July 2026

Monthly Balancing Cost Report

Analysis of balancing costs and drivers

NESO
National Energy System Operator

Monthly Balancing Costs Report – July 2026

Executive Summary

The total balancing cost for July was £302m, which is £45m (~17.5%) above the benchmark of £257m. While the benchmark captures the impact of changes in wind generation and wholesale power prices, the higher outturn costs were also driven by factors not reflected within the benchmark calculation. These included costs resulting in part from restricted network boundaries and summer outage arrangements, alongside significantly elevated voltage and inertia costs due to the effects of high renewable penetration.

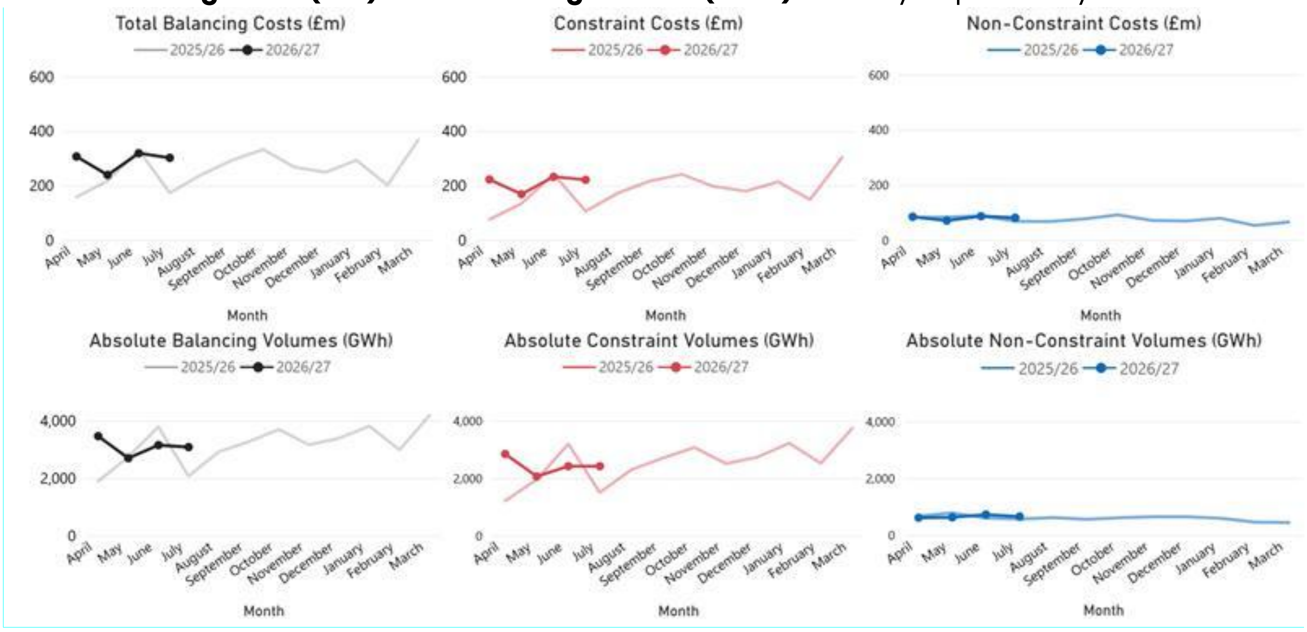
July was significantly warmer than average, with widespread heatwave conditions and record-breaking sunshine. While wind output fell from 4.6TWh in June to 4.0TWh in July across both England & Wales and Scotland, exceptionally high levels of embedded solar generation reduced transmission system demand and daytime peaks relative to both June 2026 and July 2025. These conditions increased the requirement for synchronous generation to manage system operability, particularly voltage constraints in the southwest, leading to voltage costs rising by £6.5m month-on-month to £40.8m, with inertia costs also increasing for similar reasons. Despite the sustained hot weather, July experienced fewer periods of extreme system stress than June, reflected by the fact that only three days exceeded £15m of balancing costs compared with seven in the previous month.

An Electricity Margin Notice was issued by NESO on 8 July 2026 for the evening peak period on 9 July (18:30–22:30). Similar to the reasons NESO submitted two EMNs in late June, the notice was driven by a combination of heatwave-induced demand, low wind generation, reduced generation availability, constrained interconnector imports and broader system constraints, resulting in tighter than usual operational margins. Despite the tough operating conditions, total balancing costs on these 9 July amounted to £5.1m, which, relative to others, is not generally considered a high-cost day.

Non-constraint costs have decreased in July to £80.9m from £86.6m in June. Factors behind this increase include reduced spend on Operating Reserve offsetting the increase in Response and Restoration costs compared to June. The absolute volume of non-constraint actions has further decreased by 139GWh from June. Overall response clearing prices were broadly stable between June and July 2026 for DC and DM, while DR reduced by around £1.9/MWh. The average firm requirement for DC did materially increase between June and July, despite the average clearing price remaining stable, contributing to this overall increased spend.

Wholesale electricity prices increased in July 2026, primarily due to increased geopolitical instability and the consequent impact on gas prices. The volume weighted average (VWA) price of bids in July was £16.56/MWh, which is less expensive than June's price of £8.85/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 June. CCGT bids took up the second highest volume of bids at ~15%. The VWA price of offers increased from £173.55/MWh to £173.95/MWh. Carbon prices also saw a small increase from £67.3/ton to £68.7/ton.

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



Contents

Executive Summary 2

What is NESO doing to help reduce Balancing Costs? 5

System and Market Conditions 6

Market trends 6

Generation Mix 7

Transmission System Demand 8

Wind Outturn 9

Constraints 11

Network Availability 12

Daily Costs Trends 12
High-Cost Day 13

Balancing Costs detailed breakdown 14
Constraint Costs/Volumes 14
Voltage – Monthly system cost of synchronisation actions for voltage control across 2025 and 2026: 15
Thermal – Monthly system cost of actions for thermal management across 2025 and 2026: 16
Inertia / ROCOF – Monthly system cost of actions for inertia management across 2025 and 2026: 17
Reactive Costs/Volumes 17
Reserve Costs/Volumes 18
Response Costs/Volumes 18
Comparison breakdown 20

Cost Savings 21
Outage Optimisation 21
Trading 21
Network Services 22
Further information 22

Appendix 22
Types of constraint costs 22

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	0.15									0.17
Day Ahead APX (£/MWh)	82.5	104.8	100.2	106.7									103.9
Benchmark*	299	262	278	257									1096
Outturn balancing costs[1]	**307**	**239**	**319**	**302**									**1167**

