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Drax Intelligence

Flexibility Focus

A quarterly update on demand-side revenue streams

A review of Q3 2026 and look ahead at Q4 2026

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Welcome to the sixth edition of our quarterly newsletter focusing on the key market, policy and regulatory developments affecting consumer-led flexibility (CLF).

The third quarter of 2026 has seen heatwaves that shaped demand and generation, diplomacy and re-escalation in conflict in the Middle East, as well as ongoing policy and regulatory evolution. This has contributed to unusually volatile market conditions for the time of year.

As with every quarterly report, we look at the biggest developments in this edition. If there are topics that we've missed that you think we should cover in future, or any other ways we can improve the content, please send your feedback to insights@drax.com.



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Q3 developments

Market updates

The market in the third quarter of 2026 remained volatile with high electricity prices, predominantly due to escalations in the conflict in the Middle East. However, intermittent heat waves continued to provide short-term buoyancy over the summer months.

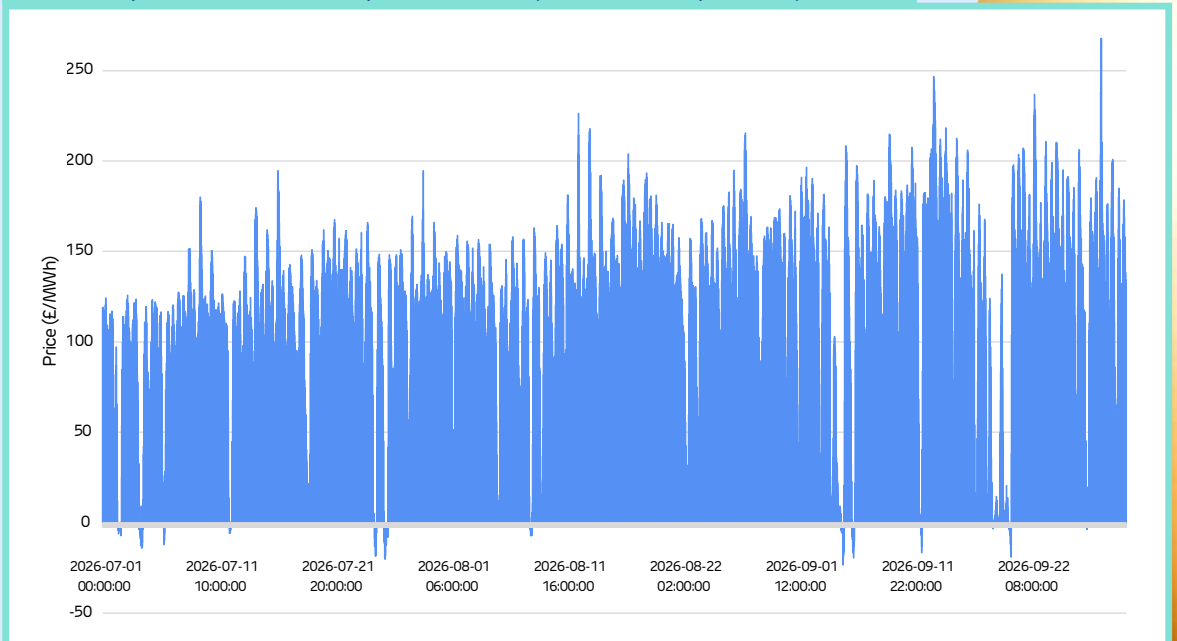
Hottest summer on record and a solar eclipse

The Met Office has provisionally recorded summer 2026 as the warmest on record. This came hand in hand with record high sunshine hours and solar generation, particularly in July, but also unprecedented demand for cooling. This caused new challenges for the UK electricity grid. In Q3, the National Energy System Operator (NESO) put out three electricity margin notices (EMNs) in July and August as it operated on tight margins during heatwaves and the solar eclipse. On 18 August, the UK experienced a partial solar eclipse between 6pm and 8pm which reduced solar generation during that time. NESO issued an EMN on the day due to an expected margin shortfall during the eclipse. However, it cancelled the EMN at around midday.

