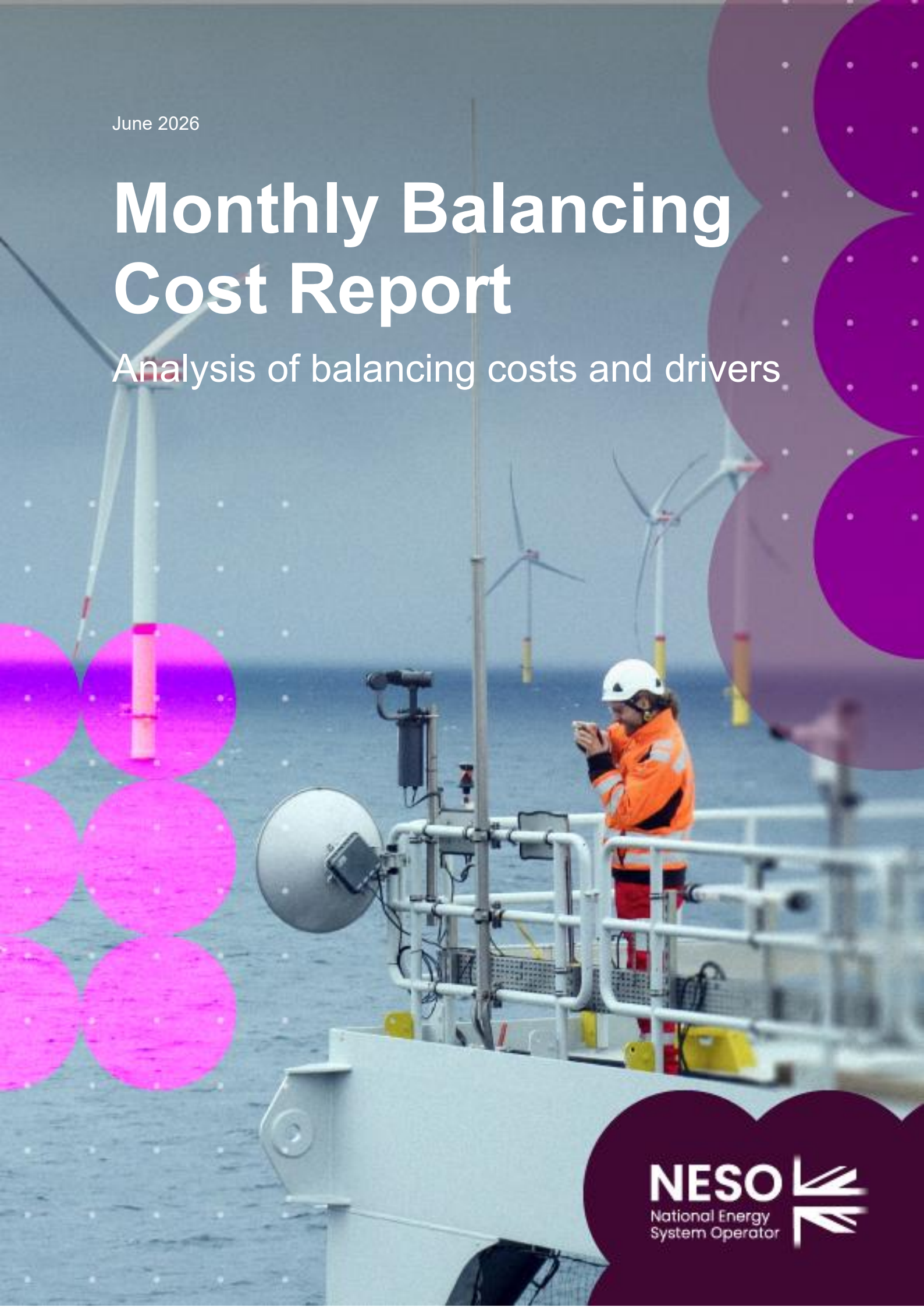
June 2026

Monthly Balancing Cost Report

Analysis of balancing costs and drivers



NESO
National Energy System Operator

Monthly Balancing Costs Report – June 2026

Executive Summary

The total balancing cost for June was £302m, which is £24m (~9%) above the benchmark of £278m.

Wind outturn rose in June to 4.6TWh up from 4.4TWh in May, with the increase in wind outturn in England & Wales offsetting the decrease in outturn observed in Scotland. Similar to May, June was a month of two halves with unsettled and cooler weather in the first half, with some windy periods. However, this was followed by rising temperatures and a record-breaking heatwave in the second half of the month, with a provisional new UK June maximum temperature set of 37.7°c. The heatwave was the major factor in NESO sending out two Electricity Margin Notices (EMN) on the 24th and 26th June. Despite the tough operating conditions; total balancing costs on these days were £10.1m and £6.0m respectively, which are not considered high cost days.

June saw several high-cost days due to a rise in wind outturn and the impacts of high temperatures throughout the month causing a reduction in both generator and network capacity. June's average TSD was both higher than May 2026 and June 2025, largely down to hotter temperatures causing a rise in demand especially in the overnight period.

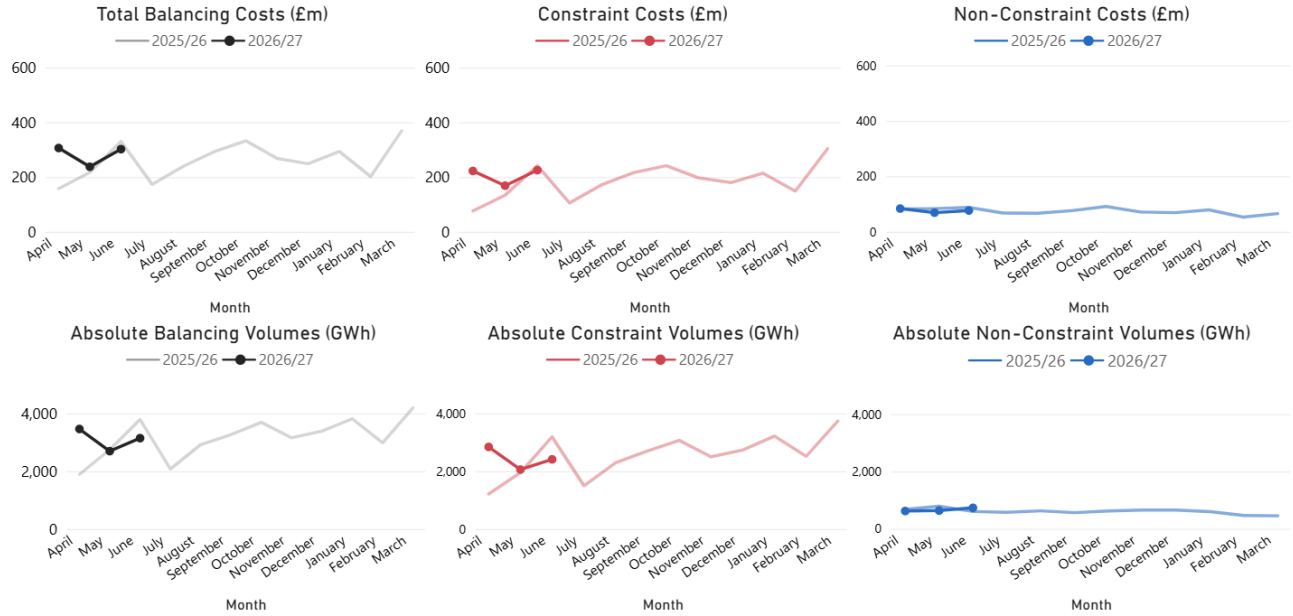
Voltage constraints increased to £34.3m in June, up by £0.3m from May. Due to the higher renewable generation on the system (especially embedded solar), more synchronous units were procured through the Balancing Mechanism, with the highest volumes in the southwest. There was an increased spend on inertia compared with May, for similar reasons to the rise in voltage costs.