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

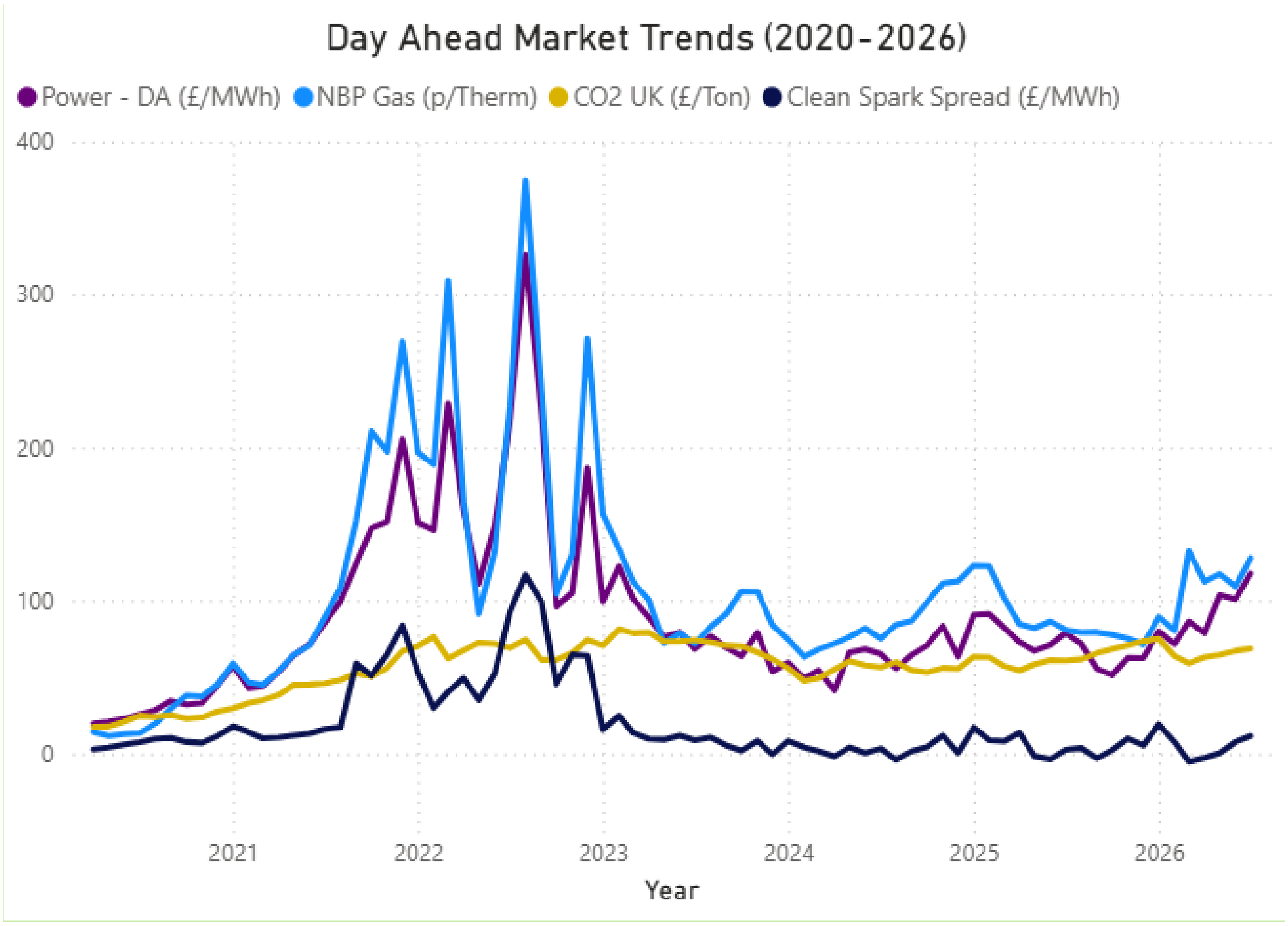
System and Market Conditions

Market trends

July 2026 was characterised by a sharp escalation in energy prices through most of the month, driven primarily by geopolitical tensions in the Middle East, concerns over LNG flows through the Strait of Hormuz, low European gas storage levels, nuclear outages and periods of low wind generation across GB and Europe. These conditions saw DA power prices rise to £106.7/MWh from £100.7/MWh in June, while gas prices rose to 127.7p/therm from 109.2p/therm.

The key difference between gas and power markets was that gas prices were far more heavily influenced by international supply concerns and LNG availability, leading to sustained and substantial price increases throughout the month, whereas power prices were additionally shaped by domestic factors such as wind generation, nuclear availability and electricity demand. By the end of July, gas markets had begun to soften as geopolitical tensions eased, while day-ahead power prices remained elevated due to weaker wind output and ongoing generation constraints.

The volume weighted average (VWA) price of bids in July was £16.56/MWh, which is less expensive than June's price of £8.85/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 June. The volume weighted average (VWA) price of offers increased marginally from £173.55/MWh to £173.95/MWh. Carbon prices also saw a small increase from £67.3/ton to £68.7/ton.



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

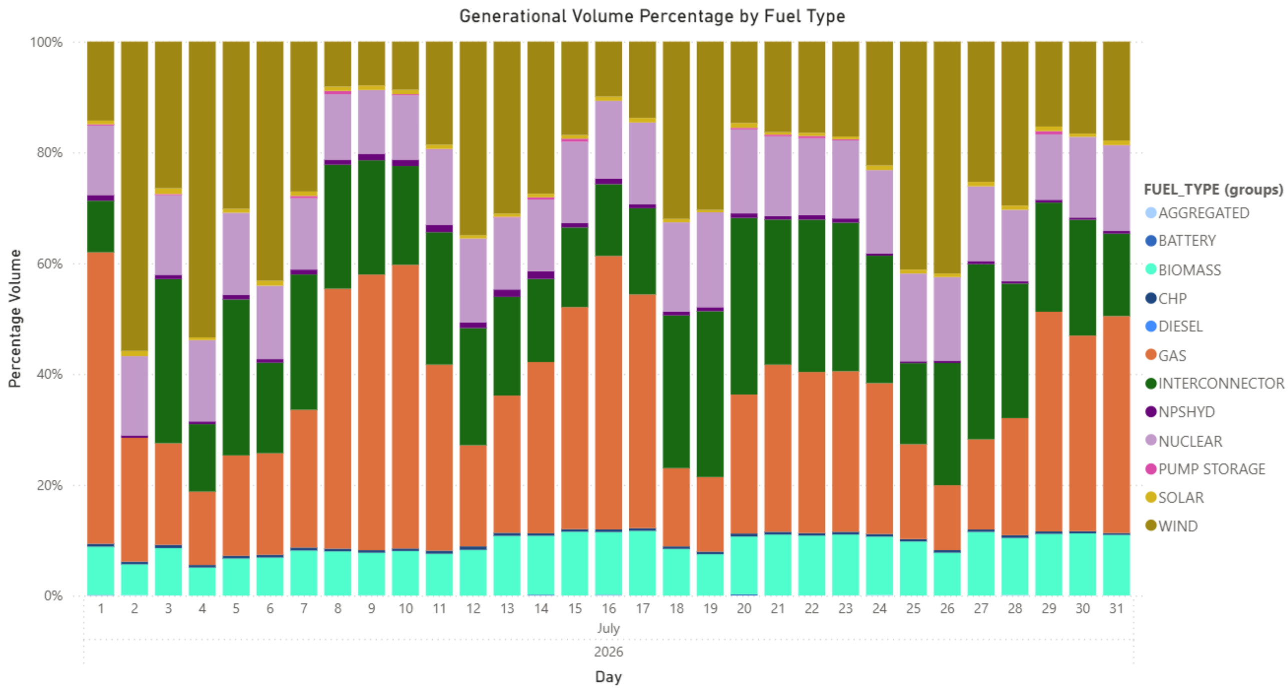
Generation Mix

In July, Gas remained the largest contributor to electricity generation, making up 30% of the total mix, followed by Wind at 23.9% and Interconnectors at 20.7%. July was very similar to June, with Gas, Wind and Interconnectors being the top three largest sources of generation; however, the percentage of both gas and wind decreased compared to June, with a ~5% decrease and ~4% decrease respectively in their share of the generation mix, and interconnection seeing a ~6% increase. The relative decline in the proportion of gas generation in the total generation mix between June and July reflected fewer periods in which extreme heat-driven demand coincided with reduced generation availability, low wind, and constrained interconnector imports & tight operating margins. Gas requirements were also reduced by greater availability of French nuclear generation in late July, and the sunniest July on record providing high levels of embedded solar generation.

