STONEHAVEN

Beyond REMA

Three provocations for the future of the UK power market

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Project Tempo

01 Foreword

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The single biggest challenge facing the Government's energy policy is bills, bills, bills. Without action to lower costs, political support for the Government Clean Power mission will ebb away, quickly and then suddenly. We've already seen significant challenge from major utilities in public fora on the thorny subject of non-commodity costs, and we should expect that to continue.

A key chunk of 'non-commodity costs' - the bits of the bill that aren't directly tied to energy demand - is made of charges for managing constraints on the network. This is an already large number that is projected to get larger as more renewable generation is deployed ahead of the grid's ability to absorb it. This needs to be fixed.

In this report, Stonehaven has laid out three options that the Government must take into account as it considers how to deliver its reformed national market proposals. Without measures that lower the costs of constraints, this key marker of rising bills will only get worse over time.

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The UK stands at a critical point in its energy transition. The Government's Clean Power 2030 mission has set out clear ambition: rapid deployment of renewables to deliver energy security and Net Zero. Yet, as we press ahead with building the infrastructure of a clean power system, we must remain laser-focused on affordability for consumers. The success of this transition will ultimately be judged not only by how green our power becomes, but by how affordable it remains for households and businesses alike.

Structural barriers to achieving this are becoming more visible. Among them, constraint payments are one of the most persistent and politically charged challenges. They are the silent cost of progress: evidence of a system straining under the weight of its own ambition. Left unresolved, these costs threaten to undermine both consumer confidence and the public legitimacy of the Net Zero project.

This report comes at the right moment. It sets out practical, politically credible options to tackle constraint costs and to reform the market signals that drive them. Doing so is not only a question of technical optimisation; it is a test of whether the UK can deliver clean energy that is fair, efficient, and resilient. Managing this transition intelligently, by confronting inefficiency rather than compensating for it, will be essential to keeping bills low and the public on side as we move towards a truly affordable Net Zero future.

02

Introduction

In current UK political energy debates, three key factors hold to be true. Firstly, despite the anticlimactic decision on REMA, in energy circles, the zonal pricing debate has not gone away. Secondly, Net Zero remains the anti-hero of today's culture war. Third; whilst energy prices and bills remain high, Labour will remain under constant pressure from Reform on its green flank.

Despite this, Clean Power 2030 (CP2030)1 remains an unshakeable mission for this government. This is demonstrated by the launch of Allocation Round 7 (AR7)2, the seventh round of competitive auction funding rounds that form Great Britain's Contracts for Difference portfolio. AR7 is holding out the prospect of a bounty of contracts for renewables, including predominantly offshore wind.

The CP2030 Action Plan included ultimate capacity targets for different renewable generation technologies, including on and offshore wind. Adding up the UK's existing capacity, and accounting for contracting and construction timelines, the UK needs to contract up to ~10GW of onshore and ~20GW of offshore technologies through AR7 to meet desired capacity targets by 2030. However, during the early 2030s, we could witness a perfect political storm.

Building this level of capacity would be an achievement in reaching renewable energy abundance, however our grid transmission infrastructure has to be ready to absorb it. Cables are needed to transmit electricity from a site of generation to a site of demand and all cables have physical limits. Grid upgrades are planned, but aggregated capacity expansion across capacity and grid connection access at speed is key. For simplicity, this paper will avoid discussing grid connections as a separate issue. Assuming grid connections are not an issue, theoretically the consequence of a grid with constrained capacity could see higher costs from extra system pressure. Twinned with extra back-up grid balancing costs to balance power supply for demand, this issue could theoretically compound and the political risk increases towards 2030.

The political spectre of Reform looms over this: they have already threatened to remove support for Contracts for Difference, which does reflect an element of public sentiment. This is in part because the political salience of constraints and constraint costs on bills is increasing, as part of the overall rhetoric on why our energy bills are so high. This is not yet a significant reputational risk outside of energy circles, but is increasingly coming to public attention: the Telegraph reported on constraint costs in June 2025. For the first time, constraint costs were identified as the reason for the price cap increase from the electricity and energy regulator Ofgem. To avoid a total loss of support for renewables, the sector will need to get ahead of this. It is not in the public interest to be seen to be costing the public purse to build renewable energy infrastructure, only to throw a considerable amount of that power away at a further expense.

