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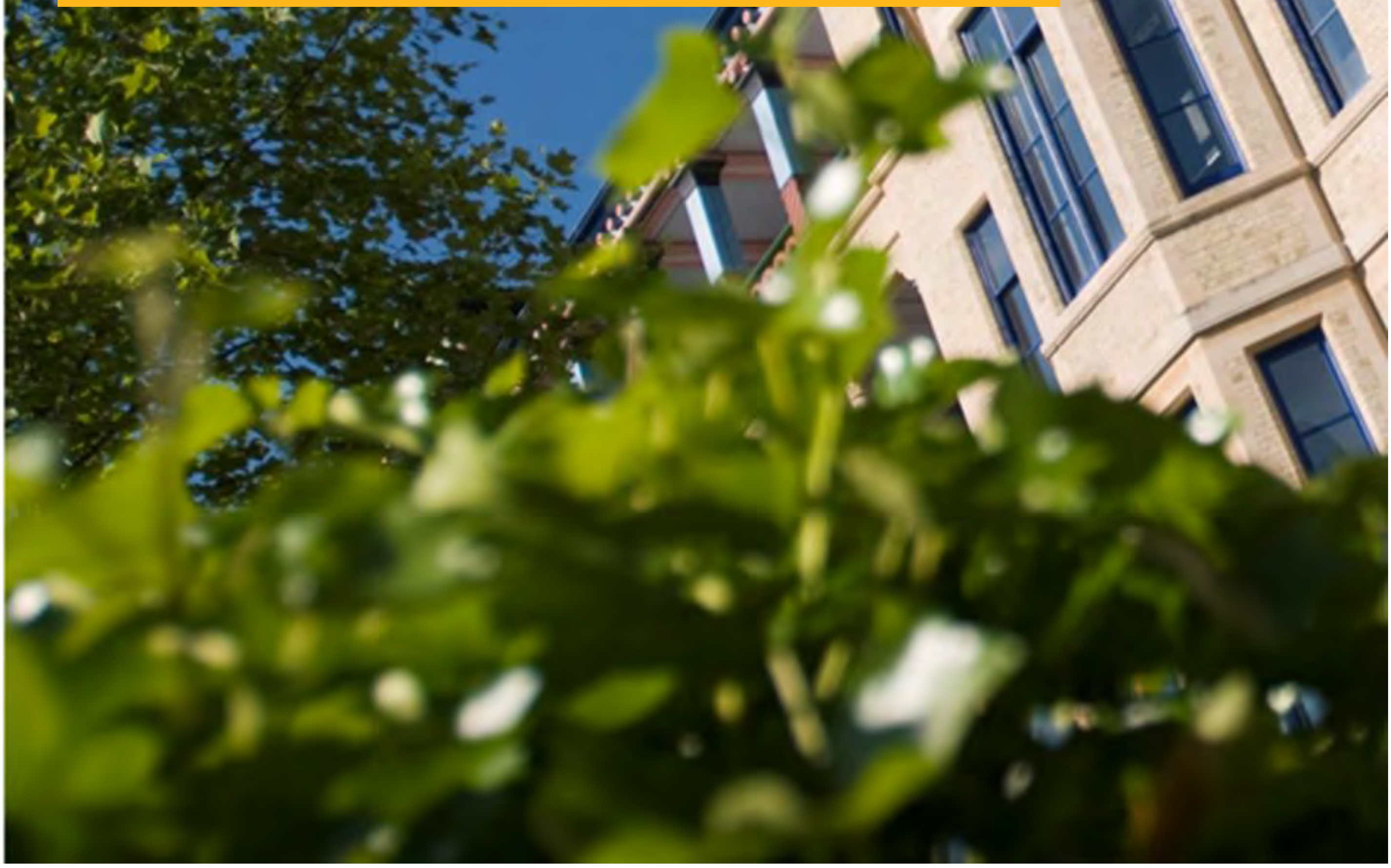
COMPETITION, CONTRACTS AND AUCTIONS FOR RENEWABLE ELECTRICITY SUPPORT: COMPETITION FOR THE MARKET BUT NOT YET IN THE MARKET

Richard Green and David Newbery



Energy Policy Research Group

UNIVERSITY OF CAMBRIDGE
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Keywords : Renewable Electricity support schemes, Auctions, Curtailment, Locational pricing.

JEL Classification : L94; Q28; Q42; Q48

Contact	Richard Green
	Imperial Business School, South Kensington, London SW7 2AZ,
	r.green@imperial.ac.uk
Contact	David Newbery
	Faculty of Economics, University of Cambridge, Sidgwick Ave., Cambridge CB3 9DE.
	dmgn@cam.ac.uk
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Competition, contracts and auctions for renewable electricity support: Competition for the market but not yet in the market[1]

Richard Green[2] and David Newbery[3]

18 March 2026

Abstract

This article surveys Britain's groping attempts at delivering adequate volumes of RES at an acceptable system cost, and proposes reforms to support contracts and transmission charging. Littlechild as the first electricity regulator oversaw the first auctions for renewable electricity contracts. Renewable Obligation certificates added a premium to the market price and accelerated deployment at high cost, until replaced by Contracts for Difference for wind and solar PV, now auctioned. Firm access and locational transmission pricing can work if support is suspended in negative price periods and transmission charges for new entrants are based on marginal expansion costs. Given this approach, the proposed new subsea HVDC links from Scotland would require new windfarms to have capacity factors of 50% to compete with windfarms in England of 34% capacity factors, while onshore links would deliver at current modest transmission charges.

Key words: Renewable support reform, congestion, transmission pricing reform.

1. Introduction

Stephen Littlechild is one of the relatively few British economists to have made significant contributions both as an academic and as a policymaker. As Professor of Commerce at the University of Birmingham, he pioneered the application of game theory for allocating joint costs of infrastructure like airport runways (Littlechild, 1975a, b; Littlechild and Thompson, 1977). A Government advisor during the utility privatisations of the 1980s, he recommended the use of a real-terms price cap on some of British Telecommunications' charges, trying to replicate many of the incentives of competition in the interim period before competition arrived. He always stresses that he was not the inventor of "RPI-X", which was first proposed by Andrew Smithers as a *quid pro quo* for allowing the corporation to raise funds on the capital markets, but it was the *Littlechild Report* (Littlechild, 1983) that brought it to a wide audience (Littlechild, 2014). He continued to advise on the later utility privatisations, until he was asked "you've helped design this system – how do you feel about regulating it?" and appointed as the first Director-General of Electricity Supply.

At that time, the regulator's duties were given to an individual, not a committee, and Stephen's annual reports were peppered with the word "I". As an American economist who knew him well once commented to RG, it seemed incongruous that someone as modest as Stephen was writing in that style, but it was the law.[4] The legal responsibility was his, but it

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[1] Paper written for Stephen Littlechild's *Festschrift*. We are indebted to Bruce Mountain for comments on an earlier draft

[2] Imperial Business School, South Kensington, London SW7 2AZ, r.green@imperial.ac.uk

[3] Faculty of Economics, University of Cambridge, Sidgwick Ave., Cambridge CB3 9DE. dmgn@cam.ac.uk

[4] Stephen has told us that this communication style copied a decision by Sir Bryan Carsberg, the first of the "individual" regulators to specifically communicate as "the face" of telecoms regulation rather

did not stop him from having many collegial discussions with his staff, including (for a year) RG. Determined to find the best answer to a problem, he valued everyone's opinion, however junior, and was willing to work for as long as it took – but always allowing those with other commitments to leave. When time permitted, he was a keen participant in post-work games at the local six-a-side football pitch. The number of former staff present at his retirement party testified to the respect and affection we had for him.

Stephen strongly believes in the power of competition to promote innovation; "RPI – X" regulation was designed to mimic this, and Stephen welcomed innovative solutions to other questions he had to decide. For example, the standard approach to connecting generators to the network has alternated between making them wait until capacity is available (sometimes delaying them for years) or requiring the transmission company to compensate the generator for all the output that the network is unable to accommodate, a practice that is now costing billions of pounds a year. In the mid-1990s, Stephen approved a third option, allowing a wind farm to connect with a cheaper (single) circuit and curtail its output (without compensation) when necessary, rather than paying (and waiting) for the more expensive double circuit normally required for a firm connection. Had this precedent been followed more widely, some of the problems we describe below could have been far less severe.

Another of Stephen's many duties was to oversee a series of auctions for renewable generators in the first of the UK's four schemes for supporting low-carbon generation. This landmark foray into support schemes that enabled competition for the market pre-dated the subsequently immensely successful spectrum auctions of 2000.

These early auctions witnessed rapid cost falls but failed to deliver adequate volumes. They were replaced in 2002 by a demand-driven market-dependent system that delivered greater volumes but at high cost. Continental support schemes demonstrated the lower cost of fixed price contracts, a form of which, Contracts for Difference with Feed-in Tariffs (CfDs with FiTs) were introduced after the third reform of British electricity markets in 2014.[5] These reverted to setting prices by last-price auctions, after an initial round in which strike prices were set administratively so that the first contracts could be issued quickly. Administered prices were also used in a fourth scheme, the feed-in tariffs that supported small-scale renewables from 2010 onwards.

