Fixing the Price:

How a Single Buyer Model Could Slash UK Electricity Prices and Build Consent for the Clean Power Mission

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June 2026

Contents

Key Points

- Britain's electricity market was designed for a fossil fuel age, but is now a barrier to a lower cost, low carbon future. Gas plants account for barely a quarter of generation but still set the national marginal price nearly 80 per cent of the time. This magnifies the impact that fossil fuel price shocks have on bills.
- The Government should instruct the National Energy System Operator (NESO) to act as a single buyer of power, moving legacy low carbon assets out of the wholesale electricity market and onto Power Purchase Agreements at prices reflecting their original business case. Gas plants should be moved into a strategic reserve subject to central dispatch at cost by NESO, lest they widen their margins as they generate less but become more indispensable to the Balancing Mechanism.
- In time, NESO should govern the whole national system through central dispatch, avoiding the growing thermal constraint costs that, in the current system, result from the self-dispatch of generators selling into national markets without regard to network constraints. Currently NESO lacks control over dispatch outside of a narrow half-hour Balancing Mechanism window.
- Given severe underinvestment in network capacity, power decarbonisation risks hitting bills hard unless storage and demand side flexibility (DSF) are rolled out cheaply and at scale. The single buyer should act as bulk procurer of DSF, overcoming the recognised coordination problems that threaten serious under-delivery relative to NESO's optimistic forecasts.
- Further savings could be realised on levelised cost of storage (LCOS) by reducing the risk premium attached to the financing of lithium-ion batteries and long duration energy storage (LDES) under merchant or cap-and-floor regimes.
- Our preliminary rough estimates suggest that, depending on the path of scenarios around wholesale prices and the delivery of flexibility under current policies, aggregate savings from this programme could amount to £10—16 billion annually in 2030, or a £125–200 reduction to household bills. This would close the gap on the Government's pledge to cut bills by £300 a year.

Executive Summary

Key issues and problem statement

UK electricity prices remain among the highest in the world, despite the growing penetration of low marginal cost renewables. The wholesale market — designed for the fossil fuel era — allows gas to set the electricity price 75–90 per cent of the time while contributing barely one quarter of power volume, generating massive windfall profits for legacy generators during price spikes. These high prices are becoming politically toxic for Labour's Clean Power 2030 plans and are a key source of hardship for households and businesses. The 2026 Strait of Hormuz crisis has further elevated prices and risks, making urgent reform unavoidable.

Savings scenarios

To capture the interaction between the 2026 Hormuz geopolitical price shock and the depth of reform, we model three scenarios. All scenarios assume the CP2030 decarbonisation target is achieved by 2030.

1. Low scenario: moderate price spike, rapid normalisation

The Hormuz crisis resolves quickly. Wholesale electricity averages ~£100/MWh in 2026, returning to pre-crisis trajectories (~£75/MWh by 2030). The Further Flex and Renewables (FFR) pathway is achieved.

Total cumulative savings 2026–2030: £40.6bn.

2. Central scenario: sustained disruption, gradual recovery

A more sustained disruption keeps prices at ~£120/MWh across 2026, easing to ~£90/MWh by 2030. The FFR pathway is delivered, with the Single Buyer crucial in avoiding moderate flexibility under-delivery.

Total cumulative savings 2026–2030: £56.1bn.

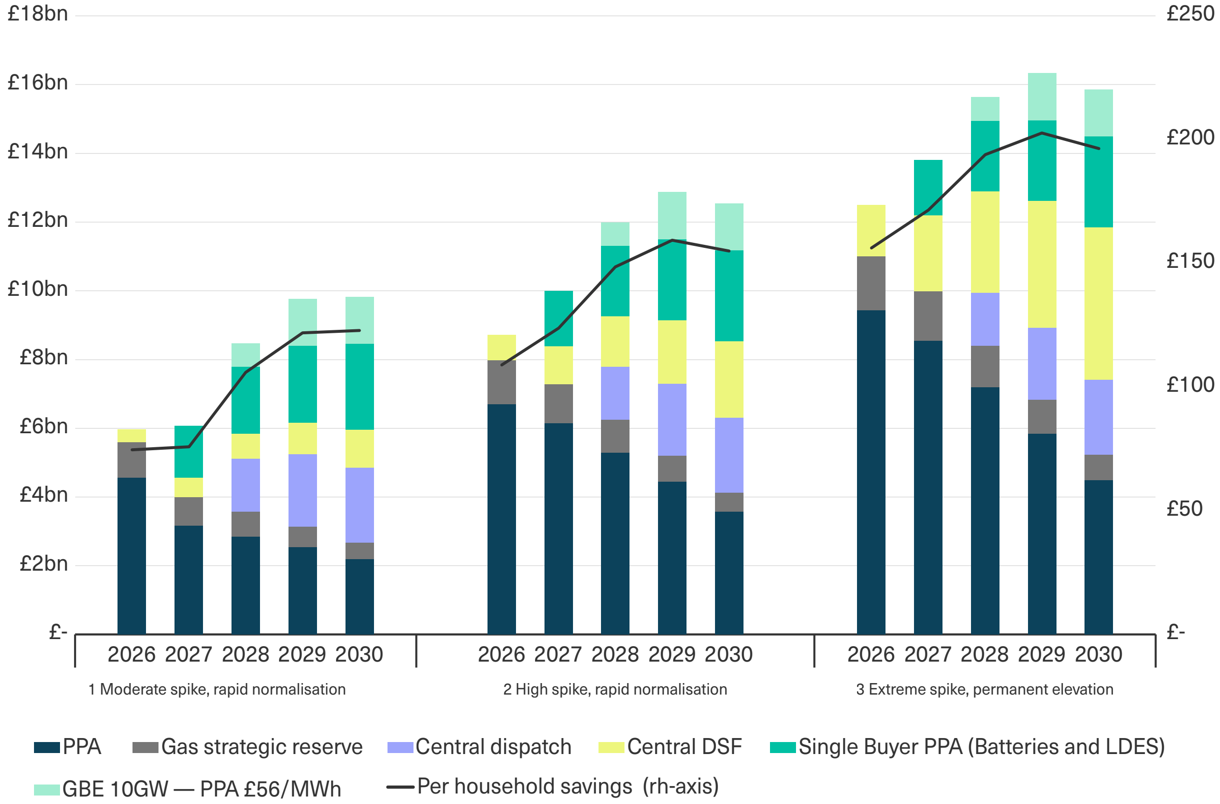
3. High scenario: extreme disruption, permanent damage

Prices average £148/MWh across 2026, with lasting structural damage from the Ras Laffan LNG outage keeping prices persistently elevated (~£100/MWh by 2030). Without the Single Buyer, sustained crisis conditions force the system onto the higher-cost New Dispatch (ND) pathway.

Total cumulative savings 2026–2030: £74bn.

Figure 1: Wholesale Price Savings Are Front-Loaded, While Additional Savings From Direct Dispatch Procurement Emerge Later

System and household savings under low, central and high scenarios



Source: Author’s calculations.

Notes: Totals are likely over-estimates due to overlap between cost saving categories, e.g. between improved DSF delivery and central dispatch.

Household savings

Domestic users account for approximately 35 per cent of electricity consumption across 28 million GB households. Annual per-household benefits in 2030 range from £125 (low) to £198 (high), with cumulative per-household savings over 2026–2030 of £507 (low), £701 (central) and £927 (high). The central and high scenarios significantly narrow the gap to Labour’s £300/year pledge.

Conclusion

The Single Buyer is not a radical departure — it revives proven principles of coordination and public accountability, updated for the renewables age. With the Hormuz crisis demonstrating once again the cost of fossil fuel dependence, this reform offers a once-in-a-generation opportunity to cut bills, end gas price exposure and rebuild public consent for the clean power mission.

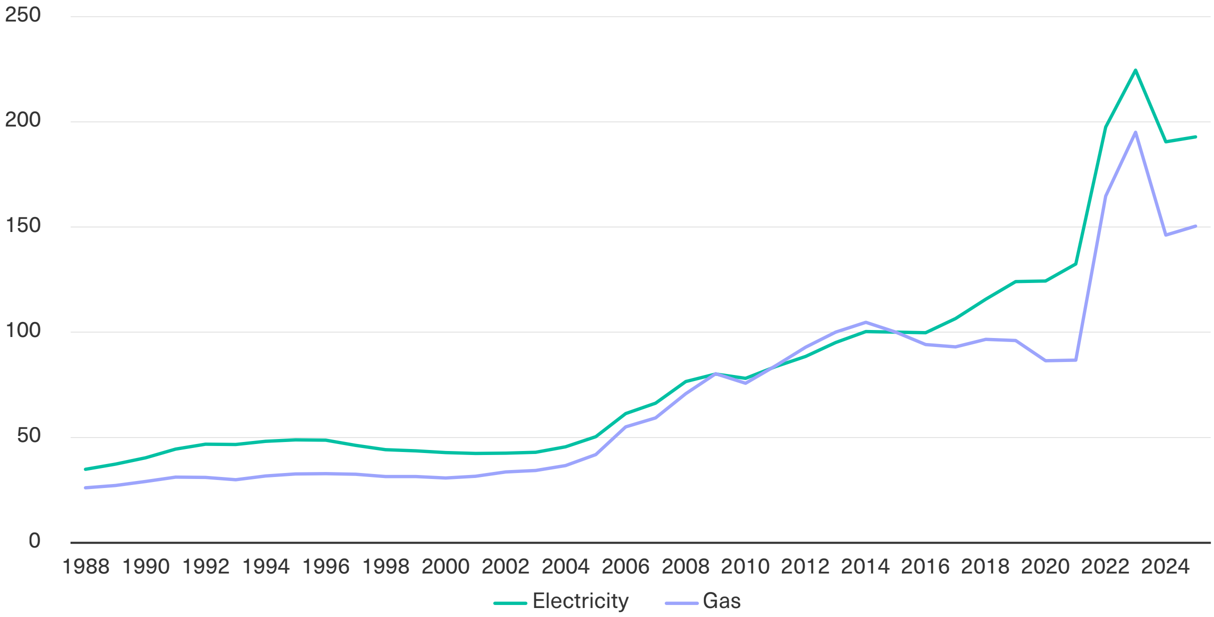
Introduction

Context: The price is wrong

Since 2010 UK's household gas and electricity prices have doubled, and they were briefly 300 per cent higher than 2010 during the 2022 energy crisis (Figure 2).[1] Over the same period, the share of renewable electricity has risen from 6.9 per cent to almost 50 per cent in 2024. The evidence shows that inflated electricity bills partly result from high wholesale natural gas prices, where gas sets the electricity price around three quarters of the time, despite representing only one quarter of power volume.[2] However, under the current policy and wholesale market framework, the Government's Clean Power 2030 (CP2030) Action Plan to fully decarbonise the grid is unlikely to reduce household bills in the near term, with the current market design blunting the effect of the growing share of low-cost renewable electricity.[3]

Figure 2: UK Energy Inflation Has Been Acute Since 2022 but Chronic Since the 2000s

`UK gas and electricity prices since 1988. 2015=100 reference year`



Source: ONS.

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[1] "Consumer price inflation, UK: January 2026", Office for National Statistics, 2026.

[2] Behnam Zakeri, Iain Staffell, Paul Dodds, Michael Grubb, Paul Ekins, Jaakko Jääskeläinen, Samuel Cross, Kristo Helin and Giorgio Castagneto-Gissey, "Energy Transitions in Europe — The role of natural gas in setting electricity prices in Europe", *Energy Reports*, vol. 10, November 2023, pp. 2778–2792.

[3] "Clean Power 2030", National Energy System Operator, 2024. Available here.

High prices present an existential threat to the political legitimacy of Labour's CP2030 target and by extension the wider net zero agenda. The Reform Party, positioning itself as the vanguard of a growing anti-net zero movement, is weaponising claims that decarbonisation will worsen the cost of living crisis as a pretext to dismantle the UK's clean energy transition.

Irrespective of these political considerations, high energy prices are a key source of immiseration in contemporary Britian — driving record levels of fuel poverty, suppressing consumer spending, driving up an unprecedented energy debt and precipitating industrial collapse. In this paper, we argue that the UK government must tackle this issue head on, radically overhauling the UK's electricity market to directly lower bills in the near term.

The need for reform

This paper proposes fundamental reforms to the design and operation of Great Britian's (GB) wholesale electricity markets. The impetus for reform is driven by two distinct but interlinked aims. The first is the near-term reduction of electricity prices — especially for households. The second is to determine the institutional structure most suitable for the future electricity system — dominated by low marginal cost variable renewable generation and the electrification of heat and transport. Consequently, the primary policy aim should be delivering the best outcomes for the British people and the environment, not rigid adherence to outdated notions of unfettered markets and a model designed for another era.

Adopting this vantage point reveals that things can be different. Firstly, the current fully privatised and liberalised electricity system is just one possible design among numerous alternatives. Many other advanced successful nations have alternative system configurations, usually with a greater share of public ownership or control. Second, the current system configuration was designed for large thermal fossil power stations assumed to compete on price and efficiency in highly liquid wholesale markets. This model is ill-suited to an electricity system where fossil power stations play a progressively smaller role.

The scale of the challenges posed by climate change and the hardships of the current cost of living crisis have recently justified extensive interventions in the energy market, including renewable subsidies, price caps and tens of billions of pounds in handouts to energy suppliers[4] — yet the basic system architecture

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[4] "An international comparison of the cost of energy support packages", Office for Budget Responsibility, 2023. Available here.

has remained largely unchanged since it was liberalised and privatised over thirty-seven years ago. We argue that the needs of the future system present a compelling case for a fundamental rethink of the system; one at the scale of previous periods of institutional transformation in the 1920s, 1940s and 1980s.

However, our proposals remain pragmatic. The UK has significantly progressed the decarbonisation of its electricity system over the past two decades, notably through the buildout of increasingly low-cost renewables. In our view, it is important not to jeopardise the current momentum and remain consistent in supporting the CP2030 goals. Second, this pragmatism must also recognise that the cost of living crisis means the Net zero goal is now at serious political risk.

It is within this context that we propose a direct intervention to replace the current wholesale market with a publicly owned Single Buyer of power, who would subsequently become the off taker for ever greater shares of publicly owned renewable and low carbon generation. This intervention could initially operate alongside the existing Contracts for Difference (CfD) mechanism and retail markets, although over time it could progressively replace them with a lower cost, publicly owned system. We argue that replacing the wholesale market with a Single Buyer could be implemented at relatively low fiscal cost. This approach would not require the wholesale “nationalisation” of parts of the electricity system, though as we outline, these changes could pave the way for greater public and community ownership.

The Electricity System and its Discontents

Recent history

The British electricity market largely descends from the era of privatisation inscribed in the Electricity Act 1989, which broke up the nationalised Central Electricity Generating Board (CEGB), unbundling transmission from generation. Non-nuclear generation was broken up into two new companies, Powergen and National Power. A separate nuclear company eventually followed. The merit order at the centre of the wholesale electricity market predates privatisation and was the basis of the CEGB's computerised central dispatch system, Generator Ordering and Loading Program (GOAL). Privatisation and liberalisation then built a market around it — the "Pool" — with day-ahead sealed bids replacing the direct estimates of each plant's short-run marginal cost, and using "pay as clear".[5]

Wholesale liberalisation also stimulated investment in new generation that could make profit by out-competing older costlier plants. The "dash for gas" in the 1990s saw a major buildout of combined-cycle gas turbines (CCGT). These were cheaper and quicker to build than the old coal power stations — which were also typically located near coal fields — and their low capital intensity and short payback periods were well suited to the preferences of relatively impatient private capital.

This market has undergone several iterations since privatisation — including the 2001 New Electricity Trading Arrangements (NETA)'s introduction of bilateral trading, which required balancing by the National Grid — culminating in its present form as the British Electricity Trading Transmission Arrangements (BETTA), established in 2005. BETTA created a single GB electricity. The wholesale electricity market today consists of spot trading and a spectrum of forward contracts, including over the counter (OTC) bilateral hedges and longer-term power purchase agreements (PPAs).[6] On top of wholesale costs, system balancing, network and policy costs all contribute towards the electricity bill.

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[5] As of 2024 >85% of electricity by volume has its price set by the wholesale market, either via long term trading or in the spot market. Source: Ofgem.

[6] Nicholas Harrington, "Addressing the high price of electricity in the UK: A systems-thinking analysis of inflated price formation", UK Collaborative Centre for Housing Evidence & School of Social and Political Sciences, University of Glasgow. Available here.

This power system design — characterised by unbundling, private ownership and a wholesale spot market — emerged within the specific political, economic and engineering conditions of the late 1980s. As we outline in Table 1, none of the conditions under which this market design emerged remain true today. The present moment's political and environmental objectives, the cost fundamentals of renewable and low carbon generation and flexibility, the UK's energy security challenges and ailing power transmission and distribution network all present a strong case for an alternative system design responsive to today's needs.

Table 1: Political, economic and engineering fundamentals of GB electricity system in the late 1980s vs the late 2020s

	Late 1980s	Late 2020s
Political and environmental objectives	Limited requirements to reduce carbon emissions; focus was largely on flue gas desulphurisation (acid rain). Limited political pressure to reduce energy bills.	Requirements to reduce carbon emissions by 95 per cent by 2030. Significant political pressure to reduce energy bills.
Cost fundamentals of new generation	Low capital cost, high operating cost generation assets — i.e. CCGTs.	High capital cost, low/zero operating cost generating assets — i.e., wind and solar.
System balancing fundamentals	Flexible centralised fossil fuel generation which can respond to price signals, with limited potential for demand side flexibility.	Decentralised and inflexible generation assets less able to respond to price signals Large, untapped potential for decentralised demand side flexibility (DSF).
Energy security fundamentals	Abundant, secure and cheap natural gas and coal reserves. Limited, unproven and uneconomic renewable energy resources.	Dwindling, insecure and expensive natural gas supplies; unusable coal reserves. Abundant and economically proven renewable energy resources.
Network fundamentals	Inheritance of a mature and highly centralised electricity transmission and distribution system.	Inheritance of an ageing centralised electricity transmission and distribution system requiring significant investment and a shift towards decentralised generation.