Constraint costs remain a core driver of increasing system costs, and could feasibly worsen if nothing is done as renewable deployment ratchets up. Market arrangements under the long-running Review of Electricity Market Arrangements were supposed to tackle this. The Department for Energy Security and Net Zero has decided to move forward under a market arrangement titled Reformed National Pricing. The underlying problems REMA was set up to solve still exist and will have to be dealt with under this framework to avoid the political storm as set up above. They will contribute an increasing amount to bills as this Parliament progresses.

Officials must now determine how to achieve the goals they set for themselves at the beginning of REMA[3]:

- Deliver a step change in the rate of deployment of low carbon technologies, and reduce our dependence on fossil fuelled generation.
- Provide the right signals for flexibility across the system.
- Facilitate consumers to take greater control of their electricity use by rewarding them through improved price signals, whilst ensuring fair outcomes.
- Optimise assets operating at local, regional, and national levels.
- Ensure that the security of the system can be maintained at all times.

It is currently unclear how any of these objectives will be achieved, aside from increasing ambition on existing instruments. We would recommend refocusing on solving two of the core challenges of the UK power market.

03

Managing Constraints

The first is task is clear: how to manage constraints in a system that will currently expect these to increase into the medium term, and potentially beyond if the network build-out is delayed. Overall balancing costs totalled £2.7bn in 2024/25, a 10% increase on the £2.5bn of 2024/24, which in part can be attributed to the rise in constraint costs and volumes, in addition to the cost of balancing actions. The UK consumer paid £1.7bn in 2024/25, and we have already reached the £1bn marker this year at the time of writing this paper[4].

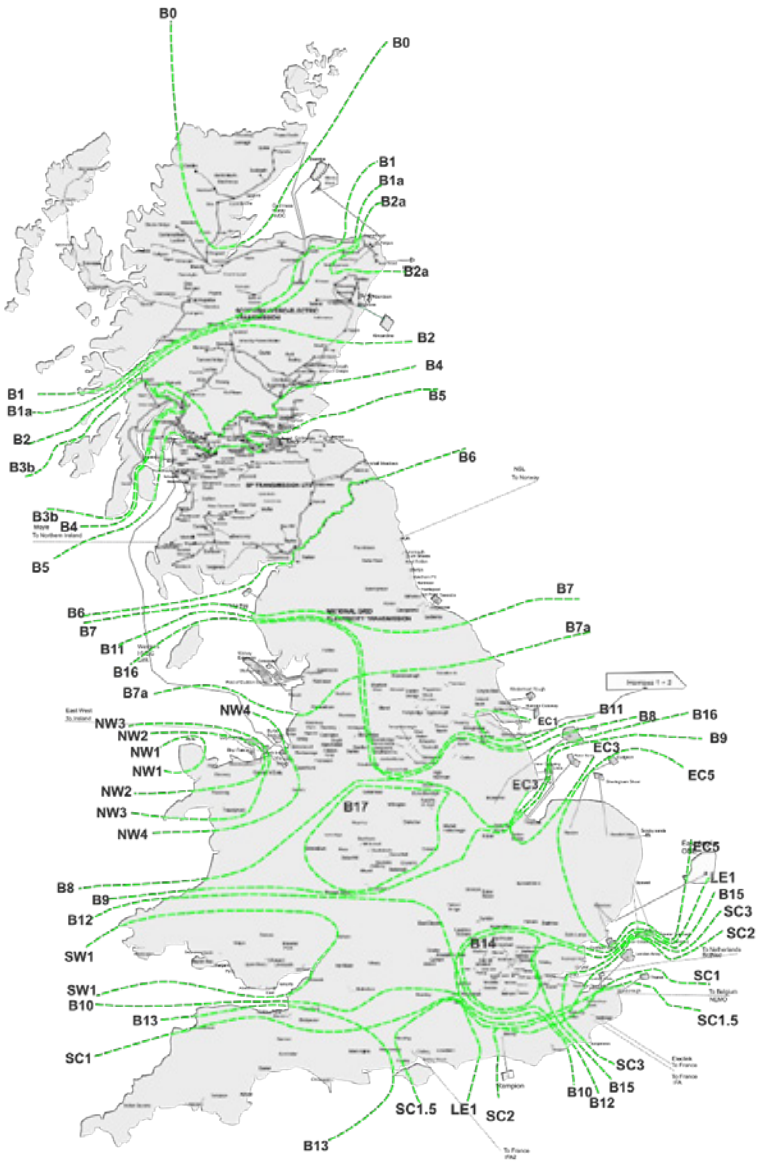
These costs derive from two main factors:

01	Power that is generated cannot be transmitted to an area of energy demand due to thermal and physical limitations of the grid itself. In really simple terms, wind farms in Scotland may generate 10GW above the B6 boundary (Figure 1), however there are only two voltage transmission corridors and one HVDC offshore cable that bring total transfer capacity to around 6.7GW[5]. Only this power can reach a city that needs it. As a result, wind farms will be paid to switch off – as much as 10% of all wind power last year was curtailed and replaced by gas generation.[6]
02	Transmission outages due to network upgrades, which are inevitable but a temporary source of bottlenecks.

