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ESO Operational Transparency Forum

15 Sep 2021

nationalgridESO

Introduction | Sli.do code #OTF

Following your feedback, we are continuing to use Slido and Microsoft Teams. 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. You can also ask questions using the normal chat function.

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 and outlook
- Costs for last week
- Constraints

Additional topics for this week

- Update on DC low auctions on EPEX platform
- Market margin signals deep dive

Questions outstanding from last week

Q: We are having issues with eNAMS not providing visibility of outages on which we are affected User and this has been logged both with NGESO IS and NAP. Are issues like this affecting our operations being resolved as a high priority? How wide spread are issues such as this e.g. other Users?

A: We are aware of several issues and are working to resolve. A major release of fixes was due last Thursday and we will continue to investigate.

Q: 2-52 week Demand (NDFW and TSDFW) on BMreports.com was last updated on 19th August. Elexon tell us they aren't receiving updated data. Assuming it is the ESO that is supplying this data to Elexon please can you make sure this datafeed is fixed.

A: The year ahead forecast was updated last Friday, 10th September. There is a slide on this topic in the presentation.

Q: Does the ESO publish a 'certainty' factor for its demand forecasts and what are key variables that create the uncertainty?

A: We don't. The key: the weather, the level of renewable generation, underlying level of demand, days around Bank Holidays, Easter, Christmas & New Year. We always endeavour to cover this as part of our monthly reports for the day ahead demand forecasting performance.

Q: Question for yesterday (Tuesday 7 September). Derated Margin for the evening was almost 0 for the evening [SP34-39] till around midday. At midday additional 2GW was found. Where did this additional 2GW come from? How come it was first "available" around midday, when initially published around 0MW?

A: We have a deep dive on market margin signals during the session today which should bring some clarity around all the inputs and outputs of these calculations. The de-rated margin information published on BMRS for 7th Sep shows that the margin forecast actually tighted for the peak (e.g. period 36, 17:30-18:00) between the 8HA and 4HA forecasts, so the comparison may have been against the day ahead forecast which has some known issues which often make it over pessimistic.

Questions outstanding from last week

Q: DC changes: when the EPEX platform goes live for DC auctions on 15th September, will the format of the results on the data portal change? Thanks

A: The format of the results will be changing and NGESO will be producing 3 results files, 1. Summary of results, 2. Accepted tenders and 3. All tenders. All results will be posted on this link https://data.nationalgrideso.com/ancillary-services/dynamic-containment-data

Q: With a lot of DC contracted assets coming OFF DC this week, should the decision not to manage largest infeed loss on BMU's be constantly assessed on availability of DC and ability to arrest a loss of frequency

A: The control room continually assess the requirements to manage the largest loss in the most optimal way. DC contracted assets coming out of the DC market is an action taken in high demand situations and in this situation largest infeed loss on BMUs is often implicitly secured through the high inertia levels on the system.

Q: On Monday an offer was accepted at ~£3500, the plant then dropped it's MEL to zero, and cashout subsequently was ~£280. Does that plant keep that £3200 spread? What is the downside for plant at the top of the offer stack from perhaps gaming this given it's essentially a free option on cashout? Will GRAIN-6 acceptance then not be included in next settlement run

A: When BOAs are not delivered there are processes to remove these BOAs to ensure that units cannot profit in this way. This means the unit will not be rewarded or penalised for non-delivery due to a technical issue. It also means the impact on cashout will be removed.

Questions outstanding from last week

Q: Response costs: Is this solely related to positioning BMUs to deliver Mandatory Frequency Response?

A: It's all response costs, so this includes response products that we procure ahead of time and also any actions taken in the control room for Mandatory Frequency Response.

Q: When do NSL buy the energy for testing, they don't publish DA remit until after the DA auction has run. What is the market price for the interconnector? Day ahead auction, cashout etc? Or do ESO offer a price for the testing?

A: NSL will have a nominated market participant who trades out the test profile for them.

Q: Once NSL commissions will it not just add to RoCoF costs? So are we really desperate for it?

A: The total frequency response the ESO procures (including Dynamic Containment) allows the ESO to secure larger losses on the system including consequential RoCoF losses. The majority of flows on NSL are expected to be imports to GB which will mean that consumers will benefit from access to a cheaper source of electricity. Interconnection is very flexible and brings increased diversity and options for system operation. Flexibility is a key enabler for the transition to net zero.

Q: What are the causes of tight margins over recent weeks you've referred to?

A: Recent weeks have seen sustained periods of lower than normal wind output. IFA has been on outage which has reduced imports from Europe. We are at the time of year when demands are increasing as the weather changes, and available generation increases, as plant returns from summer outages, to meet that demand. As both demand and generation ramp up, short delays in plant return often leads to tighter margins at this time of year. However, margins have remained adequate.

Questions outstanding from last week

Q: Why was the overall costs 3.2 vs 5.7 for those units? Why did Rye House cost add up to £2m more than WBA when their bid price and their capacity was lower at 420MW?

A: When comparing costs, we assume that we will buy a unit on at SEL and then have access to the MEL as margin. There is also a variation in run times based on their minimum non-zero time and whether the unit had submitted any PNs for other periods in the day. In this instance, West Burton submitted PNs for later in the day which means the BOAs sent only needed to join up to those.

Rye House needed a 6 hour run with a SEL of 270MW and a cost of £3900/MWh

West Burton needed a 4 hour run with a SEL of 260MW and a cost of £3950/MWh

Q: Does Grain-6 have a bilateral contract to keep the PN at zero? Seems quite a cheap station to continually sit in reserve regardless of market price

A: No

Q: Isn't the fact that all the offer prices shown in your System Operating Plan slides were extremely high but not all the units were required strong evidence that there isn't real competition in the market for positive reserve in BM timescales on tight days. Have you asked Ofgem to investigate?

A: The vast majority of the units available were required for operating margin or for contingency reserve. Both of these requirements are key to managing the system. We keep an open dialogue with Ofgem on market behaviours and trends that we see.

Since becoming a PPAT in January and our subsequent licence condition obligating the ESO to monitor market activity to identify and report potential market abuse to OFGEM, we have been developing our activities under this umbrella. The Market Monitoring team will present at a future OTF on ways the industry participants can support this activity.

Questions outstanding from last week

Q: Are you also running smaller plant, for example why are you not buying more STOR, as they seem to offer you less running hours at cheaper prices.

A: To see the story more clearly, the focus of the slides today was on the large, non-wind units. Small BMUs are dispatched in a similar way.

We procure STOR at day ahead based on our communication of our requirement for this service. Over procuring against this requirement for operating margin is not the right course of action. We procured enough STOR at day ahead to meet our requirements at the time. Things can and do change within day and we use other markets, such as the Balancing Mechanism to complement the day-ahead services. Alternative routes to market are available for providers wishing to participate in other ways.

Q: Re SOP, what's the difference between "In the plan" and "Contingency"

A: In the plan means that we are planning to run the unit on a BOA. Contingency means that we are planning to use this unit to cover any shortfalls that might happen before real-time. A unit marked as contingency is not planned to be BOA'd unless something changes between the time the SOP was made and real-time.