The competition for the market delivered by the CfD auctions led to falling prices but the contract holders failed to engage in competition in the market. As RES penetration increased and transmission investment lagged, constraint and redispatch costs escalated, leading to the inevitable consultation on changing market arrangements in 2022 – incomplete at the time of writing, although the Government has ruled out locational and zonal pricing.[6]

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than give the impression that regulation was done by an anonymous bureaucracy; the other regulators did the same.

[5] Acronyms: CfD: Contract-for-Difference; CPI: Consumer Price Index; FiT: Feed-in Tariff; LRMC: Long-run marginal cost; NFFO: Non Fossil Fuel Obligation RES: Renewable Electricity Supply; ROC : Renewable Obligation (Certificate); (G-)TNUoS: (Generation) Transmission Network Use of System; VRE: Variable Renewable Electricity, WACC: Weighted Average Cost of Capital.

[6] https://www.gov.uk/government/publications/review-of-electricity-market-arrangements-rema-summer-update-2025/review-of-electricity-market-arrangements-rema-summer-update-2025-accessible-webpage

This article surveys Britain's groping attempts at delivering adequate volumes of RES at an acceptable system cost, and suggests how the next steps may be taken.

2. **History of Renewable Electricity Support in GB**

Global environmental concerns prompted the United Nations in 1983 "to propose long-term environmental strategies for achieving sustainable development by the year 2000 and beyond." (WCES, 1987). The resulting *Brundtland Report*, followed by the Kyoto Protocol (1997), EC Directive 2001/77/EC on *Renewable Electricity Supply* (RES), the *Stern Review* (2006) and eventually the UK *Climate Change Act* (2008), gradually raised ambitions to decarbonise the economy, starting with electricity.

2.1 The Non-Fossil Fuel Obligation

The UK's first attempt to support RES was an accidental consequence of privatising electricity set in motion by *The Electricity Act 1989* (HMG, 1989) with the need to prevent the bankruptcy of nuclear power. The Fossil Fuel Levy was a charge on electricity generated by non-renewable sources, which, over its life from 1990-2002, raised £8.6 billion, of which £7.8 billion was paid to support nuclear power (£14.5 bn at 2024/5 prices, Pearson and Watson, 2012, p22). Advocates of RES argued that if this was a tax on non-renewable electricity, logically the proceeds should also be made available to support RES, and that was incorporated in *The Electricity Act 1989* as a Non-Fossil Fuel Obligation (NFFO).

Funds amounting to £1.5bn at 2024/5 prices (Pearson and Watson, 2012) were allocated to a series of technology-specific competitive bidding rounds, and the average prices paid fell from £140/MWh to £50/MWh in the last (fifth) round in 1998 (1998/99 prices uprated to 2024 prices by CPI). The distinguishing and well-designed feature of this first attempt to support RES was competitive bidding for long-term contracts ranging from 15-20 years that de-risked selling currently non-competitive technologies into a volatile spot market lacking even commercial long-term contracts.

As the industry's regulator, Stephen was responsible for assessing the bids received in a total of five auctions (four covering England and Wales and one in Scotland) and making a recommendation to the Government energy minister, who decided the winners. This may sound unusually discretionary for an auction process, but each round contained several technology-specific auctions and so the available funds had to be allocated between them. In 1994, for example, Stephen gave a pair of alternative recommendations. One was a technology-neutral list of the cheapest projects; the other ranked projects relative to the price paid for their technology in the previous auction. This allowed the (then) higher-cost schemes to receive support, as long as their costs were falling fast enough; an approach that refocused the competition between technologies.

The Non-Fossil Purchasing Agency issued 794 renewables contracts totalling 3,271 MW from a range of technologies, including wind, hydro, municipal and industrial waste, energy crops and agricultural waste, sewage gas and landfill gas.[7] While this sounds impressive, total RES only grew from 2% to 3% of total generation, and so was well below

[7] http://www.nfpa.co.uk/index.cfm?pid=32

RES targets, which by 2002 had been set at 10% of generation.[8] The main reason was that the bidders were allowed to keep their costs down by entering the auctions before securing planning permission, while the contracts were very specific as to the exact type and location of the scheme to be supported. Subsequent planning applications often rejected the contracted schemes, even though permission might be given for neighbouring sites or different models of the same technology. At a late stage it was suggested that winners could relocate freely but by then it was too late to rescue the scheme. Mitchell and Connor (2004) and Pollitt (2010) provide an excellent survey of these policies and lessons learned.

2.2 The Renewable Obligation Scheme

In 2000 the Royal Commission on Environmental Pollution's *Energy: The Changing Climate* argued for massive reductions in CO_2 emissions by 2050, a theme picked up by the Government as part of its reform of electricity markets in the *Utilities Act 2000*. The Act scrapped what was considered an overly-centralised Electricity Pool that had run day-ahead auctions to schedule and dispatch all generators, and moved to bilateral contracting and self-dispatch. As part of the reform the NFFO auctions of long-term contracts were replaced by the Renewables Obligation scheme. This was a form of competition in the market, as eligible non-fossil generators could sell Renewable Obligation Certificates (ROCs) to electricity suppliers (retailers), helping them meet an obligation to source a proportion of their sales from renewables.

The percentage obligation was to rise gradually from 3% of each supplier's sales in 2002-3 to 10.4% in 2010-11, and the Government committed that it would not fall below that level before the scheme was due to end (in 2026-27). Generators would receive ROCs for each MWh they produced for fifteen years, hence the need to guarantee that the demand for them would last that long. At the end of each scheme year, each supplier had to pay a buy-out charge for each ROC that it fell short of its obligation, and the revenue from these charges was recycled in proportion to the number of ROCs that each supplier held. This mechanism created a smoothly downwards-sloping demand curve for ROCs, as long as the supply did not exceed the obligation level. For the year from April 2002 to March 2003, for example, the buy-out charge was £30/MWh (rising with inflation) and if renewable generation equalled (just under) 3% of retail sales, the price of a ROC would be £30. If renewable generation was only equal to 2% of retail sales in that year, giving a shortfall of one certificate for every two issued, each certificate would attract £15 of recycled revenue and would have a price of £45.

Renewable generators thus had two income streams, from selling electricity and selling ROCs, and the value of the latter would be greater, the larger the gap between annual output and the (increasingly ambitious) target. It was hoped that the scheme would create the confidence for investors to respond to these targets. The RO scheme came into effect in 2002 in Great Britain, followed by Northern Ireland in 2005 (POST, 2001).

Shortcomings soon became apparent. Since all renewables initially received a single ROC per MWh generated, a ROC price high enough to remunerate relatively cheap sewage or landfill gas generation was far too low for offshore wind. A review was announced as soon as 2003, and banding was introduced from 2009, awarding 2 ROCs per MWh generated by

[8] https://hansard.parliament.uk/Commons/2002-12-03/debates/8b5c87bc-e312-44d9-a894-1c490a3981ca/RenewableEnergyTargets

offshore wind or solar PV, for example, but only 0.25 ROCs per MWh of landfill gas. The numbers were intended to reflect the expected gap between market prices and the cost of the various technologies. A further banding review in 2011-12 reflected changes to the estimated cost of each technology but such reviews risk an investment hiatus as developers waited to learn of changes to their prospective revenue streams. With more ROCs being issued as a result of banding, the Government also committed itself to adjusting the size of the Obligation so that it was always at least 10% above the expected level of renewable output in each year. This "headroom" greatly reduced the risk that the price of ROCs would fall to zero if more were issued than required to meet an Obligation set long ago.[9]

The headroom also increased the cost to electricity consumers. The supplier of the marginal MWh of demand will have to pay the ROC buy-out price multiplied by the percentage obligation level, whatever the actual level of renewable generation, and can be expected to pass this cost on to consumers. In practice, while renewable output did increase significantly over time, in the early years it fell significantly short of the Government's targets and the Obligation level. One reason for this was that it remained hard to get planning permission for renewable generators, forcing delays or abandonment for otherwise-viable projects. Another was that (for reasons further discussed below) wind developers favoured places with high wind speeds that were mostly remote from demand centres and National Grid's "invest, then connect" policy meant that many schemes had to await network reinforcement work before they could go ahead.

Figure 1 shows that the recycled buy-out revenue per ROC was (briefly) higher than the (time-weighted) wholesale spot price and stayed high until 2010. The value to a supplier of holding a ROC equals this recycled revenue plus the buy-out price, which was intended to remain constant in real terms.[10] This should form the basis for negotiating ROC prices, which combine with the wholesale price to give the revenue per MWh for a generator receiving 1 ROC per MWh of electricity.[11]

[9] For 2025-26, the fixed target gave an obligation of 39.9 million ROCs, while the headroom calculation set the actual obligation level at 122.6 million (DESNZ, 2024).

[10] Until 2024, the buy-out price was indexed to the Retail Prices Index, which has generally risen faster than the CPI that we have used to bring prices to 2024-25 money values – a gradual increase in the buy-out price is visible in Figure 1.

[11] One interesting consequence of the shift from the NFFO contracts to ROCs is that those generators' ROCs passed to their counterparty, the Non Fossil Purchasing Agency, which apparently made a decent profit on selling them.