The chart below shows the daily generation mix. Comparing July to June we have seen a decrease in high wind generation days with two days (2nd ,4th) surpassing 50% of the generation mix coming from wind sources, compared to four days in June.

There were two days in July (1,10) where gas generation was over 50% of the generation mix, compared to three days observed in June.

*Generation mix includes exports from interconnectors.

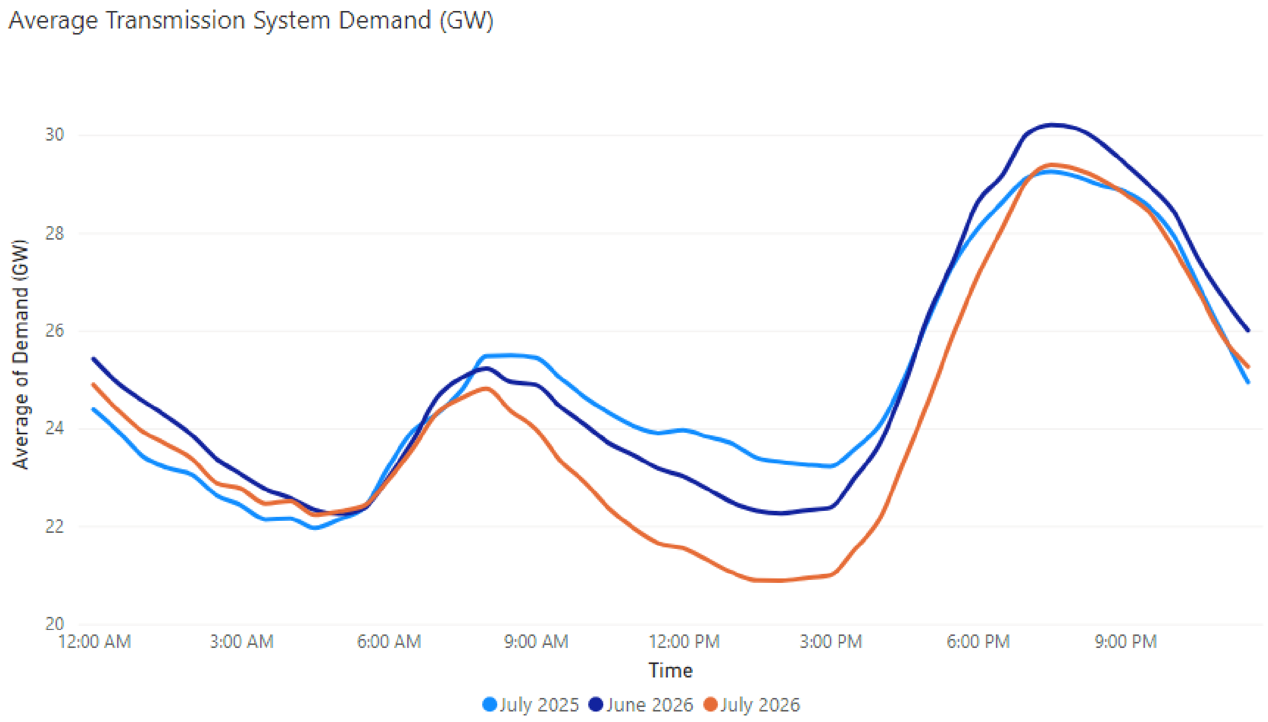


Transmission System Demand

In July 2026, the average Transmission System Demand (TSD) was lower than observed in June throughout most of the day, especially during the daytime periods. During the daylight hours, the higher levels of embedded solar generation reduced the reliance on the transmission system for generation to meet consumer demand. TSD levels were most similar to June during the early morning hours whereby the effects of embedded solar generation are largely absent.

Although overnight and evening demand levels in July 2026 were broadly similar to those seen in July 2025, daytime Transmission System Demand was materially lower. Increased levels of embedded solar generation played a key role in suppressing demand on the transmission network during daylight hours. This effect was amplified by exceptionally sunny conditions, with the UK recording over 258 hours of sunshine in July 2026 compared with 183 hours in July 2025, representing a 41% increase.

Overall, the lower Transmission System Demand levels observed in July are unsurprising when considering the month was the UK's sunniest on record, resulting in high levels of embedded solar generation.