NESO's connections reform process that will determine which assets are needed for 2030 is underway. The official release of the Electricity Transmission Design Principles (ETDPs)[7], which will set out how the transmission network will be built out, is anticipated soon. Transmission outages are an inevitable and necessary reality; investment and trading decisions of projects on either side of transmission boundaries however are mitigatable and within the reach of policy changes within this paper.

Current policy frameworks distribute these costs in ways that often dilute locational signals and fail to incentivise market participants to act on the drivers of congestion. There are several drivers of congestion, some are controllable, such as trading decisions and investment in the transmission grid, and some are physical, such as an oversupply of power. Within controllable factors, such as where renewables should optimally locate in terms of system balancing, there is no real incentive for wind farms to act any differently. By existing behind a constraint barrier, they can expect to be paid for the inability of the transmission network to take their power.

Figure 1: GB Transmission System Boundaries (simplified[8])



Despite the B6 being such a significant bottleneck, several projects are in development behind the B6 boundary. Moreover, their development, from a capacity and technology perspective, is in line with the CP2030 plan.

It is worth investigating briefly why this may be happening. Firstly, because it is not an irrational action from developers to do so. Under current market arrangements, an offshore wind project may rationally choose to site behind a constraint boundary for a few reasons: the wind speed may be the most consistent, or planning permissions may be easier than in more densely populates areas below the border.

Wind farms in **highly constrained areas are used less**, which leads to slower wear and tear on the equipment.

On the latter condition for example, the Crown Estate Scotland runs leasing rounds offshore that are specifically located behind the B6 boundary, and it is up to tools such as the Strategic Spatial Energy Plan (SSEP) to tackle this separately. The CfD strike price[9], that projects will submit into a competitive auction (through an 'Allocation Round') and achieve, is not reflective of a locational price and does not contain a locational signal – which additionally means that projects are to an extent sheltered from the consequences of locating in the wrong place from a constraint perspective.

Additionally, if a project becomes constrained, it will receive constraint payments as the lowest cost technology of available electricity generation technologies on the grid. A developer can be certain that the project is bankable regardless of the ability for a wind power project to actually run, regardless of where it is located. This is the context behind the three of the recommendations in this paper.

