You have been joined in listen only mode with your camera turned off

ESO Operational Transparency Forum

12th January 2022

nationalgridESO

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. If you do not feel able to ask a question in this way please use the email: box.NC.Customer@nationalgrideso.com

These slides, event recordings and further information about the webinars can be found at the following location:
https://data.nationalgrideso.com/plans-reports-analysis/covid-19-preparedness-materials

Regular Topics

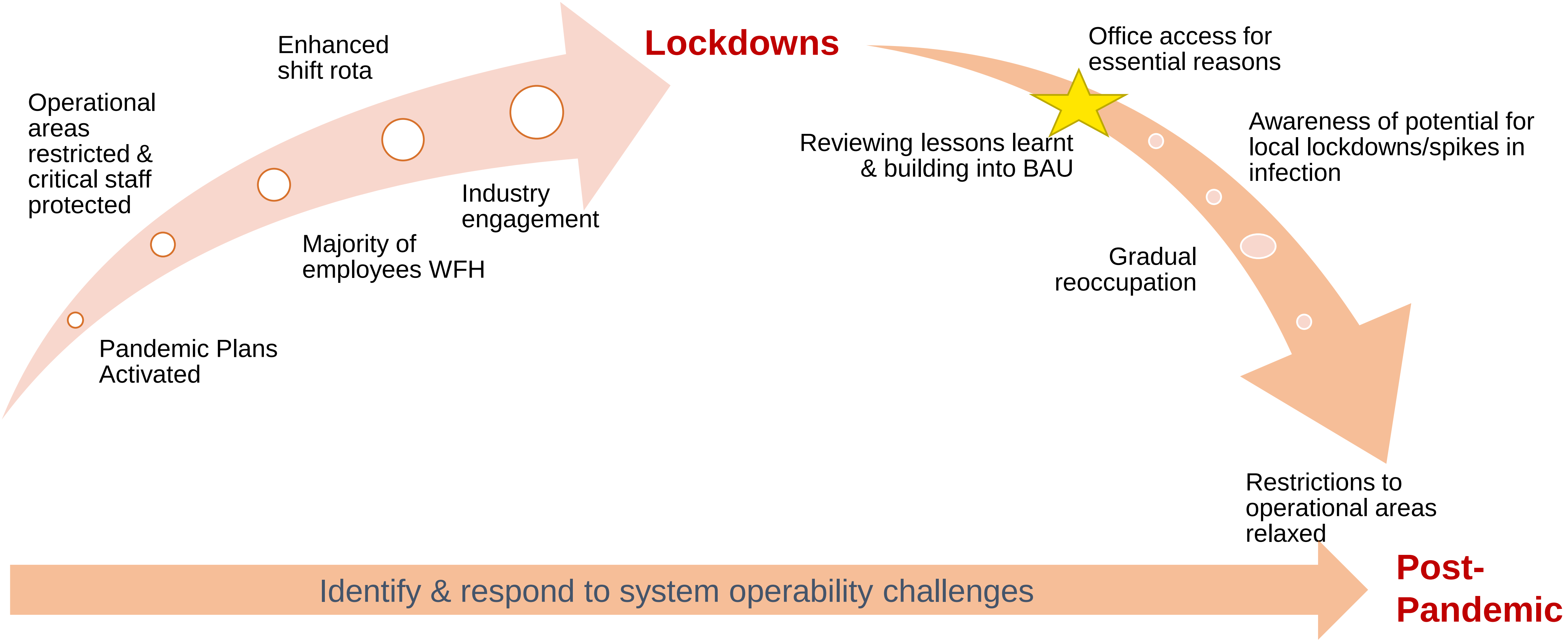
- Questions from last week
- Business continuity
- Demand review
- Costs for last week
- Outlook
- Constraints

Focus Areas

Forecasting methodology (high level overview)

SO – SO Trading

Protecting critical staff to maintain critical operations



Future forum topics

While we want to remain flexible to provide insight on operational challenges when they happen, we appreciate you want to know when we will cover topics.

We have the following deep dives planned:

January:

19th Jan: BSUoS Forecasting

26th Jan: Sterilized Headroom Overview

February:

Balancing Services Adjustment Data (BSAD) Overview

Questions outstanding from last week

Q: Are interconnector imports included in the 12:00 de-rated margin forecast for day ahead ?

A: The latest submitted IPN's for each interconnector are included, which at midday day ahead don't reflect the results of the day ahead interconnector auctions

Q: Why are BSAD data for some SO-SO trades still missing? There were BSAD for EirGrid trades on 15 November for trades across the East-West interconnector but not for those on Moyle

A: We are working on resolving the data discrepancies of the past 14 months in BSAD. Our settlements team will be carrying out a overview session of BSAD itself on 19 February and will be providing an update on these discrepancies.

Questions outstanding from last week

Q: Please can you provide some transparency on how the STOR buy curve is calculated each day.

A: We explain how the alternative cost for the buy curve is calculated in the STOR Assessment Principles March 2021. This document is published in the Daily STOR document library. The relevant text is extracted below:

The alternative cost: the buy curve

The buy curve is the assumed cost to NGESO of procuring STOR in the committed windows in an operational day, by creating short term operating reserve within day as an alternative to running a day ahead auction. This alternative cost will create an availability price cap by showing NGESO's willingness to pay for securing short term operating reserve capacity.

This will be calculated using:

- *the volume of actions (MW) required to create the reserve needed, and*
- *the prices (£/MWh) available to NGESO to access that volume.*

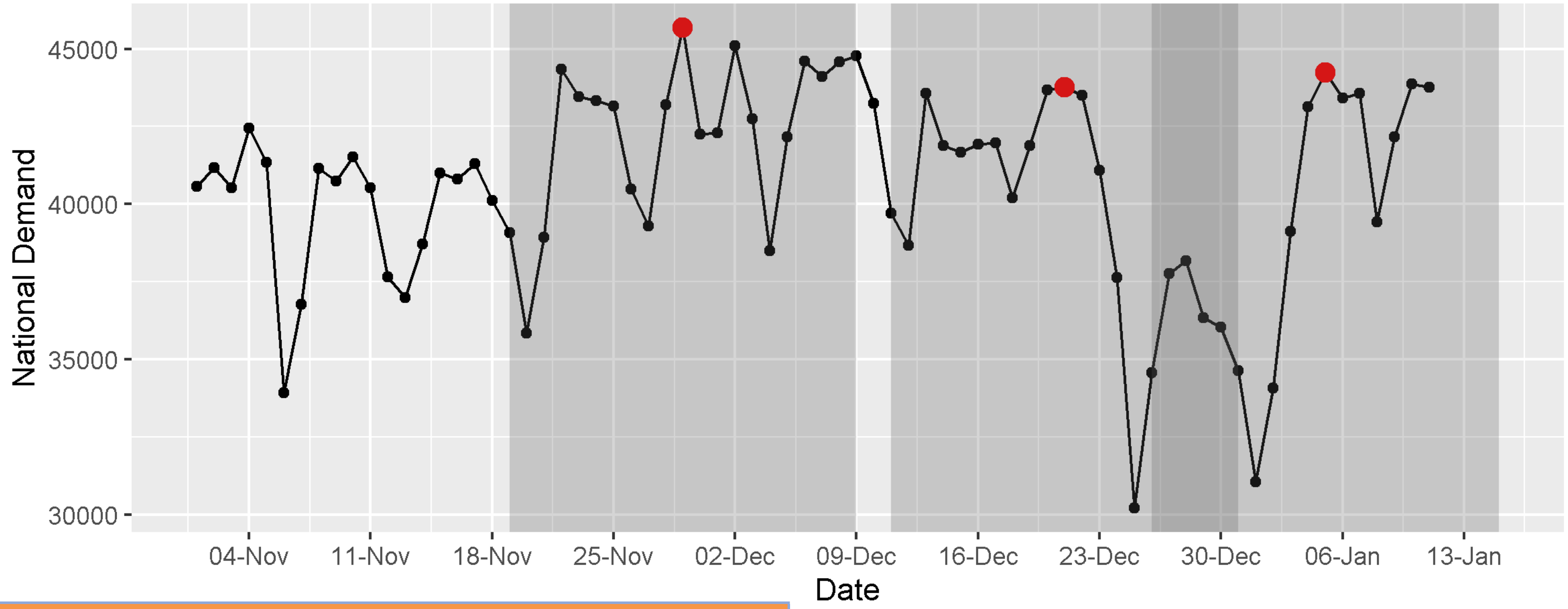
A separate buy curve is calculated for each operational day and therefore each auction, using the prevailing STOR requirement volume (currently 17000MW but as notified by NGESO from time to time). NGESO will endeavour to publish the buy curve for each auction alongside the STOR Daily Report.

