

*Winter
Balancing Costs Review*



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Market data

Balancing Market Costs

BM Costs in Winter 2022/23 are down from the previous winter but still historically high

The total cost of Bids and Offers accepted through the Balancing Market (BM) for Winter 22/23 was £1,235M*, down 20% from the peak of £1,546M in Winter 21/22.

BM costs in Winter 2021/22 and 2022/23 were significantly higher than previous years, due to:

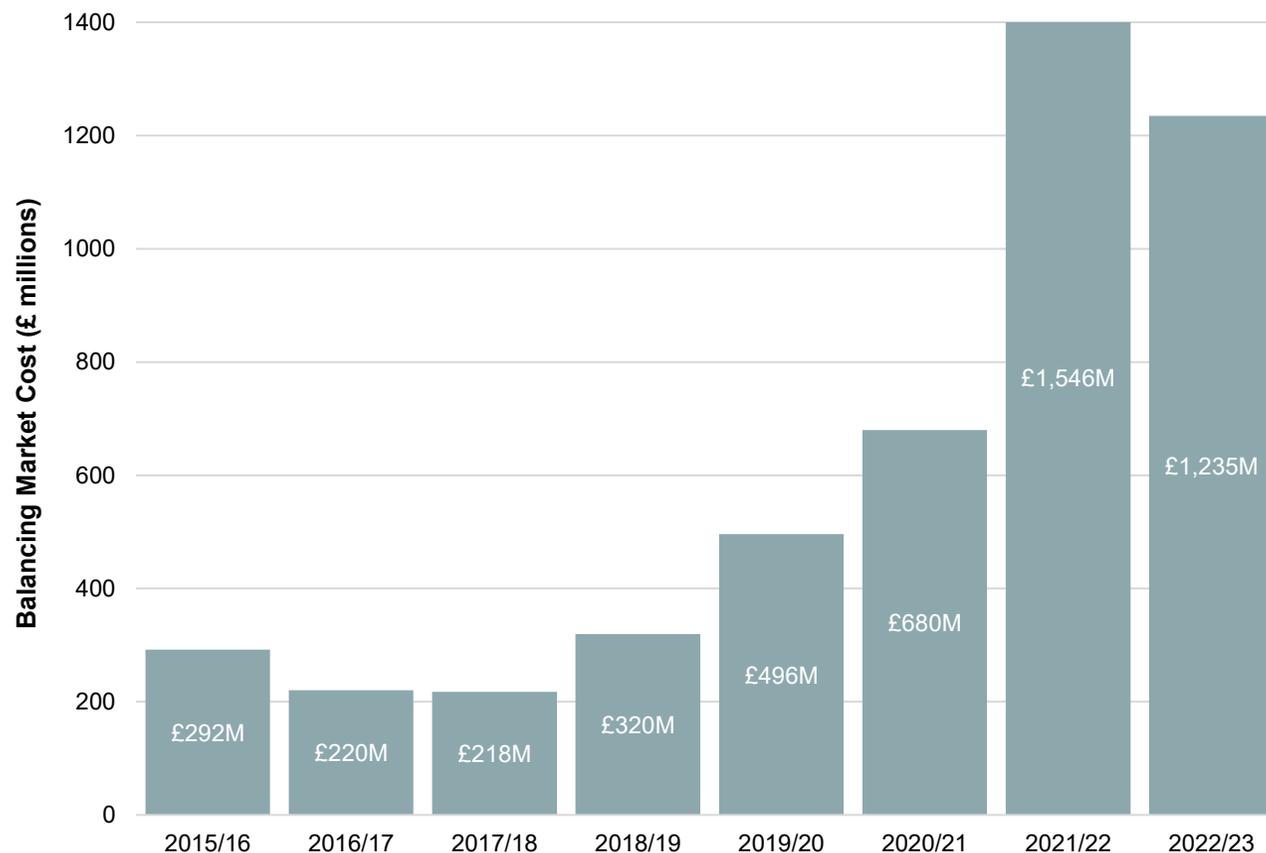
- Tighter system margins,
- High gas prices and
- Increased wind output

When tighter system margins occur this means that scarcity pricing can dominate the overall action costs, this winter £310M of BM acceptance costs were due to maintaining sufficient reserve.

High gas prices increase the costs for gas generators to operate, thus this pushes up the costs of their electricity generated. This winter £756M in BM and trade acceptance costs has been from units which use gas to generate electricity.

Increased wind output can lead to thermal congestion and therefore the requirement to reduce the wind output and replace that energy in areas not affected by the constraint limits. Direct payments to wind to manage thermal congestion were £71M this winter with a further £110M in costs to replace the energy deficit created by these actions.

Total BM Cost by Winter*



*Direct costs of bid offer acceptances and Balancing Service Adjustment Data excluding ancillary service costs

Balancing Market Prices and Volumes

Historically high BM costs have been driven by changes in pricing behaviour, rather than increased volumes

Compared to last winter, BM actions have increased:

- The volume of actions was 6TWh, an increase of **12%**.

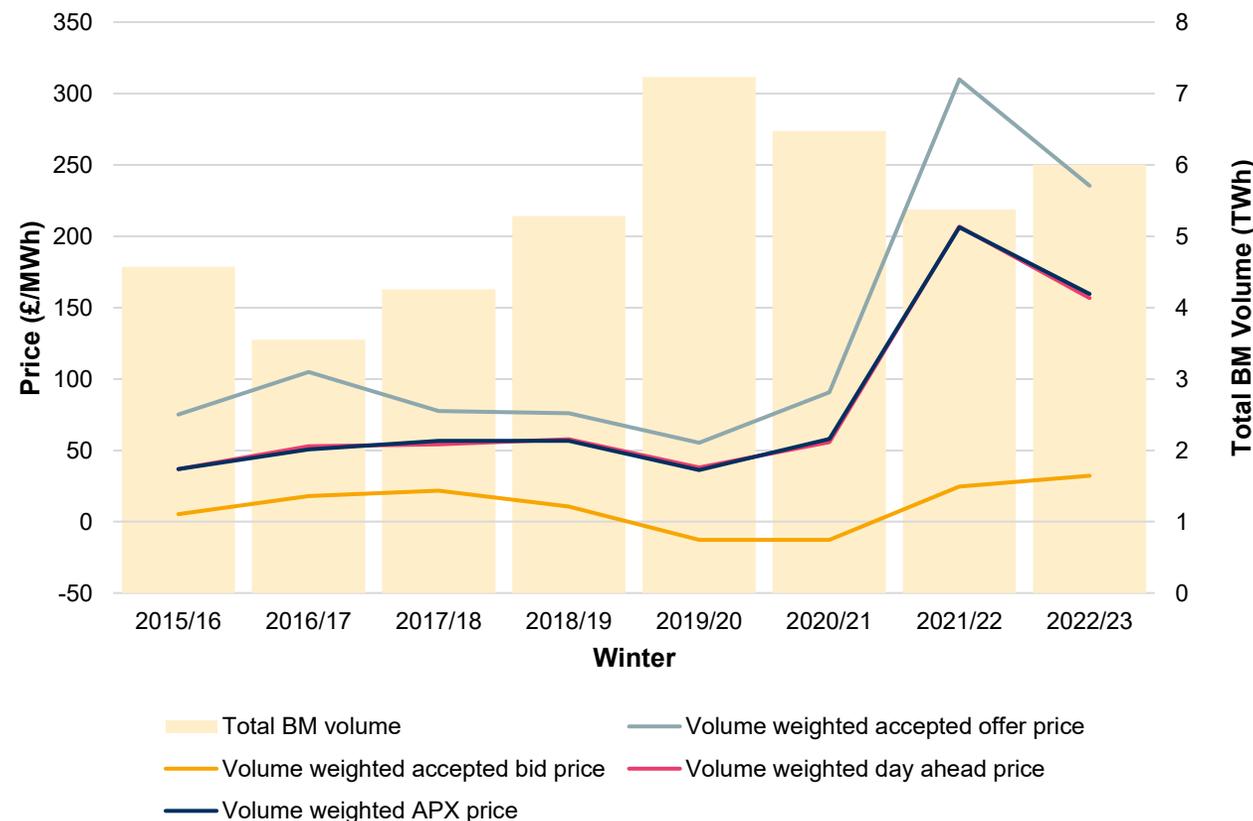
Compared to last winter, wholesale prices have reduced:

- The BM volume weighted average accepted offer price has reduced by **24%**
- The intra-day market price has reduced by **22%**
- The day-ahead market price has reduced by **24%**
- The intra-day gas price has reduced **29%**

Whilst the prices are lower than last year, they are historically very high:

- The BM volume weighted average accepted offer price has increased by **159%** compared to winter 2020/21
- The intra-day market price has increased by **175%** compared to winter 2020/21
- The day-ahead market price has increase by **181%** compared to winter 2020/21
- The intra-day gas price has increased **249%** compared to winter 2020/21

Prices and BM Volumes by Winter



Wholesale market prices

Wholesale and BM prices decouple when there are tight margins or very high wind

Winter 2021/22 Wholesale market prices



Winter 2022/23 Wholesale market prices



Wholesale market prices

Wholesale and BM prices decouple when there are tight margins or very high wind

Summary

In general, balancing market prices, such as the system price and offer and bid prices, follow the same trends as the wholesale market prices, such as the day ahead price and the intra-day market prices. This behaviour is driven by units pricing the opportunity costs from the other wholesale markets into their balancing bids and offers. If market prices were to diverge, parties would be incentivised to trade their power in one market over an other, but the increased competition should always drive the different market prices back in line with each other.

Day ahead and Intra-day market prices are lower this winter than last winter, mostly due to lower gas prices.

Last winter ~2GW of coal capacity operated outside the wholesale markets and traded its full capacity in the BM at prices close to £4000/MWh, which meant extreme prices in the BM were more prevalent. Extreme BM prices increased the opportunity cost in the BM which may have also driven increased wholesale market prices.

This winter, coal didn't consistently trade its power in the BM at high prices, as it was contracted to coal contingency contracts and operated outside of both the wholesale and balancing markets. Without coal setting very high balancing prices, the opportunity cost in the BM was lower and prices in the day ahead and intra-day markets were lower.

Spikes in VWA accepted offer prices

Last winter there were 9 days when the VWA accepted offer prices in the BM were significantly higher than the prices observed in the wholesale markets. On these days, the forecast margin was very tight and units priced the scarcity into their offer prices.

During these periods of forecast tight margins last winter, ~2GW of coal was withholding its capacity from the wholesale markets and submitting offers in the BM at prices close to £4000/MWh. With such a large amount of capacity priced at £4000/MWh during a period of system stress, other units were able to price their capacity up to that level, as the balancing market operates as a pay as bid market.

This winter, the coal units, which had sold their power at high prices in the BM last winter, were now on coal contingency contracts and weren't able to sell power in the BM directly. This meant offer price spikes were less frequent and, with the exception of the 12th December, less extreme.

Drops in VWA accepted bid prices

Whilst spikes in the VWA accepted offer prices are more obvious, there is another trend observed on many days this winter and last winter during periods of high wind.

A large proportion of wind capacity in GB has policy support, these policies include both ROCs and CfDs. The structure of these support contracts means wind units receive a payment which is proportional to the volume of power they are able to output onto the system. If supported wind capacity is turned down in the BM, its volume output onto the system is reduced and often it will lose some support revenue. As a result, wind capacity in the BM normally submits bid prices which are negative, meaning if the control room were to turn them down the wind units would be paid to do so. In addition to pricing negative to recover lost policy support, wind bids are often priced even lower to secure an additional profit margin. This means they are very unlikely to be curtailed, as they fall well down the merit order; and if they are turned down, they will recover any lost policy support payments through the BM with some additional profit on top.

During periods with high wind generation, the system often encounters constraints, which the control room must manage, such as Voltage, RoCoF and North-South flow thermal constraints. In order to manage these constraints wind is normally curtailed as it:

- doesn't generate inertia to alleviate RoCoF constraints,
- doesn't support voltage and
- is often the main driver in North-South flows, due to most of the wind capacity being in Scotland and the North of England.

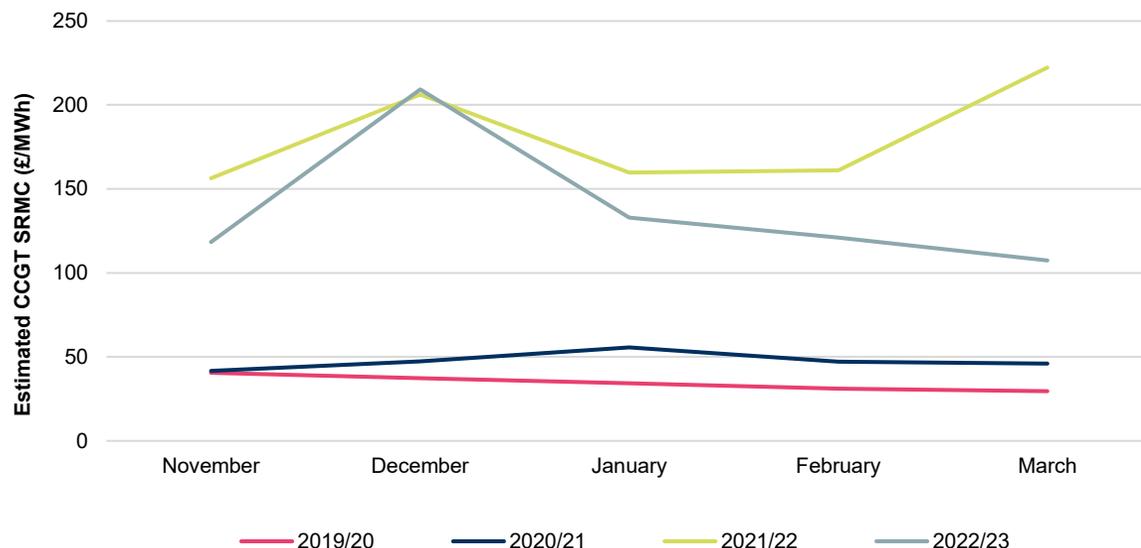
As wind is curtailed at prices which factor in its lost policy support, the VWA accepted turn off price often diverges from the day ahead and intra-day prices to be negative.

Cost drivers

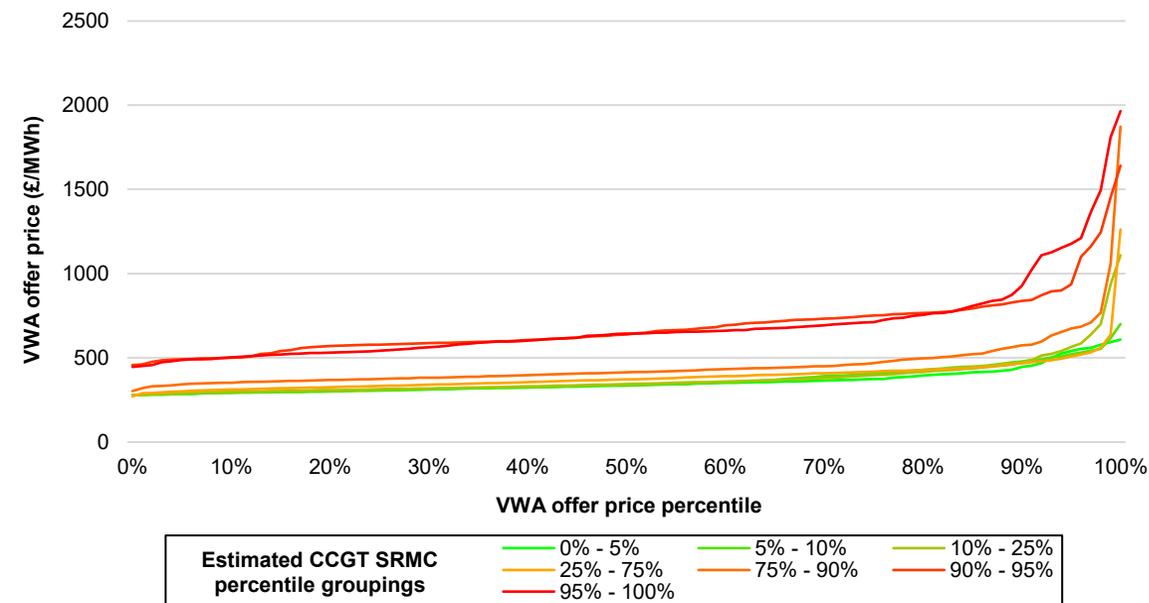
Gas price

Gas prices are a key indicator of BM costs due to their impact on CCGT SRMCs, on average these were 29% lower than last winter

Monthly average estimated CCGT SRMC by winter



Volume weighted average offer price by estimated CCGT SRMC percentile*



Gas prices are a key driver behind the jump in BM costs from winter 2020/21 to the last couple of years. Gas prices feed directly into the prices conventional units offer and bid into the BM to turn up and turn down. When the gas price is higher, costs are higher for gas units to produce more generation, and these costs are passed onto the ESO via increased offer prices.

- The average estimated SRMC for a CCGT unit this winter was £164/MWh, down from the peak last winter of £231/MWh.
- Compared to the estimated average CCGT SRMC in winter 2020/21 of £47/MWh, costs this winter were 3.5x higher.

Gas prices feed directly into the prices submitted in the BM.

- The average VWA offer price on days with the top 10% of estimated CCGT SRMC was £682/MWh, 60% higher than the average offer price this winter of £423/MWh.

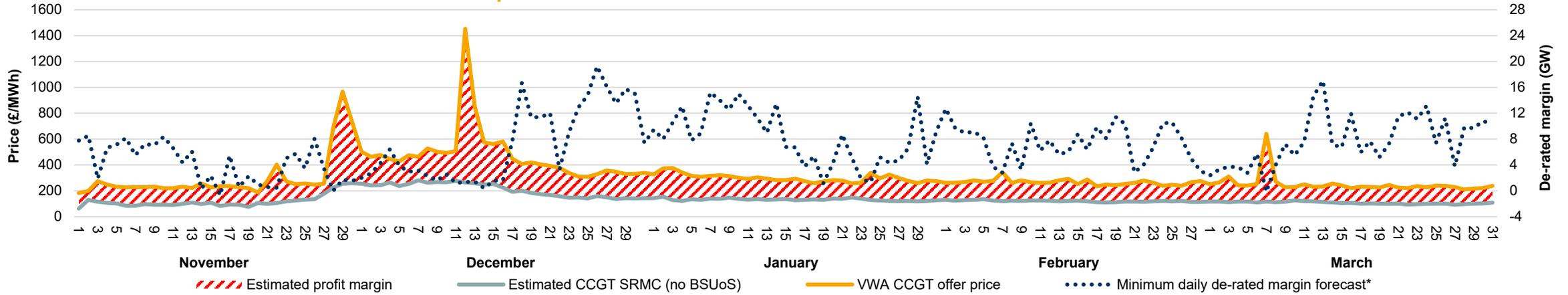
Extreme VWA offer prices are still observed for the lower percentiles of CCGT SRMC as other factors, such as forecast system scarcity, play a large role in pricing.

*percentiles are taken from Nov 22-March 23

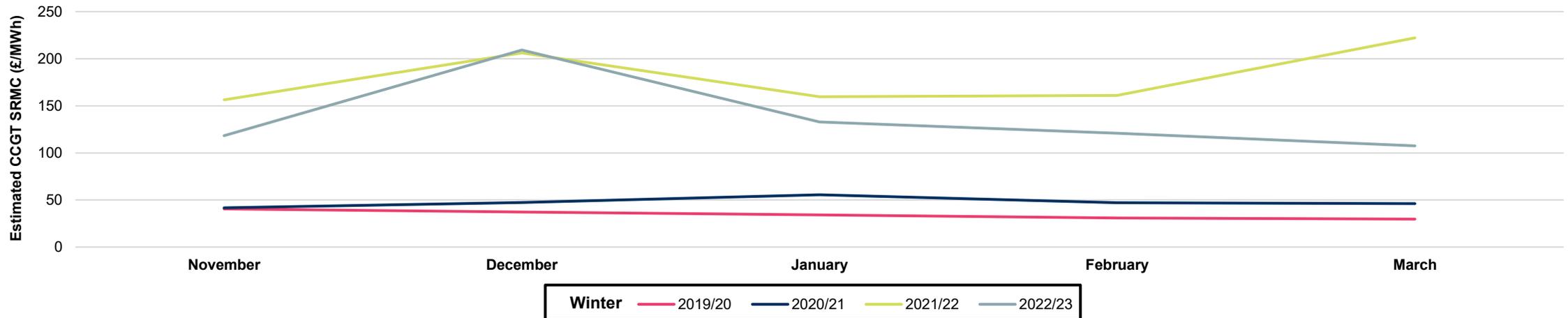
Gas price

Forecast tight margins drive offers far higher than running costs

Winter 2022/23 Estimated CCGT SRMC and offer prices



Estimated CCGT SRMC by month



Gas price

Offer prices in the BM represent a significant profit margin above estimated running costs

Gas prices have a direct impact on BM costs, as a significant volume of capacity available to the control room to balance the system is from gas fired conventional generators. Increased gas and carbon prices feed directly into the running costs of these units.

Gas prices this winter are historically very high, but lower on average compared to last winter. Of the five months Nov-March this winter, only December had an average estimated CCGT SRMC greater than last winter (and it was only 1.4% higher).

CCGTs generally represent the largest proportion of costs in the BM, because they are relatively large units which are well suited to alleviate common system constraints, such as RoCoF, Voltage and boundary constraints. Increases in CCGT costs will therefore feed directly into increased BM costs.

The top chart on the previous slide represents the estimated CCGT SRMC (ignoring BSUoS costs) against the observed VWA offer price from CCGTs in the BM. In general the price offered into the BM tracks the shape of the estimated SRMC costs, however there is a significant amount of headroom between the prices and their costs. This headroom can be thought of as an estimated profit margin and averages £181/MWh throughout the duration of this winter. Whilst viewing this headroom as an estimated profit margin is overly simplified, as it doesn't factor in the opportunity cost of not selling power in the wholesale markets and doesn't factor in BSUoS costs, it suggests actions taken on these units in the BM at these prices would be very profitable.

VWA offer price spikes

Throughout this winter there have been a few periods when the VWA offered price from CCGT units had spiked up significantly, from their estimated SRMC.

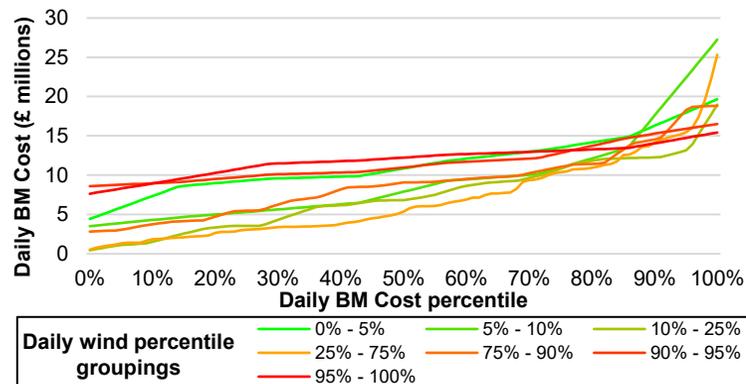
Spikes in VWA offer prices are driven by units attempting the 'delay desync' strategy on days with a low forecast de-rated margin. Overlaid on the chart on the previous slide is the minimum derated margin forecast, this represents the lowest forecast de-rated margin for the day at a horizon less than 8 hours from delivery. On days when the VWA offered price spikes, the minimum de-rated margin forecast has always dropped close to zero.

The day with the largest price divergence is the 12th December, when one unit was extended through employing the 'delay desync' strategy for 5 hours at prices as high as £6,000/MWh.

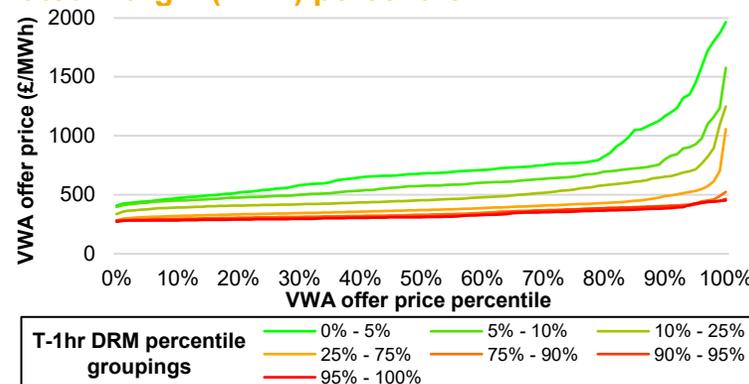
System margin

There was a £199M decrease in costs resulting from the delay de-sync strategy compared with last winter

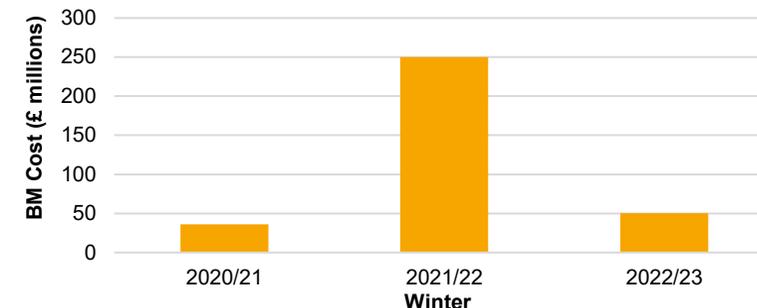
BM cost by Minimum de-rated margin percentile*



Volume weighted average offer price by T-1hr de-rated margin (DRM) percentile*



BM cost from delay-desync strategy



Derated margins represent the amount of spare capacity available, and hence is a measure of how “tight” the system is. For the chart above, we have netted off any system tagged bid volume as it is assumed this is capacity which is unable to provide energy for system reasons.