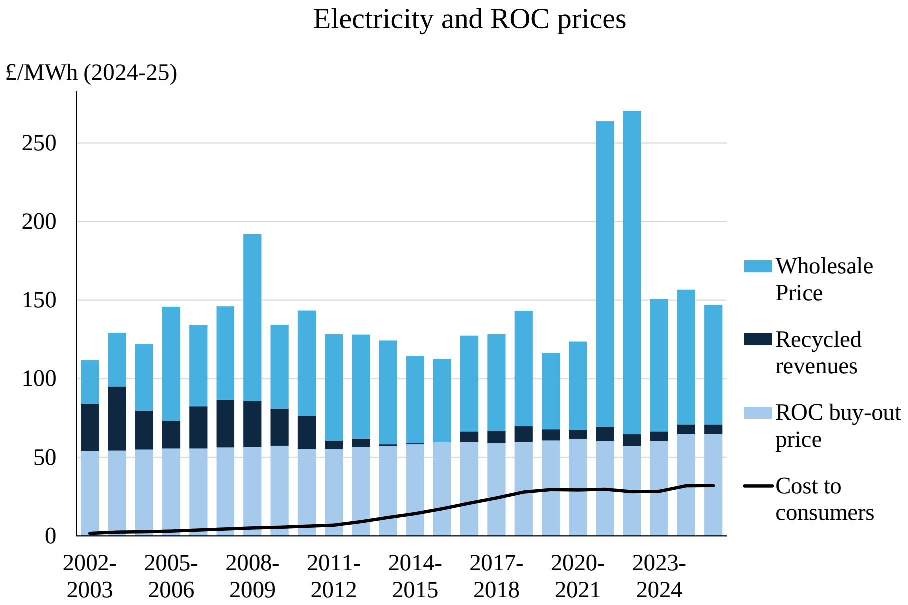

Figure 1 Evolution of the price paid for renewable electricity under the RO scheme

Sources: Ofgem. RO data from https://www.ofgem.gov.uk/renewables-obligation-ro/contacts-guidance-and-resources/public-reports-and-data-ro, prices from https://www.ofgem.gov.uk/news-and-insight/data/data-portal/wholesale-market-indicators and from APX UK

While the ROC value for suppliers has been moderately stable in real terms since 2016 (as the required volume was realistically set to lead delivery) the market price was volatile, and primarily set by the price of gas, as gas-fired generation was effectively the marginal plant. During the earlier period coal-fired generation was gradually exiting the market but arbitrage between coal and gas plant across the EU drove the CO_2 price (the EU Allowance price) to roughly equate their carbon-inclusive marginal costs, at least until 2011.[12] Figure 2 shows how the forward prices of fuel-plus-carbon costs of both coal and gas closely matched each other, and correlated highly with the forward electricity price. As a result, fossil generation was naturally hedged (the margin between sales value and fuel cost was more stable than either separately), while RES was exposed to far greater risk, reflected in the cost of financing RES.[13] More recently the impact of the energy crisis in 2022/23 gave huge windfall gains to ROC issuers. Figure 1 also shows the cost to consumers gradually rising as the number of ROCs increased with increasing RES delivery, and their increased cost was spread over an almost static total electricity consumption.

[12] Coal costs fell below gas costs until 2015 as EUA prices were unreasonably low, but electricity prices continued to be set by the gas price as coal gradually exited.

[13] Thus Morgan (2013, Annex 1) assesses the implied hurdle rate (WACC) for established RES technologies under RO financing should lie between 9.6%-10.3% and up to 11.9% for emerging technologies, such as offshore wind. NERA (2015) gives hurdle rates for offshore wind in the Rounds 2 and 3 auctions ranging from 9.3%-14.2% (all real), and as these were under a CfD regime, ROC WACCs would be higher. See §2.4.

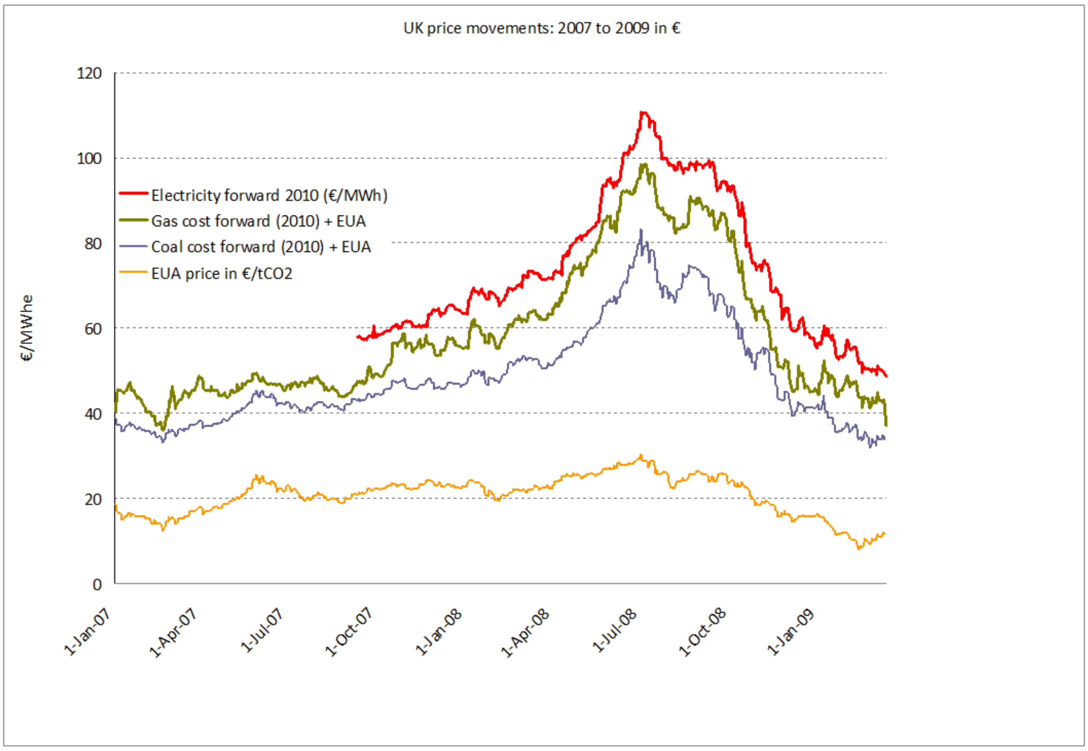

Figure 2 Forward prices of electricity, gas and coal costs for delivery in 2010.
Source: Bloomberg

The announced and escalating demand from suppliers increased RES investment, but at substantial cost compared to the evident success of Continental Feed-in Tariff schemes that guaranteed a price for the life of the contract. Wood and Dow (2011) pointed out that ''By the end of 2009, under a stable feed-in tariff mechanism, Germany had over 25 GW of wind installed in comparison to just over 4 GW in the UK, and around 16% share of Electricity in comparison to 6.6% in the UK."

In addition to the unnecessarily high cost of finance, the RO scheme failed to consider the perverse locational incentives inherent in the high premium offered to RES. National Grid, in contrast to most EU System Operators, has quite highly spatially differentiated charges for generators located in different zones. The Generation Transmission Network Use of System (G-TNUoS) charges are high in Scotland and low in the South-West, with a range (in 2024/25) of £36,280/MW per year (for a wind farm). At the assumed 34% capacity factor this amounts to £12.18/MWh, which is intended to measure the extra cost of delivering power from Scotland to load centres in the Midlands and South East by overhead lines.

If ROCs raise the value of RES by the £60/MWh shown in Figure 1, the benefit of a high capacity factor is amplified (roughly doubling its value) and this massively over-encourages locations in distant high resource areas like Scotland. Since a generator received ROCs for 15 years, over that period those at high capacity factor locations would earn substantially more than the marginal supplier setting the ROC price.

Germany's EEG has given higher Feed-in Tariffs to generators in relatively less windy places than to those at the best sites that do not need so much support. If both kinds of site must be developed to meet renewable targets, this reduces the cost of doing so by reducing the rent available to the best-placed generators. There is, however, a minimum wind speed below which no tariff is available, so that the least suitable sites should not be developed. An equivalent would have been to vary the number of ROCs per MWh inversely with the wind speed, just as it varied by technology. We return to this problem of excess rent when suggesting improvements to RES support design below.

2.3 The Feed-in Tariff Scheme for small-scale renewables

The RO was administratively complex for generators, and while some were able to avoid this by selling their output and their ROCs under a single long-term contract, the counterparties rarely offered attractive prices for such deals. It was ill-suited for small-scale generators and completely inappropriate for households looking to install PV solar panels. The Feed-in Tariff was developed for such generators, offering technology- and size-specific payments for each kWh generated,[14] indexed in real terms for between 10 and 25 years. For technologies where costs were expected to fall, "degression" would ensure that the tariffs for projects commissioned after 2012 would be lower (but still constant over each individual project's lifetime). The tariffs for 4kW or less of PV would fall by 8.8% a year, while those for less than 100 kW of wind power would fall by around 5% a year, since cost reductions were expected to be lower (DECC, 2010b). The tariffs were set with the aim of giving projects an internal rate of return of between 5% and 8% a year in real terms.