This alternative cost for securing within day short term operating reserve capacity may include:

- *Costs of securing reserve through:*
    - *Offers within the Balancing Mechanism (BM) on unsynchronised generation*
    - *BM Start-Up services*
    - *Forward Trading within day*
    - *Market length (zero cost)*
    - *Market provided headroom (zero cost)*
- *The energy balancing costs caused by these actions.*

This is the first winter a day ahead STOR auction has been in place and we are keeping this procurement under continuous review to ensure all learning from each auction is implemented, particularly learning gained on days where the auction did not clear the full volume requirement. We welcome feedback from participants via commercial.operation@nationalgrideso.com

Demand | Indicative Peak National Demand

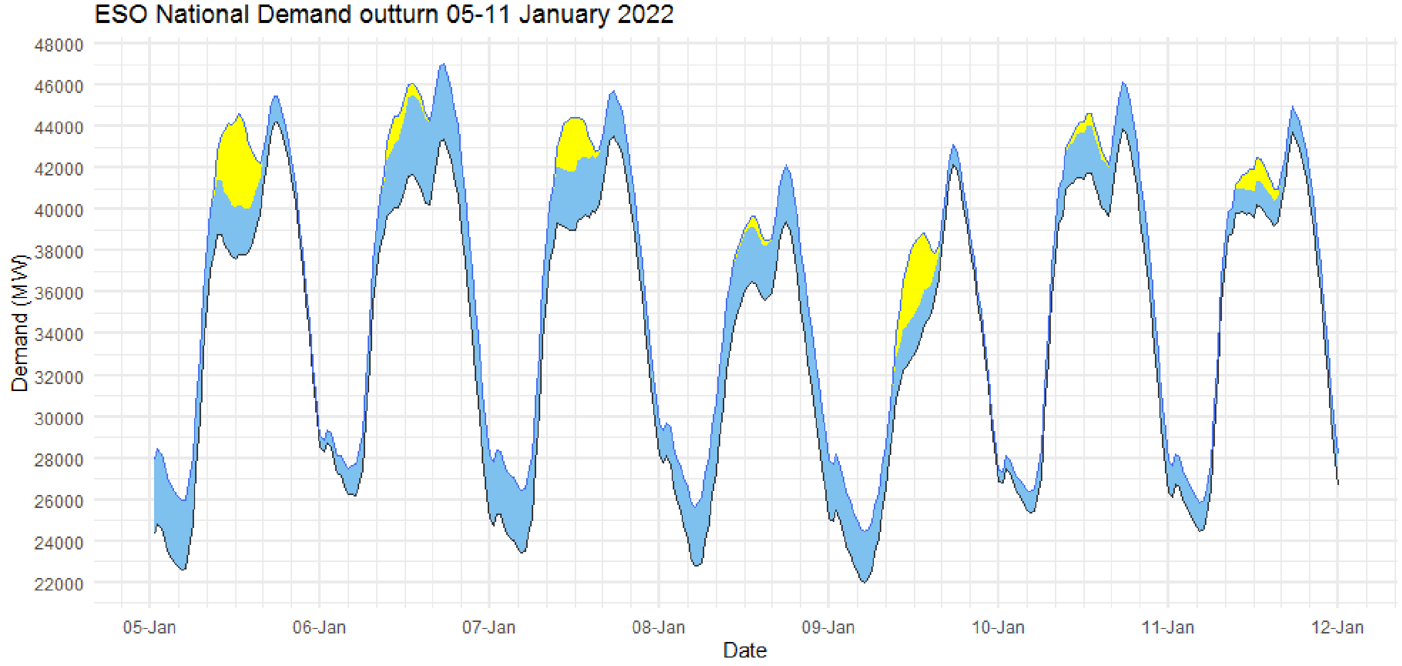


ESO operational metering			
Date	Time (HH ending)	National Demand (MW)	Estimated triad avoidance (HH corresponding with the time of the peak) (MW)
29/11/2021	1730	45679	0
05/01/2022	1800	44245	0
21/12/2021	1730	43769	900

National Demand does not include station load.

Indicative triad demand on Elexon's BMRS website quotes "GB Demand" which is based on the Transmission System Demand definition (it adds 500MW of station load onto the National Demand). It shows time as half hour beginning.

Demand | Last week demand out-turn

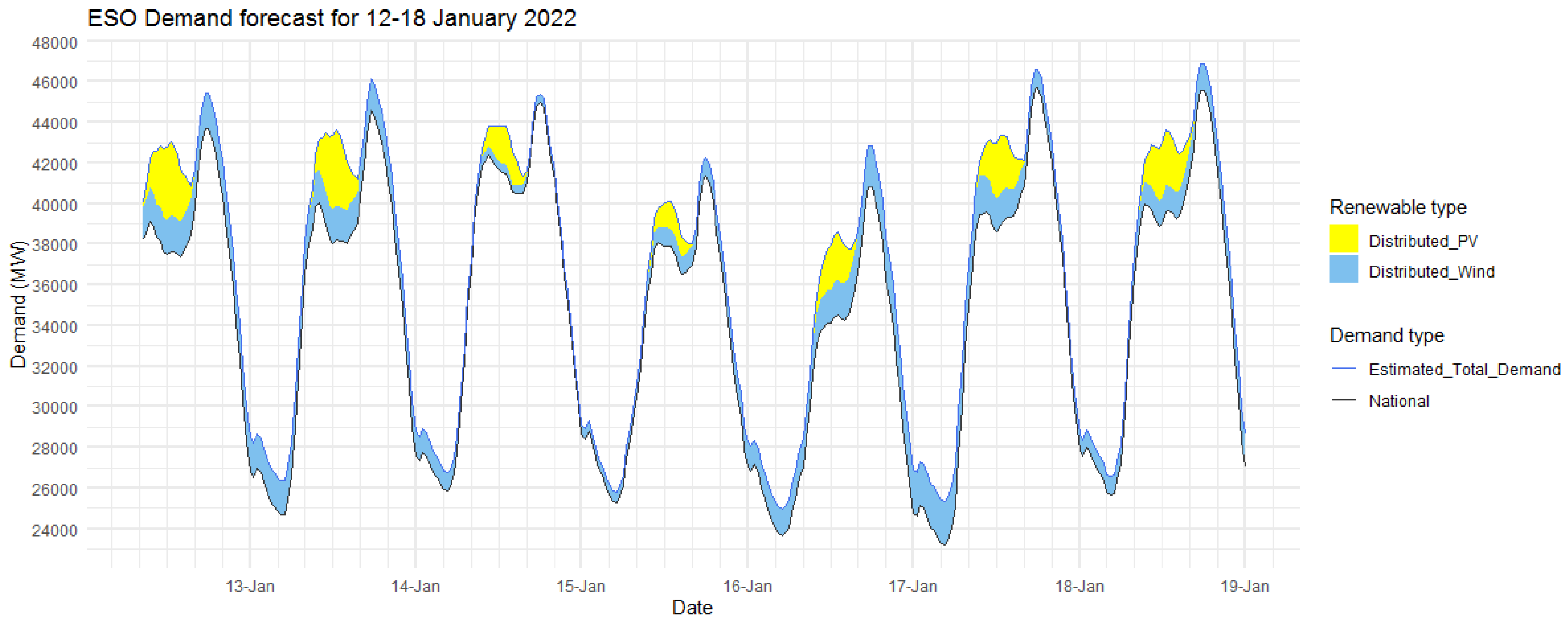


		FORECAST (Wed 05		OUTTURN			
Date	Forecasting Point	National Demand (GW)	Dist. wind (GW)	National Demand (GW)	Triad Avoidance est. (GW)	N. Demand adjusted for TA (GW)	Dist. wind (GW)
05 Jan	Evening Peak	44.8	1.4	44.2	0.0	44.2	1.2
06 Jan	Overnight Min	26.2	1.3	26.2	n/a	n/a	1.5
06 Jan	Evening Peak	44.3	3.6	43.4	0.8	44.2	3.6
07 Jan	Overnight Min	24.1	2.5	23.4	n/a	n/a	3.0
07 Jan	Evening Peak	44.2	2.1	43.6	0.0	43.6	2.2
08 Jan	Overnight Min	22.6	2.8	22.8	n/a	n/a	2.9
08 Jan	Evening Peak	38.8	3.1	39.4	0.0	39.4	2.7
09 Jan	Overnight Min	21.5	2.6	22.0	n/a	n/a	2.4
09 Jan	Evening Peak	41.3	1.5	42.2	0.0	42.2	0.9
10 Jan	Overnight Min	22.3	2.5	25.4	n/a	n/a	1.0
10 Jan	Evening Peak	43.3	2.3	43.9	0.0	43.9	2.3
11 Jan	Overnight Min	22.8	2.0	24.5	n/a	n/a	1.3
11 Jan	Evening Peak	43.8	1.7	43.8	0.8	44.6	1.2

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

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.