The power system structure and the decarbonisation agenda

> Clean Power 2030 ... can be delivered without increasing costs for consumers, without compromising security of supply and while bringing local economic and job opportunities.[7]

Since the turn of the millennium, the UK's decarbonisation agenda has been the major driver of public policy and investment in the electricity system. While the 1990s dash for gas reduced the carbon intensity of the grid — largely by accident — increasing layers of environmental regulation and subsidies have been added to the supposedly free market for electricity.

Starting with the Non-Fossil Fuel Obligation (NFFO), the subsequent Renewables Obligation (RO) required energy suppliers to purchase market-based certificates for renewable generation. These subsidies offered generators a top-up to the wholesale market price. However, these variable subsidies were deemed to provide insufficient revenue stability for private investors. In the 2010s, the RO was replaced by the Contracts for Difference (CfD) whereby reverse auctions would set fixed "strike prices" for fifteen years. A simpler price fixing mechanism, Feed-in Tariffs (FiT), incentivised smaller scale renewables throughout 2010s until closing in 2019. New nuclear power stations have also since struck similar fixed price contracts.

Growing renewable penetration undermined the revenue security of flexible firm power sources whose continued operation was needed to "keep the lights on". Hence a Capacity Market (CM) reverse auction subsidy was introduced. Coal power was ineligible for the CM and, aided by various regulations, has gradually phased out with the UK's last plant closing in 2024.[8]

The 2024 Labour Government has set itself the challenge of delivering the near complete decarbonisation (>95 per cent) of the UK's power grid under its CP2030 mission. The aim is to deliver a vast increase in low-carbon (largely renewable) generation capacity and complementary flexible capacity for balancing purposes, requiring an estimated £40bn in investment each year until 2030 — nearly quadruple

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[7] "Clean Power 2030 Action Plan: A new era of clean electricity", National Energy System Operator, 2024. Available here.

[8] This was aided by regulations such as the EU Large Combustion Plant Directive, the UK Emissions Performance Standard, and carbon pricing schemes like EU Emissions Trading System and UK Carbon Floor Price.

the last five years' average.[9] Moreover, the electrification of heat and transport required by the 2050 net zero target will require the doubling of electricity generation by volume and a 250 per cent increase in total electricity capacity compared to today. This means the 2050 system could need ~250–300 GW of capacity, depending on demand scenarios and flexibility measures.

Future price scenarios and the Strait of Hormuz crisis

The US and Israel's illegal war on Iran from spring 2026 triggered an immediate and painful rise in the price of oil and gas. While the UK only imports a small fraction of its gas from the Gulf, recently UK natural gas futures surged 70 per cent to a three-year high. These tectonic shifts are reminiscent of the convulsions in global energy markets following Russia's invasion of Ukraine, where gas prices eventually rose to five times their previous levels. The risk this transforms into a sustained energy crisis that worsens the cost of living is high and demands urgent and innovative action in response. At the time of writing, the medium and long-term impact of this situation remains unclear.

To capture the potential long-run impact of the 2026 Strait of Hormuz crisis on UK wholesale electricity prices, we model three scenarios to support our baseline projections. In all three, 2026 prices are elevated above pre-crisis levels, reflecting the disruption to global oil and LNG markets following the closure of the Strait in late February 2026 — an event the IEA characterised as the largest supply disruption in the history of the global oil market.[10] The scenarios in Figure 3 differ in the severity of the initial price shock and the speed and extent of subsequent recovery, with 2030 wholesale prices ranging from £75/MWh in the low scenario to £100/MWh in the high.

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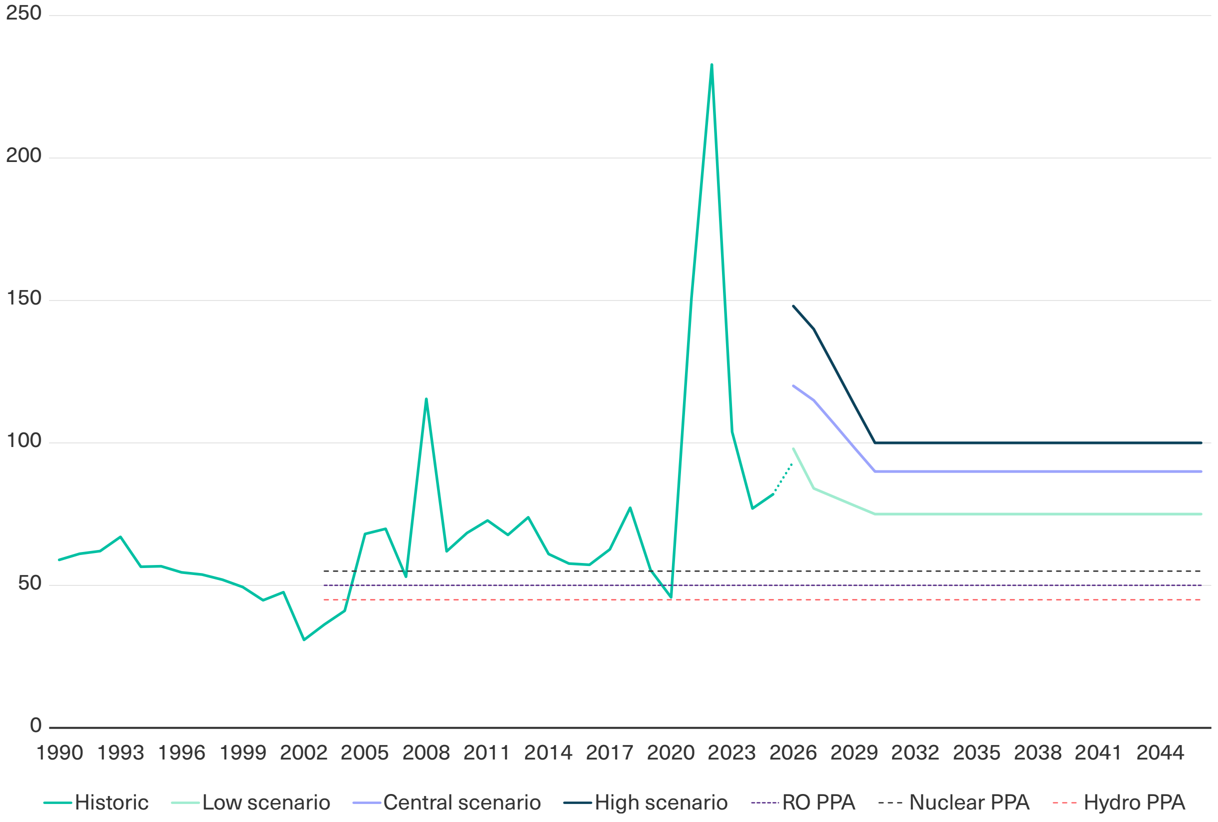
[9] 43–50 GW of offshore wind, 27–29 GW of onshore wind and 45–47 GW of solar is intended to be complemented by flexible capacity, including 23–27 GW of batteries, 4–6 GW of long-duration energy storage and flexibility technologies including carbon capture and storage (CCS), hydrogen and consumer-led flexibility. "Clean Power 2030 Action Plan: A new era of clean electricity — Main report", Department for Energy Security and Net Zero, 13 December 2024. Available here.

[10] "The Middle East and global energy markets", International Energy Agency, 2026. Available here.

Figure 3: Wholesale Electricity Prices in 2024 and 2025 Remained Far Higher Than in the 2010s

Wholesale electricity prices 1990-2026, £/MWh, 2026 prices



Source: Common Wealth based on Elexon, Institution of Civil Engineers, House of Commons, Ofgem, Cornwall Insights, NESO, OBR, ONS.

Notes: CPI-adjusted to 2026 prices. Volume-weighted averages after 2003. Observed 2026 price is year-to-date.

Low scenario

In the low scenario, wholesale electricity prices average £100/MWh across 2026, reflecting partial disruption to global LNG flows during a period of relatively mild weather and strong renewable output. The Q1 2026 price of around £98/MWh, and a ceasefire combined with warmer spring conditions pulled TTF back toward €45/MWh by April, mean the annual average rises only modestly above that level. A gradual reopening of the Strait allows markets to normalise quickly, and by 2027 prices return to the pre-crisis Cornwall Insight trajectory at £84/MWh, declining to £75/MWh by 2030 as new renewable capacity continues to erode the role of gas in setting the marginal price.[11] This scenario assumes no lasting structural damage to Gulf energy infrastructure and a relatively swift restoration of supply chains.

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[11] “Power market outlook Q1 2026”, Cornwall Insight, 2026.

Central scenario

In the central scenario, a more sustained restriction of Hormuz shipping through the second and third quarters of 2026 keeps gas and electricity markets elevated throughout the year, producing an annual average of £120/MWh. Although a negotiated resolution allows flows to partially recover, the incomplete refilling of European gas storage — which entered the summer at only around 30 per cent capacity — maintains upward pressure on prices through the autumn and winter of 2026. By 2027, a combination of recovering LNG supply and continued renewable build-out allows prices to converge toward the NESO Further Flex and Renewables CP2030 scenario, reaching around £90/MWh by 2030 as the structural gas shortage gradually resolves.[12]

High scenario

In the high scenario, prices average £148/MWh across 2026, reflecting a full crisis year with a high Q4 winter risk premium on critically depleted European storage. The crisis leaves lasting structural damage — including the prolonged outage of the Ras Laffan LNG facility, which Qatar Energy estimates could take up to five years to repair,[13] — that prevents a return to pre-crisis price levels. From 2027, prices follow a path broadly consistent with the OBR's high wholesale price trajectory at around £147/MWh,[14] declining gradually to reach £100/MWh by 2030 and remaining persistently elevated thereafter, consistent with the IEA's warning that the lasting effects of the conflict on energy prices could exceed both the 1970s oil shocks and the post-Ukraine 2022 energy crisis.[15]

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[12] "Clean power 2030: Advice on achieving clean power for Great Britain by 2030", NESO, 2024. Available here.

[13] "Statement on Ras Laffan LNG facilities", QatarEnergy, 2026. Available here.

[14] "Economic and fiscal outlook, March 2023" OBR, 2023. Available here.

[15] Tom McIlroy, "Iran war energy crisis equal to 70s twin oil shocks and fallout from Ukraine war, says IEA chief", *The Guardian*, March 2026. Available here.

Problems with the wholesale market

> For how long can the disappearing fossil fuel tail continue to wag the dog of a renewables-based electricity system?[16]

In the following sections, we outline some of the key challenges presented by the existing electricity market design for this low-carbon future. Under the current wholesale market, we expect ongoing problems of inframarginal rents (windfall profits for low-carbon generators), significant price volatility and associated rent seeking, the risk of an undersupply of demand side flexibility (DSF), and the need for ongoing subsidies due to renewable energies' price cannibalisation effects. To interrogate these issues, we also undertook off-the-record interviews with senior figures from a large energy supplier, an energy transition-oriented think tank and NESO.

To guide our analysis, we adopt the government's CP2030 decarbonisation scenarios. In developing the CP2030 models, NESO adopt two potential futures. The "Further Flex and Renewables" (FFR) pathway focuses on maximising renewable energy and energy storage, relying on increased demand side flexibility from consumers to ensure grid stability, and eliminates the need for new low-carbon dispatchable power plants. In contrast, the "New Dispatch" (ND) pathway prioritises building new dispatchable power plants, such as those using hydrogen or carbon capture and storage (CCS). It also includes a higher level of nuclear power, with a slightly lower emphasis on renewable deployment and storage.

Marginal pricing and inframarginal rents

During the 2022–2023 gas price crisis, exceptionally high gas prices generated substantial windfall profits for non-gas power generators in the UK's electricity wholesale markets.[17]

In "pay as clear" spot markets, the "marginal generator" — the cheapest source needed to fully satisfy demand — sets the wholesale price for all the cheaper sources further down the merit curve. Figure 4 illustrates how this varies from hour to hour according to the hourly profile of demand versus that of both intermittent and

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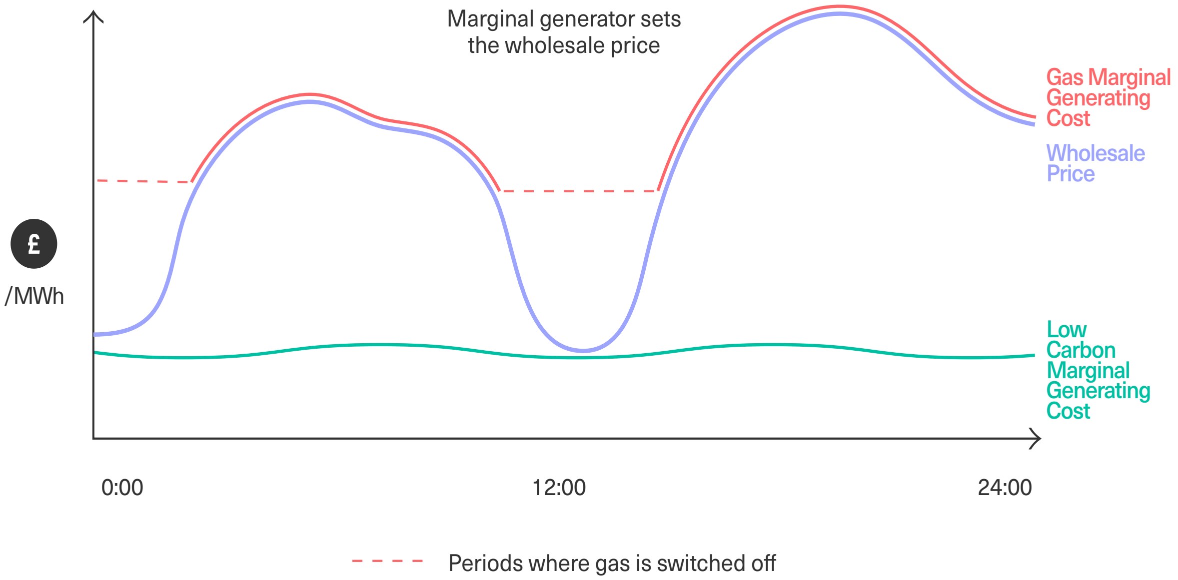
[16] Malcolm Keay and David Robinson, "Electricity market design during the energy transition", Oxford Institute for Energy Studies, 2023. Available here.

[17] For more detail see Donal Brown, Chris Hayes, Mathew Lawrence and Adrienne Buller, "A Wholesale Transformation: Evaluating Proposals for Electricity Market Reform", Common Wealth, 2023. Available here.

dispatchable supply. The delta between this "marginal", market-clearing price and the latter's lower operating costs is known as the "inframarginal rent".[18] Sustained exorbitant gas prices inflated these inframarginal rents to unprecedented levels, amplifying crises for customers, and far exceeding the expectations on which legacy generation assets had premised their original business cases. The excess cost to customers for electricity from these plants — including RO-subsidised renewables and the UK's ageing nuclear fleet — approximated £22bn by one estimate, or roughly £300 per British household,[19] although some of this is likely to have been captured by traders who had previously bought this power on forward contracts and subsequently sold it back into spot markets.[20]

Figure 4: Inframarginal Rents and Marginal Pricing



Source: `Common Wealth visualisation.`

While down from their peak, windfall profits and elevated prices remain. Structurally high gas prices and the ongoing balancing role that gas generators play will extend well beyond 2030. The NESO CP2030 scenarios project that gas will continue setting wholesale prices 47 per cent of the time under the "New Dispatch" scenario and 15 per cent under the "Further Flex and Renewables" scenario by

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[18] Importantly these effects do not occur on a fixed price regime such as the Contracts for Difference (CfD) which replaced the RO. RO assets enjoyed the usual RO top-up subsidy on top of these inframarginal rents.

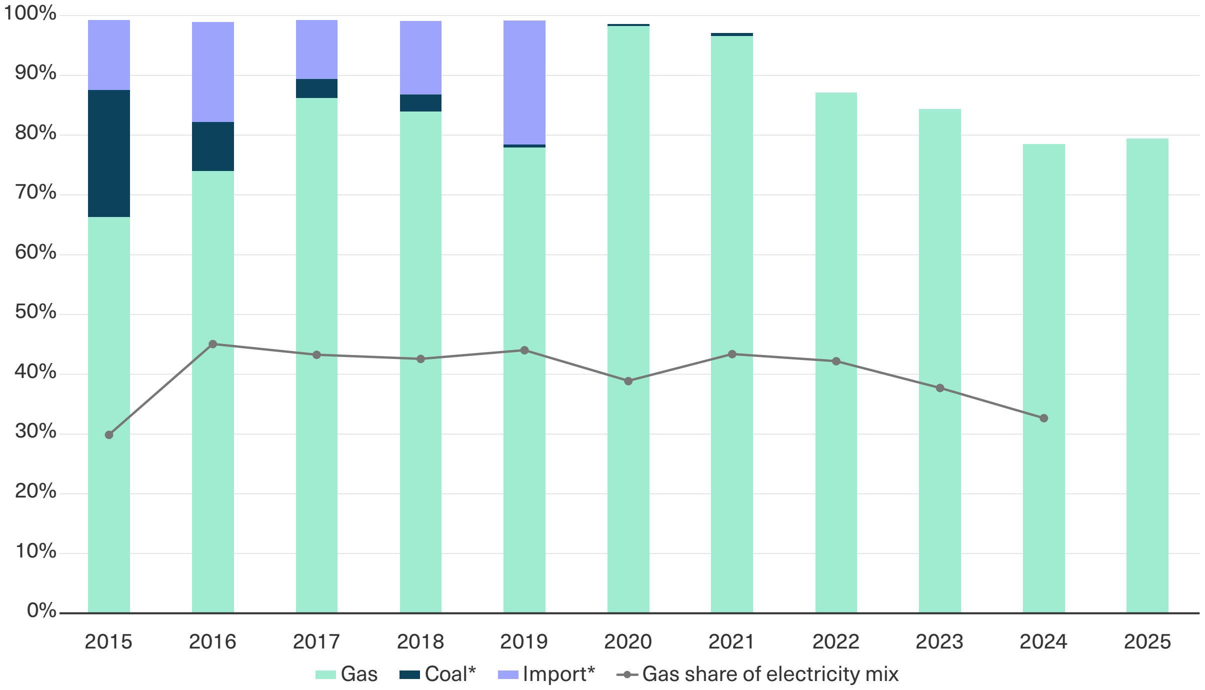
[19] "Pot-Zero: Can renewables and nuclear help keep bills down this winter?", UKERC, 2022. Available here.