When the de-rated margin forecast is very low, available capacity often increases its offer prices to reflect the relative scarcity on the system and its increased value to the control room.

- The day with the highest BM cost this winter was 12th December with a total cost of £27.2M. The minimum forecast de-rated margin was 1.4GW and offers priced as high as £6000/MWh were accepted.
- The average daily costs for days with the lowest 10% of minimum forecast de-rated margin, was £10.8M, 32% higher than the average daily BM cost this winter of £8.2M.

Offer prices are very sensitive to forecast de-rated margin. In general, when the forecast de-rated margin net of system tagged bid volumes is lower the volume weighted prices offered into the BM are higher, to reflect their value to the system.

When the forecast de-rated margin is higher, demand is often low and wind generation is often high. Under these conditions, the opportunity cost of units in the day-ahead and intra-day markets is reduced and prices entered into the BM are lower.

- The peak VWA offer price observed this winter was just below £2000 on 12th December when the T-1hr de-rated margin forecast net of system tagged bid volume was 1.4GW.

Winter 2021/22 had significant costs associated with units employing the ‘delay desync’ strategy.

The ‘delay desync’ strategy is enacted by inflexible units with long minimum zero times (MZT) on days when the forecast de-rated margin at midday for the evening peak is very tight. Units submit a positive PN in the run up to midday and then drop their PN to zero in the run up to the peak of the day, often increasing their offer price at the point they drop their PN.

If the control room allowed these units to desynchronise, their capacity will be unavailable for the duration of their MZT and forecast margins will be even tighter over the evening peak. As a result, units are accepted in the BM to maintain their generation at or above their stable export limit, often at high prices, until the control room can ensure their additional capacity isn’t needed.

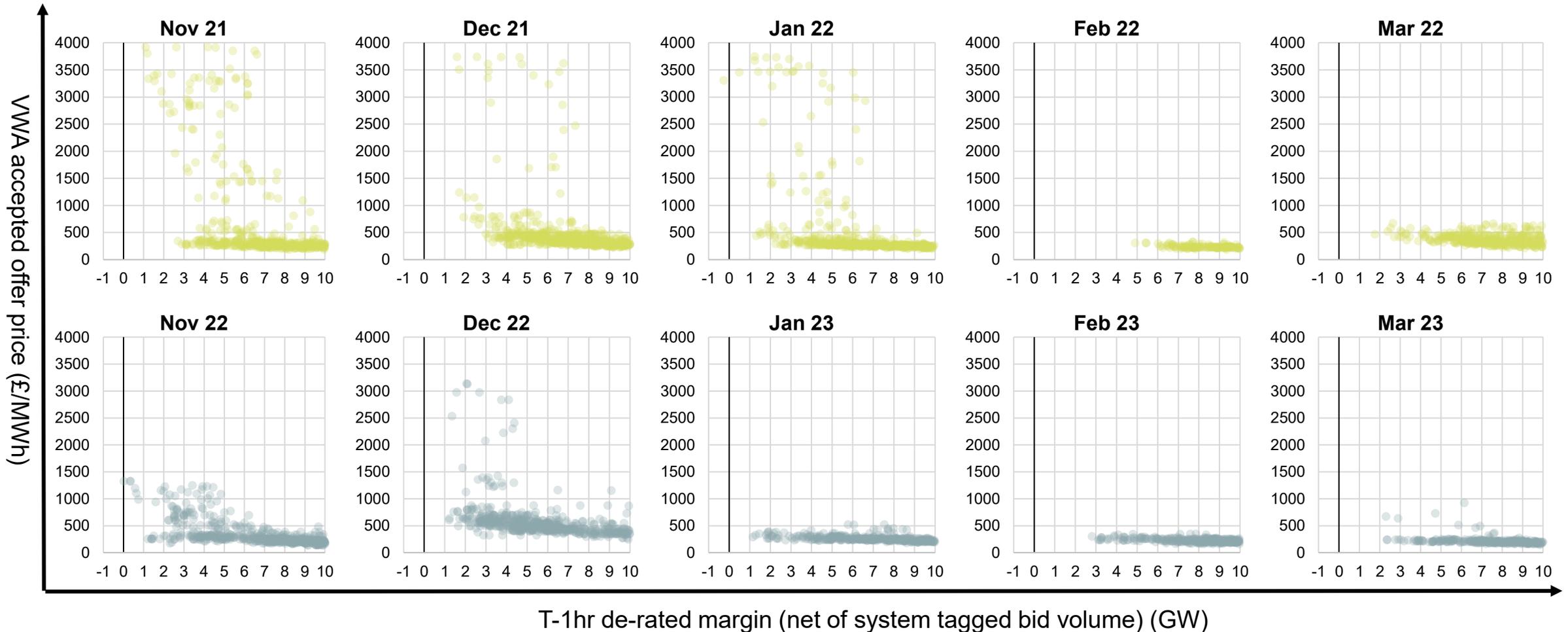
The total cost of this strategy was 80% lower this winter because: margins were not as tight; large coal units didn’t consistently sell in the BM at prices close to £4000/MWh and OFGEM guidance suggested this behaviour would likely be restricted.

*percentiles are taken from Nov 22-March 23

Scarcity

Offer prices were more extreme last winter and occurred at higher de-rated margin forecasts due to high coal unit prices and units employing the 'delay-desync' strategy

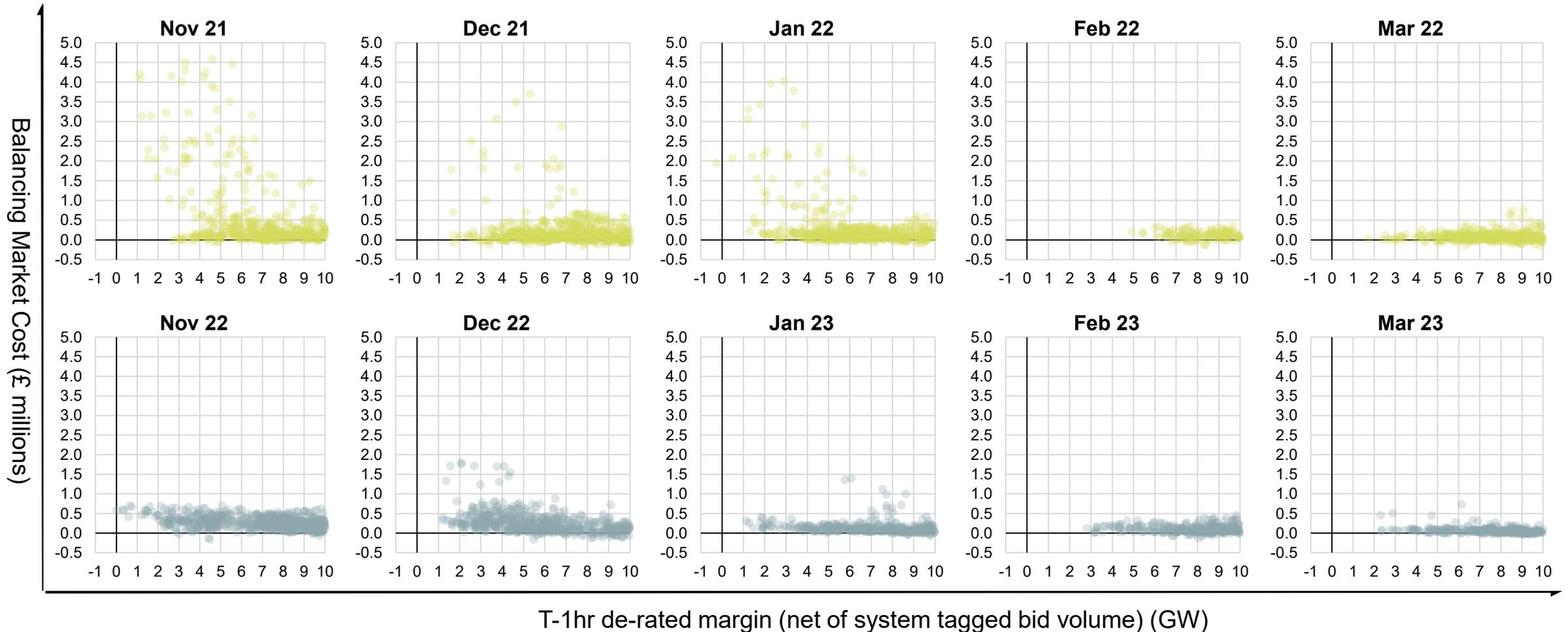
Volume weighted average accepted offer price vs T-1hr de-rated margin (net of system tagged bid volume) by month



Scarcity

Extreme cost periods were less frequent this winter. Delay desync costs and thermal constraint costs drove high price periods in December and January respectively

Period BM cost vs T-1hr de-rated margin (net of system tagged bid volume) by month



Scarcity

Without the coal ceiling of £4,000/MWh, peak VWA accepted prices were lower and extreme costs at higher de-rated margins were lower

The charts on the previous slides compare the hour ahead forecast de-rated margin (net of system tagged bid volumes) against the VWA accepted offer prices and the total BM costs for each period.

De-rated margin is a measure of system scarcity, as it represents the volume of capacity available to the control room on top of the minimum amount which is required. The volume of capacity turned down as system tagged actions has been netted off, as it is assumed that this capacity wasn't available to the control room for system reasons.

VWA accepted offer prices

As expected, there is a strong relationship between VWA accepted offer prices and de-rated margin.

If the de-rated margin is very low, units further up the merit order with higher costs and therefore higher prices must be accepted to balance the system. These units' costs are likely to be higher due to lower efficiencies and high gas and carbon prices.

As well as running costs driving prices, units price scarcity into their offers when margins are forecast to be very tight, as their value to the system is greater in periods where there may not be enough capacity to meet demand.

In the first three months of last winter we observed VWA accepted offer prices higher than £3,500/MWh, mostly at low levels of de-rated margin, but sometimes at de-rated margin levels as high as 6GW. High VWA offer prices were observed at higher de-rated margins due to two factors:

- Coal consistently bidding at close to £4,000/MWh and
- Inflexible units employing the 'Delay Desync' strategy to achieve higher prices for longer durations.

Coal offering £4,000/MWh

With approximately 2GW of coal generation consistently offering its capacity in the BM at £4,000/MWh, 2GW of capacity could only be accessed at those extreme prices. Units could assess their value to the system by shifting the de-rated margin 2GW to the left, as they knew the price would be as high as £4,000/MWh if any of the 2GW of coal was accepted.

'Delay desync' strategy

£250 million last winter was incurred through inflexible units dropping their PNs, in the run up to periods of system scarcity. In advance of forecast tight margins, units with long minimum non zero times (MZTs), often as long as 6 hours, submitted positive FPNs over the middle of the day and then dropped them to 0 in the early afternoon, signalling to the control room that their capacity won't be available over the peak of the day. Without their capacity, forecast margins would be too tight over the evening peak, so the control room had to delay their desynchronisation. At the same time they dropped their PN, these units would increase their offer price significantly, reflecting the forecast scarcity over their MZT rather than the scarcity in that specific period, forcing the control room to keep them on at great cost and higher prices.

Very high offer prices at secure de-rated margins are due to 'delay desync' units pricing their offers based on the forecast scarcity over their full MZT, rather than the scarcity in that specific period.

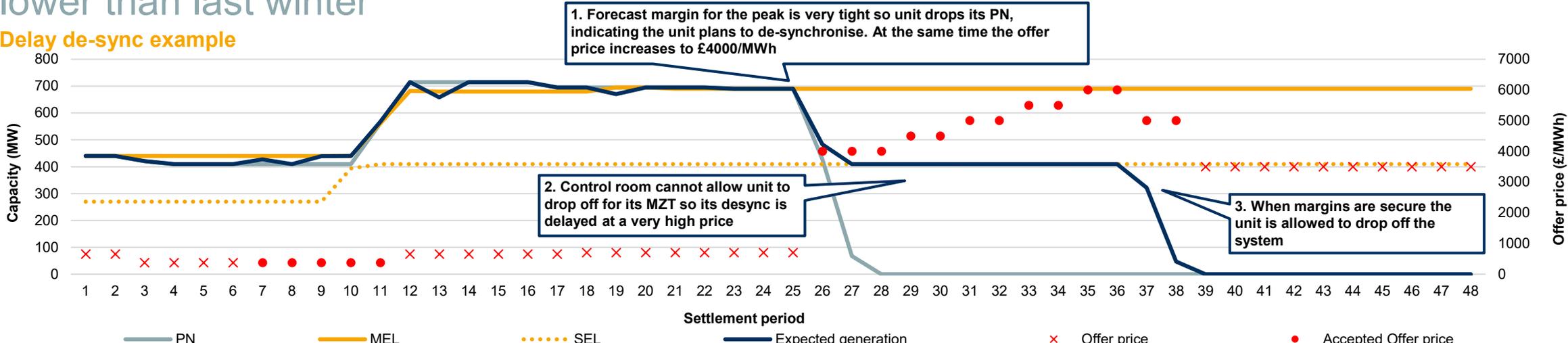
Winter 2022/23

Prices and costs weren't as extreme this winter as the coal units were given coal contingency contracts and operated outside of the BM and fewer units attempted the 'Delay desync' strategy. The only month with significant prices and costs linked to de-rated margin was December when a unit utilised the 'delay desync' strategy and was extended for over 5 hours at prices as high as £6,000/MWh.

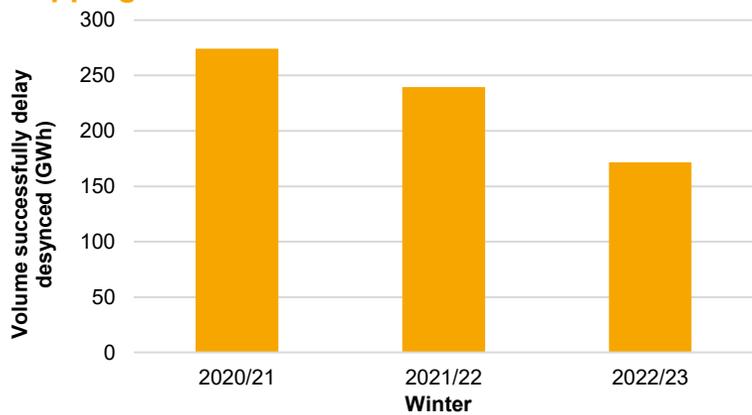
Delay De-sync

Revenue earned through implementing the delay de-sync strategy was £199M lower than last winter

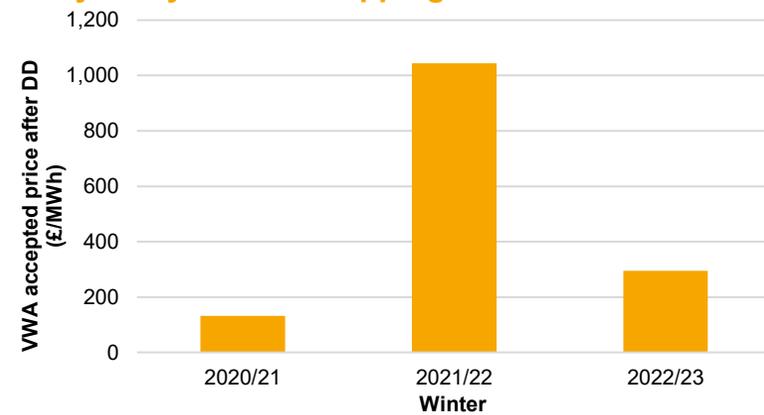
Delay de-sync example



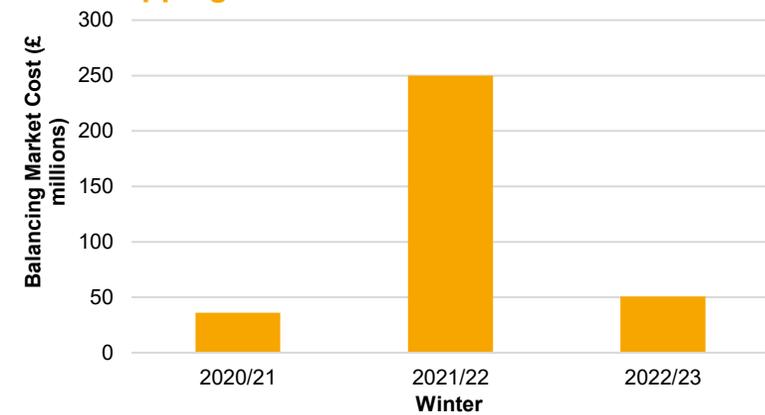
Volume instructed to delay de-sync after dropping PN



VWA accepted price for volume instructed to delay de-sync after dropping PN



BM Cost from instructing units to delay de-sync after dropping their PN



Delay De-sync

Revenue earned through implementing the delay de-sync strategy were much lower than last winter

The 'delay desync' strategy is a behaviour observed by a few inflexible units, normally CCGTs, where they signal to the control room that they are going to be unavailable for periods of forecasted tight margins, in order to be accepted in the BM at above market rate prices for longer durations.

The steps units take to implement this strategy are:

- Submit a positive PN throughout the morning into the early afternoon.
- If the forecast margin for the evening peak looks tight, they then drop their PN to 0, indicating to the control room that they are going to desynchronise. As these units often have long MZTs up to 6 hours, this would mean that their capacity is then unavailable to the ESO over the evening peak, pushing the margins even tighter than they otherwise would be.
- The unit increases its offer price to be kept on to above current market prices.
- The ESO, as a prudent system operator, decides that they cannot risk allowing this capacity to drop off the system and accepts their offer to stay online until they are confident the margin is secure.

The example on the previous slide shows the operating profile of a unit on the 12th December in the run up to a period of forecast system scarcity.

The 'delay desync' strategy isn't new to this winter and has been utilised similarly in previous winters, although the prices offers have increased to after PNs drop to zero have increased significantly.

The volumes successfully being extended in the BM through the 'delay desync' strategy has decreased over the last few winters to 172GWh this winter.

The key change observed last winter was the price at which units were willing to increase offers to and still be accepted. This may have been driven by 2GW of coal capacity holding itself outside of the wholesale market and consistently offering into the BM at prices close to £4,000/MWh.

From Winter 2020/21 to Winter 2021/22 the VWA accepted price after a unit dropped its PN increased significantly from £132/MWh to over £1000/MWh. This winter the price was only £295/MWh, much lower than last winter but still above market prices.

As a result of such a significant price increase last winter, the costs attributed to the 'delay desync' strategy increased from £36 million in Winter 2020/21 to £250 million in Winter 2021/22.

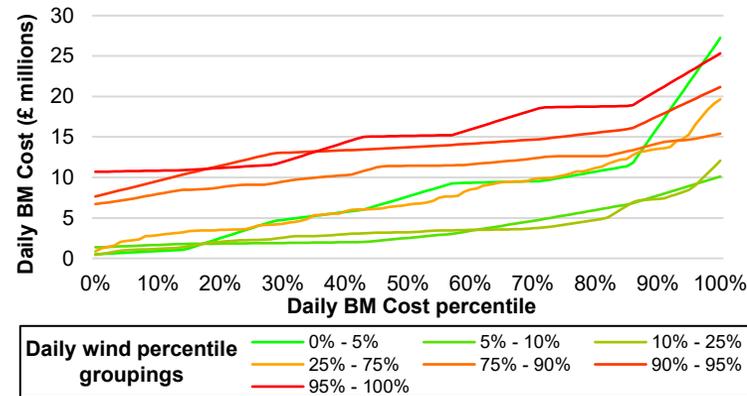
Costs from this strategy were much lower this winter due to reduced volumes and prices compared to last winter. Possible reasons for this include:

- OFGEM publishing a consultation into this behaviour and on 13th February publishing the outline of a licence condition to prevent units submitting offers well above their costs whilst having a PN of 0.
- Coal units operating outside of the BM through their coal contingency contracts, rather than offering consistently into the BM at £4,000.

Wind and Demand

Low residual load drives voltage, RoCoF and thermal constraints and very high residual load drives tight margins, this was a key source of costs this winter

BM cost by Wind generation percentile*

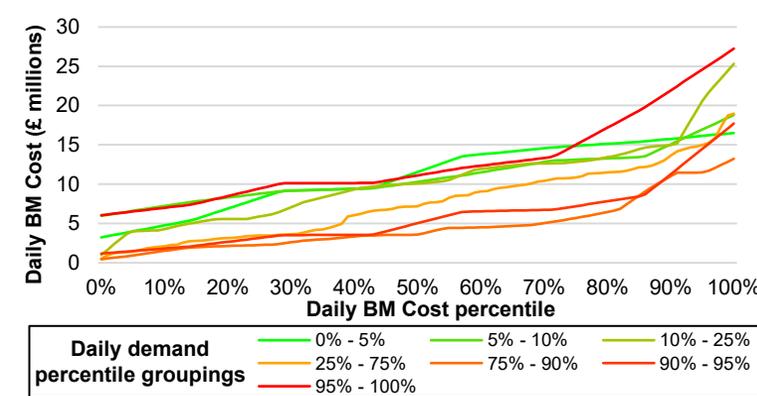


High wind generation suppresses price signals for conventional synchronous generation, which is required to maintain inertia levels and manage voltage constraints. Therefore, under high wind conditions, conventional generation is turned up, often at the expense of wind.

High wind is correlated with high flows from north to south (N-S), as most wind is located in the north of GB. When N-S flow constraints are active, wind in the north is often curtailed and conventional generation in England is turned up.

- The average daily costs for days with the highest 5% of wind generation (red 95%-100% line) was £16.2M, almost 2x the average daily BM cost this winter of £8.2M.
- Low wind generation reduces system margins, leading to scarcity pricing in the BM. Higher balancing prices increases the cost to balance the system.
- The peak daily cost for days with the lowest 5% of wind generation (green 0%-5% line) was £27.2M, the highest daily BM cost this winter.

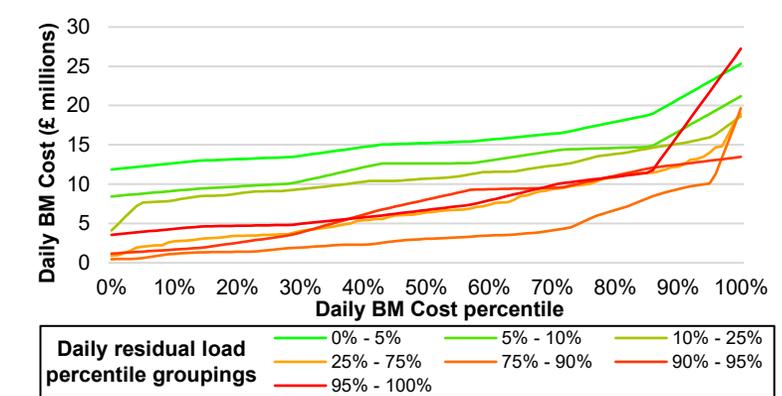
BM cost by Demand percentile*



High demand reduces system margins, which leads to scarcity pricing in the BM. Higher prices increase the cost to balance the system.

- The average daily cost of days with the highest 5% of demand (red 95%-100% line) was £13.6M, 67% higher than the average daily cost this winter of £8.2M.
- Low demand is also a key driver of BM Cost, as price signals for conventional synchronous generation are suppressed. Similarly to high wind days, conventional generation is often turned up to provide inertia and to alleviate voltage constraints at significant cost.
- The average daily cost of days with the lowest 25% of demand (green lines) was £10.6M, 30% higher than the average daily cost this winter of £8.2M.

BM cost by Residual load generation percentile*



Residual load is calculated as the national demand net of wind and nuclear generation, and is a measure of the requirement for conventional generation on the system.

Balancing costs are sensitive to residual load levels. High levels require more expensive generation to run and there is potential for scarcity pricing when margins are tight.

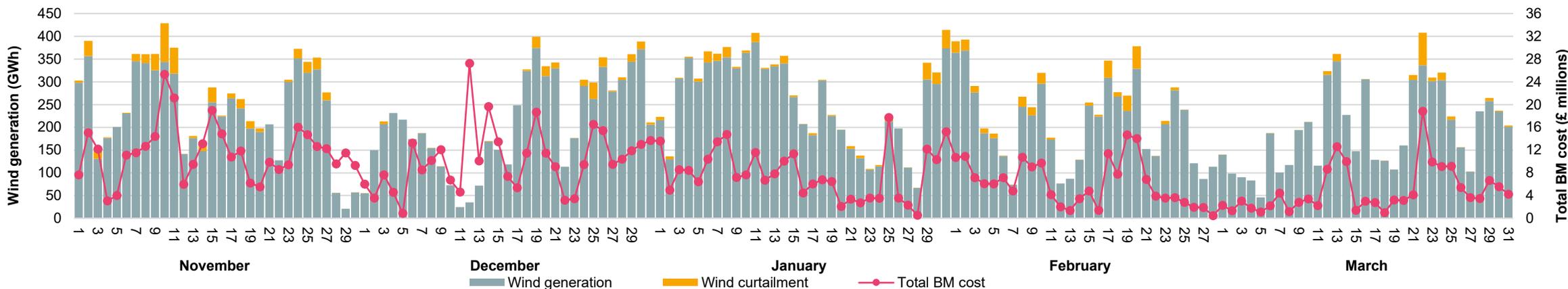
- The peak daily cost for days with the highest 5% of residual load (red 95%-100% line) was £27.2M, the highest daily BM cost this winter.
- Low residual load introduces system operability challenges, such as low system inertia and locational constraints. As a result, wind generation is often curtailed and conventional generation it turned up.
- The average daily cost of days with the lowest 25% of residual load (green line) was £12.6M, 54% higher than the average daily cost this winter of £8.2M.