Q: Today (Wednesday 8 September) SP19-23 cashed out at £270/MWh+ as peakers were used at high prices to cover the short, however DAMC was on an offer at £190/MWh with 220MW of unusued headroom. The costs of taking the significantly higher actions will feed through to consumers via BSUoS and cashout. What was the reason?

A: Damhead was required for response for these periods and as such could not be BOA'd to a higher position. This is a good example of the whole system operability and cost being considered when actions are taken.

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.

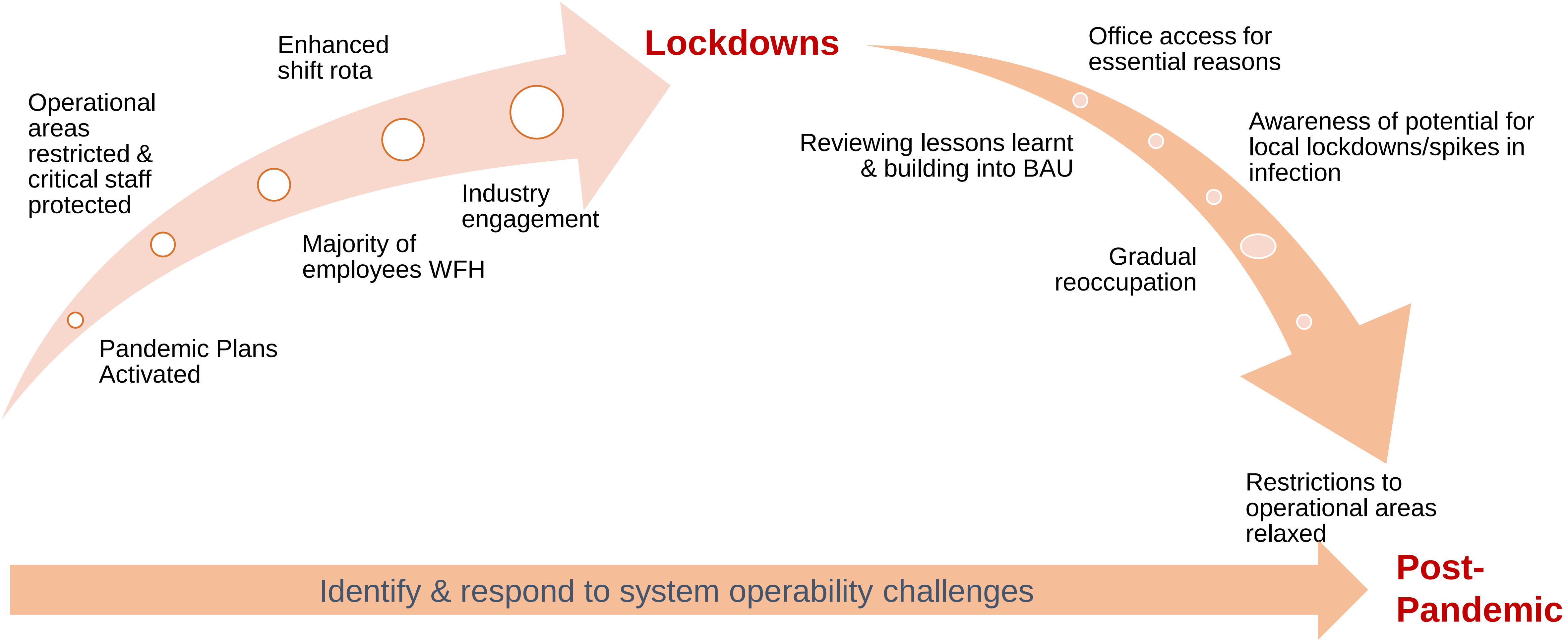
You have requested the following and we are looking at when we can bring these topics:

Stability pathfinder update

Deep dive into how Carbon Intensity is calculated

Deep dive on system flags criteria, e.g. in the context of Didcot

Protecting critical staff to maintain critical operations



Dynamic Containment (DC) Low auctions on EPEX platform

31 August 2021

Ofgem approved A.18 EBGL consultation to amend T&Cs

1 September 2021

Dynamic Containment Low (DCL) Frequency launched on the EPEX SPOT platform

15 September 2021

First DCL auction on the EPEX platform takes at 10am and will then continue to run daily at the same time

Progress to date

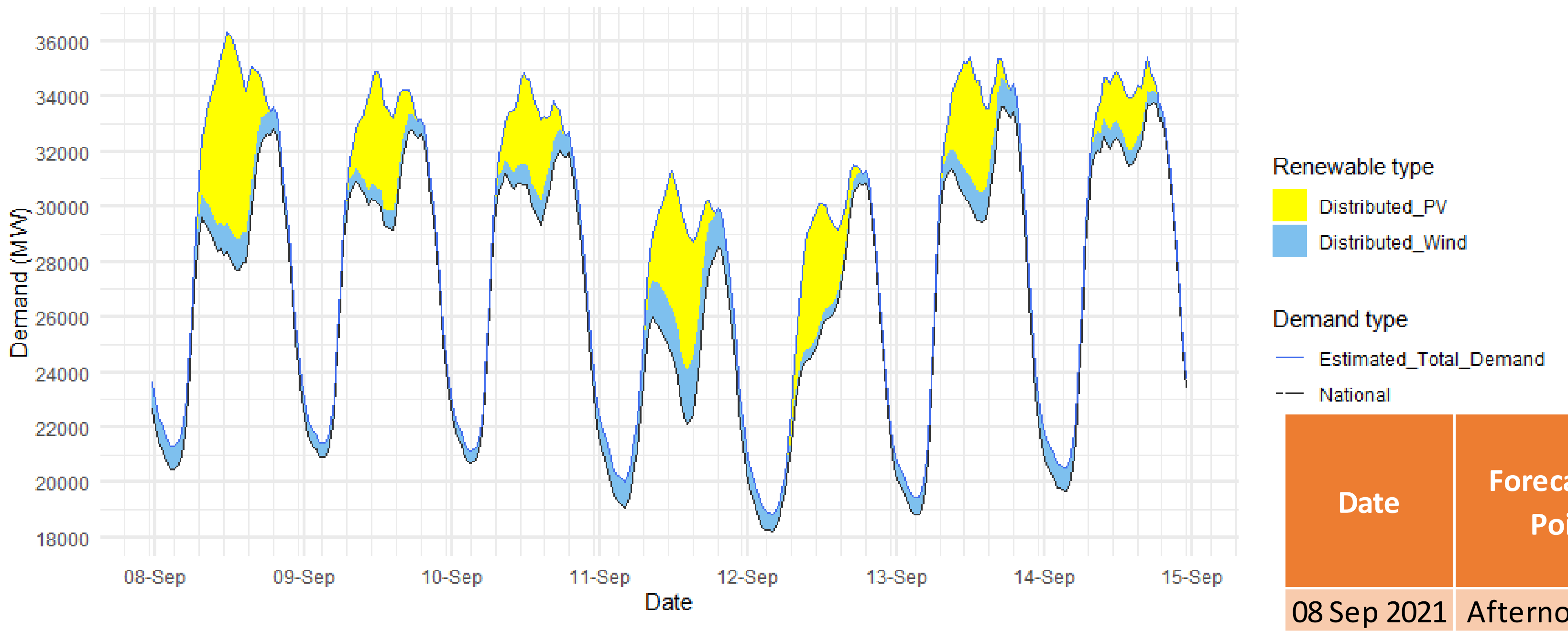
Following the success of the Weekly Auction Trial, the EPEX SPOT platform for day-ahead procurement of response services offers process automation which provides:

- **An online user interface** that enables market participants to submit offers and for the ESO to configure their requirements
- An **automated assessment algorithm** to calculate the accepted and rejected offers and the total volume of DCL procured
- A more granular **procurement by EFA periods** allowing for potential different prices and volumes in each period depending on the system needs
- A move to a **pay-as-clear** payment mechanism which makes the market more accessible to smaller providers while potentially increasing competition.