Demand | Week Ahead



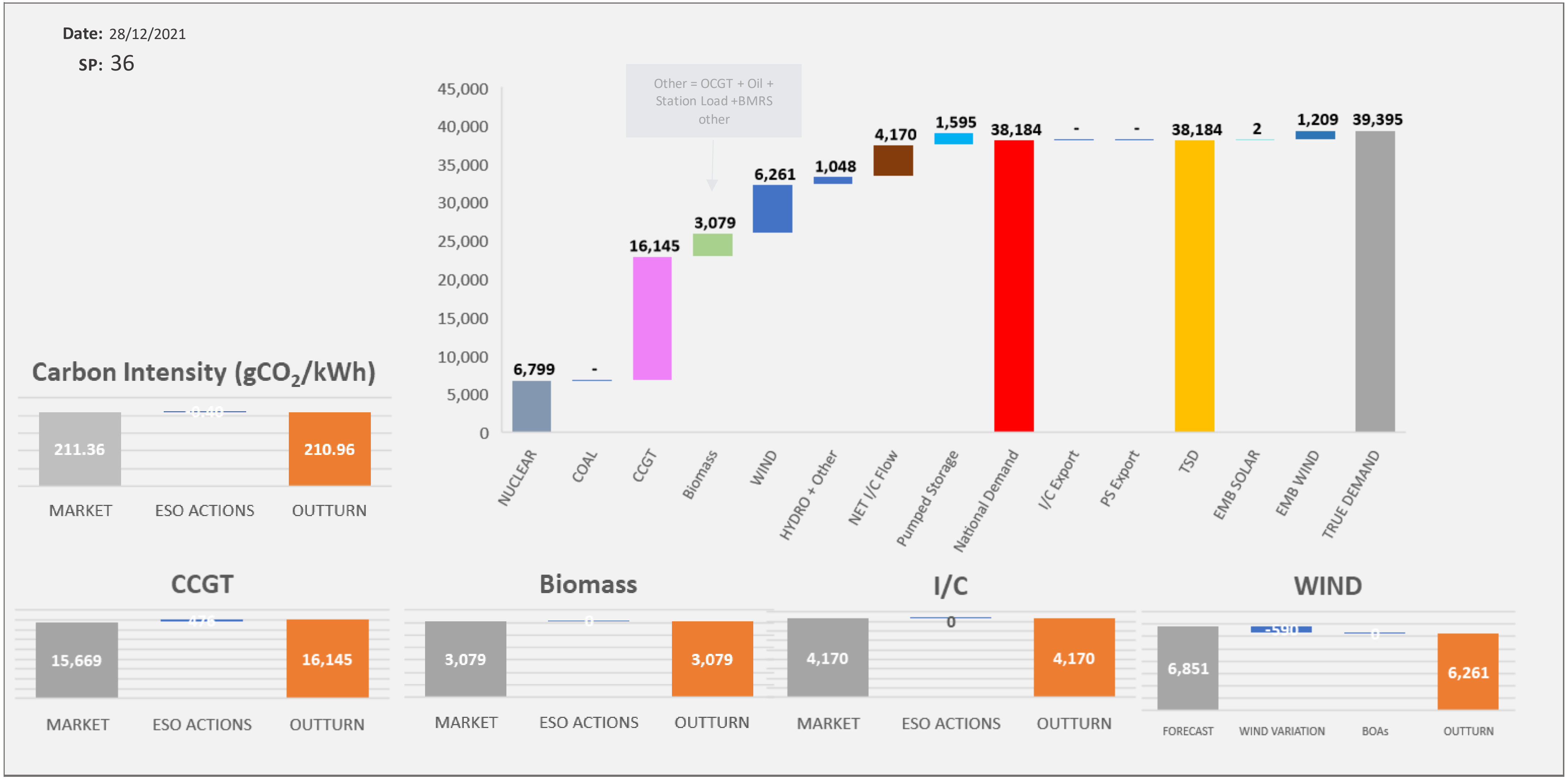
		FORECAST (Wed 12 Jan)	
Date	Forecasting Point	National Demand (GW)	Dist. wind (GW)
12 Jan 2022	Evening Peak	43.7	1.7
13 Jan 2022	Overnight Min	24.7	1.7
13 Jan 2022	Evening Peak	44.6	1.6
14 Jan 2022	Overnight Min	25.9	0.9
14 Jan 2022	Evening Peak	45.0	0.4
15 Jan 2022	Overnight Min	25.3	0.5
15 Jan 2022	Evening Peak	41.3	1.0
16 Jan 2022	Overnight Min	23.7	1.3
16 Jan 2022	Evening Peak	40.9	2.0
17 Jan 2022	Overnight Min	23.2	2.1
17 Jan 2022	Evening Peak	45.7	1.0
18 Jan 2022	Overnight Min	25.7	0.9
18 Jan 2022	Evening Peak	45.6	1.3

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

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.

First time ESO shares its Triad Avoidance adjusted **National Demand** forecast is after 21:00 on D-1

ESO Actions | Tuesday 28 December Peak



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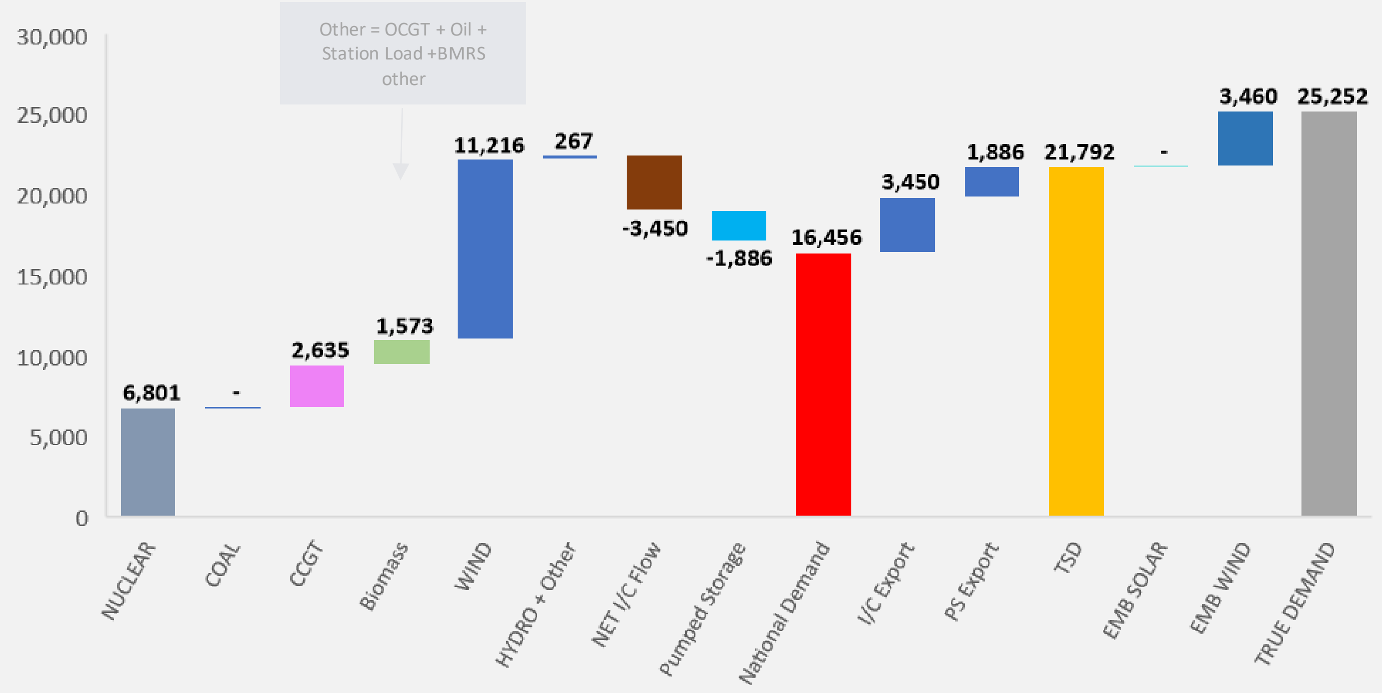
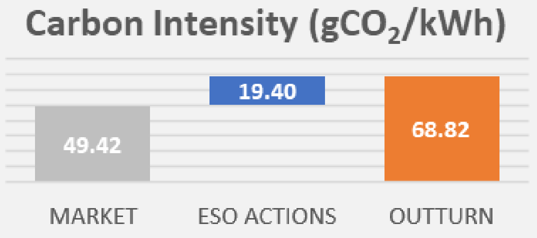
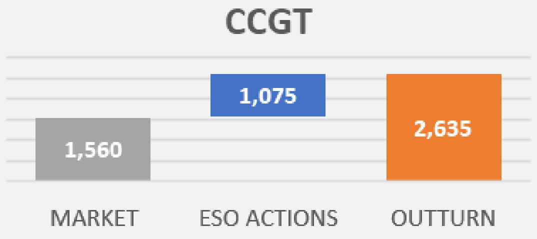
ESO Actions | Saturday 01 January Minimum