[20] "Ensuring the wholesale markets works for consumers: Government steps in to "de-link" power prices to protect Britain from energy price shocks", Regen, 2026. Available here.

2030.[21] Modo Energy estimate that gas still set the price 79 per cent of the time in 2025, down from its peak of 98 per cent in 2020 (see Figure 5).

Figure 5: Renewable Penetration Is Yet to Seriously Dent the Disproportionate Price-Setting Role of Gas

Share of hours in which price is set by technology, 2015-25



Source: Common Wealth based on Zakeri et al 2023, Modo Energy, Bloomberg, DESNZ.

Notes: *Coal and import data only available for 2015-21.

The current wholesale market design, combined with the legacy subsidy regime, threatens to bake in windfall profits for as long as gas remains costly and over-represented in market clearing. While the RO closed to new applications in 2017, existing contracts operate for 20-year terms. UK Energy Research Centre (UKERC) researchers have modelled that transitioning these legacy assets to fixed-price CfD style contracts could deliver consumer savings of £2-8bn annually through 2030 — roughly a cumulative £60bn by 2045.[22]

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[21] “Clean Power 2030: Advice on achieving clean power for Great Britain by 2030”, National Energy System Operator, November 2024. Available here.

[22] Assuming all ROC projects were shifted to a CfD style fixed strike price of £50/MWh and that wholesale electricity prices remain structurally high. Carbon prices are based on the NESO CP30 scenario, which rises to £147/tCO2 by 2030, and then we assume these stay flat thereafter. Gas prices are based on the NESO CP2030 base case and are assumed to stay flat at 100p/therm over the modelling horizon. Price cannibalisation of average market prices is assumed to remain unchanged from 2025 levels. “Pot-Zero Update Working Paper”, UKERC, 2025. Available here.

In theory, inframarginal rents are ordinarily what incentivises investment in new capacity, pushing the costlier sources out of the market, competing those profits away in the long run.[23] However, apart from new battery storage, most of the new capacity is being developed under a fixed-price regime via the CfD. This fundamentally undermines the view that elevated wholesale prices serve as effective or necessary incentives for future capacity investment. Wholesale prices will remain high, even while gas plays an increasingly marginal role.

Volatility and balancing rents

> “The National Energy System Operator (NESO) estimates that 35GW of gas capacity will be needed in 2030, which it expects to operate only five per cent of the time. It would need ‘lottery-style prices’ for the brief moments it is needed to pay for having this capacity in readiness all the time and to pay for short-term gas supplies on call.[24]

A side effect of intermittent renewable penetration is price volatility. Flexible assets needed for balancing increasingly play a supporting role, comprising fewer operating hours, but higher price premiums when these are deemed essential for system stability. Since 2010, price volatility has nearly doubled, creating “fat-tailed events” — periods of extreme price spikes that enable rent extraction by backup plants.[25] In one such instance, two CCGTs charged £5,750/MWh and £2,900/MWh on a single day in January 2025, despite natural gas prices in European markets of just €45 per MWh.

This exploitation of market power — where gas generators are needed to balance the system — can be expected to increase in frequency and severity as the system becomes dominated by wind and solar. UCL research estimates that private profits from UK gas power plants, through both the wholesale market and balancing

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[23] For a defence of this principle, see Lion Hirth, “Marginal Pricing in Electricity Markets”, Neon, 2022. Available here.

[24] Dieter Helm, “The Price of Energy and the System Costs of Renewables”, 2025. Available here.

[25] Gordon Hughes, “Variability in Market Prices and Options for Electricity Tariffs”, Renewable Energy Foundation, 2025. Available here.

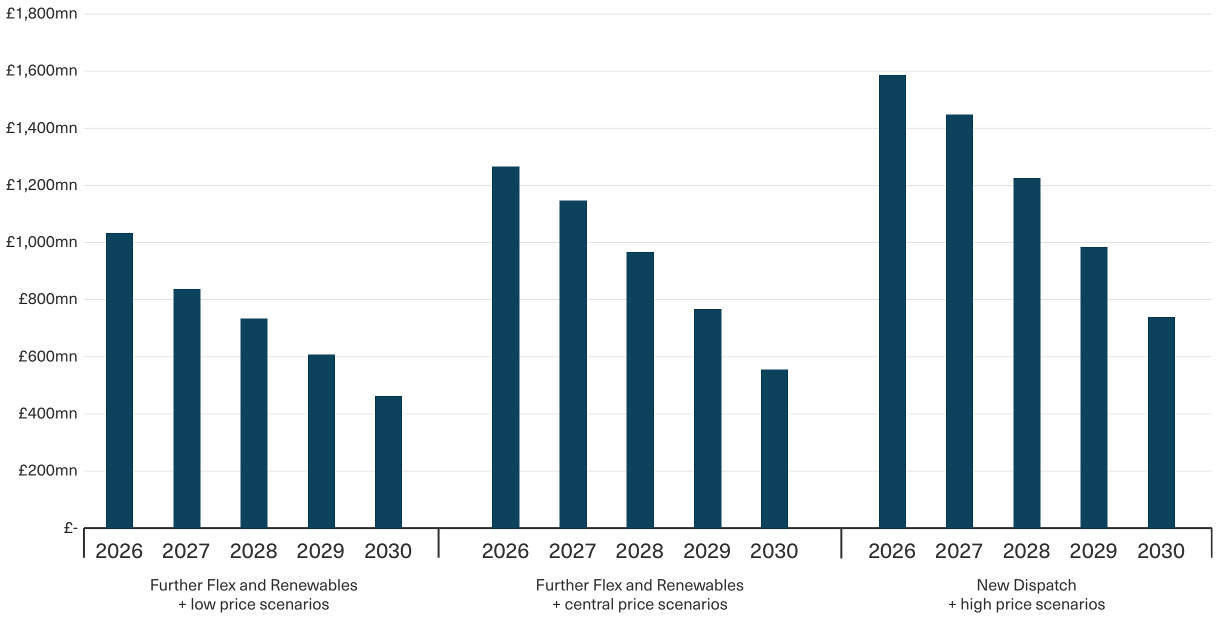
markets, reached approximately £3.2bn in 2023.[26] BM gas turn-up costs imposed £866m on consumers in 2025 and could rise to approximately £5bn by 2030.

In Figure 6, we estimate the profit to gas generators as the system tapers down to 2030. The CP2030 scenarios model the volume of gas generation falling to 27–32 TWh by 2030, exacerbating the long-running decline in average plant load factors. As gas becomes more peripheral to the overall power mix, electricity sold will diminish relative to the capital base on which those sales are expected to generate a return.[27] Simultaneously, gas's indispensability to balancing an increasingly renewable-centric system will continue to confer market power to plants in the balancing mechanism.

As such, we expect operating margins to widen, as they have done over the last six or seven years. The same period has also seen a widening wedge between the volume-weighted average wholesale price that gas plants observe compared to total generation, owing to the gas plants selling disproportionately into market expensive half-hour windows. Depending on the wholesale price scenarios detailed earlier, we model gas operating profits in the range of £0.8 to £1.3bn in 2030. Modelling assumptions are provided in Appendix 1.

Figure 6: Gas Plant Revenues and Profits Are Expected to Diminish More Slowly Than Their Share of the Power Mix

`Estimated profit for gas generation 2026-2030 based on CP2030 scenarios Future Flex and Renewables (FFR) and New Dispatch (ND)`



`**Source:** Author's calculations.`

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[26] Serguey Maximov, Paul Drummond, Philip McNally and Michael Grubb, "Where does the money go? An analysis of revenues in the GB power sector during the energy crisis", Navigating the Energy-Climate Crises Working Paper #2. UCL Institute for Sustainable Resources, 16 May 2023. Available here.

[27] "Clean Power 2030 Annex 1: Electricity demand and supply analysis", National Energy System Operator, 2024. Available here.

Constraint costs

A frequent cause for gas balancing actions are network constraints, whereby investment in transmission capacity has not kept pace with the growing geographical mismatch between renewable generation and demand centres.[28] Such constraint costs are up eightfold since 2010. With the recent decision not to implement Locational Marginal Pricing (LMP), NESO will increasingly need to pay remote wind farms to curtail generation that they have "sold" wholesale but which the overloaded grid cannot transmit, on top of the corresponding "turn-up" costs to backup gas plants — effectively charging customers twice for the same unit of electricity.[29]

Importantly, this subset of balancing costs is also exacerbated by the current "self-dispatch" model, whereby individual generators determine their own production schedules. Following bilateral trading, participants submit schedules at gate closure (approximately one hour before real-time), with NESO intervening only to balance the system through the BM. This approach increasingly creates schedules that are misaligned with the physical realities of the transmission network.

NESO projects total balancing costs will peak at approximately £8bn in 2030 under the expected network delivery pathway for CP2030 scenarios, up from roughly £2.7bn in 2024/25.[30] In 2022, NESO explained that "the need for … redispatch has markedly outgrown the residual balancer role envisaged at [2001's New Electricity Trading Arrangements (NETA) reforms] … with balancing actions now regularly exceeding 50 per cent of national demand".[31] This suggests that NESO increasingly views their lack of control over dispatch, outside of the half-hour BM window as jeopardising their mandate to keep the system in balance.

Unrealised demand side flexibility potential

A further challenge is securing sufficient demand side flexibility (DSF). The CP2030 pathway requires a five to six-fold increase from roughly 2GW today to 10-12GW by 2030. DESNZ and NESO anticipate retail consumer exposure to price

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[28] Balancing costs are the total costs incurred by NESO to keep the system in real-time equilibrium and within technical limits. Constraint costs are the subset of balancing actions needed specifically to manage network congestion. They are often a significant subset: thermal constraints counted for ~£1.7bn out of ~£2.7bn in total balancing costs in 2024/25.

[29] "Mind The Scheduling Gap: The Missing Piece of Reformed National Pricing", FTI Consulting, 2025. Available here.

[30] "2025 Annual Balancing Costs Report", National Energy System Operator, 2025. Available here.

[31] NETA replaced the 1990s "Pool" with bilateral trading, which drastically increased pressure on the balancing mechanism. "Net Zero Market Reform Phase 3 Conclusions", National Energy System Operator, 2022. Available here.

signals doing much of the work: widespread adoption of smart meters and market-wide half-hourly settlement would allow consumers to adopt time-of-use (ToU) tariffs, incentivising them to shift their consumption from high-price to low-price periods with the aid of electric vehicles, heat pumps, home batteries and other smart technologies. This strategy assumes that customers — particularly households — can and will respond rationally to price signals, and that the retail market is an efficient vehicle for delivering DSF.

DSF is needed not just across time — to match the generation profile of renewables — but also across space — to reduce strain on transmission and distribution networks. This includes producing large, timely demand shift specifically at network locations that can usefully respond to constraints. But currently ToU tariff adoption is merely voluntary and dispersed across the UK's twenty retail national electricity suppliers.[32] Anecdotal discussions with industry insiders suggest that smart tariffs still tend to be loss leading, since aggregated actions lack sufficient scale to generate adequate revenues in the wholesale or ancillary services markets.

Evidence suggests it is both ineffective and regressive to rely on rational consumers to shop around between suppliers, adopt a ToU tariff and then respond to its price signals. Consumers switch suppliers far less than is rational.[33] Only 11 per cent of households have adopted a ToU tariff, with 41 per cent surveyed saying they were unlikely to ever do so.[34] A meta-analysis of academic research on ToU found opt-in rates were generally low and strongly influenced by design factors including automation, simple structures and salient rewards.[35] Research from 2018 found that households will only shift consumption when it does not disrupt everyday practices related to care, cooking, comfort and work.[36] In such contexts, automation is preferred, while manual responses to volatile prices are perceived as excessively burdensome. The distributional implications tend to be regressive, with time-poor and some family types unable to shift consumption.[37]

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[32] Stephen Hall, "Retail Reimagined: How Regional Energy Boards Could Deliver a Fair and Flexible Energy System", Common Wealth, 2026. Available here.

[33] Hall, "Retail Reimagined", Common Wealth.

[34] Ben Cooke, "Use electricity when it's windy to cut bills, households told", The Times, 21 August 2025. Available here.

[35] Opt-in rates ranged from less than one per cent to 43 per cent. Moira Nicolson, Michael Fell, and Gesche Huebner, "Consumer demand for time of use electricity tariffs: A systematized review of the empirical evidence", *Renewable and Sustainable Energy Reviews,* December 2018, vol. 97, pp. 276–289. Available here.

[36] Ritsuko Ozaki, "Follow the price signal: People's willingness to shift household practices in a dynamic time-of-use tariff trial in the United Kingdom", *Energy Research & Social Science,* December 2018, vol. 46, pp. 10–18. Available here.

[37] Timur Yunosov and Jacopo Torriti, "Distributional effects of Time of Use tariffs based on electricity demand and time use", Energy Policy, 2021, vol. 156. Available here.

Relying on diffuse and voluntary means to achieve system stability therefore represents a significant policy gamble. Failure to deliver on CP2030 DSF targets could impose additional system costs ranging from the low billions up to tens of billions (both one-off and recurring) over the 2025–2035 period. We estimate NESO's "worst case scenario" of a 11GW additional peak power requirement — forcing extra generation, capacity payments, curtailment and heavier network reinforcement — would result in an additional £8.8bn in capital expenditure investment and forgone savings of approximately £4.4bn annually.

New capacity and investment risk premiums

The capital cost of wind and solar power has dramatically fallen over the last two decades. On a Levelised Cost of Energy (LCOE) basis, wind and solar are now the cheapest form of electricity generation in most locations, including the UK, system costs notwithstanding.[38] But despite hopes of an era of "subsidy-free" renewable power, evidence suggests ongoing price support and subsidies will remain necessary for renewables to be economically viable in wholesale electricity markets.

The key driver of this issue is the price cannibalisation effect of wind and solar assets flooding supply at the same time as each other, occasionally even turning prices negative — as increasingly observed in renewables-dominated power markets such as California or Denmark.[39] Hence price stabilisation policies such as the UK's CfDs. In recent years, however, input inflation and supply chain instability in combination with rising interest rates have substantially increased CfD strike prices, especially in offshore wind. Evidence suggests that concerns over sustained higher costs and uncertain future profitability will lead to a higher "risk premium" within the cost of future bids.[40] This risk premium is partly because ex ante price-fixing heightens the importance of elevated development risk to project profitability.[41] This means that high prices are becoming locked into the UK's CfD mechanism, with a £92/MWh strike price for offshore wind recently agreed under the CfD AR7 round. Both AR6 and AR7 showed significant increases versus the previous offshore round (AR4), with an expected hurdle rate of between eight and nine per cent, up from

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[38] These estimates conservatively assumed gearing ratios 60 per cent. "Levelized Cost of Energy+ (LCOE+)", Lazard, 2025. Available here.

[39] Brett Christophers argus this jeopardises the profitability of, and hence investment in, renewables compared to other technolocgies. Brett Christophers, *The Price is Wrong*, Verso, 2024.

[40] Neshwin Rodrigues and Duttatreya Das, "Navigating risks to unlock 500GW of renewables by 2030", Ember, 2023. Available here.

[41] Melanie Brusseler and Chris Hayes, "Nodes for socialisation", *Phenomenal World*, 2025.

around 6.5 per cent in AR4. These higher returns on capital are expected to bake in tens of billions of pounds in additional energy bills over the life of the CfD programme.

The issues for the future energy system explored in this section are summarised in the table beneath:

Problem	**Problem statement**
Inframarginal rents	Low carbon generators receive high wholesale prices plus RO subsidies
Balance rents	Gas power plants continue to set wholesale prices and extract inflated profits to balance the system, despite providing <5 per cent of generation.
Constraint costs	Generators self-dispatch their power onto the system, ignoring grid constraints and driving up balancing costs.
Unrealised demand side flexibility	Energy suppliers face low/uncertain rewards for DSF, while consumers are expected to shift behaviour to provide system stability, leading to an under-suppy of DSF.
Investment risk premium	CfDs lock in high strike prices due ot high cost of capital, uncertainties on future construction costs and profit share.

Examining an Alternative: A Single Buyer of Electricity

Monopsony and a single buyer

A Single Buyer model would transform the GB electricity market by replacing today's wholesale market with a publicly controlled system and long-term contracts. Instead of bilateral trades and generators competing to sell power into a volatile day-ahead and intraday market, all electricity would be purchased by one entity — a publicly-accountable Single Buyer. This body could be an expanded Great British Energy, the Low Carbon Contracts Company (LCCC), the Future System Operator (NESO), or a new dedicated agency. Moreover, it could rationalise some of the duplicate functions within NESO, Ofgem, the LCCC and DESNZ. Its role would be to procure all the generation required to meet national demand, dispatch it efficiently and recover the costs from suppliers. This would be a long overdue, once in a generation transformation — as radical as the previous revolutions in the governance of the power system in the 1920s, 1940s and 1980s.[42]

In several advanced economies, variations or elements of a Single Buyer structure exist, often as a legacy of vertically integrated public utilities. France, Québec and South Korea each illustrate different versions of the Single Buyer model. In France, EDF historically acted as the monopoly purchaser of nuclear and hydro power and, despite EU liberalisation, still plays a quasi-Single Buyer role through the ARENH mechanism, keeping household tariffs relatively low while supporting a high share of low-carbon generation. Québec retains a purer model: Hydro-Québec, the public utility, contracts almost all generation (largely hydro and wind) and sells directly to consumers, resulting in some of the lowest, most stable electricity prices and a near-zero-carbon power mix. South Korea takes a similarly centralised approach, with KEPCO as the sole purchaser of electricity from state and private generators.