Non-constraint costs have increased in June to £76.8m from £69.1m in May. Factors behind this increase include higher spend in Operating Reserve and Restoration offsetting the reduction in Response costs compared to May. The volume of non-constraint actions has increased by 96GWh from May. Month-on-month increases in the average clearing prices for DM/DC/DR has contributed to this increased spend, despite a drop in the absolute volume of response procured.

Wholesale electricity prices decreased slightly in June 2026 primarily down to the reduction in gas prices and increased renewable generation, despite reliance on gas generation during the heatwave. The volume weighted average (VWA) price of bids in June was £8.85/MWh, which is more expensive than May's price of £24.02/MWh. The positive bid price reflects that a greater proportion of the total monthly bid volume was taken on fuel types other than wind, similar to

what we observed in May. CCGT bids took up the second highest volume of bids at 19%. The VWA price of offers increased to £175.07/MWh from £162.32/MWh despite the drop in power and gas prices.

Total Balancing Costs (£m) and Balancing Volume (GWh) monthly vs previous year



Contents

Table: 2026-27 Monthly breakdown of balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Unconstrained Wind Penetration	0.21	0.15	0.18										0.18
Day Ahead APX (£/MWh)	82.5	104.8	100.2										95.8
Benchmark*	299	262	278										839
Outturn balancing costs[1]	**304**	**238**	**302**										**844**

Previous months' outturn balancing costs are updated every month with reconciled values. Benchmark and outturn balancing costs are rounded to the nearest £m.

For more information on our balancing costs benchmark please see our monthly incentives reporting.

What is NESO doing to help reduce Balancing Costs?

NESO is continually identifying opportunities to minimise balancing costs. We are working closely with DESNZ, Ofgem and industry to explore, develop and assess cost saving initiatives and enhance existing services from our Balancing Cost Strategy to support lower costs.

Thermal constraints currently make up the largest share of balancing costs (~60%). The Government's Summer 2025 Review of the Electricity Market Arrangements (REMA) set out the decision to move forward with RNP. Through this programme, we're working with DESNZ and Ofgem to prioritise and progress constraint management initiatives with the greatest potential for cost reduction, while ruling out less effective options. We are also working closely with Network Operators and other industry participants to optimise outage placement and drive improvements to the overall planning process - enabling system access for vital reinforcement work, whilst driving down the cost of thermal constraints.

[1] Outturn balancing costs exclude Winter Contingency costs for comparison to the benchmark as agreed with Ofgem. However, in the rest of this section we continue to include those costs for transparency and analysis purposes.

As part of the Balancing Cost Strategy, we are also progressing initiatives to further reduce non-thermal constraint costs through strategies to manage voltage and inertia. Between April 2025 and March 2026, we delivered £536m in savings across key initiatives. These savings are calculated by comparing the cost of actions taken through these initiatives with known counterfactuals (which in most cases is taking equivalent actions in the BM). This includes £128m from Network Services, £207m from trading actions, and £164m from reduced inertia requirements under FRCR. £37m in further savings have also been delivered through DFS and Balancing Reserve.

For further details on ongoing work to reduce balancing costs please see our latest Annual Balancing Cost Report.

NESO Operational Transparency Forum: High-cost days and balancing cost trends are discussed every week at the Operational Transparency Forum to give ongoing visibility of the operability challenges and the associated NESO control room actions. It also gives industry the opportunity to ask questions to our System Operations panel. Details of how to sign up and recordings of previous meetings are available here.

If you would like to find out more about balancing costs and our initiatives, visit the balancing costs website here; or click on the links below:

- Annual Report
- Portfolio
- Performance Reporting

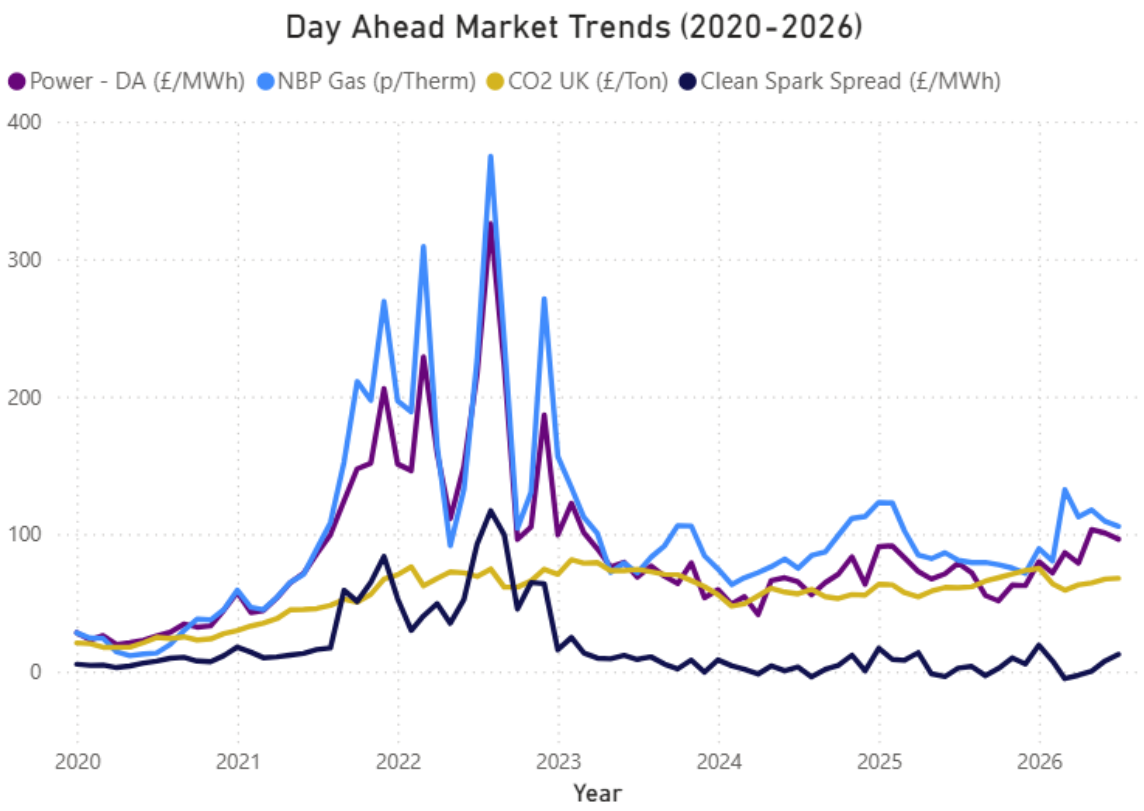
System and Market Conditions

Market trends

In June, power and gas prices fell slightly compared to the previous month, with DA power prices dropping from £103.4/MWh to £100.7/MWh, while gas prices dropped from 117.6p/therm to 109.2p/therm. DA power prices were influenced by a variety of factors, as despite increased solar generation in June, we saw reduced nuclear generation during the month due to outages, and periods of low wind generation as well. This increased reliance on gas generation, especially during the hotter temperatures in the latter half of June. These factors coupled with geopolitical factors and above average demand helped keep power prices high during the month, and significantly above June 2025. Carbon prices saw a small increase to £67.3/ton from £64.5/ton.

The volume weighted average (VWA) price of bids in June was £8.85/MWh, which is more expensive than May's price of £24.02/MWh. The positive bid price reflects that a greater proportion of the total monthly bid volume was taken on fuel types other than wind, similar to what we observed in May. This also corresponds with the percentage of CCGT bid volumes rising

slightly in June compared to May. The volume weighted average (VWA) price of offers increased to £175.07/MWh from £162.32/MWh despite the fall in power and gas prices.



DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

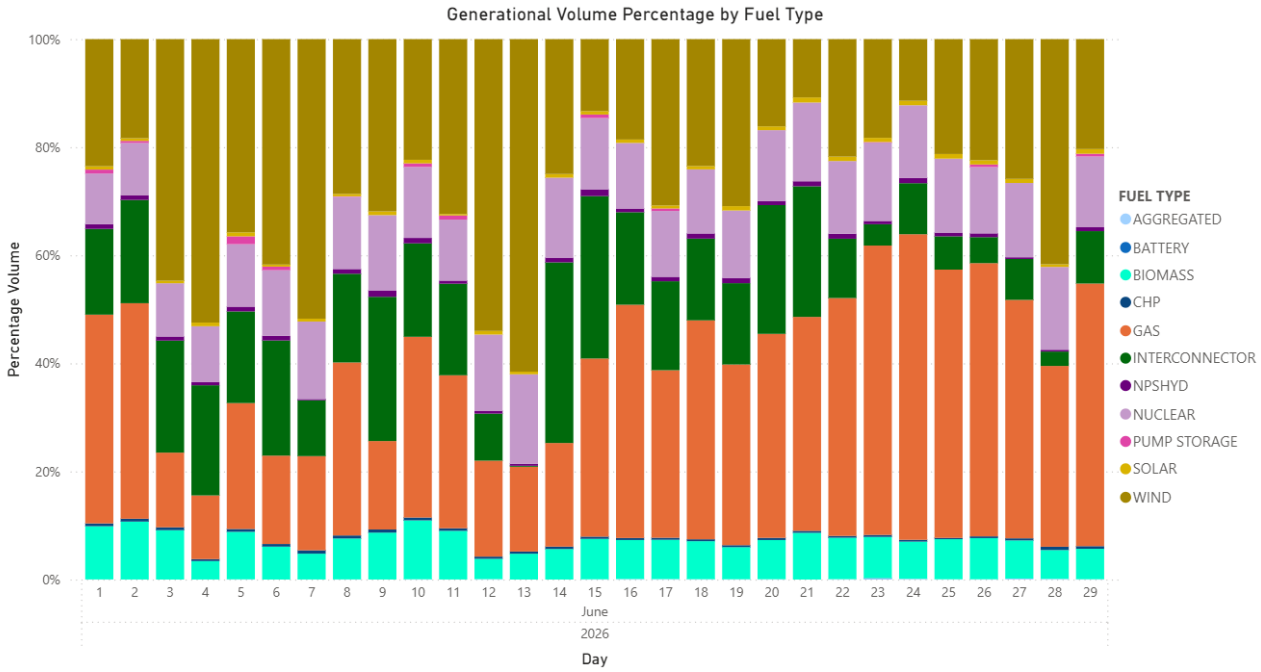
Generation Mix

In June, Gas remained the largest contributor to electricity generation, making up 34% of the total mix, followed by Wind at 28.7% and Interconnectors at 15.2%. June was very similar to May, with Gas, Wind and Interconnectors being the top three largest sources of generation; however the percentage of both gas and wind increased compared to May, with a ~6% increase and ~3% increase respectively in their share of the generation mix, and interconnection seeing a ~5% decrease. The increase in gas generation came from an increase in actions to instruct synchronous generators to turn on and provide voltage and inertia support along with providing capacity during the hotter temperatures seen in the latter half of June.

The chart below shows the daily generation mix. Comparing June to May we have seen an increase in high wind generation days with four days (4,7,12,13) surpassing 50% of the generation mix coming from wind sources compared to one day in May.

There were three days (23,24,26) where gas generation was over 50% of the generation mix; these were all during the heatwave period in late June, with NESO sending out an Electricity Margin Notice (EMN) for the 24th and 26th due to tight margins.

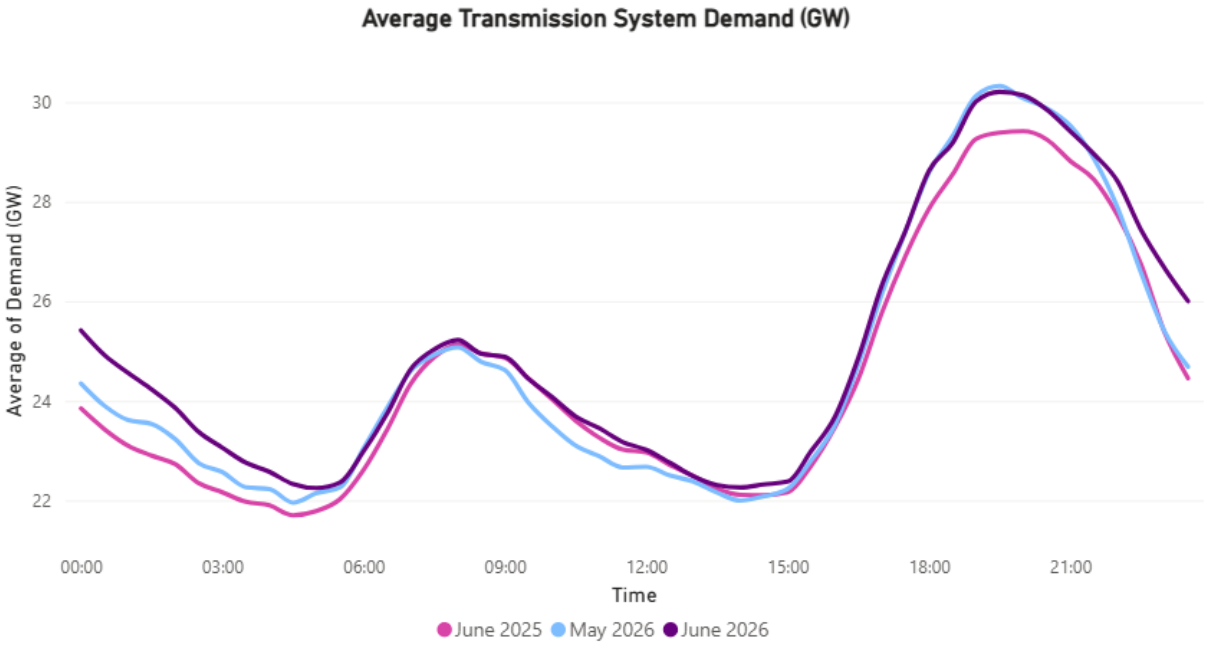
*Generation mix includes exports from interconnectors.



Transmission System Demand

In June 2026, the average Transmission System Demand (TSD) was higher than observed in May throughout most of the day, especially during the overnight periods. During the daylight hours, the higher levels of embedded solar generation (reducing the reliance on the transmission system) did not fully offset the rise in demand from higher temperatures, leading to higher average TSD. There was a much greater difference in demand levels in the overnight periods when solar generation was unavailable.

June 2025 had similar demand levels to June 2026 during daylight hours; however it was lower during the overnight periods, reflecting the impact of the hotter temperatures experienced during the month.