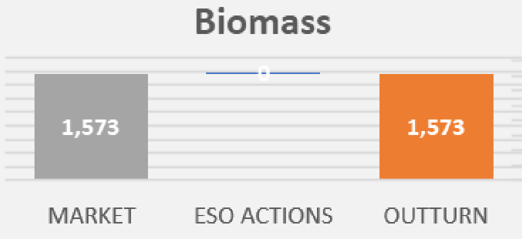
Date: 01/01/2022

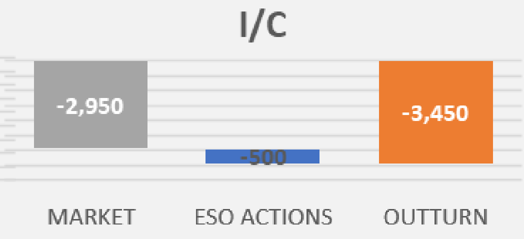
SP: 12

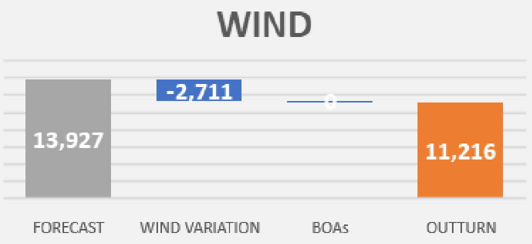




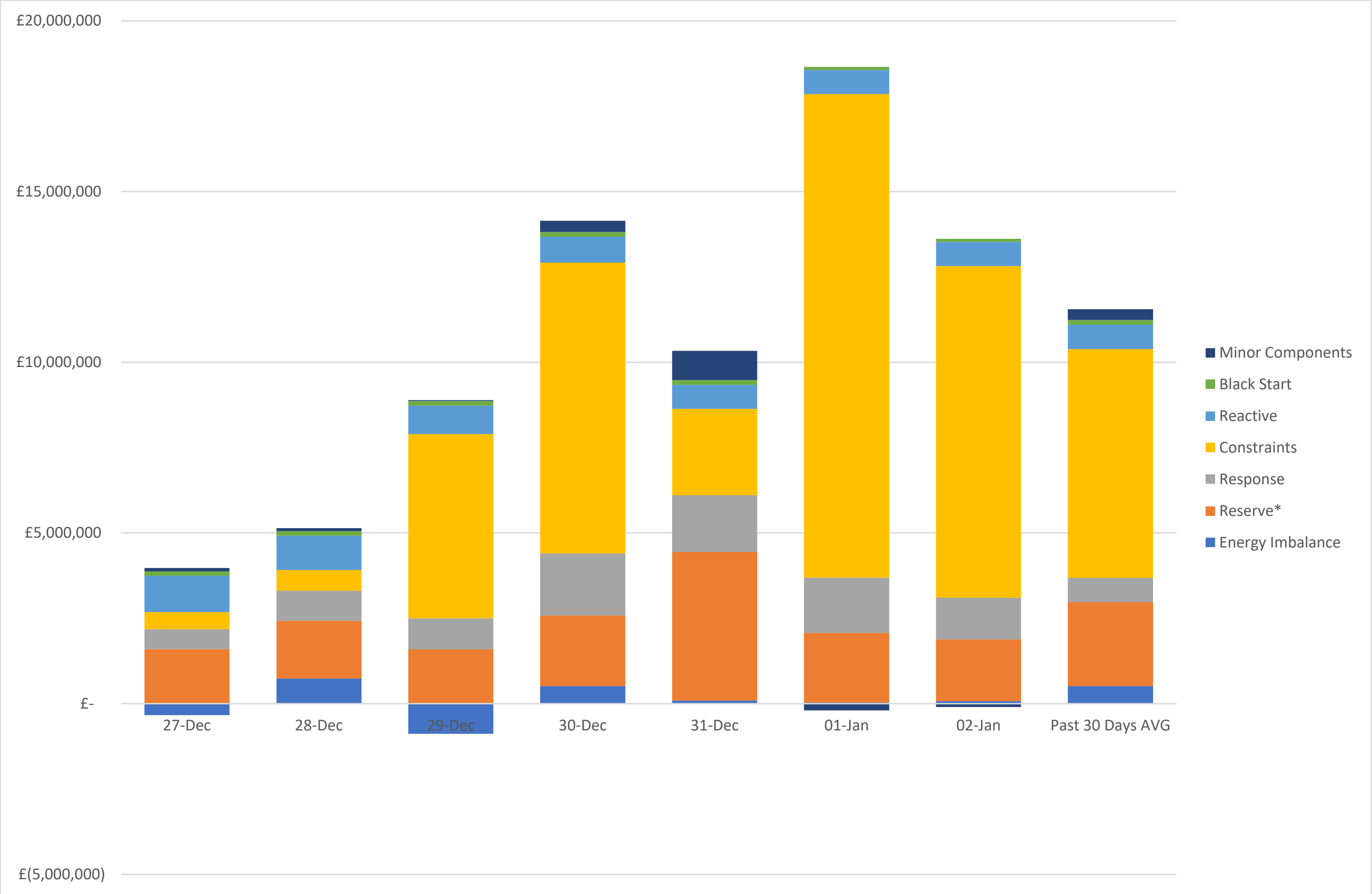








Transparency | Costs for the last week



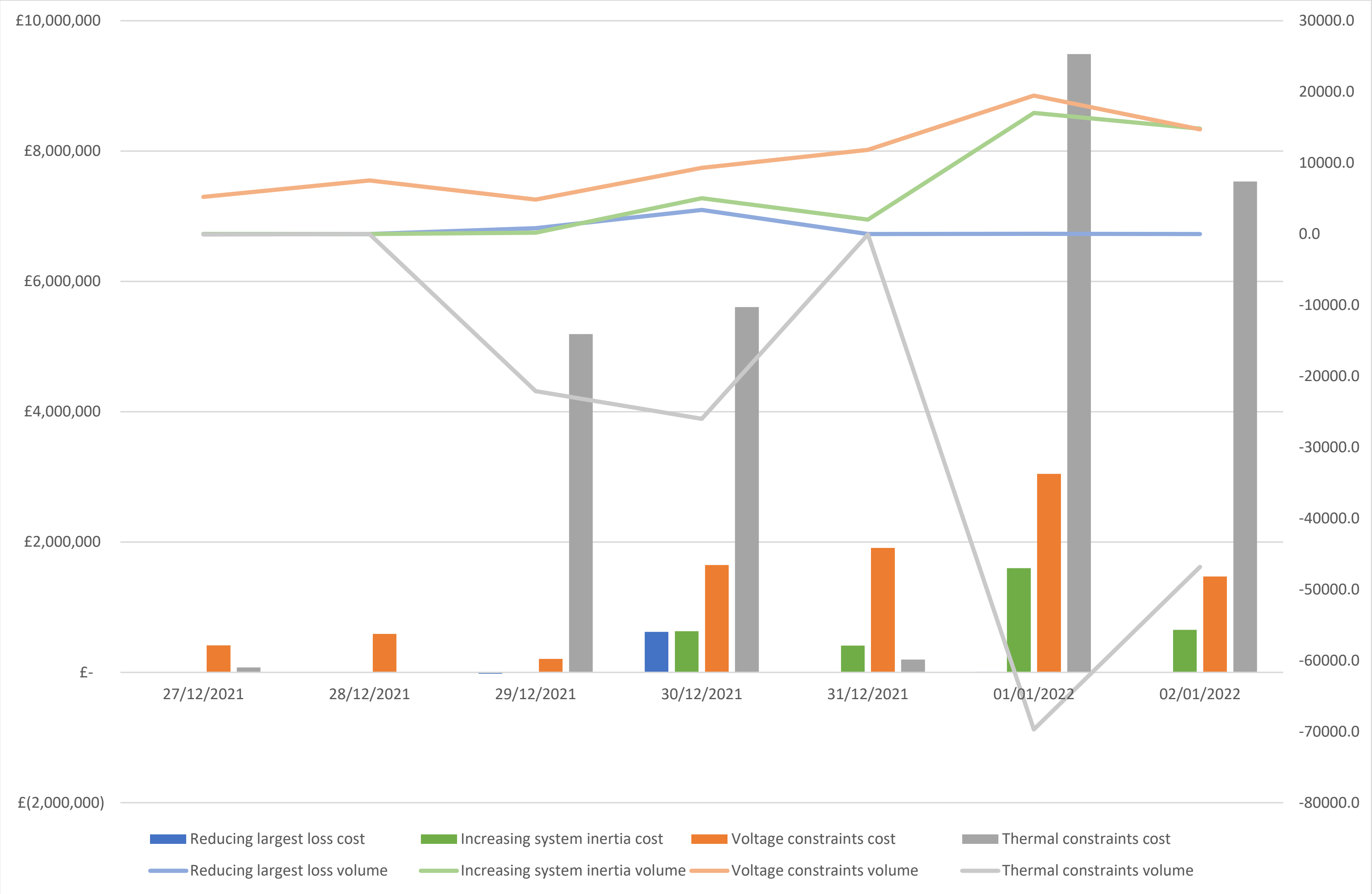
Between Thursday and Sunday daily costs remained above £10m.
Saturday was the most expensive day with a daily cost of over £18m.
Thursday and Sunday daily costs out turned at around £14m in both cases.

Constraints actions were the main drive behind high-cost days, due to the windy weather that was requiring large volume of BM actions to reduce generation to manage thermal constraints.

On Friday, reserve was the main component of the daily spend.

Past 30 Days Average added

Transparency | Constraint cost breakdown



Thermal
Wednesday, Thursday, Saturday and Sunday actions required to manage thermal constraints due to high wind level. Monday, Tuesday and Friday very little intervention required.

Voltage
Action to synchronise generation to meet voltage requirements were required throughout the week

Managing largest loss for RoCoF
Friday intervention required to manage largest loss on interconnectors.