*percentiles are taken from Nov 22-March 23

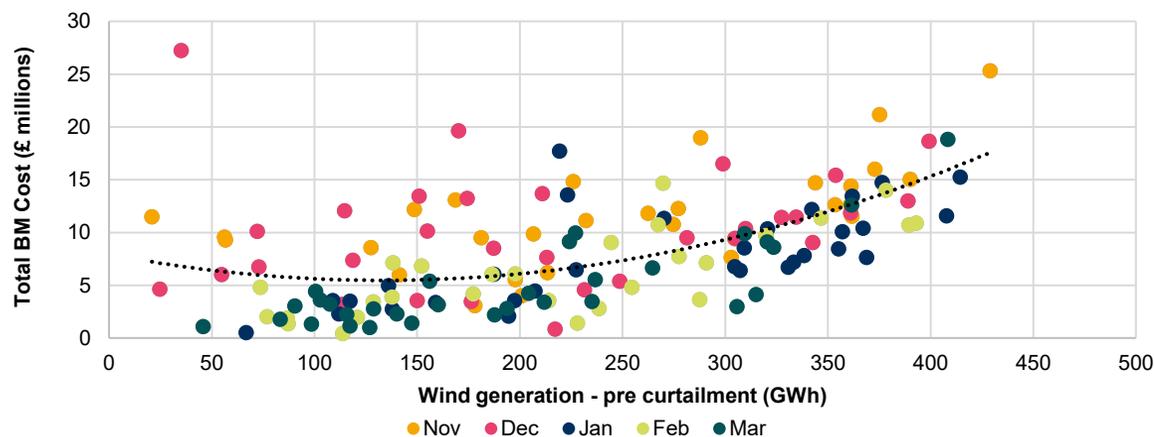
Wind generation

Curtailment this winter was less than the last two winters but wind still represented a key cost driver

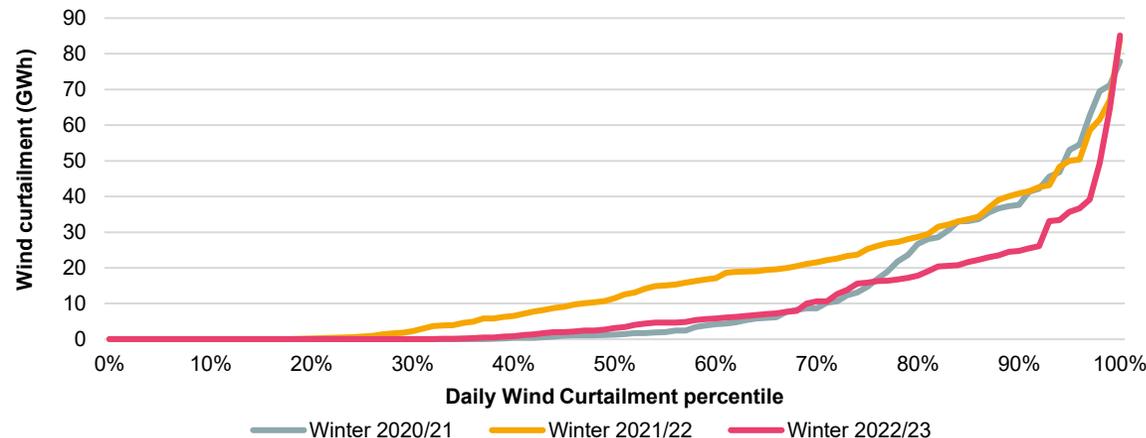
Winter 2022/23 Wind generation and Total BM Cost



Daily wind generation – pre curtailment vs Total BM Cost



Daily wind curtailment distribution by winter



Wind generation

Curtailment this winter was less than the last two winters but wind still represented a key cost driver this winter

Wind generation was a key driver in BM costs this winter. As shown by the scatter plot on the previous slide, higher BM costs are strongly correlated to periods of high wind output.

High wind levels

High levels of wind generation cause operational challenges for the control room. Wind generation doesn't currently provide inertia to the system and doesn't help manage voltage constraints. During periods of high wind output, conventional generation, which does help with RoCoF and voltage constraints is pushed out of the merit order. As a result, the control room must turn up capacity from these units, such as CCGTs and Coal, to alleviate the constraints and must therefore turn down the wind capacity to make room.

Turning up conventional units at record prices due to higher costs and turning down wind plants at negative prices due to their policy support significantly increases costs incurred by the ESO.

As most wind capacity is located in Scotland or the North of England, on days with high wind generation, flows from the North to the South often exceed boundary constraint operational limits. In these situations, capacity in the north must be turned down and capacity in the south must be turned up. This normally means northern pumped hydro increases its demand, northern wind generation is curtailed and southern conventional generation is turned up or southern interconnector trades shift flows towards GB.

These actions to tackle north-south flows are also very costly for the ESO for the same reason as inertia and voltage constraints.

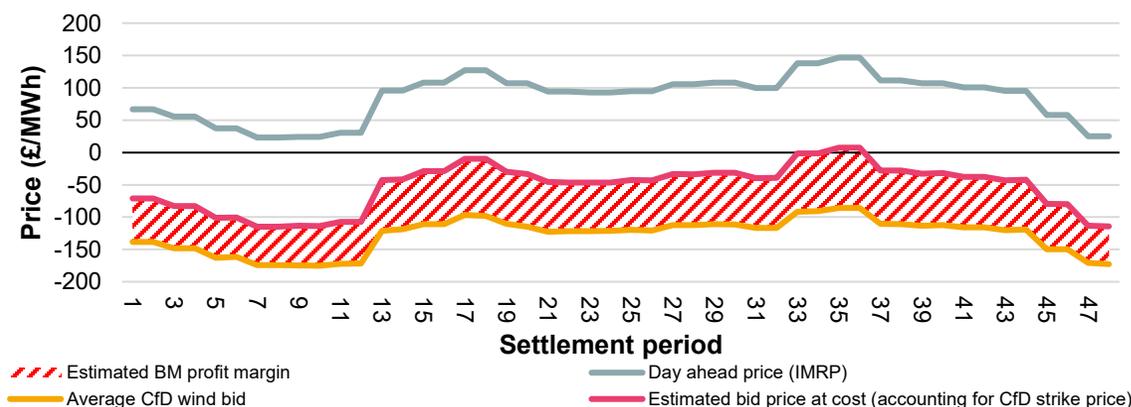
Whilst wind has been a key driver this winter, the volume of wind which was curtailed was actually lower than both last winter and the winter before. Whilst there was 8% more wind output on the system prior to an BM curtailment this winter compared to last, the volume of wind which was curtailed was 43% lower.

Low wind bid prices

Most wind capacity in GB has policy support, these policies include both ROCs and CfDs. The structure of these support contracts means wind units receive a payment which is proportional to the volume of power they are able to output onto the system. If supported wind capacity is turned down in the BM, its volume output onto the system is reduced and often it will lose some support revenue.

In order to recover any lost policy support, wind capacity in the BM normally submits bid prices which are negative, meaning if the control room were to turn them down the wind units would be paid to do so.

In addition to pricing negative to recover lost policy support, wind bids are often priced even lower to secure an additional profit margin. The chart below shows the average price of CfD supported wind units on 10th November. CfD-supported wind bids averaged -£128/MWh, which was well below the breakeven level implied by the day ahead price and their strike price of -£53/MWh. This profit margin of £75/MWh for the curtailed wind, contributed additional costs on 10th November.



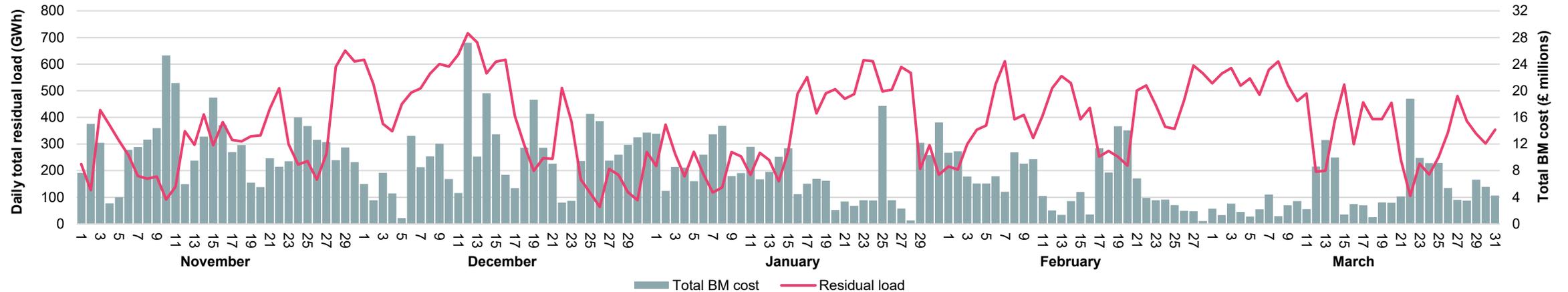
BM cost is also sensitive to very low wind levels. As the system becomes more dependent on intermittent sources of generation, during periods with low wind or solar a large burden is placed on the existing conventional gas and coal fired capacity to meet the shortfall.

On days when wind output is very low, system margins can be very tight, as was seen on 12th December. On the 12th December there was only 35GWh of wind output forecast for the whole day which meant forecast de-rated margins were as low as 1.4GW and led to units attempting the 'delay desync' strategy and getting accepted at prices as high as £6,000/MWh.

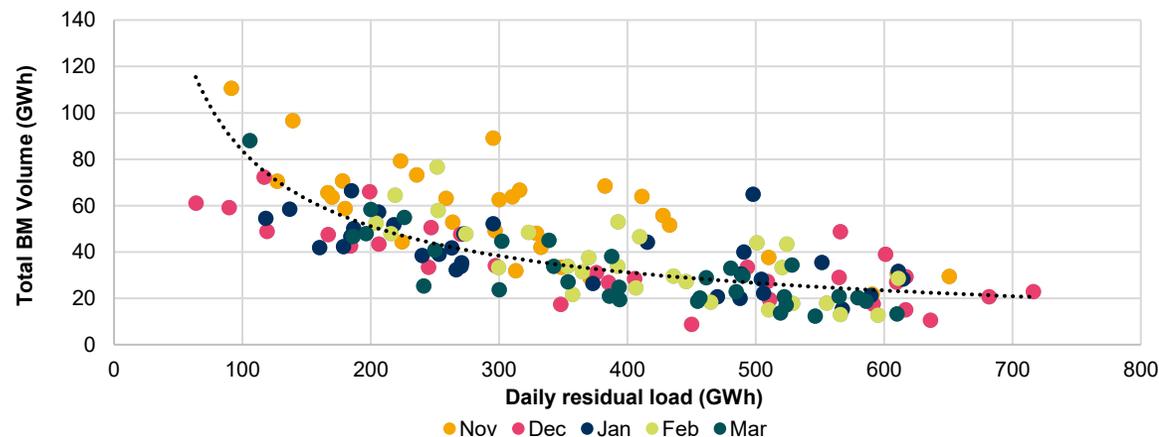
Residual load

Low residual load drives voltage, RoCoF and thermal constraints and very high residual load drives tight margins, both leading to increased costs

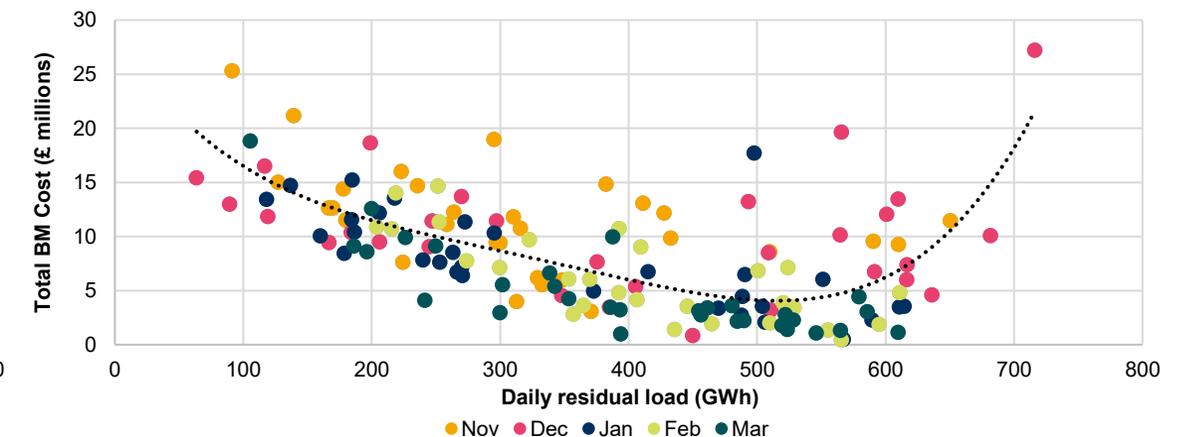
Winter 2022/23 Residual load and Total BM Cost



Daily total residual load vs Total BM Volume (Offer volume – Bid volume)



Daily total residual load vs Total BM Cost



Residual load

Low residual load drives voltage, RoCoF and thermal constraints and very high residual load drives tight margins, both leading to increased costs

Residual load is a measure of the requirement for conventional generation on the system. **High residual load** It is calculated as the national demand net of Wind and Nuclear generation.

Balancing costs are usually sensitive to residual load levels. High levels require more expensive generation to run and low levels introduce system operability challenges, such as low system inertia or locational constraints.

Low residual load

Low residual load is driven by both high wind generation and low demand. High wind brings with it the same challenges as mentioned on the slide discussing wind impacts, such as reduced conventional generation driving RoCoF and Voltage constraints. Low demand exacerbates the issues driven by high wind.

When wind generation is high and demand is low wholesale prices are suppressed and less conventional generation such as CCGT and Coal capacity runs prior to the BM. These conventional units are required to provide inertia to the system to manage RoCoF and to settle local voltage constraints. Therefore, during periods of low residual load, significant action must be taken by the control room to turn up conventional capacity at high cost and turn down wind at negative prices to make room.

The scatter plot on the left shows the relationship between residual load and the total volume of actions in the BM. The volume trends down as the residual load increases.

As the volumes of actions taken in the BM increases with lower the levels of residual load, the knock on effect is costs increasing, as more units need to be turned up and turned down to manage the system.

BM costs are also sensitive to high levels of residual load. The higher the residual load is the more generation is being provided by conventional units with higher costs. Taking actions on units which are further up the merit order means the prices accepted in the BM are higher.

High residual load also indicates potential system scarcity, as shown on the 12th December. High residual load means more generation is required from conventional units and if availability is reduced margins can become very tight. Tighter margins mean offer prices increase, as the capacity still available is worth more to the system than if the margins were more secure.

The relationship between residual load and BM cost is a U shape curve, as shown on the right hand scatter plot.

ESO Actions

Forecasting error

Whilst wind forecast error can increase BM costs, it isn't a key driver this winter

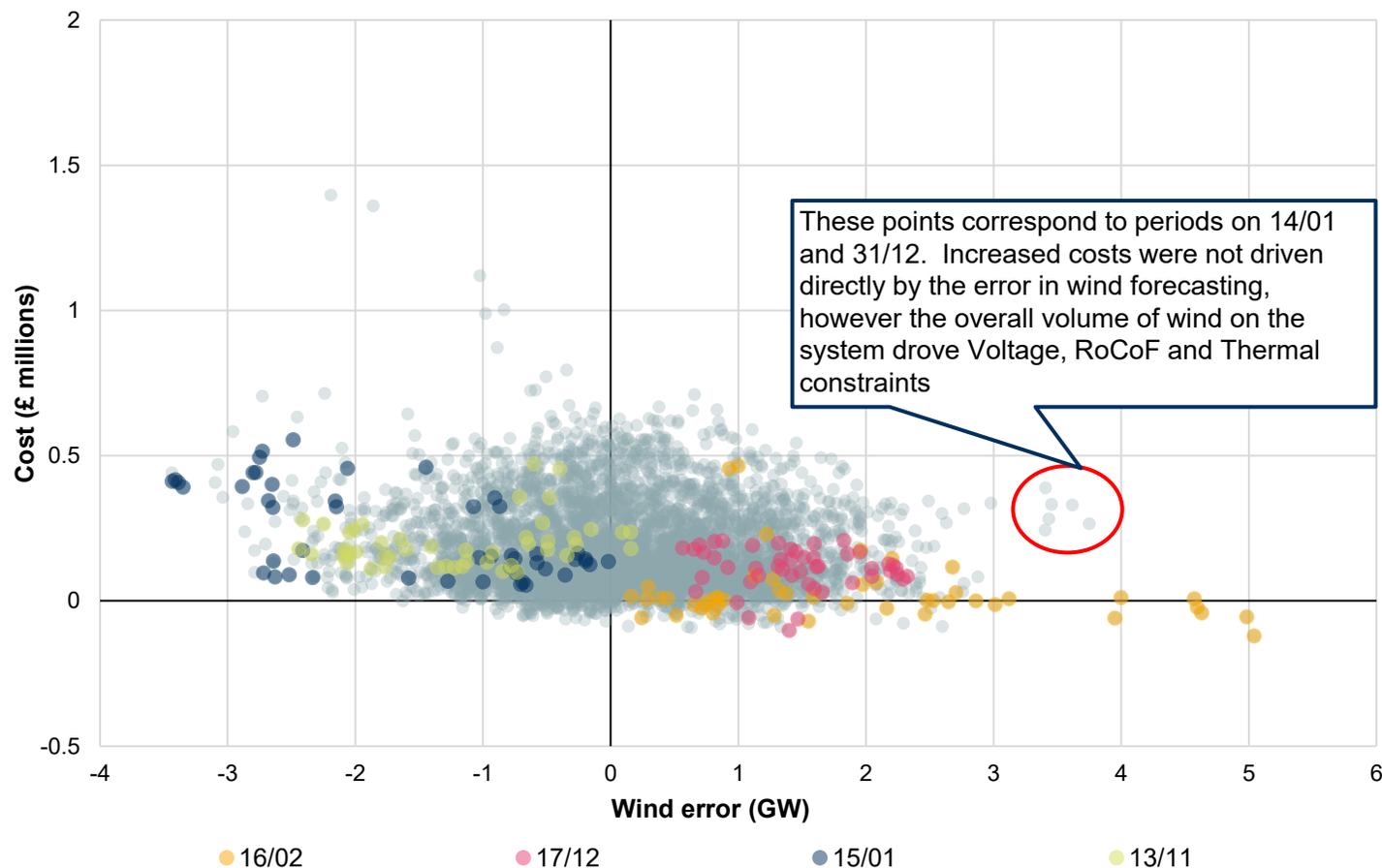
The chart to the right shows the relationship between wind forecast error and total BM cost. The wind error is calculated as the outturn wind generation – the forecast wind generation 4 hours before delivery and the Cost is the total cost of bid and offer actions in the period. Points for days with a minimum de-rated margin forecast less than 2.5GW have been filtered out, as their costs are likely to be driven by scarcity pricing rather than actions to account for wind forecast errors.

The two days with the largest volume of under-forecast wind this winter were 16/02 and 17/12 (orange and pink points on the chart). The relationship between error and cost for these two days isn't very strong, especially on 16/02. The overall relationship between under-forecast error and cost is weak, as shown by the frequency of points with high cost at low error levels.

The two days with the largest volume of over-forecast wind this winter were 15/01 and 13/11 (blue and green points on the chart). The relationship between error and cost for these two days seems strong, especially on 15/01, however most costs on 15/01 were from managing RoCoF and Inertia constraints due to low residual load over the morning, rather than the wind error.

Overall, whilst wind forecast error can drive increased costs in the BM, it doesn't seem to be a key driver this winter.

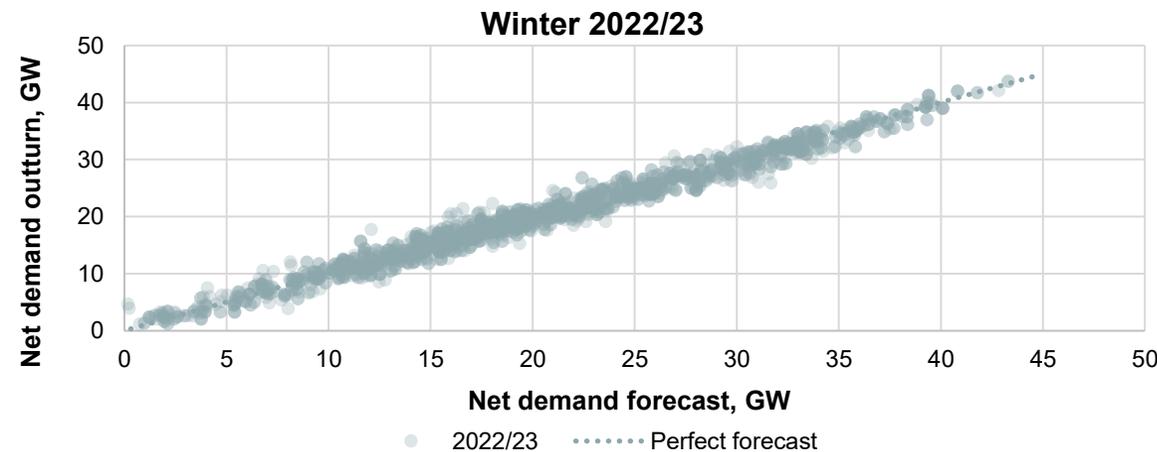
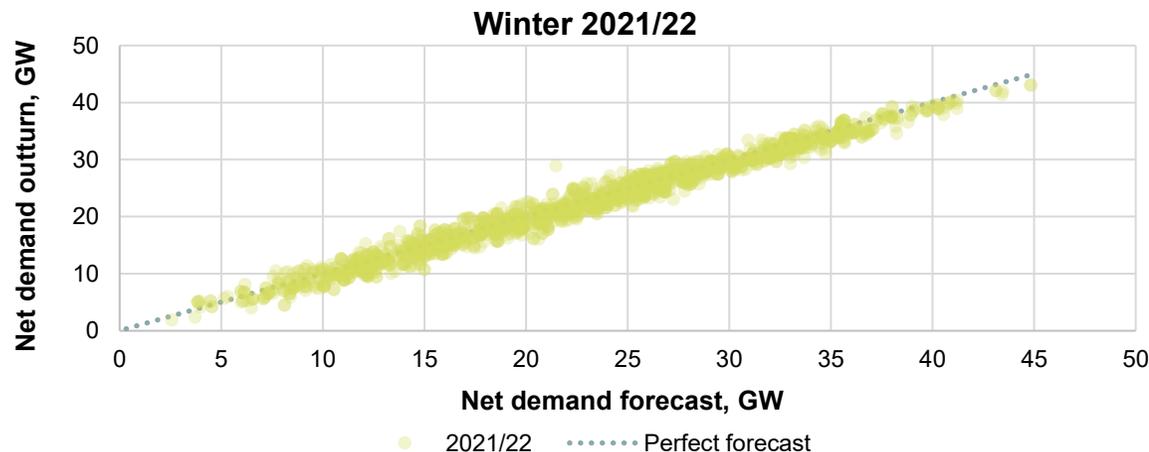
Winter 22/23 Wind error 4 hours ahead of delivery vs BM Cost



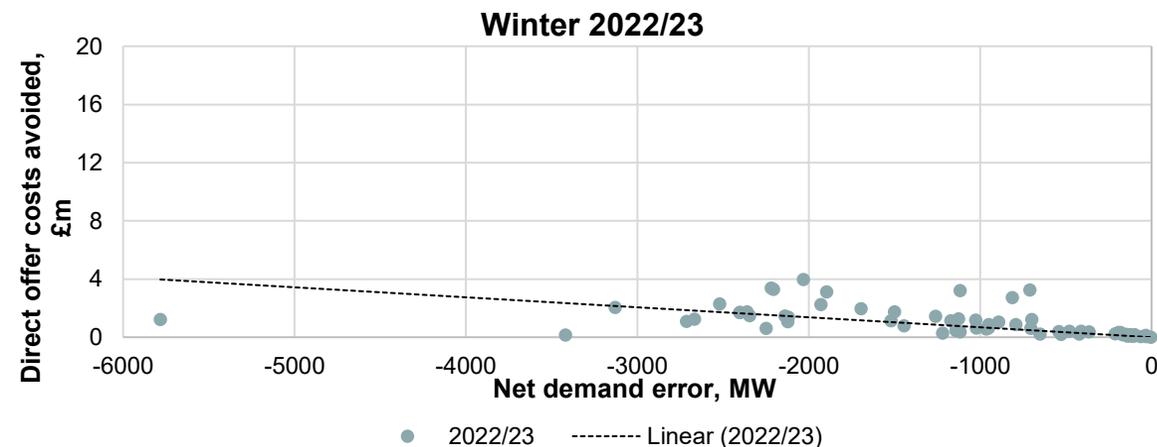
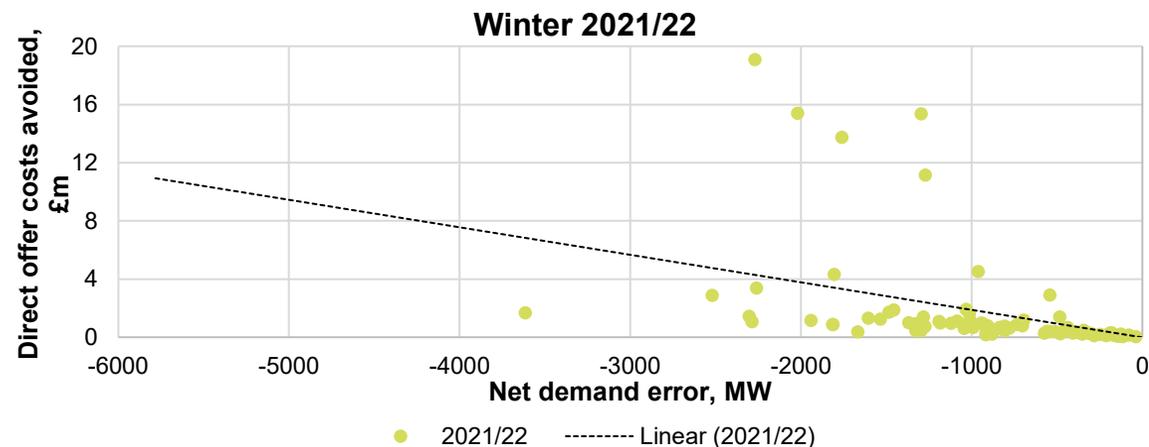
Forecasting error

When the conventional capacity requirement forecast is higher than the outturn, unnecessary actions are taken to support future margins

Net demand forecast vs outturn



Potential cost savings with perfect net demand foresight



Forecasting error

The Net demand forecast is the national demand forecast net of the transmission wind generation forecast.