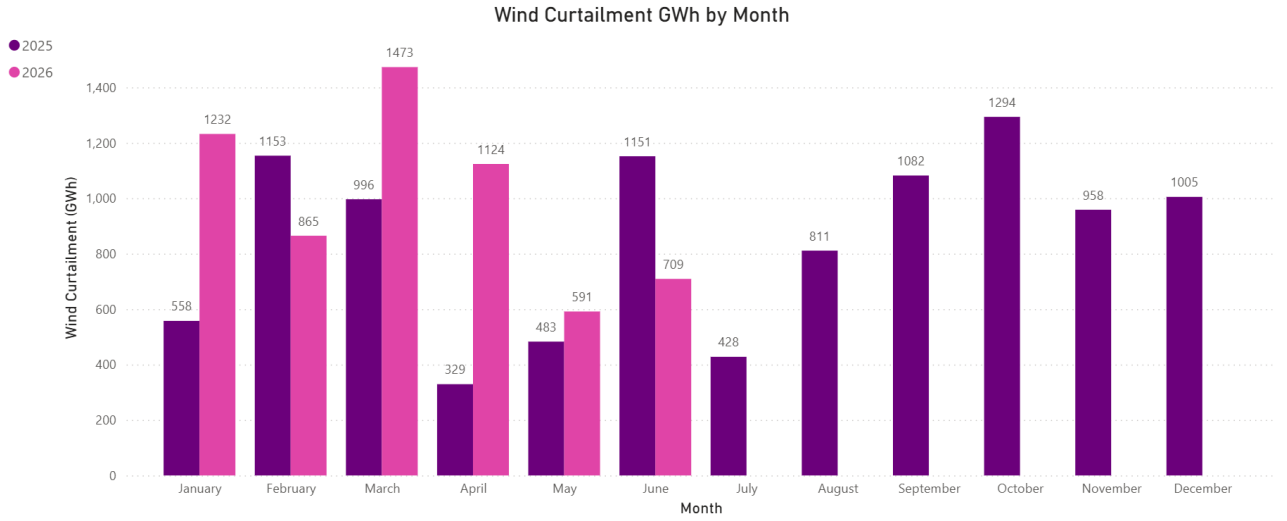


Wind Outturn

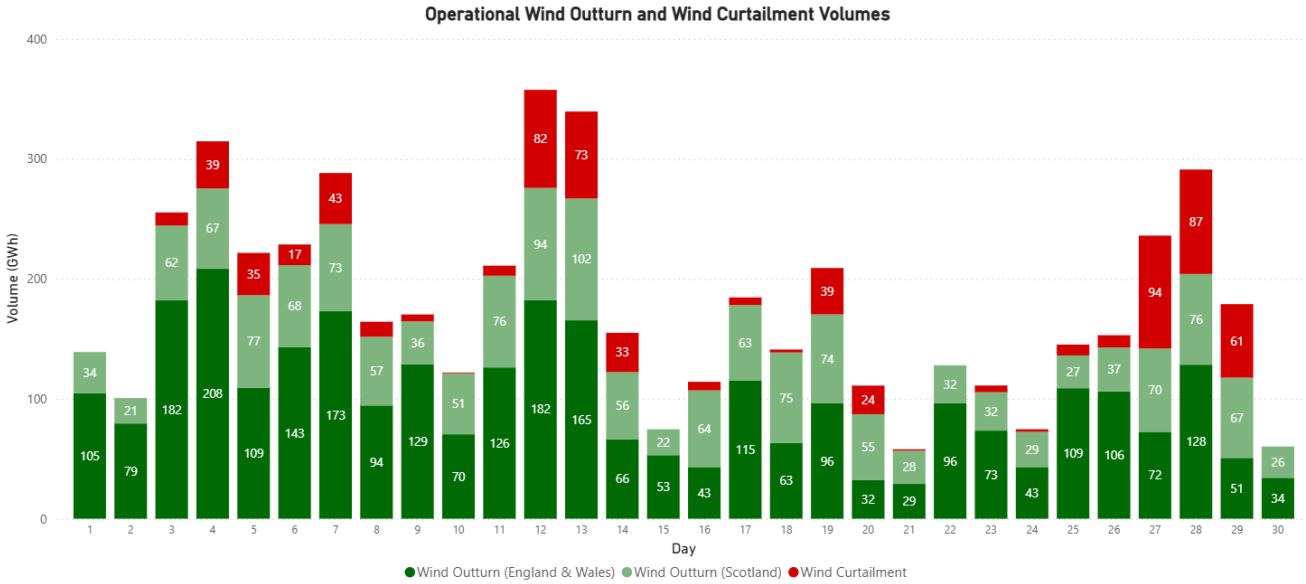
June had unsettled and windier conditions in the first half of the month followed by rising temperatures and an extreme heatwave in the second half of the month. The second half of the month also saw lower wind outturn, with wind outturn being around ~940GWh lower between the first and second half of the month.

There were several days during the month which wind curtailment was low, including three days which had no curtailment (15, 22, 30). Maximum wind outturn seen during the month was 276GWh on 12th June, which is significantly lower than the maximum outturn of 334GWh observed in May. The volume of wind curtailment in June was 709GWh, compared to 591GWh in May.

Overall wind outturn rose to 4.6 TWh in June from 4.4 TWh in May, with a 16% increase in England & Wales (from 2.6 TWh to 3.0TWh) and a 12% decrease in Scotland (from 1.9 TWh to 1.7 TWh) compared to the previous month, giving a 4.5% increase overall. There was a 20% increase in the volume of wind curtailment, largely due to the increase in wind outturn and network outages.



The day with the highest volume of wind curtailment occurred on Saturday 27th June with 94 GWh. There was a total unconstrained wind outturn of 291 GWh on this date, which is significantly above the average daily unconstrained outturn for the month. Wind was curtailed on this day largely for constraint management.

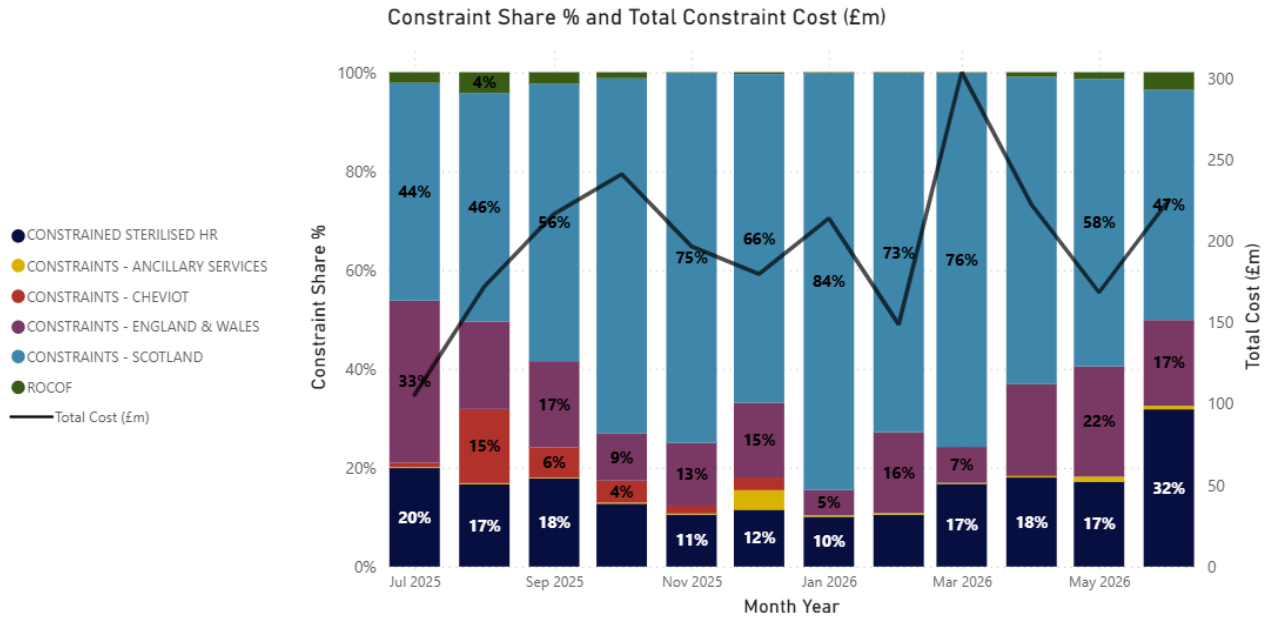


Constraints

Constraint costs increased from £168.5m in May to £225.3m in June, an increase of £56.7m. We observed an increase in all constraint categories this month except for Constraints – Ancillary Services, which saw a small decrease. The largest increase in month-on-month costs was from