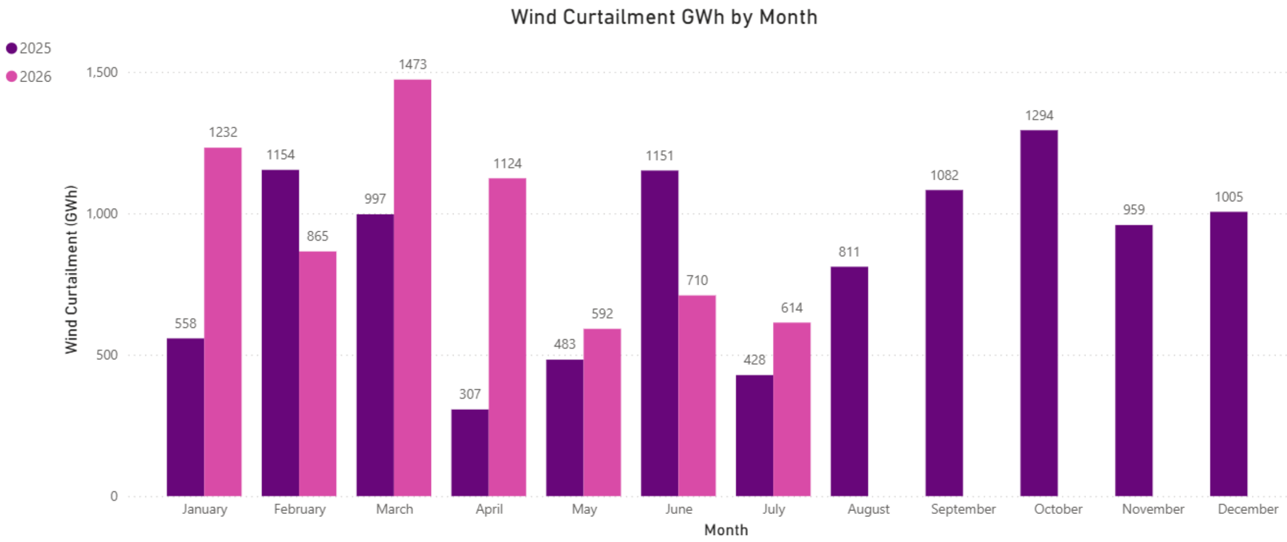


Wind Outturn

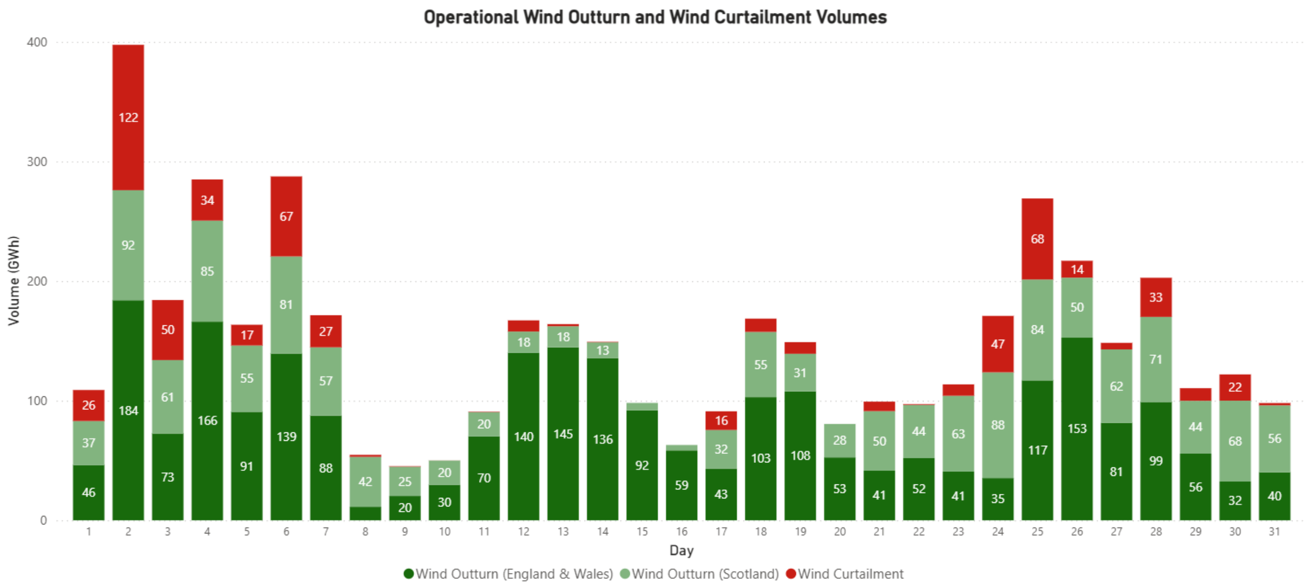
July was a hot and dry month, with high pressure dominating for most of the month, bringing settled conditions with it. The month closed with the UK seeing its second warmest and third driest July on record. Sunshine hours were well above average, leading to the sunniest July on record for the UK.

There were several days during the month whereby wind curtailment was low, including three days which had no curtailment (15th , 16th , 20th). Maximum wind outturn seen during the month was 276GWh on 2nd July, which is the same as the maximum outturn observed in June. The volume of wind curtailment in July was 614GWh, compared to 710GWh in June.

Overall wind outturn fell to 4 TWh in July from 4.6 TWh in June, with a 14.6% decrease in England & Wales (from 2.9 TWh to 2.5 TWh) and a 11.4% decrease in Scotland (from 1.7 TWh to 1.5 TWh) compared to the previous month, giving a 13% decrease overall. The decrease in overall wind outturn coincided with a 13.6% decrease in the volume of wind curtailment. Despite the month-on-month drop in wind outturn and curtailment, these are still high wind outturn conditions for this time of year – reflected by the fact that July 2026 still experienced the highest levels of wind curtailment over the previous five observed Julys. This, in addition to higher wholesale prices, contributed to the relatively high constraint costs observed for this time of year.

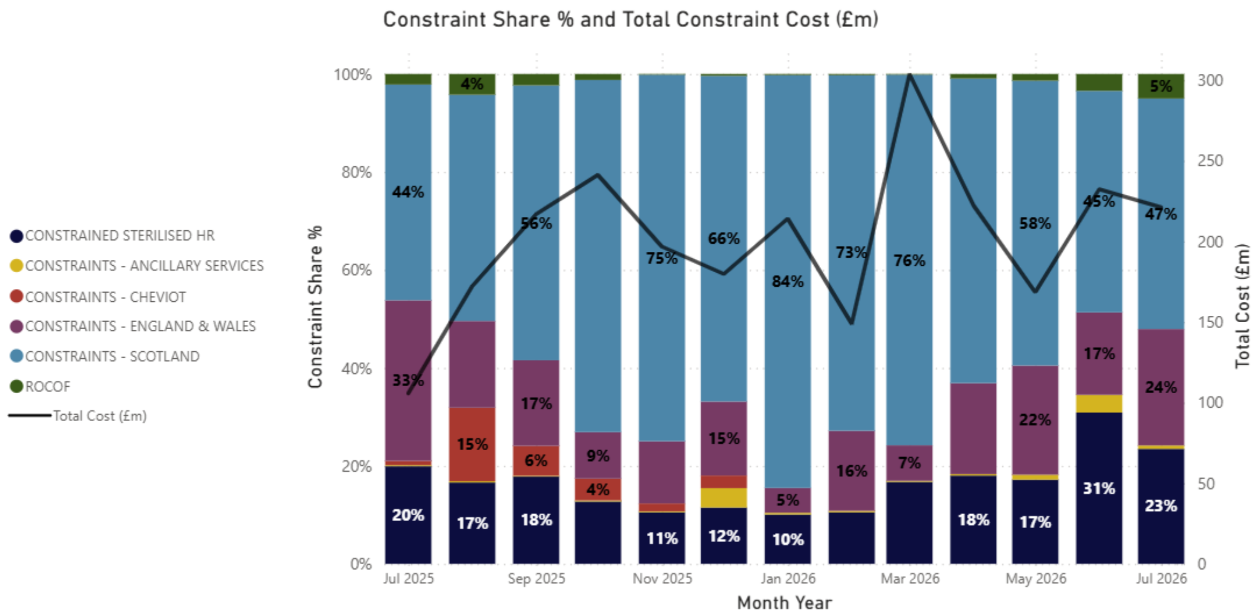


The day with the highest volume of wind curtailment occurred on Thursday 2nd July with 122 GWh. There was a total unconstrained wind outturn of 398 GWh on this date, which is significantly above the average daily unconstrained outturn for the month. Wind was curtailed on this day largely for constraint management.