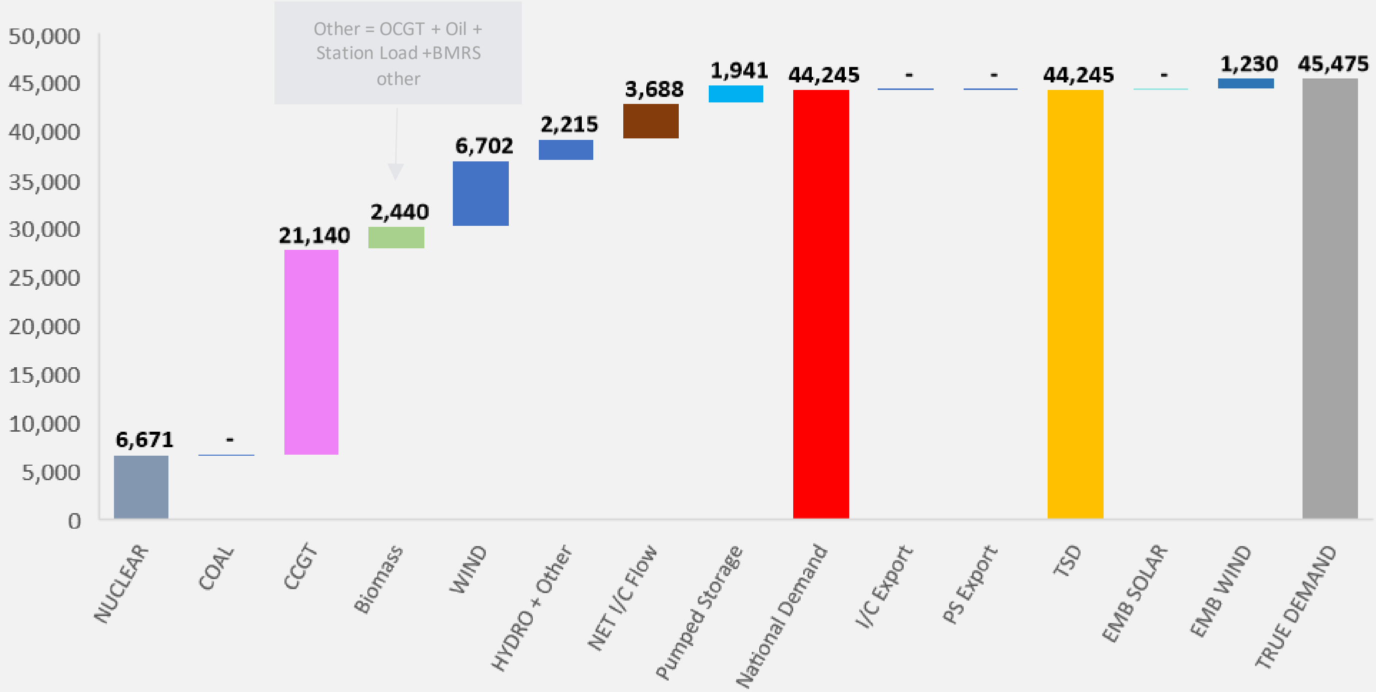
Increasing inertia
From Thursday onwards intervention required to increase minimum inertia.

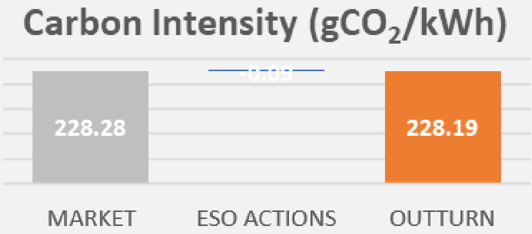
https://data.nationalgrideso.com/balancing/constraint-breakdown

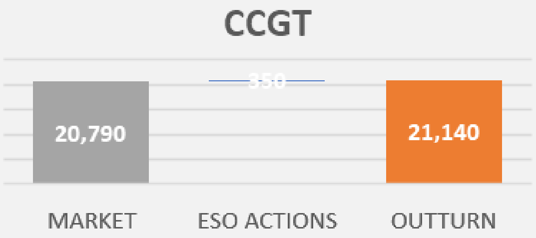
ESO Actions | Wednesday 05 January Peak

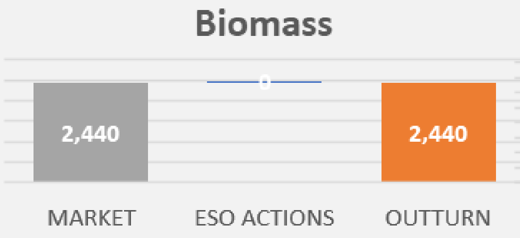
Date: 05/01/2022

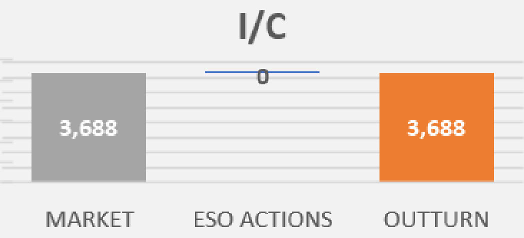
SP: 36

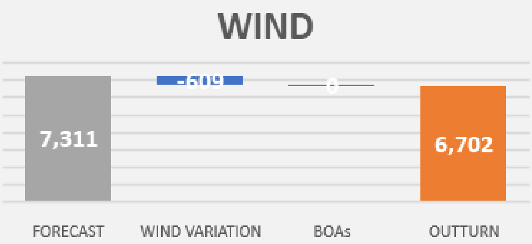










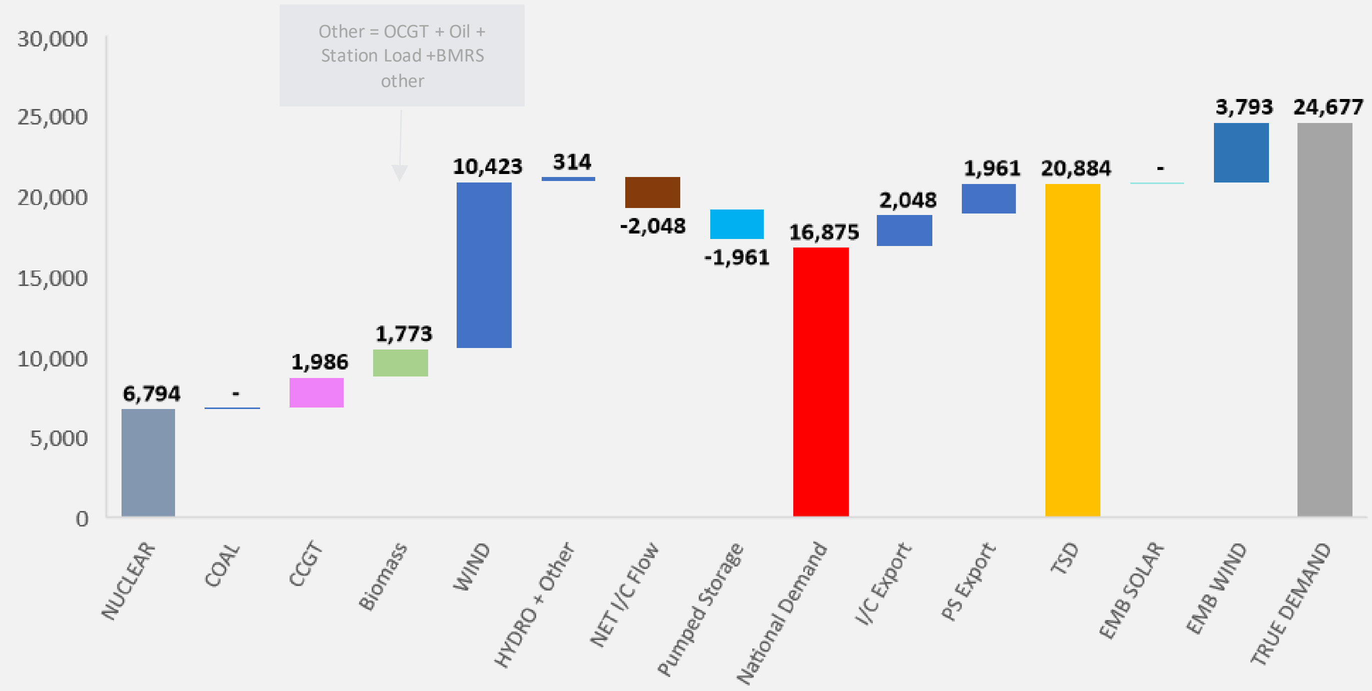


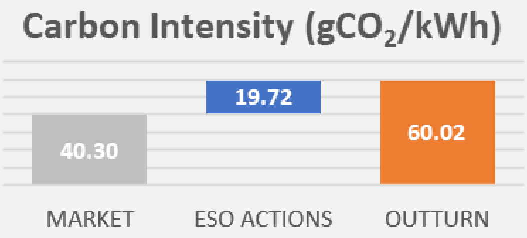
Carbon Intensity data on data portal: https://data.nationalgrideso.com/carbon-intensity1/carbon-intensity-of-balancing-actions

