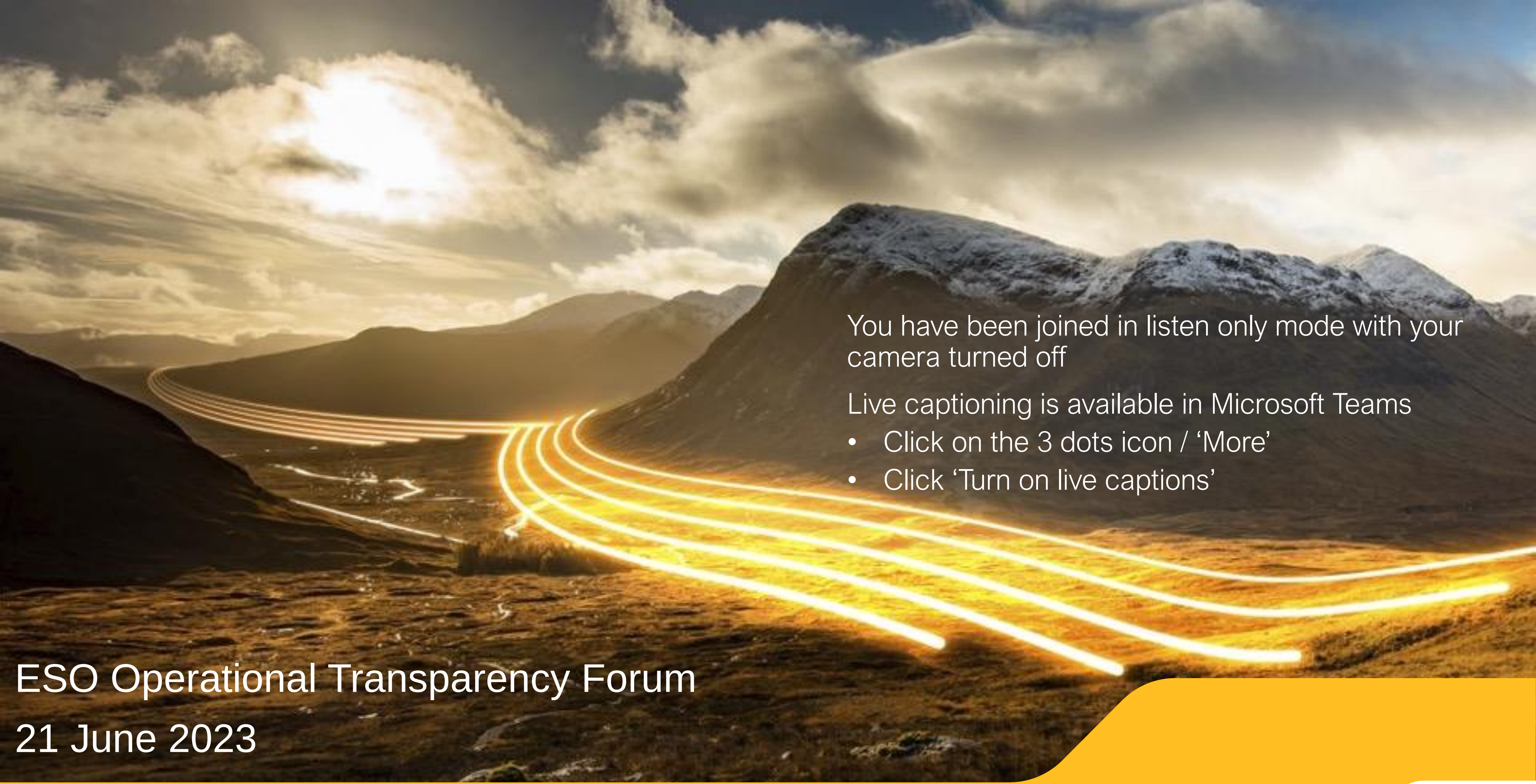

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ESO Operational Transparency Forum

21 June 2023

Introduction | Sli.do code #OTF

Please visit www.sli.do and enter the code #OTF to ask questions & provide us with post event feedback.

We will answer as many questions as possible at the end of the session. We may have to take away some questions and provide feedback from our expert colleagues in these areas during a future forum. **Ask your questions early in the session to give more opportunity to pull together the right people for responses.**

To tailor our forum and topics further we have asked for names (or organisations, or industry sector) against Sli.do questions. This is also helpful if we need to ask for more information before we can answer.
If you do not feel able to ask a question in this way please use the **Advanced questions** option (see below) or email us at: box.NC.Customer@nationalgrideso.com

These slides, event recordings and further information about the webinars can be found at the following location:

Advanced question can be asked here: https://forms.office.com/r/k0AEfKnai3

Stay up to date on our new webpage: https://www.nationalgrideso.com/OTF

Future deep dive / focus topics

Today - Key messages from the Winter 22/23 Review and Early View of Winter 23/24 reports (publication date 15 June)

28 June –Balancing Markets Cost Review for Winter 22/23

If you have suggestions for future deep dives or focus topics please send them to us at: .box.NC.customer@nationalgrideso.com and we will consider including them in a future forum

Sli.do code #OTF

Net Zero Market Reform webinar: conclusions from our assessment of investment policy support for net zero

Tuesday 4 July

09:30am – 12:30pm

Join us for:

- Conclusions from our assessment of investment policy options
- How investment policy could combine with reform of wholesale market design
- A dedicated panel discussion with industry experts
- Time for Q&A

Sign-up here

Your feedback will shape our final report, which will be published in the autumn.

If you have any questions, please email box.Market.Strategy@nationalgrideso.com. To keep up to date with the latest from the NZMR programme, do subscribe to our mailing list.

ESO

Balancing Reserve – Industry Webinar

Please join us for the Balancing Reserve Webinar on **28th June 2023 at 1pm UK time**.

The purpose of this webinar is to provide an overview of the Balancing Reserve project and provide further feedback subsequent to the ESO call for input on this topic.

We will also hold a Q&A session at the end of the presentation for any questions that you may have.

ESO **Industry Webinar - ESO Balancing Reserve**

Wed, 28 Jun, 13:00 - 14:00 BST

Online event

Link to register

Agenda

- Context for webinar & journey so far
- Feedback received as a result of call for information
- Summary of what we've been reviewing & latest thinking
- Timeline
- Q&A
- Next steps & close

NTC Commercial Compensation Methodology

The consultation is now open until **Monday 3rd July 2023 at 5pm**:

https://www.nationalgrideso.com/industry-information/codes/balancing-settlement-code-bsc/c16-statements-and-consultations#NTC-commercial-compensation-methodology-consultation

- The Commercial Compensation Methodology, which was developed in 2021, outlines the commercial arrangements for payments relating to interconnector capacity restrictions resulting from Net Transfer Capacity (NTC) restrictions set by ESO.
- The control room uses NTCs when needed to restrict the import and/or export capacity of interconnectors to maintain security of supply or due to thermal constraints or system margins.
- Because NTCs are not market-based, ESO requires a derogation from Ofgem against Standard Licence Condition (SLC) C28 to use them.
- Ofgem has granted ESO a derogation against C28, until 30th September 2023, to use NTCs. They have requested that in advance of that date we consult with stakeholders on the NTC commercial compensation methodology, to ensure that it is clear and fit for purpose.

Next Steps

- The consultation documents are available in the link above – including a cover note, the amended methodology (tracked changes and clean version) and a response pro-forma.
- Interested parties can respond to the consultation, using the response pro-forma, by Monday 3rd July 2023 at 5pm.

Capacity Market 2023 – Key Operational Dates

The EMRDB has produced the 2023 Capacity Market Operational Plan in consultation with OFGEM and DESNZ. The timeline is based on the Capacity Market Regulations and Rules and covers the T-1 2024/25 and T-4 2027/28 Auctions, and brings together Governmental and Delivery Partner milestones to provide a high-level overview of the steps involved in the operation of the Capacity Market.

Full details on our Operational Plan can be found on our website www.emrdeliverybody.com and are accessible through the CM Guidance Document Library, or via the Latest News on the front page:

Latest News

REFRESH

Register for EMR Customer Events - July 2023
published 20 Jun 2023

Join us for our 2023 Electricity Capacity Report (ECR) webinar on Thursday...
published 15 Jun 2023

Subscribe to our email platform
published 15 Jun 2023

Capacity Market Operational Plan for 2023/24
published 12 Jun 2023

EMR Customer Event - July 2023
published 8 Jun 2023

Milestone	Duration	Dates
Prequalification Submission Window	8 Weeks	26 July 2023 – 19 September 2023
Prequalification Assessment Window	6 Weeks	20 September 2023 – 31 October 2023
Tier 1 Disputes Submission Window	5 Working Days	01 November 2023 – 07 November 2023
Tier 1 Assessment Window	15 Working Days	08 November 2023 – 28 November 2023
Tier 2 Disputes Submission Window	5 Working Days	29 November 2023 – 05 December 2023
Tier 2 Disputes – Ofgem Assessment Window	20 Working Days*	06 December 2023 – 12 January 2024*
T-1 2024/25 Auction	2 Working Days	20 February 2024 – 21 February 2024
T-4 2027/28 Auction	2 Working Days	27 February 2024 – 28 February 2024

If you have queries regarding the operational plan, please get in touch:

Contact Details
EMR Delivery Body
Prequalification Team
email: Box.EMR.Prequal@nationalgrideso.com

Phone: 01926 655300 (option 1)

** While Ofgem will seek to make a decision within the timeframe provided, they may exceed this target if they determine that it is necessary.*

Winter Review 2022/23

Operational Transparency Forum
21 June 2023

ESO

Key Messages / Winter Review 2022-23

1. Margins

Winter margins were broadly in line with those of our Base Case from the *Winter Outlook Report* and there was no interruption to customer demand due to unavailable supply.

Winter 2022/23 was generally milder than average with three notable cold spells in December, January and March.

We issued one Electricity Margin Notice for 7th March, which was cancelled ahead of real-time. This was also the only day we dispatched coal contingency units.

Reciprocal support between European system operators helped maintain an efficient position across all markets, delivering benefits for us and our European neighbours. This led to periods of the winter when Great Britain exported power on interconnectors to Europe and periods when imports flowed from Europe when we needed them.

2. Demand

Electricity demand was lower than expected for most of the winter, except during the coldest spells.

Daily peak demand (weather-corrected) was generally lower than our central forecast and lower than comparable demand from the previous winter, as customers responded to high prices.

Peak demand during cold spells in December, January and early March was relatively high with little apparent reduction.

The highest observed peak demand of the winter was close to our average cold spell (ACS) peak forecast, indicating electricity customers prioritised their use of energy for the coldest days in winter.

3. Demand Flexibility Service

Our world-leading Demand Flexibility Service (DFS) delivered 3.3 GWh through consumer & business demand flexibility over the winter.

DFS demonstrated that demand flexibility can be provided at national-scale, allowing customers to benefit from shifting electricity usage away from specific periods.

Participation grew throughout winter with over 31 suppliers signing up, highlighting the potential for further growth of such services.

We used the service on two days in January and there were a further 20 tests of the service.

At its peak, DFS reduced electricity demand by around 300 MW when the service was used live.

4. Balancing costs

While balancing costs have reduced by 20% from the peak of winter 2021/22, this is still higher than previous years, driven principally by gas wholesale prices.

An independent Balancing Market Cost Report commissioned by the ESO reviewed balancing costs for winter 2022/23, considering the impact of different factors on balancing costs, including the drivers behind high cost days. The report is available on our website here.

The report found that tight margins were one of the factors that led to days with higher balancing costs. It also found that, in general, use of our enhanced actions did not lead to increased costs.

Review / Surplus

How did the winter compare to the Winter Outlook Report?

The daily operational surplus varied throughout winter in line with the credible range set out in our Base Case.

Figure 1 shows how the indicative outturn surplus (solid purple line) was broadly in line with the expected credible range (shaded red region) set out in the Winter Outlook Report.

The out-turn surplus was generally below the central forecast throughout November. This was due to net exports on the continental interconnectors, driven mainly by the availability of the French nuclear fleet returning from outages. Reciprocal support between European system operators maintained an efficient position across all markets. The out-turn surplus was more balanced for the rest of winter, with periods above and below our central forecast.

There were a small number of days where the indicative outturn surplus was outside the red-shaded region. This was around 10% of the days and consistent with the modelled 90% confidence bound.

The tightest days outside the lower bound were in late November, mid-December, and early March. These periods saw below average temperatures and low wind generation.

The days outside the upper bound were in late December, early January, and late March. These were periods of low demand, above average temperatures, and high wind generation.