Escalations in the Middle East

In the previous quarter, Q2, there was slightly more market optimism surrounding the conflict in the Middle East between Iran and the U.S. as both countries engaged in peace deal discussions. However, in the last week of June and at the start of July the peace talk progress broke down and strikes resumed. Over the course of Q3, the conflict escalated causing high spikes in wholesale costs, with prices trending upwards over the period. The highest prices in September were around 33% higher than those of July, reflecting the growing concern over European gas storage levels sitting at lows not seen in over a decade, alongside no clear route for resolving the conflict in the Middle East.

Half-hourly wholesale electricity market index prices for 1 July - 30 September



Policy and regulation updates

Capacity Market 2027 pre-qualification consultation

On 2 September, the Department for Energy Security and Net Zero (DESNZ) released a consultation on changes for prequalification for the Capacity Market in 2027. Proposals include changes to frameworks to ensure capacity providers meet obligations as well as changes to the DSR de-rating methodology.

DESNZ has proposed changes to the delivery assurance framework to ensure that capacity providers can meet obligations during the Obligation Period. DESNZ is now focusing on how it can improve capacity verification and testing. It's proposed changes in the following areas:

- Satisfactory Performance Days (SPD): DESNZ believe reforming the process is required to better reflect a provider's ability to respond to a Capacity Market Notice during peak demand periods.
  - Capacity Market Units (CMU) would need to pass three SPDs in peak demand windows in winter and demonstrate that it can respond to a Delivery Body instruction. DESNZ proposed to remove most access to summer testing.

- Improving data set-up: pausing capacity payments until the approved metering solution process and metered data setup is complete. DESNZ has added this to improve confidence of capacity delivery from the start of an agreement.

Following previous consultations, DESNZ has also proposed two potential approaches to changing the DSR de-rating factor methodology.

The options are:

- A duration-based approach, which would de-rate DSR capacity by the nominated response duration relative to that duration's Equivalent Firm Capacity. DSR CMUs would be de-rated according to the length of time they're able to meet their Capacity Obligation. This would apply at a CMU level, not for each component.

- A technology-based approach, categorising and de-rating DSR components based on the underlying technology used to provide capacity. DESNZ propose initial categories of demand turn-down, behind the meter (BTM) storage, and BTM generation.

Capacity Market 2027 pre-qualification consultation (continued)

In its proposals, the Government also seeks to address some of the administrative burdens faced by DSR capacity providers that aggregate many small components together into a CMU. It plans to introduce a 30kW capacity threshold for mandatory metering tests at component level, with only 2% of components under 30kW requiring a full metering test. This aligns with the threshold for Capacity Market Register reporting introduced for the 2026 pre-qualification.

It's also proposed plans for a relief mechanism to address data flow errors that have resulted in Termination Notices for some unproven DSR CMUs. Under this framework an unproven DSR CMU can avoid termination where failure to complete a DSR Test by the deadline was due to factors outside the Capacity Provider's control, rather than a lack of delivery capability.

The proposal also covers other administrative and operational changes such as stronger compliance incentives. The consultation closes on 27 October 2026 with a Government response expected in Spring 2027. DESNZ aims to introduce changes ahead of prequalification 2027 for the 2028 auctions.



Government electricity demand turn up trial

The Government opened an expression of interest for flexibility providers to take part in a demand turn up (DTU) trial, which closed on 18 September. The aim is to test whether rebating the value of eligible Final Consumption Levies (FCLs) can make DTU more cost competitive and encourage consumer participation. It is the planned first stage of selecting flexibility service providers in a research trial that'll assess if DTU can reduce renewable electricity curtailment in Great Britain. Successful applicants can apply for funding of up to £3 million per provider.

The government is also planning to launch additional trial phases in 2027, which may exempt DTU from further costs such as some network charges.

FMAR design consultation

Elexon consulted on the final design and implementation arrangements of the Flexibility Market Asset Registration (FMAR) service between 14 September and 9 October. It's developing FMAR as a common, trusted registration capability for flexibility assets across local and national flexibility markets. It aims to reduce duplication, improve asset visibility and support interoperability between markets by providing a consistent approach to asset registration. We expect it to have the greatest impact on flexibility service providers, rather than asset owners, and so haven't gone into the detail of the changes here.

