Regulatory spillover: The impact of the Contracts for Difference scheme on wholesale electricity prices in the United Kingdom

Huanhuan Chen[a], Jinke Li[b*], Nigel O'Leary[b], Jing Shao[c]
[a] *Zhengzhou College of Finance and Economics, Henan, China*
[b]*Department of Economics, School of Social Sciences, Swansea University, United Kingdom*
[c]*University of Wales Trinity Saint David, United Kingdom*
* *Corresponding author (jinke.li@swansea.ac.uk)*

Abstract

The Contracts for Difference (CfD) scheme provides low-carbon electricity generators with long-term price stabilisation while requiring them to participate in wholesale electricity markets. This study investigates whether wind generation supported by CfD affects wholesale prices differently from wind generation operating outside the scheme. Using daily average hourly values for Great Britain from April 2017 to December 2025, this study examines whether the wholesale price effect of wind generation differs between CfD and non-CfD wind farms, using regression models estimated by Prais–Winsten methods. The results show that CfD wind generation has a significantly larger negative effect on wholesale electricity prices than non-CfD wind generation. This difference becomes stronger under more crowded market conditions, consistent with the view that the CfD scheme weakens generators' exposure to wholesale price risk and strengthens incentives to secure eligible output when competition among wind farms intensifies. The findings suggest that the expansion of CfD wind generation may impose regulatory spillover effects on legacy wind farms, particularly those supported under the Renewables Obligation (RO) scheme, by reducing their market revenues and weakening their competitive position. More broadly, the study highlights the importance of accounting for interactions between successive support regimes when designing renewable energy policy.

Keywords: Contracts for Difference; Renewables Obligation; Wholesale Electricity Prices; Policy Design; Output-securing incentives; Regulatory risk

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D4 Market Structure, Pricing, and Design
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1. Introduction

Electricity generation from wind power has increased substantially over the last two decades in the UK. Installed wind capacity increased from 0.43 GW in 2002 to 33.09 GW in 2025, while wind generation rose from 1.26 TWh to 87.10 TWh, accounting for 29.98% of total electricity generation by 2025 (DESNZ, 2026). The literature has documented that the growth of low-marginal-cost renewable generation reduces wholesale electricity prices through the merit-order effect, with evidence from the UK (Shao et al., 2022; Lee et al., 2026), Germany (Würzburg et al., 2013; Kolb et al., 2020), Spain (Figueiredo and Silva, 2019; Macedo et al., 2022), and Italy (Clò et al., 2015; De Siano and Sapio, 2022). Despite this established consensus on the price-reducing effect of renewable generation, limited evidence exists on whether these effects differ across the regulatory support regimes under which wind farms operate.

This question is especially important in the UK, where wind farms supported under two successive policy regimes coexist in the wholesale electricity market. Large-scale renewable projects were first supported under the Renewables Obligation (RO) scheme, which was introduced in 2002 and closed to new applicants in April 2017, although accredited generators continue to receive support for twenty years. The Contracts for Difference (CfD) scheme, introduced in 2014, offers low-carbon generators pre-agreed prices for fifteen years.[1] With operational capacity under this newer scheme reaching 14.92 GW by 2025, these two distinct incentive structures will coexist and interact within the same wholesale market until the final legacy projects phase out in 2037.[2]

Although the CfD scheme is also a price-based support mechanism, it differs from both Feed-in Tariffs (FITs) and Feed-in Premiums (FIPs). FIT generators typically receive a fixed tariff and do not participate directly in the wholesale market, whereas FIP generators sell electricity in the market and receive a premium on top of the market price.[3] CfD generators also sell electricity into the market, but the contract managed by the Low Carbon Contracts Company (LCCC) stabilises the price received for eligible output at the strike price, thereby weakening the link between wholesale prices and generator returns. This insulation is nevertheless incomplete. Under the UK CfD scheme, support is generally linked to eligible metered output rather than unavailable generation, meaning that curtailed electricity that is not generated or exported is not automatically compensated. In addition, the treatment of negative

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[1] An early example of a CfD scheme was implemented in Nord Pool between 2000 and 2006 to hedge against price differentiation across locations, rather than to support renewable projects (Kristiansen, 2004; Marckhoff and Wimschulte, 2009).