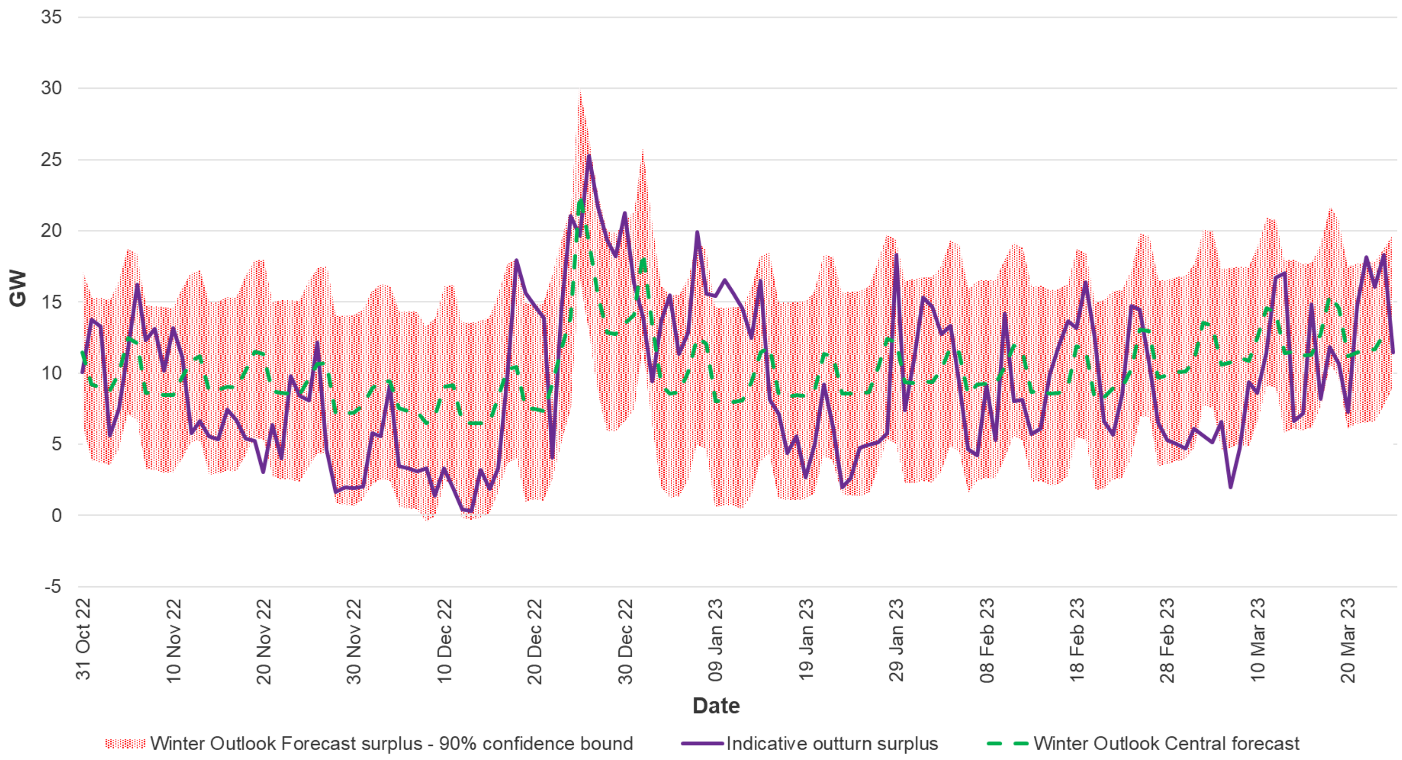

Figure 1. Day-by-day view of actual operational surplus for winter 2022/23 against the forecast surplus and credible range sensitivity from the Winter Outlook.

Interpreting this chart: Figure 1 shows the credible range of operational surplus that we expected on each day's demand peak throughout winter as published in the 2022/23 Winter Outlook Report. The credible range (red-shaded region) represents the 90% confidence bound reflecting day-to-day variations in weather and available generation. A central view (dashed green line) was also published in the Winter Outlook Report. The solid purple line shows an indicative view of the outturn operational surplus on each day.

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Review / Surplus
How did the winter compare to the *Winter Outlook Report*?

Margins were sufficient throughout the winter in-line with those expected in the Base Case from the *Winter Outlook Report*. On some tighter days margin notices and enhanced services were used to manage uncertainty.

There was one Electricity Margin Notice (EMN) issued in winter 2022/23 compared to none issued in winter 2021/22. There were two Capacity Market Notices (CMNs) issued, which is the same as the previous winter. The EMN and both CMNs were cancelled ahead of real-time. On each occasion when market notifications were issued, actual transmission system demand was lower than the actual winter peak transmission system demand (47.1 GW) shown in Table 2. This highlights how times when margins are tight do not necessarily occur on the days with the highest demand because shortfall of generation also needs to be accounted for. See Appendix B for more information on EMNs and CMNs.

Over the winter, the Operational Transparency Forum (OTF) featured deep dives on each of the days in Table 1. For more information, please see the OTF slides (or watch the recorded webinars here):

- CMNs: OTF on 30th November
- EMN: OTF on 15th March

Date	Day of week	EMN	CMN	Actual Peak Transmission System Demand (GW)
22nd Nov 2022	Tuesday	No	Yes	40.8
28th Nov 2022	Monday	No	Yes	40.1
7th Mar 2023 (issued 6th Mar)	Tuesday	Yes	No	42.6

Table 1: Days of EMNs and CMNs over Winter 2022/23 with actual peak Transmission System Demand (not weather corrected)

What we said in the *Winter Outlook Report*	What actually happened	Explanation
In the Base Case, we expect to have sufficient operational surplus throughout winter when routine tools such as margin notices are used. Tight margins to be likely throughout December to mid-January (excluding the Christmas period).	Operational surplus was sufficient throughout the winter and there was available supply from Europe when we needed it. Enhanced services were activated on a few days to manage uncertainty around interconnector flows and margins. The potential risk of reduced electricity imports from Europe and gas supply shortages (outlined in the illustrative scenarios in the *Winter Outlook Report*) did not materialise.	Throughout the winter the ESO took a collaborative approach to managing margins, working closely with neighbouring TSOs to provide reciprocal support. While the contingency coal units were warmed for 7 days across winter as a precaution, they were only run on 7th March. This is the same day an EMN was issued for. For more information on this event see the slides from the OTF on 15th March. Live Demand Flexibility Service (DFS) events were run on 23rd and 24th January to help manage uncertainty around interconnector flows. See more about DFS on page 8 and on the slides from the OTF on 25th January.

Review / Demand

The day-to-day peak demand was generally lower than the previous winter and the Winter Outlook central forecast. However, periods of cold, calm weather in December, January and March led to relatively high demand.

Due to the potential impact of high wholesale electricity prices, there was large uncertainty in the level of demand ahead of the winter. Figure 2 shows the outturn demand (weather corrected) was significantly lower than the previous winter (approximately 6% across winter). This is a result of increased embedded generation and a change in customer behaviour, likely due to price sensitivity.

Figure 3 shows that, in general, the outturn demand (solid purple line) was lower than our central forecast (dashed green line). However, periods of cold, calm weather in December, January and March led to relatively high demands (close to the top of the credible range (red shaded region) from the *Winter Outlook Report*). Milder, windier weather over the Christmas and New Year period led to relatively low demand.

The actual peak transmission system demand was 47.1 GW on 12th December as a result of much lower than seasonal normal temperatures and wind speeds.

Table 1 shows the actual weather corrected peak demand was lower at 44.2 GW which occurred in the week commencing 9th January.

2022/23 Winter Outlook Report forecast peak (normal weather) (GW)	Actual 2022/23 peak (weather corrected) (GW)	Actual 2022/23 peak (GW)
45.3	44.2	47.1

Table 1: Peak transmission system demands (TSD)* for winter 2022/23

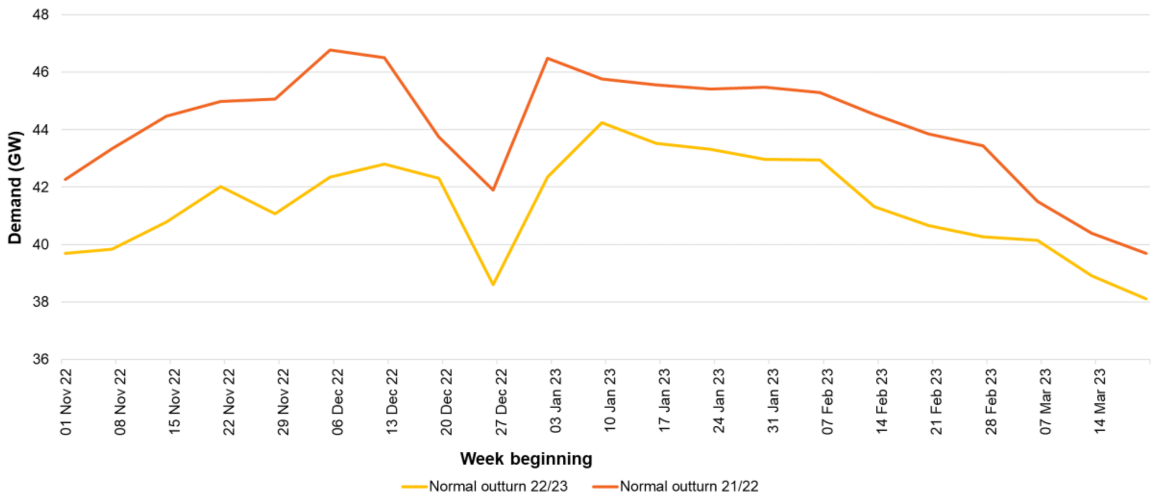

Figure 2: Peak Transmission System Demand (TSD) outturn (weather corrected) for winter 2022/23 compared to winter 2021/22.

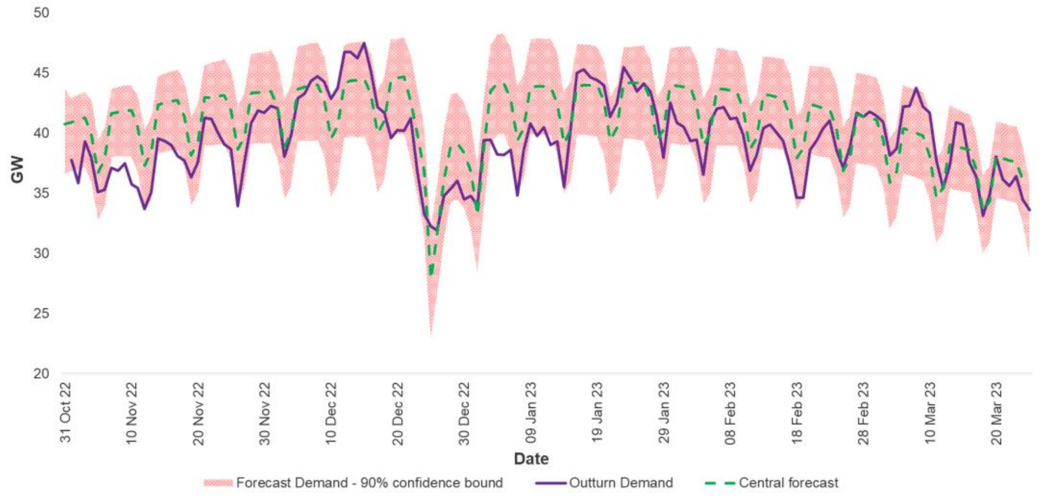

Figure 3: Comparison between the daily outturn peak demand and our forecasts from the *Winter Outlook Report*. The dashed green line shows our central forecast, while the red-shaded region represented a credible range for our forecast reflecting natural variation in weather.

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

Review / Supply

Generator availability

Generation availability was broadly in line with, or above, expectations in our Winter Outlook for most of the winter.

Figure 7 shows the how the actual available generation at real time (including actual wind output) compared with the expected available generation (including availability notified at the time of publication and wind at its Equivalent Firm Capacity (EFC)) forecast in the *Winter Outlook Report*.

For most of winter generator availability was above that estimated in the Winter Outlook, but there were some short periods with a supply shortfall, mostly due to low wind generation. The time period with the biggest shortfall was in the second half of November. This was primarily driven by nuclear generators extending their summer outages beyond the dates notified when the *Winter Outlook Report* was produced, along with low wind. As there were some tight days in late November, generator availability would have contributed to low surplus on those days.

Wind generation output

Wind generation during peak demand was highly variable throughout winter but generally higher than the Equivalent Firm Capacity level.

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).

Figure 8 shows this Equivalent Firm Capacity (EFC) for wind and the actual availability throughout the winter at peak.

At time of peak, wind generation output was generally higher than the EFC level, however there were 10 points where the output was below. Of these only three were significantly below, which all fell in late November to Mid-December. These three were some of the tightest days this winter (according to the indicative outturn surplus), and so this wind generation output shortfall would have contributed to the low surplus on those days.

