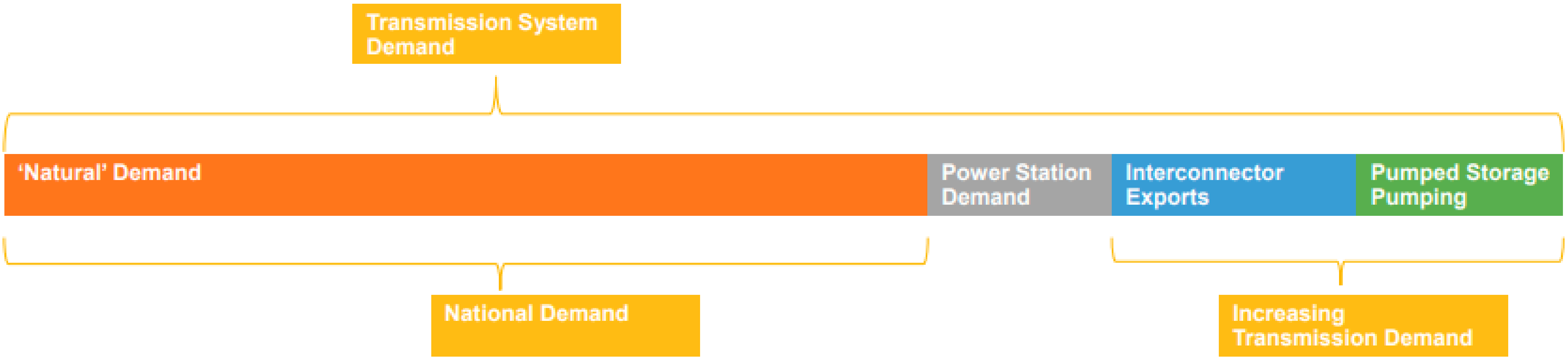
No generation was constrained on the GB network, the Irish and continental interconnectors were fully importing. The tightness of margin was consistently reported from 8th January onwards. The EMN was cancelled ahead of the darkness peak as the situation improved and contingency margin requirements reduced. The demand outturn was in line with forecasts. The demand forecast from Energy Forecasting did not factor in any allowance for price response.

Day ahead prices peaked at **£1,500/MWh** on 13th January. High Balancing Mechanism prices were setting imbalance prices of up to **£990/MWh**.

Settlement Period	CET/CEST Time	Price (£/MWh)
00 - 01	23 - 00	66.51
01 - 02	00 - 01	65.09
02 - 03	01 - 02	61.58
03 - 04	02 - 03	60.59
04 - 05	03 - 04	59.02
05 - 06	04 - 05	58.09
06 - 07	05 - 06	60.50
07 - 08	06 - 07	66.53
08 - 09	07 - 08	66.53
09 - 10	08 - 09	88.65
10 - 11	09 - 10	142.16
11 - 12	10 - 11	167.70
12 - 13	11 - 12	199.93
13 - 14	12 - 13	195.60
14 - 15	13 - 14	167.28
15 - 16	14 - 15	145.59
16 - 17	15 - 16	103.18
17 - 18	16 - 17	411.61
18 - 19	17 - 18	1499.62
19 - 20	18 - 19	694.54
20 - 21	19 - 20	175.19
21 - 22	20 - 21	99.99
22 - 23	21 - 22	60.52
23 - 00	22 - 23	54.98

Table 20. Day ahead auction prices on 13/01/21 from the N2EX dataset

Demand Definitions



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 if required.

Glossary

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

Breakdown rates
A calculated value to account for unexpected generator unit breakdowns, restrictions or losses. Forecast breakdown rates are applied to the operational data provided to the ESO by generators. They account for restrictions and unplanned generator breakdowns or losses close to real time. Rates are based on how generators performed on average by fuel type during peak demand periods (7am to 7pm) over the last 3 winters.

BritNed
BritNed Development Limited is a joint venture between Dutch TenneT and British National Grid that operates the electricity interconnector between Great Britain and the Netherlands. BritNed 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. This is achieved by providing a payment for reliable sources of capacity, alongside their electricity revenues, ensuring they deliver energy when needed.

Carbon intensity
A way of examining 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.

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. Generation that is connected to the distribution system is not usually directly visible to National Grid ESO as the system operator and acts to reduce demand on the transmission system.

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/.

Electricity Forward Agreement (EFA)
EFA blocks are a product used to trade electricity on the wholesale market. There are 6 EFA blocks in a baseload day. EFA5 (15:00 – 19:00) contains the Darkness Peak in winter.

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.

Glossary

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

Forward prices
The predetermined delivery price for an underlying 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.

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

Interconnexion France–Angleterre (IFA)
A 2,000 MW link interconnector between the French and British transmission systems. Ownership is shared between National Grid and Réseau de Transport d'Electricité (RTE).

Interconnexion France–Angleterre (IFA)
A 1000 MW link between the French and British transmission systems (commissioned early 2021). Ownership is shared between National Grid and Réseau de Transport d'Electricité (RTE).

Inertia
System inertia is how resilient a system is to frequency change. System inertia will depend on what types of generation are connected to the system. Typically, generators with large moving parts have high inertia – because their moving parts continue to move even after they are switched off or turned down. In contrast, some types of generation that have no moving parts, such as solar panels, are classed as low inertia generation

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 due to commercial arrangements or technical reasons. Examples of inflexible generation include nuclear, combined heat and power (CHP) stations, and some hydro generators and wind farms.

Interconnector
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
An indication of how much a generation plant or technology type has output 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.

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

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

National electricity transmission system (NETS)
High voltage electricity is transported on the transmission system from where it is produced to where it is needed throughout 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, while the system as a whole is operated by a single Electricity System Operator (ESO).

Nemo Link
A 1000MW interconnector between GB and Belgium. Ownership is shared between National Grid and Elia.

Positive and negative reserve
To manage system frequency and to respond to sudden changes in demand and supply, the ESO maintains positive and negative reserve which is the capability to increase or decrease supply and demand.

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.

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

You can write to us at:
Energy Insights and Analysis, Electricity System Operator
Faraday House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

The *Winter Review and Consultation Report* is part of a suite of documents prepared by the Electricity System Operator on the future of energy. They inform the energy debate and are shaped by feedback from the wider industry. Visit our website for more information.

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