The scheme proved popular, for the cost of PV panels fell much faster than assumed when the tariff rates were set. Only a few months into its life, the (new) Coalition Government announced a review into the rates to be offered to (new) larger-scale PV projects, provoking a storm of protest from developers who argued that they had incurred significant costs but would be unable to complete their investments before the tariff rates fell. Nonetheless, the Government cut the tariff for PV schemes of 50-100 kW from 31.5 p/kWh to 19.0 p/kWh and for those of 250kW-5MW from 29.3 p/kWh to 8.5 p/kWh.[15] The Government's spending review had "made clear for the first time that there are spending parameters within which the FITs scheme must operate" (*ibid*, para 4), and too much investment in larger schemes would reduce the budget available for (voting) households. On the other hand, take-up of anaerobic digestion schemes had been below expectations, and the Government increased the FiTs for this technology.

While tariffs for schemes starting up to eleven years later had been announced in 2010, another review was needed in 2012, halving the tariff offered for the smallest PV schemes. This review introduced contingent degression, under which the tariff for a technology would be further reduced if the amount of capacity commissioned in a calendar quarter exceeded the Government's projections, taken as a signal that costs were falling faster than expected. Even so, this responsiveness to the market was not enough to prevent another review in 2015, which capped the number of new installations that could be accredited in each three- or six-month period. Projects that exceeded the capped capacity had to wait until

[14] This contrasted with the Germany Feed-in Tariff which only paid for the electricity actually exported to the grid. The UK scheme did not require two-way metering for households, and an additional payment, on top of the headline tariff, was made for the 50% of PV output deemed to have been exported.

[15] Schemes between 100 kW and 250 kW saw slightly smaller reductions than these. In 2024 prices per MWh they are respectively £452, £272, £420 and £122/MWh, assuming the original sums are at 2011 prices.

the next period, and over 100 MW of capacity was in the queue for support when the FiT scheme closed to new projects in 2019. These episodes show the difficulty of administratively setting fixed prices for a technology with rapidly evolving costs, a problem that also haunted the UK's fourth and final (to date) scheme for renewable support.

2.4 The Energy Act 2013 and Contracts-for-Difference for renewables

The high cost of the RO scheme and its failure to match Continental deployment rates, combined with the 2009 EC *Renewables Directive* (EC, 2009) and the Labour Government's decision to source 40% of electricity from low carbon sources and around 30% of electricity from renewables by 2020 (DECC, 2009) raised questions of how to accelerate RES investment. This also coincided with serious concerns about security of supply and the failure of the energy-only market to attract sufficient investment, not just in RES but in conventional dispatchable power. The resulting market rethink under the succeeding Coalition Government, the 2010 *Electricity Market Reform* (DECC, 2010a) eventually resulted in the 2013 *Energy Act* (HMG, 2013).

In addition to legislating a carbon price floor to provide forward certainty on the carbon price, and a capacity auction to procure adequate conventional generation to deliver security of supply, the RO scheme was to be replaced by Contracts-for-Difference with Feed-in Tariff (CfD with FiT). The CfD would pay the contracted strike price, (indexed[16] for 15 years) to assure a revenue stream that could be largely debt-financed at a low cost of capital. A conventional CfD specifies an amount M MW and a strike price s £/MWh, and pays $M(s - p)$ per hour when the reference market price is p (or, if $p > s$, the holder pays back to the counterparty). As such this is a purely financial hedge, leaving the generator free to decide whether to generate and receive s at a unit cost of c for an overall profit of $(s - c)M$. If $c > p$, it is better to not generate and receive the larger amount of $(s - p)M$. The CfD with FiT in contrast pays not on the pre-specified amount but on metered or offered volumes, giving the generator an incentive to produce as much as it can, unless, improbably, $s < c$.[17] The CfD with FiT differs from the Continental FiT in that the RES owner remains responsible for marketing the output. As National Grid offers firm connection contracts, if supply offered exceeds the grid's ability to accept, the generator is compensated for its curtailed output, thus ensuring the predicted revenue from the CfD[18] for 15 years.

The strike prices in the first round of CfD allocations were set bureaucratically (DECC, 2013a). The Panel of Technical Experts[19] recruited to advise the Secretary of State on the capacity auction argued that the hurdle rate (the weighted average cost of capital, WACC) was excessive, given the de-risking offered by the CfD (compared to the earlier riskier ROCs, DECC, 2013b, p4). One (rather poor) defence of the high strike prices was that the RO scheme was kept open until 2017, and that by now overly generous scheme set a

[16] Arguably setting a nominal price would make more sense as most debt is nominal, and the gradual fall in the real value both front-loads the revenue and is a better match to declining RES costs.
[17] The generator would not accept a contract in which s was always below its variable cost (except in exchange for a suitable fixed fee), but the incentive to over-produce can be curbed if the strike price falls or the contract cannot be exercised when market prices are negative, as discussed below.
[18] From this point on, we follow industry practice in simply calling the contracts "CfDs", dropping "with FIT".
[19] Disclosure: Newbery was a member of this Panel.

reference benchmark. The administered price for off-shore wind was set at £140/MWh and for on-shore wind at £95/MWh (in 2012 prices, giving £195/MWh and £132/MWh at 2024 prices, uprating by the CPI). DG Comp argued that these prices amounted to overly-generous state aid. In response the Government announced sealed-bid auctions for three technology-based ‘pots’ and this market-friendly support was granted state aid approval in July 2014.[20] This and subsequent Allocation Round (AR) auction results are shown in figure 3, showing that compared to the administered prices the first round auction prices were £28-£36/MWh lower for offshore wind and £17-£21/MWh lower for onshore wind (at 2024 prices).

Newbery (2016, p1325) used this and cost data to calculate the implied overpayment on the assumed hurdle rate (WACC) in setting the administered prices as 3.3% real. If the Government had persisted in using its preferred hurdle rate for the expected £75 billion of RES investment to 2020 set out in DECC (2011b, fn3, p6, presumably at 2011 prices, so £(2024)108 billion) the extra cost would be £(2024)3.5 billion per year for 15 years, demonstrating the power of competition for the market.

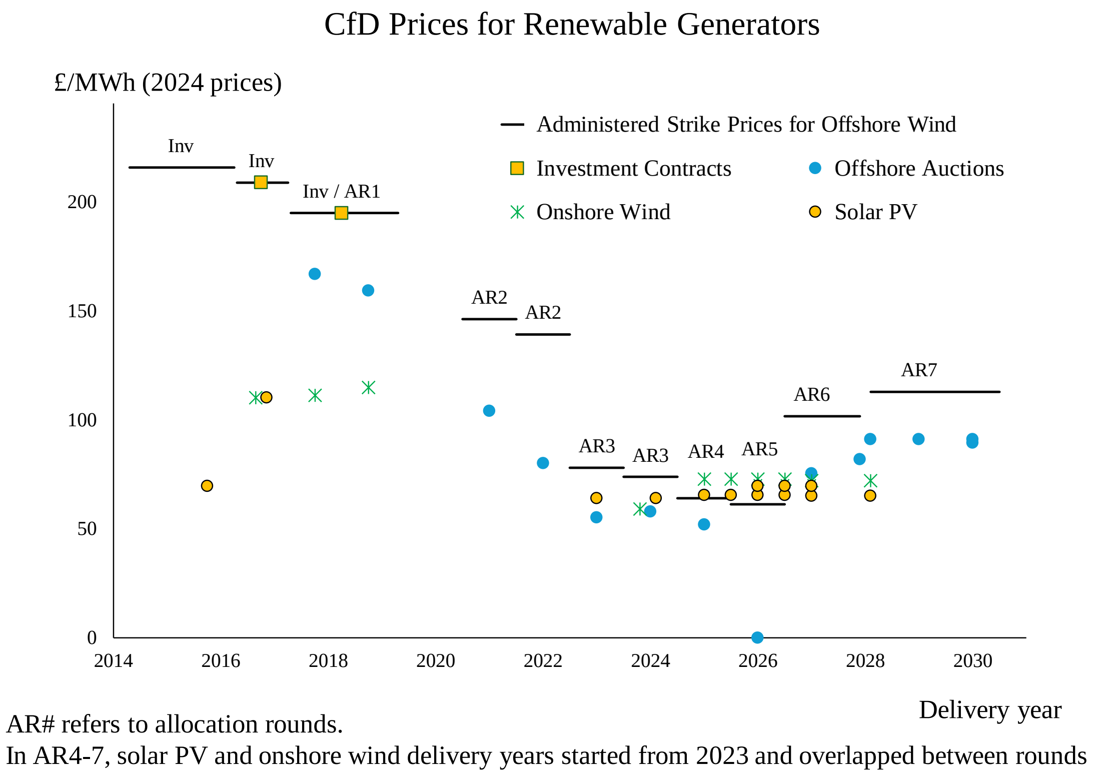

Figure 3 Strike prices for on- and off-shore wind and PV auctions in £(2024)

Source: https://www.gov.uk/government/publications/contracts-for-difference-cfd-allocation-round-7-results and https://assets.publishing.service.gov.uk/media/698a0dc06da2dee8230a9c3a/contracts-for-difference-AR7a.pdf uprated by CPI from original 2012 prices.