Revenue opportunities

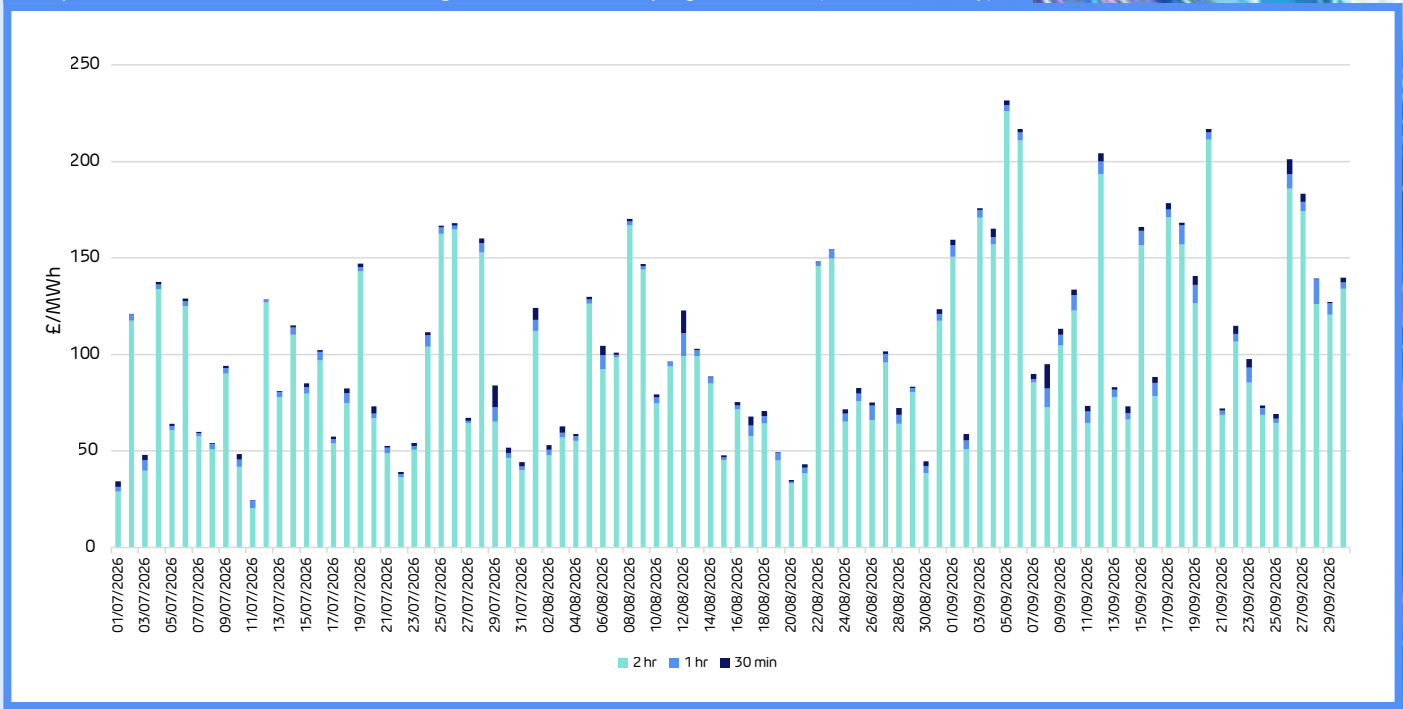
Wholesale arbitrage

In Q3 2026 (July, August and September), we saw continued elevation of wholesale prices and periods of volatility. Prices in Q3 were 25% higher than Q2 prices, when averaged across every 30-minute settlement period.

The highest daily maximum price across the quarter was £267.79/MWh on 28 September, £293.02/MWh less than Q2's. However, prices remained consistently high over the three months with daily maximum prices exceeding £150/MWh on 74 days out of 92, which is 47 days more than we saw in Q2.