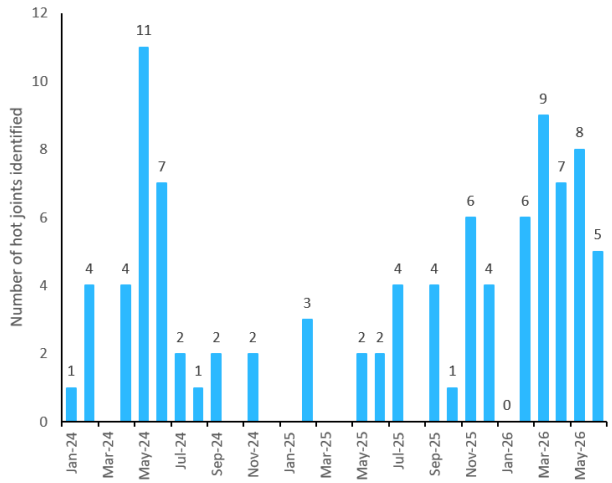
Constrained Sterilised HR at £42.7m, with smaller increase seen in Constraints – Scotland and ROCOF at £6.9m and £5.7m respectively.

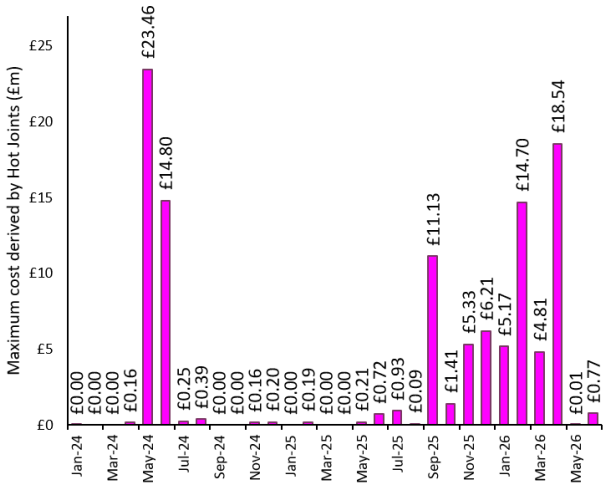
Higher costs in the Constraint Sterilised HR category were observed on days with high wind curtailment during the month, or on some of the tight margin days during the heatwave.



Network Availability

Hot joints refer to transmission equipment that tends to overheat during normal operational conditions. Transmission Owners are responsible for notifying NESO of any service reductions associated with this equipment. Hot joints in the system have both operational and economic impacts. In June 2026, five hot joints were identified: two in the south-east of England, one in the north-east of England, one in the east of England, and a final one in the west midlands. The hot joints had a limited impact, as the affected operational constraints were rarely active during June. The estimated maximum cost was £0.7 million.

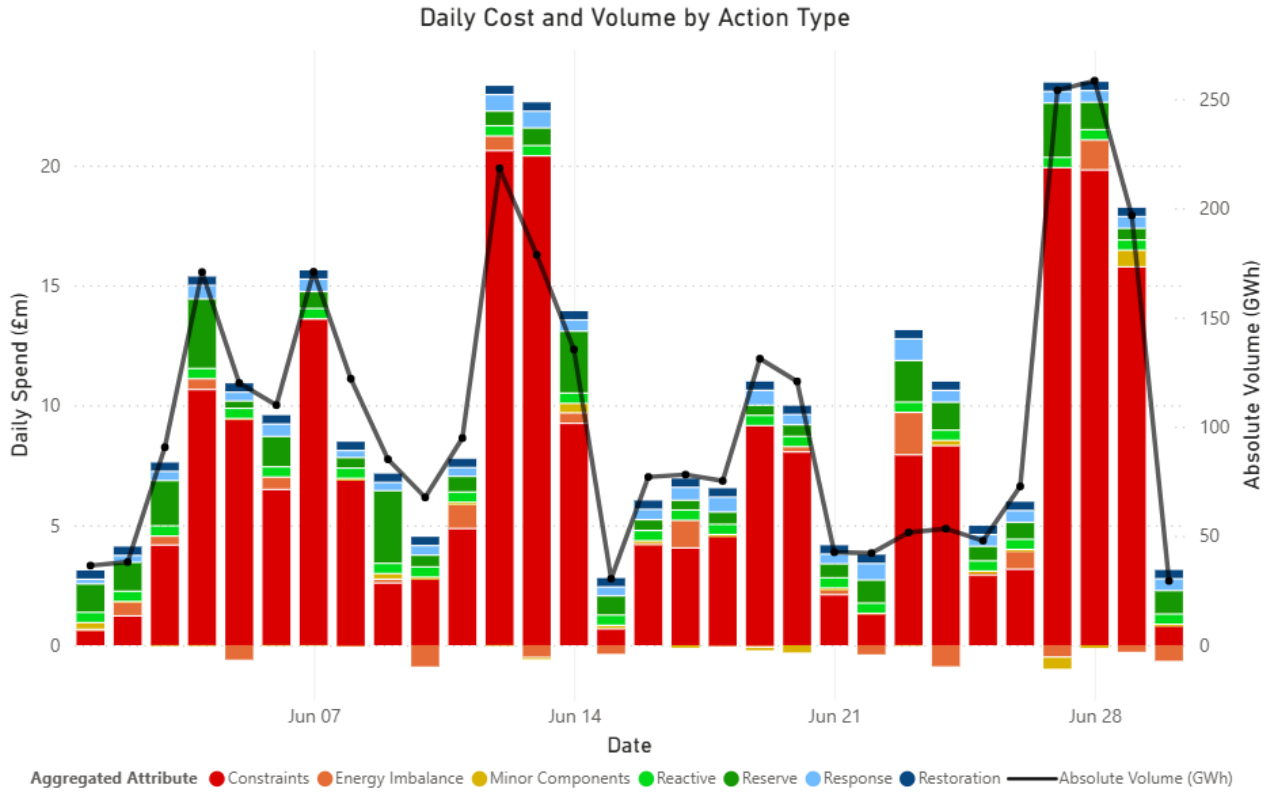




Daily Costs Trends

June's balancing costs were £302m, an increase of £64m from May but a decrease of £28m from last June. Seven days in June had a total cost spending above £15m (4,7,12,13,27,28,29) up from the two days we saw in May. There were a further five days above £10m (5,14,19,23,24), while the daily average cost increased to £10.1m, up from £7.7m in May and an increase of 31%.

The highest cost day was Sunday 28th June at £23.4m, of which around 85% of the total cost was from constraint management, with 93% of this being for managing thermal constraints. The lowest costing day was the 15th June with a total cost of around £2.4m, which was a day of no wind curtailment along with low wind outturn. We saw this trend consistently throughout the month with days of low wind curtailment also being low-costing days.