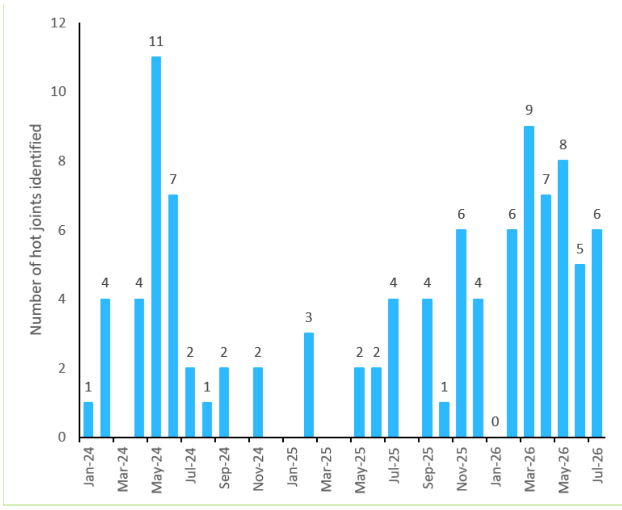
Constraints

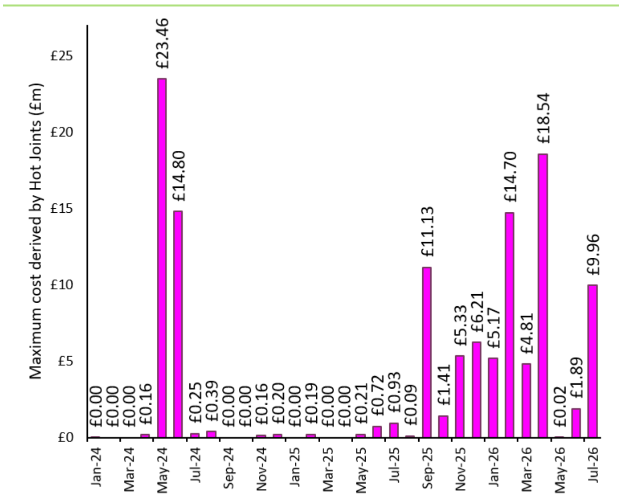
Constraint costs decreased from £232.3m in June to £221.2m in July, a decrease of £11.1m. Decreases in costs were observed for certain constraint categories, such as: Constraints – Ancillary Services; Constrained Sterlised Headroom; Constraints – Scotland. All other categories oversaw increases in costs, except for Constraints – Cheviot, which remained the same at £0. The largest increase in month-on-month costs was from Constraints – England & Wales at £13.5m.



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 July 2026, six hot joints were identified: one in the east midlands, two in the north-west, one in the east of England and the other two in the north of London. The estimated maximum cost associated to the hot joint was £9.96 million.



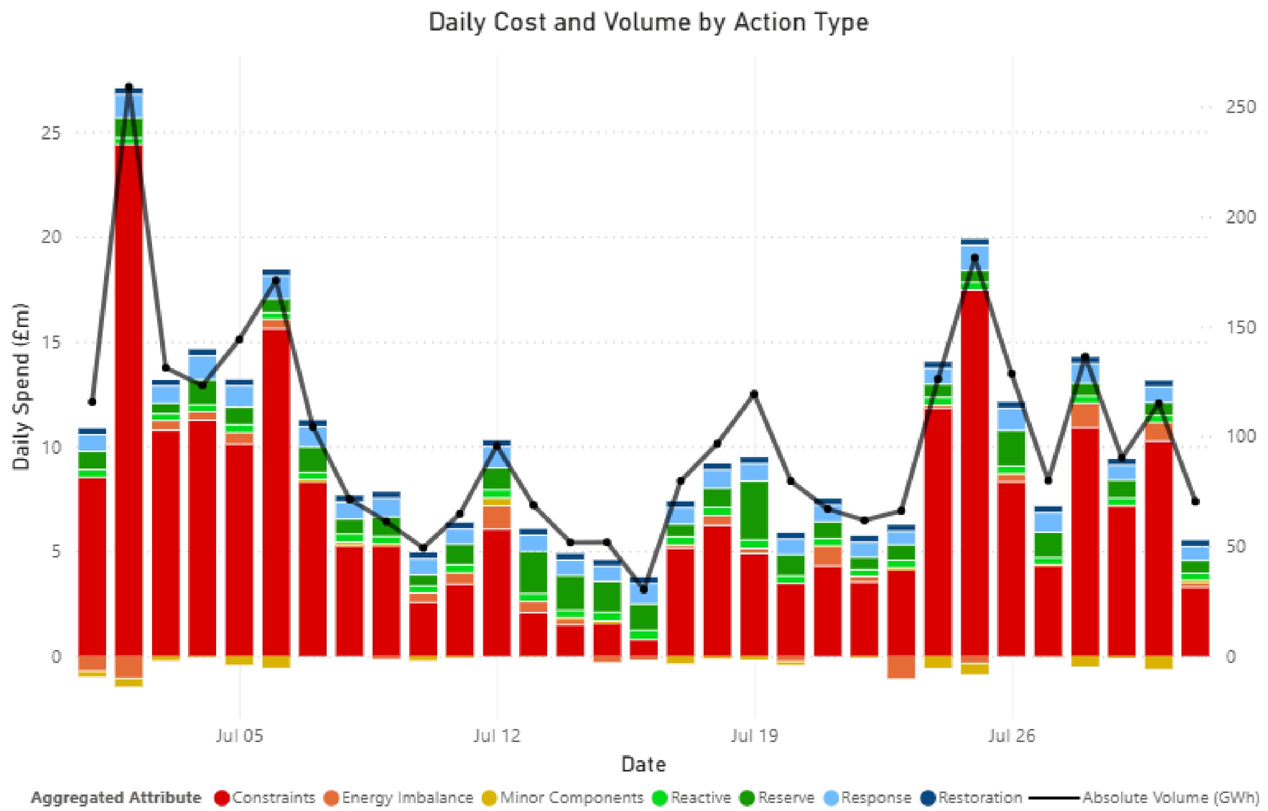


Daily Costs Trends

July's balancing costs were £302m, a decrease of £17m from June but an increase of 129m from July 2025. Three days in July had a total cost spending above £15m (2,6,25), down from the seven days we saw in June. There were a further 10 days above £10m (1,3,4,5,7,12,24,26,28,30), while the daily average cost decreased to £9.8m, down from £10.1m in June - a decrease of 3%.

The highest cost day was Thursday 2nd July at £25.6m, of which around 95% of the total cost was from constraint management, with 97% of this being for managing thermal constraints. The system experienced exceptionally high wind levels (around 400GWh) and was compounded by outages that reduced southbound transfer capability on this day, necessitating the increased levels of thermal constraint management observed.