Note Only bids at or below the Administered Strike Price are accepted.

[20] https://ec.europa.eu/commission/presscorner/detail/en/ip_14_866

Figure 3 also shows the impressive continuing decline in clearing prices that continued until the offshore cost inflation following the Ukraine war and energy crisis, which does not seem to have impacted onshore costs. What is striking is the low prices of solar PV, in the most recent round nearly 30% below offshore wind prices.

3. Reforming RES support

Recent experience has highlighted three main problems caused by RES support schemes. The high gas and electricity prices stemming from Russia's attack on Ukraine delivered windfall profits to generators that are supported by a premium on top of market prices. Almost at the same time, however, markets across Europe have been seeing a rising proportion of hours with negative wholesale prices. These are driven not by genuinely negative marginal costs (as when inflexible coal or nuclear plants compete to avoid being turned off) but by support schemes that incentivise renewable generation even as market prices become negative. Third, a growing proportion of the potential renewable output cannot be accepted because of system constraints, and the GB system operator spent almost £1 billion compensating these generators in 2024-25. The latter two problems can start to arise even at relatively modest overall shares of wind and solar generation, as their peak output is much greater than their average, given their dependence on a variable resource, specifically of wind strength and solar insolation. The affected technologies, on- and off-shore wind and solar PV, can be collectively described as Variable Renewable Electricity (VRE). Dispatchable renewable generators, such as biomass or hydro, do not suffer from these issues.

3.1. Problems with existing renewable support schemes

The first problem described above, that of windfall profits, comes from VRE support schemes that add a premium to the market price received for the generator's metered output. The premium might be set administratively, or as the result of a market for tradable green certificates, as with Britain's Renewables Obligation.[21] Such schemes looked attractive as market responsive while de-risking the adverse effects of generally low electricity prices or price cannibalisation when surplus VRE lowers the wholesale price. This might have made some sense when energy prices remained within a modest range but was revealed a very costly mistake when the Russian invasion of Ukraine raised gas prices five-fold, bringing massive increases in electricity prices. Figure 4 demonstrates the high cost of linking RES support to market prices. The dotted horizontal line shows the approximate level of both market prices and the marginal costs of coal- and gas-fired generators that were driving them upwards.[22] Written-down nuclear stations and renewables that received the market price alongside revenues from ROCs (or their contract counterparties) made significant windfall profits. The feed-in tariffs paid to the earlier PV generators remained above the market price, but the lower rates for more recent schemes represented a saving, as did the CfDs held by

[21] Another variant is a one-sided CfD that guarantees a minimum price with all the upside to the developer.
[22] The market for emissions permits ensured that the carbon price rose with the gas price to keep gas-fired generators competitive with coal.

offshore wind projects: they sold their output in the market but had to return the excess via difference payments.[23]

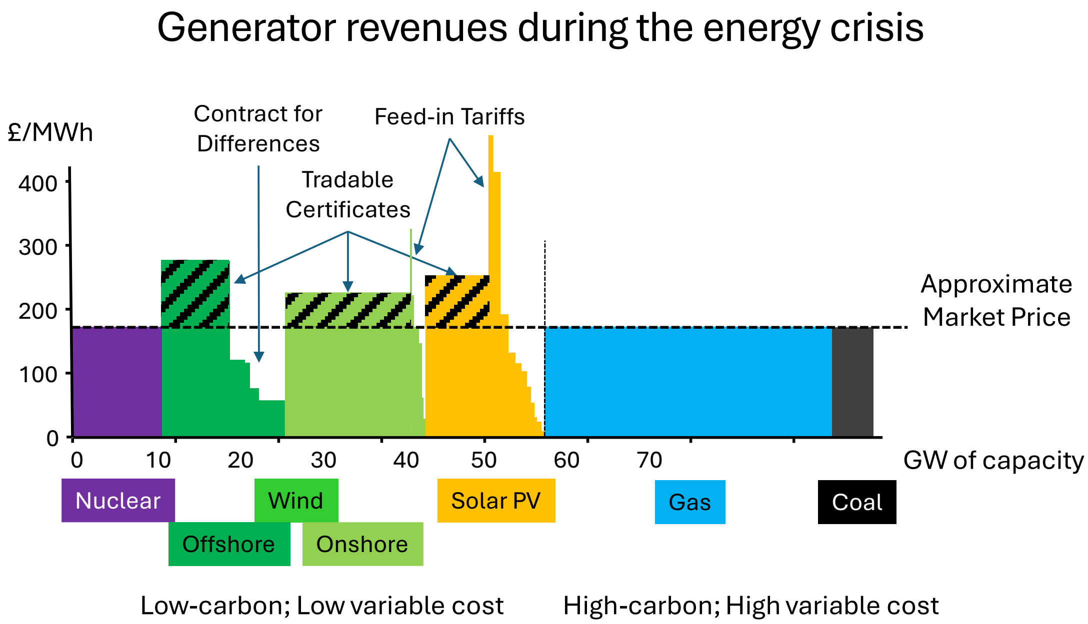

Figure 4 Revenue per MWh of various generation sources and support schemes
Source: Staffell *et al.* (2022) The estimates are not adjusted for the timing of output or for old renewables that no longer received ROCs.

The UK government clawed back some of these excess profits with the Electricity Generator Levy announced in November 2022: nuclear and renewable generators without CfDs would pay a tax of 45% on their wholesale revenues above £75/MWh from April 2023 until March 2028. The effects of hedging contracts were included, but receipts from selling Renewables Obligation Certificates were excluded when calculating the taxable revenues. Biomass generators were able to deduct any increases in feedstock costs relative to a pre-pandemic baseline.

The levy did not affect the level of electricity prices, but in April 2026, with gas prices raised by the war between the US, Israel and Iran, the government announced that it would negotiate CfDs with those existing generators that wished to exchange volatile wholesale revenues for a fixed price. To encourage them to volunteer for this, the levy would be extended past 2028 and raised to 55%. This is a version of a "pot zero" proposal made during the Ukraine crisis (Gross *et al*., 2022), which suggested that fixing the generators' revenues with a CfD would allow refinancing at lower interest rates, so that they would be willing to accept relatively low strike prices. Without such cost reductions or tax exemptions, generators would be most likely to accept a contract price below current market levels if the

[23] Controversially, one project that was being commissioned during the crisis extracted a windfall profit by delaying the start of its CfD for as long as its contractual terms allowed.

government was promising they would be paid more than the expected level of market prices in the longer term.[24]

The problem of negative prices is illustrated in Figure 5, which shows that by 2025 this was becoming a material issue in many countries, with all those shown experiencing over 500hr/yr. and Spain over 800 hours per year of negative prices. Negative prices as such need not be a problem, if they accurately signal that overall economic costs could be reduced if electricity consumption increased, but this is unlikely to be the case in Europe. If the potential volume of renewable output exceeds the demand for it, its price ought to fall to the level of marginal cost, beyond which generation is no longer profitable. With marginal costs of close to zero, that should set the lower bound on prices. When support payments are contingent on actual output, however, the marginal cost of not generating is the foregone support revenue and prices can fall to the level of this opportunity cost – minus the price of renewable certificates, for example. That price at least sets a lower bound on the negative market price, but a badly designed CfD might offer an unlimited subsidy for generation at increasingly negative prices. This has recently been addressed by the European Commission, see section 4.

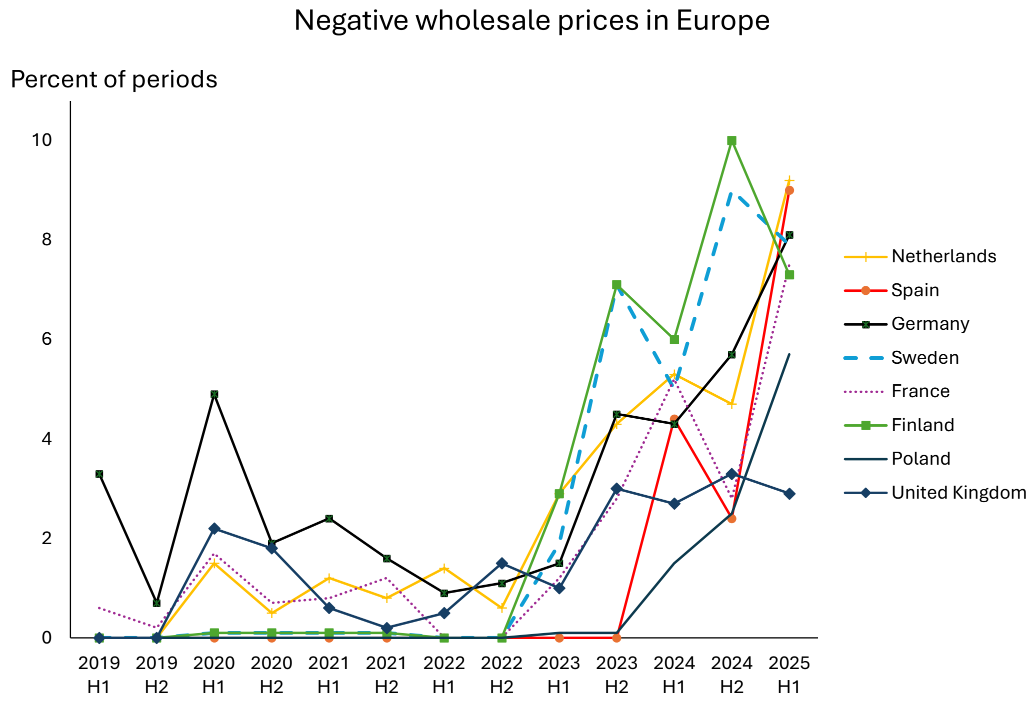

Figure 5 Negative hours as percent of year 2019-25, selected European countries

Sources: https://www.iea.org/data-and-statistics/charts/fraction-of-negative-hourly-wholesale-electricity-prices-in-europe-in-the-first-half-of-the-year-2019-2025 ; https://www.iea.org/data-and-statistics/charts/fraction-of-negative-hourly-wholesale-electricity-prices-in-europe-2019-2024

[24] This pattern was clearly seen in the contracts signed by the California Department of Water Resources during the California electricity crisis of 2001. While spot prices were reduced by regulatory changes made soon after the contracts were signed, the Department had committed to over $42 billion of purchases over ten years, with up-front savings that were more than offset by expected losses in later years. Information in the report by the California State Auditor (2001) suggests an overall loss of almost $5 billion, discounted at 9% (authors' calculation from data in Tables 2 and 3 and Figure 2).