The changes will introduce additional functionality which will give market participants greater flexibility in how they provide the DC service, potentially leading to an increase in supply of DC

Demand | Last 7 days outturn

ESO National Demand outturn 08-14 September 2021

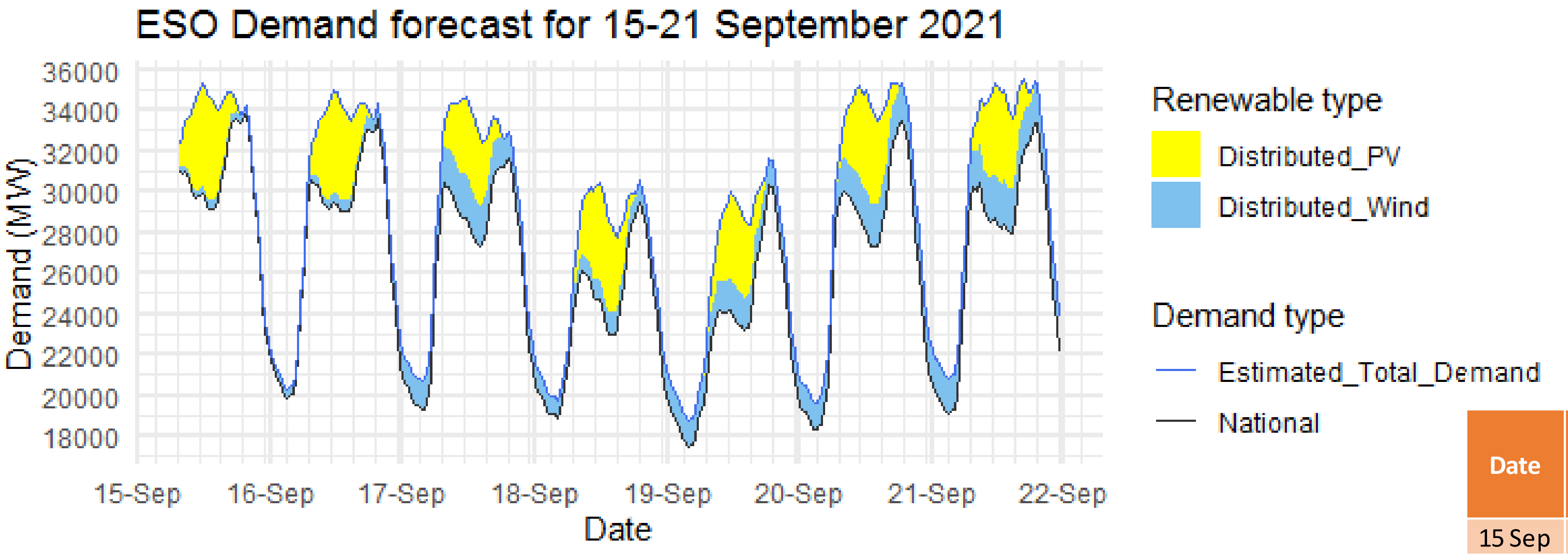


The black line (National Demand) is the measure of portion of total GB customer demand that is supplied by the transmission network.

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.

		FORECAST (Wed 08			OUTTURN		
Date	Forecasting Point	National Demand (GW)	Dist. wind (GW)	Dist. PV (GW)	National Demand (GW)	Dist. wind (GW)	Dist. PV (GW)
08 Sep 2021	Afternoon Min	28.4	1.2	5.4	27.7	1.1	6.4
09 Sep 2021	Overnight Min	20.8	0.5	0.0	21.0	0.5	0.0
09 Sep 2021	Afternoon Min	29.7	0.7	3.5	29.2	0.7	3.4
10 Sep 2021	Overnight Min	20.4	0.5	0.0	20.7	0.4	0.0
10 Sep 2021	Afternoon Min	28.9	0.8	4.0	29.3	0.9	2.9
11 Sep 2021	Overnight Min	19.2	0.6	0.0	19.1	0.9	0.0
11 Sep 2021	Afternoon Min	23.4	0.8	4.8	22.1	2.0	5.0
12 Sep 2021	Overnight Min	18.4	0.4	0.0	18.2	0.6	0.0
12 Sep 2021	Afternoon Min	24.8	0.5	3.4	25.9	0.4	3.8
13 Sep 2021	Overnight Min	18.9	0.7	0.0	18.8	0.6	0.0
13 Sep 2021	Afternoon Min	28.1	1.1	4.8	29.4	1.1	3.3
14 Sep 2021	Overnight Min	19.6	1.0	0.0	19.7	0.8	0.0
14 Sep 2021	Afternoon Min	28.4	1.2	4.6	31.5	0.5	1.9

Demand | Week Ahead



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		FORECAST (Wed 15 Sep)		
Date	Forecasting Point	National Demand (GW)	Dist. wind (GW)	Dist. PV (GW)
15 Sep	Afternoon Min	29.2	0.4	4.8
16 Sep	Overnight Min	19.9	0.4	0.0
16 Sep	Afternoon Min	29.0	0.5	4.7
17 Sep	Overnight Min	19.3	1.4	0.0
17 Sep	Afternoon Min	27.3	2.0	3.4
18 Sep	Overnight Min	18.9	0.9	0.0
18 Sep	Afternoon Min	23.0	1.0	3.8
19 Sep	Overnight Min	17.5	1.3	0.0
19 Sep	Afternoon Min	23.2	1.6	3.8
20 Sep	Overnight Min	18.3	1.3	0.0
20 Sep	Afternoon Min	27.3	2.0	4.2
21 Sep	Overnight Min	19.1	1.7	0.0
21 Sep	Afternoon Min	28.0	2.1	3.5