In Winter 2022/23, the net demand forecast was on average in 240MW higher than the outturn. In the top 5th percentile of net demand periods, net demand was over forecast even more at 370MW.

On days when the net demand forecast is very high, two actions are often taken to ensure enough margin over the peak:

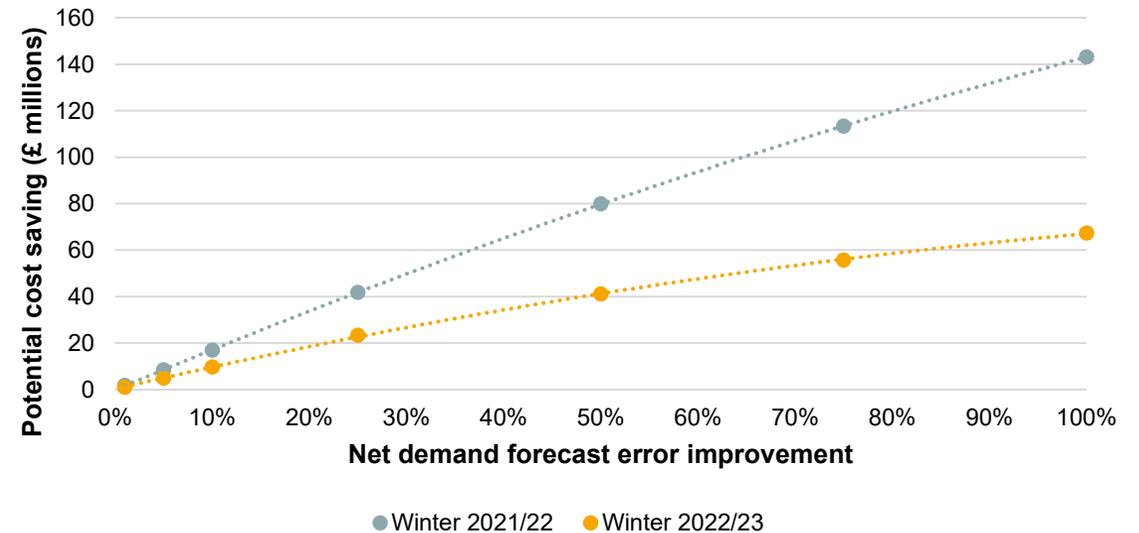
- Units with long MZTs, which intend to drop off the system in the run up to the peak, may have their desynchronisation delayed to keep their capacity available to the control room. Often units which drop their PN in the run up to the peak submit high prices to remain on, which can make these actions very costly for the ESO.
- Trades may be instructed on the interconnectors to reduce exports or increase imports.

Both of these actions must be committed prior to knowing whether the action is actually needed or not. Therefore, if the net demand actually out turned lower than was forecast some actions may have been unnecessary and costs could have been saved. If the control room are ensuring an additional 370MW of capacity is available unnecessarily, improved forecasting could result in significant cost savings.

The cost savings charts on the previous slide assume the most expensive delayed on units aren't used, up to the capacity of the net demand error, and sums up their total costs. Over Winter 2022/23, this calculation estimates a total of £67 million would have been saved with perfect foresight, down from £143 million last winter. The chart to the right shows the incremental cost saving for different levels of forecasting improvement. If the net demand forecast error was reduced by 10% the total cost savings for this winter could have been £9.7M.

Whilst it isn't reasonable to expect net demand forecasting to be perfect and all of these cost savings to be achievable, small improvements, especially during periods of high forecast net demand, could have significant cost savings.

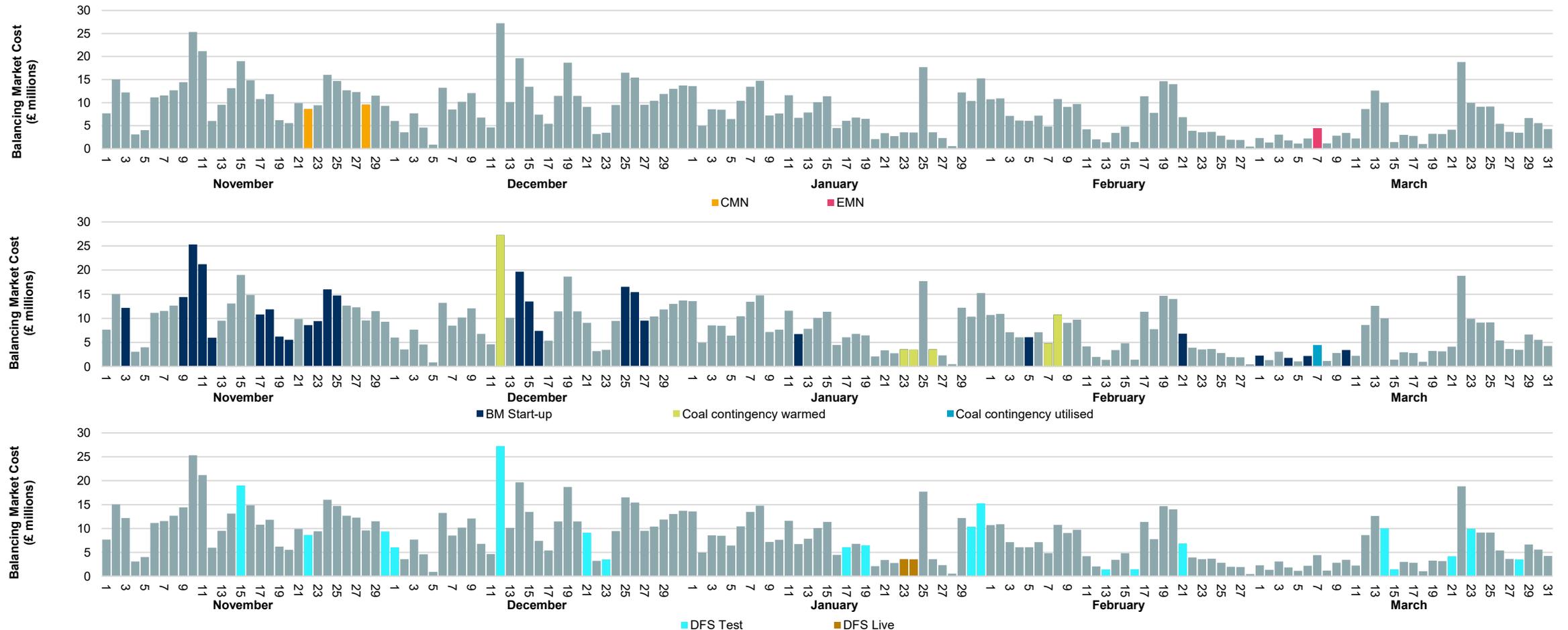
On the 16th and 22nd November and 3rd December, the net demand forecast for the evening peak was over 2GW too high, which led to unnecessary volumes of capacity being extended over the evening peak. The average daily cost incurred from net demand forecasting error on these days was over £3 million.



Enhanced actions

In general, enhanced actions didn't lead to increased costs. Days when contingency units were synchronised or with DFS live events had relatively low BM costs*

Daily BM Cost during enhanced actions



November Market notices

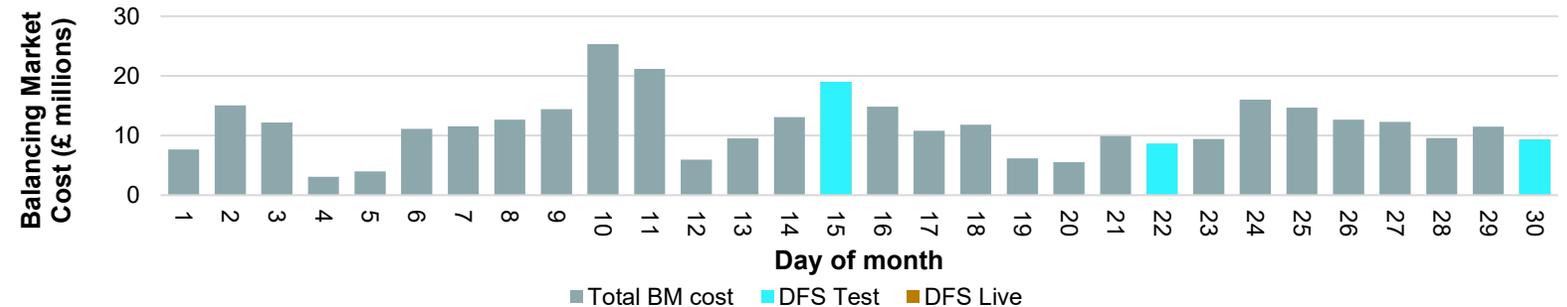
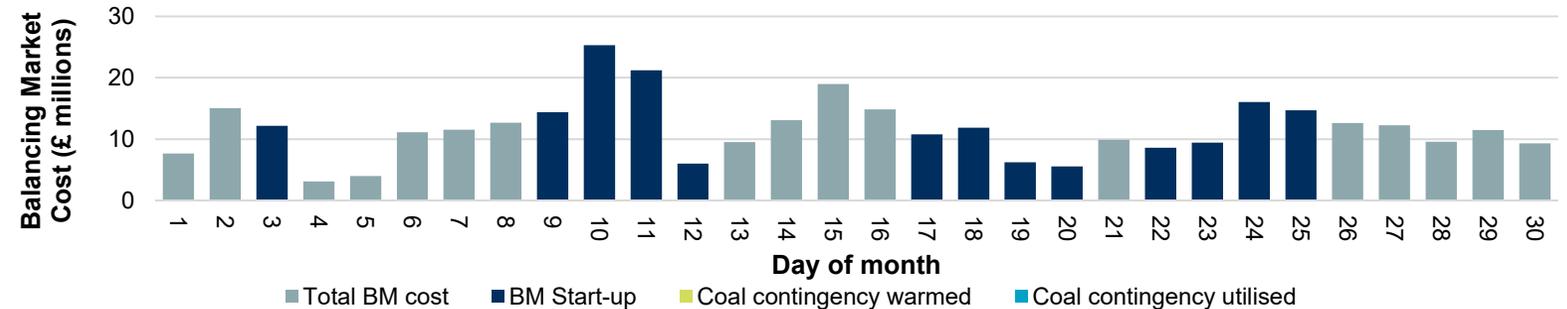
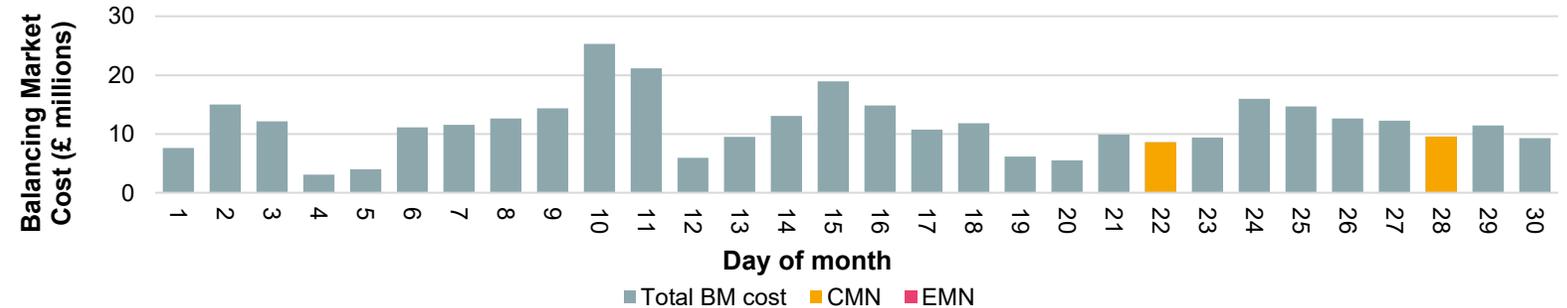
Although costs were not high, on both CMN days offers were accepted above £1000/MWh

BM Start-up instructions were made on 13 days in November, mostly to warm the two coal units to reduce their NDZs.

Three DFS tests took place on 15th, 22nd and 30th. The tests on 22nd and 30th aligned with two of the tightest days in the month. However, the relatively low costs on these days are unlikely to be directly due to the DFS tests, as only 140MW and 158MW of capacity were procured on each day.

Two CMNs were triggered on 22nd and 28th, but these don't align with particularly high cost days for the month. Most cost in November were driven by high wind levels causing system operability issues, however the two CMN days did both see high prices offers accepted with offers over £1000/MWh accepted in both days.

Daily BM Cost during enhanced actions



December Market notices

Warming coal contingency contracts may drive up offer prices and therefore costs

BM start-up instructions were made on 7 days in December, mostly to warm biomass units to reduce their NDZs. On 12th December a Coal unit, with a **coal contingency** contract, was warmed which coincided with the highest cost day in the month.

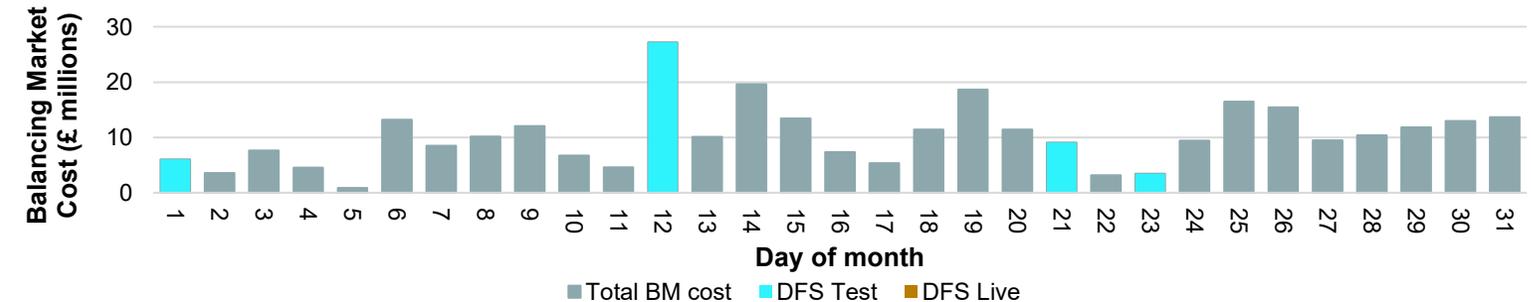
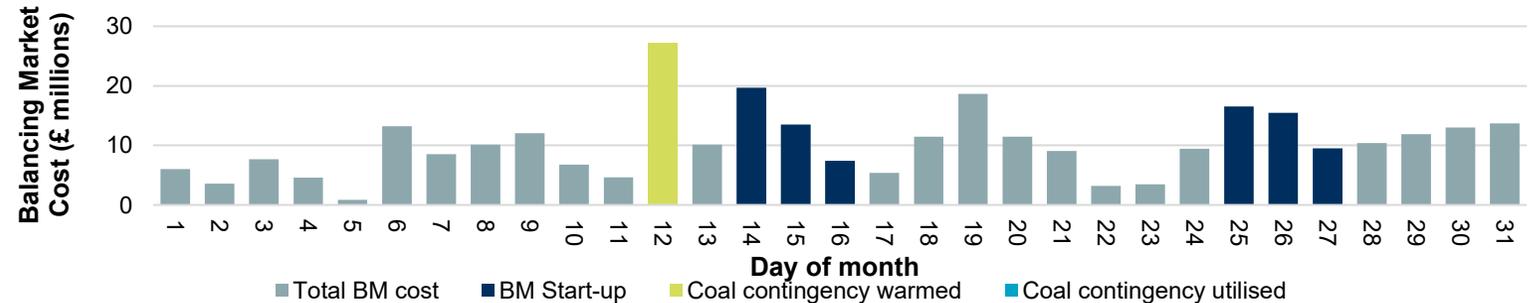
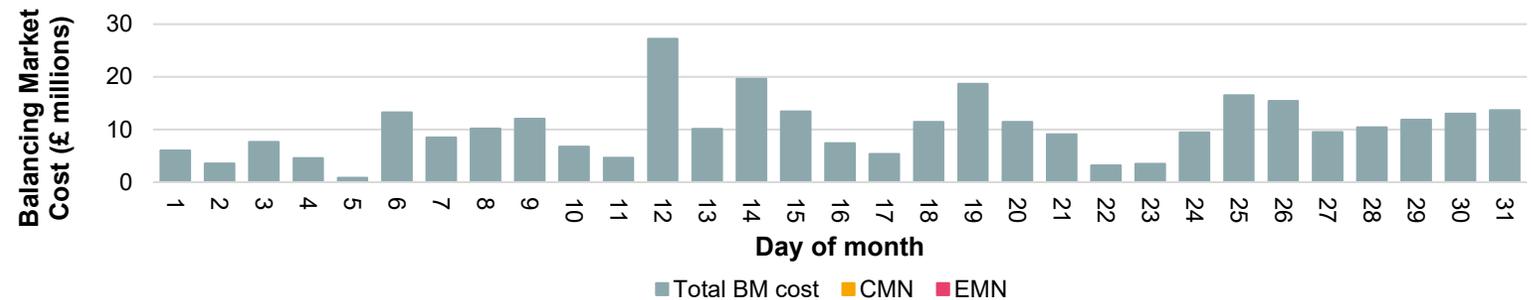
Warming the **contingency contract** unit may have driven up offer prices as it signals to the market the ESO feels the day will be tight. The highest submitted offer prices did not always align with the periods with lowest DRM, sometimes better coinciding with times when contingency contracts were activated.

Three **DFS tests** took place on 12th, 21st and 23rd. The test on 12th corresponded to one of the tightest days in the month and 150MW of demand reduction was procured.

At the time of the DFS test, a CCGT was being offered on at an average price of £5,500/MWh, if DFS capacity reduced the capacity required from Rye House, it led to a cost saving of £0.76M.

There were no **CMNs** triggered in December.

Daily BM Cost during enhanced actions



January Market notices

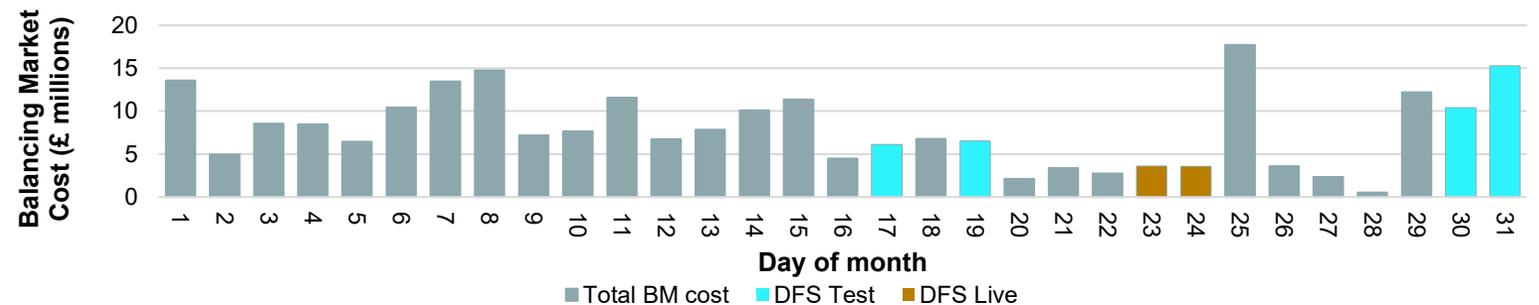
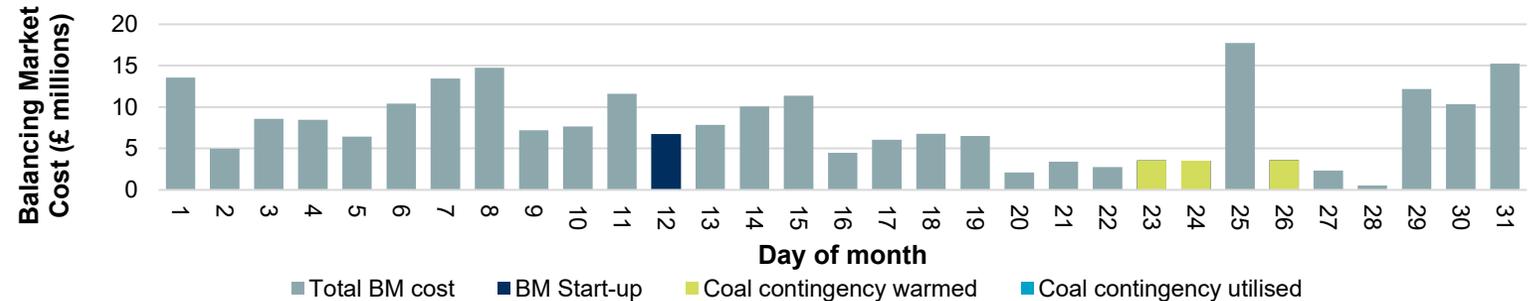
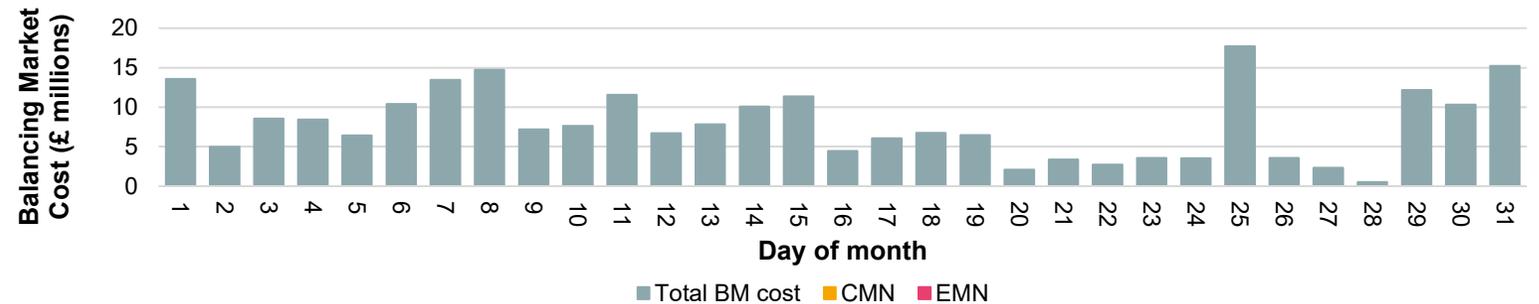
There wasn't a strong relationship between any market notice and high BM costs in January

BM start-up instructions were made on 4 days in January, **Daily BM Cost during enhanced actions**

and on 3 of those days units with **coal contingency** contracts were warmed. Costs on these days were not significantly higher than other days, suggesting warming units doesn't drive high BM costs.

The offer and bid costs for the **two DFS live** event days were very low compared to the rest of the month. Closer to delivery the system wasn't as tight as feared when the live events were triggered. This meant offer prices were not extreme and costs remained relatively low.

There doesn't seem to be a strong relationship between market notices and high costs in January 2023. The 25th January, the highest cost day, didn't coincide with any event, but did had significant issues around the FLOWSTH constraint.