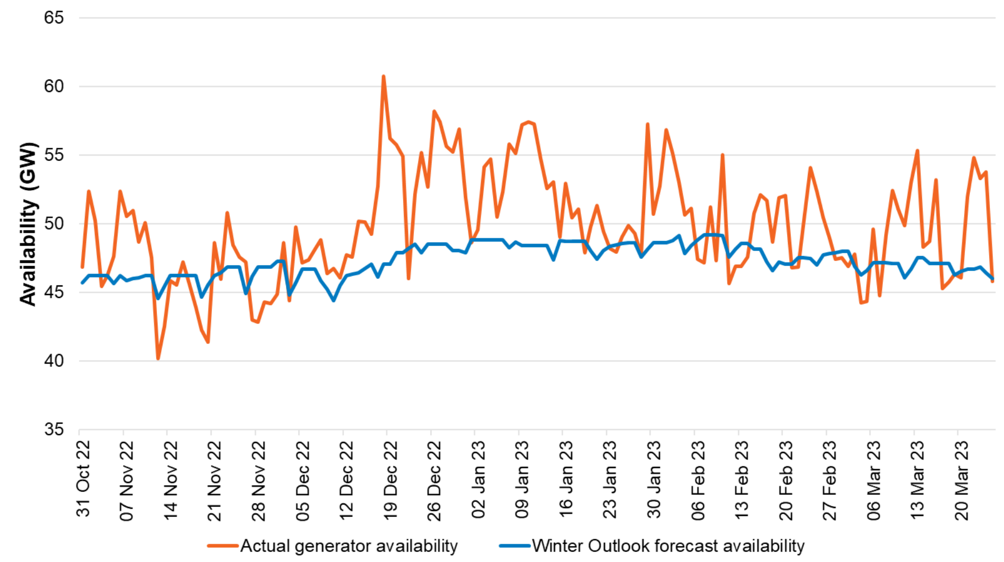

Figure 7: Shortfall between generation availability notified in the *Winter Outlook Report* and actual generator availability (including wind generation)

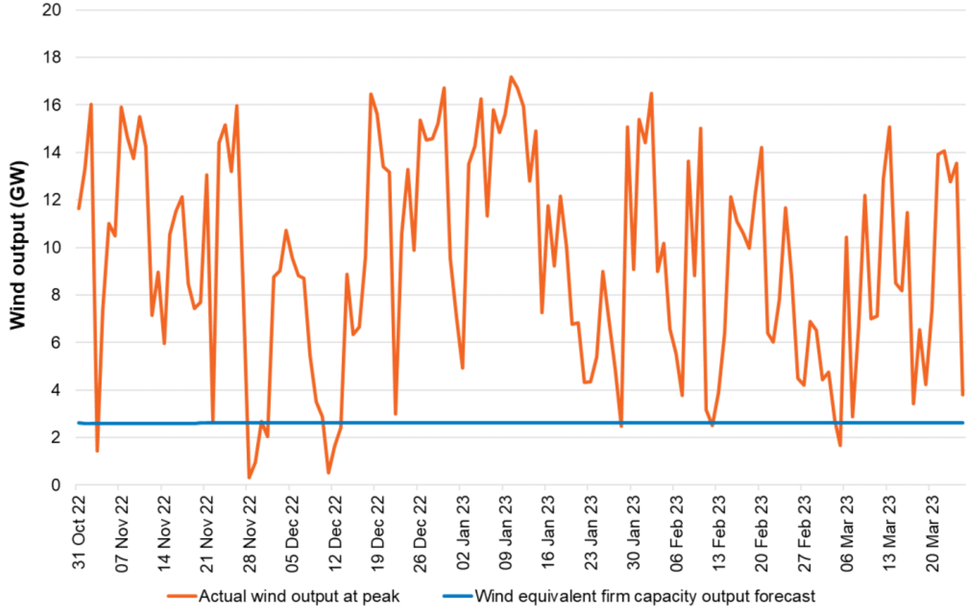

Figure 8: Wind output at peak against equivalent firm capacity

Review / Europe and interconnected markets
Continental Interconnector Flows

Across the winter, interconnectors with Continental Europe were generally importing to Great Britain at peak, following the direction of the price spreads. However, there were some days, particularly in November, when we saw export to France at peak.

	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, NSL)	Based on forward prices for the 2022/23 winter products, we expect imports into GB at peak times from the Netherlands and Belgium under normal network operating conditions. We may see greater levels of export to France at peak times than in previous years.	Over winter, we generally saw imports into GB at peak times from Continental Europe as expected (see Figure 9). Most exports that were seen at peak were in November and over interconnectors to France. There were a similar number of days with export to France in this winter compared to the previous winter.	Figure 10 shows that France generally had higher prices at peak than GB in November which contained most of the days with net export to France.
	We expect net imports from Norway across the NSL interconnector over the winter period, particularly at peak.	For the vast majority of days, we saw imports of electricity across NSL at peak. However, this couldn't always be at full capacity as there were capacity restrictions on flow to GB for most of winter to support the management system security.	On 97% of days this winter NSL was importing to GB, which matches our expectations of net imports across winter.

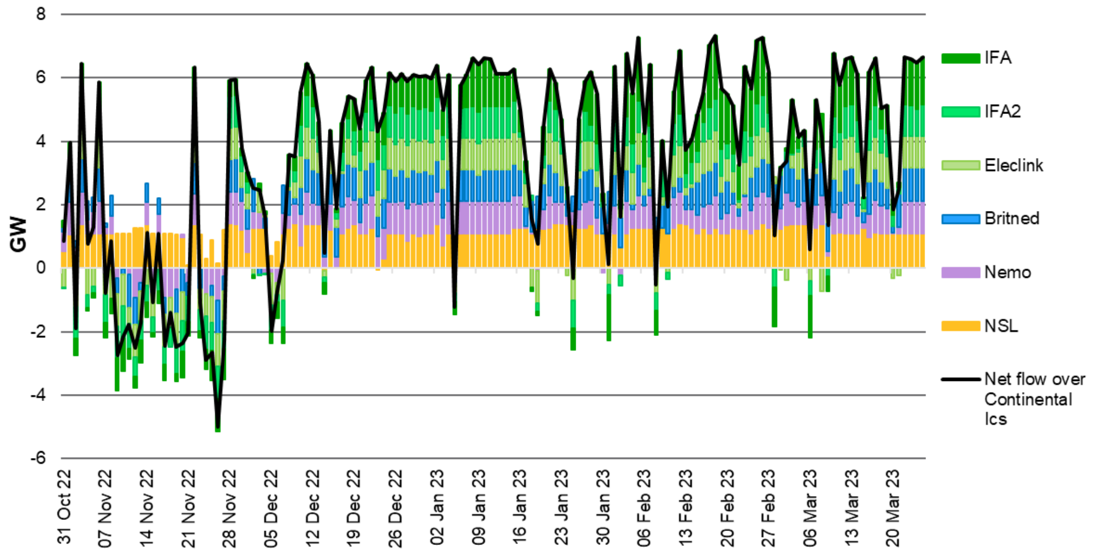

Figure 9: IFA, IFA2, BritNed, Nemo Link and NSL flow at peak times

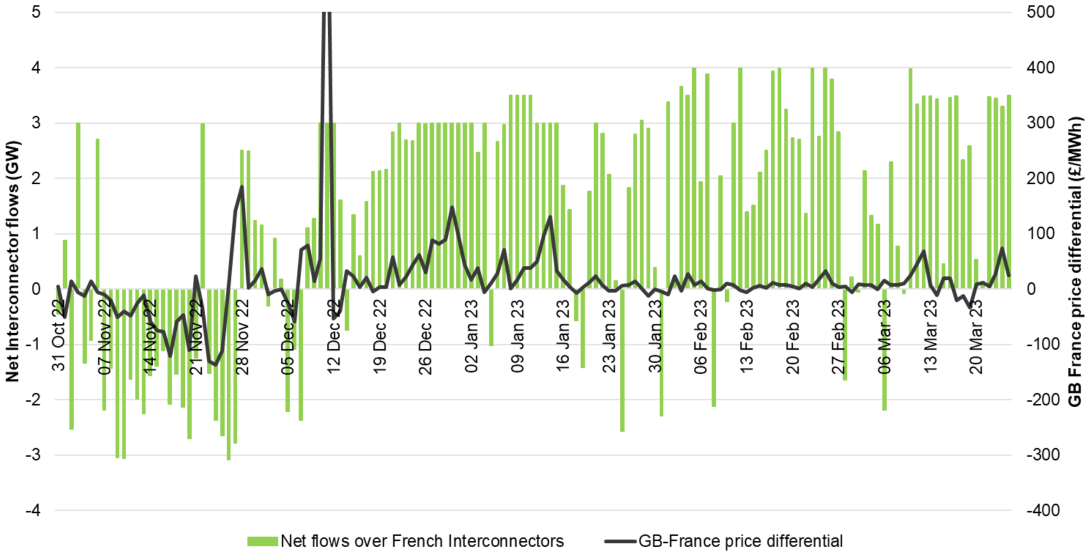

Figure 10: Interconnector flows between France and GB at the GB demand peak for each day combined with the GB France price differential based on the within-day prices at that same time (positive values signify imports into GB and GB prices higher than French prices)

Spotlight / Interconnector Trading

Over this winter, the ability to trade on interconnectors was vital to maintain security of supply in GB.

The ESO can step in and seek to trade to deliver the operational flows required to secure the system. The period with the largest amount of trading was in November (see Figure 14). Market prices supported exports to the continent, but surplus in GB was not high enough every day to support this at peak and so trading was used to reduce the magnitude of the exports. Without this action, some of these days would have been among the tightest of the winter.

When temperatures dropped below seasonal normal in late November and early December, there were less trades because the market positions already provided imports into GB. After January there was some trading on tight margin days, but generally trading contributed much less to the margin position.

On some of the tighter days (Table 6), there was minimal trading because the net positions were importing to GB, and in some cases additional uncertainty due to industrial action in France. Interconnectors were not necessarily importing at their maximum levels because reciprocal support between European system operators maintained an efficient position across all markets.

For more information on interconnector trading, see the Operational Transparency Slides from 8th March here.

Key Dates	Net IC Flow pre-trading (GW)	Net IC Flow post-trading (GW)
22/11/2022 (CMN)	5.2	6.0
28/11/2022 (CMN)	5.7	5.7
23/01/2023 (DFS Live)	4.2	4.2
24/01/2023 (DFS Live)	2.7	2.7
07/03/2023 (EMN)	2.2	2.2

Table 6: Interconnector flows at the demand peak on key dates in winter

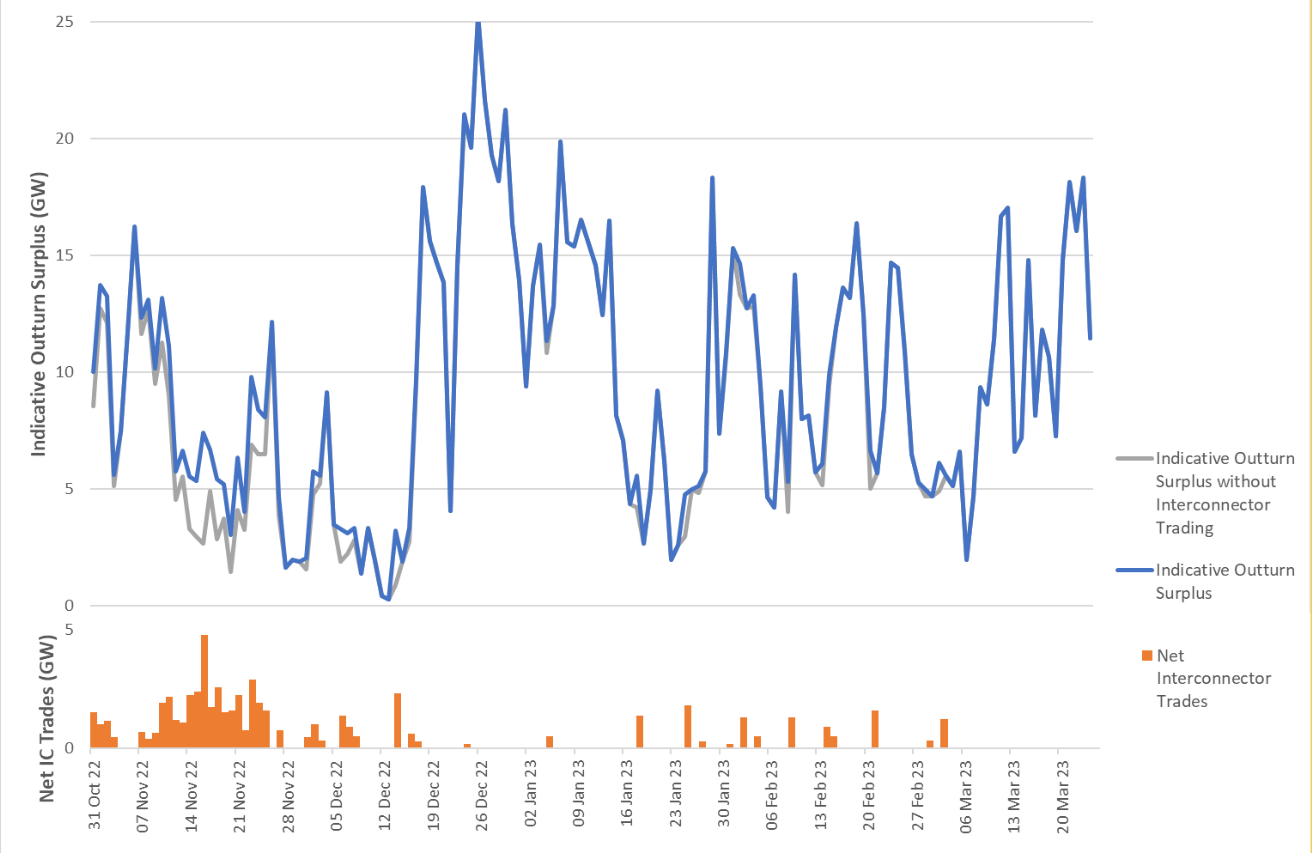

Figure 14: Indicative outturn surplus at the time of the demand peak each day, both the final position after any trading and the positions using the interconnector flows that were provided by the markets (prior to trading). Trades are also shown in the orange bars.