The greatest spread (the difference between the highest and lowest prices on the same day) occurred on 5 September at £231.65/MWh, with the lowest spread of £24.62/MWh on 11 July. The average spread across Q3 was £102.84/MWh, higher than Q2 highlighting unusual levels of volatility for the time of year. In the summer, electricity prices have previously been less volatile than in the winter; however, ongoing geo-political tension and the hottest British summer on record, have created the backdrop for volatility.

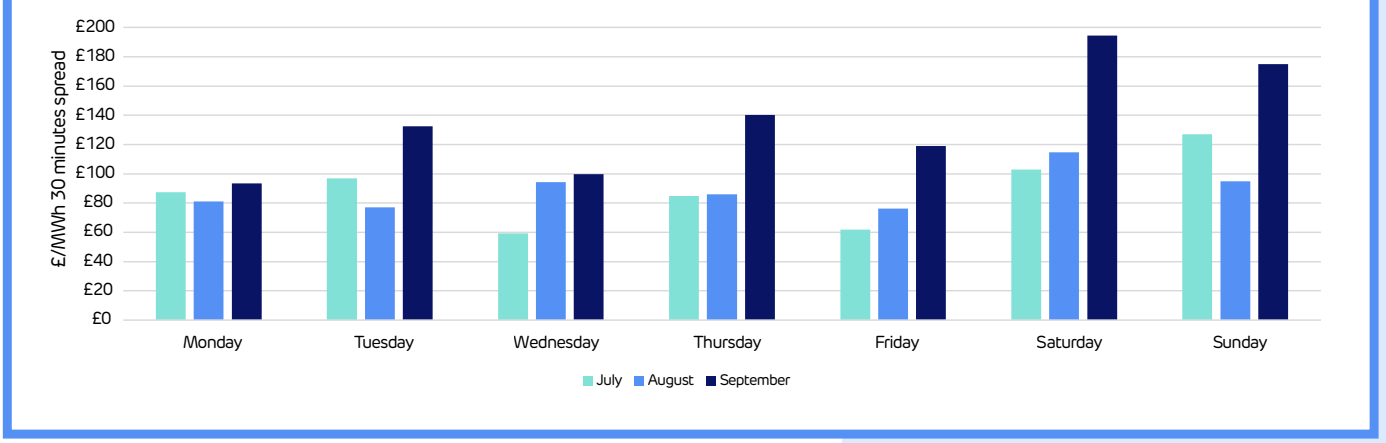
Daily maximum £/MWh value for a single load shift of varying durations (wholesale only)



In the quarter, we saw significant deviation between minimum and maximum wholesale prices over weekends compared to weekdays. Minimum prices were typically lower on Saturdays and Sundays ranging from an average of £65/MWh over the weekend to £85/MWh on weekdays. This reflects the lower demand on weekends. And while maximum prices were typically slightly lower than weekdays, the much lower minimum prices typically meant spreads were higher over weekends than weekdays in the quarter (£132/MWh vs £92/MWh on weekdays).

There was also monthly variation; in September, minimum prices were similarly low to July and August, however, as the maximums were higher, this created much greater spreads during September weekends.