The lowest costing day occurred on 16thJuly with a total cost of around £3.6m, 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 **2nd July 2026.**

Breakdown of Cost and Volume

- Total cost: £25.6m
- Total Absolute Volume: 259.1 GWh

Balancing Costs detailed breakdown

Comparison Between July 2026, June 2026 and July 2025

Constraint Non-Constraint Group	Latest Month Total	Month Change	Year Change
Constraints	**£221.18**	**-£11.15**	**£115.53**
CONSTRAINED STERILISED HR	£51.92	-£19.84	£30.86
CONSTRAINTS - ANCILLARY SERVICES	£1.55	-£6.85	£1.31
CONSTRAINTS - CHEVIOT	£0.00	£0.00	-£0.92
CONSTRAINTS - ENGLAND & WALES	£52.56	£13.47	£17.92
CONSTRAINTS - SCOTLAND	£104.07	-£0.98	£57.55
ROCOF	£11.08	£3.06	£8.80
Non-constraints	**£80.92**	**-£5.65**	**£13.24**
ENERGY IMBALANCE	£5.75	£1.15	£5.94
FAST RESERVE	£7.52	£0.85	-£3.97
MINOR COMPONENTS	-£4.43	-£5.24	-£6.67
NEGATIVE RESERVE	-£0.05	-£0.60	-£1.23
OPERATING RESERVE	£14.10	-£4.57	£6.91
OTHER RESERVE	£1.97	-£0.20	£1.38
REACTIVE	£11.21	-£0.47	-£1.90
RESPONSE	£26.86	£1.58	£3.93
RESTORATION	£10.52	£2.66	£6.83
STOR	£7.47	-£0.81	£2.02
Total	**£302.10**	**-£16.80**	**£128.77**

As shown in the table above, constraint costs and non-constraint costs decreased by £11.2m and £5.7m respectively, which results in an overall decrease in costs of £16.8m compared to June 2026.

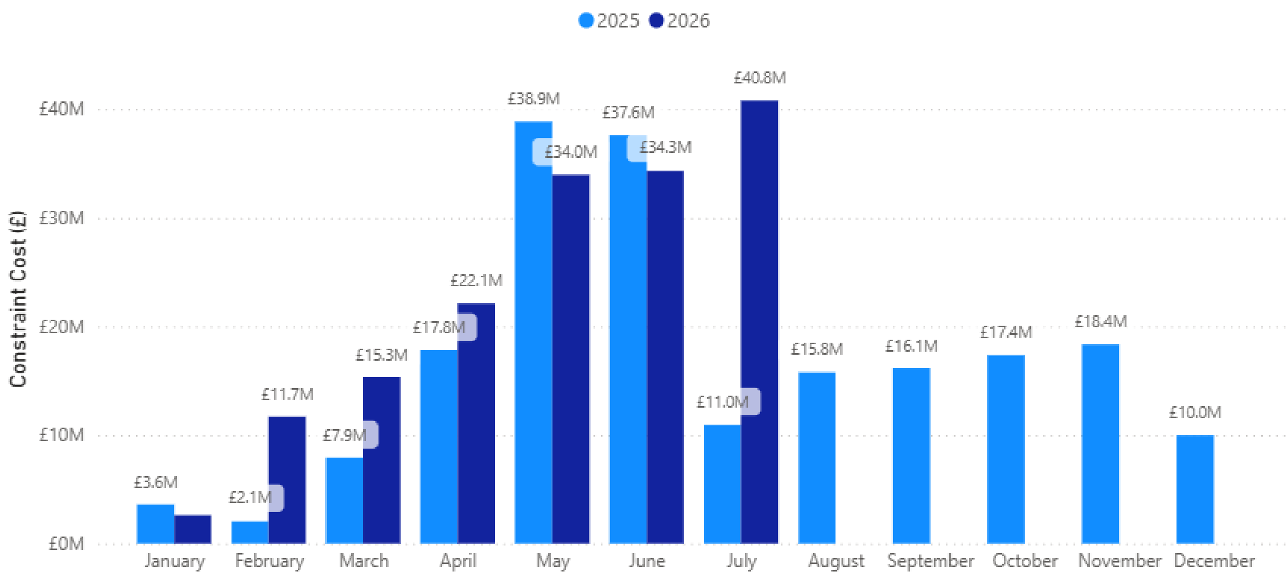
Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
Constraint-Scotland & Cheviot: -£1m	**Constraints – Scotland & Cheviot: +£56.6m**
Constraint – England & Wales: +£13.5	**Constraints – England & Wales: +£17.9m**

Constraint Sterilised Headroom: -£19.8	Constraints Sterilised Headroom: +£30.9m
Overall constraint costs decreased by £11.2m, despite a marginal increase in the absolute volume of actions at 0.8GWh. This is partly due to the increased availability of the Scottish network observed, which is reflected in the reduced Constraint Sterilised Headroom costs.	Constraint costs across GB have increased by £115.5m compared to July 2025. Factors influencing this include substantially higher power prices as well as a 1,833GWh increase in the absolute volume of constraint actions taken, despite an overall lower demand observed on the system.

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

In July, the system synchronisation costs for voltage (what it costs to the system, which factors in energy replacement and headroom among others) were £40.8m, representing an increase of approximately £6.5m compared to June 2026 and is £29.8m higher than we observed in July 2025.

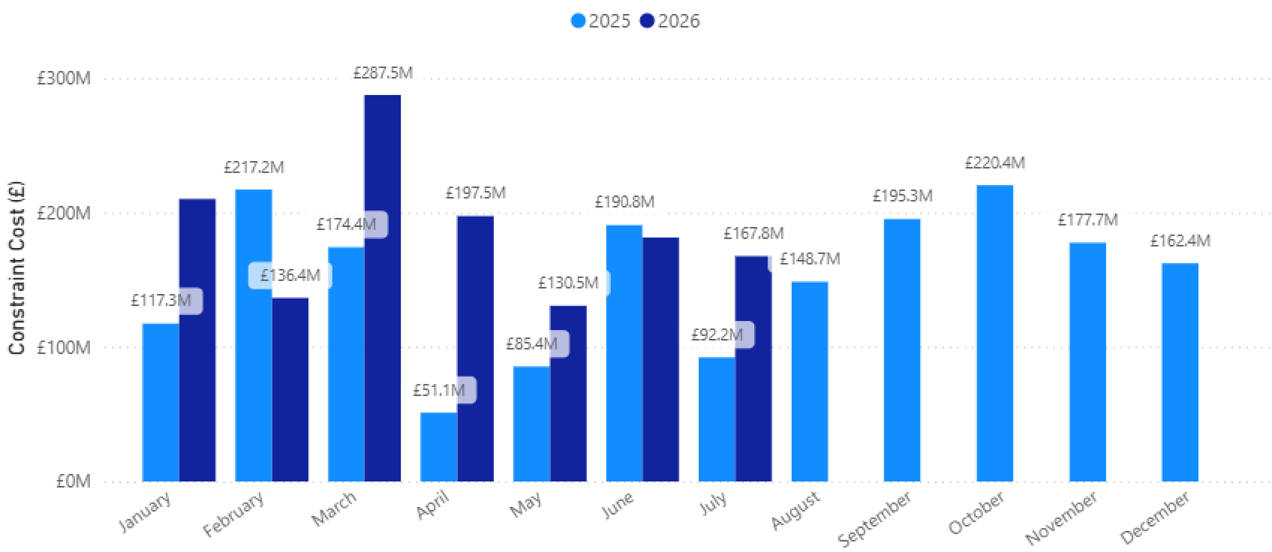


Voltage spending is usually higher overnight: lower demand means that some synchronous units (mostly CCGTs) that usually provide reactive support are not self-dispatched, which forces NESO to procure those services through the Balancing Mechanism. Most voltage costs arise from the South-West region of 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.

