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By Brian Tam,
Alan Walker
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# Electricity Market Reform

## Overview

- Wholesale electricity market arrangements determine the prices that suppliers pay generators to procure electricity for their consumers. The arrangements also provide investment signals for generation and network infrastructure.
- There is a wholesale market for electricity across Great Britain, with separate arrangements for Northern Ireland. Wholesale electricity prices are set by trades between generators and suppliers, which are ultimately passed on to consumers in the retail market.
- Electricity market reforms are needed if decarbonisation of the electricity system is to be achieved by the Government's 2035 target, while ensuring affordability for consumers and that the system remains reliable. These reforms are being considered by the Government in the Review of Electricity Market Arrangements (REMA).
- Proposed reforms include modifying government support mechanisms that promote decarbonisation and ensure security of supply, implementing location dependent wholesale prices to reduce network constraints, and options to pass on the low costs of renewables to consumers by separating the market.
- A future Government consultation in autumn 2023 will put forward proposals for packages of reforms.
- Opinions differ over the degree and pace of reforms to the market arrangements needed.

# Background

The UK Government has committed to decarbonising the electricity system by 2035.[1]

There is a general consensus across industry and academia[2] that the current electricity market arrangements will need reform to deliver the pace and scale of change to meet this target, although opinions vary on the degree and pace of reform needed.

In 2022, the then Department for Business, Energy & Industrial Strategy launched its Review of Electricity Market Arrangements (REMA)[3] consultation. The summary[2] of responses[4–7] has been published, and a subsequent consultation in autumn 2023 will put forward packages of reforms.[8]

Reforms are required to incentivise greater decarbonisation, keep prices affordable for consumers and maintain a secure and reliable system.[2] Equally, there is agreement that any reforms should consider investor confidence and avoid disrupting the deployment of new generation and network infrastructure.[2]

REMA focuses on the wholesale electricity market in Great Britain (GB). The electricity market in Northern Ireland operates as part of a Single Electricity Market with the Republic of Ireland,[9] and is outside the scope of this briefing.

# Current wholesale electricity market arrangements

The GB electricity system is illustrated in Figure 1 and described below. REMA is concerned with the wholesale electricity market indicated within the dashed border and it involves:

- Generators[*] deliver electricity to consumers via the national high-voltage transmission and local low-voltage distribution networks.[10–12] Generators receive revenue for the electricity they generate from trades in the wholesale market, or through power purchase agreements[†13] or a Contract for Difference (CfD).[14]

- Some smaller (distributed) generation feeds directly into the distribution network.[15]

- Suppliers purchase electricity, either from trades in the wholesale market or via contracts with generators, to sell to their consumers through the retail market.

- Operators of the transmission and distribution networks charge users for their connection and use of the networks to maintain, operate and invest in the

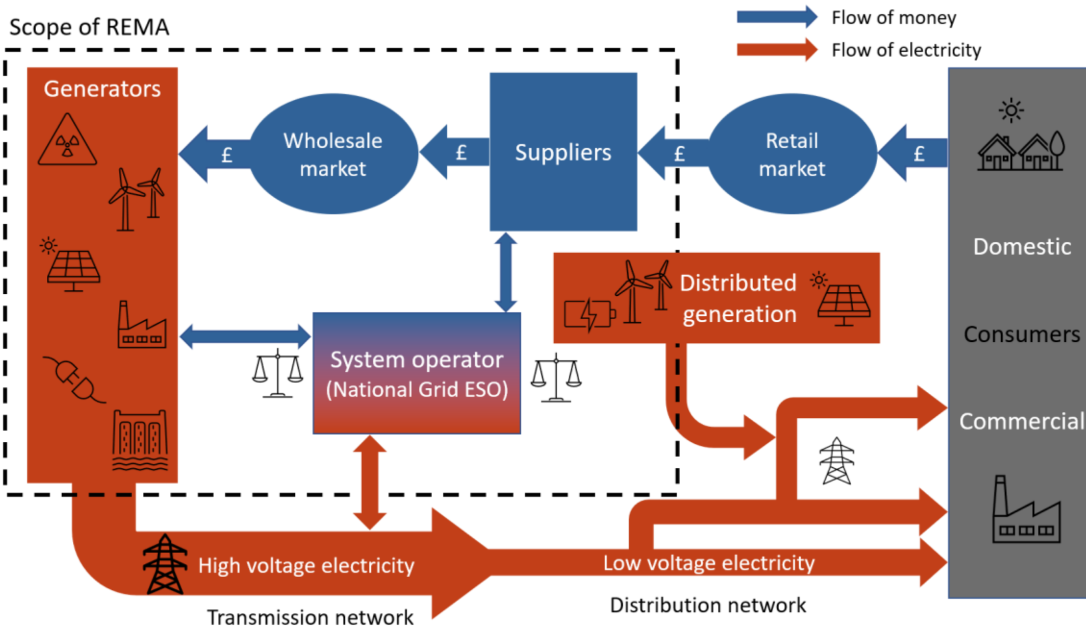
[*] Major generators' sources include: gas, biomass (PN 690), hydro, nuclear (PN 687), wind (PN 602), solar and interconnectors with neighbouring countries (PN 569).