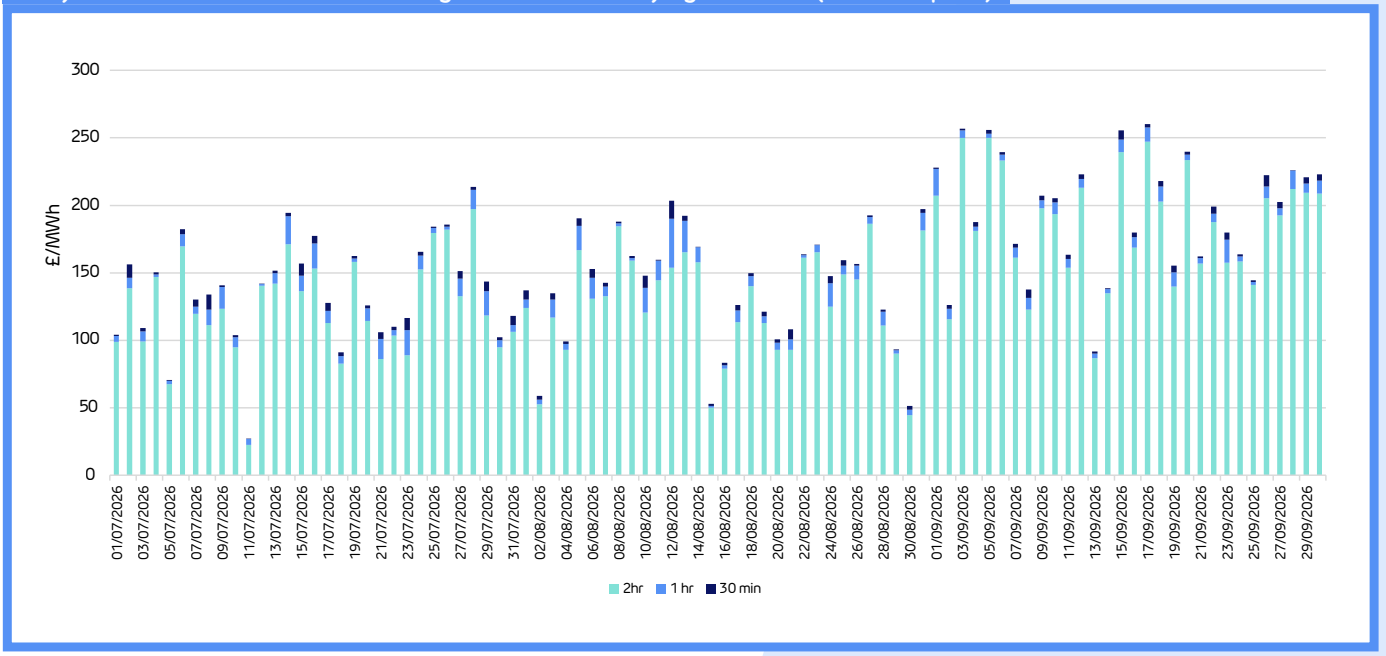
Average 30-minute load shift by day – wholesale only



Delivered cost arbitrage (example customer)

The delivered cost arbitrage is usually less in summer compared to winter, as the winter seasonal time-of-use charges (e.g. triad charges and Capacity Market Supplier Charge) are only applied in winter months. Opportunities in the summer are driven more by wholesale prices rather than third party charges. However, due to volatile wholesale markets, there have been greater opportunities than average for the time of year.

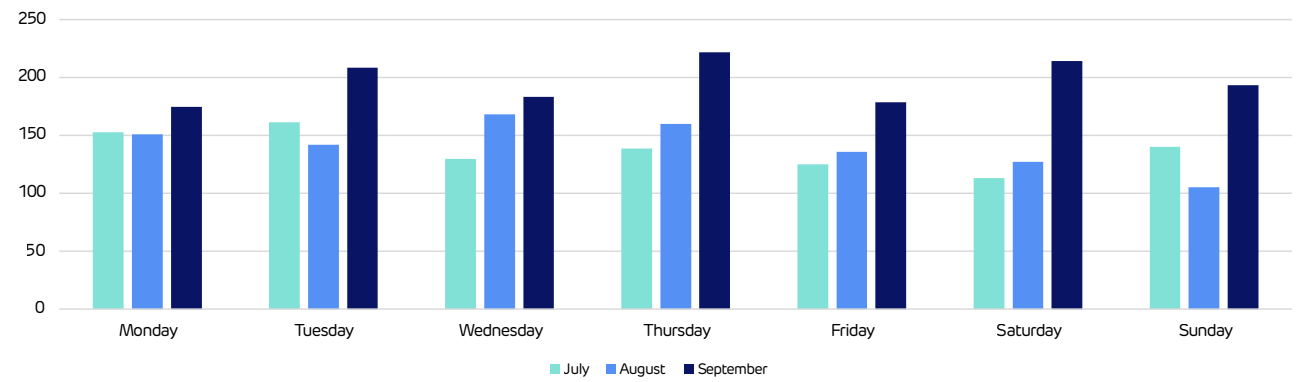
Daily maximum £/MWh value for a single load shift of varying durations (delivered price)



By shaving peak demand consumption, customers on a tariff that fully passes costs through could have saved up to £260.10/MWh on 17 September. This was £270/MWh lower than the highest potential savings in Q2 26. However, the average amount that flexible participants could save over the three months was 16% higher than the previous quarter at £157.12/MWh for 30 minutes of peak demand shaving. The average for two hours of demand shaving was £145.09/MWh - 17.5% higher than Q2 26.