Winter Outlook 2023/24: Early View

Operational Transparency Forum
21 June 2023

Key Messages / Early view of Winter 2023/24

1. Margins

Our current analysis shows that margins are expected to be adequate and within the Reliability Standard under normal market conditions.

Our current Base Case margin is 4.8 GW / 8% with an associated loss of load expectation (LOLE) below 0.1 hours, which is broadly in line with recent winters.

We expect there to be sufficient operational surplus in our Base Case throughout winter.

There may be some days where we need to use tools in our standard operational toolkit, including use of system notices.

2. Reciprocal support with neighbouring countries

We expect to continue working closely with our neighbours in Europe, adopting a coordinated approach providing reciprocal support.

Close cooperation between European system operators through reciprocal support has played an important role in helping maintain secure supplies for customers in Great Britain and Europe.

We expect this to continue this winter leading to periods when imports flow from Europe when we need them, provided by the market and / or ESO trading, which is an important operational tool for us.

We expect it will also lead to periods when exports flow from Great Britain to Europe, including over some peak periods, when we have sufficient operational surplus.

3. Preparing for winter

We are continuing to build resilience ahead of winter to mitigate the impact of risks and uncertainties due to Russia’s illegal invasion of Ukraine.

We are actively engaging with Government, Ofgem, National Gas Transmission and industry stakeholders to ensure we understand and mitigate emerging risks for the upcoming winter.

We believe it is prudent to maintain our Demand Flexibility Service for next winter, and the service terms are now out for consultation, reflecting feedback from industry stakeholders.

We are continuing to have discussions on the availability of having two coal units in contingency contracts this winter. One of the units held in contingency last winter has returned to the market. The other two units have now closed.

System margins / Base Case

Margins are expected to be within the Reliability Standard under normal market conditions. Our current Base Case margin is 4.8 GW / 8% with an associated loss of load expectation (LOLE) below 0.1 hours, which is broadly in line with recent winters.

Our current assessment shows that we expect there to be sufficient available capacity to meet demand in our Base Case, with a de-rated margin of 4.8 GW (around 8%). This assumes normal energy market conditions with no disruptions to fuel supplies and that electricity interconnectors continue to respond to market prices. The associated LOLE is below 0.1 hours, which is within the Reliability Standard of 3 hours.

We assume peak average cold spell demand of 60.3 GW (including operating reserve). This assumes there is no reduction in customer demand on the coldest days of winter, as we saw in winter 2022/23.

Our assessment assumes all providers with Capacity Market (CM) agreements deliver in line with their obligations unless we have specific market intelligence otherwise (e.g. notified outage on REMIT).

Available generation includes one of the coal contingency units from winter 2022/23 operating back in the market. It assumes an additional 0.9 GW (de-rated) generation from units that were partially or fully unavailable last winter. It also assumes over 2 GW (de-rated) more battery storage and demand-side response (DSR) since last winter, reflecting delivery through the CM and improved data quality of our data sources.

We assume 5.1 GW net imports will be available via interconnectors at times when needed which is in line with CM agreements held by interconnectors. Should it be required the ESO can also step in and seek to trade* to deliver the operational flows required to secure the system – this is an important operational tool available to support security of supply.

While the Base Case margin is slightly higher than last winter, it is still broadly in line with those of recent winters. We are continuing to monitor risks and uncertainties for winter, arising from Russia's illegal invasion of Ukraine, and we have outlined some of the steps we are taking to build additional resilience as part of our winter preparations in the full document.

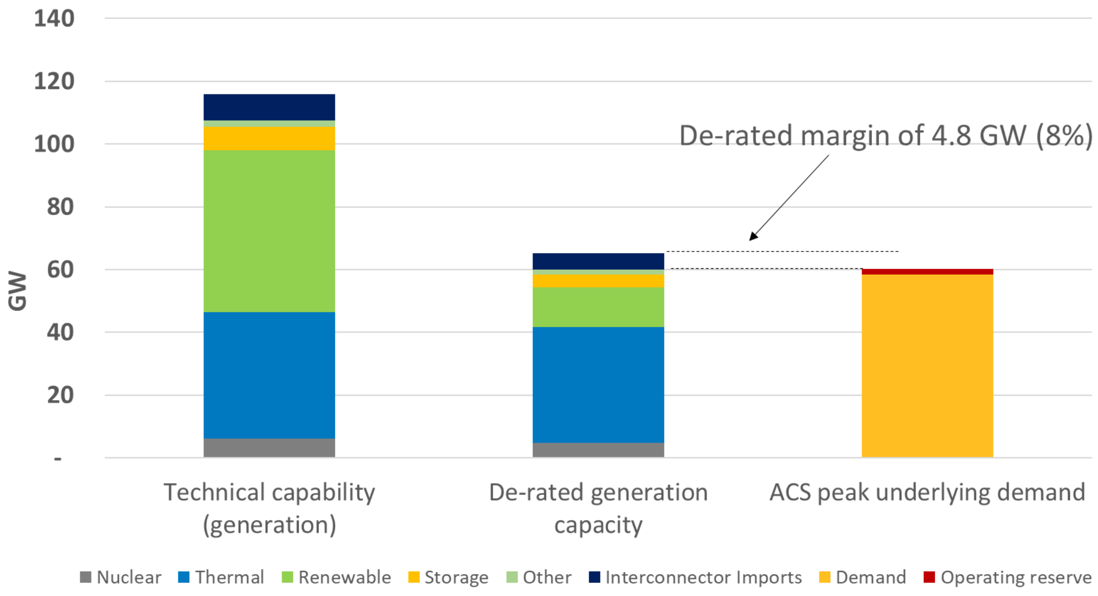

Figure 4: Supply margin in relation to generation capacity and demand

Note**:** our Base Case does not assume any contribution from enhanced actions or out-of-market services such as the Demand Flexibility Service.

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* Please see the Spotlight in our 2022/23 Winter Review and Consultation for further information on ESO trading and its impact last winter

Operational margins / Base Case

We expect to have sufficient operational surplus throughout winter in our Base Case, even when we consider the expected natural variation of demand, wind and outages. There may be some tight days, and based on the current available information, these are most likely to be in January.

A single view is not appropriate in assessing the potential risk due to natural variation in demand, wind, outages etc. Therefore, Figure 5 shows the daily operational margin under typical conditions, together with a credible band within which the margin can fluctuate because of these factors.

When the shaded region dips close to 0 GW, there is a risk that the system may become tight, and operational tools, including market notices, could be used to increase margin.

Our operational modelling indicates sufficient operational surplus throughout winter in our Base Case, even when we consider the expected natural variation of demand, wind and outages. There could still be days where the operational surplus falls below this range (up to 5% of days) and we may need to use our standard operational tools to manage these periods, which may mean issuing Market Notices*.

We expect there to be sufficient available capacity to respond to these market signals to meet consumer demand.

The outturn surplus will ultimately be determined by market positions which could lead to us providing exports to Europe at peak times.

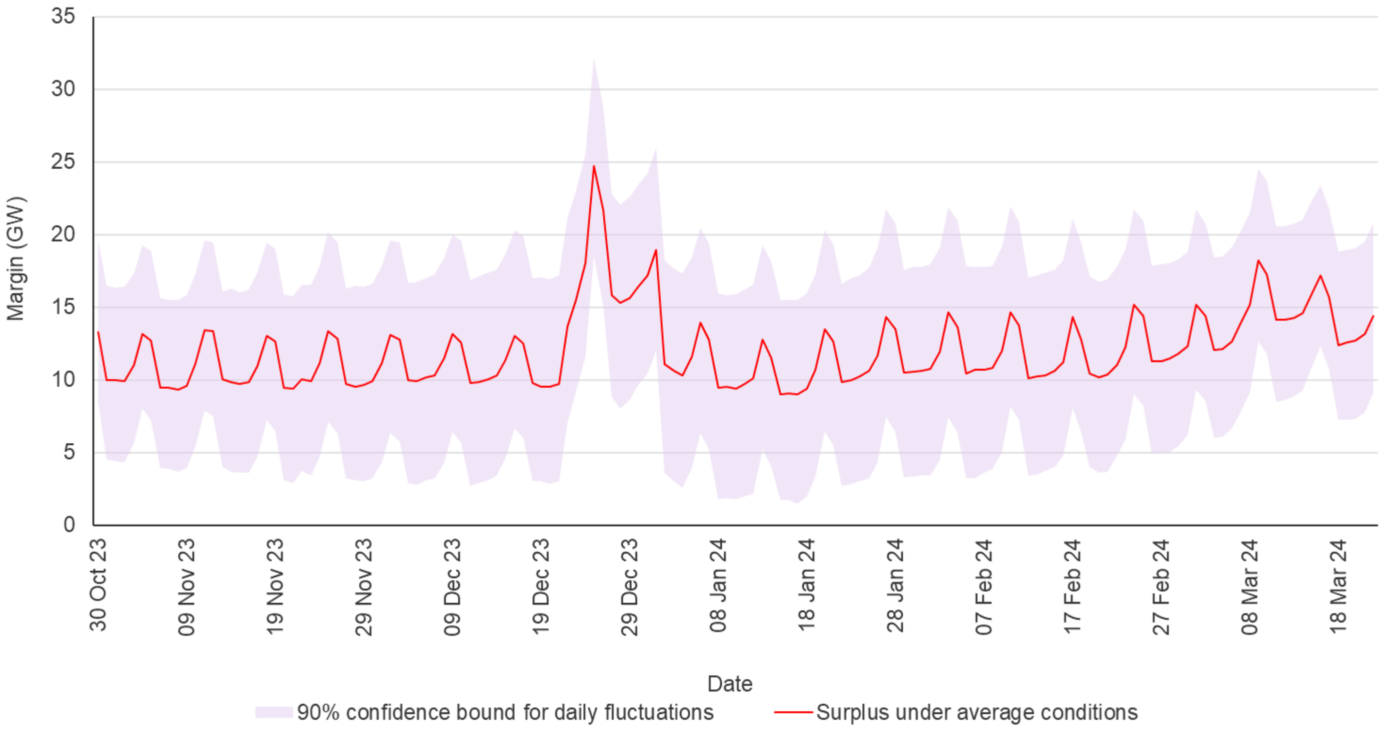


Figure 5: Central forecast with range of credible outcomes for daily margin during Winter 2023/24 using our Base Case assumptions

Note on the methodology: the central case in Figure 5 considers a situation under typical conditions, using average weather conditions for demand, average availability for conventional generation and average wind conditions when margin is tight. To explore the variation around this central view, we simulate many possible scenarios for weather, demand, conventional generation availability, wind generation output and interconnector availability and, for each of these scenarios, we calculate the daily surplus time series across the entire winter for that scenario.

* Including Electricity Margin Notices (EMNs) and Capacity Market Notices (CMNs)

Preparing for Winter

We are working closely with Government, Ofgem and National Gas Transmission to assess potential risks and uncertainties for this winter, arising as a direct result of Russia's illegal invasion of Ukraine and its subsequent impact on both global and UK energy markets. While markets have now had longer to respond to the crisis, lessening the market risks since last winter, as a prudent system operator, we remain vigilant, continuing to monitor developments that could change quickly and taking steps to build our resilience and minimise the potential impact to electricity customers in Great Britain.

1

Industry engagement

We are engaging with industry stakeholders to ensure we understand and can mitigate any emerging risks as they materialise.

This includes working closely with Transmission Owners to minimise the impact of network outages over winter to maximise the amount of energy available for customers.

It also includes discussions with neighbouring Transmission System Operators in Europe. This helps us better understand risks and uncertainties in neighbouring markets enabling a coordinated approach with reciprocal support* to meet the needs of all electricity customers.

We are also actively monitoring market developments to ensure we have access to the latest market intelligence in our assessments. This will underpin our detailed modelling for the full Winter Outlook Report, and the analysis that we continue throughout winter to monitor any potential changes. This is used to keep industry stakeholders informed on developments to the security of supply outlook during winter at the weekly Operational Transparency Forum

2

Demand Flexibility Service

We launched our new Demand Side Flexibility service for last winter. This innovative service incentivises consumers to voluntarily flex the time when they use electricity allowing the ESO access to additional flexibility when demand is highest.