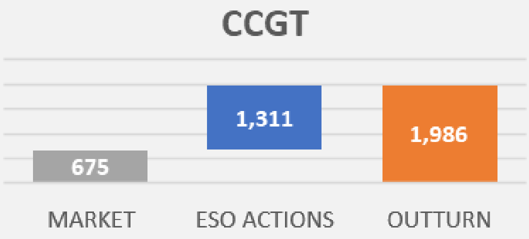
ESO Actions | Monday 03 January Minimum

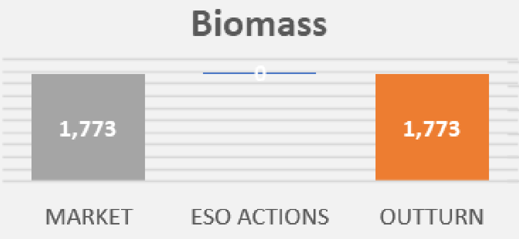
Date: 03/01/2022

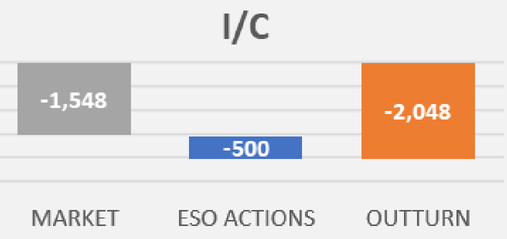
SP: 10

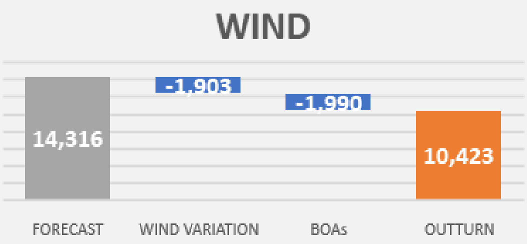






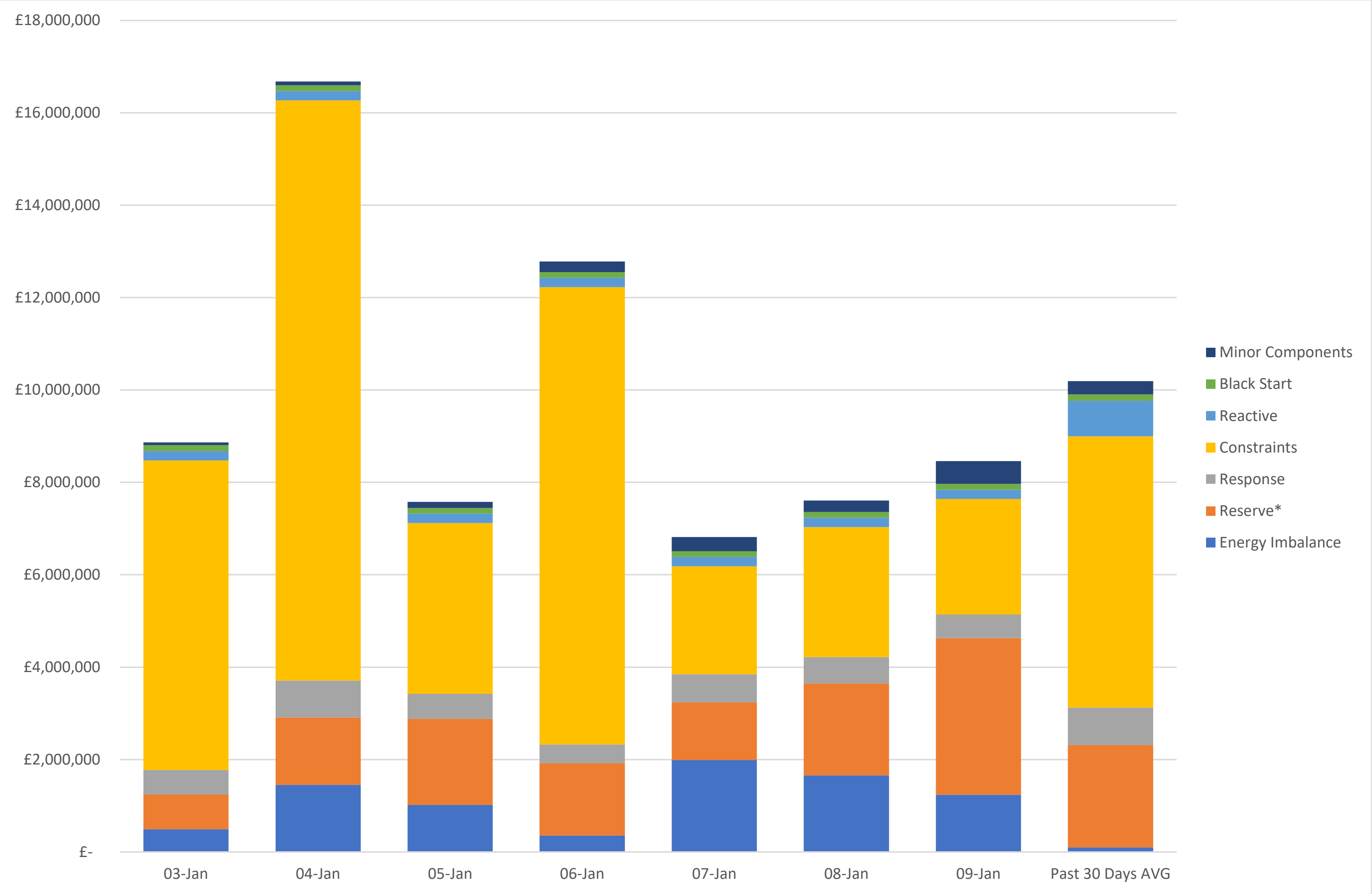






Carbon Intensity data on data portal: https://data.nationalgrideso.com/carbon-intensity1/carbon-intensity-of-balancing-actions

Transparency | Costs for the last week



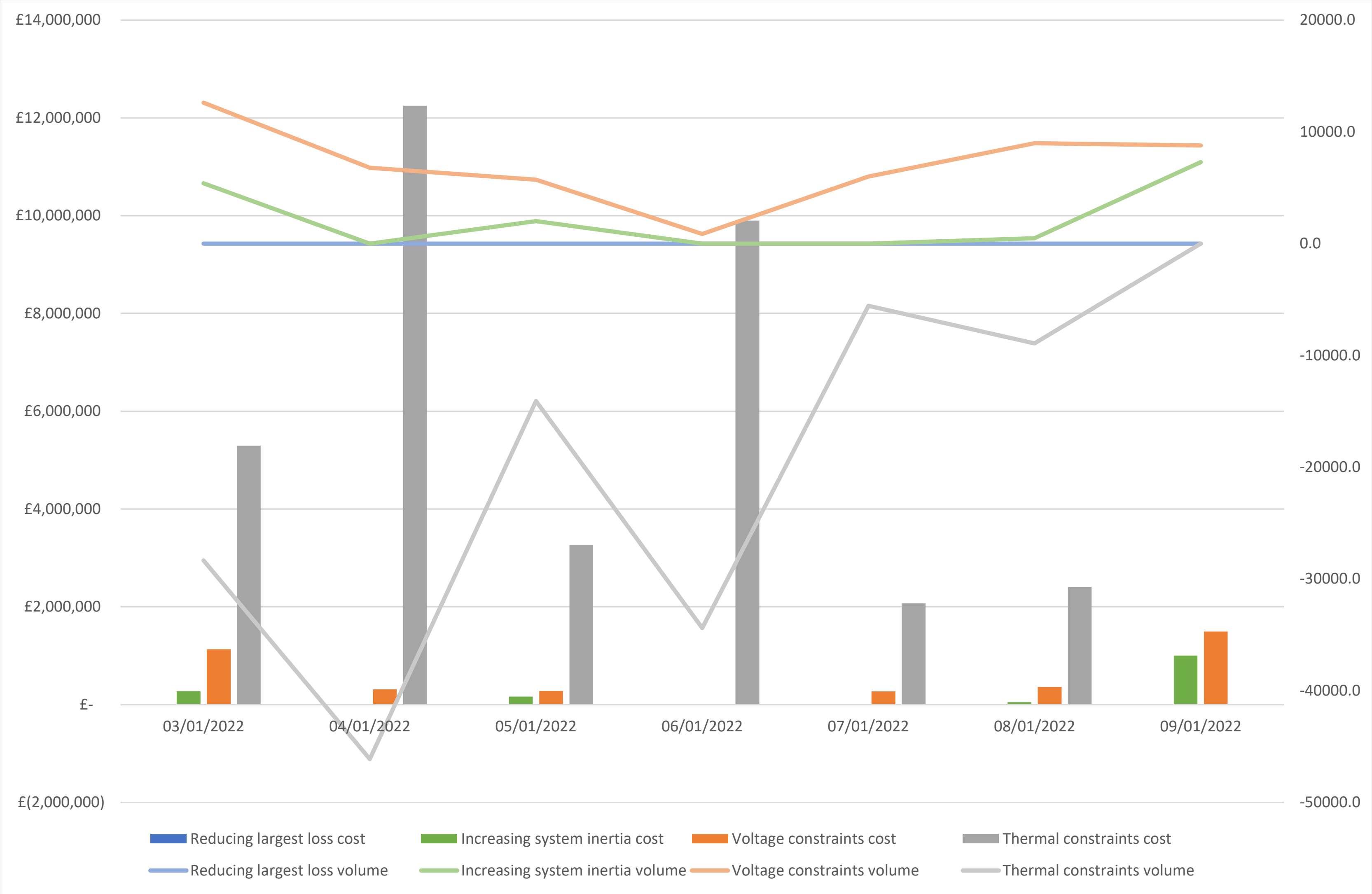
Tuesday 4th and Thursday 6th were the most expensive days, with a daily spend of around £17m and £13m respectively.