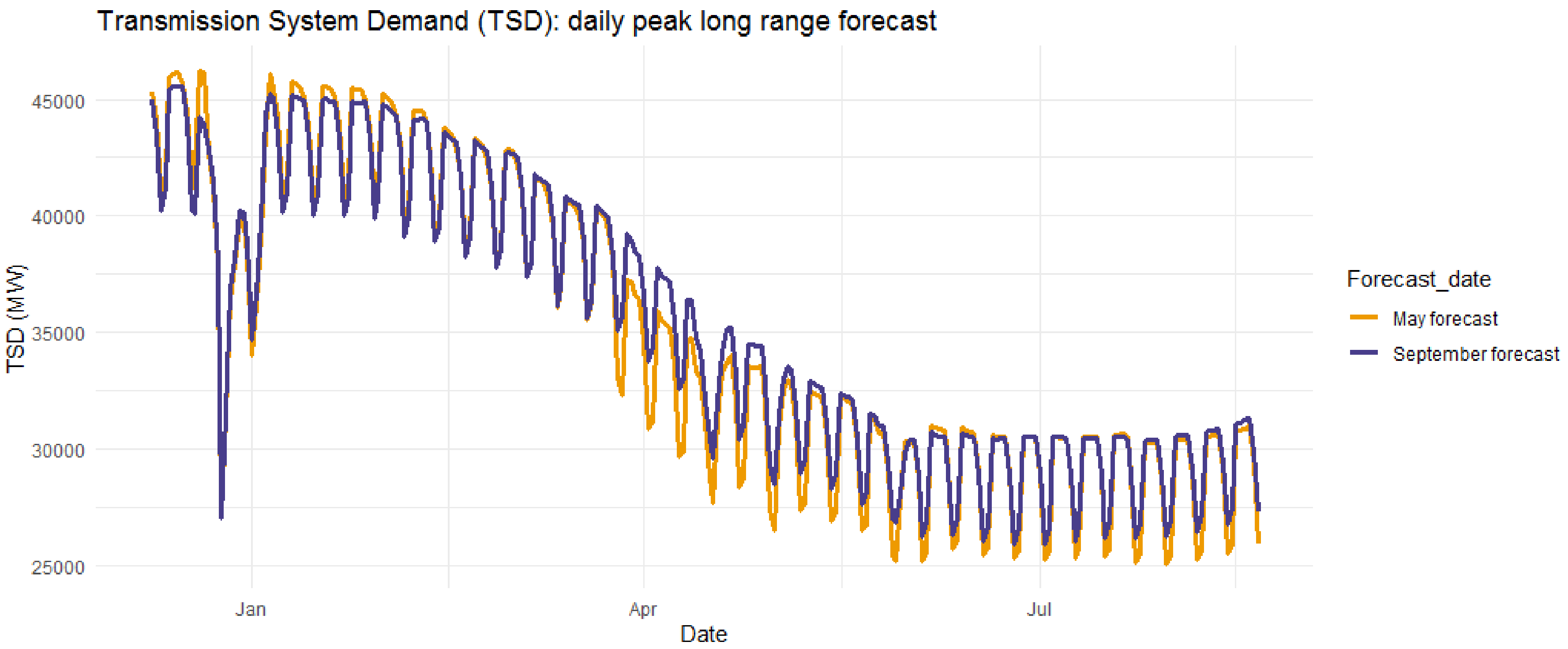
Demand | Long range, year ahead, forecast

The graph compares the latest long range forecast (blue) with the one previously published (gold).

It includes **daily peaks forecast*** of the Transmission System Demand (TSD) starting from 9th December 2021 up to 20th August 2022.

When compared with the previous forecast, the main differences are:

- slightly lower demand in the two weeks leading to Christmas & in January
- higher forecast after the clock change up to beginning of May
- higher forecast for weekend days after the clock change



REASON FOR THE CHANGE

We introduced a major technical change in the way we do forecasting to account for the pandemic related fluctuations.

We replaced linear regression model with a technique called generalized additive model (GAM).

This a technical change in the background and does not affect the meaning of the forecast.

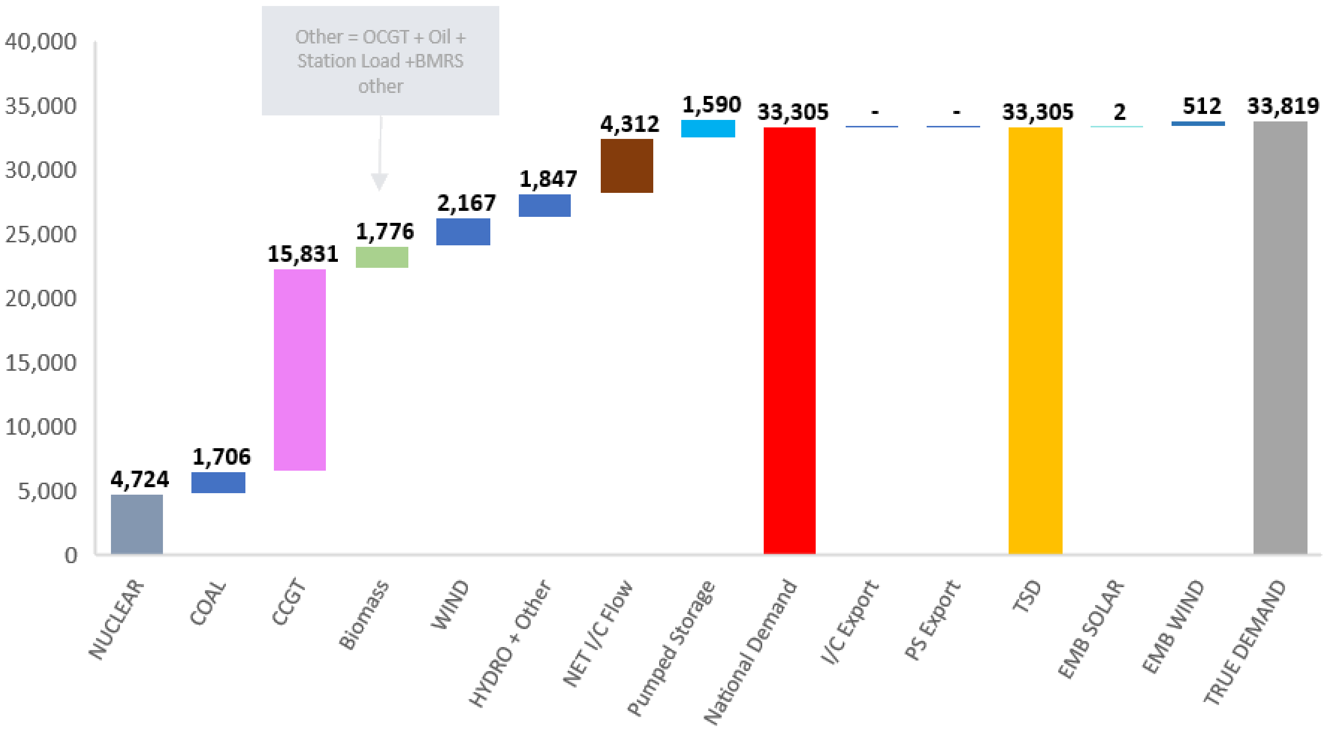
This has improved the way we are using data from last year.