[†] Power purchase agreements are long-term electricity contracts between a generator and a typically large, commercial consumer.

infrastructure (CBP 8472).[16,17] Some companies operate and compete in multiple parts of the market (CBP 7243).

- The system operator (see Box 1) works with all parties to ensure real-time system operability.[18]

**Figure 1: Representation of the electricity market participants**




## Box 1: Role of the system operator

The System Operator (SO) is the entity responsible for ensuring a secure electricity supply. National Grid ESO is the current system operator for the GB electricity system and Ofgem is the independent energy regulator.[19]

Supply and demand must always be kept in balance across the network. To achieve this aim, the SO employs **Balancing Services**[20] including frequency and voltage response, reserve services, system security services and, recently, demand flexibility services.

These services provide **flexibility** (PN 587), which gives the SO the ability to control the output of generation or manage levels of demand. Flexible generation or demand can be turned on or off – or 'dispatched' – as required. Currently, generators 'self-dispatch', meaning they choose when to supply.

Part of the function of the SO is to **rebalance** the system to account for discrepancies between predicted and actual supply and demand, and manage network constraints. The SO makes **constraint payments** to generators in constrained areas to reduce output, known as 'curtailment', and to procure flexible electricity supplies at higher cost.[21]

In the current system, flexibility is largely provided by thermal generation (mainly gas), pumped hydro power and interconnectors but as the grid decarbonises, new, low-carbon sources of flexibility will be required (PN 688).

Following privatisation in the late 1980s,[22] a wholesale electricity market based on marginal pricing was established to ensure a secure supply at the lowest cost for consumers.

The marginal price is defined as the price offered by a generator for the most expensive unit of electricity needed to meet immediate demand – the ’spot price’. Marginal pricing is where any electricity generated in a given period (outside bilateral trades) receives the marginal price,[23] also known as ‘pay-as-clear’.

Renewable electricity from wind or solar and nuclear power have relatively low marginal costs[24] because they have zero or minimal fuel costs. Since the New Electricity Trading Arrangements reforms of 2001, an increasing proportion of electricity is traded in bilateral agreements between generators and suppliers over a range of time periods and so less of the market is sold at the marginal price.[25]

The need to decarbonise the electricity system led to the implementation of the Renewables Obligation in 2002.[26] This supported low-carbon generation by paying a premium to generators in addition to the wholesale price.[27] In 2021, Renewables Obligation generation accounted for 31% of UK generation.[28] This proportion will decrease over time because the scheme was closed to new generators in 2017 and the remaining contracts will gradually run out.[27]

Greater decarbonisation and a need to maintain system reliability with an increasing proportion of variable generation was partially addressed by the Electricity Market Reform of 2013. This reform introduced Contracts for Difference (CfDs), the Capacity Market (CM), the carbon price support and the emissions performance standard.[29]

## Contracts for Difference (CfDs)

CfDs are a Government support mechanism for incentivising renewable and low-carbon generation.[14] They are long-term (typically 15-year) contracts that guarantee a ‘strike price’ for electricity generated. When prices are low, generators receive a top-up and when prices are high, generators pay back the difference. CfDs give revenue certainty for generators and lower the cost of borrowing capital for new developments.[30] Most stakeholders consider CfDs to have been successful in growing renewable generation capacity and support its continuation in some form.[2]