04

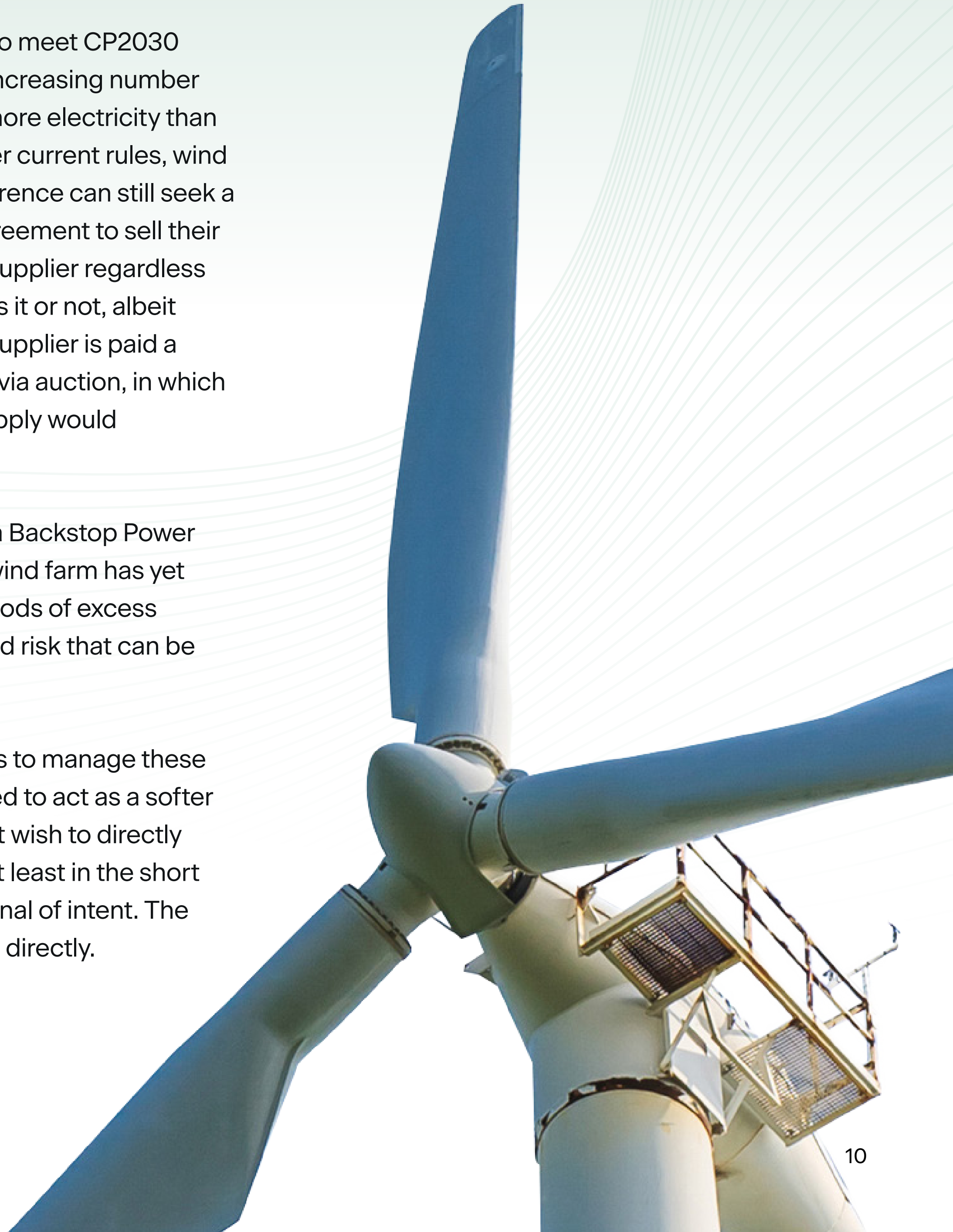
Managing Overproduction

The second challenge is not yet fully visible, but is on its way.

As the wind farms necessary to meet CP2030 come online, there will be an increasing number of hours when they produce more electricity than the system can absorb.[10] Under current rules, wind farms with a Contract for Difference can still seek a Backstop Power Purchase Agreement to sell their entire output to a nominated supplier regardless of whether the system requires it or not, albeit at a £25/MWh discount. The supplier is paid a management fee determined via auction, in which the costs of managing oversupply would be captured.

No wind farm has yet to seek a Backstop Power Purchase Agreement; no UK wind farm has yet been subject to extended periods of excess supply. This is a straightforward risk that can be managed now.

Below we set out three options to manage these challenges. The first is intended to act as a softer option if Government does not wish to directly impact the finances of wind, at least in the short run, while sending a strong signal of intent. The latter two options tackle costs directly.



Option 1 Softly, softly, get wind farms to figure it out

Wind generation represents a significant share of constraint costs, particularly in Scotland and offshore projects. This could worsen under CP2030 as more wind projects come online. There is therefore a political and reputational onus on windfarms to take responsibility for this, and for the regulator to create an environment where trading decisions that materially benefit from extracting rents from the balancing mechanism through constraints is actively discouraged through greater transparency of individual project behaviour.

For example, in order to participate in the CfD process wind farm developers are obliged to develop a supply chain plan that sets out how they will endeavour to source components and labour from UK sources. This is a soft measure to encourage them to consider UK supply chains as part of their commercial arrangements and it is non-binding.

Similarly, we recommend that Ofgem introduce an obligation on licensed wind farm operators to take active steps in reducing their constraint costs.

This obligation could be structured in two phases, taking inspiration from supply chain plans for the first:

Phase 1

Disclosure Regime

Operators would be required to publish annual reports detailing their constraint costs, measures taken to reduce them, and future plans. These reports would be standardised and made public, enabling benchmarking across the sector.

Phase 2

Compliance Requirement

After an initial disclosure period, Ofgem could introduce minimum standards for constraint cost management, obligating operators to demonstrate proactive action such as flexible operation, co-located storage, or contractual coordination with the ESO.

A disclosure regime would highlight best practices and create incentives based on reputation and critically provide Ofgem and the LCCC with data on generator behaviour that could be considered as part of future CfD terms. This would encourage renewables operators to invest in storage, flexible grid connections and coordinate with NESO to actively coordinate grid management.