High-Cost Day

The highest cost day of the month was the **28th June 2026.**

Breakdown of Cost and Volume

- Total cost: £23.4m
- Total Absolute Volume: 258.4 GWh

Balancing Costs detailed breakdown

Comparison Between June 2026, May 2026 and June 2025

Constraint Non-Constraint Group	Latest Month Total	Month Change	Year Change
Constraints	**£225.27**	**£56.73**	**-£16.78**
CONSTRAINED STERILISED HR	£71.68	£42.71	£7.47
CONSTRAINTS - ANCILLARY SERVICES	£1.60	-£0.12	-£3.67
CONSTRAINTS - CHEVIOT	£0.00	£0.00	-£5.39
CONSTRAINTS - ENGLAND & WALES	£39.08	£1.50	-£28.75
CONSTRAINTS - SCOTLAND	£104.89	£6.94	£13.90
ROCOF	£8.02	£5.70	-£0.34
Non-constraints	**£76.81**	**£7.76**	**-£11.18**
ENERGY IMBALANCE	£4.56	-£2.33	-£7.83
FAST RESERVE	£5.14	-£1.88	-£5.68
MINOR COMPONENTS	£1.27	£1.58	£0.50
NEGATIVE RESERVE	£0.55	-£0.26	-£0.57
OPERATING RESERVE	£18.67	£8.89	-£0.80
OTHER RESERVE	£2.59	£0.44	£2.00
REACTIVE	£12.81	-£0.41	£1.86
RESPONSE	£14.51	-£6.19	-£9.38
RESTORATION	£11.97	£7.60	£8.32
STOR	£4.74	£0.31	£0.41
Total	**£302.09**	**£64.49**	**-£27.96**

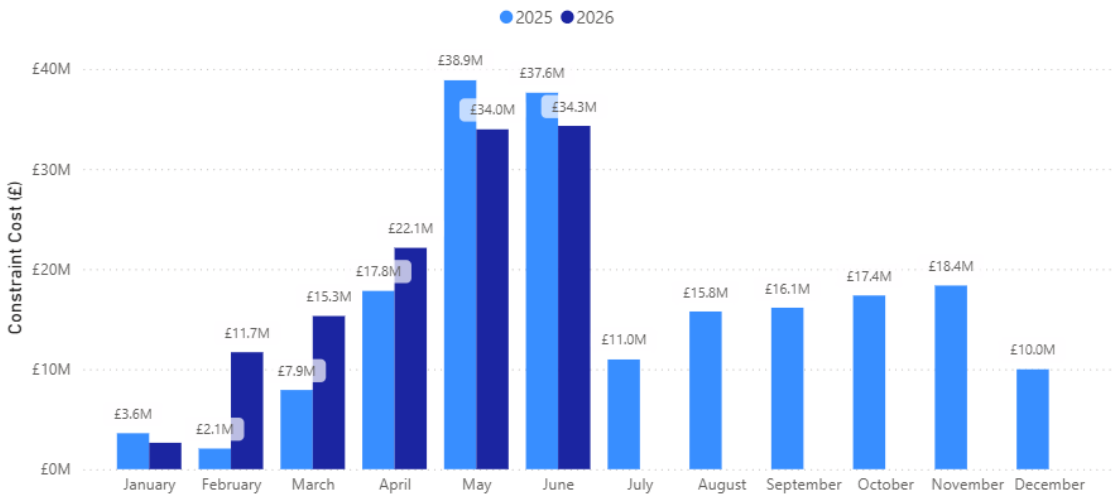
As shown in the table above, constraint costs and non constraint costs increased by £56.7m and £7.8m respectively which results in an overall increase in costs of £64.5m compared to May 2026.

Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
Constraint-Scotland & Cheviot: +£6.9m **Constraint – England & Wales: +£1.5m** **Constraint Sterilised Headroom: +£42.7m** Overall constraint costs increased by £56.7m, corresponding with an increase of 353 GWh in the absolute volume of actions taken. This is partly down to a rise in wind curtailment volumes in June of 118GWh, with ongoing outages in Scotland over the month.	**Constraints – Scotland & Cheviot: +£8.5m** **Constraints – England & Wales: -£28.8m** **Constraints Sterilised Headroom: +£7.5m** Constraint costs across GB have decreased by £11.2m compared to June 2025. Factors influencing this include higher demand on the system, and a 442GWh decrease in the volume of wind curtailed compared to last June.

Voltage – Monthly system cost of synchronisation actions for voltage control across 2025 and 2026:

In June, the system synchronisation costs for voltage (what it costs to the system, which factors in energy replacement and headroom among others) were £34.3m, representing an increase of approximately £0.3m compared to May 2026 and is £3.3m lower than we observed in June 2025.



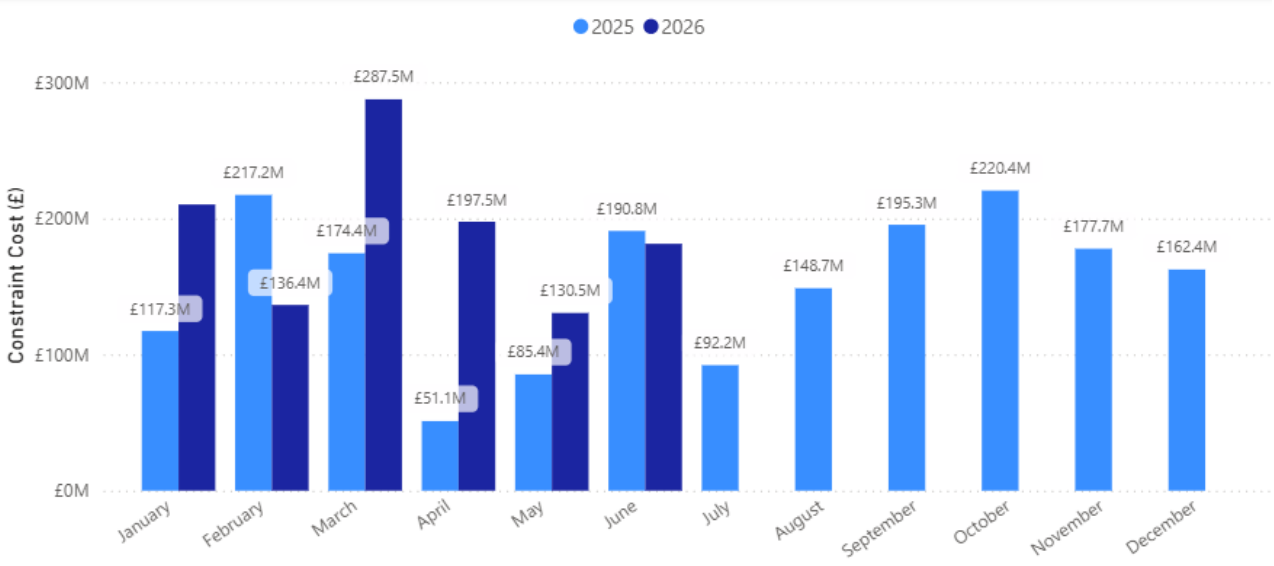
Voltage spending is usually higher overnight: lower demand means that some synchronous units (mostly CCGTs) that usually provide reactive support are not self-dispatched, which forces NESO

to procure those services through the Balancing Mechanism. Most voltage costs arise from the South-West region of Great Britain, where the system relies on Combined Cycle Gas Turbines (CCGTs) for voltage management; however the system's operational condition and outages in other areas also influence the system spending.

Due to higher demand and hotter temperatures this month compared to last June, synchronous units were more likely to have self dispatched on the system, reducing the need to bring them on for voltage support. However during periods of high renewable generation during the month, NESO still needed to procure these services through the Balancing Mechanism, and coupled with higher power prices than we saw last June, voltage spend is comparable between the months. Also, some units that would have provided reactive support out of service which drove up the absorption requirement and therefore contributed to the high spend on voltage.