When looking at delivered price arbitrage, weekdays are typically more valuable than weekends (a £161/MWh spread for a 30-minute load shift vs a £146/MWh spread over the weekends). This is predominantly due to the application of red rate Distribution Use of System (DUoS) charges over the weekday evening periods, driving up the maximum cost of importing power. Interestingly though, September weekend delivered price spreads remained comparable with weekday spreads.

Average 30-minute load shift by day – delivered price





Demand Flexibility Service (DFS)

Q3 saw huge volume increases procured through the service, up from ~4GWh in Q2 to ~8.8GWh. Additionally, the most extreme accepted bid prices hit £987.4/MWh, the highest since the updated service launched in April. With NESO running more test events, issuing multiple electricity margin notices, and feedback that there's more value to unlock in demand flexibility; there's plenty to unpack.

Test Events

In September, NESO once more conducted DFS test events; one for demand turn down and two for demand turn up. It guaranteed prices of £500/MWh for turn down and £180/MWh for turn up. NESO called both turn up events on Sundays during the 1-2PM period where it often needs to curtail renewable generation due to relatively low demand.

Whilst the first of the turn up events was unconstrained across all DFS zones, NESO targeted the second turn up event specifically for Zone 4, the zone around Newcastle, and the turn down event targeted Zone 12, London. NESO wanted to explore using demand turn up in Zone 4 as a means of absorbing power which typically flows from Scotland to the South and can often be constrained at the B6a boundary (across Newcastle) and B7 between Leeds and Newcastle. Meanwhile, NESO is seeking to offset the constraints at transmission boundaries bordering Zone 12 by calling for turndown volume in the area during a high demand period. Despite offering guaranteed acceptance prices, only 33.35MWh of volume applied to the Zone 4 turndown event, whilst the Zone 4 turn-up event had just 0.25MWh. Only the first, unconstrained, turn up event had a significant level of volume come forward (152.6MWh).

Whilst NESO originally marketed DFS as a system margin tool, the service is transitioning into a multipurpose tool for network management. This has become clear following NESO's inclusion of Local Constraint Market on the 7 October alongside its specific targeting of localised DSR.