Under this model the marginal generating unit would no longer set the price for the other generators. Instead, prices would be derived from an average of their

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[42] These periods respectively began the system's rationalisation and part-nationalisation under the Central Electricity Board (CEB), its full nationalisation under the Central Electricity Generating Board, and finally its unbundling, privatisation, and liberalisation. See Arthur Downing, *Power and the People*, Verso, 2026, ch. 2–4.

production costs.[43] Thus, renewable generators, nuclear, storage and flexible gas capacity would sell their output to the Single Buyer under pre-agreed contracts — CfD-style PPAs, Regulated Asset Base (RAB) arrangements, or capacity/flexibility contracts. While the price paid to these assets would be higher than the short-run marginal costs that comprise the merit curve under the status quo — reflecting fixed costs — the cost passed on to consumers would be a volume-weighted average of these PPA prices, rather than the highest such short-run marginal cost. The Single Buyer would then optimise the portfolio, centrally controlling dispatch in real time to minimise system costs. It would eliminate the wholesale market as we know it, lower risk premia for investors, and simplify planning, but at the cost of reduced competition and reliance on a publicly accountable body. As shown in our worked example, it would substantially reduce electricity prices.

What problems would this solve?

In our model the key advantage would be tens of billions in savings from reduced rents and improved system efficiency. The following sections unpack how our proposed model addresses the five problems outlined above: eliminating high inframarginal rents for through legacy low carbon generators via low-cost public PPAs; eliminating balancing rents for legacy gas plants through a strategic reserve; reducing system constraint costs via central dispatch; enhancing DSF via direct procurement by from suppliers and aggregators; and reducing the average costs of new generation capacity as a counterparty to a growing share of new publicly owned and community-owned generation at low cost of capital.

Under a Single Buyer, the wholesale market would be replaced by bilateral contracts between the Single Buyer and generators, reducing windfall profits from inframarginal rents while still enabling private investment in the rapid buildout of the low carbon power system. If also paired with a Strategic Reserve of gas plants, this would avoid the temporary fix of splitting the wholesale market into two — also likely exceeding the price benefits of these proposals.[44]

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[43] In our wholesale market example generators bid at their short run marginal cost of production, with the final price set by the marginal generating unit — in our case gas at £180/MWh. In the single buyer example, these bids would instead be replaced by fixed PPAs which would reflect long run marginal cost of production, which includes recovery of CAPEX and other costs, with the final wholesale price comprised of an average of these generating costs.

[44] Split markets would still require ongoing price caps and near-term winddown of the “brown power market” — grafting on further complexity to a failing structure. Rob Gross, “Discussions on REMA: Splitting the wholesale market”, UKERC, 2023. Available here.

Legacy inframarginal rents: Public PPAs

This section focuses on the existing low carbon capacity of the system, namely the Renewables Obligation (RO) funded renewables and the legacy nuclear and hydroelectricity capacity built under public ownership. Most assets either built their business cases and secured capital investment in an era of much lower wholesale prices or were built under public ownership — suggesting that considerable savings are possibly through long-term Power Purchase Agreements (PPAs), decoupling the price of this generation from gas prices.

To model the impacts of these changes we apply similar assumptions to the UKERC "Pot Zero 2025 update" proposals.[45] However, instead of hoping that legacy RO renewables voluntarily adopt a CfD, in our scheme we assume they would receive a fixed PPA at a rate determined by the Single Buyer. In Figure 7 we assume the legacy RO sites are shifted onto a fixed PPA of £50/MWh, the hydro to £45/MWh and the existing nuclear to £55/MWh. Although these values are illustrative, these strike prices are broadly consistent with other studies reflecting a reasonable risk-free return.[46] The £50/MWh price for legacy RO assets is lower than the £65/MWh average day-ahead price that prevailed from 2003 to 2017 (expressed in 2026 prices adjusting for CPI — see Figure 3) when these assets were commissioned, but is defensible as their debt financing expires — many of them now over a decade old — leaving them with only operating costs and a return on equity, especially in the context of continued ROC subsidy payments and historic windfall rents following the invasion of Ukraine. Hydro capacity was mostly constructed during the early twentieth century, while the legacy nuclear capacity dates mostly back to the 1980s.

Here we assume that the PPAs would be implemented rapidly from 2026, reflecting a Low, Central and High counterfactual wholesale price. Figure 7 depicts the substantial savings from those PPAs under the three counterfactual wholesale price scenarios depicted previously in Figure 3. These savings are plotted against the projected decline in volume of generation by these legacy assets. In 2026 alone we estimate savings to be £4.57bn (low), £6.71bn (central) and £9.43bn (high). These savings diminish as the price spike recedes to a steady state. Declining savings thereafter are driven by attrition in the fleet of legacy assets.

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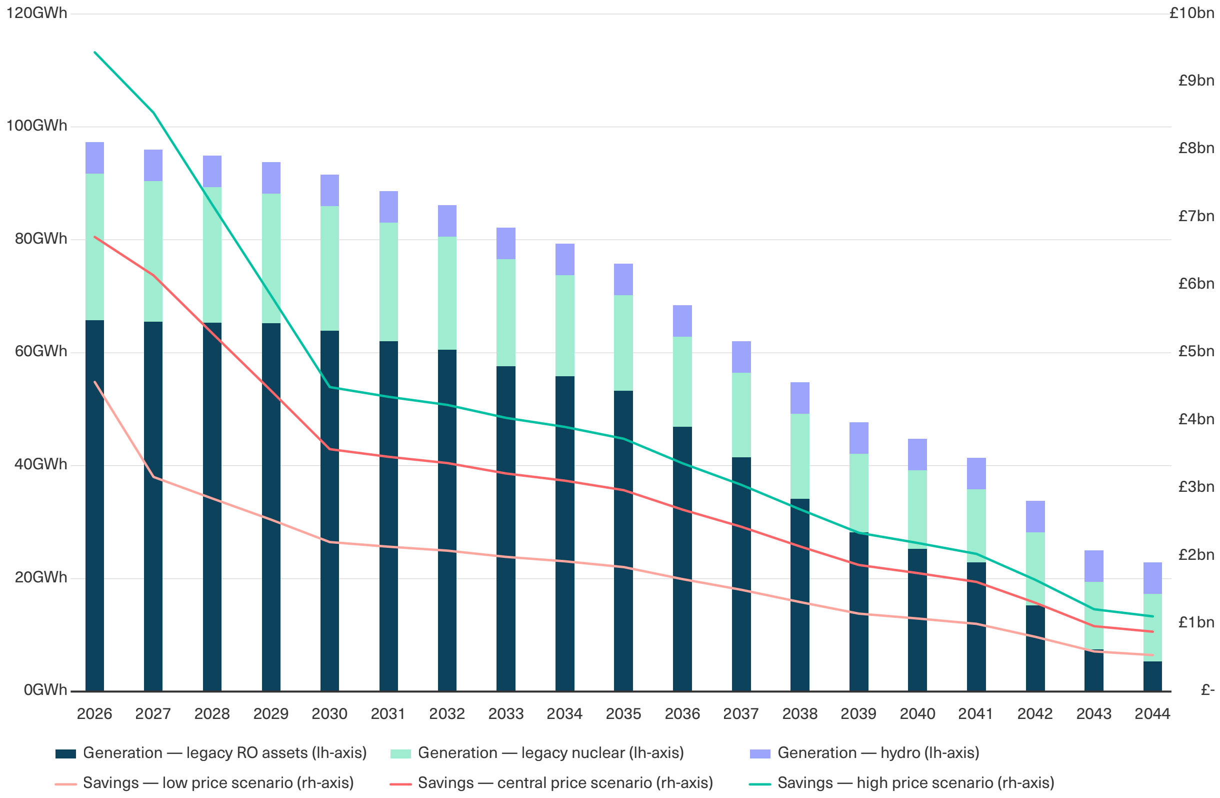
[45] Will Blyth, Rob Gross and Callum MacIver, "Pot-Zero 2025 Update: Reducing the Cost of Renewable Support to Consumers", UKERC, 2025. Available here.

[46] Will Blyth, Rob Gross and Callum MacIver, "Pot-Zero 2025 Update", UKERC. Available here.

Figure 7: Savings Are Greatest up Front While Day-Ahead Prices Are Elevated and before Legacy Assets Expire

Savings under price scenarios (£bn, rh-axis) vs generation by legacy assets (GWh, lh-axis)



Source: Author's calculations.

Under this example, the ROC subsidy payments themselves are preserved, as these were contracts agreed in good faith. Thus, the Single Buyer would be the entity obliged to procure electricity from the legacy RO generators and to buy their ROCs. Alternatively, the government could also choose to end the ROC contracts, savings consumers an additional £44.35bn, though this would likely incur legal challenge, investors would then likely require a higher PPA with the Single Buyer to recoup their investment.

Under different future wholesale price scenarios, cumulative savings amount to:

- Low prices: £15.3bn (2030) and £35bn (2045)
- Central scenario: £26.2bn (2030), and £58bn (2045)
- High prices: £35.5bn (2030) and £75bn (2045)

Importantly, this approach would deliver savings in any scenario where the counterfactual future wholesale price is >~£50/MWh.

Volatility and balancing rents: Regulated strategic gas reserve

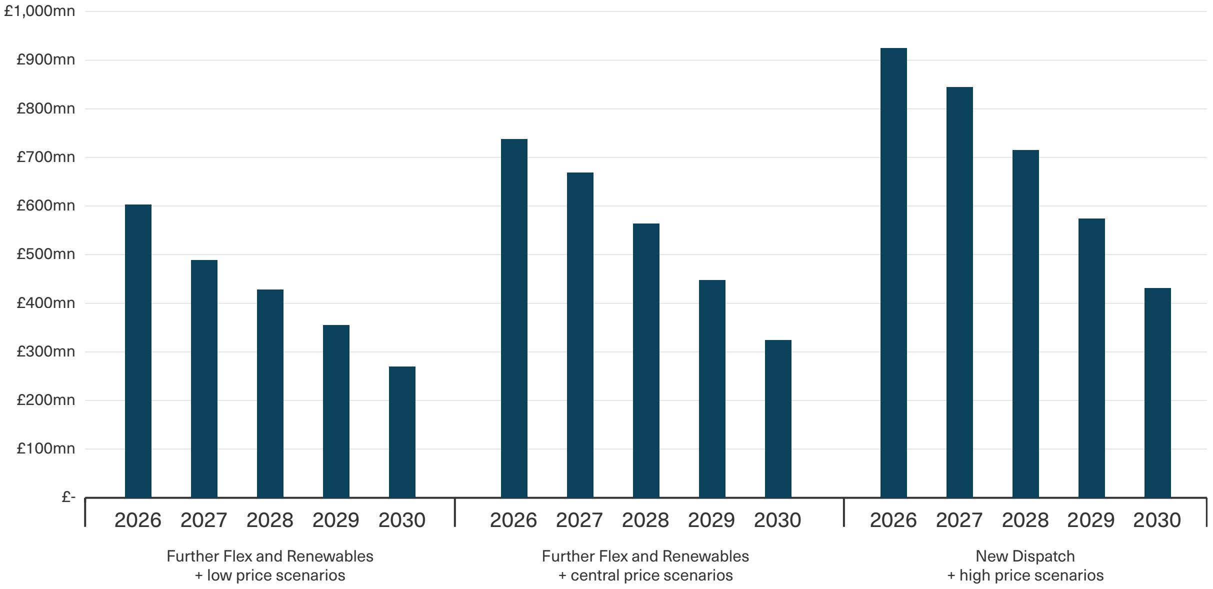
As explained in Section 2, the transitional role of gas in the system is expected to be a source of balancing rent in the current setup.

Unlike legacy RO assets, fuel price uncertainty makes fixed PPAs unviable for gas plants. We propose moving these plants into a strategic gas reserve. This is consistent with public ownership of the plants, as argued previously by Common Wealth, or a Regulated Asset Base (RAB) model based on a regulated rate of return, as argued by Stonehaven and Greenpeace and by Dieter Helm.[47] Here, either could be implemented in advance of larger Single Buyer reforms, with NESO as the monopsony buyer.

As shown in Figure 8, the RAB model saves a substantial approximately £3–6bn by 2030, eliminating 60 per cent of the profits from wholesale and balancing revenues. The scale of savings corresponds to volume of gas generation still needed and the prevailing prices that the plants are marking up. Figure 8 shows our low and central wholesale price scenarios in combination with NESO's Further Flex and Renewables scenario, and the high price scenario in combination with NESO's New Dispatch scenario. The latter scenario therefore sees greater savings owing to a greater capital base whose returns could be reduced through a RAB by eliminating the merchant risk premium.

Figure 8: Gas Savings Expected to Diminish as Gas Becomes Peripheral

Savings from strategic reserve under RAB for CP2030 scenarios



Source: Author's calculations.

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[47] Adam Khan, Chris Hayes and Mathew Lawrence, "Nationalise Gas to Lower Bills: How a Public Strategic Reserve Can Lower Costs and Enhance Energy Security", Common Wealth, 2025. Available here.

While these numbers are illustrative, they clearly demonstrate the bill savings potential from moving to a Strategic Reserve in the winddown of the GB gas fleet and are consistent with the scale of actions and mandate that a Single Buyer, tasked with achieving price reductions in the GB electricity system, could achieve.

Constraint costs: Central dispatch

Under our proposed model, the Single Buyer would help to address growing system constraint costs through the central dispatch of power on the system. As outlined in Section 2, Balancing Mechanism costs are expected to rise from £4bn to around £6.6bn by 2030, with thermal constraint costs being a major driver.

Central dispatch typically benefit electricity networks materially suffering from locational imbalances.[48] FTI Consulting have argued that moving away from a self-dispatch model and towards a "central dispatch" model could substantially reduce the growing constraint costs on the system:

> “ If GB's current self-dispatch approach was replaced with central scheduling, NESO would run a Security Constrained Unit Commitment ("SCUC") process (likely at the day-ahead stage, though other options are possible) to determine the optimal scheduling of individually generating units, interconnectors, storage and demand across the system, taking account of network constraints in real time.[49]

Additional FTI analysis, commissioned by NESO, provides a rigorous quantitative basis for estimating the impact of central dispatch, identifying two countervailing effects that together determine the net saving from central dispatch. The first is the benefit: by setting the generation schedule a day ahead using explicit network constraints, NESO replaces expensive last-minute Balancing Mechanism payments with cheaper day-ahead transfer payments — a direct reduction in constraint costs. The second is the cost: by locking in a schedule earlier, central dispatch is less able to respond flexibly to forecast errors in wind and solar output, which instead must be resolved through the Balancing Mechanism at greater expense than the intraday trading that generators currently use under self-dispatch. The net annual saving is the difference between these two effects.

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[48] "Central Dispatch Model", Glowacki Law Firm, 2023. Available here.

[49] "Mind The Scheduling Gap: The Missing Piece of Reformed National Pricing", FTI Consulting, 2025. Available here.

Critically, the FTI analysis demonstrates that the benefit of central dispatch improves substantially as network congestion increases. At the projected constraint cost levels of £4–6bn per year approaching 2030, day-ahead transfer payments under central dispatch represent approximately 47–55 per cent of self-scheduling constraint costs — implying a gross constraint saving of 45–53 per cent, before deducting forecast error handling costs of approximately £0.5–0.6bn per year. The net saving is therefore highest in the years of peak congestion (FY2027/28–FY2029/30) and diminishes as network reinforcement progressively reduces constraints from FY2030/31 onwards. Table 2 sets out our estimated annual savings under a FY2027/28 introduction of central dispatch, based on the FTI-derived transfer payment ratios applied to NESO's projected constraint cost trajectory. Full methodology is provided in Appendix 4.

Table 2: Estimated annual savings under Central Dispatch (FTI Consulting / NESO methodology, 2025)[50]

Year	Projected Total Balancing Costs — Self-Dispatch (£bn)	Gross Constraint Saving from CD (£bn)	Forecast Error Cost under CD (£bn)	Net Annual Saving from CD (£bn)	Projected Total Costs with CD (£bn)
FY2024/25	£3.16	—	—	—	£3.16
FY2025/26	£3.94	—	—	—	£3.94
FY2026/27	£4.72	—	—	—	£4.72
FY2027/28	£5.60	£2.01	£0.48	£1.53	£4.07
FY2028/29	£6.58	£2.64	£0.54	£2.10	£4.48
FY2029/30	£6.86	£2.78	£0.60	£2.18	£4.68
FY2030/31	£5.04	£1.66	£0.66	£1.00	£4.04
Total	**£35.90**	**£9.10**	**£2.28**	**£6.82**	**£29.08**

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[50] Figures are approximations based on calendar year model outputs mapped to financial years. Baseline trajectory reflects NESO Annual Balancing Costs Report 2025 projections (Holistic Transition, Expected Network scenario). Net savings apply from FY2027/28 assumed implementation date. Post-FY2030/31 savings diminish rapidly as network delivery reduces thermal constraints, with central dispatch approaching cost-neutrality by FY2032/33.

This finding has an important implication for implementation. Because the value of central dispatch is directly contingent on the severity of network congestion, a FY2027/28 introduction captures the period of maximum benefit while the network remains heavily constrained. Delay would reduce the window of greatest value. Central dispatch and network investment are therefore complementary rather than alternative policy levers: network build reduces the problem, while central dispatch manages the residual constraint cost more efficiently in the intervening period.