Thermal – Monthly system cost of actions for thermal management across 2025 and 2026:

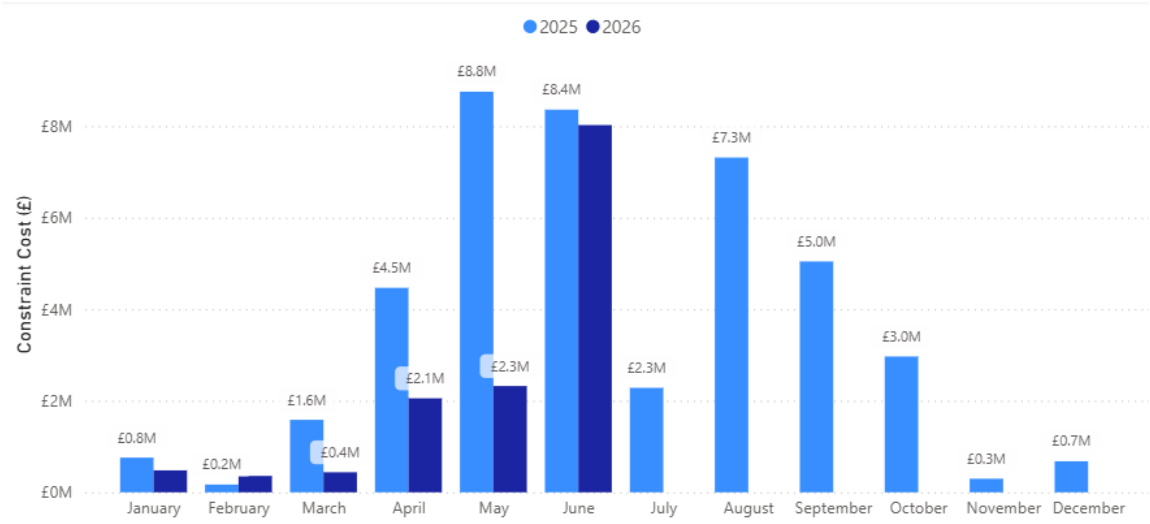
In June, the system thermal constraint cost (which includes factors such as energy replacement and headroom) amounted to £181.3m, reflecting an increase in costs of £50.8m compared to the previous month (£130.5m), though it was a decrease of £9.5m from June 2025 (£190.8m).



June 2026 saw a rise in wind curtailment compared with May as we saw higher wind outturn and reduced network capacity, which is reflected in higher thermal constraint costs. However, despite significantly lower volumes of wind curtailment compared with last June, higher power prices meant that thermal constraint costs are similar between June 2025 and June 2026.

Inertia / ROCOF – Monthly system cost of actions for inertia management across 2025 and 2026:

In June, the system inertia constraint cost (which includes factors such as energy replacement and headroom) amounted to £8.0m, resulting in an increase of £5.7m compared to May 2026. However, this was £0.4m lower than June 2025.



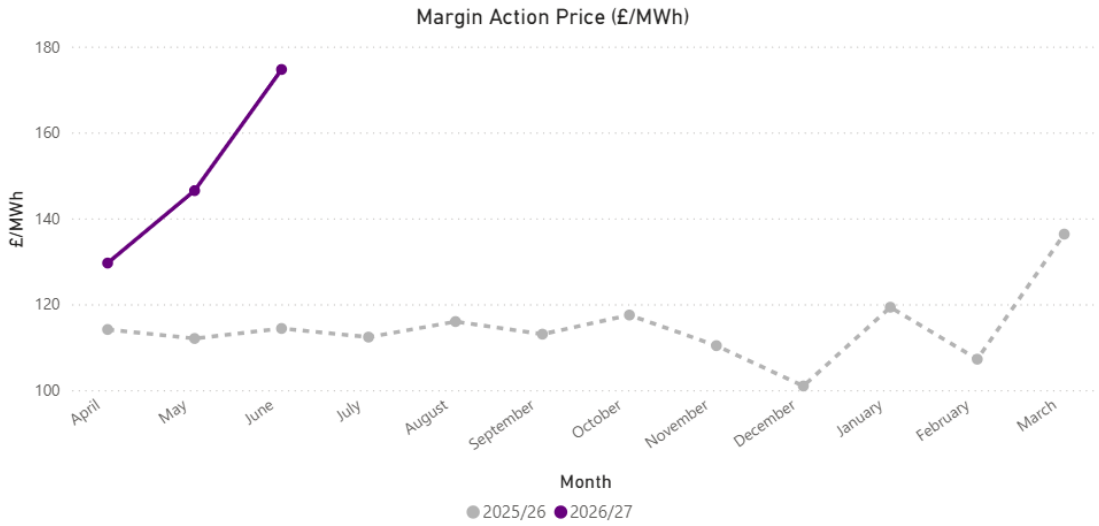
The inertia expenditure rose in June compared to May due to the same reasons for increased spending on voltage constraints. This is expected as we move further into the summer period where we would expect to see lower demand and higher renewable generation (particularly solar). This means that there would be fewer self-dispatching units available to provide inertia on the system. As a result, additional units would be required to manage system inertia leading to higher costs this month.

Reactive Costs/Volumes

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
-£0.4m Reactive costs have decreased on last month reflecting changes in system conditions since May.	**+£1.9m** Reactive costs have increased on last year due to changes in system conditions between June 2025 and June 2026.

Reserve Costs/Volumes

Reserve prices increased from £146.5/MWh in May to £174.7/MWh in June, continuing the upwards trend observed since March.



Comparison Versus Previous Month	Comparison Versus Same Month Last Year
Operating Reserve: +£8.9m **Fast Reserve: -£1.9m** There was a 92 GWh increase in volume of operating reserve and a 1GWh decrease in the volume of fast reserve to secure the system compared to May.	**Operating Reserve: -£0.8m** **Fast Reserve: -£5.7m** There was a 232 GWh decrease and a 7GWh increase in the volume of operating reserve and fast reserve respectively required to secure the system compared to June 2025.

Response Costs/Volumes

Our Dynamic Services for response, Dynamic Containment (DC), Dynamic Moderation (DM) and Dynamic Regulation (DR) continue to benefit from more competitive and more liquid markets and the continued development of the Single Market Platform.

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
-£6.2m	**-£9.4m**

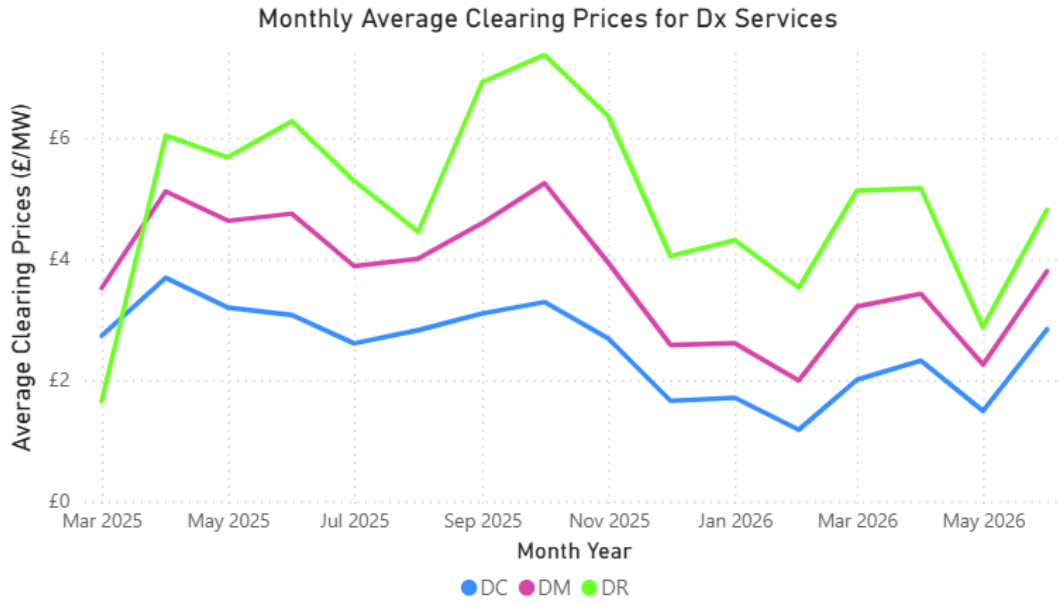
There was an 8 GWh decrease in the absolute volume of actions compared to May. Average clearing prices for DC, DM, DR services rose compared to May.	The volume of actions taken for response decreased by 56 GWh compared to June 2025. Average clearing prices for DM, DC & DR were all lower in June 2026 than June 2025.