Option 2 Make wind farms pay constraint costs

Constraint costs are currently socialised across the system through the Balancing Services Use of System (BSUoS) charge.

There is an upcoming change that will see 100% of BSUoS charges recovered from demand from suppliers, which will exclusively hit consumers energy bills, reflecting the historical view that consumers are the primary beneficiaries of balancing services. However, this structure no longer aligns with how constraints arise. In practice, they are driven by trading behaviour and locational imbalances, not by frequency risk alone. When wind farms in Scotland sell power to customers in England, they do so on the assumption that the system can physically deliver that trade — an assumption that is increasingly invalid as transmission boundaries such as the B6 constraint become saturated.

BSUoS recovers NESO's costs for maintaining real-time balance, including operation of the balancing mechanism and procurement of ancillary services. These costs fluctuate with deployment rates, wholesale prices, and particularly transmission outages — signalling system pressure from both increased renewable output and the limited pace and capacity of aggregated grid upgrades. Without reform to influence generator behaviour, constraint costs will continue to rise and will remain unfairly distributed.

The Balancing Services Task Force (2019) considered reallocating constraint costs under the "polluter pays" principle but rejected the idea on three grounds: complexity in attributing responsibility, the absence of a marginal pricing component within BSUoS, and the expectation that zonal pricing would ultimately solve the problem. With zonal pricing now off the table, the first two arguments warrant renewed examination.

Since 2019, NESO's Local Constraint Market covering the B4 and B6 boundaries has provided new data on constraint management. By accepting bids from flexibility providers in day-ahead and intraday markets, NESO now creates a marginal price for managing constraints before they occur. Although still limited in scope, this capability allows for the development of a forward-looking cost signal that could be allocated to generators whose trading decisions exacerbate congestion.

A reformed BSUoS could therefore specify, a day ahead, the expected cost of managing a constraint on a given boundary and charge generators behind it accordingly. Those operators could then alter trading strategies — for instance by diverting output to co-located storage or local buyers — to avoid incurring the charge.

This approach would operationalise a genuine ‘polluter pays’ principle: aligning financial responsibility with system impact, creating incentives for generators to respond to locational signals, and reducing the overall burden on consumers. While implementation would require safeguards against gaming and false demand, the tools now exist to reopen a serious discussion on BSUoS allocation and modernise a charging framework that has not kept pace with the energy system it serves.

Incentives to shape generator behaviour through this form of real-locational signal is critical. Taking a step back, we must consider what behaviour this measure should encourage. Currently, there is no incentive to not locate a generator behind a constraint barrier, as it can recover its costs regardless. The Strategic Spatial Energy Plan should improve outcomes here, however there has to be a real financial incentive to not contribute to constraints. This proposal shifts the cost of constraints, normally borne by consumers to the tune of around £20 per household energy bill per annum, back to the generators causing the cost. The behaviours that this should drive are either different locational decisions, selling power to demand that’s also behind the constraint or investing in matching storage.

Option 3 Reforming the off-taker of last resort

The Offtaker of Last Resort (OLR) is a risk reduction mechanism that was designed to de-risk early rounds of the Contracts for Difference (CfD) regime, providing investors with assurance that they could always sell their output even if suppliers refused to contract with intermittent generation.

This backstop made sense in a market characterised by scarcity, limited renewable penetration, and untested merchant appetite. However, those conditions no longer apply. It has never been utilised throughout the history of the scheme, because generators with a CfD can always beat the market price in order to sell their power. Taking it up would mean accepting at least 50% of a wind farm's output would be sold at a discount of £25/MWh.[11]

However, this pricing power is eliminated when the market is oversupplied. Faced with CfDs at a strike price well in excess of £50/MWh and marginal costs well below this number, generators may decide that a £25/MWh haircut is an acceptable price to pay if the difference is no revenue at all.

This presents a critical reputational risk to the sector; wind generation would earn not simply to generate, but to generate when there is no need for its electricity. It is not clear that this mechanism is still required, but in any case we would recommend significantly increasing the 'haircut' to at least £50/MWh[12] to ensure that it is only used by generators who genuinely cannot find a buyer for their power.

As the system moves toward surplus generation, particularly during high-wind, low-demand periods, the OLR now risks encouraging behaviour that runs counter to system efficiency. Under current rules, generators may choose to exercise the OLR rather than curtail, accepting a manageable discount in exchange for guaranteed offtake. This effectively rewards production in times of negative system value — a reputational and fiscal risk that will grow as CP2030 deployment accelerates.