The third problem identified above is the increasing proportion of VRE that has to be constrained off by the system operator. This has two causes: congestion on the transmission system and the need to maintain an acceptable level of inertia. In the event of a fault, the rotating turbines in a system dominated by fossil-, hydro- or nuclear-powered generators will continue to spin fast enough for long enough for automated controls to arrest the drop in frequency and keep the system stable. VRE are connected to the system via power electronics and do not naturally offer any inertia, leaving the grid more vulnerable. Thus on the island of Ireland, non-synchronous generation (onshore wind) is kept at or below 75% of demand. When this limit is reached, wind is curtailed, causing the loss of 4.7% of total output in 2024.[25] In future, grid-forming inverters and fast frequency response (largely from batteries) may decrease the amount of inertia needed from turbine generators.

Transmission constraints limit the amount of power that can flow along a line or across a system boundary (along a group of lines) without exceeding thermal or voltage limits. Ideally, the grid should be co-designed with the location of generation to limit constraints. In England and Wales, both the grid and generation were in the same state-owned Central Electricity Generating Board until privatisation in 1990 and so generation and transmission were located to minimise constraints and make firm connections logical. The grid connection across the border to the South of Scotland Electricity Board was much weaker, but the Scottish system was kept largely separate at privatisation. Constraints accelerated when reforms in 2005 abolished this *de facto* zonal boundary, and since then Scottish wind has been increasingly curtailed, meanwhile enjoying the full value of an unconstrained location. The problem is exacerbated as wind generators tend to seek out windy sites that may be far from demand and the existing grid – transmission limits caused 9.4% of Irish wind to be constrained in 2024.

[25] https://cms.eirgrid.ie/sites/default/files/publications/DD-Historical-v5.png

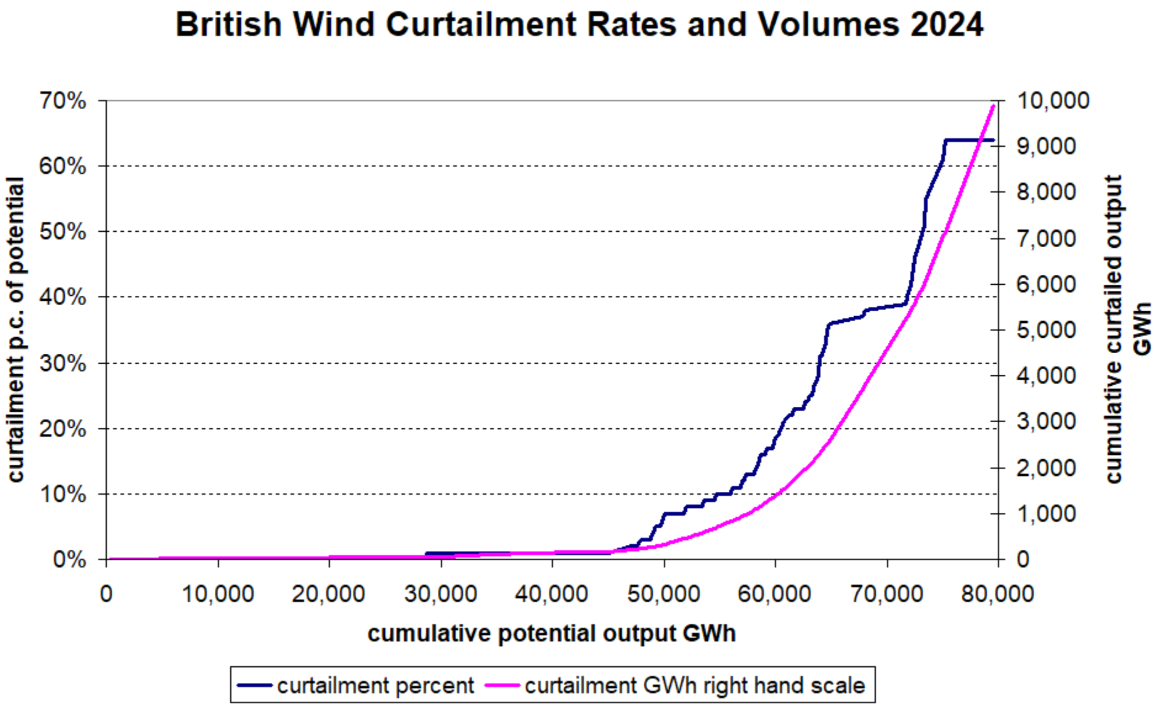

Figure 6 British wind farm curtailment rates and volumes, 2024

Source: https://www.windtable.co.uk/ Volumes are based on an "average wind" year

Figure 6 shows the curtailment rates of individual transmission-connected[26] windfarms and hence potential output lost from British (on- and off-shore) windfarms in 2024. In fact, the Wind Table map given by the source shows that practically all curtailment occurs in Scotland and that of the potential 80 TWh that would be produced in a year with average wind, 10 TWh would be curtailed, but compensated by consumers.[27] Distribution-connected RES is either not curtailed if paying deep connection charges or only curtailed to the agreed amount under shallower connection charges.

Although Figure 6 is ranked by increasing curtailment rate, rather than by date of connection, curtailment has been increasing quite steadily over time. VRE investment is outstripping the ability to expand transmission capacity, so that congestion is rising rapidly, while inertia constraints are binding more frequently. Newbery (2023) showed that the VRE marginal curtailment rate (i.e. the curtailment caused by the last MW installed) was typically 3+ times the average curtailment rate normally reported. Newbery and Biggar (2024) model a piece-wise linear curtailment schedule (i.e. the graph of curtailment with maximum curtailment in hour zero decreasing to zero at the total number of hours curtailed), which is a good approximation in most cases. They provide a geometric (and algebraic) proof that the ratio of marginal to average curtailment (*mc/ac*) is $(V+V_0)/(V-V_0)$ where V is total VRE capacity (measured by its peak output) and V_0 is the VRE capacity above which some curtailment is inevitable. Thus if $V=2V_0$ $mc/ac=3$.

[26] Distribution–connected wind farms, including almost all the onshore wind farms in England and Wales, are not visible to the System Operator and face a different access regime, as mentioned below in §3.3.

[27] The actual 2024-25 output was lower than this (63 TWh produced and 9 TWh constrained off), suggesting that curtailment rates might have been higher in a year with average wind.

This marginal curtailment relationship holds for a region within which there is no congestion, exporting to an external region – a situation that closely describes isolated Renewable Energy Zones in Queensland, Australia, connected by a spur to the main grid. Congestion is, however, a serious problem in Britain, particularly at the Scottish –England border. Chyong and Newbery (2025) show that internal constraints magnify curtailment, raising the ratio of marginal to average curtailment further, and emphasising the importance of location for minimising system costs.

3.2. Recent attempts at reform

The 2022 energy crisis delivered entirely unjustified windfall gains to premium support schemes (and to nuclear power), and encouraged a rethink on support schemes by the European Commission.[28] EU Regulation 2024/1747[29] noted that "the energy crisis ... has revealed a number of shortcomings and unexpected consequences" (§9). The conclusion was that public support schemes "should be two-way CfDs" (2-w CfD, §35), they should be voluntary (§37), and critically, that CfDs holders "should participate efficiently in the electricity markets" (§41). This was further strengthened by EC guidance[30] (C/2025/6701 p15): "As under competitive circumstances beneficiaries are expected to offer their production at marginal cost, a 2w-CfD should not incentivise them to offer their production below their marginal cost. In particular, beneficiaries should not receive any aid for electricity production during periods when the market value of that production is negative.[31] For the purpose of this document, the marginal cost of solar and wind electricity production is assumed to be zero.[32] Consequently, it is crucial that these technologies do not receive support when the market value of produced electricity is negative."