It should also be noted that the FTI analysis is conservative as it assumes no intraday market operates alongside central dispatch to manage forecast errors — an assumption that likely overstates the cost of the second effect noted above. Several European jurisdictions that operate central dispatch, including Italy, maintain intraday markets alongside their day-ahead schedule. Incorporating intraday trading would reduce forecast error costs by an estimated £0.3–0.5bn per year and further improve the net saving. The figures therefore represent a conservative estimate.

Unrealised demand side flexibility potential: Centralised flexibility procurement

A further significant advantage of the Single Buyer approach is in procuring sufficient Demand Side Flexibility (DSF) — shifting demand in response to fluctuating power supply or network constraints. Because these actions provide value to the system, they can be rewarded with price incentives. The current system design is likely to undersupply these services as domestic suppliers of flexibility lack a reliable counterparty and price for aggregated flexibility. Moreover, CP2030 forecasts rely on highly optimistic assumptions regarding consumer responses to price signals.

The coordination problem in today’s flexibility markets

The scale of this coordination challenge is evident in the operation of GB’s existing flexibility markets. The system currently spans more than twenty distinct procurement activities. NESO procures national ancillary services, runs the Balancing Mechanism and operates the year-round Demand Flexibility Service, while each of the six DNO/DSO areas runs its own local flexibility tenders, predominantly via Piclo Flex or Localflex.[51] Each applies different product definitions, baselining methodologies, prequalification rules and settlement processes. The result is under-delivery of flexibility volume. Piclo Flex has registered over 55,000 assets and 16 GW of capacity across GB but has historically converted only around 1.1 GW of this

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[51] “Market facilitator draft delivery plan”, Elexon. Available here.

potential into contracted flexibility — a participation rate of roughly seven per cent.[52] Imperial College describe how the competitive aggregation of demand side resources by independent intermediaries exhibits a "price of anarchy"[53] — an efficiency loss relative to coordinated aggregation — because each aggregator optimises against the others rather than against the underlying system need.[54] Whole-system modelling commissioned by BEIS and the Committee on Climate Change reaches a similar conclusion: an under-coordinated approach to flexibility could generate up to £9bn per year in avoidable system costs by 2050, with much of this attributable to coordination failure rather than physical scarcity of flexible assets.[55]

The Government has partially recognised this problem. From December 2025, Elexon assumed a new statutory role as Market Facilitator, empowered through licence conditions on NESO and the DNOs to standardise asset registration via the Flexibility Market Asset Register (FMAR), set common market rules and align product definitions across local and national markets.[56] This is a welcome step and broadly consistent with the direction we propose. But the Market Facilitator is a coordinator, not a buyer — it smooths the interfaces between fragmented markets without removing the fragmentation. Aggregators continue to face many counterparties with differing risk appetites and procurement horizons, individual DSOs still bear the cost consequences of their procurement decisions in isolation and no entity has the balance sheet or mandate to issue the long-duration contracts that would mobilise the scale of investment CP2030 requires. LCP Delta's recent Project Harmony review reaches a similar conclusion, describing current arrangements as structurally incapable of delivering whole-system value without a more coordinated buyer function.[57]

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[52] Henry Edwardes-Evans, "Interview: Piclo pursues rapid gains in longer-term power market reform", S&P Global Commodity Insights, August 2023. Available here.

[53] Christos Papadimitriou, "Algorithms, games, and the internet", Proceedings of the 33rd Annual ACM Symposium on Theory of Computing, 2001, pp 749-753. Available here.

[54] Daiwei Qiu, Dimitrios Papadaskalopoulos, Yujian Ye and Goran Strbac, "Investigating the effects of demand flexibility on electricity retailers' business through a tri-level optimisation model", *IET Generation, Transmission & Distribution*, March 2020, vol, 14 no. 10, pp. 1739–1750. Available here.

[55] Carbon Trust, & Imperial College London, "An analysis of electricity system flexibility for Great Britain", Department for Business, Energy & Industrial Strategy, 2016. Available here.

[56] "Market facilitator policy framework decision" Office of Gas and Electricity Markets, Ofgem, 20125. Available here.

[57] "Project Harmony: Improving coordination in GB flexibility markets", LCP Delta, 2025. Available here.

How the Single Buyer would procure flexibility

When paired with Central Dispatch, the Single Buyer could resolve these coordination problems by becoming the sole procurer of bulk DSF in GB. It would procure sufficient flexibility capacity from energy suppliers and aggregators, giving the providers of these services greater revenue certainty and ensuring sufficient flexibility capacity to meet CP2030. Table 3 illustrates a unified architecture of central procurement and dispatch of DSF organised across three layers.

Table 3: Central Procurement and Dispatch of DSF

Layer	Function	Outcomes
Long-term contracts 5 to 15 years Replaces: short-term schemes with no revenue certainty	The Single Buyer auctions guaranteed minimum revenue to aggregators — comparable to the long-term fixed-price contracts used to fund new wind and solar farms, applied here to demand flexibility.	Gives providers the confidence to invest in smart chargers, heat pump controls and software platforms. Lowers the cost of borrowing, matching rates available to renewable energy developers. Locks in where on the network flexibility is needed, not just how much.
Medium-term contracts Annual and seasonal Replaces: dozens of separate tenders run by local network operators	Rolling auctions each year and season to secure the volumes needed for that period, broken down by region to match where the grid actually needs support.	Secures the capacity needed to keep the lights on and manage the grid across the year. One national process and one set of rules, replacing today's fragmented local markets. Regions defined by real network needs, not administrative boundaries.
Short-term dispatch Day-ahead to real-time Replaces: overlapping systems run separately by network operators, the system operator and energy suppliers	The Single Buyer calls directly on contracted providers — the day before, within the hour, or in real time — through a single interface co-ordinated with the national system operator.	One instruction, one interface — replacing multiple overlapping systems. Providers can automate responses fully: no need for households to act manually. Joined up with the wider grid, cutting unnecessary balancing costs.

This would also mean an increased role for the Distribution System Operators (DSO) in manging their networks and sourcing and enacting flexibility services in partnership with the Single Buyer. This has the further advantage of simplifying suppliers' role in the future system, moving away from the complex need to balance customer actions with an uncertain upstream revenue profile.

A knock-on effect should be greater automation of DSF via domestic appliances, heat pumps, EVs and batteries thanks to a reliable flexibility volume and upstream price. Such changes may be the key step in unlocking "energy as a service" offerings, optimising hardware without the users' involvement.[58] They also address the distributional concerns highlighted earlier, with the cognitive burden of response shifted from time-poor households to aggregators and their automated platforms, participation no longer depends on the time and attention budgets of individual consumers.

International precedent for centrally procured flexibility

Variants of centrally procured demand side flexibility are already operating in several comparable systems. In France, the NEBEF mechanism allows the system operator RTE to procure and activate demand reductions directly, settling them at wholesale prices without requiring retail suppliers to intermediate.[59] In California, the Demand Response Auction Mechanism places CAISO as the central auctioneer of aggregated demand response under multi-year contracts.[60] Ireland's integrated Single Electricity Market includes centrally dispatched Demand Side Units, and Australia's Reliability and Emergency Reserve Trader, run by AEMO, performs an analogous backstop-procurement function.[61]

Savings potential

These changes could be key to realising the ambitious flexibility targets contained within the CP2030 scenarios. In a recent report, the Association for Decentralised Energy (ADE) estimated that flexible electricity demand could save the

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[58] Donal Brown, Stephen Hall, Mari Martiskainen and Mark Davis, "Conceptualising domestic energy service business models: A typology and policy recommendations", *Energy Policy*, February 2022, vol. 161. Available here.

[59] "Notification d'échange de blocs d'effacement — Règles relatives au mécanisme de valorisation des effacements", Réseau de Transport d'Électricité, 2024. Available here.

[60] "Demand Response Auction Mechanism (DRAM): Final report", CAISO, 2023. Available here.

[61] "Reliability and Emergency Reserve Trader (RERT) procedures", AEMO, 2024. Available here.

GB electricity system £14.1bn per year by 2040.[62] These savings include reductions in wholesale generation and balancing (including constraint) costs, as well as reduced network costs thanks to more efficient utilisation of existing system assets.

While NESO does not provide cost estimates, a worst case where no further DSF is delivered — representing a 11GW shortfall — is presented. Below we have made direct estimates of the avoided "generation costs" which would involve building additional capacity in the form of gas peaking plant and fuel costs. Indeed, in the extreme cases undersupply of DSF may lead to blackouts.[63] We have also used the ADE assumptions to model wider "forgone savings" from avoided balancing and curtailment costs, deferred network reinforcement and system efficiency gains. These are based on three under-delivery scenarios: Modest (25 per cent), Material (50 per cent) and Severe (100 per cent). The avoided cost potential by 2030 is shown in Figure 9.

1. Modest (2.75 GW shortfall):
   Generation costs ≈ £0.7bn/yr + £2.2bn capex.
   Forgone savings ≈ £1.1bn/yr.
2. Material 50 per cent (5.5 GW shortfall):
   Generation costs ≈ £1.3bn/yr + £4.4bn capex.
   Forgone savings ≈ £2.2bn/yr.
3. Severe 100 per cent (11 GW shortfall):
   Generation costs ≈ £2.7bn/yr + £8.8bn capex.
   Forgone savings ≈ £4.4bn/yr.

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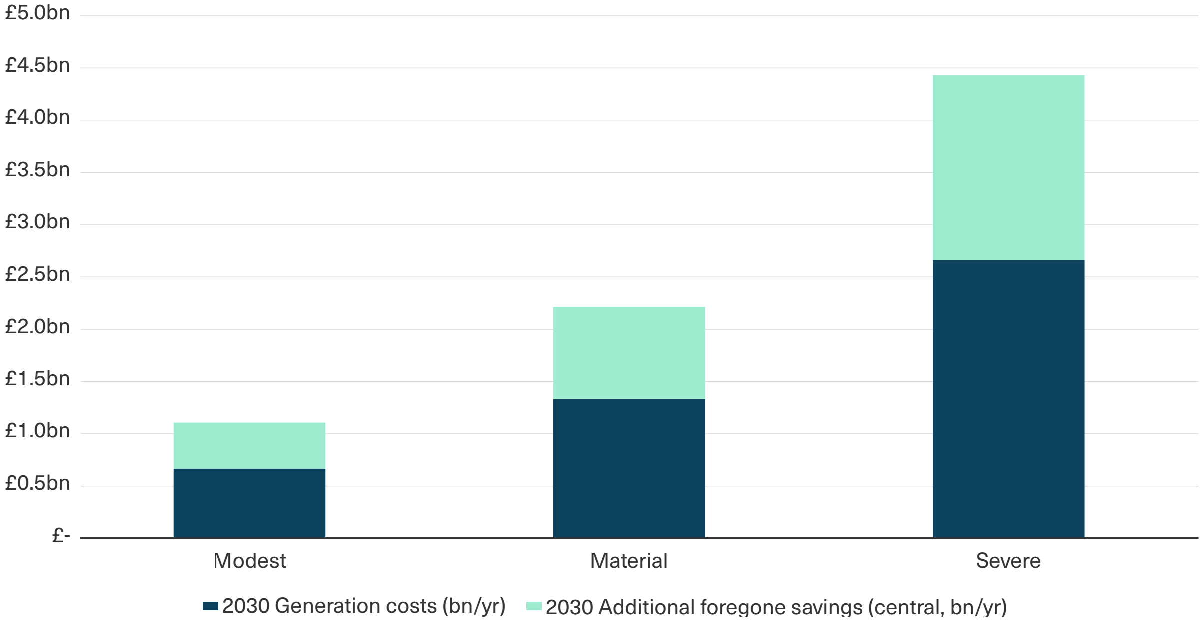
[62] "Demanding More: How the National Energy System Operator can empower energy demand", ADE, 2024. Available here.

[63] Caroline Kuzemko, Marie-Claire Brisbois, James Price, Steve Pye, Louis Fletcher, Natalie Ralph, and Michael Bradshaw, "UK energy security: Making the most of demand side measures", UKERC, 2025. Available here.

Figure 9: Shortfall of Demand Side Flexibility Relative to CP2030 Projection Could Cost Billions

CP2030 Avoided annual costs under modest (25%) Material (50%) and Severe (100%) DSF shortfall scenarios



Source: Author's calculations based on Association for Decentralised Energy.

New capacity and investment: Public PPAs and ownership

The benefits of the Single Buyer model are not exclusively in reducing costs from the existing generating fleet. By removing the volatility and opacity of the wholesale market's marginal pricing regime, it is likely that the Single Buyer could induce investment at a lower cost than the counterfactual scenario. This is primarily due to two factors: a lower regulated price for new generating assets and a lower cost of capital. In the next two sections, we examine the implications of this for new capacity brought onto the system, based on delivery of the CP2030 targets.

Grid scale batteries

By 2030, the CP2030 plans envisage a vast buildout of approximately 24 GW of short-duration Lithium-ion batteries and ~6 GW of Long Duration Energy Storage (LDES), delivering about 36–40 TWh/yr of flexible dispatch.[64] This is a

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[64] Such as Pumped hydro, Compressed air energy storage (CAES), Liquid air energy storage (LAES), Flow batteries (vanadium, zinc-bromine, iron-air), and Hydrogen or e-fuels (as "power-to-power" storage).

massive increase from the 6.8GW or so of Li-ion and 2.8GW of LDES capacity built today.[65] Under current policy, delivery of this capacity is expected to be financed by a combination of Capacity Mechanism, wholesale market and ancillary services revenues, especially the Balancing Mechanism. As outlined above, under a high penetration of renewables we expect providers of these balancing services to earn extraordinary revenues during times of system stress.

The commercial returns currently available under private merchant battery finance are illustrated by Gresham House Energy Storage Fund, the UK's largest listed battery storage fund, which reported a 64 per cent EBITDA margin on portfolio revenues of £60.4 million in 2025, with merchant cash flows discounted at 10.85 per cent — more than double the five per cent cost of capital that would apply under Regulated Asset Base (RAB) and a direct measure of the premium consumers currently bear through market-based pricing.[66]

In the status quo scenario we assume that the Li-ion battery capacity would operate at average prices in the region of £230–240/MWh, while the LDES would receive approximately £310–320/MWh. For Li-ion, these figures are based on a merchant Weighted Average Cost of Capital (WACC) of eight per cent, consistent with the evidence on hurdle rates for storage assets operating under partially merchant conditions.[67] For LDES, the equivalent merchant price now reflects the cap-and-floor scheme as the appropriate status quo counterfactual for qualifying assets, as discussed further below. By 2030, this accounts for approaching £10bn per year in system costs across the full battery fleet.

Under the Single Buyer, revenues for these battery systems could be tightly controlled through a Regulated Asset Base (RAB) structure, providing secure revenues to the owners of these assets whilst reducing the price paid by consumers. For both Li-ion batteries and LDES assets, the primary saving arises from the reduction in the cost of capital — from eight per cent under merchant or cap-and-floor financing conditions to approximately five per cent under de-risked public financing, consistent with RAB precedents and the HM Treasury Green Book social discount rate.[68] This would also eliminate the need for Capacity Market payments. Based on these assumptions, the Single Buyer model would deliver Li-ion battery capacity prices in the £190–200/MWh range, with LDES at around £250–260/MWh. These are shown as levelised cost of storage (LCOS) savings in Figure 11.

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[65] Daniel Sutherland, “Stacking up the storage: where the UK battery market stands in 2025”, RenewableUK, 2025. Available here.

[66] “Gresham House Annual Review”, Gresham House, 2025. Available here.

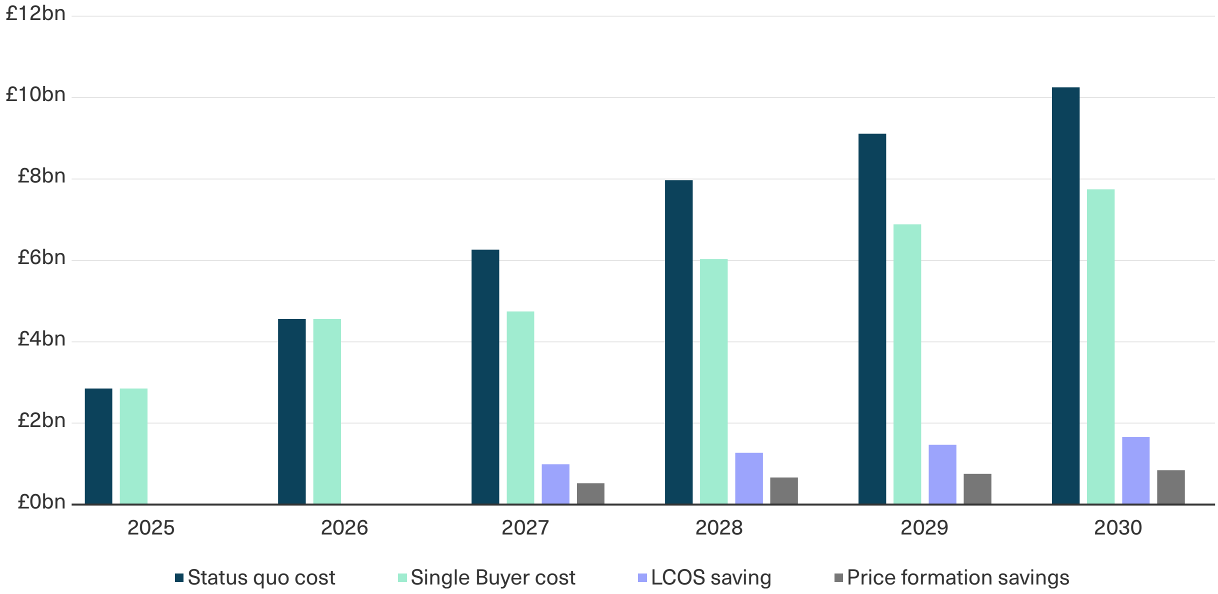
[67] “Cost of capital for generation technologies”, UK Government, 2020. Available here.

[68] “The Green Book: Appraisal and evaluation in central government”, HM Treasury, 2022. Available here.