We have been engaging with industry stakeholders since last winter to review the service and to consider how we can make further developments for the coming winter.

We believe it is prudent to maintain the DFS service for this winter and have taken industry feedback on board to improve the design in order to grow volumes in this market.

The service terms for DFS are now out to consultation until 17th July. For more information please see our website here.

3

Coal contingency contracts

As reported in our Operational Transparency Forum in March, we received a request from Government to explore the extension of the coal contingency contracts that were available last winter.

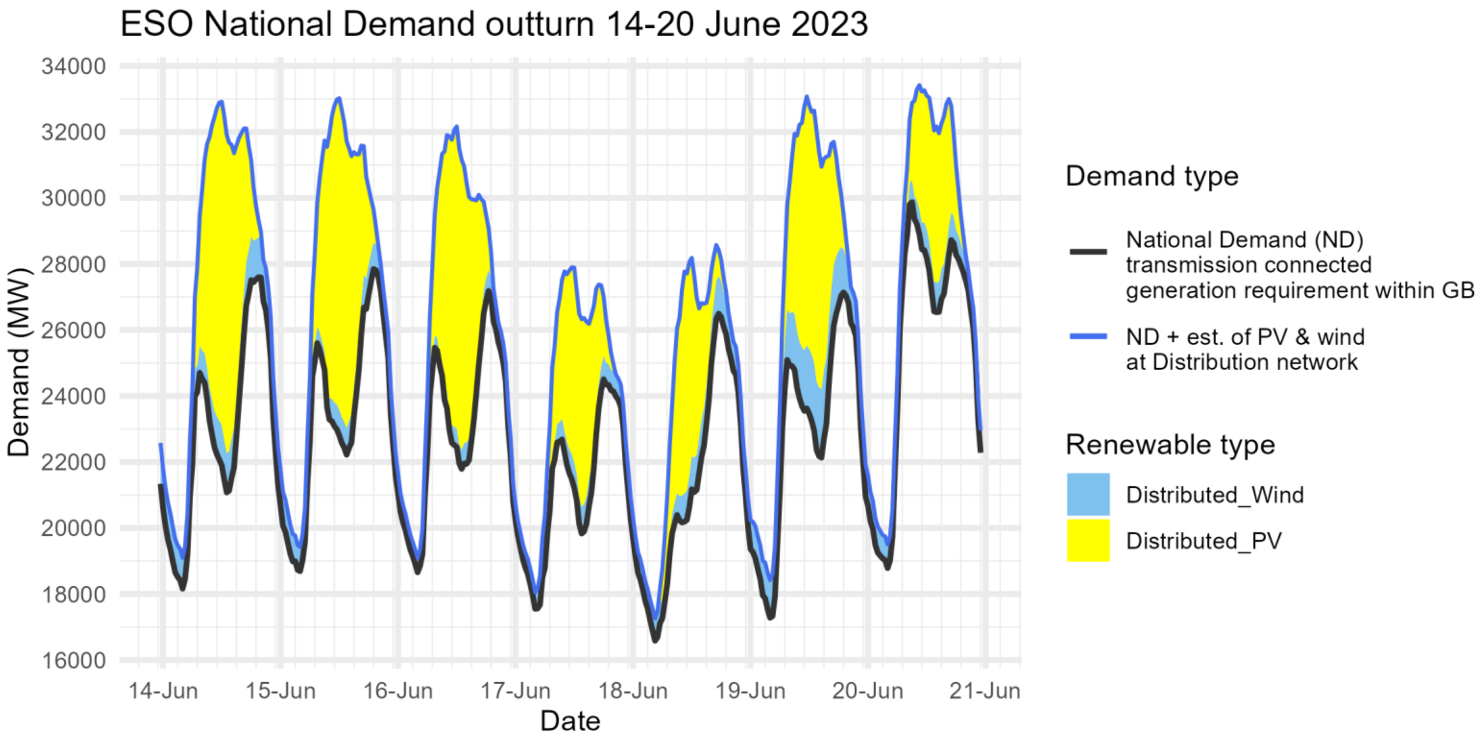
We expect one of the five units to be commercially available in the market having secured a Capacity Market agreement in the recent T-1 auction.

The units at West Burton A have now closed and will be unavailable. There is less certainty on Drax and discussions are ongoing. These discussions are commercially sensitive and so we are unable to report on the outcome until they have reached their conclusion.

We will expect to inform market participants when we can on any updates through the weekly Operational Transparency Forum and / or the Winter Outlook Report in the autumn.

* Providing reciprocal support can mean flows on electricity interconnectors can be importing or exporting from Great Britain delivering mutual benefits for us and our European neighbours

Demand | Last week demand out-turn



		FORECAST (Wed 14 Jun)			OUTTURN		
Date	Forecasting Point	National Demand (GW)	Dist. wind (GW)	Dist. PV (GW)	National Demand (GW)	Dist. wind (GW)	Dist. PV (GW)
14 Jun 2023	Afternoon Min	21.7	1.3	9.4	21.1	1.2	9.7
15 Jun 2023	Overnight Min	18.5	0.8	0.0	18.7	0.7	0.0
15 Jun 2023	Afternoon Min	22.9	0.8	8.5	22.2	0.8	8.7
16 Jun 2023	Overnight Min	18.9	0.4	0.2	18.7	0.4	0.0
16 Jun 2023	Afternoon Min	22.1	0.5	7.8	21.8	0.6	8.8
17 Jun 2023	Overnight Min	17.7	0.3	0.5	17.6	0.5	0.0
17 Jun 2023	Afternoon Min	18.2	0.7	7.3	19.8	0.8	5.7
18 Jun 2023	Overnight Min	16.6	0.7	0.3	16.6	0.7	0.0
18 Jun 2023	Afternoon Min	19.8	1.2	5.8	21.1	1.0	5.5
19 Jun 2023	Overnight Min	17.6	1.0	0.0	17.3	1.1	0.0
19 Jun 2023	Afternoon Min	24.1	1.4	5.4	22.1	2.1	6.7
20 Jun 2023	Overnight Min	18.6	0.8	0.0	18.8	0.7	0.0
20 Jun 2023	Afternoon Min	23.7	1.3	5.9	26.5	0.9	4.7

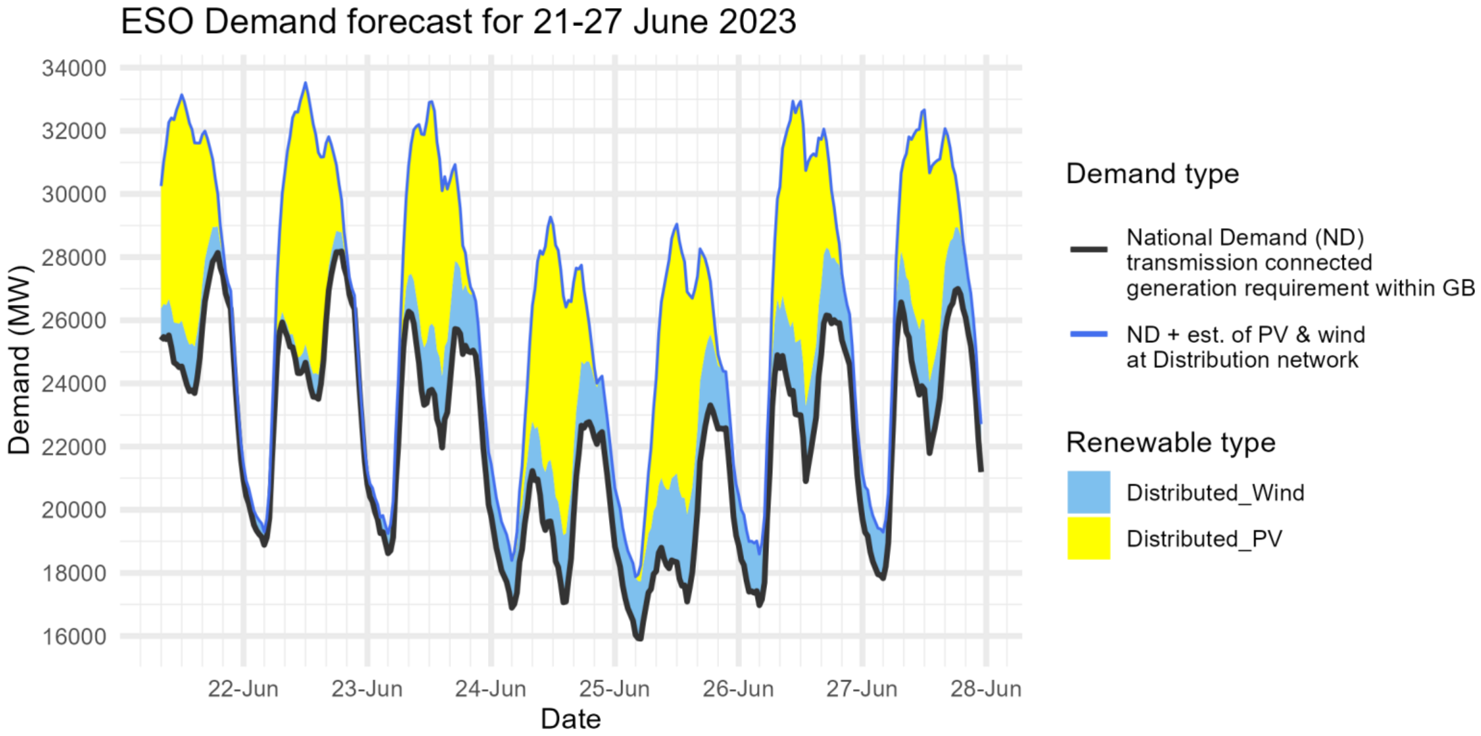
The black line (National Demand ND) is the measure of portion of total GB customer demand that is supplied by the transmission network.

ND values **do not include** export on interconnectors or pumping or station load

Blue line serves as a proxy for total GB customer demand. It includes demand supplied by the distributed wind and solar sources, but it does not include demand supplied by non-weather driven sources at the distributed network for which ESO has no real time data.

Historic out-turn data can be found on the ESO Data Portal in the following data sets: Historic Demand Data & Demand Data Update

Demand | Week Ahead



		FORECAST (Wed 21 Jun)		
Date	Forecasting Point	National Demand (GW)	Dist. wind (GW)	Dist. PV (GW)
21 Jun 2023	Afternoon Min	23.7	1.5	6.4
22 Jun 2023	Overnight Min	18.9	0.4	0.0
22 Jun 2023	Afternoon Min	23.5	0.8	7.0
23 Jun 2023	Overnight Min	18.6	0.6	0.0
23 Jun 2023	Afternoon Min	22.0	2.3	5.9
24 Jun 2023	Overnight Min	16.9	1.5	0.0
24 Jun 2023	Afternoon Min	17.1	2.1	7.6
25 Jun 2023	Overnight Min	15.9	1.8	0.5
25 Jun 2023	Afternoon Min	17.1	2.8	7.1
26 Jun 2023	Overnight Min	17.0	1.6	0.0
26 Jun 2023	Afternoon Min	20.9	2.4	7.5
27 Jun 2023	Overnight Min	17.8	1.5	0.0
27 Jun 2023	Afternoon Min	21.8	2.2	6.6