Margin Notice Events

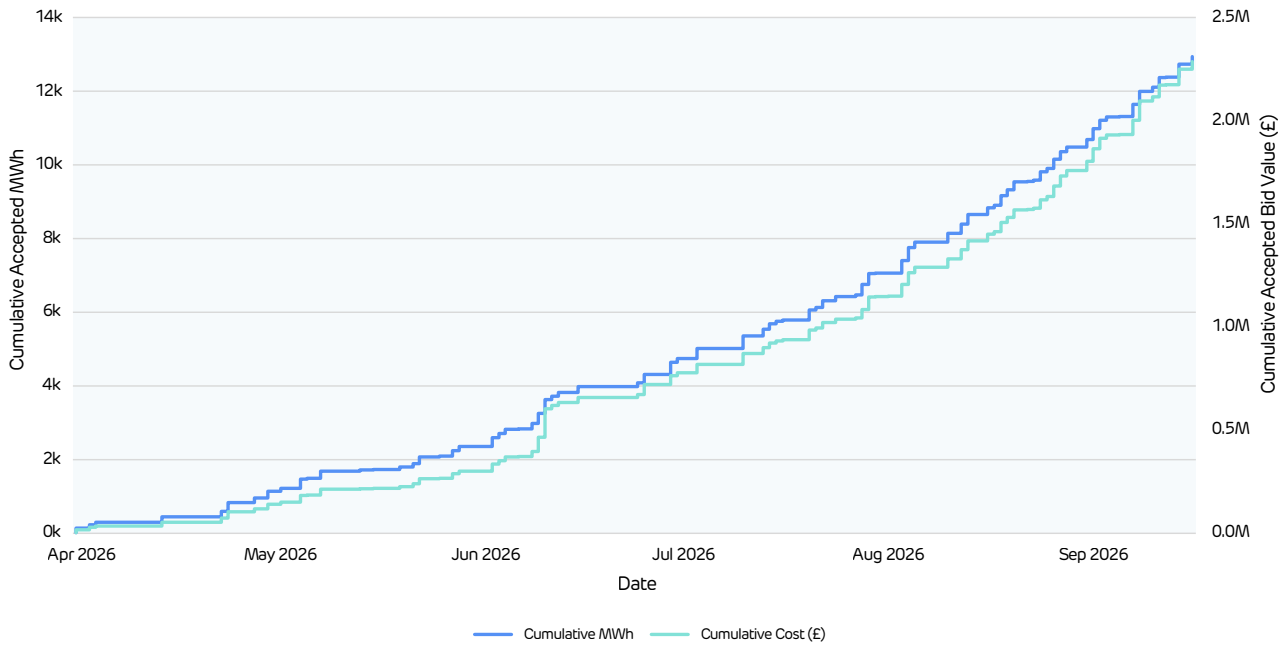
This year has been unusual in that NESO has called six electricity margin notices (EMNs) to date, with three of them falling in Q3. To contextualise this, NESO called only one EMN in both 2024 and 2025. Margin notices are NESO's way of signaling to generators to come forth with additional generation, so NESO can meet its safety headroom of available generation over demand – the margin. NESO has historically actioned this mechanism in winter periods, where demand spikes in the cold winter evenings. This year was the first time EMNs had been issued in summer. As margins tightened, the value of volume in DFS increased - prices hit £500/MWh, £987.40/MWh and £350/MWh across the margin notice days.



More value to be unlocked

At the start of October, NESO's Power Responsive group hosted a challenge group discussing the development and scaling of demand-side flexibility and the untapped value within DFS. Since the updated DFS went live in April, NESO has calculated the total opportunity for providers at ~£44mn, based on its analysis of its required volumes and competitive prices. However, NESO only awarded 5.3% of the £42.3m demand turn-down opportunity and 1.6% of the potential £1.73mn demand turn-up opportunity. In total NESO calculated that 6.18% of its requirements were met by demand turn-down, and that there is significantly more value to unlock through increased participation in the service.

Cumulative DFS Volume and Awarded Bids





Looking ahead at Q4 2026

What we're doing at Drax

We're continuing to develop products and services for our customers, supporting them to achieve value from flexibility. Look out for more information shortly.

Market and policy developments

In Q4, we're expecting NESO to publish its Winter Outlook in October highlighting its expected system margins for the winter. The system is typically tighter in the winter months and, while the Early Winter Outlook suggested margins would be lower this winter, they remained relatively comfortable. It will be interesting to see how NESO's forecasts of margins have evolved over recent months.

We're also expecting Ofgem to publish an update on its Cost Allocation Recovery Review (CARR) in Q4. This will look at how future energy system costs could be allocated. Based on the Government's Clean Flexibility Roadmap: July 2026 update, it could include plans for flexibility incentives by encouraging low carbon technology uptake and sharper price signals.

Meanwhile, Ofgem and DESNZ continue to assess which market reforms should be progressed as part of the Reformed National Pricing (RNP) programme, including potential changes balancing and settlement.

The Chancellor is due to deliver his Autumn Budget on 28 October. It'll be the first budget under the new Government with Andy Burnham as Prime Minister. Although we don't know ahead of time what the Government will include, the Prime Minister has already suggested he's planning to implement some measures that could affect energy bills and the wider industry. We'll follow any developments closely.



For more information on **Drax Energy Solution's flexibility offering and services**, please visit our website or message insights@drax.com.

For more information about the **latest market, regulatory and policy developments**, please visit our Intelligence webpage.

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