July costs were driven by frequent periods of low transmission demand and high embedded solar output, which reduced the number of synchronous generators self-dispatching and required NESO to instruct additional, predominantly gas-fired units through the Balancing Mechanism to provide location-specific voltage support. The absolute volume of voltage control actions increased significantly between June and July, rising from 517GWh to 690GWh. The financial impact was further amplified by substantially higher gas and wholesale power prices during July, which increased the cost of synchronisation. Comparing July 2026 with July 2025, there has been a year-on-year increase in costs of £29.8m. This vast increase can be largely attributed to the significantly lower daytime transmission system demands observed in July 2026 as a result of record-breaking sunshine and the subsequent impacts of embedded generation. This required NESO to more often instruct synchronous machines during the daytime hours to keep voltage levels within Security and Quality of Supply Standard (SQSS) limits.

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

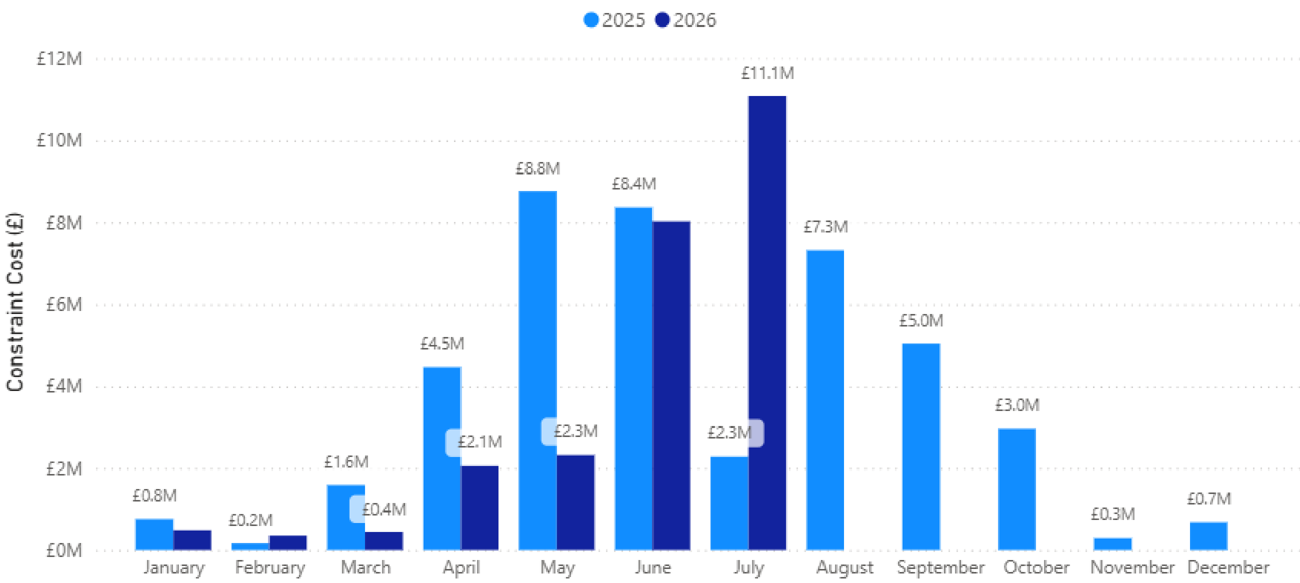
In July, the system thermal constraint cost (which includes factors such as energy replacement and headroom) amounted to £167.8m, reflecting a decrease in costs of £13.8m compared to the previous month (£181.6m), though it was an increase of £75.6m from July 2025 (£92.2m).



July 2026 saw a decrease in wind curtailment compared with June as we also saw lower wind, which is reflected in higher lower constraint costs. In contrast, July 2026 saw significantly higher thermal constraint costs compared to July 2025, driven largely by the fact that gas and power prices were much higher in July 2026 than the same month in the previous year.

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

In July, the system inertia constraint cost (which includes factors such as energy replacement and headroom) amounted to £11.1m, resulting in an increase of £3.1m compared to June 2026 and £8.8m compared to the same month in the previous year.



The inertia expenditure rose in July compared to June 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. Similar to the year-on-year increase in spend on voltage constraints, year-on-year inertia spend increased significantly due to the record levels of sunshine, subsequent impacts on embedded generation and NESO consequently instructing further synchronous machines to comply with the Security and Quality of Supply Standard (SQSS) limits.

Reactive Costs/Volumes

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
-£0.5m Reactive costs have decreased on last month reflecting changes in system conditions since June.	**-£1.9m** Reactive costs have decreased on last year due to changes in system conditions between July 2025 and July 2026.

Reserve Costs/Volumes

Reserve prices decreased from £174.6/MWh in June to £167.3/MWh, a contrast to the upwards trend observed between April - June.

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
Operating Reserve: -£4.6m **Fast Reserve: +£0.9m** There was a 135 GWh decrease in the volume of operating reserve and a 2GWh increase in the volume of fast reserve to secure the system compared to June 2026.	**Operating Reserve: +£6.9m** **Fast Reserve: -£3.9m** There was a 105 GWh increase and a 3GWh increase in the volume of operating reserve and fast reserve respectively required to secure the system compared to July 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.

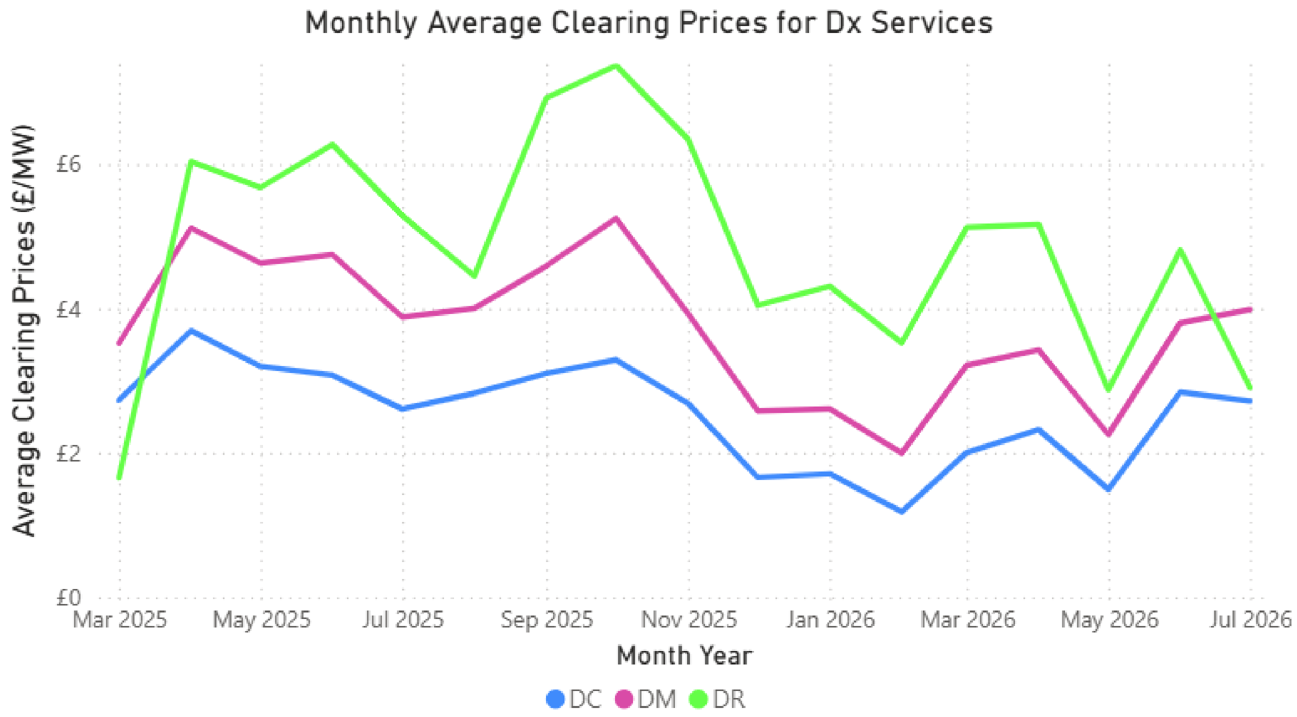
Comparison Versus Previous Month	Comparison Versus Same Month Last Year
+£1.5m There was an 6 GWh increase in the absolute volume of actions compared to June. Average clearing prices for DM services also rose compared to June.	**+£3.9m** The volume of actions taken for response decreased by 80 GWh compared to July 2025. Average clearing prices for DM & DC were marginally elevated whilst DR prices were significantly lower than July 2025.