Costs associated to constraints actions were prevalent cost component throughout the week. This was due to the windy weather that was requiring large volume of BM actions to reduce generation to manage thermal constraints.

Over the other days of the week, costs remained below or around £8m.

Past 30 Days Average added

Transparency | Constraint cost breakdown



Thermal
From Monday through actions required to manage thermal constraints. Sunday no intervention required.

Voltage
Action taken to synchronise generation to meet voltage requirements on most days

Managing largest loss for RoCoF
No intervention required to manage largest loss on interconnectors.

Increasing inertia
Monday, Wednesday and Sunday intervention required to increase minimum inertia.

https://data.nationalgrideso.com/balancing/constraint-breakdown

Operational margins: week ahead

How to interpret this information

This slide sets out our view of operational margins for the next week. We are providing this information to help market participants identify when tighter periods are more likely to occur such that they can plan to respond accordingly.

The table provides our current view on the operational surplus based on expected levels of generation, wind, imports and peak demand. This is based on information available to National Grid ESO as of 12 January and is subject to change. It represents a view of what the market is currently intending to provide before we take any actions.

The indicative surplus is a measure of how tight we expect margins to be and the likelihood of the ESO needing to use its operational tools.

For higher surplus values, margins are expected to be adequate and there is a low likelihood of the ESO needing to use its tools. In such cases, we may even experience exports to Europe on the interconnectors over the peak depending on market prices.

For lower (and potentially negative) surplus values, then this indicates operational margins could be tight and that there is a higher likelihood of the ESO needing to use its tools, such as issuing margins notices. We expect there to be sufficient supply available to respond to these signals to meet demand.

Margins are adequate for the next seven days, but slightly tighter on Friday 14 January.

Day	Date	Notified conventional generation (MW)	Wind (MW)	Interconnector availability (MW)	Peak demand (MW)	Indicative surplus (MW)
Thu	13/01/2022	44366	6226	3900	45209	6331
Fri	14/01/2022	44834	689	3900	45579	898
Sat	15/01/2022	42327	2570	3900	41929	2481
Sun	16/01/2022	42972	7301	3900	41455	8075
Mon	17/01/2022	44227	3374	3900	46289	1540
Tue	18/01/2022	44501	4271	3900	46158	2705
Wed	19/01/2022	44501	6969	3900	45643	5741

Operational margins: week ahead

How to interpret this information

This slide sets out our view of operational margin range for the rest of the winter period. We are providing this information to help market participants identify when tighter periods are more likely to occur such that they can plan to respond accordingly.

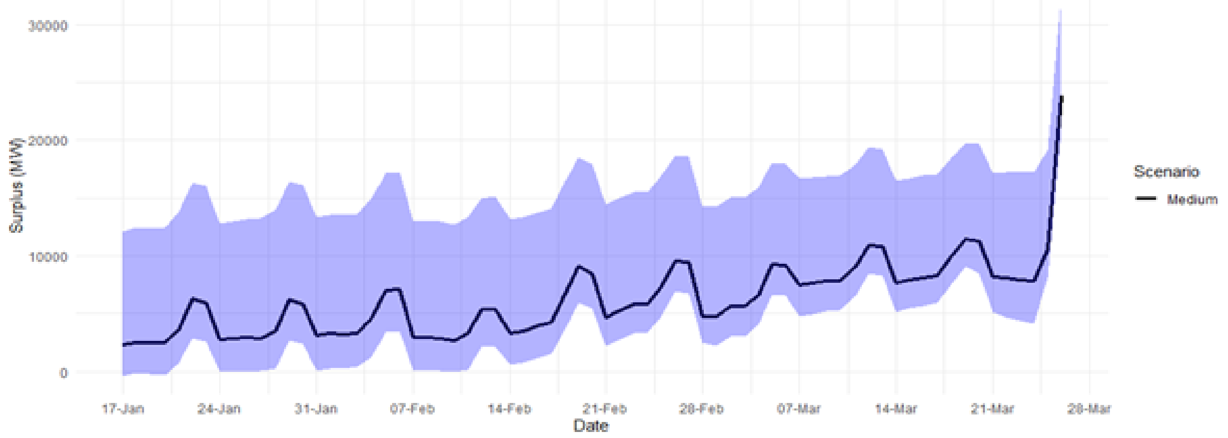
This view is based on information available to National Grid ESO as of 11 January and is subject to change as generators update their availability via REMIT.

The chart represents the potential surplus range we may expect on each day. It is based on 50,000 simulations that account for variation in demand, wind, generation and interconnector availability.

The chart represents a view before the ESO takes any actions. Periods where the lower bound is lowest (and even negative) represent the times when there is a higher likelihood of the ESO needing to use its operational tools such as issuing margins notices. We expect there to be sufficient supply available to respond to these signals to meet demand.

We don’t provide an update of this view each week, since in most weeks there is little change.

The risk of negative surplus has decreased for the final weeks of January compared to the position before Christmas. We continue to expect there to be sufficient supply available to respond to market signals in order to meet demand.



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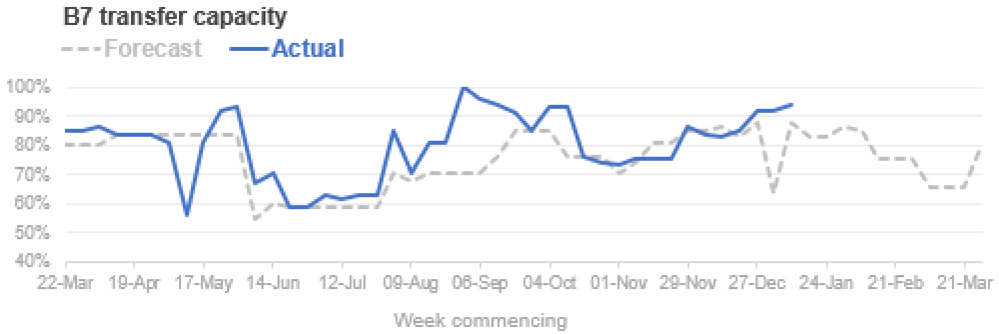
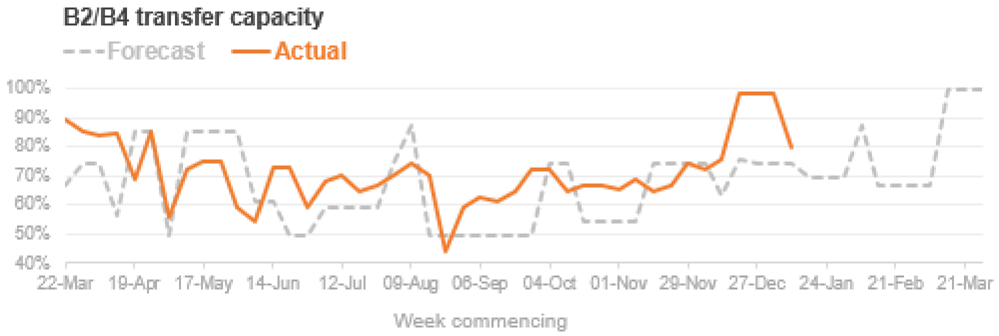
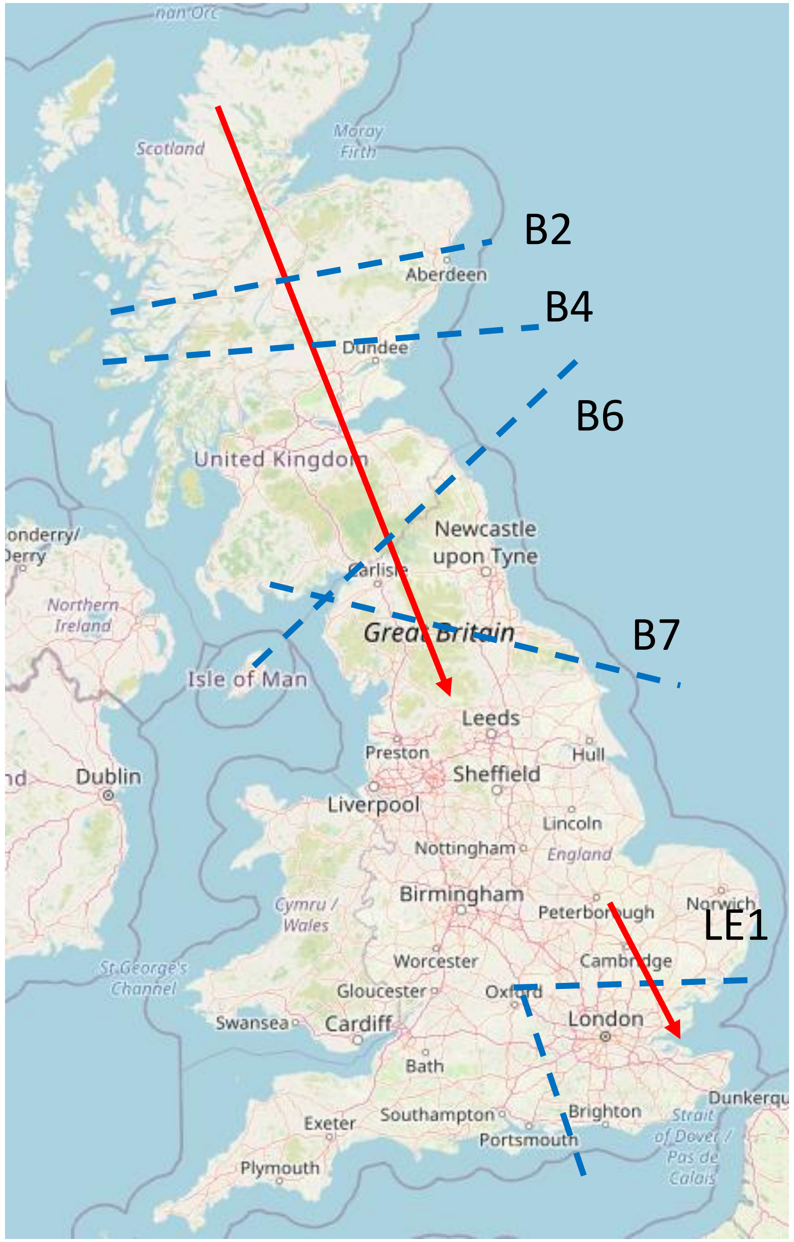
Transparency | Constraint Capacity