DFS Cost

The DFS service cost the ESO £4.1M in January, with most costs incurred during the live events on 23rd and 24th

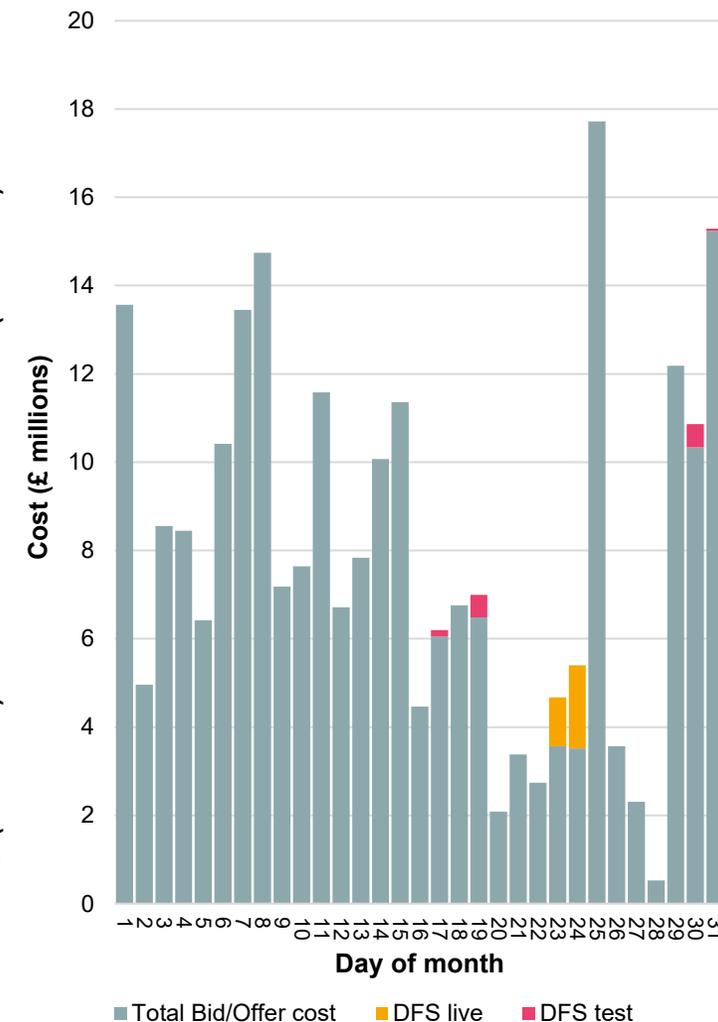
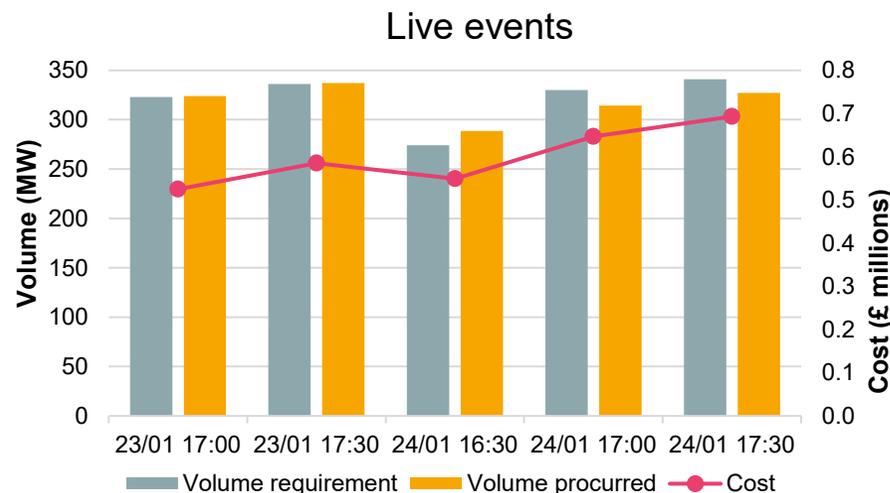
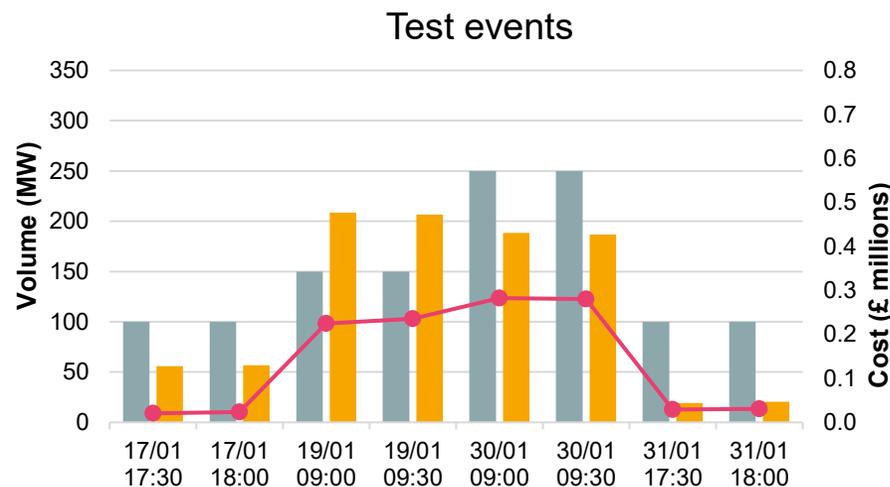
The estimated cost of the DFS service in January 2023 is £4.1M, of which £3M was incurred on 23rd and 24th during the live DFS events.

The test DFS events guaranteed a minimum price of £3000/MWh. Some participants tendered in at higher prices but none were accepted.

In contrast to the test events, prices during the live events on 23rd and 24th had much higher pricing. The volume weighted accepted price for the Live DFS events was £4400/MWh and some participants were paid £6500/MWh.

The live DFS events were signalled due to uncertainty over the French interconnector availability and concerns over system margin however at delivery DFS seemed unnecessary.

At delivery on 24th, several units had offers available below £1000/MWh to provide a total capacity of 980MW with a total headroom of 106MW. In addition, a further unit could have been extended at a price of £825/MWh to provide 410MW and 305MW of headroom.



February Market notices

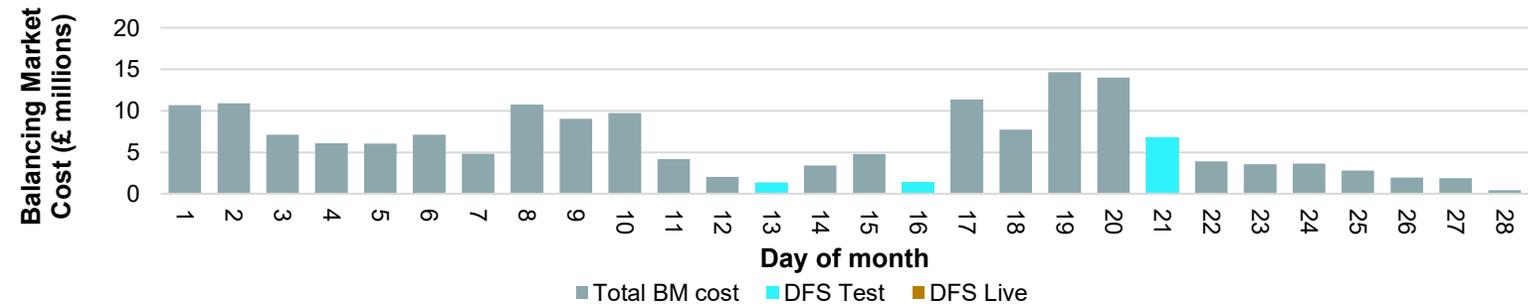
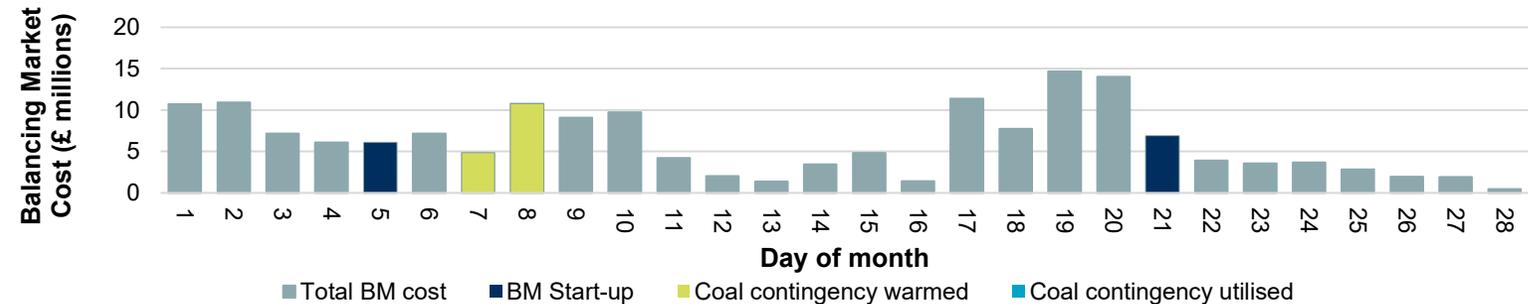
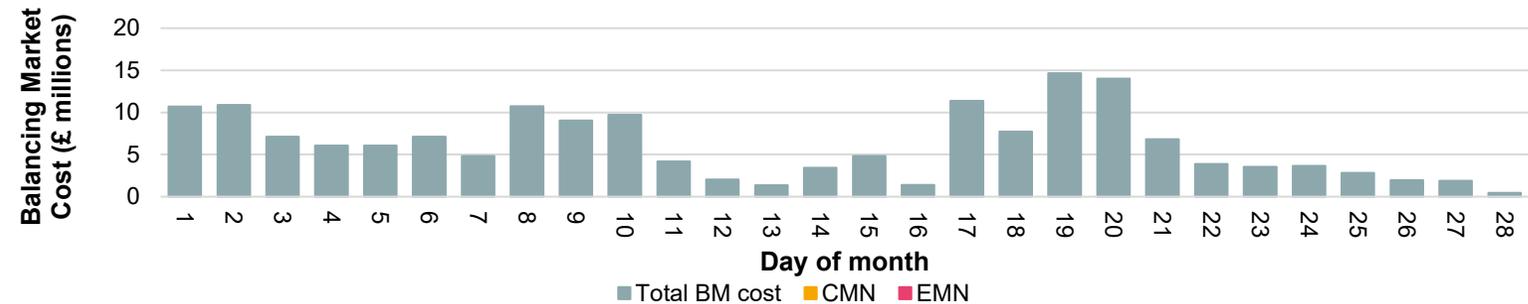
Contingency coal warming didn't result in higher costs on 7th and 8th

BM start-up instructions were made on 4 days in February, and on 7th and 8th coal contingency contracts were warmed. Costs on these days were not significantly higher than other days, suggesting warming units doesn't drive high BM costs.

There was a slight spike in costs on the 8th February which coincided with warming of coal units. This spike is unlikely to be a result of market participants changing strategy, as the majority of additional costs were flagged for thermal constraints as opposed to margin reasons.

There doesn't seem to be a strong relationship between market notices and high costs in February 2023. The 19th and 20th, the two highest cost days in February, didn't coincide with any events.

Daily BM Cost during enhanced actions



March Market notices

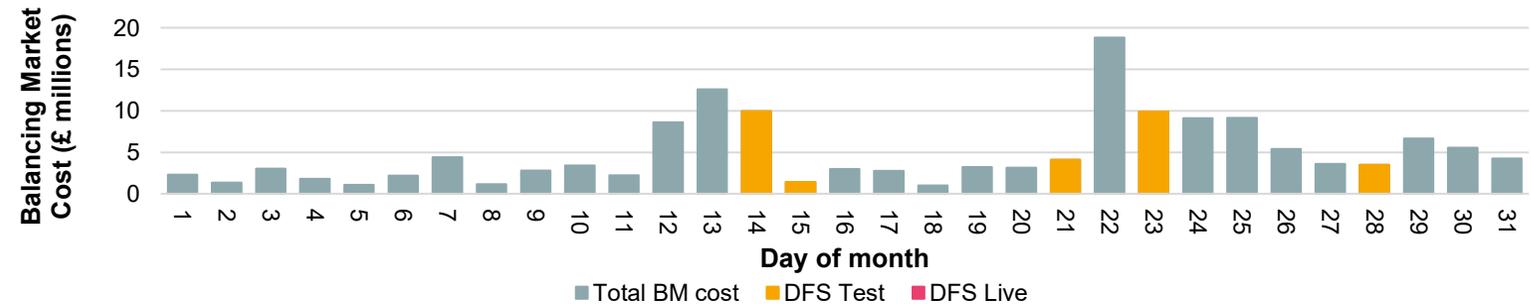
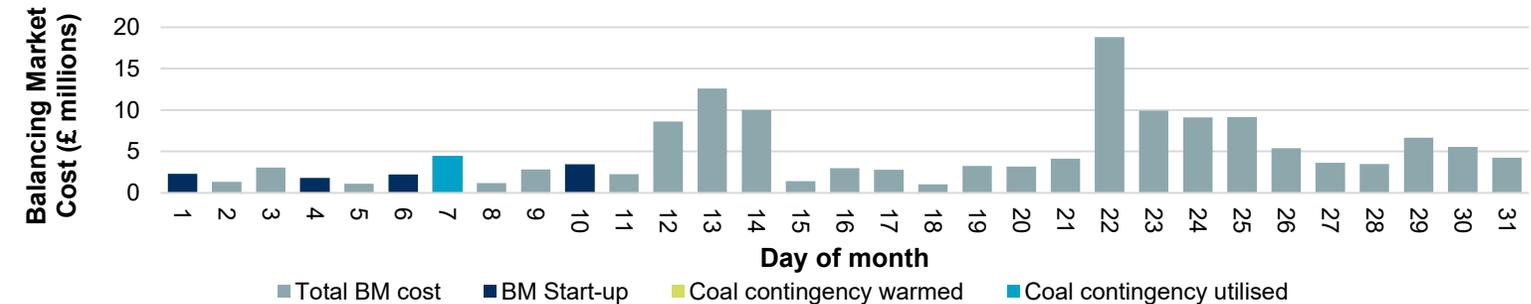
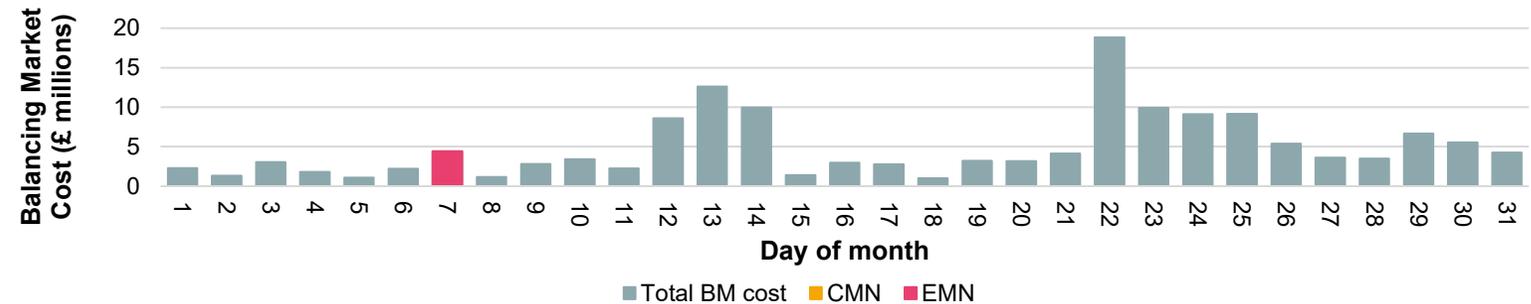
BM start up and coal contingency utilisation didn't increase BM costs significantly

BM start-up instructions were made on 5 days in March, and on 7th two coal contingency units were synchronised. Costs on these days were not significantly higher than other days.

We would have expected costs to be higher on the 7th when coal contingency units were utilised, as these are only meant to be used when all actions available have been taken. Some units did factor in system scarcity to their offer prices, however the two highest priced units were not used which meant costs were lower. Had the last available CCGT offer been accepted there would have been an additional £11M incurred on 7th making it the second most expensive day of the month.

The two highest cost days didn't have any market notices, so other factors must have driven the costs, such as low residual load and Voltage/RoCoF constraints.

Daily BM Cost during enhanced actions



Enhanced actions

In general, enhanced actions didn't lead to increased costs. Days when contingency units were synchronised or with DFS live events had relatively low BM costs

Capacity Market Notice (CMN) and Electricity Margin Notice (EMN) impact

CMN

A CMN is triggered when the forecast margin is below a threshold set out in the Capacity Market Rules. During periods when a CMN is active, parties with capacity market contracts must make their contracted capacity available to the system to secure margins and prevent loss of load.

There were two CMNs this winter, 22nd and 28th November, however both were cancelled after forecasted margins improved throughout both days. As both CMNs were cancelled, units didn't have to make their capacity available.

The average BM cost on the days with a CMN was £9 million, £2.6 million lower than the average daily cost for November of £11.6 million. As costs weren't significantly higher than other days this winter, CMNs are unlikely to drive BM costs.

EMN

An EMN is similar to a CMN, although it is issued by the control room based on their specialist knowledge of the national and international energy situation.

Due to forecast tight margins ahead of the 7th March, an EMN was triggered. As well as the EMN, coal contingency units were warmed and two units were synchronised over the evening peak.

Even though an EMN indicates very tight margins, costs on 7th March were only £4.4million, very low compared to other days this winter.

These costs could have been significantly higher had some very high priced offers on the table been required, but margins had recovered prior to these very expensive units needing to be instructed.

BM Warming and Coal contingency units

BM Warming

The control room instructs inflexible units to warm ahead of forecast scarcity. Warming units reduces their Notice to Deviate from Zero (NDZ) to be within BM timescales, allowing their capacity to help secure the system margin when it is tight.

When coal units aren't warmed they have long NDZs, so, on days when the contingency coal units may have been required, warming instructions were sent (often a day prior to the forecast scarcity).

In general, warming actions correspond with higher cost days, however this is unlikely to be due to the warming actions themselves. As warming instructions are sent in advance of forecast scarcity, it is more likely scarcity is the real driver.

Coal Contingency

The 7th March was the only day when coal contingency units were synchronised, however the total cost was only £4.4M. As expected, coal synchronising lead to extreme offer prices, however at the moment the highest offers would have been accepted, there was no longer a need as margins had recovered.

Had the most expensive offer still on the table been required to secure the margin, an additional £10.6million would have been incurred due to its very high offer and long minimum non zero time (MNZT).

Demand Flexibility Service (DFS)

DFS is an enhanced action which is available to the control room in advance of forecast system scarcity. Demand can tender for contracts to be paid to reduce demand during specific times to help with system margin. The deadline for the control room to commit to a live DFS event is 14:30 on the day before the demand reduction is required.

DFS test events

Test events were held on 19 different days from November 2022-March 2023 to test the reliability of the demand reduction the control room were able to contract at particular times on different days.

Demand, which was contracted on these tests, was guaranteed a minimum price of £3000/MWh for the demand which they were able to reduce in the required periods.

As DFS tests were spread out over the winter and weren't triggered by specific market conditions, the correlation in costs with their occurrence is weak. Whilst the most expensive day this winter (12th December) had a DFS test, it is very unlikely the test itself drove the higher costs and it was more likely due to forecast scarcity and units executing the 'Delay De-sync' strategy.

DFS live events

DFS live events must be committed to by 14:30 on the day before the demand reduction is required. On 23rd and 24th January, two DFS live events took place, and overall costs were very low compared to other days this winter. Low costs were unexpected on days when enhanced actions were taken due to forecast tight margins.

Costs were low on the 23rd and 24th January, as, closer to delivery than the 14:30 commitment deadline, margins recovered and there was no longer a requirement for DFS.

Key winter days

Key Winter Days

The following section will look into events on specific days this winter to investigate key cost drivers and key events which occurred this winter.

Four key days have been identified for inclusion within this report, featuring interesting market characteristics or the use of enhanced actions.

This report does not intend to review the activity of any specific generators, therefore whilst identifiable information is kept for the completeness of reporting, no generator unit names are kept in the report.

Date	Cost	Volume of actions	Reason for review
12 th December	£27.2M	23GWh	<ul style="list-style-type: none"> • Highest cost day this winter • Offer accepted at £6,000/MWh
29 th December	£11.9M	49GWh	<ul style="list-style-type: none"> • Large wind curtailment costs • IMRP was negative for 8 hours
24 th January	£3.5M	32GWh	<ul style="list-style-type: none"> • DFS live event
7 th March	£4.4M	20GWh	<ul style="list-style-type: none"> • EMN and coal contingency units synchronised

12th December - BM Costs by technology

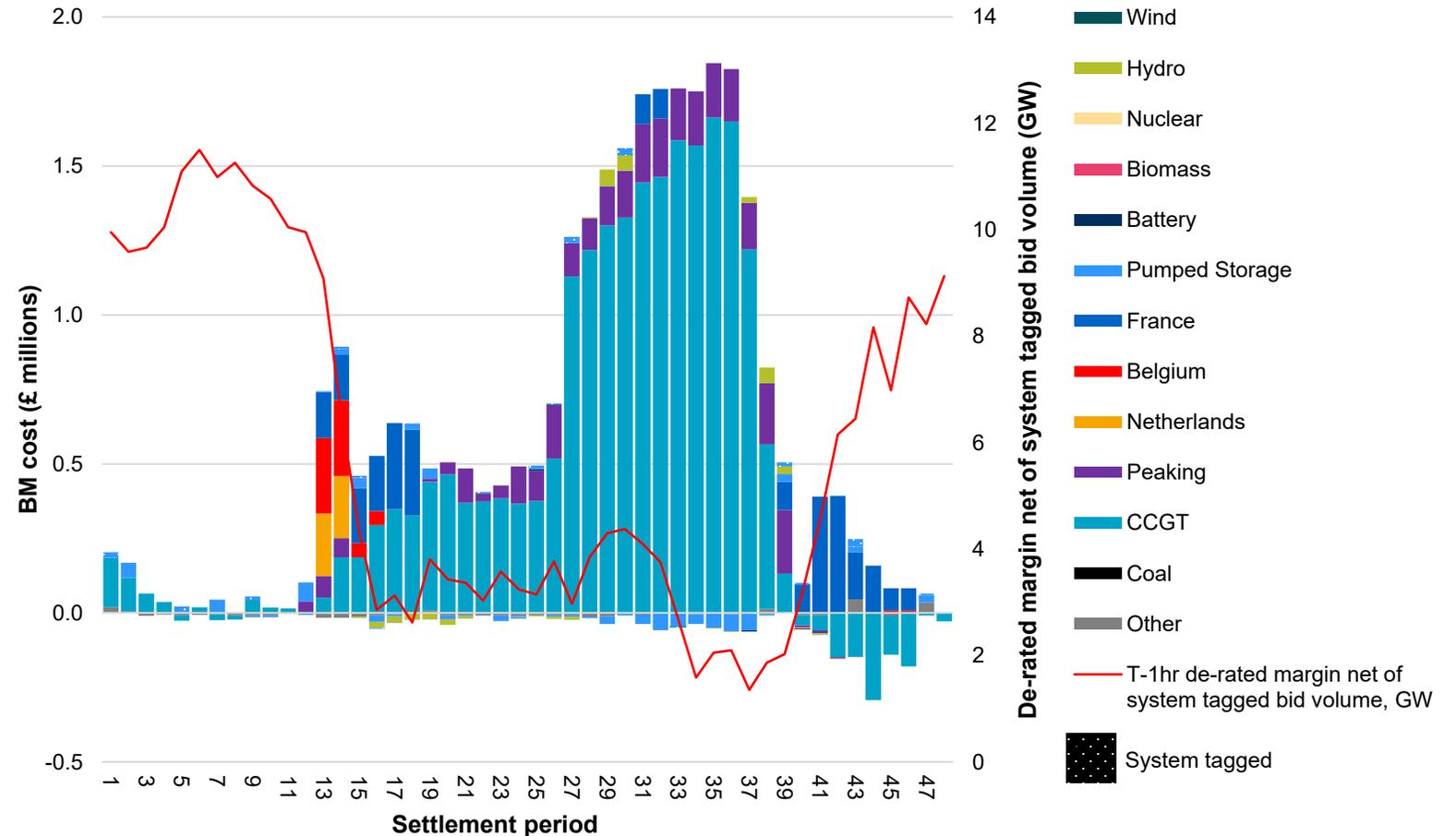
75% of total BM costs were from CCGT payments and 85% of total costs were paid to 2 CCGTs

The 12th of December 2022 had the highest daily BM cost this winter (£27.2M).

75% of the total BM costs were paid to CCGTs. With 2 CCGTs, making up 85% of total BM costs.

The key drivers for costs on the 12th were tight system margins in GB as well as in continental Europe.