The Single Buyer's dispatch authority would deliver a further consumer saving not captured in the cost-of-capital comparison above. Under merchant operation, battery operators bid their energy output into wholesale and balancing markets at or near the prevailing clearing price — which averages around £57–70 per megawatt-hour in day-ahead markets and rises substantially higher during periods of tight supply.[69] Under Single Buyer central dispatch, by contrast, batteries would be instructed whenever the system requires them at their actual variable operating cost of around £12–15 per megawatt-hour. The difference — the gap between what consumers currently pay through the market and what it costs to run the battery — is eliminated under the Single Buyer model. Applied conservatively to the energy dispatch portion of the projected 2030 battery fleet, this price formation saving adds approximately £0.98bn per year by 2030, or around £3.2bn cumulatively over 2027–2030. These are shown as price formation (PF) savings in Figure 11, bringing the combined cumulative saving to approximately £8.65bn by 2030.[70] See Appendix 5 for methodology.

Figure 10: Reducing the Merchant Premium on Cost of Capital Provides Majority of Battery Savings

Battery costs under status quo vs single buyer (£bn)



Source: Author's calculations.

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[69] "GB BESS index: De-risking BESS returns in Great Britain Q3 2025", Modo Energy, 2025. Available here.

[70] "Balancing cost winter report 2023/24", National Energy System Operator, 2024. Available here.

The Single Buyer and public generation capacity

A final place where the Single Buyer could reduce costs is in supporting the public ownership of renewable electricity capacity.

> “[Great British Energy (GBE) has a mission to] invest in, develop, build and operate the technology the UK needs to increase our energy independence, and we’ll give communities a direct stake in the clean energy revolution.[71]

Though the role that GBE may play in the energy system remains debated, Common Wealth has argued its primary aim should be the ownership of low carbon energy capacity in the public interest.[72] GBE has been given an initial settlement of £8.3bn to invest.[73] We believe this money is best deployed via ownership and equity investment in low carbon energy projects. When paired with low-cost public borrowing, this model could deliver capacity at a much lower cost than the current privately financed and owned CfD rounds are delivering.

Following a failure to secure any bids in Auction Round 5 (AR5) of the CfD auction process, AR6 and AR7 saw a substantial increase in the strike price for offshore wind. This rose from £37.35/MWh (AR6) to £58.87/MWh in 2012 prices. This represented over a 50 per cent increase, and roughly £82/MWh in 2024 prices, with AR7 reaching £92/MWh. While global materials and supply chain inflation were significant contributors to this, a greater factor was the growing cost of capital and resultant hurdle rate of these projects — estimated to rise from 6.3 per cent in AR5 to 8.5 per cent in AR6 and AR7.[74] High strike prices are likely to further undermine the government’s narrative that CP2030 goals and renewables more generally can drive down bills.

Our proposal is that the Single Buyer and GBE would work together to drive down the cost of future renewable capacity via facilitated public ownership. Offshore wind typically runs 70/30 debt-equity ratios in private finance. We might expect GBE to achieve a smaller equity share via higher gearing, given that projects would

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[71] Chris Fox, “The steps needed to achieve the UK’s offshore wind mission: Reset, scale and deliver”, RenewableUK, 2025. Available here.

[72] Adam Khan, “Common Wealth’s Vision for Great British Energy”, Common Wealth, 2024. Available here.

[73] Although £2.5bn has been given to Great British Nuclear.

[74] “Electricity generation costs 2020”, Department for Business, Energy and Industrial Strategy, 2020. Available here.

effectively be backed by government. Therefore, if we assume an 80/20 gearing ratio, £8bn of GBE equity could conceivably deploy £40bn of capital in this parliament. This would deliver around 10GW of capacity. However, under public ownership, we project returns would be pegged to the average cost of borrowing for the UK government.

While the AR6 round required a hurdle rate of around 8.5 per cent, GBE and the Single Buyer could likely deliver a much lower cost of capital. If GBE issues debt (or borrows via Treasury), its cost could be close to UK gilt yields. While GBE may want a higher return on its equity, it could be willing to simply cover its costs, bringing the required returns on equity much closer to the price of debt. Because the state can absorb risks that private investors must price in, both debt and equity can therefore be cheaper.

Based on a public WACC of 4.8 per cent we estimate this could deliver 10GW of capacity at an average strike price of £64/MWh, about £28/MWh less than the privately financed counterfactual. This would lead to around £1.36bn in annual savings versus the privately financed plant. The Single Buyer could underwrite contracts at prices consistent with a 4.8 per cent WACC, while also ensuring that these savings are passed through to consumers rather than captured as private rents. Because the Single Buyer centrally manages dispatch and contracts across the system, it can co-ordinate generation, flexibility, and reserves more efficiently, further reducing balancing costs. Given that AR7 auctions are currently underway, we expect this model could augment or replace the planned capacity for AR8, due to come online in 2028–2030. See Appendix 6 for methodology.

Summary of Single Buyer Savings

The Single Buyer model as outlined in this report has the potential to deliver massive savings for GB electricity consumers. These savings arise primarily from the reduction of inflated private profits across various areas of the system. Savings are estimated in the context of the CP2030 decarbonisation programme and the 2026 Hormuz crisis price environment. It is important to note that most of these savings would be even greater under the counterfactual scenario, where gas remains more dominant in the generation mix. This underscores the importance of the rapid decarbonisation of the electricity system. However, as we demonstrate, the Single Buyer represents a more suitable means of governing this new system, ensuring the low costs of renewable energy and the savings from demand flexibility are felt by households and businesses.

Below we outline the phased implementation pathway and then the three savings scenarios.

Phased implementation

We propose that the Single Buyer model is delivered in stages. The most straightforward reforms — moving legacy low-carbon generators onto fixed PPAs and restructuring the gas fleet — can be delivered through emergency legislation in 2026, with the more complex changes such as central dispatch and battery RAB model operational by 2028. The sequence below reflects the phasing of these each element.

2026	**Crude awakening: emergency legislation:** Emergency legislation moves legacy low-carbon generators (RO renewables, nuclear, hydro) onto fixed public PPAs, decoupling their revenues from the gas price. Gas generators are simultaneously restructured into a publicly regulated Strategic Reserve. NESO begins small-scale trials of centrally procured demand side flexibility.
2027	**Transition underway: building the Single Buyer** A reduced wholesale market continues in parallel as the Single Buyer takes shape. NESO and the LCCC begin procuring battery and LDES capacity through a RAB/PPA structure, replacing costly merchant arrangements. Central Dispatch moves into detailed design, and the institutional infrastructure for the transition is well underway.
2028	**Transition complete: Central Dispatch goes live** The wholesale market is wound down, and the Single Buyer assumes full responsibility. NESO begins centrally dispatching power, directly addressing the inefficiencies of self-dispatch. Great British Energy (GBE) brings the first 5GW of publicly financed offshore wind online at a strike price well below privately financed equivalents.
2029	**Full operation: maximum benefits delivered** A further 5GW of GBE offshore wind comes online, bringing the total to 10GW. The full Single Buyer savings stack — PPAs, Strategic Reserve, Central Dispatch, centralised flexibility procurement and cheaper new capacity — delivers hundreds of pounds of savings per household annually. Consumer bills demonstrably fall.
2030	**CP2030 achieved: clean power, lower bills** The CP2030 decarbonisation target is met with the Single Buyer running at full capacity. Annual system savings of up to £13bn flow through to households, businesses and public services, demonstrating that clean power and lower bills are not in conflict — and rebuilding public consent for the net zero agenda.

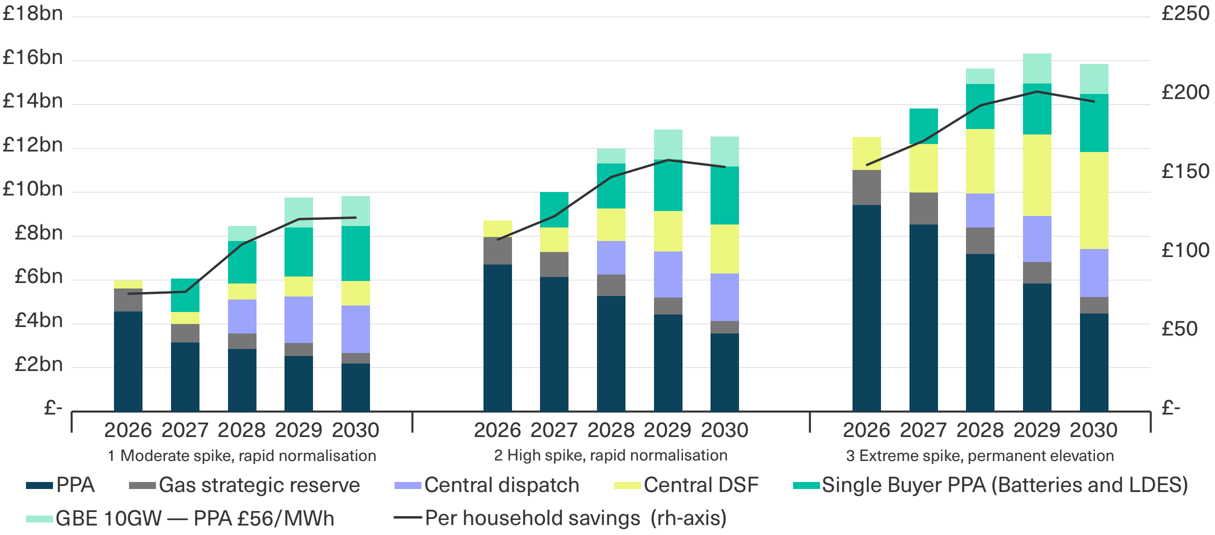
Savings scenarios

To capture the interaction between the geopolitical price environment and reform depth, we model three scenarios rooted in the three Hormuz crisis trajectories set out in Section 2. In all three, the CP2030 decarbonisation target is achieved by 2030. The scenarios differ in the severity and persistence of the price shock, whether the FFR or ND system pathway results, and the depth of reform that political circumstances make possible.

Please note that aggregate savings figures should be treated with caution, since the components are modelled in isolation and modelling does not account for likely overlap between components, for example, between the congestion costs avoided both by central dispatch and by enhanced DSF delivery.

Figure 11: Wholesale Price Savings Are Front-Loaded, While Additional Savings From Direct Dispatch Procurement Emerge Later

System and household savings under low, central and high scenarios



Source: Author's calculations.

Notes: Totals are likely over-estimates due to overlap between cost saving categories, e.g. between improved DSF delivery and central dispatch.

Low: moderate price spike, rapid normalisation

The Hormuz crisis resolves quickly. The ceasefire holds, allowing prices to normalise — wholesale electricity averages around £100/MWh for 2026 before returning to the pre-crisis Cornwall Insight trajectory of ~£84/MWh by 2027, declining to ~£75/MWh by 2030. No lasting structural damage occurs. The FFR pathway is achieved with only a modest under delivery of flexibility.

Table 4: Disaggregated Impacts (Low)

Savings component	Cumulative 2026–2030	2030 annual
Legacy LC PPAs (moderate spike, FFR basis)	£15.3bn	£2.2bn
Gas Strategic Reserve (RAB, FFR)	£3.7bn	£0.5bn
Central Dispatch (ramped from 2028)	£5.8bn	£2.2bn
Battery & LDES PPA structure	£3.7bn	£1.1bn
Great British Energy (10GW from 2028)	£8.6bn	£2.6bn
Avoided DSF under-delivery (modest)	£3.4bn	£1.4bn
Total	**£40.6bn**	**£10bn**

Central: sustained disruption, gradual recovery

In our Central Scenario, the crisis is more durable. Restricted Hormuz shipping through Q2–Q3 2026 keeps electricity prices elevated at ~£120/MWh for the year, with European gas storage entering the winter critically low. Prices ease from 2027 as LNG supply recovers and renewable build accelerates, converging toward wholesale electricity prices of ~£90/MWh by 2030. In the counterfactual scenario, the FFR pathway is delivered, but with the Single Buyer crucial in avoiding moderate under delivery of demand side flexibility.

Table 5: Disaggregated Impacts (Central)

Savings component	Cumulative 2026–2030	2030 annual
Legacy LC PPAs (high spike, FFR basis)	£26.2bn	£3.6bn
Gas Strategic Reserve (RAB, FFR)	£4.7bn	£0.6bn
Central Dispatch (ramped from 2027)	£5.8bn	£2.2bn
Battery & LDES PPA structure	£7.4bn	£2.2bn
Great British Energy (10GW from 2028)	£8.6bn	£2.6bn
Avoided DSF under-delivery (moderate)	£3.4bn	£1.4bn
Total	**£56.1bn**	**£12.5bn**

High: extreme disruption, permanent damage

In our high scenario, prices average £148/MWh across 2026. The Ras Laffan LNG outage creates lasting structural damage, with prices following the OBR high trajectory: ~£147/MWh in 2027, declining gradually to ~£100/MWh by 2030. Critically, in the status quo scenario, without the Single Buyer the sustained crisis overwhelms the market mechanisms underpinning the FFR pathway: consumer DSF delivery collapses under financial pressure, forcing the system onto the New Dispatch (ND) pathway — requiring expensive new build dispatchable gas, CCS and hydrogen. ND would mean higher wholesale prices, more expensive balancing, and higher system costs throughout the decade. The Single Buyer's centralised flexibility procurement is the key intervention averting the worst consequences of severe DSF shortfall.

Table 6: Disaggregated impacts (High)

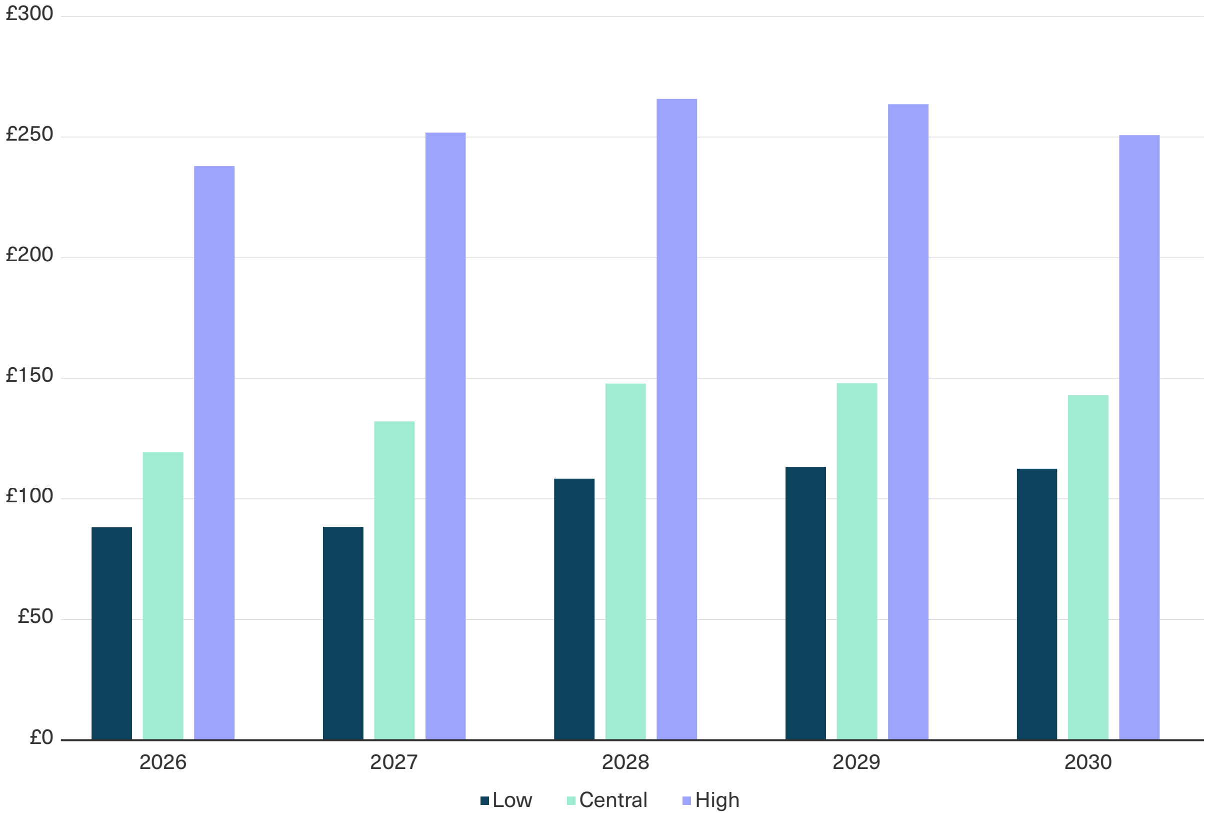
High Savings component	Cumulative 2026–2030	2030 annual
Legacy LC PPAs (extreme spike, ND basis)	£35.5bn	£4.5bn
RO levy cancellation	£6bn	£0.7bn
Gas Strategic Reserve (RAB, ND)	£5.8bn	£2.2bn
Central Dispatch (ramped from 2027)	£14.8bn	£4.4bn
Battery & LDES PPA structure	£8.6bn	£2.6bn
Great British Energy (10GW from 2028)	£3.4bn	£1.4bn
Avoided DSF under-delivery (severe)	£74.1bn	£15.9bn
Total	**£35.5bn**	**£4.5bn**

Household savings

The savings above would accrue to all electricity bill payers on a broadly volumetric basis. Domestic users account for approximately 35 per cent of electricity consumption — a share that will grow substantially through CP2030 electrification — with the remainder flowing to businesses and public services. Based on 35 per cent of system savings distributed across 28 million GB households, annual per-household benefits in 2030 range from £125 in the low scenario to £198 in the high (Table 7). All three scenarios would deliver meaningful bill reductions; in the central and high cases, the Single Buyer significantly narrows the gap to Labour's £300/year pledge. The lower business energy costs not captured in these household figures will additionally reduce prices across the wider economy.

Figure 12: Combined Household Savings Expected to Exceed £100

Annual household bill savings from combined measures



Source: Author's calculations.