*Forecast uses seasonal average weather and doesn't assume potential future restrictions due to the pandemic

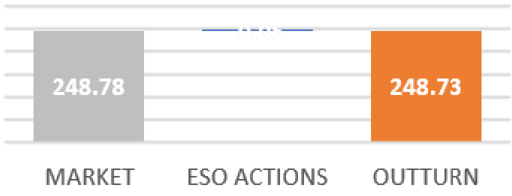
ESO Actions | Monday 6 September Peak

Date: 06/09/2021

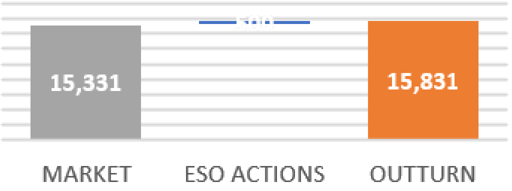
SP: 41



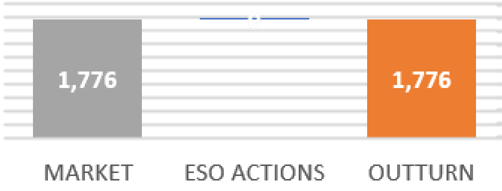
Carbon Intensity (gCO_2/kWh)



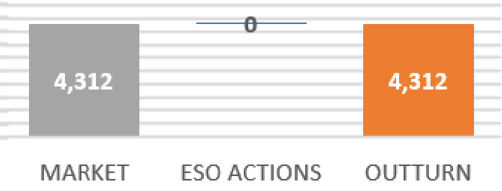
CCGT



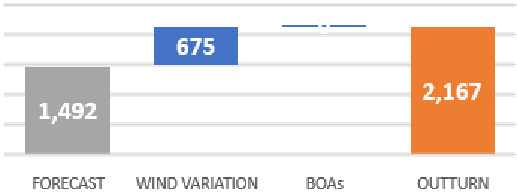
Biomass



I/C



WIND

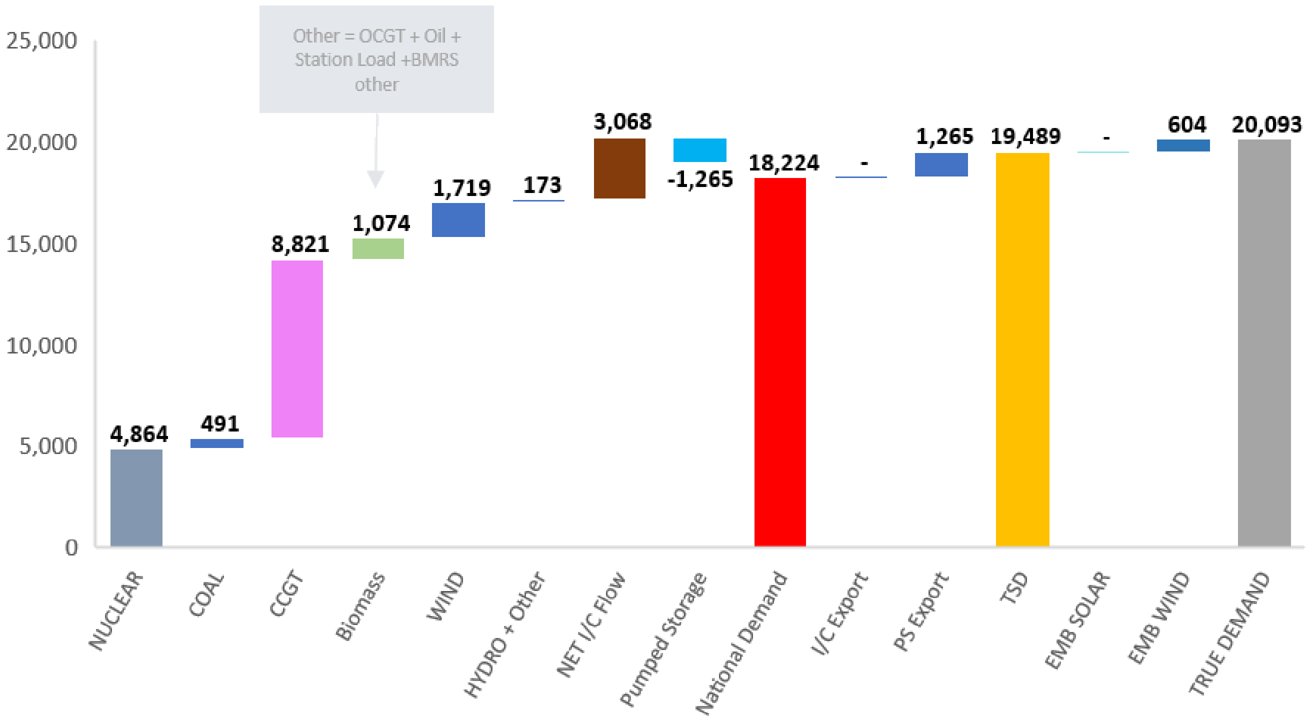


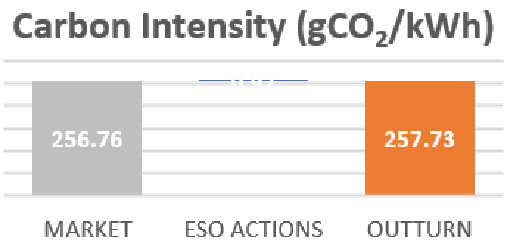
Carbon Intensity data on data portal: https://data.nationalgrideso.com/carbon-intensity1/carbon-intensity-of-balancing-actions

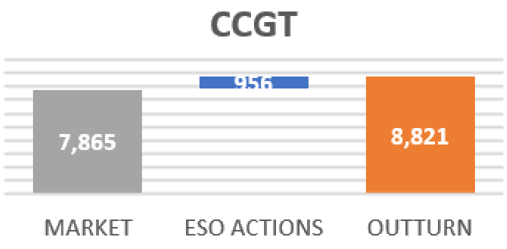
ESO Actions | Sunday 12 September Minimum