Comparison Between July 2026, June 2026 and July 2025

Service	Monthly Variance	Yearly Variance
DC	-£0.1	£0.1
DM	£0.2	£0.1
DR	-£1.9	-£2.4

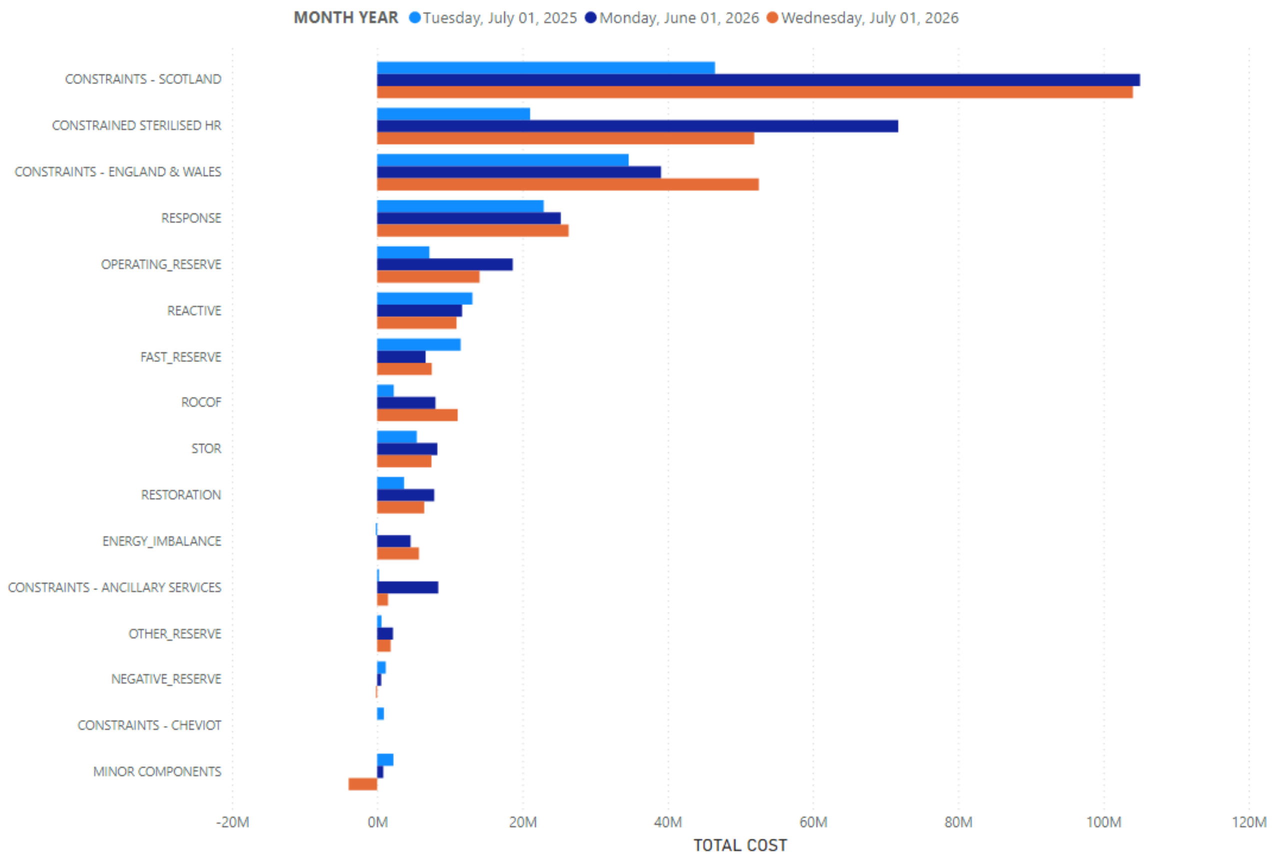
Average clearing prices for Dynamic Moderation (DM) increased in July, whilst Dynamic Containment (DC) oversaw a marginal decrease, and with Dynamic Regulation (DR) experiencing a significant reduction in average clearing price. Despite an increased average firm requirement for DCH and DCL, the month-on-month variance is more likely to reflect changes in liquidity, participating units and the shape of the sell-order stack rather than a material change in requirement.

Compared to July last year, DR has experienced a significant decrease in average clearing price, whilst DM and DR saw a marginal increase.



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 £105m in July 2026. This is a decrease of £67m relative to June 2026 (£172m). The most valuable action was a new running arrangement proposed at a 275kV substation in Scotland, which increased the transfer limit of a nearby thermal constraint by roughly 500 MW. The savings for this action are estimated in approximately £39 million.

Trading

The Trading team were able to make a total saving of £20.9m in July through trading actions as opposed to alternative BM actions, representing a 37% increase on the previous month and the highest trading savings seen since November 2025. Savings from trades for downwards regulation made up the largest component of savings from the month, largely down to sell trades taken against wind units with high negatively priced bids. Voltage trading was steady throughout the month; however, with lower savings due to the lack of competitive pricing leading to units being procured in the BM. Constraint savings increased compared to June, largely due to savings being made by managing constraints in South East England. The day with the greatest trading savings was on 19 July at a cost of £4.3m with the greatest savings being made for downwards regulation. The day with the greatest spend on trades was 6 July at a cost of £1.3m with the greatest component being for managing voltage in Southern England.

From Friday 24th July, NESO have started to use DA NTC restrictions more regularly, which we expect to impact trading savings in the future. These are used to help guarantee the security of the GB system, should available intraday options not provide this certainty. For further information please see our notice at the OTF here (slide 12).

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). Please note that savings data for Network Services currently extends to May 2026 and will be updated for later months once available.

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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