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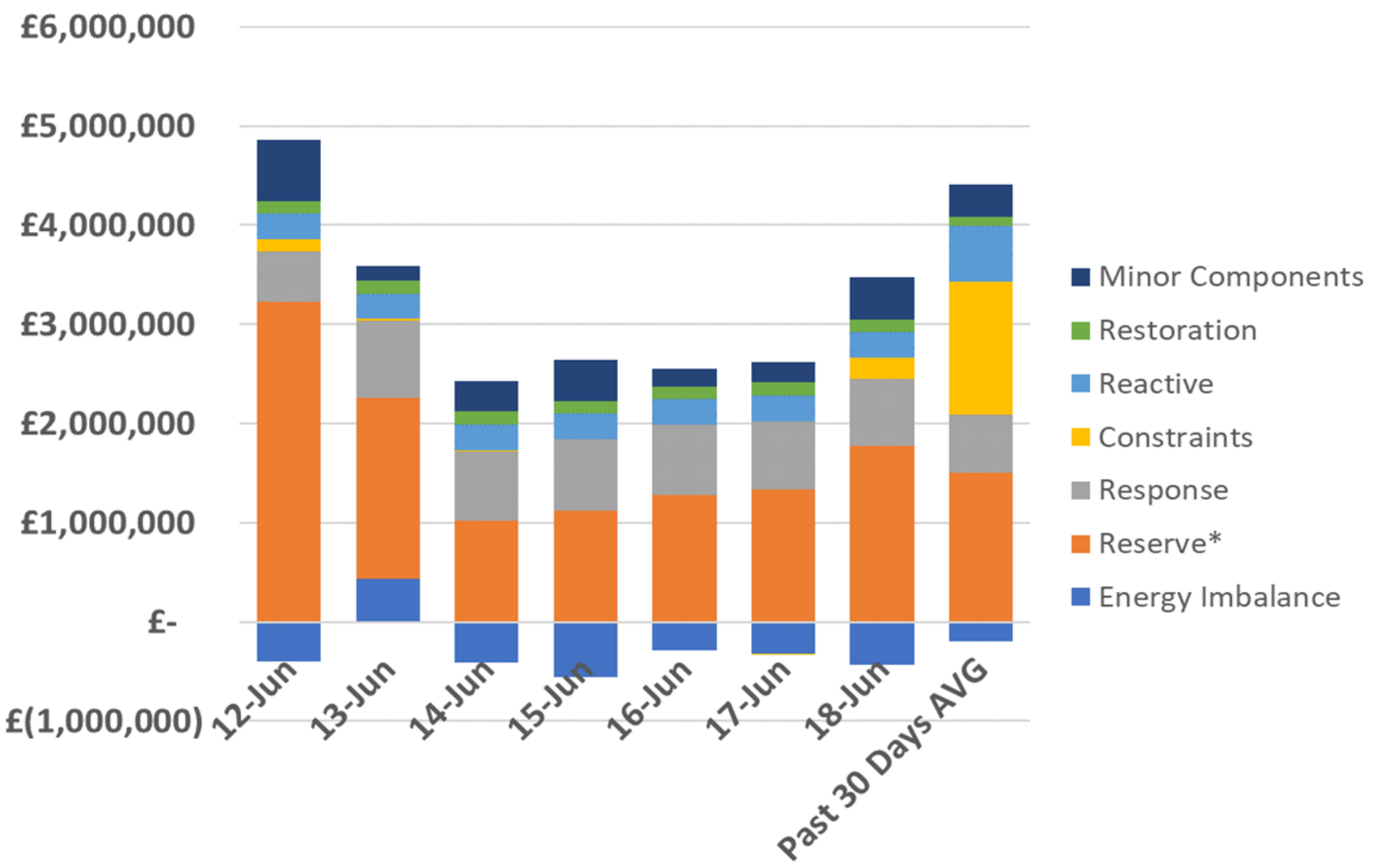
ESO Actions | Category costs breakdown for the last week



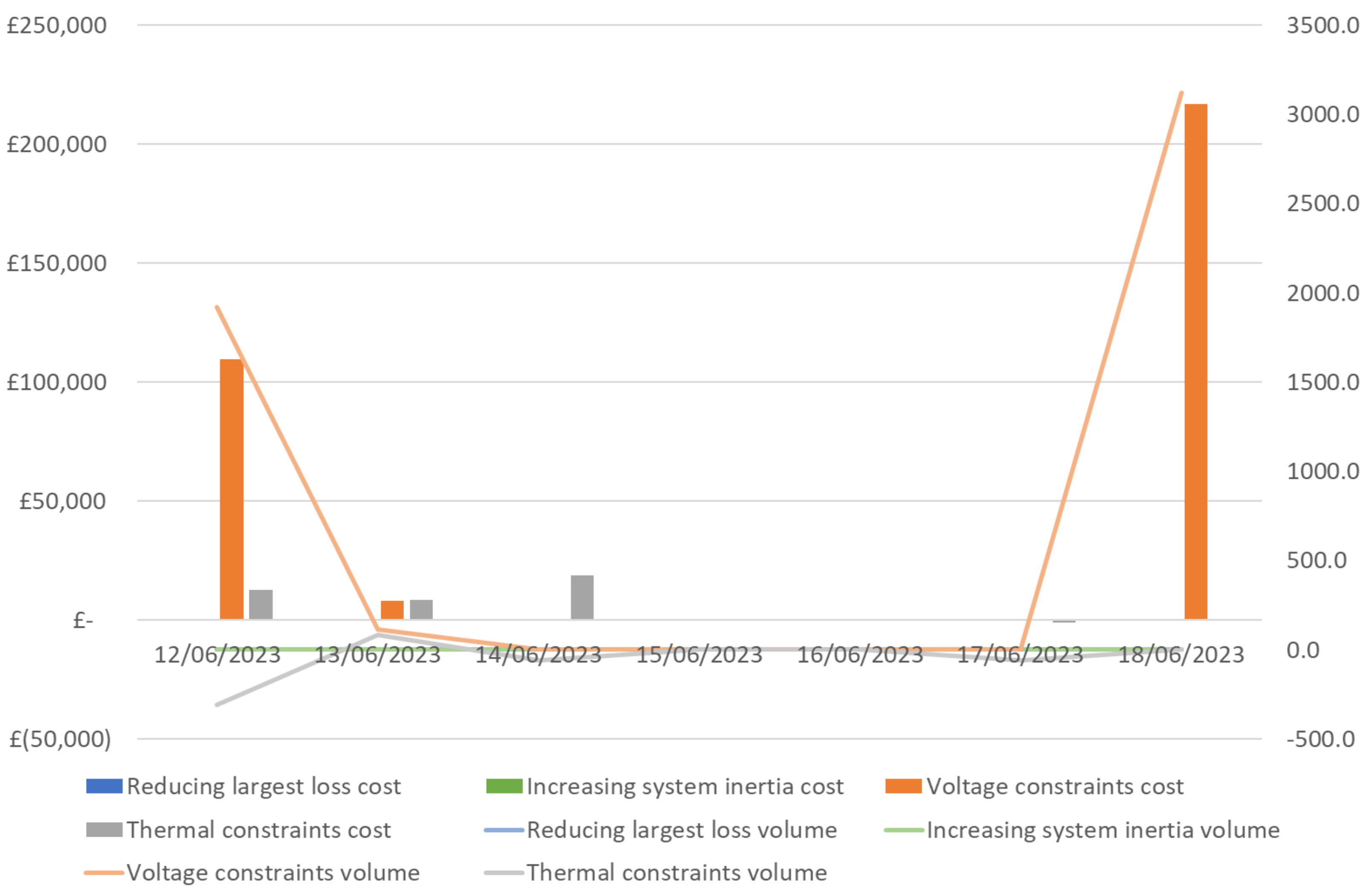
Date	Total (£m)
12/06/2023	4.5
13/06/2023	3.6
14/06/2023	2.0
15/06/2023	2.1
16/06/2023	2.3
17/06/2023	2.3
18/06/2023	3.0
Weekly Total	19.8
Previous Week	28.5

Reserve costs were the key cost component for the week.

Please note that all the categories are presented and explained in the MBSS.

Data issue: Please note that due to a data issue on a few days over the last few months, the Minor Components line in Non-Constraint Costs is capturing some costs on those days which should be attributed to different categories. It has been identified that a significant portion of these costs should be allocated to the Operating Reserve Category. Although the categorisation of costs is not correct, we are confident that the total costs are correct in all months. We continue to investigate and will advise when we have a resolution.

ESO Actions | Constraint Cost Breakdown



Thermal – network congestion
Actions were required to manage thermal constraints on Mon, Tues Weds and Sat.

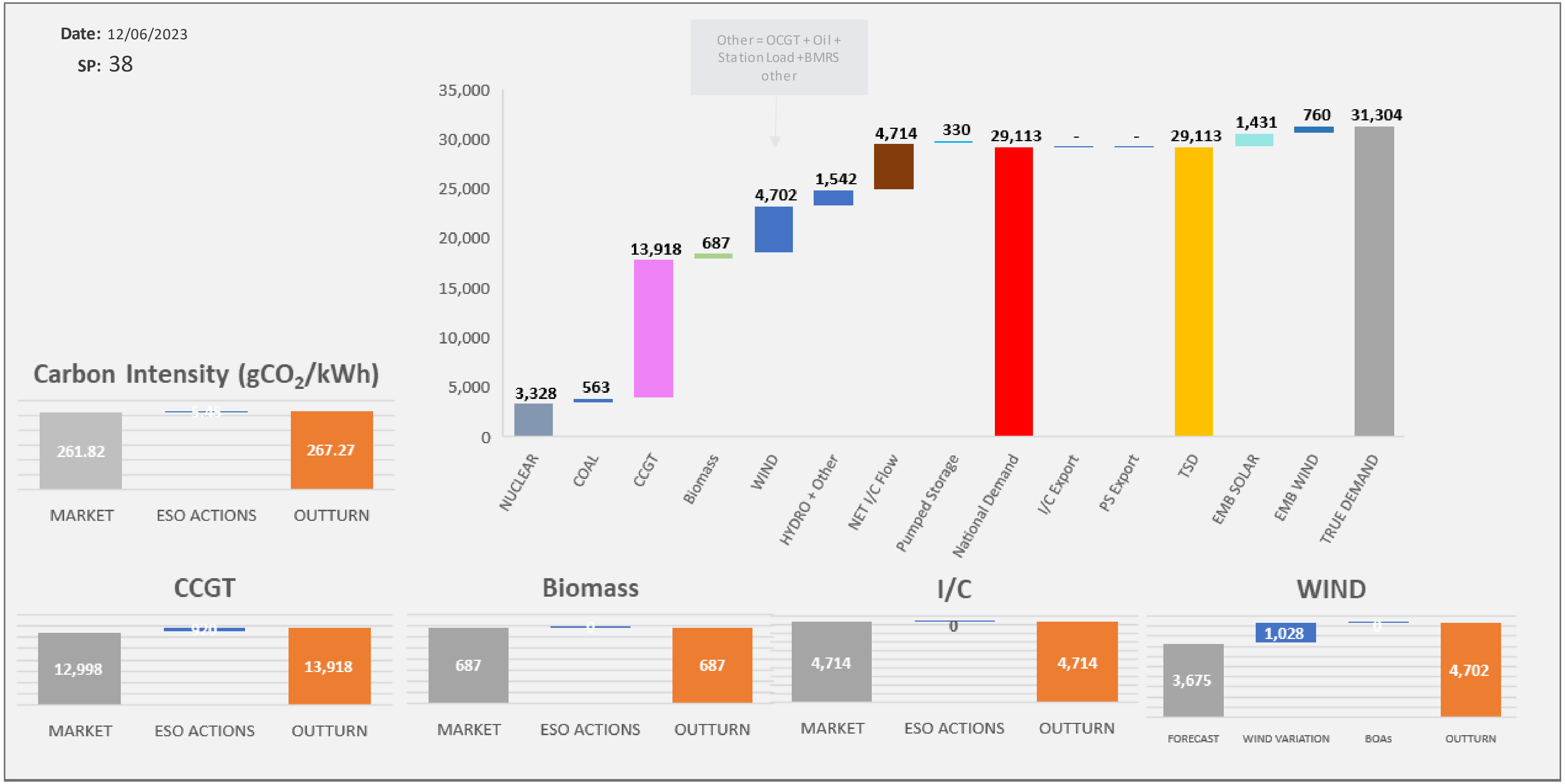
Voltage
Intervention was required to manage voltage levels Mon, Tues and Sun.

Managing largest loss for RoCoF
No intervention was required to manage largest loss.

Increasing inertia
No intervention was required to manage system inertia.