CfDs are awarded to generators through auctions, held separately for different groups of technologies based on their maturity.[31] These auctions determine the strike prices, which have consistently decreased to date.[32,33] CfDs made up about 7.5 GW[‡] of installed capacity in early 2023 and are projected to increase to almost 30 GW in 2030.[34] The total UK generation capacity was 77 GW in 2021.[35] Further growth in the proportion of CfDs in the market and price competition is expected to lead to lower consumer prices.[36]

## Capacity Market (CM)

The CM is a Government support mechanism to ensure the system has sufficient reliable generating capacity and to support active demand management.[37] Auctions

‡ A gigawatt (GW) is a unit of the rate of electricity generation equal to a billion watts.

award agreements to generators and demand side response for payments for capacity to meet security of supply criteria (PN 676).[38] Both new generation and existing generation may bid, with gas-fuelled plants winning 68% of the most recent auction in February 2023 for delivery in 2026-27.[39] Stakeholders have mixed opinions as to whether the CM in its current form is compatible with a fully decarbonised electricity system.[2]

## Carbon Price Support and Emissions Performance Standard

The Carbon Price Support increases fuel costs for carbon-emitting generators (CBP 5927), and the Emissions Performance Standard limits emissions of new facilities,[40] effectively banning new coal-powered generation. As a result of these measures and the doubling of renewable and low-carbon generation from less than 30% to around 55% of the generation mix, the share of coal-fired electricity reduced from 30-40% in the early 2010s to 2% in the early 2020s.[41]

# Criticisms of the current arrangements

Given the scale of the transition required in the electricity system, the current market arrangements have been criticised by stakeholders as requiring reform.[2,3] The following four sections highlight areas that are particularly challenging.

## Decarbonisation by 2035

The share of renewable generation has increased significantly, making up 40% of electricity generation in 2021 (55% including low-carbon generation).[35] There is, however, concern that the scale of new infrastructure required for decarbonisation may not be delivered by the current market arrangements.[2]

Total investment needed in electricity supply and network infrastructure is predicted to rise to around £20 billion annually in the 2030s.[42,43] An additional challenge is the need to meet increases in electricity demand, estimated by the Climate Change Committee in their Balanced Pathway to be 50% by 2035 and 100% by 2050 with the electrification of transport, heating and industry.[41,44]

Stakeholders have also criticised CfDs as being vulnerable to rising costs from supply chain issues, incentivising maximum output even when the generation adds to system costs, and not sufficiently supporting other less-utilised technologies such as marine energy (PN 625) and geothermal energy (PB 46).[2]

## Flexibility and security of supply

System stress will increasingly be driven by weather patterns as the electricity mix transitions from one dominated by large, easily dispatchable fossil-fuelled generators (which currently supply the bulk of balancing services, see Box 1) to one with more variable renewables.[45] Significant deployment of new flexible low-carbon generation, storage (PN 688) and demand management will be needed to replace gas generation and mitigate the increased temporal variability in renewable generation supply.[2]

The capacity market is presently the primary mechanism for ensuring security of supply, but is criticised as lacking incentives for low-carbon characteristics or flexibility services other than capacity.[2] The Government are holding a consultation on the future of the CM.[46]

# Locational signals that minimise system cost

The wholesale electricity market presently allows market participants to trade electricity irrespective of their location. The SO only rebalanced 5% of the electricity market prior to 2012 (see Box 1),[47] when the market was dominated by large, flexible generators. Currently, balancing services regularly make up over 50% of national demand[47] in large part due to the increase in network constraints. Rebalancing payments from the SO are predicted to rise from £0.5-1 billion in 2022[48] to £2-2.5 billion per year in the 2030s,[45,48] and these are recouped from end-use consumers.[49]

Generators and suppliers are subject to Distribution Use of System and Transmission Network Use of System charges,[16,17] but their effectiveness as incentives for optimising asset location is disputed among stakeholders.[2] Some stakeholders support the introduction of stronger locational price signals so that the market arrangements more accurately reflect the physical realities of the system and lead towards an optimal network.[2,50]

# Affordability and price volatility

Wholesale electricity prices were an average of £50 per MWh[§] between 2010-2019[51] and were dependent on the price of gas most of the time (84% in 2019).[52]

Wholesale electricity prices ranged between £100-500 per MWh in 2022 due to the energy price crisis caused in part by the war in Ukraine (CBP 9491) and in spite of the low prices of renewable energy (CfD strike prices for delivery in 2024-25 for onshore wind were £42/MWh, offshore wind £37/MWh and solar PV £46/MWh[33] in 2012 prices).