[2] RO wind farms are also referred to as non-CfD wind farms in this study, as non-CfD wind capacity is approximated by the difference between total wind capacity and CfD wind capacity.

[3] FIT/FIP schemes have been used as the main instruments to encourage renewable electricity in countries such as Germany (Böhringer et al., 2017; Hitaj and Löschel, 2019; Winter and Schlesewsky, 2019) and Spain (del Río González, 2008; Schallenberg-Rodriguez and Haas, 2012; Ciarreta et al., 2017; Marques et al., 2019). For recent review studies on FIT/FIP schemes, see (Winkler et al., 2016; Nicolini and Tavoni, 2017; Schallenberg-Rodriguez, 2017). FIT schemes were also adopted in the UK for small-scale projects such as household solar panels (Balta-Ozkan et al., 2015; Pearce and Slade, 2018; Castaneda et al., 2020; Lee et al., 2025).

prices depends on contract design, and more recent CfD contracts suspend difference payments during sustained negative-price periods. The CfD scheme therefore substantially reduces generators' exposure to wholesale market conditions, but does not eliminate it entirely.

This coexistence creates an important but underexplored issue of regulatory spillover. A new support mechanism does not affect only the projects that receive it; it may also alter market outcomes for assets financed under earlier rules. In the present context, if CfD wind farms are less sensitive to wholesale prices than non-CfD wind farms, they may have stronger incentives to secure sales volume, as their revenues are less directly exposed to wholesale prices. This behaviour could amplify the downward pressure of wind generation on wholesale prices and, in turn, adversely affect the revenues and competitiveness of non-CfD supported wind farms that remain more exposed to market prices. The introduction of the CfD scheme may therefore have created a spillover from the newer regime to legacy renewable assets supported under the earlier regime. Indeed, concerns about the possibility of low and negative prices have already been raised in the literature (Bunn and Yusupov, 2015; Grubb and Newbery, 2018).[4]

This study exploits the unique coexistence of CfD and non-CfD wind farms in the Great Britain electricity market to examine whether wind generation under different support regimes has different effects on wholesale electricity prices. Using daily data from 11 April 2017, when CfD wind farms first became operational, to 31 December 2025, the study first examines the effect of total wind generation on wholesale electricity prices before distinguishing between generation from CfD and non-CfD wind farms. The results show that CfD wind generation has a significantly larger negative impact on wholesale electricity prices than non-CfD wind generation. However, a simple cost-based explanation is not fully convincing, because most CfD capacity in the sample is offshore, while a large share of non-CfD wind capacity is onshore and has historically been less costly.

The analysis then investigates whether this difference varies with market crowdedness. If the stronger price effect of CfD wind is driven partly by market behaviour rather than solely by technology or cost differences, it should become more pronounced when competition among low-marginal-cost generators intensifies. To assess this, three measures of market crowdedness are used, namely the de-rated margin (Osorio and van Ackere, 2016; Castro, 2017), residual demand (Wagner, 2014; Chyong et al., 2020), and wind penetration (Hirth, 2013; Hirth and Müller, 2016; Marshman et al., 2020), to test whether the price effect of CfD wind differs between more crowded and less crowded market conditions. The results show that the negative price effect of CfD wind is stronger when the market is more crowded. This finding suggests that regulatory risk was imposed on non-CfD wind farms, which faced lower prices and reduced competitiveness due to the design of the subsequent support scheme.

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[4] A negative electricity price means that market participants pay to dispose of surplus electricity and are paid to consume electricity.

These findings make three main contributions to the literature. First, the study extends the merit-order effect literature by distinguishing wind generation by support regime rather than treating wind as a homogeneous source of supply. Second, it contributes to the literature on renewable support design and market incentives by providing empirical evidence that price stabilisation under the CfD scheme may affect wholesale price formation. Third, it contributes to the literature on regulatory risk and policy transitions by showing that the introduction of a new support mechanism may generate spillover effects for assets supported under an earlier regime. More generally, the study highlights that renewable support policies may produce not only environmental and price-related co-benefits, but also unintended distributional consequences across different cohorts of investors.

The remainder of the study is structured as follows. Section 2 reviews the literature. Section 3 provides institutional background on the UK support schemes and develops the testable propositions. Section 4 describes the data and empirical methodology. Section 5 presents the estimation results and discussion. Section 6 concludes.