Notes: Totals are likely over-estimates due to overlap between cost saving categories, e.g. between improved DSF delivery and central dispatch.

Wider Implications of a Single Buyer Model

Would it require the nationalisation of retail supply?

A Single Buyer model would not automatically require nationalisation of retail supply companies because the reform addresses how generated power is procured, not who bills end users. In the current GB system, suppliers are responsible for buying power from the wholesale market and passing it on to households and businesses. In a Single Buyer model, that procurement function shifts upstream: the Single Buyer contracts with all generators and pools the costs. Suppliers would secure a uniform — but real-time, cost-reflective — price from the Single Buyer that reflects the average cost of the generation mix, which they would then recover from their customers. However, this could be regionally differentiated.

Suppliers would then no longer compete on how well they can hedge or buy electricity but instead act as billing and energy service providers. Their commercial focus would be customer service, product innovation (heat pumps, bundled EV/solar offers), demand side flexibility and credit risk management — rather than wholesale trading.

Would it be expensive?

The creation of a Single Buyer for electricity in Great Britain would not in itself be overly expensive when set against the overall scale of the power system, but it would be institutionally complex and politically sensitive. The main costs will come from the bureaucratic legal and contractual transition such a reform would require.

Some have argued that contracts with the Single Buyer would count towards public debt.[75] However, insofar as the public PPAs would be backed by expected customer revenues, arguably those expected revenues could be treated as a corresponding financial asset under the new Public Sector Net Financial Liabilities (PSNFL) rules for accounting purposes, although this remains a question of ONS

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[75] Gordon Hughes, "Variability in market prices and options for electricity tariffs", Renewable Energy Foundation, 2025. Available here.

technicalities. In the worst case, the increase in PSNFL would be understood as a paper increase but not a substantial one.

Britain already has much of the technical machinery that a Single Buyer would need. NESO, Ofgem's settlement systems and Elexon's balancing functions already handle the flow of contracts, dispatch instructions and financial settlements. A Single Buyer could be established by repurposing and enlarging these functions, with a dedicated procurement arm to contract with generators. The administrative outlay for staff, IT and governance might run into the hundreds of millions of pounds over several years, but that is modest compared with the £50–60bn spent annually on electricity system costs.

Would it be difficult to implement?

The real challenge lies in the transition. Significant legislative change would be unavoidable, since the 1989 Electricity Act and the current set of industry codes are designed for a liberalised, self-dispatch market. Cross-border trade would also need new arrangements, given Britain's integration into European markets. The Single Buyer would also need to establish credibility with investors: long-term PPAs and financing depend on confidence that the buyer is stable and politically reliable.

There are several precedents that illustrate both the opportunities and the challenges of this transformation. Before privatisation in 1990, the CEGB was effectively a single buyer and seller for England and Wales. More recently, the Single Electricity Market on the island of Ireland introduced a centrally dispatched mandatory pool, created through new market rules and IT systems rather than nationalisation of suppliers. However, the exact structure and governance model of the Single Buyer is beyond the scope of this report.

Would it affect future investment in the electricity system?

While our proposals for a Single Buyer would involve a major overhaul of the GB electricity market, they would not in principle impact the main means of delivering investment in renewable generation capacity — the CfD. Our proposed approach instead would instead align the governance of the system with the emerging reality of low marginal cost bulk renewable power operating on long term fixed price contracts. Current CfD auctions could proceed as planned, leveraging private investment in the new capacity. The presence of the Single Buyer could further de-risk investment, although those generators who have their profits reduced by the single buyer reforms would have less surplus capital to invest. In our view, however, rising interest rates — themselves a product of the supply side inflation the Single Buyer is aiming to mitigate — are a much greater threat to the economics of these projects.

The Single Buyer could also pave the way for a greater share of public ownership of the power system. With electricity prices substantially reduced, the government and Great British Energy could make the case that their plan is working and expand the scale and remit of the public generator. However, without these reforms there is a high chance that the status quo regime and the high resulting electricity prices will mean that the CP2030 ambition and wider energy transition is punished at the ballot box.

Conclusion

GB's electricity market is no longer fit for purpose. A system designed for an era of fossil-fuel dominance now acts as a brake on the clean power transition, inflating bills, delivering windfall profits and undermining political support for decarbonisation. At the very moment when low-cost renewables should be driving down household and business energy costs, the market structure continues to tether prices to gas.

This report has shown that a Single Buyer model offers a credible and practical alternative. By contracting directly with all generators, centrally dispatching power and procuring flexibility in a planned way, it would eliminate excess rents, smooth volatility and pass through the benefits of cheap renewable power to end-users. The evidence from comparable systems internationally — France, Québec, South Korea — demonstrates that this model can deliver affordability, stability and investment at scale.

The potential consumer savings are substantial. Depending on wholesale price trajectories and the depth of reform, the Single Buyer could deliver £41–75bn in cumulative savings by 2030, equivalent to £125–198 per household annually. These savings would flow not just to households, but also to businesses and public services, easing the wider cost of living crisis and strengthening the competitiveness of UK industry.

Implementing a Single Buyer will not be without challenges. It requires legislative reform, careful management of cross-border trade and robust governance to build investor confidence. Yet the administrative costs are modest compared with the £50–60bn spent annually on electricity, and Britain already possesses much of the technical capacity needed to deliver such a transition.

The choice is therefore not whether reform is possible, but whether it is politically achievable. Continuing with the current model risks ongoing exposure to fossil fuel volatility, rising system costs and growing public disillusionment with net zero. By contrast, a Single Buyer would realign the power system with the realities of low-cost renewable energy, lock in lower costs and restore public consent for the clean power mission.

Appendices

Appendix 1 — Legacy Public PPA model methodology

The modelling assessed the potential bill savings that would result from transferring Great Britain's existing low-carbon generation — Renewables Obligation (RO) assets, legacy nuclear and large hydro — onto fixed-price Power Purchase Agreements (PPAs) under a single-buyer structure. It integrated detailed RO cohort data with stylised wholesale price trajectories from the *Clean Power 2030* (CP2030) analysis, extending to 2045.

This integrated model therefore quantifies annual and cumulative consumer savings from placing all legacy low-carbon generation under cost-reflective PPAs.

1. Wholesale Price Scenarios

The baseline wholesale counterfactual price path is derived from the CP2030 "Flexible Future" (FFR) scenario published by the National Energy System Operator (NESO). This series begins at £118/MWh in 2027, gradually declining to approximately £110/MWh by the mid-2030s, before stabilising around that level through to 2045.

Two sensitivity cases were constructed to test price risk:

- A High scenario, starting at £147/MWh in 2027, representing an upper-bound trajectory aligned with OBR futures-based price forecasts for the late 2020s.
- A Low scenario, starting at £84/MWh in 2027, consistent with Cornwall Insight medium-term projections of lower post-crisis power prices.

Both sensitivities retain the same year-on-year shape as the CP2030 FFR path, simply shifted upward or downward by a fixed margin (+£29 and –£34 respectively).

Each scenario represented the reference price against which consumer savings from fixed PPAs are calculated.

2. Renewables Obligation (RO) Cohort Representation

The RO component of the model is constructed from UKERC's Pot-Zero 2025 Update dataset (Table A1), which records annual capacity additions by technology between 2005 and 2019. Six technology classes are included: onshore wind, offshore wind, solar PV, landfill gas, "fuelled" biomass/CHP (excluding Drax conversions), and other renewables.

Each cohort is assigned:

- A load factor based on technology averages: onshore 26.3 per cent, offshore 41.4 per cent, solar 10.9 per cent, landfill gas 55.3 per cent, fuelled 55.9 per cent, and other 39.0 per cent.
- A ROC banding schedule corresponding to Ofgem policy eras (e.g. onshore 1.0 ROC/MWh until 2014, 0.9 thereafter; offshore 2.0 until 2016, tapering to 1.8 from 2018).
- A technical lifetime of 25 years for wind and fuelled biomass, 30 years for solar PV, 20 years for landfill gas, and 40 years for other minor sources.

Each project receives 20 years of RO support, concluding in 2036 in line with Ofgem policy. The model sums the annual output of all cohorts still operational in each year to obtain total RO generation, expressed in MWh.

3. RO levy and Buy-out Price

The RO levy is calculated by multiplying each active cohort's MWh output by its ROC banding and the annual buy-out value, which represents the per-ROC consumer subsidy.

A buy-out value of £67.06/ROC is applied for 2025/26 and then uprated by 3 per cent per year through 2045. This yields a rising series of RO subsidy costs, reaching approximately £104/ROC by 2045 in nominal terms. The RO levy is expressed in £ billions per year as:

$$ROLevy = \sum_{i} \left[MWh_i \times \left(\frac{ROCs}{MWh} \right)_i \times Buyout\pounds \,/\, ROC \right]$$

This levy represents the consumer cost removed if legacy RO contracts were cancelled.

4. PPA Strike Prices and Savings Calculation

For each wholesale price scenario, the model applied three illustrative fixed PPA strike prices for the RO portfolio: £30/MWh, £50/MWh, and £80/MWh.

For each year (t) and strike price (s):

$$ROSaving_{t,s} = (Wholesale_t - PPA_s) \times ROOutput_t$$

This value represents the reduction in consumer electricity costs if RO generators were paid a fixed PPA price rather than the wholesale market rate.

5. Nuclear and Hydro Assumptions

The model incorporates two additional low-carbon asset classes that currently receive wholesale market revenues:

- Nuclear generation, assumed to earn a £55/MWh cost-reflective PPA.
- Large hydro, assumed to earn £45/MWh.

These PPA values are based on central estimates from the Helm Review (2017), UKERC cost benchmarks, and recent Carbon Tracker analyses.

Nuclear output is modelled to decline linearly from 25 TWh in 2027 to 12 TWh in 2045, approximating the retirement of AGR reactors while omitting the new Hinkley point C. Hydro output is held constant at 5.5 TWh per year.

Wholesale savings for each are computed as:

$$Saving_t^{Nuc} = (Wholesale_t - 55) \times MWh_t^{Nuc}$$
$$Saving_t^{Hyd} = (Wholesale_t - 45) \times MWh_t^{Hyd}$$

6. Aggregation and Cumulative Results

For each year, the model aggregates:

1. Total wholesale savings = RO savings + nuclear savings + hydro savings.
2. Total including RO-end savings = Total wholesale savings + RO levy.

Cumulative series are produced for both categories by summing all prior years. A final comparative chart plots the cumulative wholesale savings at £50/MWh across the three price scenarios (FFR = £118, High = £147, Low = £84), illustrating the sensitivity of consumer benefits to underlying market conditions.

Table A1:

Category	**Source**
Wholesale trajectories	NESO, 2023. Available here.
High/Low price anchors	OBR Fiscal Forecast Tables, 2023. Available here. Cornwall Insight, 2023. Available here.
RO cohort capacities, load factors, lifetimes	UKERC, 2025. Available here.
RO buy-out price and growth	Ofgem, 2025-2026. Available here.
Nuclear/hydro PPAs and cost context	DESNZ, 2023. Available here. Helm Review, 2017. Available here.

Appendix 2 — Strategic Gas Reserve Methodology and Assumptions

Our projections for gas profits are based on the volume of gas generation projected in NESO's CP 2030 two scenarios and an extrapolation of the widening operating margins observed over the last decade.

1. Applying Clean Power 2030 (NESO) pathways

The CP2030 scenarios model the volume of gas generation falling to 27–32 TWh by 2030. The future evolution of gas use follows the National Energy System Operator's CP2030 pathways. Under the Future Flex and Renewables (FFR) scenario, rapid deployment of renewable capacity and storage reduces gas generation to 27 TWh in 2030. Under the New Dispatch (ND) scenario, gas generation only falls as far 32 TWh in 2030, with new abated gas capacity needed to make up for the insufficient expansion of flexibility. Both scenarios see continued decline in plant load factors, and the increasing relative importance of the balancing mechanism to gas operations.

2. Financial baseline

Based on firm-level annual financial statement data for UK-registered companies holding an Ofgem electricity generation licence (and no other Ofgem licence) that could be associated with gas generation rather than any other technology, we observe a general upward trend in aggregate margins. In particular, the 2020s marks a new era of operating profitability relative to weak profitability in the 2010s. Our observed operating margins in the financial statements are consistent with the margins implied by cost and revenues estimated by UCL analysis, based on half-hourly price and generation data. Assuming a certain degree of hedging both fuel purchases and electricity sales in forward markets, they estimate gas plant operating profits of roughly £3.2 billion out of £19.2 billion in revenues in 2022. Our data shows 2022 was a high point for these firms in terms of absolute profit, return on assets and margin relative to revenue.

3. Applying price scenarios

We combine these profit margins and generation volumes with the same three wholesale price scenarios detailed in Appendix 1 but adjusting for the skew of gas generation towards more expensive hours. The three scenarios refer to annual average prices of the wholesale market in total. Half-hourly Elexon data on generation by technology also shows a widening wedge between the volume-weighted average wholesale price observed in total and that observed by gas plants, from near parity in 2017 to over 10 per cent in 2025. We exponentially extrapolate this widening wedge over the forecast horizon, reaching 20 per cent by 2030. As noted in Chapter 1, this is justified in light of decreasing plant load factors and sharpening market power in the balancing mechanism.

4. Savings via profit reduction under RAB or nationalisation

Our model then uses differences in the cost of capital between the status quo merchant regime and alternative RAB or public ownership regimes to estimate the savings available through profit reduction. A merchant CCGT is assumed to operate at a 12 per cent IRR. Under nationalisation, the relevant public cost of capital is set at 2.5 per cent, while a RAB-regulated gas fleet uses a five per cent WACC. These ratios imply that nationalisation removes around 80 per cent of rents, while a RAB model removes around 60 per cent.

Overall, our model for projected absolute operating profits Π_t in year t under the status quo merchant regime can be expressed thus:

$$\Pi_t = \pi_t \alpha_t p_{w,t} V_t$$

where π_t denotes operating margin, α_t is the ratio of volume weighted average wholesale price facing gas plants and the overall market, $p_{w,t}$ is the average wholesale price for the overall market, and V_t is the annual volume of gas generation.

Absolute operating profits for a strategic reserve, under public ownership or a private RAB, are calculated thus:

$$\Pi_{\{public,RAB\}} = \left\{ \frac{2.5}{12}, \frac{5}{12} \right\} \times \Pi_{merchant}$$

The table below summarises the core input assumptions and external evidence used in the modelling of CCGT/OCGT profits and potential savings under Clean Power 2030.

Table A2:

Category	Assumption / Input	Value Used	Source
Historic baseline	2022 CCGT gross profit (wholesale + balancing)	£3.2bn	UCL, 2023. Available here.
	Historic operating margins among licence-holding firms associated with gas, 2017-24	8 per cent in 2017, 16 per cent in 2024	FAME data on Ofgem licencees. Available here. NG ESO, 2025. Available here.
	Half-hourly wholesale prices and generation by technology	77 TWh from gas at £94.80/ MWh in 2025	Elexon BMRS. Available here and here.
	Non gas share	72 per cent	NG ESO publications. Available here.
Clean Power 2030 Pathways (NESO)	Gas generation under ND pathway	32 TWh in 2030	NESO, 2024. Available here.
	Gas generation under FFR pathway	27 TWh in 2030	NESO, 2024. Available here.
Cost of Capital Assumptions	Nationalisation WACC	2.5 per cent	DMO. Available here.
	RAB-regulated WACC	Five per cent	Ofgem. Available here.
	Merchant CCGT WACC / IRR	12 per cent	Carbon Tracker; SSE/RWE. Available here.

Appendix 3 — Cost Assumptions for DSF Shortfall Scenarios

Modelling is based on the National Energy System Operator (NESO) estimate that the system could face a peak shortfall of 11 GW of demand side flexibility (DSF) by 2030 if planned flexibility measures do not materialise. Three proportional scenarios are constructed to test the implications of missing this target: a Modest (25 per cent), Material (50 per cent), and Severe (100 per cent) DSF shortfall. These correspond respectively to 2.75 GW, 5.5 GW, and 11 GW of missing peak-shifting capability by 2030. A linear trajectory between 2025 and 2030 is assumed for each scenario.

1. Replacement Capacity and Capital Expenditure

If DSF is not delivered, the model assumes the system compensates with additional open-cycle gas turbines (OCGTs). A central capital cost of £0.8bn per GW — equivalent to £800/kW — is applied. This value aligns with the DESNZ Electricity Generation Costs (2023) estimates for peaking plant and is consistent with OECD/IEA benchmarks of around $500/kW (pre-inflation).

Incremental Capex = Shortfall (GW) × £0.8bn/GW.

2. Capacity Market (CM) costs

Replacement OCGTs are assumed to receive CM contracts to ensure reliability. The analysis applies a real £65/kW/year clearing price, based on the T-4 2027/28 auction, and uses a derating factor of 0.93, consistent with CM technology-specific derating guidance.

Annual CM cost = Shortfall (GW) × 0.93 × £65m/GW.

3. Balancing and Constraint Costs

NESO estimates that without required upgrades and flexibility, balancing costs could reach approximately £8bn per year by 2030. A conservative attribution of 25 per cent of this risk to DSF under-delivery is used to avoid over-estimating flexibility impacts. Under this assumption, the Severe case (11 GW) DSF shortfall implies ~£2bn per year in additional balancing expenditure.

4. Forgone system-wide savings (ADE envelope, rescaled to CP2030)

In its *Flexibility in Great Britain* study (2020/21), the Association for Decentralised Energy (ADE), with the Carbon Trust and Imperial College, estimated £10–17bn per year of whole-system savings in a high-flex 2050 electricity system. These savings reflect avoided generation and peaking, reduced balancing and curtailment, deferred network reinforcement and improved utilisation of low-carbon assets.