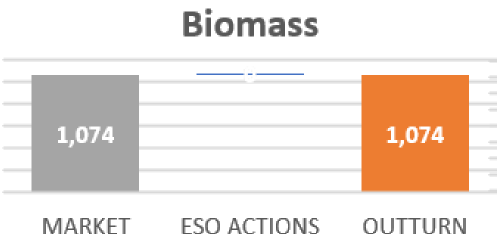
Date: 12/09/2021

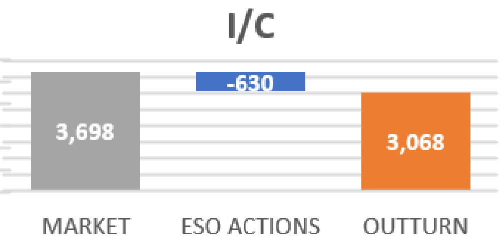
SP: 10

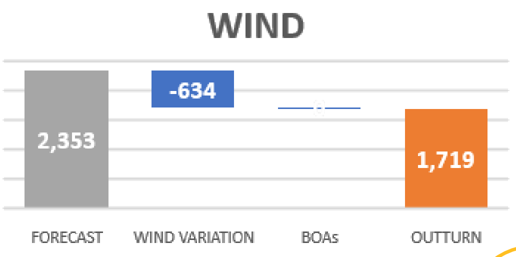






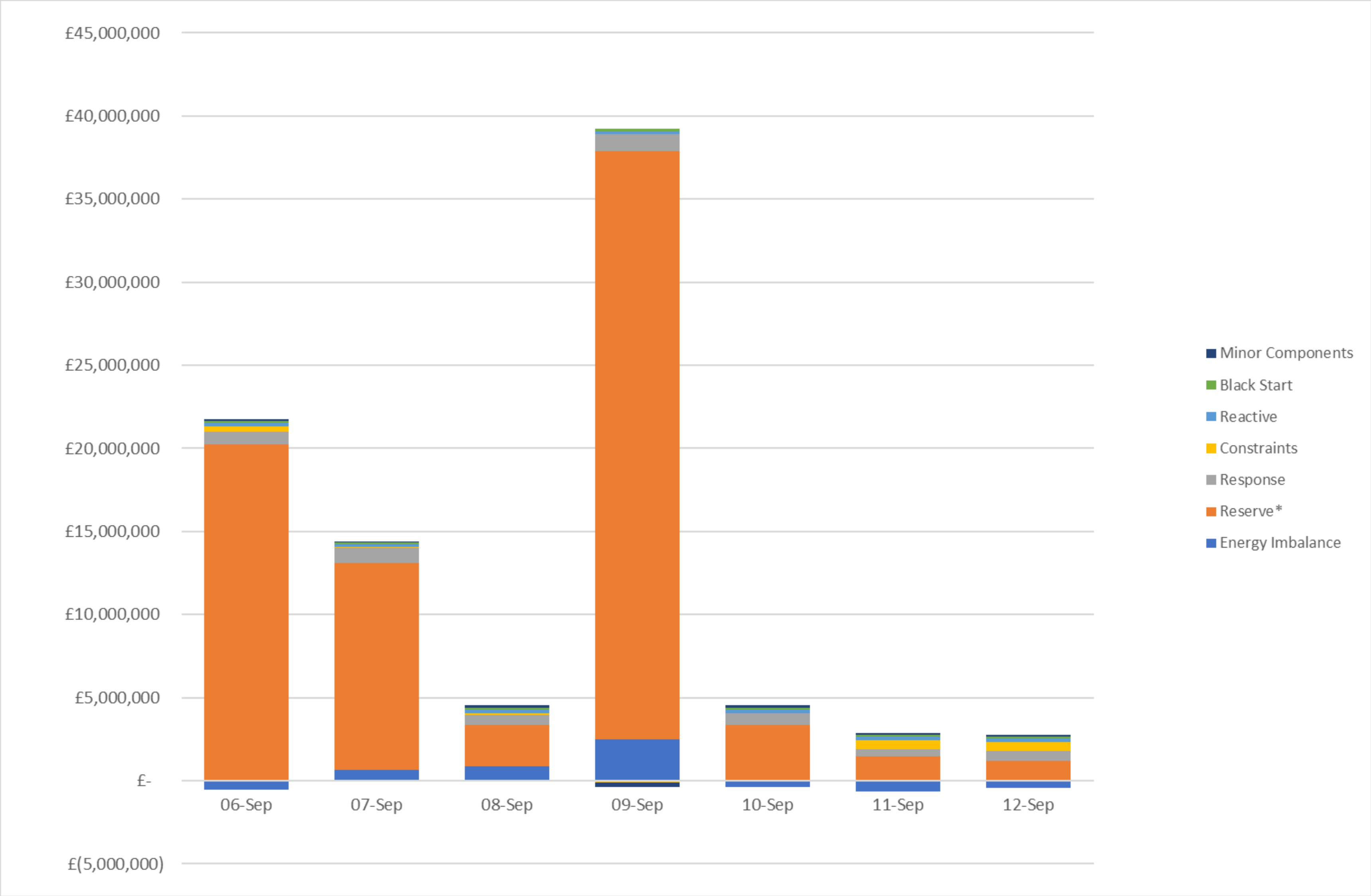






Carbon Intensity data on data portal: https://data.nationalgrideso.com/carbon-intensity1/carbon-intensity-of-balancing-actions

Transparency | Costs for the last week



Reserve
Tight but adequate margins through the week led to high balancing costs, particularly for Monday, Tuesday and Thursday.
For Thursday, Ireland were in amber alert status and had requested flows from GB to Ireland. Eirgrid bought c.3GWh of energy from ESO through SO-SO trades throughout the day. These trades prevented disconnection of Irish consumers. The cost of this action has been passed through to the Irish market and once reconciliation takes place the GB balancing costs will be reflective of the total cost of operating the system, c.£27m.
Response
Response costs remain quite a large component of spend. This is driven by the large volumes of response required to manage the system and the high submitted prices at which this response is procured.
Constraints
Low wind throughout the week contributed to lower constraint costs

Transparency | Constraint cost breakdown

Voltage
Lower demand on weekend meant fewer synchronous generators self-dispatched and more intervention required to meet voltage requirements

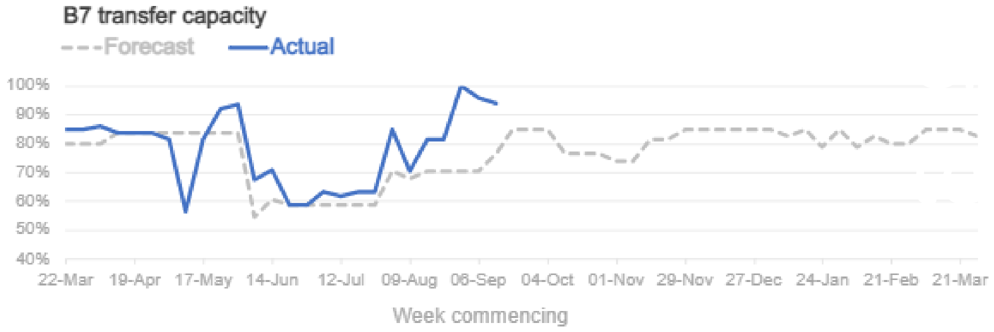
Thermal
Small volume of action required to manage on Monday and Saturday