2. Literature review

2.1 Wind generation, wholesale prices, and the merit-order effect

A substantial literature shows that renewable generation, especially wind, lowers wholesale electricity prices through the merit-order effect by displacing higher-cost conventional generation, a pattern documented in Great Britain and many other electricity markets.

For Great Britain, Shao et al. (2022) show that higher wind generation significantly reduced wholesale electricity prices over the period 2009–2021, while later studies suggest that the expansion of wind generation also brings wider benefits, such as reduced energy imports and emissions (Shao et al., 2023; Pashakolaie et al., 2024). Similar conclusions have been reached for other liberalised electricity markets. Early evidence for Germany shows that renewable deployment exerts downward pressure on wholesale prices (Sensfuß et al., 2008), and later studies confirm substantial price-depressing effects of wind and solar generation in the German market (Würzburg et al., 2013; Cludius et al., 2014; Ketterer, 2014; Kolb et al., 2020). For Spain, studies find that renewable output lowers electricity prices, although the size of the effect varies across hours and market conditions (Gelabert et al., 2011; Ballester and Furió, 2015; Figueiredo and Silva, 2019; Macedo et al., 2022). Similar evidence is found for Denmark (Jónsson et al., 2010; Unger et al., 2018), Italy (Clò et al., 2015; De Siano and Sapio, 2022), Ireland (Denny et al., 2017; Di Cosmo and Valeri, 2018), the United States (Woo et al., 2016; Quint and Dahlke, 2019), and Australia (Nelson et al., 2012; Forrest and MacGill, 2013; Csereklyei et al., 2019; Rai and Nunn, 2020). Looking across countries, Moreno and Díaz (2019) examine multiple European electricity markets and suggest that Germany, Spain, and Italy experienced the largest electricity price reductions associated with increases in dispatched wind capacity.

At the same time, a related literature stresses that the price effect of wind generation is not constant, but depends on system conditions, flexibility, and the level of renewable penetration. For example, the marginal price effect of wind may vary with penetration levels (Ketterer, 2014; Quint and Dahlke, 2019), while the market value of variable renewables declines as their penetration increases, reflecting increasing temporal concentration of output and stronger price suppression at high-output periods (Hirth, 2013; Hirth and Ziegenhagen, 2015). This point is especially relevant to the present paper because it links the merit-order effect to the idea of market crowdedness: when many wind generators are producing simultaneously, competition among low-marginal-cost units may intensify and wholesale prices may fall more sharply.

This literature is closely related to this paper because the merit-order effect is an important co-benefit of wind generation, alongside decarbonisation, lower wholesale prices, reduced exposure to fossil-fuel price shocks, and improved energy security. However, existing studies usually treat wind as a single category, leaving limited evidence on whether its price effect differs across support regimes, particularly between CfD and non-CfD supported wind, and under different market conditions.

2.2 Renewable support design: the RO scheme, the CfD scheme, and market incentives

The second stream of literature examines how renewable support schemes affect investment incentives, revenue risk, and market behaviour. Earlier studies of the Renewables Obligation (RO) scheme highlight the exposure of renewable generators to certificate-price uncertainty, wholesale price risk, and volume risk. Early criticisms of the RO scheme highlighted the difficulties renewable generators faced regarding price and volume risks. For example, Woodman and Mitchell (2011) emphasise the competition in the RO scheme and argue that revenue uncertainty adversely affected investments from renewable developers. Wood and Dow (2011) attribute the scheme's inefficiency to the uncertainty of future certificate prices. They also point that the scheme's banding implementation decreased onshore wind deployment and suggested that the existing framework might not support significant expansion of solar PV, wave, and tidal stream technologies until 2020. Wang et al. (2024b) later confirm that the introduction of banding significantly promoted offshore wind development, helping the UK achieve its renewable generation targets.