UK CfDs with FiTs by now meet almost all of these requirements. They are voluntary and two-way, the strike price is on offered output (with compensation if constrained-off in the balancing market) and since 2020 CfDs receive no difference payments "when the Intermittent Market Reference Price is negative." (DESNZ, 2020, p51). To complete the reform the System Operator, NESO, needs to ensure that constrained-off compensation in the balancing market is never more than the strike price, as in Italy.[33] At present VRE can bid negative prices to be turned down and hence receive more by being curtailed than if generating, creating very perverse locational signals. In the spirit of the EC guidelines all VRE should be deemed to have a non-negative avoidable cost. If indeed there is some slight

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[28] COM(2025) 72 final Brussels, 26.2.2025 *Report on energy prices and costs in Europe* https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52025DC0072

[29] https://eur-lex.europa.eu/eli/reg/2024/1747/oj/eng

[30] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=OJ:C_202506701

[31] "See paragraph 123 of the *Guidelines on State aid for climate, environmental protection and energy*. Please note that in certain circumstances, the costs of operating the unit also encompass the costs of ramping up and down, for example for nuclear installations." [Footnote in original.]

[32] "The marginal cost of production of solar or wind generation assets (i.e. the cost of producing one additional MWh) is considered to be very low, close to EUR 0/MWh." [Footnote in original.]

[33] "If the installation has to cut production according to dispatching orders from the TSO (Terna) in the Italian Balancing Market and/or in the EU balancing platforms. In this case Terna accepts downward offers that those installations must place at a price equal or greater than zero in the relevant periods" (C(2024) 9136 final, at §55(b). https://ec.europa.eu/competition/state_aid/cases1/202451/SA_115179_72.pdf

cost of turning off and then turning back on, that is part of the signal not to locate behind a transmission constraint. NESO has proposed *Modification P462 The removal of subsidies from Bid Prices in the Balancing Mechanism*[34] which, if implemented, would have the desired effect.

The energy crisis also strengthened the case for a more rapid transition to a low/zero carbon electricity sector, argued to reduce exposure to, and dependence on, international fuel prices. In Britain, replacing fossil generation by VRE located in very different places and often distant from demand has caused a rapid increase in congestion at zonal boundaries, demands for new transmission links, and a growing urgency to provide better locational guidance for investment, dispatch, and balancing the system in real time. In response the UK Government launched its *Review of Electricity Market Arrangements* (*REMA*) in July 2022 (HMG, 2022).

The *REMA* consultation floated a number of possible solutions, starting with an ambitious idea to move to the US Standard Market Design of Locational Marginal Prices (LMP), which signal the Short-Run Marginal Cost of transmission constraints. The present system of self-dispatch allows generators and consumers to freely contract supplies and demands, and only inform the System Operator (SO) shortly before dispatch. The SO then tests the feasibility of these positions and if necessary compensates those that cannot be accepted to reduce output, paying for costlier feasible replacements. Under LMP, only feasible dispatch instructions are issued by the SO, setting low prices at export congested nodes and higher prices where injections are needed to deliver to that node. Instead of poorly located generators earning extra money to move from an infeasible to feasible solution, they face lower prices and have lower volumes accepted.

REMA also considered zonal pricing as a less drastic form of locational pricing. Norway was a leading example, dividing the country into seven zones. The EU Target Electricity Model treats countries (with no internal zones) and regional zones and since 2014 simultaneously clears all zonal markets to make efficient use of the links between zones. Where boundaries are constrained, prices would differ each side of the boundary. This was effectively the situation with respect to Scotland before 2005 – the flows to England were limited but no compensation was payable. The greater the number of zones within a country, the higher the proportion of congestion that is resolved via price differences and the stronger the incentive for (currently) efficient location decisions.

Moving from the current system to LMP or zonal pricing moves large sums of money between market participants. The regulator, Ofgem, commissioned FTI to assess the impacts of *REMA* (FTI, 2023). The headline figures were that consumers would gain up to £54.9 billion (discounting over 2030-2050), although the net benefit was only £25 billion after accounting for producers’ losses. Unsurprisingly, generators successfully lobbied against and after an extended period of consultation (HMG, 2025) the Government has ruled out both nodal and zonal pricing, and instead asked for advice on how to reform other parts of the policy mix that impact location decisions.[35] That is the subject of the next section.

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[34] https://www.elexon.co.uk/bsc/mod-proposal/p462/
[35] https://questions-statements.parliament.uk/written-questions/detail/2025-12-12/99556

4. Reforming Transmission charges

Britain is unusual in Europe in charging transmission-connected generators an annual fee that varies quite strongly with location - the Generation Transmission Network Use of System (G-TNUoS) charge.[36] The purpose of these locational charges is to signal to developers the cost of choosing different locations, ideally so that they choose the least system (generation and transmission) cost solution. The G-TNUoS charges are high in Scotland and low in the South-West. Table 1 shows selected G-TNUoS charges for 2023-24. Charges depend on the type of generation and the demands it makes on the system and so three cases are shown for different generation types and capacity factors (CF).

Table 1 G-TNUoS charges for 2023-24 £/kWyr.

Zone	Zone name	100% CF	baseload 90% CF	wind 34% CF	wind 60% CF
1	North Scotland	£40.26	£38.21	£23.71	£29.05
2	East Aberdeenshire	£32.63	£31.45	£20.72	£23.79
7	Argyll	£36.17	£34.76	£23.71	£27.38
10	South West Scotland	£25.93	£24.59	£14.40	£17.87
15	South Lancs and Yorkshire	£5.05	£4.84	-£0.49	£0.04
16	North Midlands and North Wales	£1.94	£1.89	-£1.37	-£1.25
18	Midlands and East Anglia	£3.97	£3.55	-£0.10	£1.00
23	Central London	-£4.21	-£4.63	-£3.62	-£2.51
27	West Devon and Cornwall	-£11.74	-£10.76	-£4.85	-£7.40
	range 1-27	£52.00	£48.97	£28.56	£36.44
	Western bootstrap Z10-Z16	£23.99	£22.70	£15.77	£19.12
	SEGL 1 Z11-Z13	£7.82	£7.09	£3.93	£5.82
	SEGL 2 Z2-Z15	£27.58	£26.61	£21.22	£23.75

Source: NESO (2023)
Note: CF is capacity factor

The range (in 2024/25) for a baseload generator with a 90% capacity factor, CF, is £48.97/ kWyr. or £48,970/MW of Transmission Entry Capacity per year. This can be compared with the latest GB capacity auction result of £60/ kWyr. for new build.[37] For a 34% CF windfarm the charges are on average about 53% of the baseload charge, but with considerable variation. Thus a windfarm connected in Argyll in Scotland (a windy location) would pay £23.71/ kWyr. while one connected in the Midlands and E Anglia would be paid £0.10/ kWyr. if delivering in winter peak hours (otherwise zero). At the assumed 34% load or capacity factor (CF) the difference between the two translates to £7.96/MWh, a substantial incentive to locate wind farms in low charge zones instead of zones distant from demand. To put this figure into context, the Feb 2026 Auction Round 7a cleared at £72.24/MWh for onshore wind.[38] A wind farm in Argyll would earn a net revenue of £63.28/MWh, compared

[36] E.g. for 2025/26 at https://www.neso.energy/document/374811/download
[37] https://www.rwe.com/en/press/rwe-generation/2025-03-11-uk-t-4-capacity-auction-for-delivery-in-2028-29-finished/
[38] https://assets.publishing.service.gov.uk/media/698a0dc06da2dee8230a9c3a/contracts-for-difference-AR7a.pdf

to the full £72.24/MWh in East Anglia. The Argyll windfarm would need to have a 38.2% capacity factor to earn the same gross profits as a 34% CF East Anglian wind farm. As Argyll has good wind this is probably still economic, but only if adequate transmission built at the cost of existing overhead lines is available. The following section casts doubt on these assumptions.

TNUoS charges are set according to the Investment Cost Related Pricing (ICRP) methodology explained in the *Connection and Use of System Code* (CUSC: at NESO, 2025, p31 et seq.). This is roughly equivalent to the Long-run Marginal Cost (LRMC) of investing in transmission to transport power. The charges are then shifted down by a uniform amount per kWyr. so that the average does not exceed €2.50/MWh to ensure compatible trading with neighbours.[39] This average requires some charges to be negative to preserve the range of prices required by ICRP. The detailed explanation in NESO (2025) is extremely complex, as it has to account for the laws of physics governing load flows in meshed circuits and the different demands made by different output patterns, summarised by their type and load (or capacity) factors.

While G-TNUoS charges should measure the annuitized value of the investment needed to deliver an extra unit of power from each zone, they assume that each existing line can be immediately expanded by 1 MW. In practice it takes on average 14 years to build new overhead lines (Winser, 2023), and it appears almost impossible to strengthen onshore overhead lines (OHLs) from Scotland to England. Instead, National Grid and NESO are building offshore HVDC (High Voltage Direct Current) links. The Western Bootstrap,[40] WB, was commissioned in 2017 at a cost (then) of £1.2 billion (£1.55 billion, 2024 prices), and two Scotland England Green Links, SEGL 1[41] and SEGL 2[42] have been approved at a cost for SEGL 1 of £2.0 billion[43] and SEGL 2 of £3.45 billon.[44] Two further Eastern Green Links have been approved to proceed[45] but cost data are not readily available. If transmission charges are to give good locational guidance for new connections, they should reflect the cost of expanding capacity given the options available. It is, however, difficult to gain a clear sense of what these might be. It is even harder to relate either the published charges or the underlying construction costs to the current cost of building specific new lines.