Comparison Between June 2026, May 2026 and June 2025

Service	Monthly Variance	Yearly Variance
DC	£1.3	-£0.2
DM	£1.5	-£0.9
DR	£1.9	-£1.5

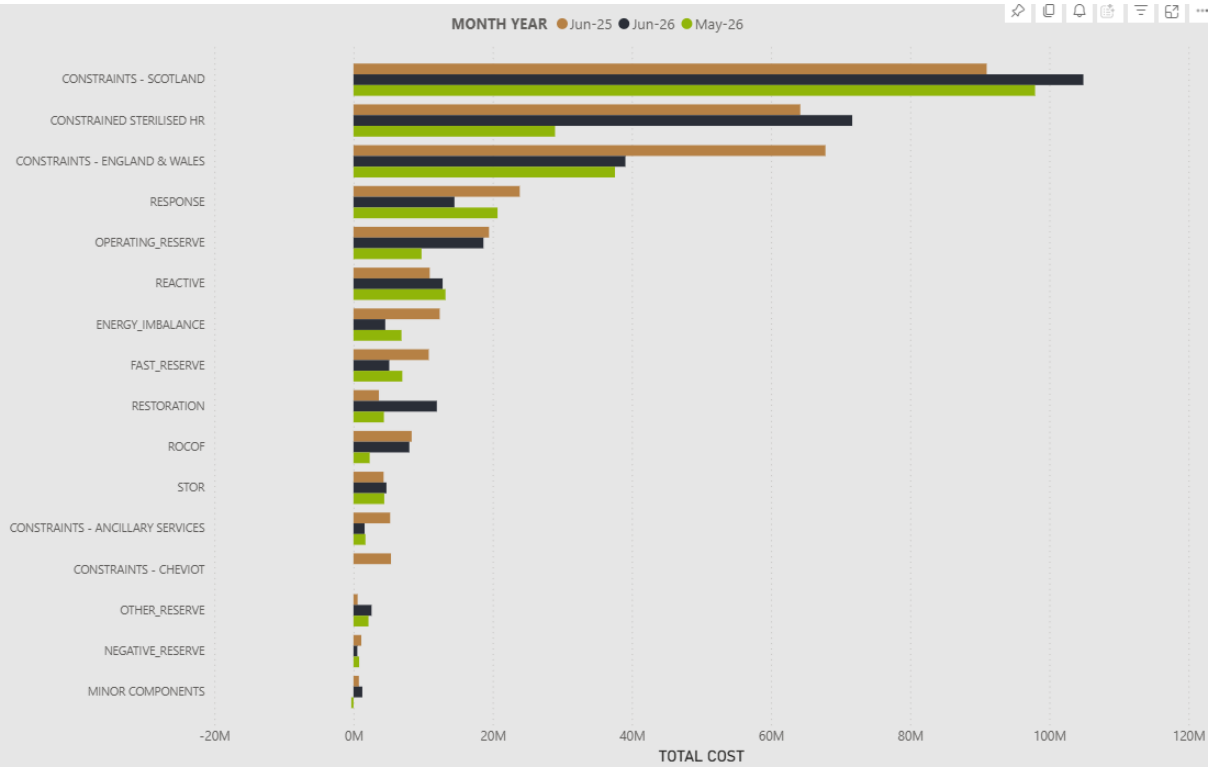
Average clearing prices for Dynamic Containment (DC), Dynamic Moderation (DM), and Dynamic Regulation (DR) increased in June. Factors influencing this include tighter system conditions and increased procurement of DC (both DC High and DC Low) to help manage demand swings on the system.

Compared to June last year, all three dynamic services have seen a decrease in average clearing prices.



Comparison breakdown

The graph below provides a breakdown of cost components compared to the previous month and previous year.



Cost Savings

Outage Optimisation

The total savings from outage optimisation were approximately £172m in June 2026. This is an increase of roughly £73.5m relative to May 2026 (£98.6m). The most valuable action was postponing an outage in the East Midlands and Yorkshire/Humber regions of England, which would have otherwise costed £18m.

Trading

The Trading team were able to make a total saving of £15.3m in June through trading actions as opposed to alternative BM actions, representing a 29.5% increase on the previous month and the highest monthly trading savings seen in 2026. The most significant trend in trading savings between May and June came from actions for downwards regulation, which experienced a 56% increase (£5.1m in May to £11.7m in June). This was driven by periods of low wind conditions and relatively low demand, requiring the Trading team to procure additional downwards flexibility.

The day with the greatest trading savings was on 14 June at £3.2m, with the greatest savings being made for downwards regulation. The day with the greatest spend on trades was 24 June at a cost of £9.1m, with the greatest component being for margin and representing the second greatest single day spend on trades in 2026. The large spend can be attributed to a combination of very high temperatures, low wind conditions and reduced availability from some generation assets leading to tighter than usual system margins, with an Electricity Margin Notice also being issued for that day. These challenging conditions, compounded by the new interconnector restrictions, resulted in NESO accepting trades at high prices on the interconnectors for margin reasons, contributing to the high cost observed on 24 June.

On the 20th May new restrictions on interconnector trading were implemented, limiting the volume of trading that can take place at the intraday stage which we expect to have an impact on actions taken in the BM. NESO does not have concerns that these trading restrictions will impact electricity system security, and we are monitoring the financial impacts of these restrictions. For further information please see our market notice on our webpage here.

Network Services

We are using Network Services to implement solutions to operability challenges in the electricity system. This includes the Constraint Management Intertrip Service, and Voltage & Stability pathfinders. We have calculated that the B6 and EC5 Constraint Management Intertrip Services, Voltage Mersey, Voltage Pennines, and Stability Phase 1 have delivered approximately £17.9m in savings across 2026/27 to date (April 2026 – May 2026).

Further information

For further information please see our balancing costs website.

Appendix

Types of constraint costs

Voltage Synchronisation Costs

Synchronisation costs are associated with specific actions required to support voltage in the system. These actions involve units that are instructed to provide MVArs and maintain voltages within SQSS limits. It is a highly location-dependent issue, so only a limited set of assets are effective in voltage support.

Inertia Costs

Inertia refers to the resistance of the system to changes in its rotational speed. Inertia is primarily provided by the rotating mass of large synchronous generators, mainly CCGTs, but also includes hydro, pumped storage, biomass, and Combined Heat and Power (CHPs), among others. The costs associated with inertia tend to be marginal in the system compared to thermal or voltage constraints.

Thermal Constraint Costs

Thermal constraints are linked to operational limitations on transmission assets due to temperature-related factors. In Great Britain, these are generally linked to highly congested areas in the Scottish region, often referred to as the B4, B5, and B6 boundaries. The expenditure on thermal constraints is highly correlated with levels of curtailment in Scotland, as well as planned or forced outages in transmission assets that limit the grid's transfer capacity. Thermal constraints constitute most of the system constraints, accounting for a significant percentage of system actions.

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