This increase has been temporarily mitigated by the Electricity Generator Levy[53] and the Energy Price Guarantee for consumers (CBP 9714).[54] Prices may be mitigated further by measures in the retail market such as targeted support for vulnerable households.[55]

There may be increasing wholesale price volatility as the market price fluctuates between the higher prices for flexible generation and the near zero marginal cost of renewables, instances of which may increase as renewables become a larger proportion of the generation mix. When there is a surplus of renewable energy the wholesale price could drop to very low levels, also known as 'price cannibalisation'.[56]

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[§] A megawatt-hour (MWh) is a unit of energy equal to a million watts running for an hour. Total UK electricity demand in 2021 was 334,200,000 MWh.[35]

# Proposed market reforms

Proposed market reforms being considered by the Government are discussed in isolation in this section; the future market arrangements are, however, likely to include combinations of interacting reforms or a sequence of reforms.

## The case for change

Stakeholders' positions on the case for change range from advocating for a comprehensive and immediate overhaul to advocating for an incremental change approach by modifying existing market mechanisms.[2] Those in favour of incremental reforms feel that this approach is most likely to maintain investor confidence in the market, preventing an investment hiatus.[57,58]

However, the need for policy clarity[58] from the Government on the path forward is highlighted by most stakeholders. GB will also need to compete with attractive investment environments created by the United States Inflation Reduction Act and EU Green Deal Industrial Plan.[41,59]

## Locational energy pricing

Locational energy pricing is a proposed alternative to single wholesale market pricing.[60] It aims to provide locational market incentives (augmenting network charges and balancing services) by allowing prices to vary between network locations based on the local generation capacity, constraints of the network, and demand.[3] Two models, zonal and nodal, are possibilities.

- Zonal pricing separates the GB electricity system into broad zones based on network constraints. Each zone would have its own wholesale market and the supply and demand would be balanced within the zone and across the boundaries with neighbouring zones.
- Nodal pricing is a more granular regime where prices differ between 'nodes', such as the boundary between the transmission and distribution systems.[61] Nodal pricing is often referred to as Locational Marginal Pricing (LMP) and requires a shift from self-dispatch, where generators dispatch electricity that is then rebalanced by the SO, to centralised dispatch where generators bid into a market and are then dispatched by the SO.

### Benefits of zonal and nodal pricing

Under locational energy pricing, zones or nodes constrained by the network are limited in the amount of electricity that can be exported or imported. In times of excess local generation, there is an oversupply that lowers prices. When there is deficient local generation, there is an undersupply that raises prices.

This mechanism results in prices that vary across the network depending on real-time local generation and network constraints. Flexible generation, flexible demand, and interconnectors may then be incentivised to dispatch in a way that reduces system constraint payments (see Box 1).

It could also incentivise developers to build generation in places that are better connected or new sources of demand (including energy storage) in constrained areas.[50,62] The influence of pricing, however, on siting location of renewables is limited by geography and planning restrictions.[2]

For nodal pricing, locational signals are maximised, potentially improving the dispatch efficiency of generation and flexibility assets.[63] Total GB socioeconomic benefits are estimated by FTI Consulting for Ofgem to be as much as £31 billion between 2025-40 for a nodal market, and £15 billion in the same time frame for a zonal market.[64] Ofgem have yet to publish their own cost-benefits analysis.[65]

Zonal pricing in Europe and nodal pricing in the US and New Zealand have mostly been implemented successfully, but these markets have significantly less variable generation than that proposed for GB.[66]