12th December, BM net costs by technology



12th December – Large CCGTs Synchronised

France being on alert state and 1GW of unsuccessful interconnector trades meant all units were needed for margin reasons

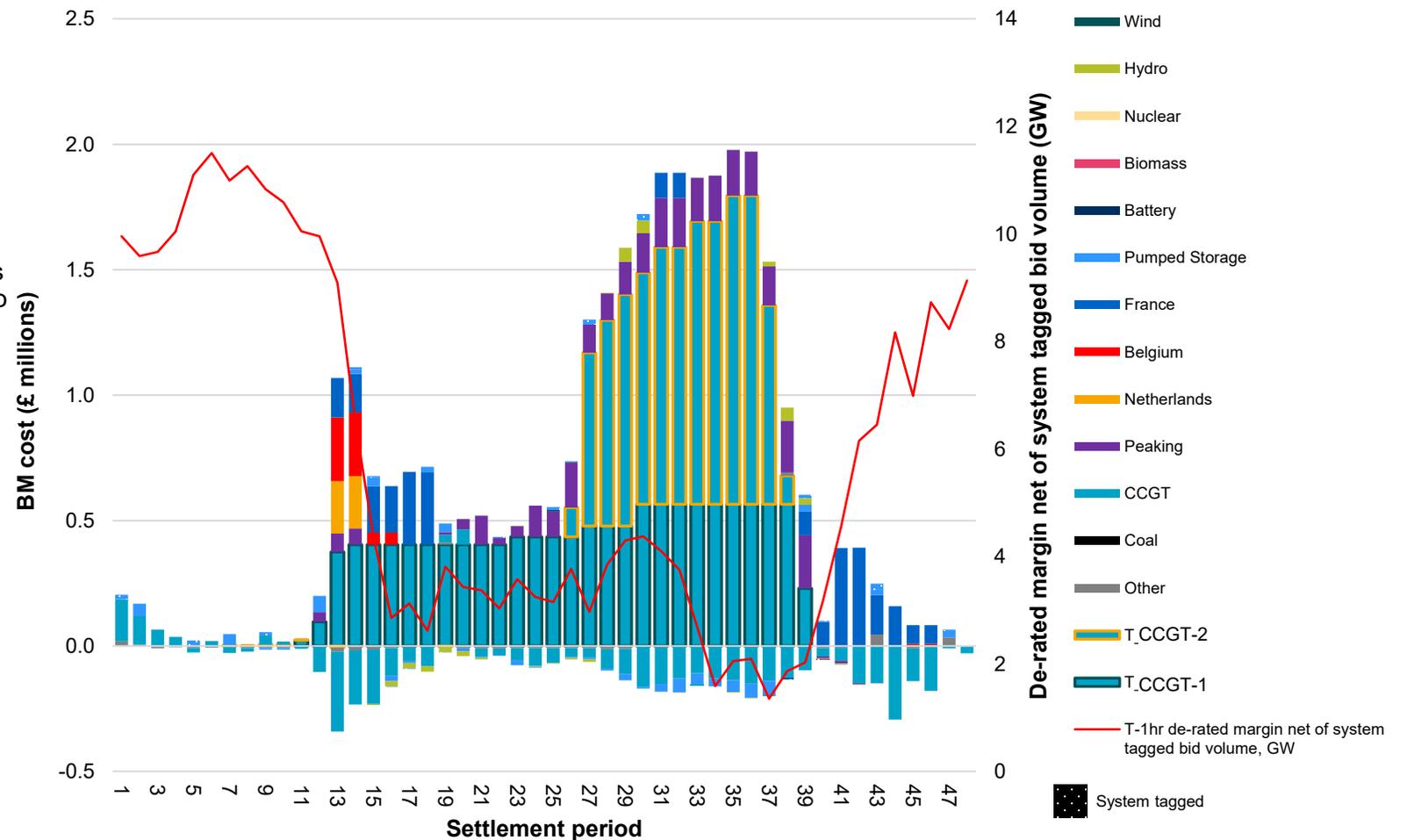
87% of all direct BM costs were paid to two CCGTs.

A CCGT was turned on in period 11 for system margin reasons to help cover 1GW of unsuccessful trades on continental interconnectors and cover possible import reductions due to France being in alert state between 07:40 and 13:36. Due to its MNZT of 6 hours, it was accepted at its turn-on price until period 22 (although due to France being in alert state it would be needed for this full time anyway) contributing £4.1M to the total costs for the day.

After the unit completed its MNZT in period 22, it raised its offer price. The control room extended its turn on further to period 39 to cover the operational risk that importing interconnectors would be instructed to 0 by RTE (France was in an alert state). The additional cost of extending the turn on was £8.5M.

A different CCGT dropped its PN to 0 from 13:30 onwards and upped its offer price to £4,000/MWh. It was also extended for the same reasons, contributing an additional £11M to BM costs.

12th December, BM net costs by technology



12th December – France system margins

Without French imports GB de-rated margin would be less than -1GW over the peak of the day

The top chart shows the margin available to the French ESO on the 12th of December. Emergency margin is margin generated through SO-SO emergency trades (curtailing exports/increasing imports).

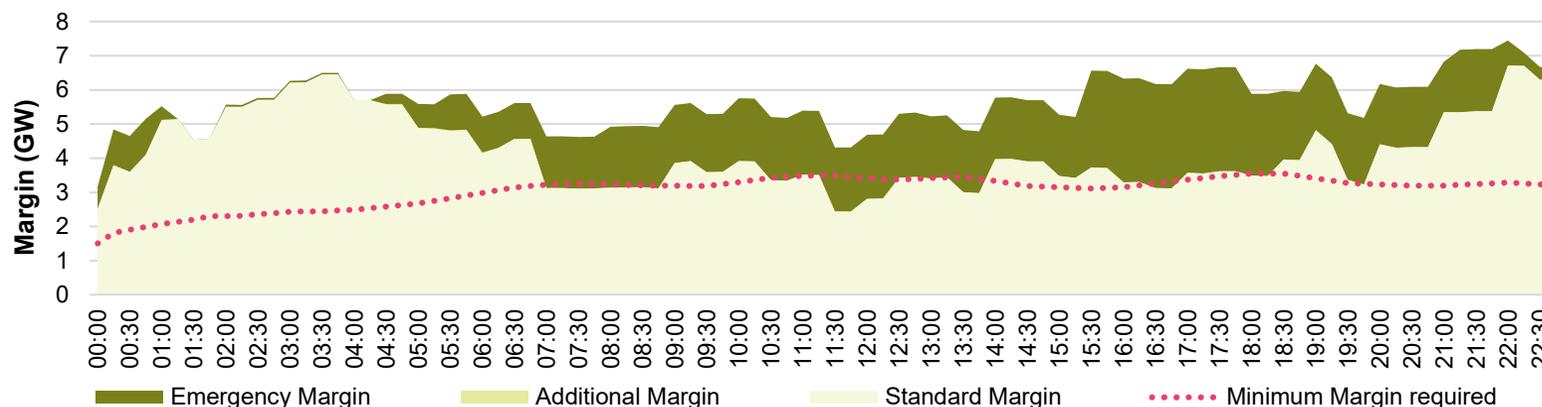
The Minimum margin required fell within the Emergency Margin band for 6 hours on 12th December in both the morning and evening peaks. This meant French interconnector imports to GB were at risk of being curtailed to secure the French system.

The bottom chart to the right shows the T-1 de-rated margin net of system tagged bid volumes with and without the French interconnector imports.

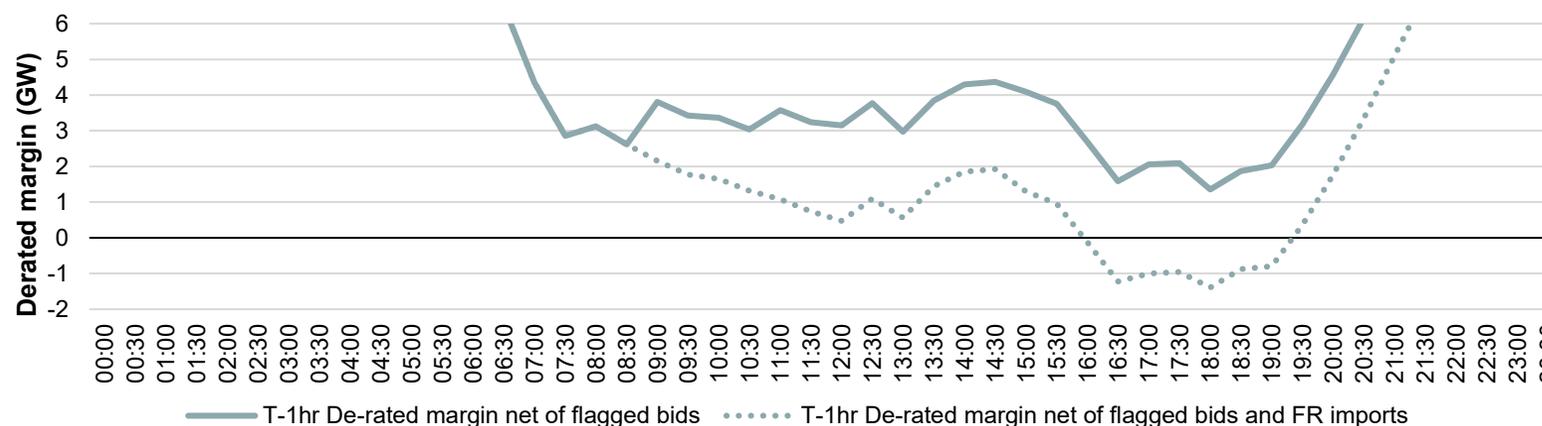
Without French imports, the de-rated margin drops below 1GW between 12:00 and 13:00 and is below -1GW over the evening peak.

Expensive actions needed to be taken by the control room to ensure all possible GB capacity was available in case French imports were stopped.

12th December, France margins



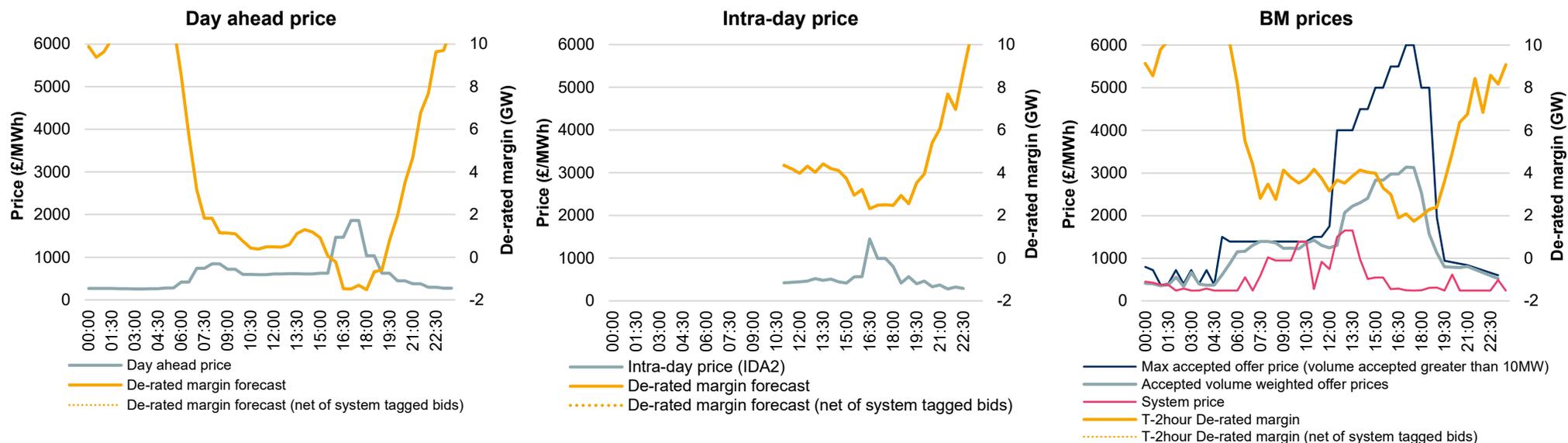
12th December, GB de-rated margin with and without French imports



12th December - Wholesale market prices

VWA accepted offer prices were greater than £1200/MWh from 07:30-18:30

12th December – price alignment across different markets



Due to very tight de-rated margin forecasts at the day-ahead stage (dropping as low as -1.5GW), the day-ahead price cleared at £1,900/MWh over the peak of the day. De-rated margin forecasts ahead of the IDA2 auction were less extreme (dropping to 2.3GW), therefore the IDA2 price peaked lower than the day-ahead auction at £1,500/MWh. Even though the wholesale market prices were extreme, significantly higher prices were observed in the BM.

A key difference between the markets is the length of time that BM prices remain elevated. BM accepted volume weighted offer prices remained above £1,200/MWh from 07:30 through to 18:30 whereas the DA and IDA2 markets are only above that level for 4 periods and 1 period respectively.

29th December – Wind and Demand

Prior to 7am, 78% of demand could be met by wind alone

Compared to 12th December, 29th December had very high wind and low demand.

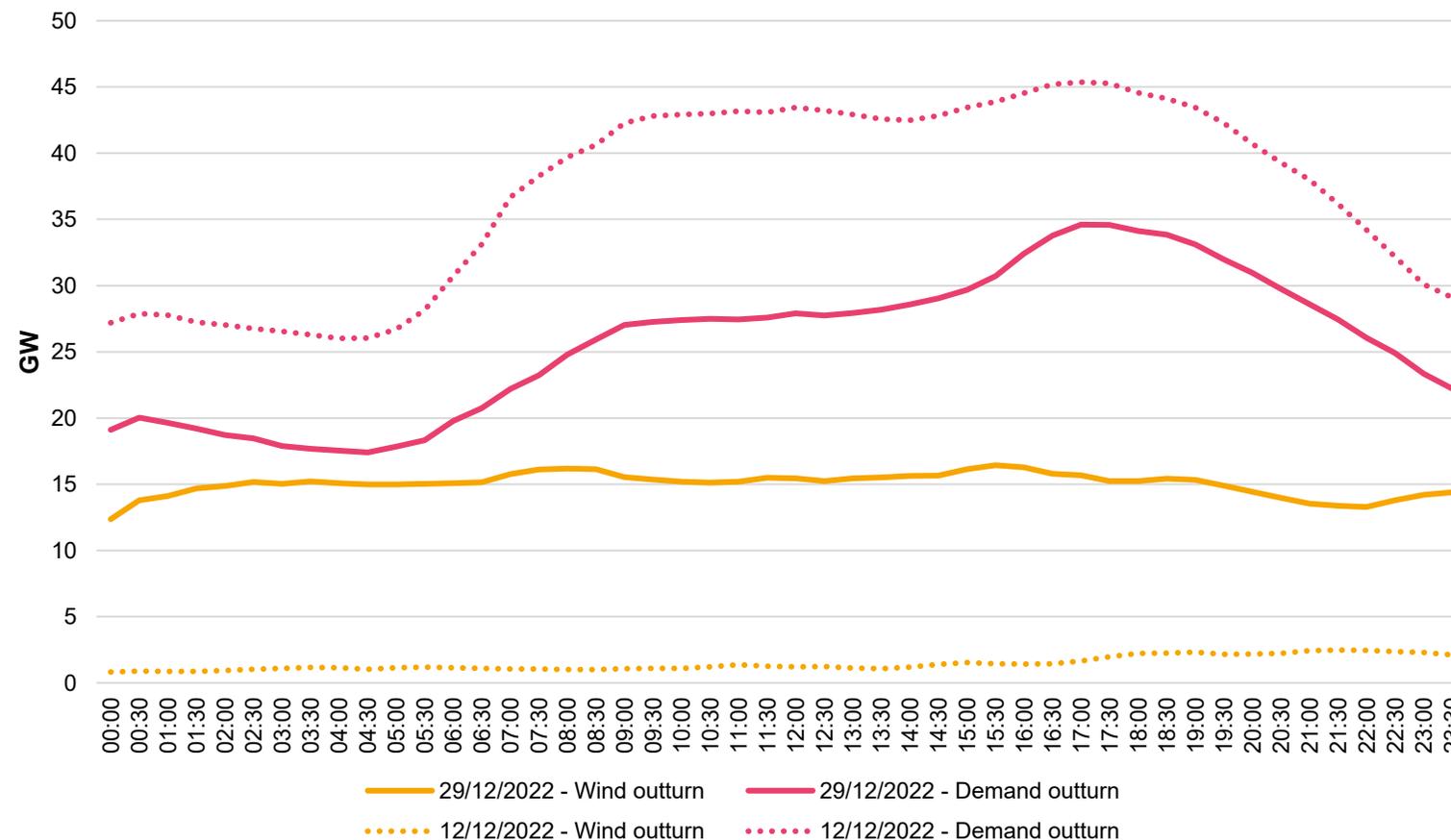
Prior to 7am, over 78% of national demand could have been met solely by wind, with the tightest residual load representing a shortfall of only 2.4GW in wind capacity to meet demand, much of which would have been met by inflexible baseload Nuclear generation.

High wind and low demand can cause significant operational challenges for the control room, such as:

- Voltage constraints.
- High RoCoF, due to reduced system inertia.
- Thermal constraints, due to the location of wind generation in GB.

These challenges are often costly to overcome as expensive generation is needed to turn on and low priced renewables need to be curtailed.

29th December, Wind outturn (net of BOA) and National demand outturn



29th December - Generation changes

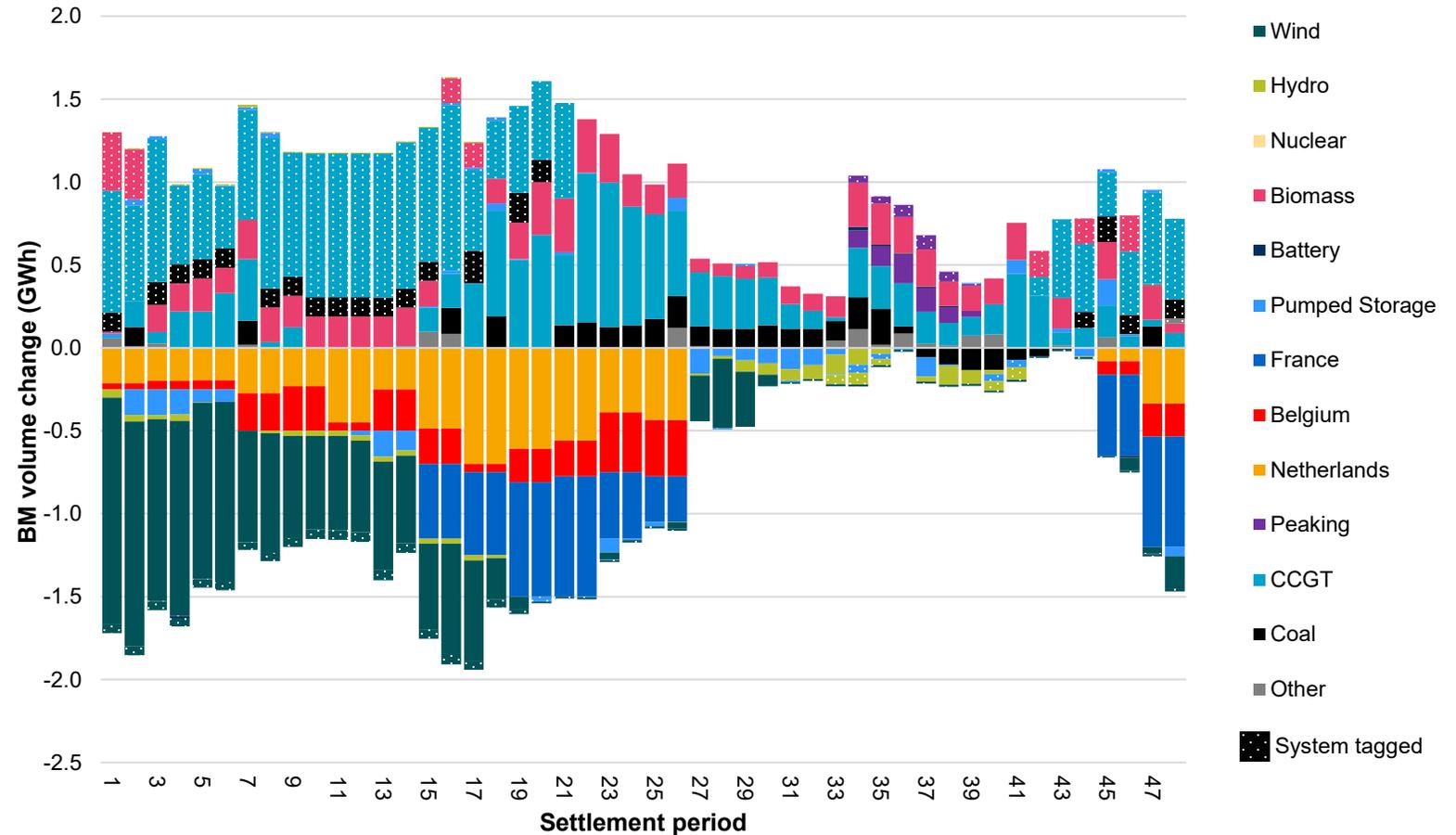
17.4GWh of Coal, CCGT and Biomass was kept on to ensure suitable voltage and RoCoF levels

17GWh of wind was curtailed on the 29th December. Unlike the 10th November in last month's report, only 8% of the total wind curtailment was system tagged.

Low demand and high wind caused very low (even negative) wholesale market prices which meant the volume of conventional generation on the system which could be turned down was very low.

In the morning, 17.4GWh of Coal, CCGT and Biomass generation was kept on from the previous day to ensure suitable voltage and RoCoF levels on the system. Due to increased generation from these units, turn downs were required and wind was the only option.

29th December, BM net generation changes by technology



29th December – Cost change by period

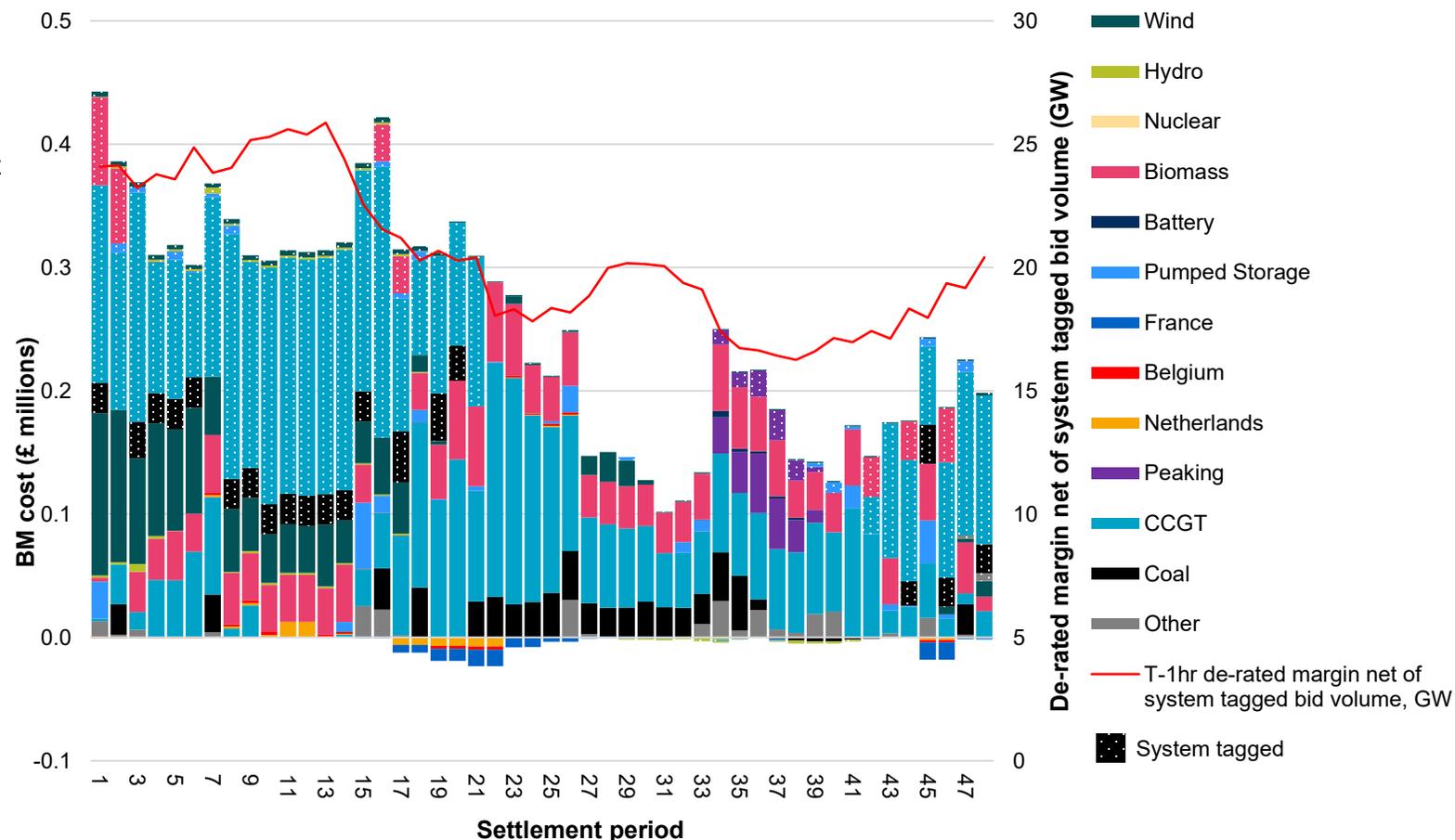
Most cost was incurred in the morning due to extending CCGT, Coal and Biomass units at high cost and curtailing wind at negative prices.

Unlike the 12th December and other tight days, the majority of BM costs were incurred in the morning during the period of very low demand.

CCGT, Biomass and Coal offers were accepted at high cost to maintain inertia and voltage levels on the system.

Wind was curtailed to offset the increase in conventional generation as it was the only option. Non-AR2 Wind bid negatively, as these assets would lose their policy support if they were curtailed, which resulted in a net positive BM cost.