Other studies focus on the strategic and institutional features of certificate-based support. Theoretically, Li et al. (2020) develop a model illustrating that the recycling mechanism in the RO scheme induces strategic behaviour (Nash-Cournot type) among suppliers, allowing for strategic collaboration that lowers renewable generators' revenue. Shao et al. (2021) suggest that insufficient supply of certificate in the market may disadvantage independent suppliers, while Wang et al. (2024b) indicate that this market condition ensures price certainty and sales guarantees by comparing the tradable green certificate schemes in the UK and Australia. These studies suggest that support design can affect not only investment incentives but also the competitive environment faced by renewable generators. More broadly, comparative work on renewable support instruments, such as (Menanteau et al., 2003; Held et al., 2006; Del Río and Cerdá, 2014), show that different policy instruments vary in their risk allocation, dynamic efficiency, and incentives for technological deployment, implying that support design may also shape how supported generators participate in electricity markets after commissioning.

The literature on the CfD scheme places stronger emphasis on price stabilisation and the allocation of market risk. Newbery (2012) argues that the CfD framework may leave generators exposed to basis and volatility risks relative to a more traditional feed-in tariff, while Bunn and Yusupov (2015) compare the RO and CfD schemes and discuss the different risk implications for generators. Grubb and Newbery (2018) highlight that long-term price stabilisation can lower financing costs and encourage investment, especially for capital-intensive technologies such as offshore wind. This concern is closely related to a wider electricity-market literature showing that contract structures, balancing rules, and support arrangements can materially affect generators' offer behaviour and exposure to spot-market signals. In addition, Chen et al. (2026) suggest that the CfD scheme may have vulnerabilities in enforcement that require attention from the regulator.

A related international literature on market premia, feed-in premiums, and negative prices points in the same direction. Studies such as (Klessmann et al., 2008; Couture and Gagnon, 2010; Ciarreta et al., 2017) discuss how different renewable support designs transmit price risk and market signals to generators, and whether such designs strengthen or weaken incentives to respond to wholesale prices. The implication is that support schemes influence both investment incentives and operational behaviour. This literature motivates our main hypothesis that, because CfD wind farms are less exposed to wholesale price outcomes than non-CfD supported wind farms, they may have a stronger wholesale-price effect; yet direct empirical evidence for Great Britain remains limited.

2.3 Market crowdedness, regulatory spillovers

The third relevant stream of literature concerns the interaction between renewable support design, market conditions, and competition among low-marginal-cost generators. As wind penetration rises, or as residual demand falls, competition among renewable generators may intensify, especially in trading environments in which offers must match to secure sales. In such circumstances, the market incentives created by support mechanisms may become particularly important. This idea is related to the literature on the declining market value of variable renewables and price cannibalisation, which shows that the value of wind output falls as penetration rises because output tends to be concentrated in the same periods across plants (Hirth, 2013; Hirth and Ziegenhagen, 2015; Bushnell and Novan, 2018). While much of that literature focuses on value rather than bidding behaviour per se, it points to the same underlying mechanism: increasing renewable penetration changes the competitive environment faced by low-marginal-cost generators.

Relatedly, the literature on policy design and regulatory change suggests that the introduction of a new support mechanism may have spillover effects on assets supported under earlier regimes. Research on policy credibility, regulatory stability, and energy investment risk has long emphasised that the profitability of long-lived energy assets depends not only on current support arrangements, but also on how later policy changes alter market conditions and expected returns. In the context of renewable support, studies such as (Mitchell et al., 2006; Batlle et al., 2012; Polzin et al., 2019) highlight the importance of stable policy frameworks and predictable risk allocation for investor confidence. If the CfD scheme changes market participation incentives and increases downward pressure on wholesale prices, this may adversely affect the revenues of generators operating under the RO scheme, even though those projects were financed under different policy expectations. In this aspect, renewable support may generate not only environmental and price-related co-benefits, but also regulatory spillovers across different cohorts of investors.

3. Background and propositions

3.1 The RO and CfD schemes in the UK electricity market

The RO scheme was introduced in 2002 to support large-scale renewable generation. Under the RO scheme, accredited generators receive tradable certificates issued by the regulator and sell electricity in the wholesale market, meaning that their revenues remain directly exposed to wholesale price conditions. Although the scheme was closed to new applicants in April 2017, with grace periods until January 2019, accredited renewable generators continue to receive certificates for a period of twenty years. The scheme expanded substantially over time, with costs rising from £250.44 million in 2002-03 to £7.7 billion in 2024-25. By 2024-25, wind had become the dominant technology under the RO, accounting for 64.14% of certificates issued and 46.52 TWh out of 74.79 TWh of total RO-supported generation (Ofgem, 2026).[5]