### Challenges of zonal and nodal pricing

Nodal pricing substantially increases the regulatory and technical complexity.[67] There may be revenue uncertainty leading to higher investment risk,[68,63] and barriers to entry and transaction costs.[69] Developments in network capacity may also significantly impact local prices in a nodal pricing model.[70] These challenges, however, spread risks to parties who may be better placed to manage them and may be mitigated by additional financial instruments such as financial transmission rights and locational basis swaps.[71]

Whether a transition to locational energy pricing would lessen investor confidence or lead to a rise to the cost of capital[57] is debated among stakeholders.[2,50,64] A 'postcode lottery' situation may also arise,[63] where due to having limited possible locations, existing generators and consumers benefit or are penalised through no fault of their own without additional policies. Zonal or nodal boundaries may also need to change over time as the local generation and transmission changes.[63] There is a risk that the implementation of locational energy pricing would delay decarbonisation in the short-term.[72]

## Splitting the electricity market structure

Splitting the wholesale market is aimed at reducing the proportion of electricity sold for a gas-based price.[73] Separate markets for as-available, renewable electricity and flexible on-demand electricity[73,74] (receiving the marginal price) is suggested as a solution to affordability and to ensure the competitiveness of energy intensive industries.[75] As-available generation is variable and weather dependent, whereas on-demand generation is dispatchable.

A similar scheme is the dual-market Green Power Pool (GPP) model that would facilitate renewable energy being aggregated and the price savings, if any, distributed through various means including by being targeted to industries sensitive to electricity prices or vulnerable domestic consumers at affordable rates.[76]

Proponents for splitting the markets suggest it may allow more consumers to access affordable renewable energy and prevent excess profits for generators with low operating costs at times of high gas prices (as have been experienced recently).[2] Power pool models may be useful for local energy systems to secure their zero emission electricity supply.[77]

Opponents have stressed that details are uncertain about how split markets would operate in practice as this has not been tried in any equivalent markets,[2] although the operating principles have been detailed.[73] Splitting the market may result in an investment hiatus[78] and put decarbonisation by 2035 at risk. The as-available market consumers would also have to be exposed to the marginal price (or have support schemes[79]) in times when as-available electricity is insufficient to meet demand.

# Improving flexibility and operability

Some market reforms considered in REMA[3] for accelerating the development of low-carbon flexible generation or flexible demand capacity are detailed below.

## Reforms optimising the Capacity Market

Stakeholders have suggested that CM auctions could be separated by flexibility characteristics such as response time or duration, or by low-carbon characteristics.[2] The Scottish Government's 2018-2032 Climate Change Plan also asserts that without locational elements, the CM does not incentivise new flexible generation in Scotland.[80] The UK Government held a consultation on the reforms to the CM in early 2023.[46]

## Centralised reliability option

A centralised reliability option[81,82] is an alternative mechanism to the CM and has been used in Ireland since 2018.[83,84] Participating generators are contracted to provide a capacity guarantee and receive an auctioned strike price with a reliability premium for ongoing generation. In contrast to a CfD, generators are obligated to pay back the difference when the wholesale market price is higher (but not lower) than the strike price regardless of whether they are generating,[3,84] incentivising their participation during periods of system stress.

## Reforms to the Contracts for Difference

The Government issued a Call for Evidence closing in May 2023 on potential reforms to CfDs.[85] These reforms are listed below and would only apply to new contracts.

- **CfDs with wholesale price exposure.** CfDs could be moderately exposed to the market conditions by implementing a 'strike price range'.[2]

- **Separating revenue from generation.** CfD revenue may also be based on predicted generation in a particular location.[86] This so-called 'Deemed CfD' and similar reforms may alleviate system constraints by decoupling payments from real-time generation.[87]

- **Revenue cap and floor.** A cap and floor support mechanism guarantees minimum revenue (the 'floor') while limiting excessive profits through a revenue maximum (the 'cap').[88] This support mechanism is seen by some stakeholders as potentially effective for incentivising assets with high capital cost such as renewables and flexible low-carbon generation.[2] There is criticism, however, that lower capital cost measures such as demand side response and batteries would be disadvantaged.[2] Revenue cap and floor mechanisms are already successful in supporting interconnectors with Europe.[88,89]

# Wider system reforms

Outcomes of the electricity market reforms may also be impacted by wider system issues, some of which are outside the scope of REMA. Stakeholders have indicated that demand flexibility, network build and connections, and cross-border electricity flows have been under-examined in REMA despite their importance to the electricity market.[2] Infrastructure planning and permission regulations, the retail electricity market and future local area energy markets[90] are policy areas that may also need clarity or reform.