Because ADE's scenario reflects 2050 conditions and includes technologies beyond DSF (notably interconnectors, storage and thermal flexibility), their numbers are rescaled to align with the 2030 DSF-only requirement under CP2030. ADE's modelling suggests a DSF-only end-state of ~35 GW (EV smart/V2G, domestic appliances, and industrial/commercial DSR). Relative to the 11 GW CP2030 DSF requirement, this implies a proportional scaling factor: 11 GW / 35 GW ≈ 0.31.

Applying this factor to ADE's £10–17bn /year yields a 2030-aligned forgone-savings envelope of £3.1–5.3bn/year, with a central estimate of £4.4bn /year. These values are not additive to the NESO hard cost estimates: the ADE envelope already contains avoided OCGT build, avoided CM payments, and lower balancing costs. NESO's hard costs should therefore be interpreted as a subset of the ADE savings envelope.

The key sources and assumptions for these estimates are provided below.

Table A3:

Topic	Parameter / Value	Source
DSF shortfall	11 GW by 2030 (worst case)	NESO, 2024. Available here.
OCGT build cost	£0.8bn/GW (≈ £800/kW)	DESNZ, 2023. Available here.
International capex benchmark	~$500/kW pre-inflation	IEA/OECD. Available here.
CM clearing price	£65/kW/yr (T-4 2027/28)	EMR Delivery Body, 2024. Available here.
Derating factor	0.93 for OCGTs	Capacity Market Derating Guidance. Available here.
Balancing cost risk	£8bn/yr risk -> 25 per cent DSF share	NESO, 2025. Available here.
ADE savings envelope	£10–17bn/yr (high-flex 2050)	ADE, Carbon Trust & Imperial College, 2020/21. Available here.
ADE DSF-only potential	≈35 GW DSF-only	Imperial College modelling annex (ADE study) — same link as above
CP2030 DSF requirement	≈11 GW by 2030	NESO, 2024. Available here.
Price base	2024£	Model assumption.

Appendix 4 — Central Dispatch Assumptions

The savings estimates are grounded in quantitative modelling published by FTI Consulting for NESO in March and April 2025. Year-by-year estimates require interpolation between modelled anchor points and should be treated as indicative scenario estimates rather than precise forecasts.

Data sources

Three documents underpin the model. The “NESO Annual Balancing Costs Report 2025” provides outturn costs for FY2024/25 and projected balancing cost trajectories to 2035 by scenario. The baseline thermal constraint trajectory is derived from Figure 29 (Holistic Transition, Expected Network scenario). The “FTI Consulting / NESO FES22 Core Report” (March 2025) provides the primary quantitative inputs: annual-level thermal constraint costs under self-scheduling and day-ahead transfer payments under central dispatch for 2030, 2035 and 2040, together with forecast error handling costs for those years. The “FTI Consulting / NESO FES24 Update” (April 2025) applies updated generation and network assumptions, producing lower projected savings consistent with a more ambitious network build.

Central dispatch efficiency: Transfer payment ratio

Under self-scheduling, thermal constraints are resolved post-gate-closure through expensive pay-as-bid Balancing Mechanism actions. Under central dispatch, NESO resolves the same constraints a day ahead via cheaper "make whole" transfer payments, substituting lower-cost resources (interconnectors, batteries, nuclear) for the more expensive last-minute BM options. The ratio of transfer payments to self-scheduling constraint costs improves as congestion increases, because higher congestion gives NESO greater scope to substitute between redispatch options at the day-ahead stage.

The FES22 Core Report provides three anchor points: a ratio of 78 per cent at £0.9bn constraints (2030), 51 per cent at £5.3bn (2035) and 56 per cent at £5.5bn (2040). The model interpolates linearly between 78 per cent at £1bn and 52 per cent at £5bn, producing ratios of approximately 55 per cent at £4.5bn, 48 per cent at £5.5bn and 47 per cent at £5.8bn for the peak congestion years. The gross constraint saving is the difference between self-scheduling constraint costs and the transfer payments that replace them.

Forecast error costs

Central dispatch locks in the generation schedule a day ahead, leaving forecast errors in wind and solar output to be resolved in the Balancing Mechanism rather than through the lower-cost intraday trading available under self-dispatch. The FES22 Core Report models these at approximately £0.6bn in 2030 and £0.9bn in 2035, growing with the expanding intermittent renewables fleet. The model interpolates between these anchor points.

These costs are conservative: the FES22 model assumes no intraday market operates alongside central dispatch, whereas European precedent (Italy, Ireland, Greece) shows that intraday markets can and do coexist with central scheduling, reducing forecast error costs by an estimated £0.3–0.5bn per year.

Net annual saving

Net saving = Thermal constraint costs (self-dispatch) − DA transfer payments (central dispatch) − Forecast error costs.

Other balancing costs (reserve, response, voltage, stability) are held unchanged, consistent with the FTI scope. Co-optimisation of energy and ancillary services procurement — which FTI separately estimated could deliver a further £4.9bn of benefit over 2025–2035 — is excluded.

Key sensitivities

The model is most sensitive to four assumptions.

- First, the *baseline constraint trajectory*: this is the dominant driver, and the range between the CP30 recommended network (£1.8bn thermal constraints in 2030, following accelerated delivery of three critical projects) and the no-further-network scenario (£12.7bn) implies a very wide range of potential central dispatch savings.
- Second, the *transfer payment ratio*: a ±5 per centage point shift moves the cumulative net saving by approximately ±£1.5bn.
- Third, *forecast error costs*: if an intraday market is assumed alongside central dispatch, cumulative savings improve by an estimated £1.5–2.0bn.
- Fourth, *implementation year*: a one-year delay from FY2027/28 to FY2028/29 foregoes approximately £1.5bn; a two-year delay foregoes approximately £3.6bn.

Relationship to previous estimate

The revised methodology produces net savings of 19–32 per cent of self-scheduling constraint costs at peak. The cumulative net saving of £6.8bn over FY2027/28–FY2030/31 is comparable to the previous ramp scenario total of £5.98bn, but with a more defensible analytical basis, a more accurate year-by-year profile, and a clear post-2031 tapering as network delivery reduces the congestion that makes central dispatch most valuable.

$$DAT_t = T_t \times \left[\alpha_H + (\alpha_H - \alpha_L) \frac{T_t - T_H}{T_H - T_L} \right]$$

Appendix 5 — Battery Fleet Single Buyer Cost Savings Methodology and Assumptions

The model computes a levelised cost of service (LCOS) — the per-megawatt-hour price at which each technology must sell electricity to recover its capital and operating costs over its lifetime, at the specified cost of capital. This is used as a proxy for the consumer price under each scenario. Under the merchant case this represents the minimum expected market revenue required to sustain investment; under the Single Buyer/RAB case it represents the regulated allowed revenue.

1. Capex (£/kWh)

For short-duration batteries, the model assumes an installed cost of £500/kWh for a 4-hour system, equal to approximately £2 million per MW of rated capacity. This aligns with the DESNZ *Electricity Generation Costs 2023 Update*, which projects £480–520/kWh for utility-scale Li-ion by 2030.[76] It also matches the cost benchmarks reported in BNEF's *Levelized Cost of Storage* (LCOS) Q2 2024 dataset, which estimates approximately £450–500/kWh at 2024 exchange rates.[77]

For long-duration storage (LDES), a central £500/kWh for a 10-hour asset is used. Although LDES costs remain uncertain, this value sits within the £400–700/kWh range described in Lazard's *Levelized Cost of Storage Plus (LCOS+)* 2023 report covering flow-battery, CAES, and liquid-air technologies.[78] NESO's *Clean Power 2030* modelling treats LDES costs as uncertain and applies wider sensitivities.[79]

2. Cycles per year

Short-duration batteries are assumed to deliver 350 cycles per year. This is consistent with cycle-range assumptions in NESO's "Clean Power 2030" modelling (300–400 cycles depending on penetration) [80] and with BNEF's 2023 UK battery market analysis, which implies 330–360 cycles annually.[81]

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[76] "Electricity generation costs 2023 update", Department for Energy Security & Net Zero, 2023. Available here.

[77] "Levelized cost of storage (LCOS), Q2 2024", BloombergNEF, 2024. Available here

[78] "Levelized cost of storage plus (LCOS+)", Lazard, 2023. Available here.

[79] "Clean Power 2030", National Energy System Operator, 2024. Available here.

[80] Ibid.

[81] "Levelized cost of storage (LCOS), Q2 2024", BloombergNEF, 2024. Available here.

For LDES, 220 cycles per year are assumed. This is consistent with the 200–250 cycle range reported in Lazard's LCOS+ 2023 dataset and the LDES Council's 2022 "Net-Zero Power" report.[82] CP2030 also assumes low annual utilisation for long-duration storage because it is dispatched primarily for adequacy rather than daily arbitrage.[83]

3. Duration

Short-duration batteries are modelled at 4 hours, the midpoint of the 2–6-hour range used across NESO's CP2030 model. Long-duration storage assets are assigned an average discharge period of 10 hours, consistent with the >6-hour category used in CP2030, and with the 8–12-hour configurations reported in LCOS+ and LDES Council studies.

4. Lifetime

Battery systems are assigned a 15-year lifetime, consistent with DESNZ EGC 2023 assumptions for Li-ion systems before augmentation or repowering.[84] LDES systems are assigned a 25-year lifetime, which is typical for pumped-hydro and flow battery designs in Lazard's LCOS+ reporting and the LDES Council's 2022 analysis.[85]

5. Round-trip efficiency

Battery round-trip efficiency (RTE) is set at 88 per cent, consistent with DESNZ and BNEF benchmarks.[86] LDES RTE is set at 80 per cent, matching the 70–85 per cent range reported for multi-hour flow and LAES systems in LCOS+ 2023.[87]

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[82] "Levelized cost of storage plus (LCOS+)", Lazard, 2023. Available here.

[83] "Clean Power 2030", National Energy System Operator, 2024. Available here.

[84] "Electricity generation costs 2023 update", Department for Energy Security & Net Zero, 2023. Available here.

[85] "Levelized cost of storage plus (LCOS+)", Lazard, 2023. Available here.

[86] "Electricity generation costs 2023", Department for Energy Security & Net Zero, 2023. Available here.

[87] "Levelized cost of storage plus (LCOS+)", Lazard, 2023. Available here.

6. Operation and maintenance (O&M) costs

Fixed O&M is set at 1.5 per cent of capex per year. This parameter appears in DESNZ EGC datasets and BEIS technology cost-of-capital (hurdle-rate) studies.[88] Variable O&M is set at £5/MWh for batteries, following the National Grid ESO Future Energy Scenarios 2023 Technical Annex,[89] and at £7/MWh for LDES, based on mid-range LCOS+ values.[90]A degradation reserve is included to represent augmentation costs: £10/MWh for batteries, in line with BloombergNEF LCOS practice,[91] and £5/MWh for LDES, consistent with flow battery and LAES performance data.[92]

7. Cost of capital (WACC)

Two financing conditions are used:

- Merchant case: eight per cent nominal WACC, based on the BEIS / Europe Economics "Cost of Capital for Generation Technologies" update (2020), which recommends real pre-tax hurdle rates of 7.3–10 per cent for storage under merchant or partially merchant conditions.
- Single-Buyer case: five per cent WACC, consistent with de-risked public financing conditions (e.g., GBE proposals, Regulated Asset Base precedents) and the social time discount rate framework set out in HM Treasury's *Green Book*.

8. Price formation effect

This section sets out the methodology for estimating the price formation saving, which is presented as a separate and additive component alongside the LCOE saving in the Results sheet. The price formation saving captures the difference between what investors actually earn through market bidding and what it costs to operate the battery. Under a Single Buyer with direct dispatch authority, the ability to maximize the arbitrage at these moments of scarcity is reduced.

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[88] "Electricity generation costs 2023 update", Department for Energy Security & Net Zero, 2023.. Available here.

[89] "Future energy scenarios 2023: Technical annex", National Grid ESO, 2023. Available here.

[90] "Levelized cost of storage plus (LCOS+)", Lazard, 2023. Available here

[91] "Levelized cost of storage (LCOS), Q2 2024", BloombergNEF, 2024. Available here.

[92] "Levelized cost of storage plus (LCOS+)", Lazard, 2023. Available here.

Under merchant operation, battery operators submit bids and offers into the Balancing Mechanism and wholesale market at prices that maximise their revenue. Rationally, operators bid near the prevailing market clearing price rather than at their variable operating cost. Evidence from the GB market shows that day-ahead price spreads averaged £57–70 per megawatt-hour in 2025, with intraday spreads and Balancing Mechanism offer prices reaching significantly higher levels during tight supply conditions.[93]

Under Single Buyer direct dispatch, batteries are instructed at variable operating cost (£17 per megawatt-hour, comprising variable O&M of £5–7 per megawatt-hour and degradation reserve of £5–10 per megawatt-hour as modelled in Section 6). The price formation saving per dispatched megawatt-hour is the difference between the average clearing price and this variable cost. A gross spread of £43 per megawatt-hour is used (midpoint of £57–70 less £17), to which a 30 per cent haircut is applied to account for dispatch periods where the clearing price is near but not at the scarcity level, giving a central rate of £30 per megawatt-hour. This rate is applied to the energy dispatch portion of fleet output (60 per cent of gross throughput TWh), reflecting that frequency response and availability-based services operate under different pricing mechanics.[94]

Key sources are summarised below.

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[93] "GB BESS index: De-risking BESS returns in Great Britain Q3 2025", Modo Energy, 2025. Available here.

[94] "Balancing cost winter report 2023/24", National Energy System Operator, 2024. Available here.

Table A4:

Function	Source
Provides capex ranges for Li-ion batteries (480–520 £/kWh), Li-ion lifetimes (~15 years), battery round-trip efficiency benchmarks, and fixed O&M assumptions (1.5 per cent).	DESNZ, 2023. Available here.
Supports WACC assumptions: merchant WACC of ~eight per cent and the 2–3 p.p. uplift between contracted vs merchant financing that underpins the merchant risk premium.	Europe Economics, 2020. Available here.
Used to justify the five per cent "Single Buyer" WACC scenario, reflecting low-risk public financing benchmarks.	HM Treasury, 2018. Available here.
Provides cost ranges for LDES technologies (£400–700/kWh), round-trip efficiency assumptions (70–85 per cent), cycles/year for 8–12h storage (200–250), and variable O&M inputs.	Lazard, 2023. Available here.
Used for LDES cycle assumptions (200–250/yr), 10–12h duration archetypes, 25-year lifetimes, and indicative operational profiles.	LDES Council, 2022. Available here.
Provides evidence of GB merchant revenue volatility supporting the merchant risk premium (e.g., fluctuating spreads, FCAS saturation).	Modo Energy. Available here.
Source for £5/MWh variable O&M assumption for Li-ion; provides broader system context for battery utilisation and balancing roles.	National Grid ESO, 2023. Available here.
Provides battery (23–27 GW) and LDES (4–6 GW) deployment ranges; cycle assumptions (300–400 for batteries); treatment of LDES as adequacy resource.	NESO, 2024. Available here.
Used for validation of capex (£450–500/kWh), degradation reserve assumptions (£10/MWh), and cycle ranges (~330–360).	BloombergNEF. Available here.
Provides market-based justification for merchant risk premia, including revenue cannibalisation and increasing volatility with fleet growth.	Aurora Energy Research, 2022–2023. Available here.

Appendix 6 — 10GW Public Generation Assumptions

1. WACC build-up

Under a conventional private AR6-style financing model, typical assumptions include a gearing ratio of 70:30 between debt and equity, with a risk-free gilt rate of four per cent over twenty years. A debt spread of +200 basis points results in a cost of debt of approximately six per cent, while an equity premium of +700 basis points gives a cost of equity of about 11.0 per cent. Allowing for a 25 per cent tax shield on debt, the nominal weighted average cost of capital (WACC) is calculated as 0.3×11 per cent + 0.7×6 per cent × (1−0.25) = 8.5 per cent. This is consistent with the hurdle rates outlined in DESNZ recent estimation of financing costs for renewable energy. Adjusting for roughly two per cent inflation produces a real WACC of about 6.3 per cent, which aligns with AR6 strike prices around £82/MWh.

In comparison, under a public or Great British Energy (GBE) financing structure, the assumptions reflect a de-risked, state-backed entity. Here GBE is envisaged to borrow at close to gilt rates, averaging 4.8 per cent at the time of writing.

2. Strike price calibration

At a WACC of 8.5 per cent (private financing), the strike price is approximately £92/MWh, as achieved in AR7. Under the public model with a 4.8 per cent WACC, the strike price would fall to around £64/MWh. The resulting financing delta of about £28/MWh is driven entirely by the reduction in the cost of capital, since other parameters such as capital expenditure, operating costs, load factor, and asset lifetime remain unchanged.

3. How much capacity £8bn of equity can support

With an 80:20 gearing ratio in the public model, the equity share represents 20 per cent of total project capital. An £8bn equity investment therefore supports £40bn of total capital expenditure. Using an assumed offshore wind capital cost of roughly £4.0m per MW, this equates to about 10 GW of installed capacity that could be delivered under the GBE framework.

4. AR8 programme impact

Assuming the AR8 allocation round represents a 10 GW build, with a 55 per cent load factor, each gigawatt produces approximately 4.82 TWh of electricity annually, giving a total output of around 48 TWh per year.

If all 10 GW were financed privately at a strike price of £92/MWh, the annual cost would be £92 × 48 TWh, or approximately £4.43bn per year. Under the GBE public financing model, with a strike price of £64/MWh, the annual cost would be £64 × 48 TWh, or about £3.07bn per year. The annual saving from public financing compared to private investment is therefore around £1.36bn.

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Publication design by Sophie Monk

June 2026

https://doi.org/10.25377/sussex.31342471

The author would like to thank interviewees from Octopus Energy, Regen and National Energy System Operator, and expert reviewers, Arthur Downing, Gareth Fearn, Stephen Hall, Matthew Lockwood, Madeleine Pauker and Chris Hayes. Any errors or omissions are the authors' own. Interviewees do not represent the views of their employers.

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