Sli.do code #OTF

ESO Actions | Monday 12 June – Peak Demand – SP spend ~£64k

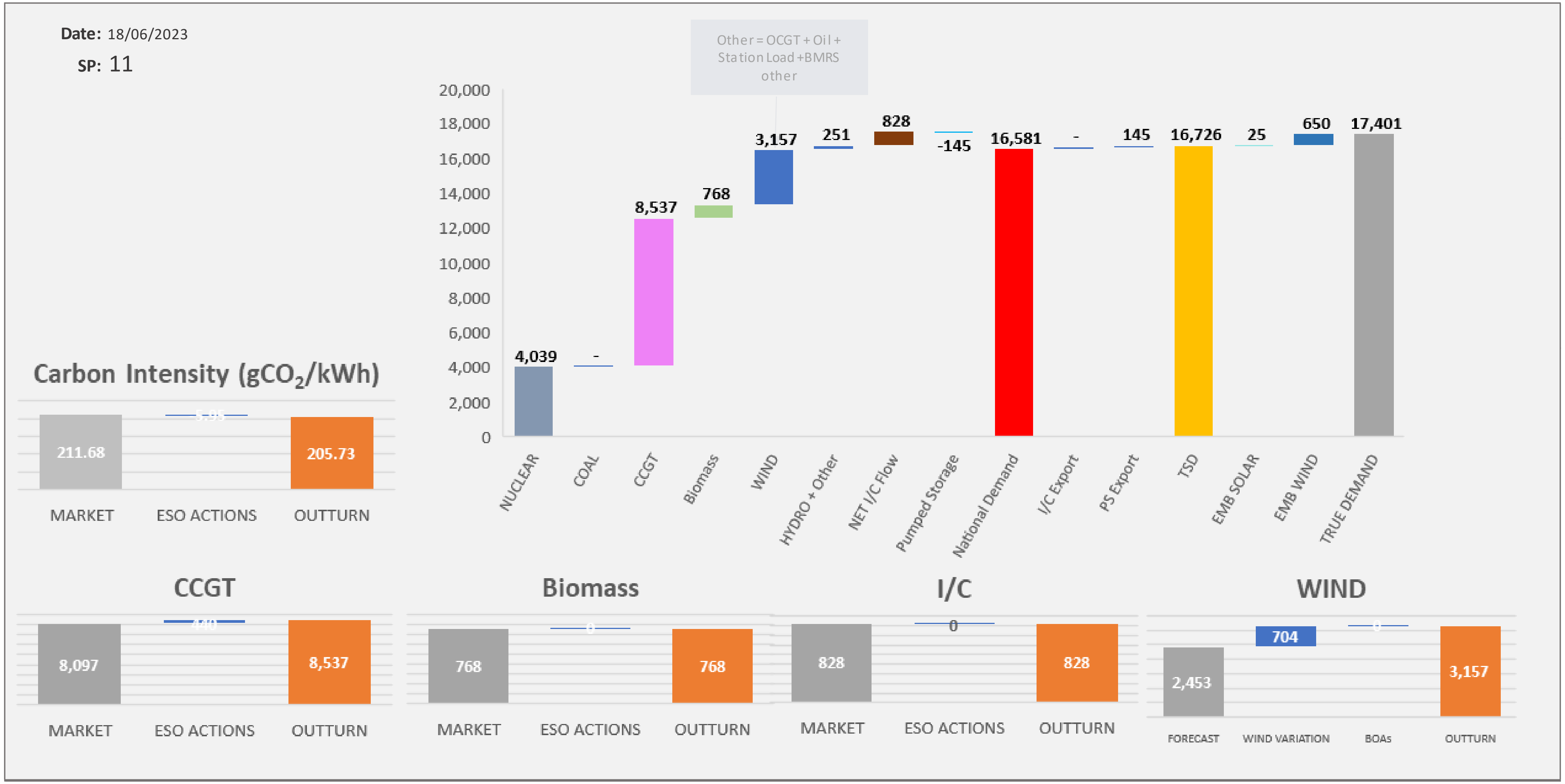


Carbon Intensity data on data portal: https://data.nationalgrideso.com/carbon-intensity1/carbon-intensity-of-balancing-actions

ESO

Sli.do code #OTF

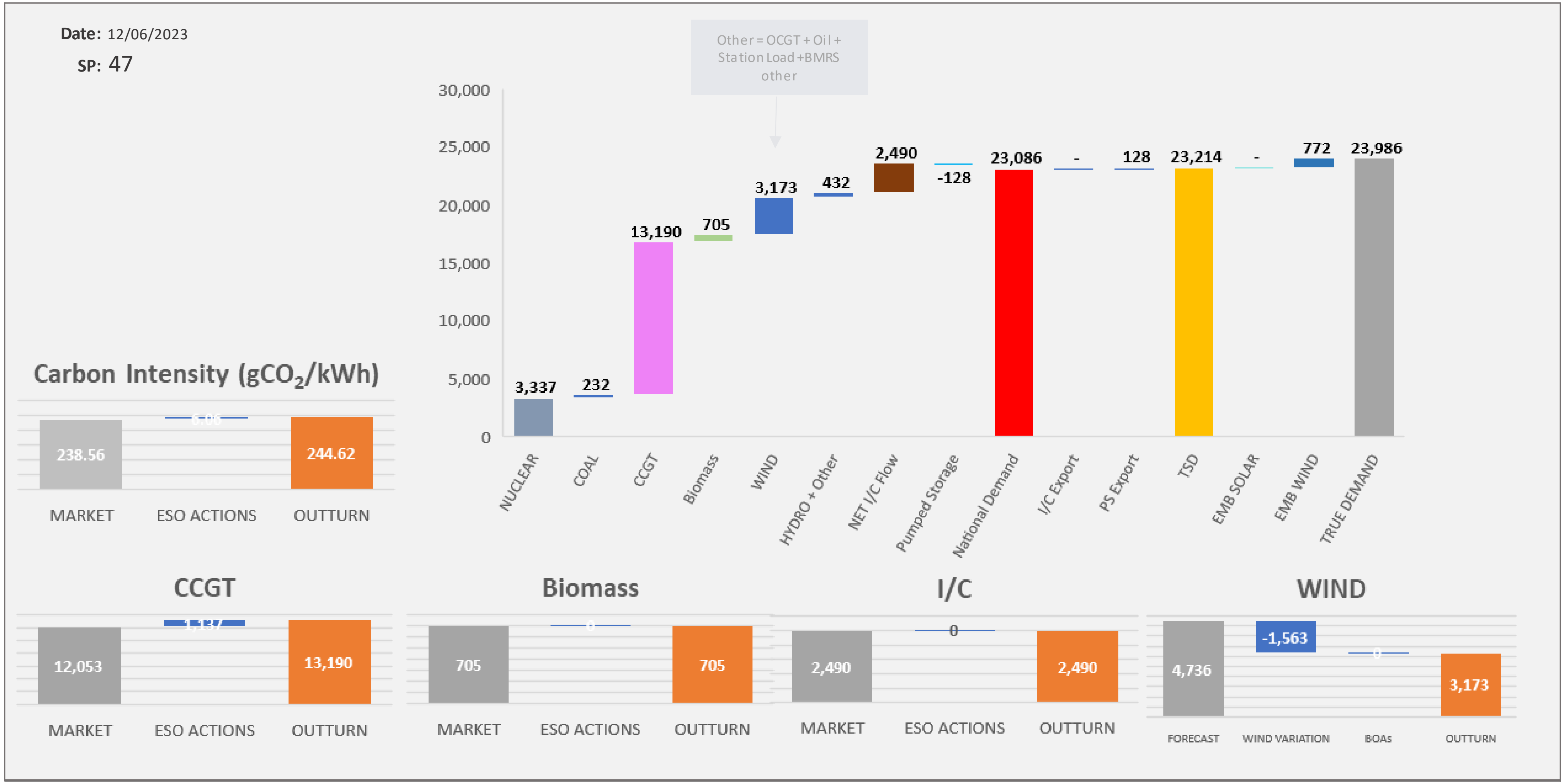
ESO Actions | Sunday 18 June – Minimum Demand – SP Spend ~£10k



Carbon Intensity data on data portal: https://data.nationalgrideso.com/carbon-intensity1/carbon-intensity-of-balancing-actions

ESO

ESO Actions | Monday 12 June – Highest SP Spend ~£135k



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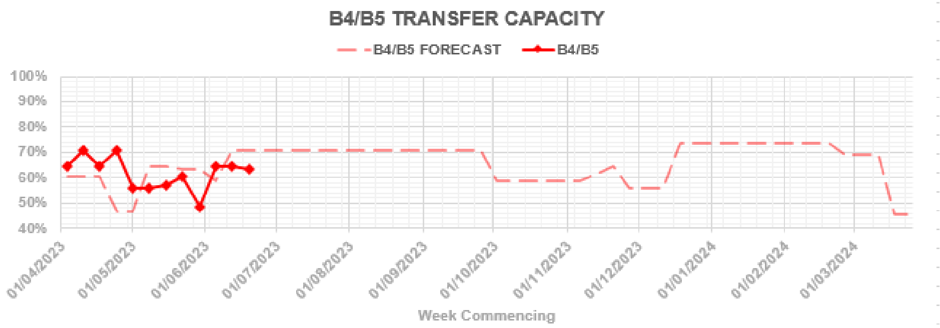
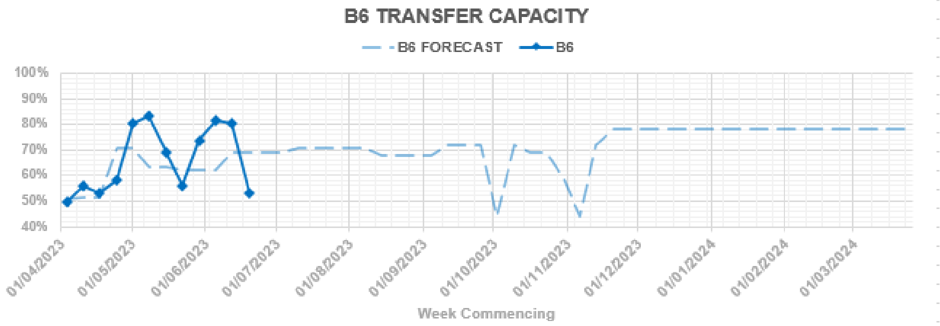
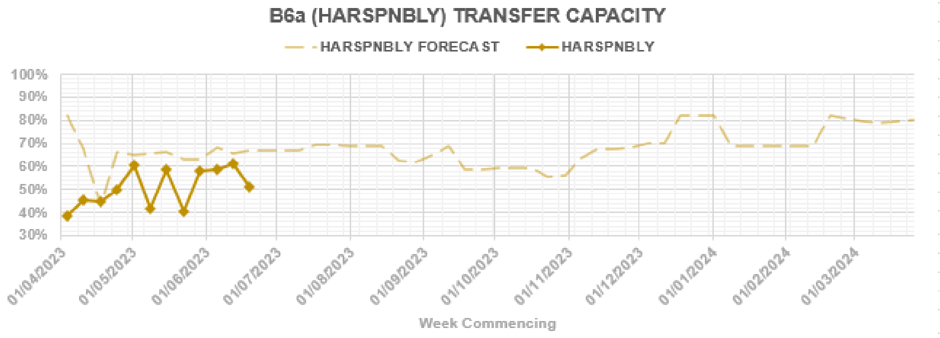
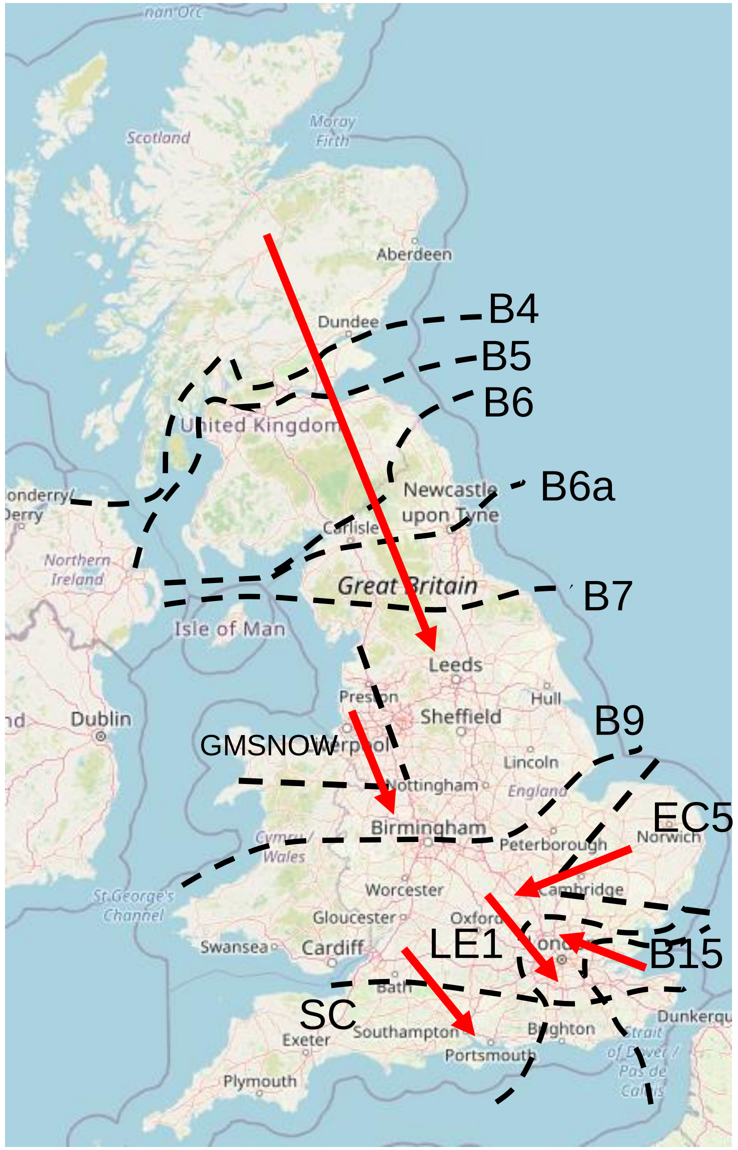
Transparency | Network Congestion