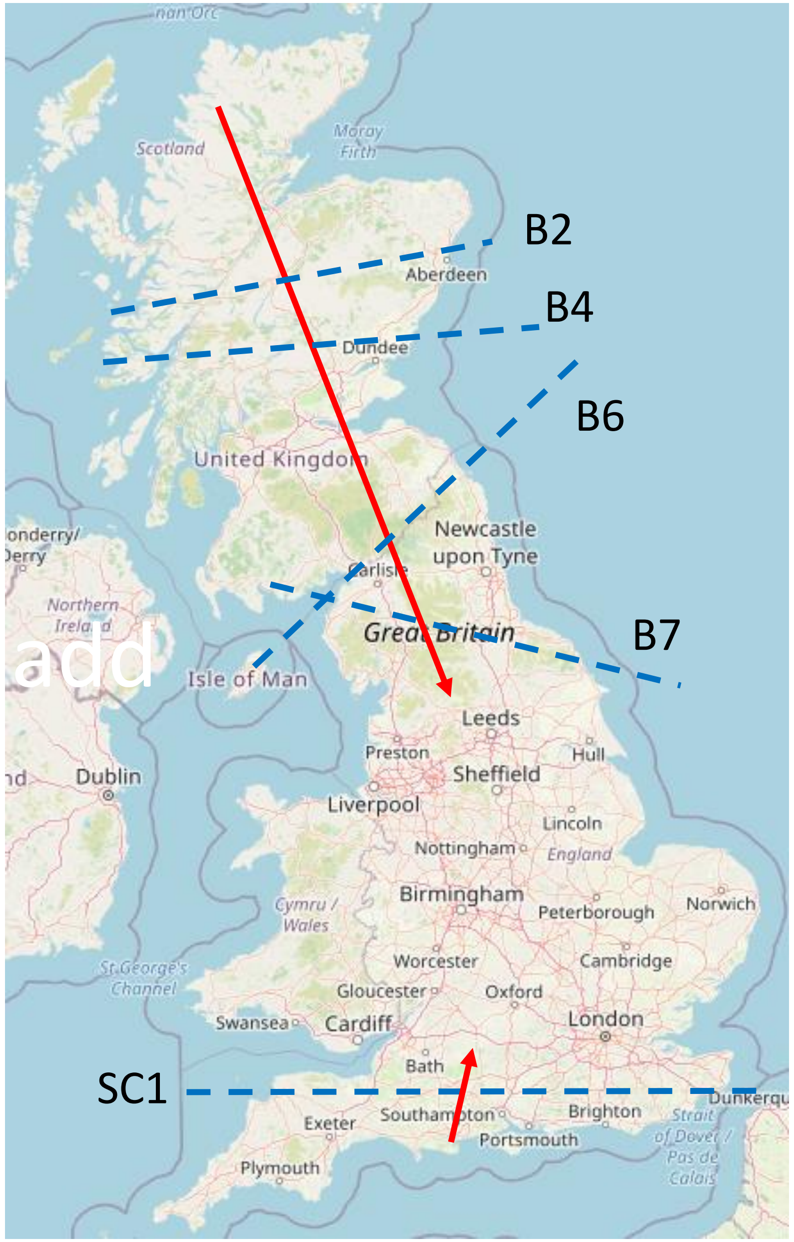
Managing largest loss for RoCoF
Action required to manage largest loss on interconnectors throughout the week. Varies due to varied inertia levels on the system and interconnector flows.

Increasing inertia
No units synchronised for inertia during the week.

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

Transparency | Constraint Capacity





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Operational Transparency Forum

15 September 2021

Market Margin Signals – deep dive

Richard Price – ESO
Market Requirements

nationalgridESO

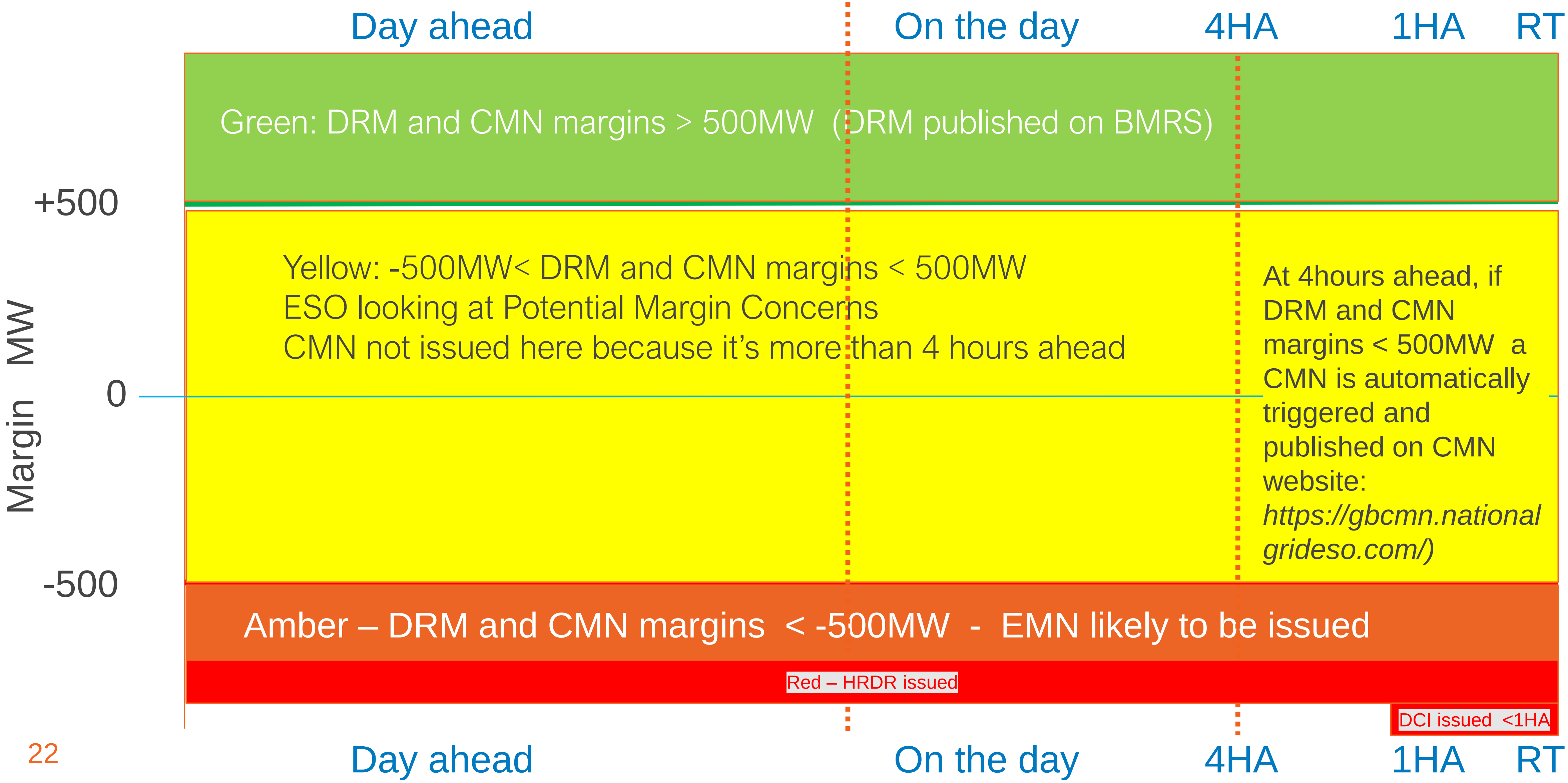
Areas to discuss

- Overview of market signals and differences
- Traffic lights and thresholds
- Detailed breakdown of De-rated Margin (DRM) margin calculation
- Potential changes to DRM and CMN calculations