29th December, BM net costs by technology



29th December – Wholesale prices

The IMRP was negative for 8 hours suspending CfD support for AR2 CfD units

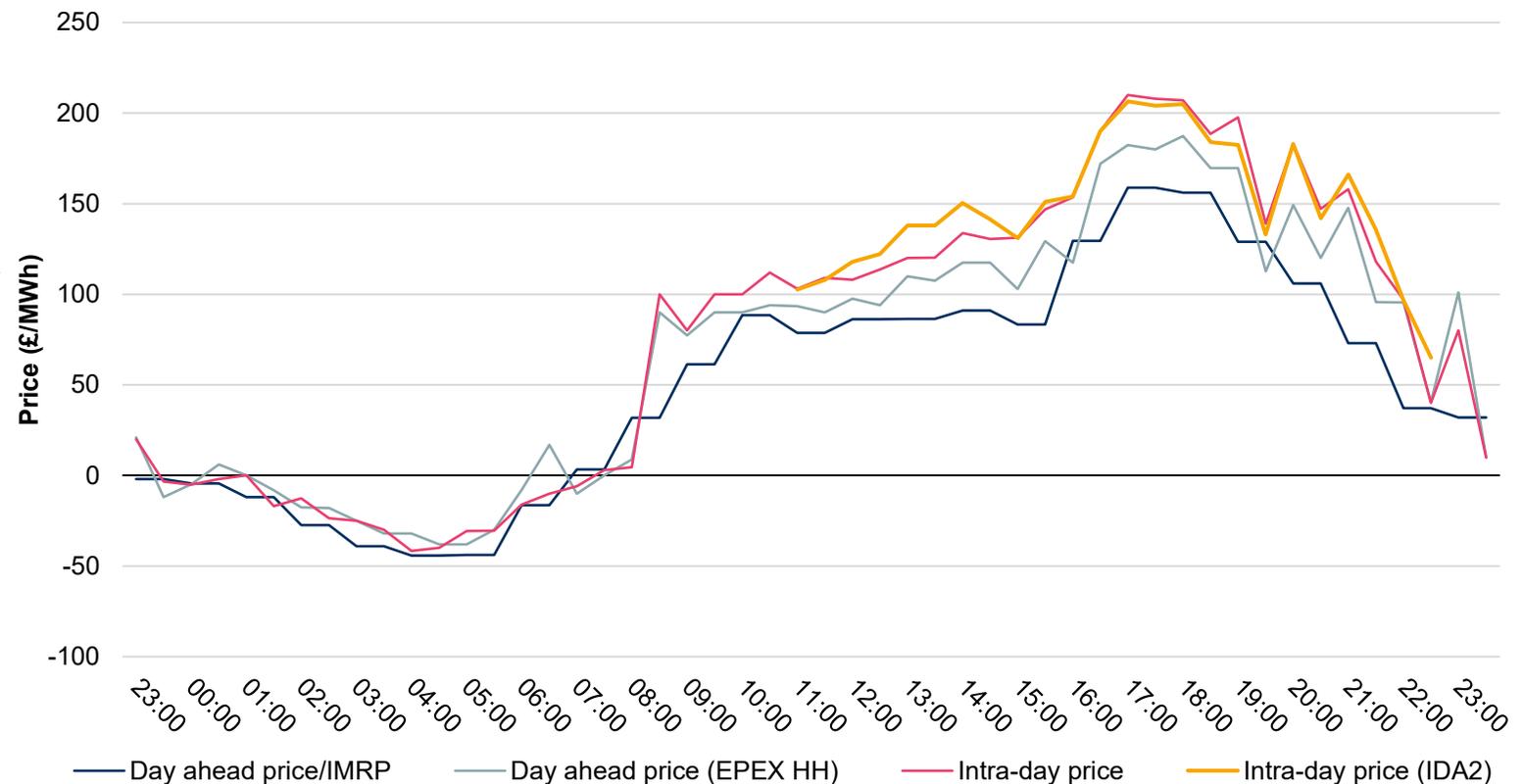
The volume weighted day ahead price/IMRP from 23:00 on 28th to 07:00 on 29th December was negative, dropping as low as -£44/MWh. The intraday markets also cleared at very low prices, with most periods below 0. Low wholesale prices mean conventional units with positive running costs are less likely to generate, causing voltage and inertia issues.

On 29th, the control room turned on and kept on large amounts of conventional generation to alleviate voltage constraints and increase inertia.

The volume weighted day ahead price (IMRP) was negative for 8 consecutive hours.

Note that AR2/3 CfD plant lose their support payments for the full negative price period if the IMRP is negative for 6 or more consecutive periods and as a result on 29th a large block of AR2/3 CfD supported wind was expected to drop off the system.

29th December, Wholesale prices



29th December – Wind reduction

Uncertainty around the output of AR2 wind plant meant additional response was held at a cost of £1.3M

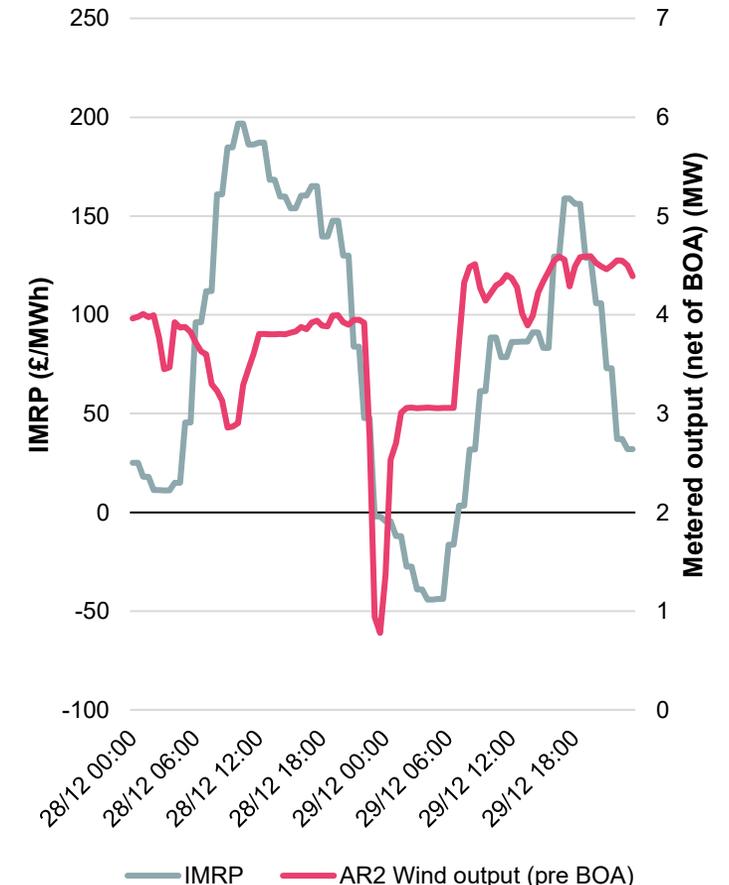
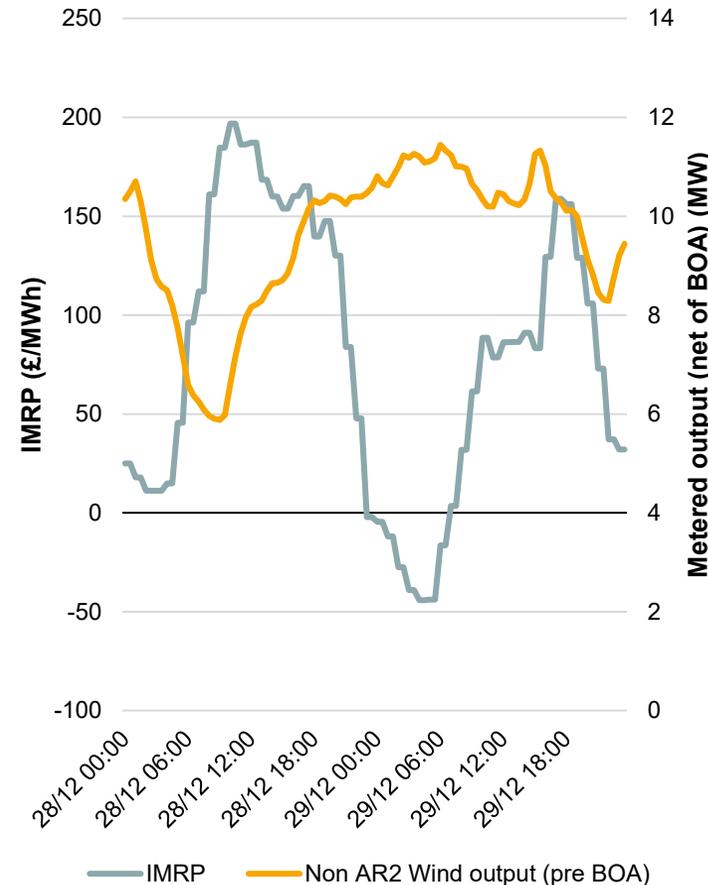
The charts show the total metered output from wind plant net of any BOA instruction from the ESO for both AR2 and non-AR2 plant, alongside the IMRP for the day.

The control room anticipated all AR2 CfD units would drop off the system throughout the period of negative IMRP and had to call every operator to understand what they were planning to do. This meant actions were taken to ensure there was enough response available without their generation.

In reality, after a sudden drop in output for the first hour of negative pricing the output from AR2 units was around 3GW over the remaining negatively priced periods. This is possibly due to wind farms trading their power over the European interconnectors to secure positive prices.

With better transparency between the wind farms and the control room on how they would be dispatching over the period of negative prices some offer costs (taken to secure margin) could have been avoided. Assuming non tagged actions were taken to secure the margin with no generation from the AR2 units, as they actually produced 2.7GW, £1.3M in offer costs could have been avoided.

28-29th December, Wholesale prices



24th January - BM Costs by technology

35% of the daily costs were from the DFS event but margins close to delivery were adequate

Total BM cost for the 24th January was £5.4M, relatively low compared to £8M average daily cost for the month.

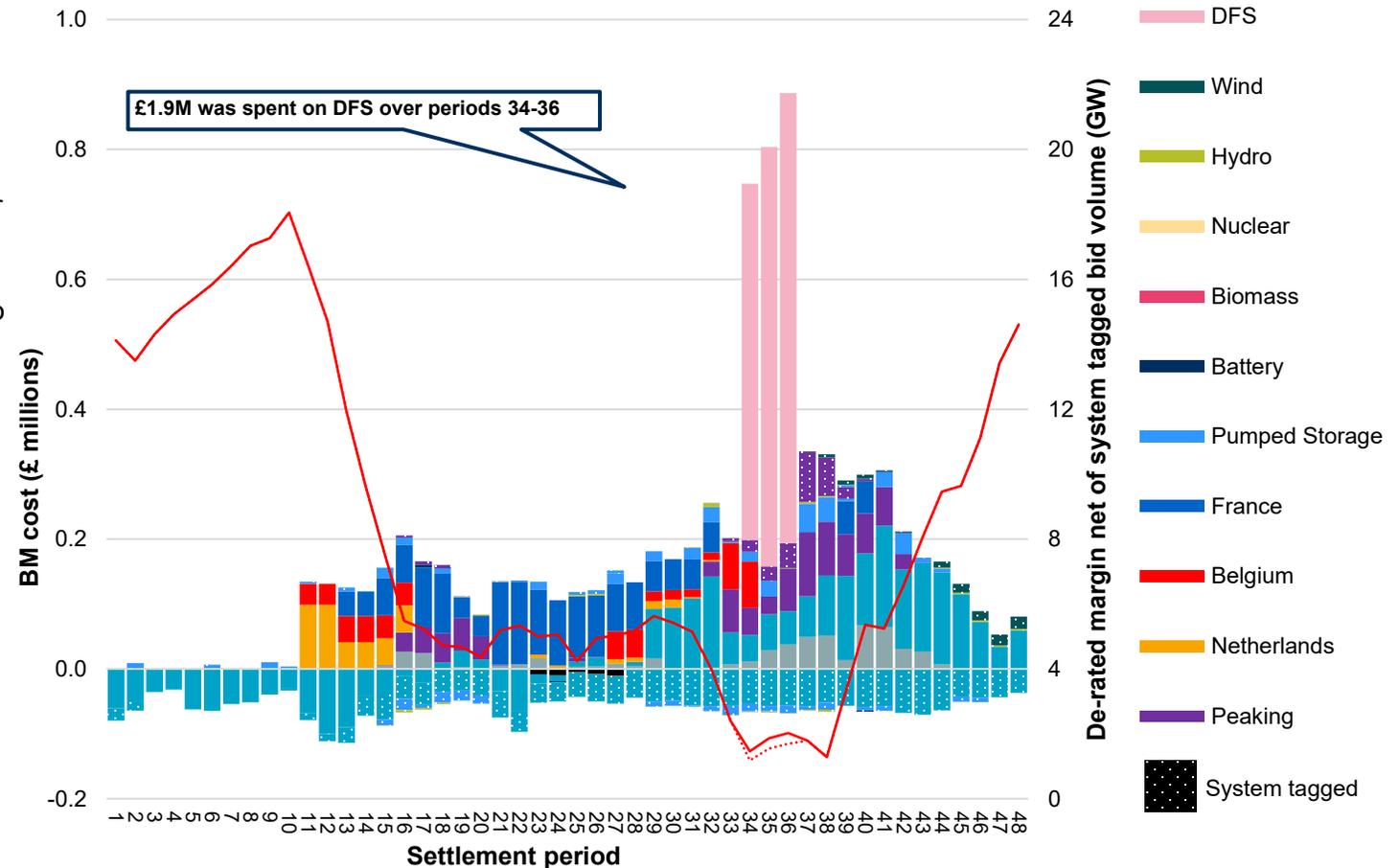
35% of the total costs for the day were incurred between settlement periods 34-36 to pay for the DFS live event.

When considering the forecast margins 1 hour from delivery, it doesn't look like a DFS live event was necessary. The lowest de-rated margin forecast 1 hour from delivery was 1.3GW at 18:30, not even the lowest for the month, as 19th January saw a minimum de-rated margin of 1.15GW 1 hour from delivery.

Netting off the additional margin procured through DFS (to assess the margin had there not been a DFS event), the minimum margin forecast 1 hour from delivery was still relatively secure at 1.2GW.

Whilst the system seemed secure on the day, live DFS events must be triggered at 14:30 the day before, based on the forecast margins at the time.

24th January, BM net costs by technology



24th January – De-rated margin forecast

Without Coal contingency and French interconnection a shortfall of 1GW was forecast at 17:00

DFS live events must be committed at 14:30 the day before the event is going to take place.

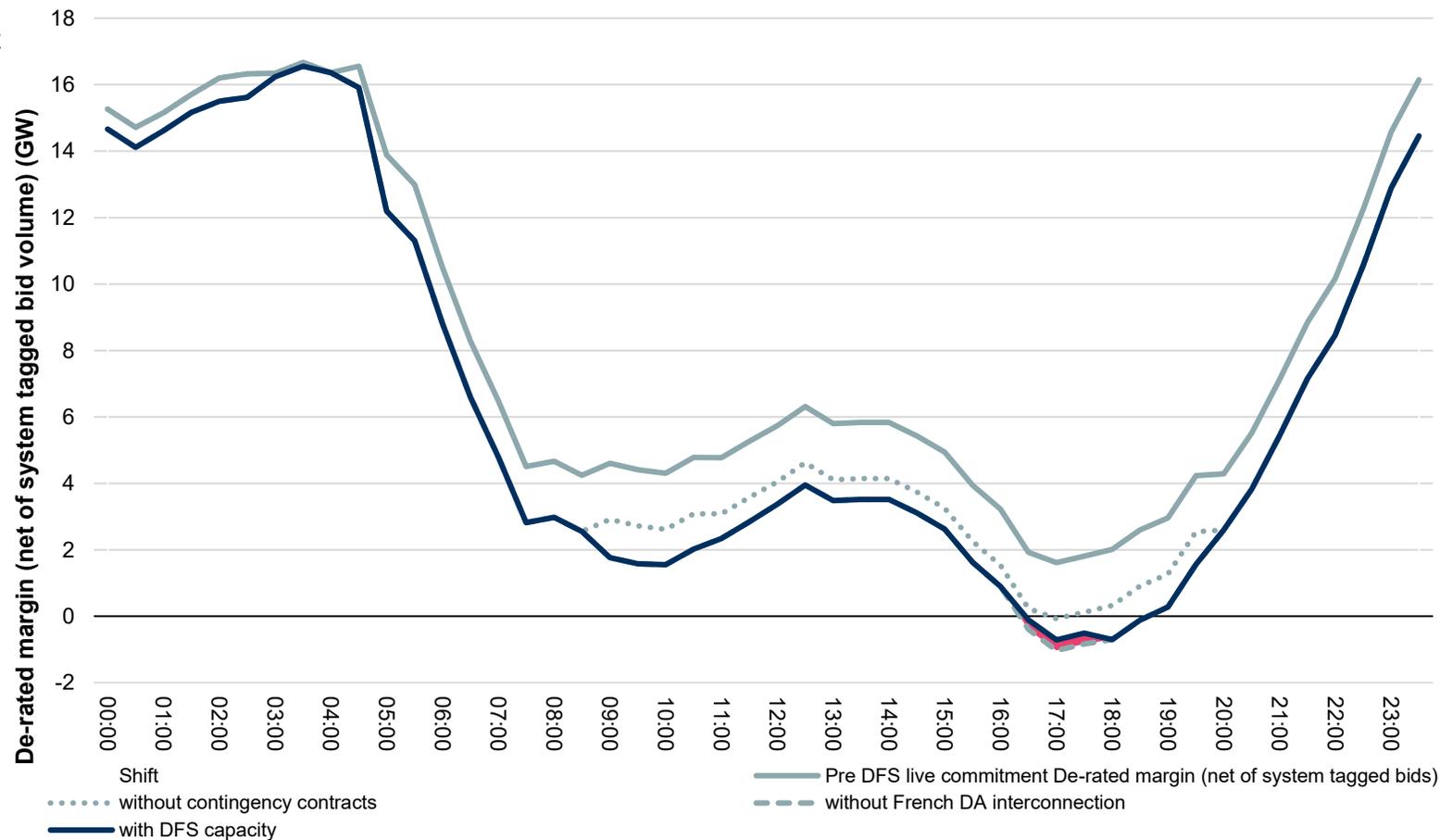
The minimum forecast de-rated margin on 24th January at the time the DFS event was committed was 1.6GW for 17:00. Whilst the margin seemed adequate it includes the 3 coal contingency units which were warmed in advance of the day. Netting off the 1.7GW of coal capacity drops the minimum de-rated margin below 0.

In addition to the need for the coal units there was increased uncertainty over the availability of French interconnection. At the DA stage French interconnectors were scheduled to import into GB, however when margins are tight in France capacity may be withheld increasing the potential for margin issues in GB.

If the forecast French interconnection is also netted off the forecast margin the minimum de-rated margin drops as low as -1GW at 17:00.

Factoring in coal contingency and French interconnection therefore justifies the use of DFS, even though margins were much more secure closer to delivery.

Forecast de-rated margin for 24th January at 14:30 on 23rd January



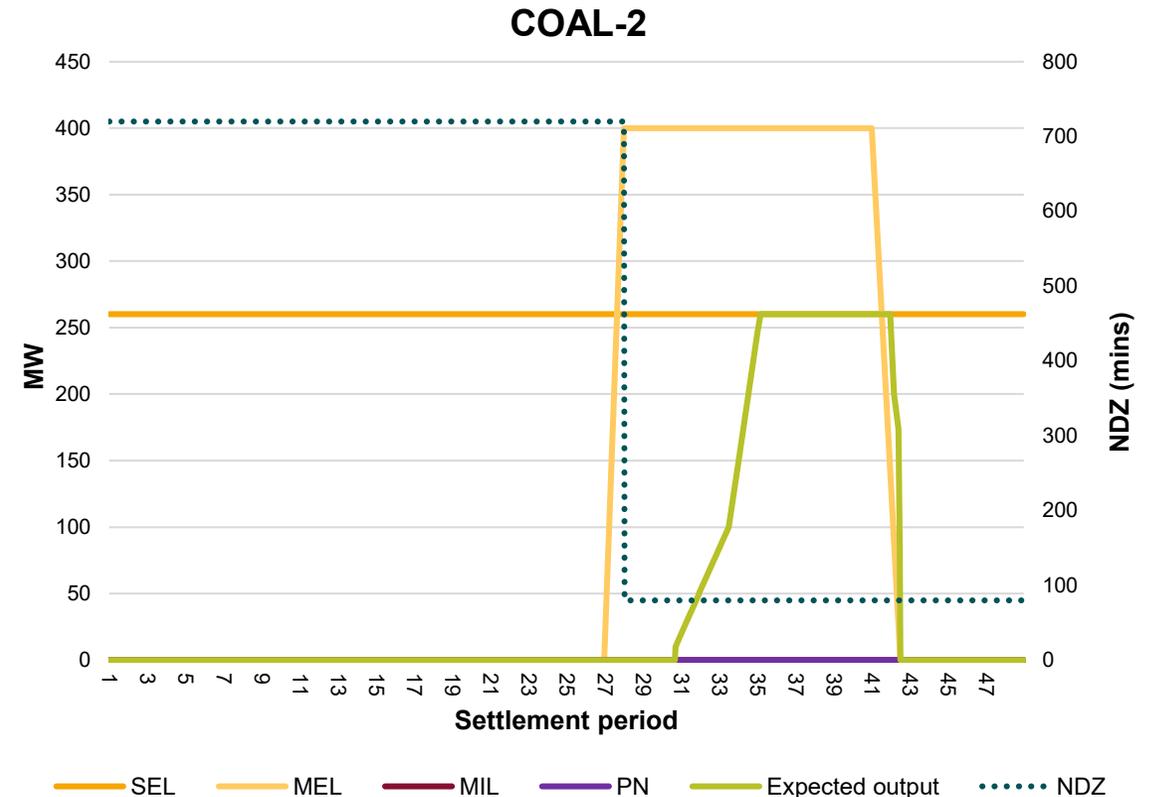
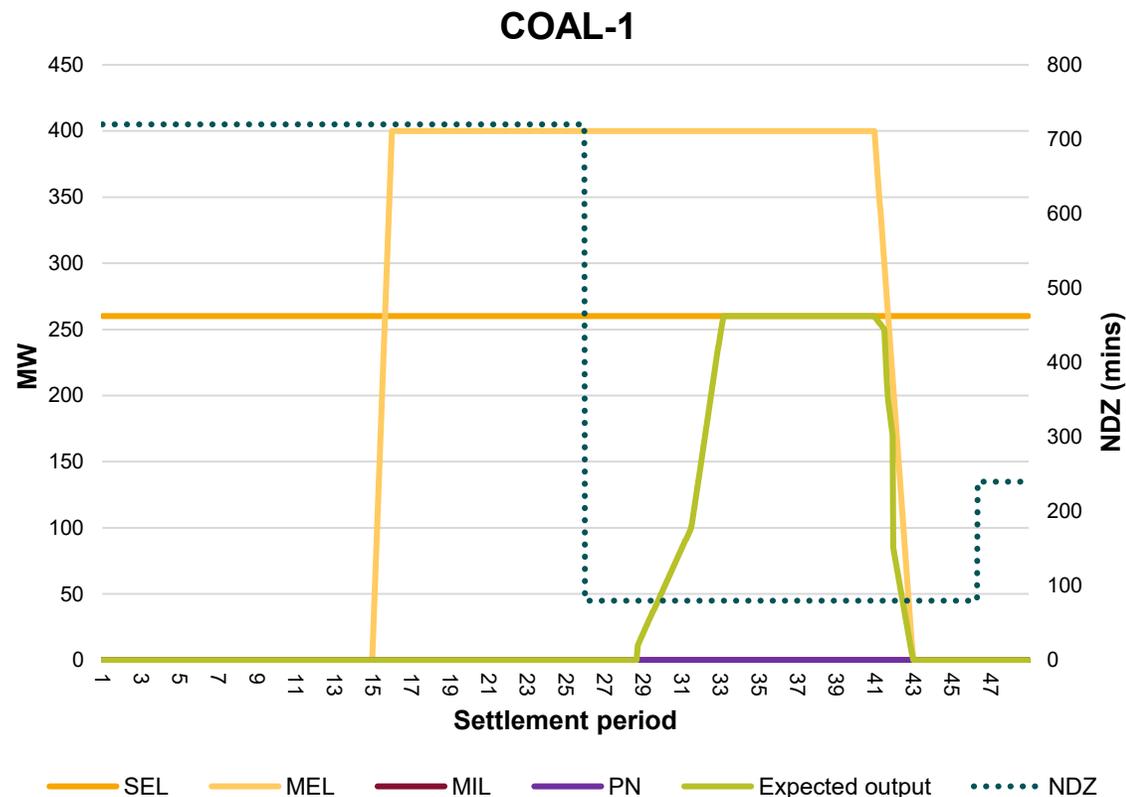
7th March – Coal contingency units were synchronised

At the point the two coal contingency units finished warming they were instructed to synchronised immediately and ran at SEL for over 3 hours

The 7th March had the tightest forecast de-rated margin of any month this month, with a forecast 8 hours ahead of -150MW. This forecast system scarcity meant the two coal contingency units (COAL-1 and COAL-2) began ramping up to SEL at 13:50 and 14:50 respectively.