To address this, government and the LCCC should recalibrate the OLR in three ways:

01

Reprice the guarantee
significantly increase the current £25/MWh haircut to at least £50/MWh to ensure that utilisation only occurs as a last resort.

02

Introduce volume caps
limit the proportion of generation that can be sold under the OLR within a given settlement period, reducing system exposure during prolonged oversupply.

03

Link eligibility to behaviour
restrict access to generators that can demonstrate participation in flexibility measures, such as co-located storage, active curtailment scheduling, or local balancing markets.

Over the medium term, the OLR could be repurposed as a strategic market stability mechanism, triggered only under exceptional conditions (e.g., systemic supplier failure or black swan curtailment events), rather than a standing commercial backstop. This reform would align investor protection with system value, maintaining confidence in the CfD framework while restoring price discipline and consumer trust.

05

Conclusion

Constraint costs have become one of the most material and politically salient challenges within the GB electricity market.

Delivering CP2030 is a defining test of how serious the UK is about delivering Net Zero affordably. With over £1 billion now spent annually on managing transmission constraints and an expectation that this could worsen in the future, a line must be drawn. The current framework fails to incentivise generators to reduce their impact or reward behaviours that ease system pressure. As deployment under CP2030 accelerates, these inefficiencies risk entrenching costs that are ultimately borne by consumers, and damaging confidence in the energy transition's affordability and fairness.

Our recommendations set out a practical route to addressing these risks. A disclosure and compliance regime for wind operators would bring transparency and accountability to constraint management, creating reputational and commercial incentives for improvement. Revisiting the allocation of BSUoS costs on a 'polluter pays' basis would ensure that those whose trading decisions drive constraint costs bear an appropriate share of the burden, aligning market behaviour with system efficiency. Finally, reforming the Offtaker of Last Resort to reduce its attractiveness as a backstop would discourage perverse incentives to generate in periods of oversupply. Together, these measures would shift the market from one that passively accommodates inefficiency to one that actively rewards operational responsibility.

Delivering Net Zero at least cost will require a shift in emphasis—from building more generation to using what we have more intelligently. The actions proposed here provide a route to achieve this without undermining investor confidence or deployment momentum. By clarifying responsibilities, strengthening locational and behavioural signals, and modernising outdated guarantees, government and regulators can make the next phase of CP2030 a test of market design success rather than consumer tolerance.

06 Reference

1. CP2030 refers to the UK government's Clean Power 2030 initiative, a plan to transition Great Britain's electricity system to a net zero carbon system by 2030. The plan aims to create a secure, affordable, and clean energy supply by increasing clean sources to generate at least as much power as the nation consumes, ensuring they account for at least 95% of total generation by 2030. More information available: https://www.gov.uk/government/publications/clean-power-2030-action-plan

2. Allocation Round 7 (AR7) is the seventh auction for the UK government's Contracts for Difference (CfD) scheme, which aims to secure clean energy for the country. Launched in August 2025, AR7 is designed to support renewable energy projects, including both offshore wind (AR7) and other technologies (AR7a), through competitive bidding. More information available: https://www.gov.uk/government/publications/contracts-for-difference-cfd-allocation-round-7-allocation-framework

3. Review of Electricity Market Arrangements

4. 2025 Annual Balancing Costs Report

5. Transmission Network Unavailability – the Quiet Driving Force Behind Rising Curtailment Costs in Great Britain | UKERC | The UK Energy Research Centre

6. Demand for Constraints report,

7. Electricity Transmission Design Principles (ETDP) are strategic and technical guidelines that aim to standardize and accelerate the design and construction of electricity transmission infrastructure by providing clarity on asset choices, routing, and environmental mitigation.

8. elexon.co.uk/bsc/documents/data/operational-data/gb-transmission-system-boundary-zone-map/

9. The CfD strike price is the fixed price per megawatt-hour (MWh) that a low-carbon electricity generator is guaranteed to be paid for their power output over the life of a CfD contract. When the wholesale market electricity price is lower than the strike price, generators are topped up to the level of the strike price through consumer funded levies. When the wholesale market electricity price is higher, the generator pays the difference back.

10. Zonal Pricing, Volume Risk and the 2030 Clean Power Target | UKERC | The UK Energy Research Centre

11. In £2012. In £2025, approximately £36/MWh.

12. £72 in £2025.