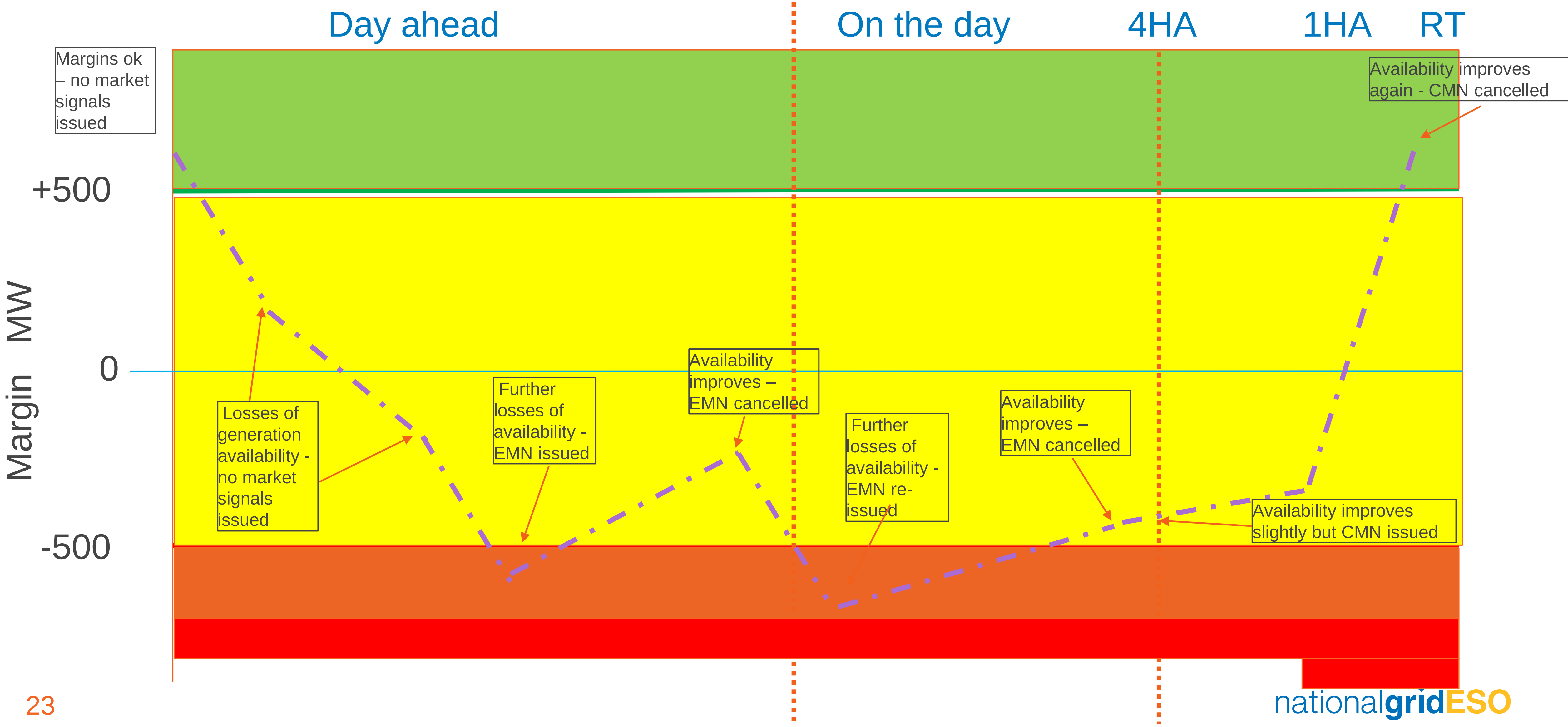
Overview of signals and differences

DRM and LoLP	Published automatically and continuously on bmreports	From midday day ahead to one hour ahead of real-time
CMN	Only published at 4 hours ahead if calculated margin forecast is <500MW trigger threshold	Published on a separate dedicated website
EMN / HRDR / DCI	Manual calculated and normally only issued if reserve has already been eroded (margin < -500MW)	Sent out to individual market participants and published on BMRS

Margin thresholds – traffic lights explainer



Margin thresholds – traffic lights



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Consistency of signals

- Generally we believe that our margin signals are consistent and based on the same underlying source data.
- However, there are different trigger levels and different lead times, and although DRM and CMN margins are calculated completely automatically, the EMN margin calculation is manually generated.
- As such, there is an opportunity for the control room to incorporate some adjustments to the raw submitted availabilities and our latest demand forecasts based on their judgement and experience.
- Last winter, there was some concern over apparent inconsistency when a CMN was issued just after an EMN had been cancelled.
- From the previous slide you can see that this is entirely possible, because for example, even if the margin improves from say 5-6HA when an EMN is issued in the RED zone, it can still be in the AMBER zone and tight enough for a CMN to still be triggered at 4HA.

Detailed breakdown of De-rated Margin (DRM) calculation

- For a given lead time: Forecast Margin = Available Generation less Demand Forecast less Reserve Requirement.
- Lead times published are Midday Day ahead; 8, 4, 2 & 1 Hour ahead on the day
- Available Generation is sum of MEL for plant with PN>0, or NDZ < lead time or PN>0 <8hrs ago
- Wind generation is forecasted separately
- Demand forecast is the National Demand Forecast
- Interconnector PN positions and non-BM STOR availability are also included
- Reserve requirement to cover the largest loss.
- Probability distributions of generation and total requirement convolved into a single distribution of the margin. LoLP calculated as Prob (Margin <0). A LoLP of 0.5 at one hour ahead indicates that there is a 50% chance that the margin will be negative.
- The detailed methodology is published here: https://www.elexon.co.uk/wp-content/uploads/2015/10/37_244_11A_LOLP_Calculation_Statement_PUBLIC1.pdf

Key difference between DRM and CMN margin calculations

- Both calculations are based on submitted availabilities from market participants and our demand forecasts and reserve requirements
- DRM are published at several lead times from day ahead onwards up to 1HA
- CMN margin is only published at 4HA if a CMN is triggered by margin < 500MW
- CMN calculation includes a higher reserve requirement than DRM. DRM only covers the reserve for response at 1HA to cover the largest generation loss. CMN also includes regulating reserve.
- CMN includes a more sophisticated calculation of availability using ramp rates to predict actual levels achievable, e.g. for plant desynced or below MEL.

Potential changes to the DRM and CMN calculations

DRM – delay the day ahead midday run to allow interconnector PN positions to be reflected after the day ahead interconnector auctions

CMN – include non-BM Fast Reserve; modify the threshold

EMN – consideration of publishing extra information alongside an EMN, such as interconnectors, network constraints and contingency requirements.

How well do you understand the differences between CMN & EMN

ⓘ Start presenting to display the poll results on this slide.

Key conclusions from ELEXON Issue 92 group

- In January we initiated an ELEXON Issue group to look at the ongoing suitability of the Reserve Scarcity Pricing mechanism and concerns that inaccurate margin signals could trigger high cashout prices similar to those on 4th March 2020.
- Following three issue group meetings, the ESO were asked to carry out further investigations and provide a cost benefit summary of any suggested improvements to the methodology to improve the accuracy of the margin calculations.
- As a result of our investigations, we concluded that:
  - Our margins calculations are more accurate than we expected at times of tight system margins.
  - Our suggested improvements would not achieve the benefits that we were expecting in terms of improvements in accuracy to the margin calculation.
  - These changes would be very hard to justify in terms of the costs (>£1m), the time taken (not possible by this winter) and the other key factor which the Issue group were concerned about - the displacement of other more important IS work already in flight if we did proceed.
- Instead of making these changes, we propose to focus more on improved customer communications ahead of this winter to explain the reasons behind expected differences between our margin signals (e.g. different trigger thresholds)

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

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

Q&A

Please remember to use the feedback poll after the event. We welcome feedback to understand what we are doing well and how we can improve the event ongoing.

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