Warming instructions were sent to the two units at 01:40 on 07/03 for COAL-1 and at 15:35 on 06/03 for COAL-2 to reduce their NDZ from its initial 720 minutes. This ensured that the units were able to be instructed within the necessary BM time horizons, as their NDZ dropped to 80 minutes at 12:30 and 13:31 for COAL-1 and COAL-2 respectively.

COAL-1 remained at SEL for 3 hrs 56 mins and COAL-2 remained at SEL for 3 hrs 25 mins to provide positive reserve over the peak of the day and ensure system security.

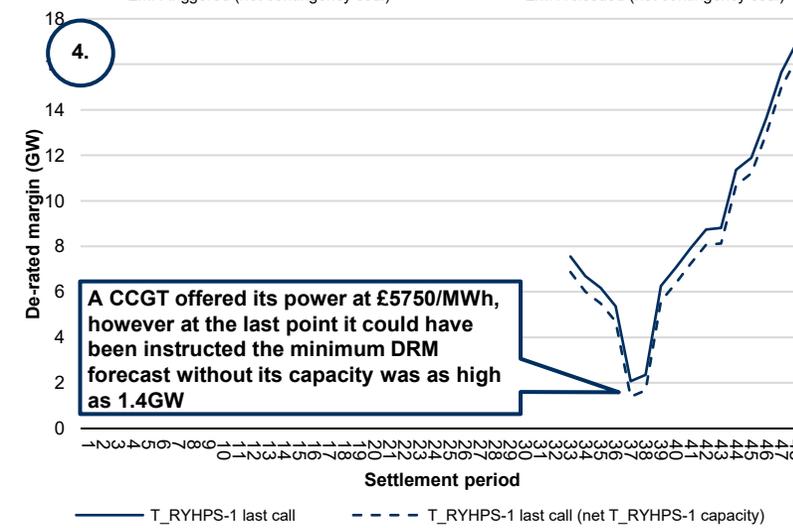
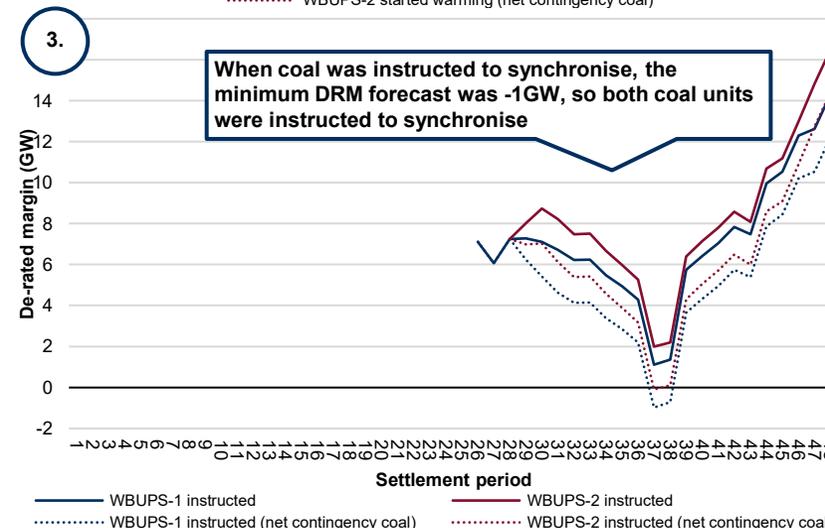
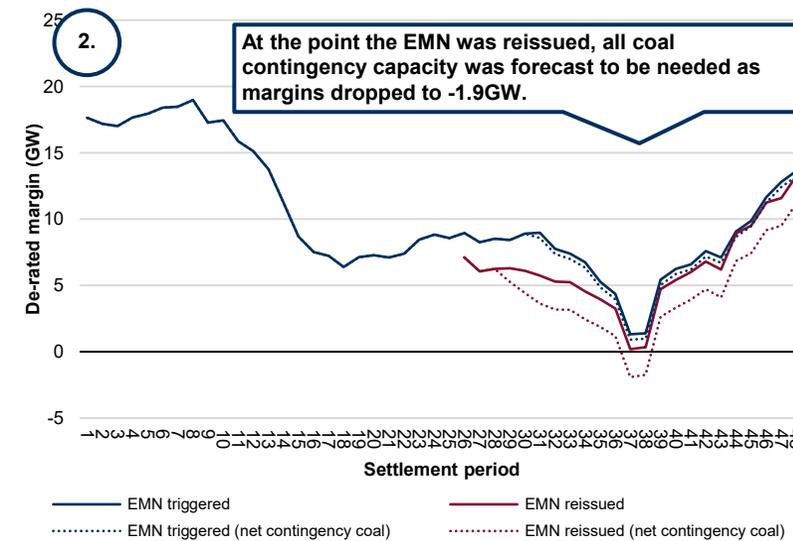
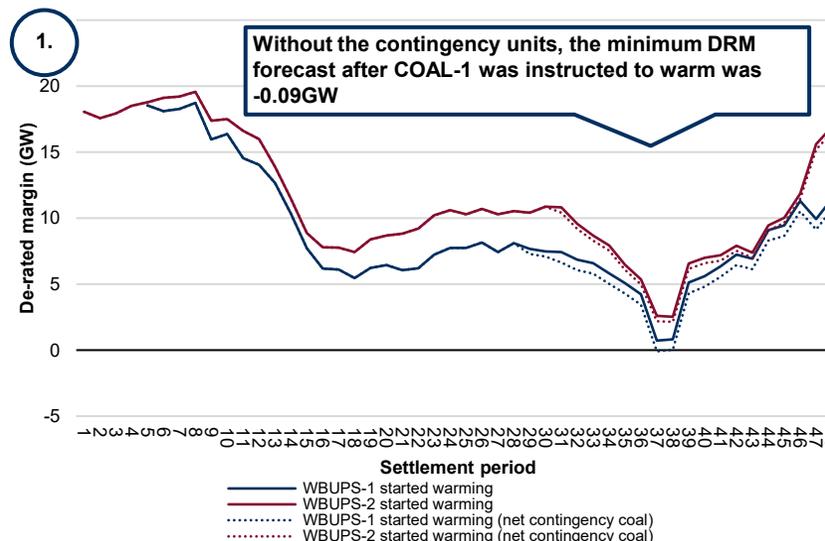


Forecast margins at key decision points

At the point the last CCGT's offer needed to be accepted, margins were secure without its capacity

Forecast margins were very tight on 7th March, even at the day ahead stage.

1. In preparation, COAL-2 was instructed to warm at 14:33 on 06/03 and COAL-1 was instructed to warm at 01:40 on 07/03. Two further contingency units were also instructed to warm. The forecast DRM without the warmed contingency units dropped as low as -0.09GW at the point COAL-1 was warmed.
2. An EMN was triggered at 22:05 on 06/03 for the evening on the 7th, as the forecast DRM without the already warmed coal units was <1GW. The EMN was reissued at 12:25 on 07/03, as without the coal capacity which had already been warmed the DRM forecast at the time dropped as low as -1.9GW.
3. When COAL-1 was instructed to synchronise at 12:30, the forecast DRM without the contingency units was -1GW. COAL-2 was also instructed to synchronise but their contract required a delay of 1 hour between the units.
4. The last available CCGT, wasn't synchronised and was let go, as at the last point it could be instructed, the minimum margin forecast without its additional capacity was 1.4GW.



7th March - BM Costs and Volume by technology

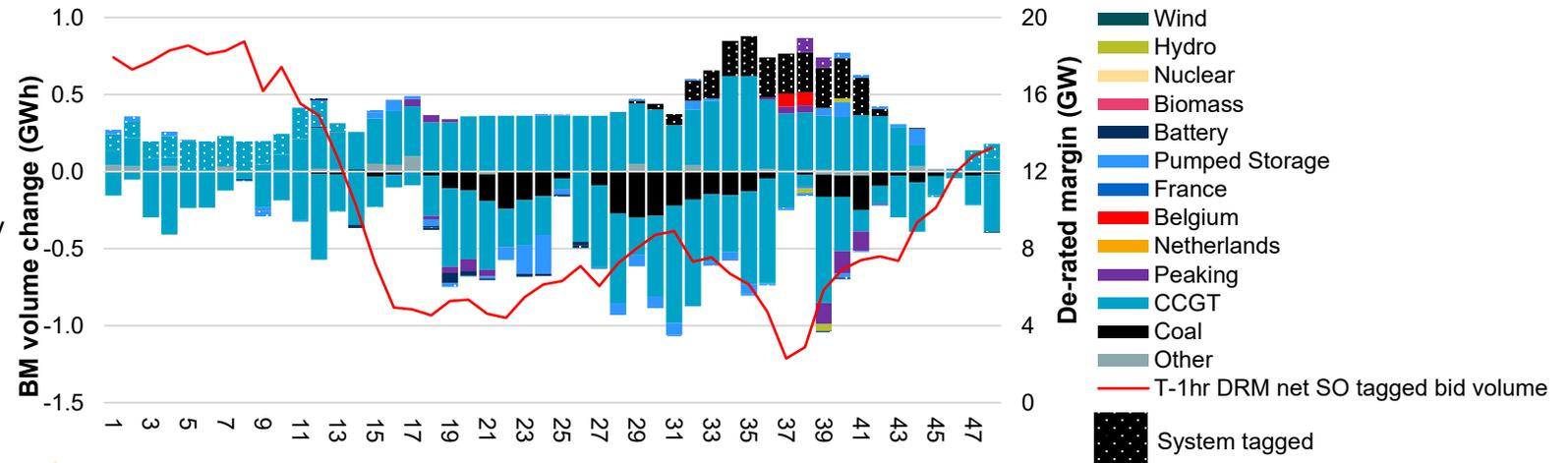
Most units which weren't already planning to run were turned on and increased their prices in the run up to the evening peak when coal contingency was synchronised

CCGT and Coal dominated the volumes traded in the BM on the 7th March. Over the peak of the day 2 coal contingency units were synchronised, represented by the speckled black bars to the right.

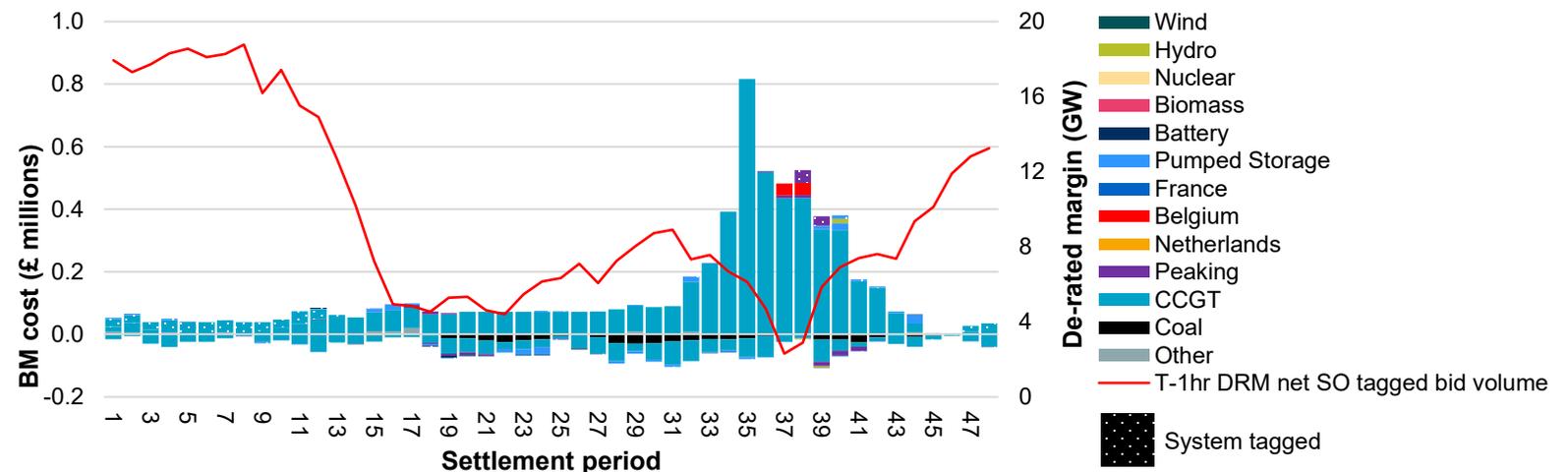
Actual margins were not very tight close to delivery, but uncertainty in interconnector availability, demand and wind predicted the system to be much tighter at greater time horizons. As a result most units which hadn't already planned to run were turned on to SEL in the BM and provide positive reserve. To make room and also provide reserve, other units were turned down.

The costs are concentrated in the run up to and over the evening peak, as expensive units were turned on to provide positive reserve. Units turned on by the control room, increased their offer prices in the run up to the evening peak, as forecast margins became tighter and coal contingency was synchronised. The large spike in costs for period 35 was due to a CCGT being accepted at a price of £1950/MWh.

7th March, BM generation change by technology



7th March, BM net costs by technology



Conclusions / Overview

Conclusion / Overview

Observations on ESO performance

Did the control room take the correct actions?

In general, there is little evidence that the ESO could have done better this winter given the current market arrangements and their current operational constraints.

On the days with the highest BM costs, the control room took the necessary actions available to them with the information they had available at the time to minimise the cost of balancing the system.

What improvements could be made?

One area for potential improvement is forecasting error. The net demand forecast error appears to be biased towards over forecasting for periods in the top 5th percentile.

As these days have a higher chance of extreme prices, due to increased system scarcity, the cost of actions to secure the system margin over the peak, such as delaying the desynchronisation of units, can be extremely high. A 10% reduction in the net demand forecast error over the peak periods of the day could have led to a cost saving of close to £10m.

Changes in market behaviours

Coal offer prices have reduced

Last winter, ~2GW of coal capacity consistently offered its generation into the BM at prices close to £4,000/MWh. This meant the units ahead of coal in the merit order, such as inflexible CCGT units, were able to price their offers close to the £4,000/MWh with the same likelihood of being accepted as they had before. This led to very extreme BM prices and costs on some days.

This winter the coal units were given coal contingency contracts and operated outside of the BM. This removed the upper limit of £4,000/MWh for units to price up to and led to average peak prices dropping. The removal of this upper bound did however lead to some rare occasions when even more extreme prices were seen, as the marginal units were able to set their own ceiling, and on the 12th December prices as high as £6,000/MWh were accepted.

The 'delayed de-sync' strategy had less impact on BM costs

Fewer units attempted the 'delayed de-sync' strategy and prices after dropping their PNs were far less extreme than last winter.

Publications by OFGEM throughout the winter, culminating in the published Inflexible offers licence condition on 13th February, highlighted the behaviour referred to as the 'delay de-sync' strategy. These publications may have influenced the levels at which some units were willing to increase their offer price to after dropping their PN to zero. The knock on effect was reduced costs for units having their desynchronisation delayed until after the evening peak. The removal of the £4,000/MWh coal price ceiling may have also influenced the pricing behaviour of these units.

Conclusion / Overview

Current market inefficiencies

Is the BM doing too much?

Currently the BM is being used to do a lot more than just balance the levels of generation and demand on the system. Actions are being taken to manage the levels of inertia, solve locational voltage constraints and reduce boundary flows when limits are being exceeded. These actions are contributing a significant amount to the overall costs of balancing the system through the BM.

Work has been done by the ESO to procure voltage and inertia outside of the BM through their pathfinder contracts, which has helped to mitigate the costs of operating the system under low residual load conditions, however it is still a key driver in costs this winter, so there is potential for more to be done.

As the wholesale markets provide little locational incentive for generation to be located near demand, or generation to be located where there are voltage constraints, the burden of relocating generation falls entirely on the BM. If markets were structured with locational signals incorporated, such as moving towards a locational marginal pricing (LMP) or similar, less burden will fall on the ESO and BM costs may be reduced, however this could result in unforeseen cost impacts elsewhere in the sector.

Does DFS provide value for money?

DFS was introduced this winter as an enhanced action to be taken ahead of forecast tight margins. There were two live DFS events this winter, however on both occasions there wasn't a need for DFS closer to delivery.

As the commitment to a DFS event must be made by 14:30 on the day before and prices for the service are extremely high, the risk the service isn't actually needed may be too high to justify the cost. If the commitment can be made closer to delivery, when there is more information available, the high costs may be better justified. However, it should be noted that if the primary objective is to reduce consumer costs, then as DFS results in payments to consumers, higher costs may be justified.

Can interconnection uncertainty be better managed?

Uncertainty over interconnector availability on some days this winter meant additional BM actions were taken to ensure adequate margins over the evening peak. On a few occasions this winter, strikes in France meant their margins were tight and exports to GB couldn't be guaranteed. In order to cover the risk of reduced imports from the continent, additional actions were taken, including:

- additional CCGT units were synchronised and others which had planned to desynchronise were kept on to provide additional response,
- live DFS events were triggered and
- coal contingency units were synchronised.

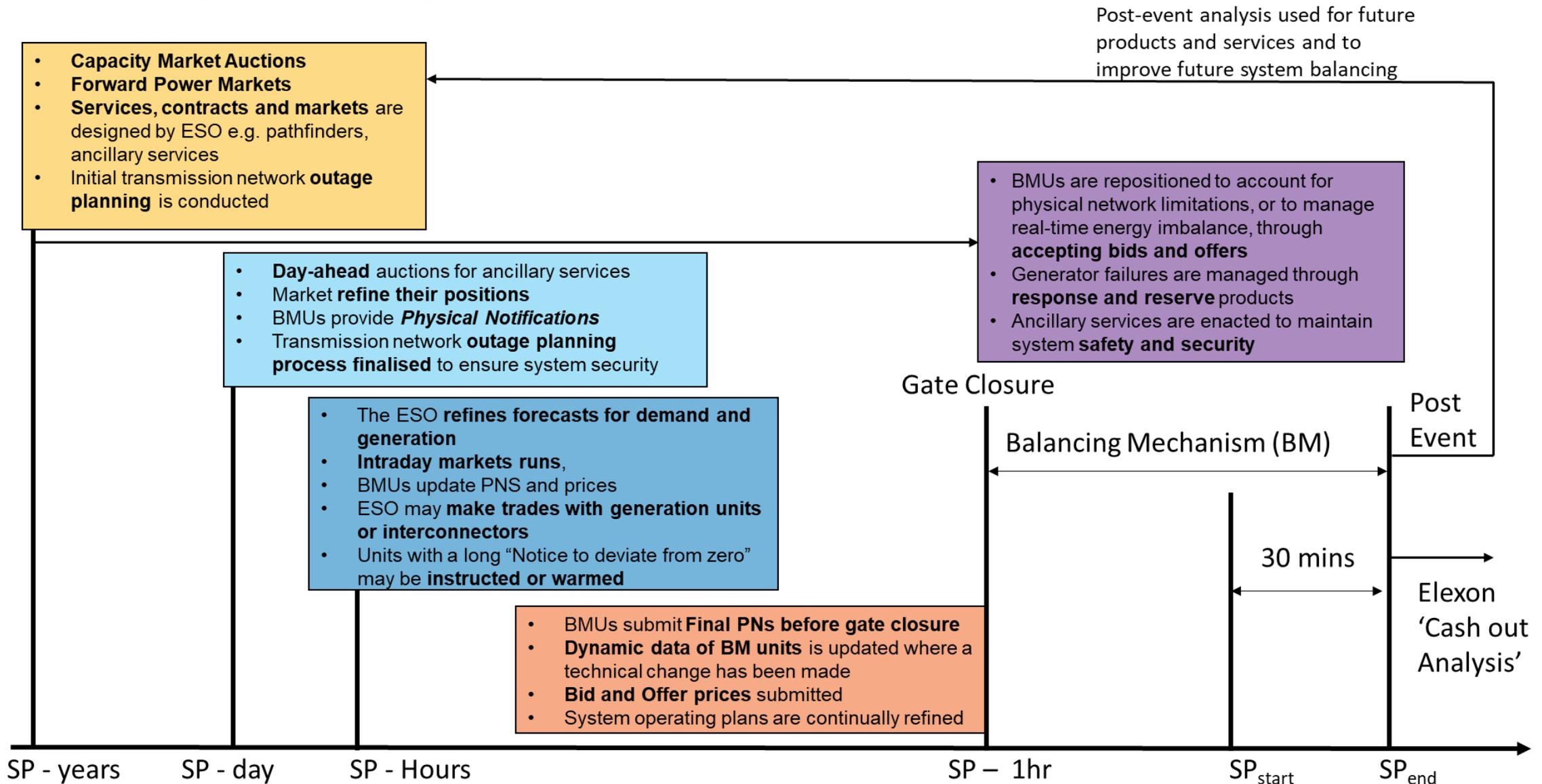
The need to take these enhanced actions outside of the BM suggests a need to better manage interconnection uncertainty and that there currently may be an overreliance on interconnection to meet our capacity requirement.

Appendix

Data Sources and Limitations

Data	Source	Comment
BM Accepted prices and volumes	Enact (received from BMRS)	Data has been taken from the Enact platform, which receives data from BMRS.
Fuel/Tech assumptions	Enact	Enact maintains a mapping of BMU to Tech based on: Dynamic parameters, Fuels, Capacity and LCP Delta's own market expertise.
Outturn wind, demand, wind curtailment	Enact (received from BMRS)	Data has been taken from the Enact platform, which receives data from BMRS.
Residual load	Enact	Calculated from by netting wind and nuclear generation from national demand.
Estimated running costs	Enact	Costs are taken from backing to the Enact leader board. Assumes gas price paid is the within day spot price.
CfD strike prices	CfD Register	Used to calculate lost revenues for curtailed wind
System tag	National Grid ESO data	Tagging to identify reasons for balancing actions came from NG ESO's internal tagging dataset
Forecasting error	National Grid ESO data	Wind and demand forecasts for the darkness peak
Interconnector trades	National Grid ESO data	Interconnector trades in advance of delivery

Timeline of Balancing Markets



Term	Explanation
Balancing Market	Across this report the balancing market refers to the balancing mechanism and Balancing Services Adjustment Data items only. This includes all schedule 7 trades and interconnector trades conducted.
Balancing Mechanism (BM)	The GB real time electricity market which is used by ESO to regulate supply and demand and to meet any wider system requirements that are not met through ancillary services.
Bid Offer Acceptance (BOA)	Bid and Offer prices are submitted by balancing mechanism units to decrease or increase their output respectively, these prices may then be accepted by ESO to initiate the change in output
CCGT	Combined Cycle Gas Turbine generators (CCGTs) are a generation type with both gas and steam generating units
Coal Contingency Contract	A contract agreed with ESO for coal units which were due to decommission to keep them available over winter without participating directly in the electricity market.
Delay de-sync	A commercial strategy employed where a unit places its Minimum Zero Time across the lowest margin period to reduce the margin available to the control room if the unit is not prevented from de-synchronising.
Intraday Price / Intraday Market, Day Ahead Price / Day Ahead Market	In GB the intraday and day ahead markets are facilitated by EPEX and Nordpool. When data is designated APX this refers to data from EPEX, when data is designated as N2X this means it refers to data from Nordpool. If volume weighted then the cleared volume (MWh) in each market is used to average the market prices. If the data is IDA-2, this is an intraday auction which is coupled with the GB bidding area and the Irish Single Electricity Market based upon the interconnection across EWIC and Moyle interconnectors.

Glossary

Term	Explanation
Margin	Margin is used to refer to the difference between supply, demand and the required risk margin to account for real system out-turn conditions. Derated margins represent the amount of spare capacity available considering generator availability factors, and hence is a measure of how “tight” the system is. The de-rated margin can be found on: https://www.bmreports.com/bmrs/?q=transmission/lossloadProbDerateMargin
MEL	Maximum Export Limit (MEL) is the maximum output a unit can deliver and can be declared in real time to reflect any changes in expected availability
MZT	Minimum Zero Time (MZT) the duration for which a unit must remain at 0MW after previously having a non 0MW position due to Bid Offer Acceptance or Physical Notifications
PN	Physical Notification (PN) is the units intended energy output, this cannot be changed after gate closure
Residual Load	Residual load is a measure of the requirement for conventional generation on the system. It is calculated as the national demand net of Wind and Nuclear generation.
RoCoF	Rate of Change of frequency is a measure of the speed at which frequency changes when the supply and demand on the system are out of balance. Actions are taken to the limit the rate at which frequency can change such as increasing inertia levels.
ROCs / CfDs	Renewable Obligations Certificates (ROCs) and Contracts for Difference (CfDs) are subsidy mechanisms which are held by clean energy generation to support their operation in the market.
SEL	Stable Export Limit (SEL) is the minimum non-zero output a unit can technically deliver

Term	Explanation
SRMC	Short Run Marginal Cost (SRMC) is a measure of the expected costs for operating a unit. In reality each unit has its own cost base but these can be used to measure relative average operational costs and can be calculated for different fuel sources and efficiencies.
System Price (Short / Long)	System Price / Cash Out Price / Imbalance price are all means of describing the price which is paid by parties. The average for a day is provided when the market is short (market provided energy is lower than demand for that settlement period) or long (market provided energy is higher than demand for that settlement period)
Thermal Congestion / Thermal Constraints / Import Constraint / Export Constraint	Transmission equipment has temperature ratings for each season dictating the allowable current flow across circuits. Therefore it is not always possible to enable all energy to be transmitted across boundaries, this leads to congestion or constraints on the network that must be resolved by increasing (Import constraint) or decreasing generation (Export constraint) in specific groups.

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