## Demand flexibility

Although addressed in REMA, demand flexibility from consumers who can shift their consumption to reduce system stress is currently limited. This may expand with reforms in the retail market[91] and as electric vehicle (CBP 7480) and heat pump use increases.[42] Vehicle batteries integrated with the electricity network, for instance, may act as a form of electricity storage and improve system flexiblity.[92]

National Grid ESO's new Demand Flexibility Service[93] resulted in approximately 0.25 GW of flexibility capacity accepted during the winter of 2022-23.[94] Other demand-side measures such as, but not limited to, advice and services to households to encourage energy conservation could be supported by subsidies for investment in energy saving technology.[95,96]

## Network build and connections

The electricity network's present system of 'connect and manage' is being reviewed by National Grid ESO in their Holistic Network Design to ensure long-term efficiency.[97,98] Many stakeholders agree that the pace and scale of investment into the transmission and distribution networks should be accelerated,[99] but rigorous planning is required to ensure networks provide other system benefits such as reduced constraint costs.[100,101] Currently, most network reinforcement projects optimally take 5-10 years to complete.[102]

Proposed offshore wind farms currently have to wait about a decade for a new network connection,[99] because the current system was designed for smaller numbers of applications from large fossil fuel plants. The backlog of generation connection applications in 2023 currently totals over 300 GW of generation capacity.[103] Stakeholders have indicated this delay is raising costs and making developments uncertain.[2]

## Cross-border electricity flows

The electricity network in GB is connected to continental Europe and Ireland by several interconnectors totalling 8.4 GW of capacity and growing to an expected 15.9 GW in 2025.[89] Increased interconnector capacity may improve reliability and operability while ensuring supply security.[104] Additionally, international CM cooperation could improve efficiency in cross-border flows.[105] Any reforms in GB will need to take into consideration EU reforms, which are also aiming to decarbonise generation while protecting consumers by supporting power purchase agreements and expanding CfDs among other measures.[104]

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# Contributors

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Members of the POST Board*

Daniel Atzori, Cornwall Insight*

Owen Bellamy, Climate Change Committee

Adam Berman, Energy UK

Rachel Cary, Department for Business, Energy and Industrial Strategy*

Timothy Chapelle, Energy Systems Catapult*

Jieyang Chong, University of Reading

Simon Dawes, Department for Business, Energy and Industrial Strategy*

George Day, Energy Systems Catapult*

Phoebe Finn, Ofgem

Edward Gill, Energy Networks Association*

Johnny Gowdy, Regen*

Euan Graham, Citizens Advice

Richard Green, Imperial College Business School*

Rob Gross, UKERC

Michael Grubb, University College London*

Stew Horne, Energy Savings Trust

Sarah Keay-Bright, National Grid ESO*

Desen Kirli, University of Edinburgh

Furong Li, University of Bath*

Tom Luff, Energy Systems Catapult*

Andrew Lyden, University of Edinburgh

Serguey Maximov Gajardo, University College London*

Cian McLeavey-Reville, National Grid ESO*

Phil McNally, University College London*

Dan Monzani, Aurora Energy Research

Kate Mulvany, Cornwall Insight*

Ana Musat, Renewable UK

David Newbery, University of Cambridge*

Rebecca Pickavance, Energy Savings Trust

Lewis Pickett, Department for Business, Energy and Industrial Strategy Committee

Daisy Powell-Chandler, Public First

José Luis Ramírez-Mendiola, University of Reading*

Duncan Sinclair, Baringa

Heather Stewart, Ofgem

Isabel Sunnucks, National Grid ESO*

Anna Taylor, Public First

Jacopo Torriti, University of Reading*

Simon Virley, KPMG*

Stephen Woodhouse, AFRY

*denotes people and organisations who acted as external reviewers of the briefing.

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post@parliament.uk

parliament.uk/post

@POST_UK