100% transfer capacity (MW)	
B6	5400
B7	8250
B2/B4	2700







Forecasting methodology high level overview

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The Company Forecasts

The Company Forecasts are specified in The Grid Code Operation Code (OC).
OC1 Demand Forecasts

OC1.6 THE COMPANY FORECASTS

OC1.6.1 The following factors will be taken into account by **The Company** when conducting **National Electricity Transmission System Demand** forecasting in the **Programming Phase** and **Control Phase**:

(a) Historic **Demand** data (this includes **National Electricity Transmission System Losses**).

(b) Weather forecasts and the current and historic weather conditions.

(c) The incidence of major events or activities which are known to **The Company** in advance.

(d) Anticipated interconnection flows across **External Interconnections**.

(e) **Demand Control** equal to or greater than the **Demand Control Notification Level** (averaged over any half hour at any **Grid Supply Point**) proposed to be exercised by **Network Operators** and of which **The Company** has been informed.

(f) **Customer Demand Management** equal to or greater than the **Customer Demand Management Notification Level** (averaged over any half hour at any **Grid Supply point**) proposed to be exercised by **Suppliers** and of which **The Company** has been informed.

(g) Other information supplied by **Users**.

(h) Anticipated **Pumped Storage Unit** demand.

(i) the sensitivity of **Demand** to anticipated market prices for electricity.

(j) **BM Unit Data** submitted by **BM Participants** to **The Company** in accordance with the provisions of **BC1** and **BC2**.

(k) **Demand** taken by **Station Transformers**

(l) Anticipated **Electricity Storage Module** demand

OC1.6.2 Taking into account the factors specified in OC1.6.1 **The Company** uses **Demand** forecast methodology to produce forecasts of **National Electricity Transmission System Demand**. A written record of the use of the methodology must be kept by **The Company** for a period of at least 12 months.

OC1.6.3 The methodology will be based upon factors (a), (b) and (c) above to produce, by statistical means, unbiased forecasts of **National Demand**. **National Electricity Transmission System Demand** will be calculated from these forecasts but will also take into account factors (d), (e), (f), (g), (h), (i) and (j) above. No other factors are taken into account by **The Company**, and it will base its **National Electricity Transmission System Demand** forecasts on those factors only.

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Demand definitions

National Demand

the measure of portion of total GB customer demand that is supplied by the transmission network.

National Electricity Transmission System Demand

the total demand to be met by the transmission network.

It is a sum of National Demand, station load, exports on the international interconnectors and demand from pumped storage units.

"Virtual" demand (proxy)

National Demand plus 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.

National Electricity Transmission System Demand (TSD)

National Demand (ND)

Power Station Demand

(500MW in BST, 600MW in GMT)

Interconnector Exports

Pumped Storage Pumping

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

Increasing TSD

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.

23 **This figure shows the relationship between different types of demand**

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Demand definitions

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

	Term	Definition	Note
Types of demand	GB Customer demand	Sum of all demand used within GB. Total demand requirement for GB.	This includes demand offset by embedded generation on the distribution networks and is similar to the demands quoted in FES.
	Transmission system demand	Sum of all generation that flows through the GB Electricity Transmission network to meet internal GB demand or exports out of GB.	These are the demands typically presented in the Summer and Winter Outlook.
	National demand	Sum of all generation that flows through the GB Electricity Transmission network to meet internal GB demand, excluding electricity used to power large power stations	
	Triad demand	Transmission demand minus exports out of GB. Used to determine the days on which Triads have occurred	
Types of outturn	Operational outturn	Uses all real-time metering feeding into NG ESO live systems	
	Settlement metering outturn	Uses metering from Elexon settlement metering which is then reviewed by all parties so anomalies can be resolved. For generation this only includes plant that participates in the Balancing Mechanism (BM)	
	Normal or Weather Corrected outturn	Operational outturn adjusted to provide the equivalent demand under average weather conditions	
	Average Cold Spell (ACS) outturn	A measure of hypothetical maximum demand over some period (usually an entire winter period) based on all the possible weather variation that could have occurred over the period. The ACS outturn is the value that, based on all the hypothetical weather variation, had a 50% chance of being exceeded. It is the average value of the maximum demand.	This is used in the Winter Outlook when considering supply margins.
Types of forecast	Operational forecasts	Forecasts based on using detailed meteorological forecasts when available (out to 14 days ahead) or average weather conditions (beyond 14 days ahead)	
	Normal or Weather Corrected forecasts	Forecasts based on using average weather conditions (beyond 14 days ahead). All longer range forecasts are on this basis	These are the forecasts presented in the summer and winter outlook.
	Average Cold Spell (ACS) forecast	A forecast of maximum demand over some period (usually an entire winter period) based on all the possible weather variation that could have occurred over the period. The ACS forecast is the value that, based on all the hypothetical weather variation, has a 50% chance of being exceeded. It is the forecast for the average value of the maximum demand.	Used in the winter outlook for peak demand forecasting when considering capacity available to meet peak demands during low temperatures.

Modelling Approach

- Forecasting models build using “virtual” demand definition of demand
- Using a technique called generalized additive model (GAM).
- Explanatory variables in the models are mostly weather variables & time of year
- Historical demand is used to train the models.
- Recent demand is used to set the level of the model.
- Demand is forecast at Cardinal Points which are points on the demand curve that carry significant meaning, typically turning points on the curve
- Demands for half hour settlement periods in between Cardinal Points are interpolated using a well-chosen historical curve as recent as possible, similar time of year, similar weather pattern

System Operator to System Operator (SO-SO) Trades

- SO-SO Trades are one of the tools NGESO uses to alter scheduled cross border flows close to real time, to aid the operational of the GB system, for example for frequency management or to provide Emergency Assistance.
- NGESO has established SO-SO Trades in conjunction with our neighbouring Transmission System Operators (TSO). They are reciprocated and therefore available to both TSOs however TSOs have the ability to reject a request for an SO-SO trade.
- The TSOs exchange prices ex-ante that are set following the principle that the supporting TSO should not be exposed to additional net cost.
- Bilateral SO-SO Trades may ultimately be superseded by pan-European mechanisms such as TERRE and MARI however following the EU-Exit such platforms are not available to GB at the time. The Trade and Cooperation Agreement requires a review of SO-SO tools in balancing timescales by GB and EU TSOs

Enabling the transformation to a sustainable energy system:
Our RIIO-2 BP2 webinar series

Webinars	Date & Times
Webinar 1: A look ahead to 2023 and beyond: our journey to enabling the transformation to a sustainable energy system	Monday 24th January (13:00-14:15)
Webinar 2: Looking ahead to 2023 and beyond: Control centre operations	Wednesday 26th January (13:00-14:15)
Webinar 3: Looking ahead to 2023 and beyond: Market development, transactions and our role in Europe since Brexit	Thursday 27th January (13:00-14:15)
Webinar 4: Looking ahead to 2023 and beyond: Our innovation priorities	Thursday 3rd February (13:00-14:15)
Webinar 5: Looking ahead to 2023 and beyond: Our commitment to providing open data and transparency	Monday 7th February (13:00-14:15)

Details of further webinars in the series, to be shared very soon!

The RIIO-2 Price Control:

Purpose of the webinars:
To share with stakeholders our initial thoughts for what could be new / materially changed from our 5-year business plan (covering 2021-2026), with respect to the RIIO-2 BP2 period.

Sign up to our webinars [here]
(This link will take you to our "Get Involved" ESO web page, where you can sign up to each of the webinars separately via Eventbrite)

Q&A

After the webinar, you will receive a link to a survey. We welcome feedback to understand what we are doing well and how we can improve the event ongoing.

Please ask any questions via Slido (code #OTF) and we will try to answer as many as possible now. If we are unable to answer your question today, then we will take it away and answer it at a later webinar.

Please continue to use your normal communication channels with ESO.

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

Audience Q&A Session

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Q&A

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