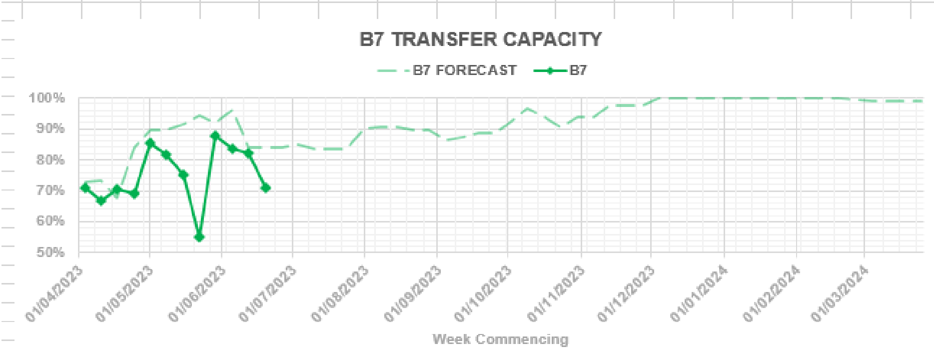


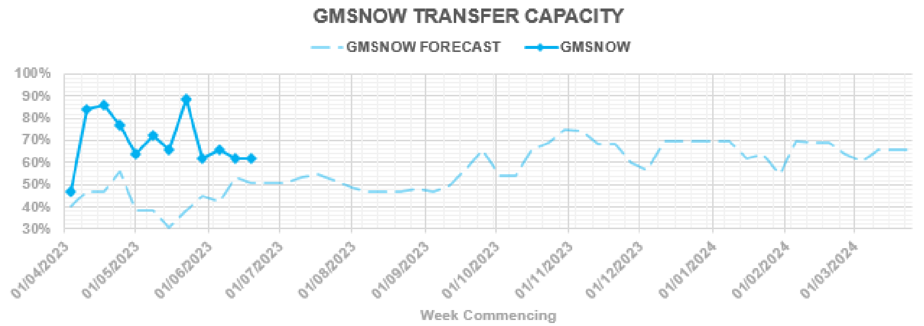
Boundary	Max. Capacity (MW)
B4/B5	3400
B6	6800
B6a	8000
B7	8325
GMSNOW	4700
B9	10600
EC5	5000
LE1	8500
B15	7500
SC	7300

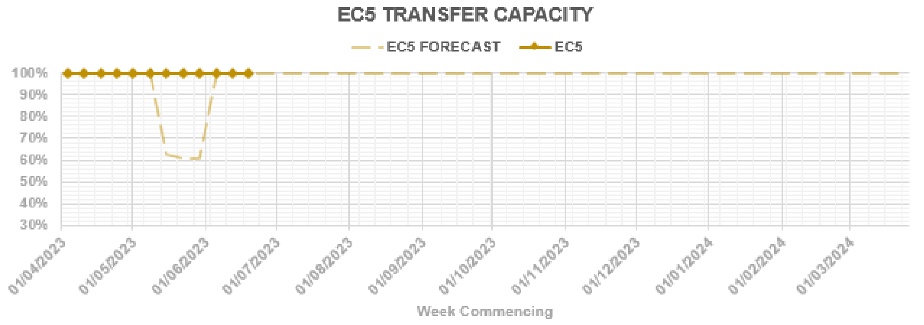


Day ahead flows and limits, and the 24-month constraint limit forecast are published on the ESO Data Portal:
https://data.nationalgrideso.com/data-groups/constraint-management

Transparency | Network Congestion







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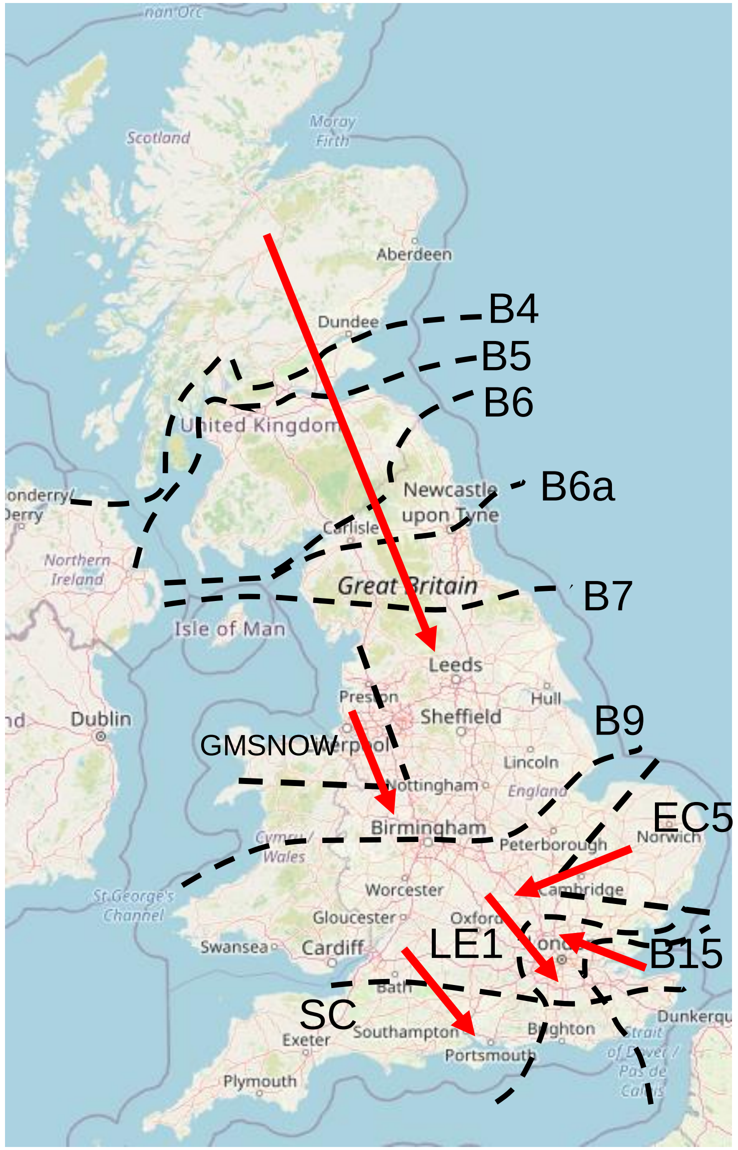

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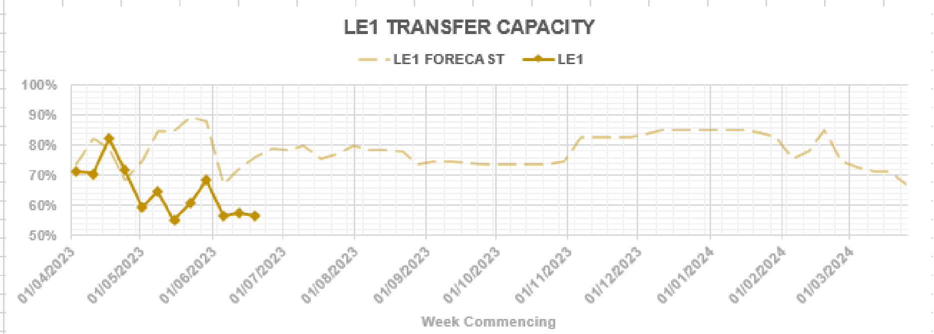

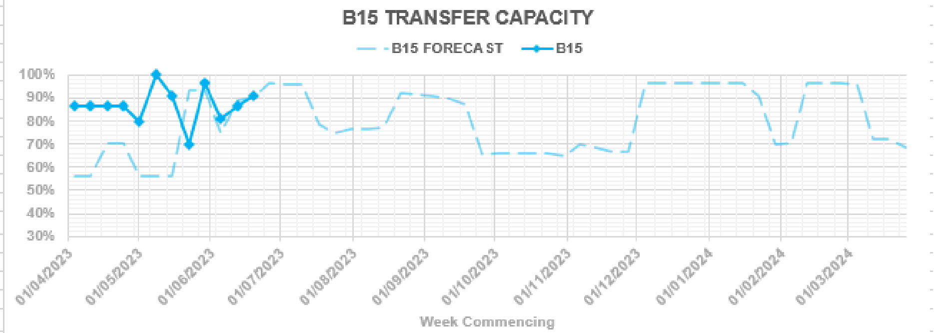

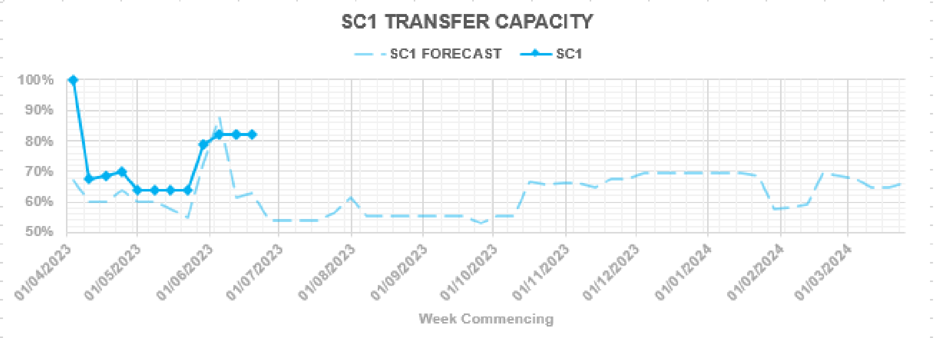

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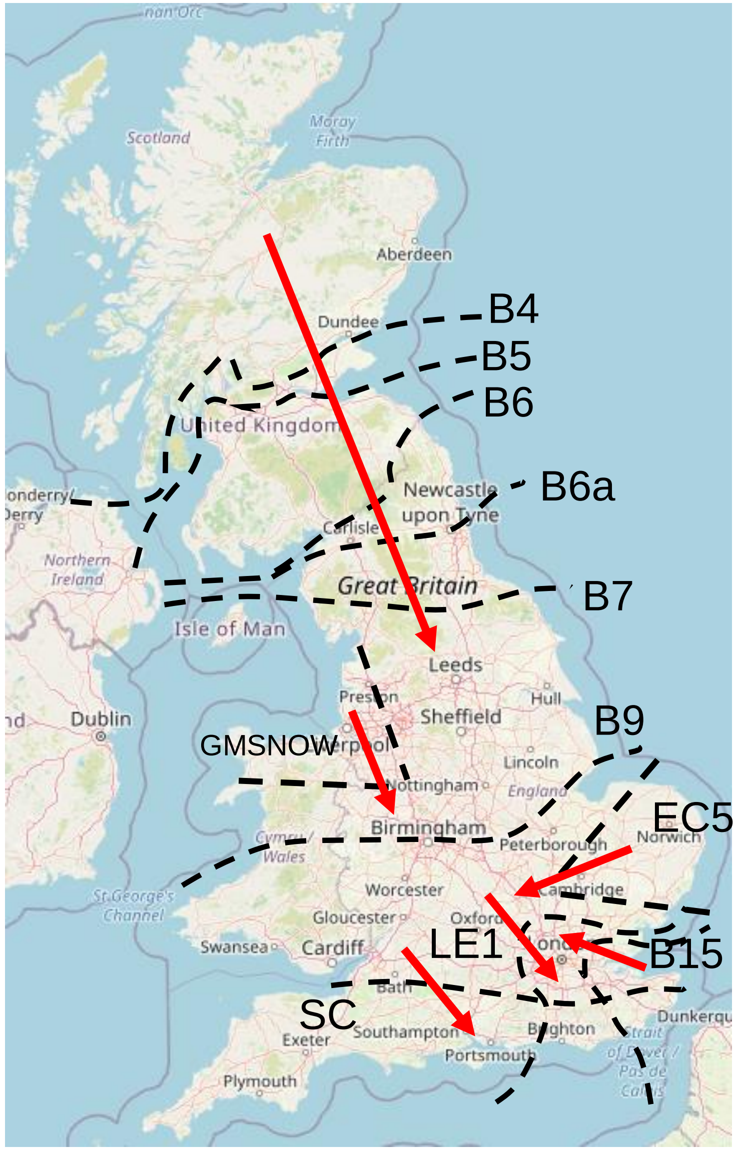

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Questions from last week

Q: Thank you for the answer regarding HPC (Hinckley Point C). However at low sync gen levels with HPC as a large P.U loss....?

A: That is part of Frequency Risk & Control Report, we are moving to a position where we would have enough DC and DM/DR to be able to manage HINCP C, hence the long term target of 102 GVAs. At the moment we aren't down there as the current largest loss isn't as high and thus the additional cost of DC etc isn't justified. The target in the latest approved FRCR is 120GVAs (600MW) allowing a circa 1450MW loss once implemented. Use this link for more details https://www.nationalgrideso.com/industry-information/codes/security-and-quality-supply-standard-sqss/frequency-risk-and-control.

Q: Under what arrangements are DNOs activating ANM (Active Network Management) schemes to deal with localised NRAPM (Negative Reserve Active Power Margin)? Is this an obligation, a transaction, a service or something else?

A: We are not aware that any DNO should be using an ANM for this purpose as all current DNO ANMs only act as far out as their ‘connection assets’ (i.e. not beyond the GSP interface point). The only exception to this rule that we’re aware of are the ANM monitoring locations that SPD are deploying in southern Scotland, which do monitor Tx circuits beyond the GSP.

slido

Audience Q&A Session

ⓘ Start presenting to display the audience questions on this slide.

Feedback

Please remember to use the feedback poll in sli.do after the event.

We welcome feedback to understand what we are doing well and how we can improve the event for the future.

If you have any questions after the event, please contact the following email address:
box.NC.Customer@nationalgrideso.com