Table 2 is an attempt to gain some sense of the relative costs or charges for three specific routes from Scotland to England, and to draw on the Mott MacDonald consultancy report of the costs of generic links of HVAC and HVDC overhead lines and HVDC subsea connections comparable to WB and the two SEGLs. The figures are not directly comparable,

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[39] https://www.neso.energy/industry-information/codes/cusc/modifications/cmp261-ensuring-tnuos-paid-generators-gb-charging-year-201516-compliance-eu25mwh-annual-average-limit-set-eu-regulation-8382010-part-b-3
[40] https://www.spenergynetworks.co.uk/pages/western_hvdc_link.aspx
[41] https://www.easterngreenlink1.co.uk/
[42] https://www.ssen-transmission.co.uk/projects/project-map/eastern-green-link-2/
[43] https://www.ofgem.gov.uk/sites/default/files/2024-11/EGL1%20Project%20Assessment%20Decision%20Final.pdf
[44] https://www.ofgem.gov.uk/sites/default/files/2024-03/2024%2003%2027%20EGL%202%20Policy%20Consultation%20Document.pdf
[45] https://www.ofgem.gov.uk/consultation/accelerated-strategic-transmission-investment-material-scope-change-and-early-construction-funding-egl3-egl4-and-gwnc

as TNUoS charge differences reflect the cost difference between the entry/exit zones of the subsea cables, and include a variety of system-wide adjustments.

Table 2 Various cost estimates for expanding transmission lines

Item	WB	SEGL 1	SEGL 2
Length km	420	190	440
capital cost £/kW	£1,032	£647	£2,150
annuitized cost £/kWyr.	£41.75	£75.75	£130.29
TNUoS	£23.99	£7.82	£27.58
Cross border HVAC 4GW	£29.66	£13.42	£31.07
ratio subsea/TNUoS	1.74	9.68	4.72
MM 2 GW subsea HVDC	£166.28	£111.45	£174.20
MM 2.5 GW HVAC OHL 113km	£20.29	£9.18	£21.25
MM 7.5 GW HVAC OHL 113km	£9.28	£4.20	£9.72

Notes: HV: High voltage; OHL: overhead lines

Sources: For WB, SEGL 1 and 2 see links above and are augmented by 20%% to cover O&M, as in Mott MacDonald (2025). TNUoS charges are for the difference in charge in the entry and exit zones for 100% CF (from Table 1). Cross Border Connection is the National Grid proposed 58km link south to Carlisle (National Grid, 2025). MM is from Mott MacDonald (2025) and are derived from specific line lengths, converted to costs per MW-km. The subsea HVDC lines are either for 180km (for SEGL 1) or 275km for the others, long lines are cheaper per MWkm. The annuitizing factor is 6.6% (as in the CUSC), also applied to the Mott MacDonald capital costs, which have been adjusted to exclude power losses.

Nevertheless, the G-TNUoS charges seem defensible given the cost of just the onshore OHL HVAC lines reported by Mott MacDonald, noting that these are quite sensitive to their capacity and fall with distance. What is striking are the comparisons for HVDC lines on- and off-shore. The first point to note is that, with the exception of the WB, the proposed offshore HVDC cables are 5 -10 times as costly as current TNUoS charges (and the similar MM estimate for onshore OHL HVAC lines). Mott MacDonald's estimate (p109) for long distance (700km) high capacity (8GW) HVDC onshore lines is only 16% of the cost of the shorter (275km) 2GW lines and considerably cheaper than current G-TNUoS long distance charge differences (from Table 1). In addition, power losses are considerably lower on DC lines, and this offsets the higher cost compared to AC lines over distances of more than 500-600 km.

The 2025 REMA update announced its intention to reform "TNUoS so that it reflects the true long-term system benefits of new generation (to) ensure that it sends an effective and predictable signal about where new investment should be located" (HMG, 2025). How location signals can be improved is considered in the next section.

4.1. Using reformed TNUoS charges for locational guidance

Now that all wholesale locational price signals have been ruled out, the problem of signalling efficient location and operation needs alternative solutions. The simplest to introduce is to grandfather all existing G-TNUoS charges, and to offer carefully designed forward-looking long term (e.g. 20 year) contracts for new connections. Grandfathering (i.e. allowing existing generators to enjoy the current methodology of setting G-TNUoS charges) might seem to commit the regulator to an inflexible regime, but it does not change the existing rules of the game. All residual required revenue not collected by G-TNUoS is in any case collected from load providing all the regulatory flexibility needed. If necessary, the (indexed) legacy charges could be set for five-year periods, matching the price-control period, or, where the forward-looking charges are much higher, sold to new entrants who place a higher value on firm capacity, signalling an efficient exit. Incumbents have no cause to oppose the proposed reform and the new contracts can give very powerful locational guidance.

Similar models of deep connection charging already apply to new connections to the distribution networks, while off-shore wind farms are offered 20-year offshore transmission contracts, whose charges are set in OFTO auctions.[46] Further, as the regulator, Ofgem, has a duty to ensure that charging is efficient as well as revenue-adequate, the new methodology could be introduced in the next annual round to apply to all developers who have not yet made their final investment decision and/or not yet secured a connection agreement.

Provided new entrants pay the efficient cost of transmission and are not over-compensated in the Balancing Market for curtailment, location decisions should be efficient with the now-revised CfDs (zero compensation for system-wide curtailment that leads to zero prices). The forward-looking G-TNUoS charges in Scotland based on the costliest (and therefore marginal) proposed SEGL 2 would be £110/kWyr. (assuming the same 65% ratio of 34% CFs to 100% CF for the range 1-27 line in Table 1). This translates to £32.96/MWh for a 34% CF wind farm (once the line is commissioned). This would raise the required capacity factor for an equivalent gross profit by £32.96/£72.24 (AR7a strike price), 46% (e.g. from say a CF in E Anglia of 34% to 49.5%, very high for an onshore wind farm. The TNUoS charge would also increase with the higher CF, further slightly raising the required CF. Facing future windfarms in Scotland with these marginal transmission charges would likely lead to a considerable reallocation to suitably windy sites in England and Wales.

By contrast, the Western Bootstrap would only cost £53/kWyr., less than half as much. Onshore HVDC might cut the cost by between one-third and two-thirds of the Green Links, and should be cheaper than conventional OHLs over long distances as well as having lower less obtrusive pylons. Following existing OHL routes would further reduce visual impact. It would seem sensible to consider these options before committing to the more expensive offshore HVDC links.

If only a limited export capacity at any node is currently available, only that amount would be offered firm, with no compensation for generation above the export capacity that must be curtailed, and with priority curtailment – last connected first curtailed. This has been proposed for the island of Ireland by Eirgrid (2022), which offers a non-firm connection until the link is reinforced or after five years, whichever is sooner. Earlier entrants with firm connections might even trade any surplus they have to non-firm later entrants – following the Littlechild approach of seeking market-friendly solutions. The agreement could be attached to a grid contract that reflects the (suitably shared) amortized deep connection charge (Newbery and Biggar, 2024). A similar contract is offered to VRE connecting to GB

[46] https://www.ofgem.gov.uk/energy-regulation/electricity/offshore-electricity-transmission/ofto-tender-rounds

distribution networks, a result of an innovation competition initiative to accelerate connections.[47] Developers are offered either a firm contract at the deep connection cost, or an existing cheaper option but subject to a capped level of curtailment, with no compensation after the cap is exceeded. The precedents for this go back to the 1990s, when Stephen approved a scheme to connect a wind generator with a cheaper (single) circuit and curtail its output when necessary, rather than paying for the more expensive double circuit normally required for a firm connection.

5. Conclusions

Renewables support has evolved over time to require competition for the market through auctions for two-sided CfDs. These are a significant improvement on premium FiTs or green certificates that give all the upside to producers and politically unattractive windfall gains in energy crises or other high-price periods. A CfD rather than the Continental Feed-in-Tariff, FiT, also forces the generator to sell in the market, but normally compensates for any curtailment unless otherwise specified (e.g. by negative prices). By itself, even a competitive CfD auction for firm connection contracts gives poor location signals, and fails to direct VRE investment to the right place at the right time. Forward-looking long-term grid contracts that reflect deep connection costs deal with part of the problem but need further adjustment to discourage early investment in areas experiencing high marginal curtailment. One solution is to offer non-firm connections until reinforcement allows the required Transmission Entry Capacity to be provided, with priority dispatch – last-in first curtailed without compensation.

It then remains to ensure that CfD offers in the balancing market cannot be negative, which, with no compensation for negative GB-wide wholesale prices, should finally deliver an efficient dispatch. Carefully-designed contracts resulting from competition for the market can be compatible with effective competition in the market.

[47] Ofgem financed the *Flexible Plug and Play* project – see https://www.ofgem.gov.uk/sites/default/files/docs/2015/02/fpp_progress_report_dec_2014_v1.0_pxm_151214_with_signature.pdf

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