The CfD scheme was introduced as the successor to the RO scheme to provide greater price stability for low-carbon generation. Under a CfD, a generator sells electricity in the market and receives a top-up payment when the wholesale price is below the strike price, while paying back the difference when the wholesale price exceeds the strike price. Relative to the RO scheme, this substantially reduces generators' exposure to wholesale price fluctuations.[6] The strike price is set to provide the long-term revenue needed to support investment in a given technology while reducing low-carbon generators' exposure to electricity price volatility and, in turn, lowering investor risk (National Audit Office, 2014).

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[5] The difference between the number of certificates issued and installed capacity is caused by banding. Banding was introduced in 2009-10 to provide different levels of support to technologies at different development stages. For example, the banding level increased from one to 1.5 for offshore wind in 2009-10 and decreased to 0.9 for onshore wind in 2013-14 (Wang et al., 2024a). In terms of support per MWh of renewable electricity, offshore wind farms receive more certificates than onshore wind farms.

[6] For nuclear power, contracts can be decided through bilateral negotiation. For example, Hinkley Point C has a negotiated strike price of £92.50/MWh for 35 years, in 2012 prices (House of Commons Library, 2020).

The coexistence of the two schemes is central to this study. Non-CfD supported and CfD wind farms operate in the same wholesale market but face different revenue incentives. This creates the potential for regulatory spillover, whereby the later support scheme affects price formation and thereby alters the market environment faced by generators supported under the earlier scheme.

In 2014, eight renewable electricity projects were awarded Investment Contracts (early CfDs) on a non-competitive basis through the Final Investment Decision (FID) Enabling for Renewables programme with strike prices agreed upon bilaterally (National Audit Office, 2014). Since then, seven competitive allocation rounds have been held by 2026. Together, the FID programme and these allocation rounds awarded CfD contracts to 48.38 GW of low-carbon capacity, including 38.51 GW of wind capacity.[7] Offshore wind accounts for the majority of this total, highlighting the central role of wind generation within the CfD scheme. By 2024-25, operational CfD wind capacity had reached 14.92 GW, with substantial further growth expected as contracted projects are commissioned. Table 1 summarises CfD wind capacity by delivery year.

Table 1. The allocation of contracts to wind farms, with strike prices reported in brackets (£/MWh, in 2012 prices). Sources: DECC, BEIS, DESNZ.

Delivery Year	Early CfDs to Offshore Wind (MW)	CfDs to Offshore Wind (MW)	CfDs to Onshore Wind (MW)	CfDs to Remote Island Wind (MW)	CfDs to Floating Offshore Wind (MW)	Cumulative Capacity (MW)
2016-17	678 (£150)	-	45 (£79.23)	-	-	723
2017-18	922 (£140)	714 (£119.89)	77.5 (£79.99)	-	-	2437
2018-19	784 (£140)	448 (£114.39)	626.15 (£82.50)	-	-	4295
2019-20	400 (£140)	-	-	-	-	4695
2020-21	400 (£140)	-	-	-	-	5095
2021-22	-	860 (£74.75)	-	-	-	5955
2022-23	-	2336 (£57.50)	-	-	-	8291
2023-24	-	2612 (£39.65)	-	225.72 (£39.65)	-	11128
2024-25	-	2854 (£41.61)	887.96 (£42.47)	49.5 (£41.61)	-	14920
2025-26	-	-	31.1 (£52.29)	-	-	14951
2026-27	-	6994.34 (£37.35)	476.98 (£51.50)	597.6 (£46.39)	32 (£87.30)	23052
2027-28	-	-	1963.03 (£51.78)	223.6 (£52.29)	-	25238
2028-29	-	5073.07 (£61.09)	-	-	400 (£139.93)	30712
2029-30	-	1380 (£65.45)	-	-	192.5 (£155.37)	32284
2030-31	-	5155 (£65.12)	-	-	-	37439

Note: where a delivery year includes more than one auction component, reported capacity is the sum across components and the strike price is the capacity-weighted average. This applies to offshore wind in 2028–29 and 2030–31, and onshore wind in 2027–28.

3.2 Generation, payments, and incentive properties of CfD wind generation

As Table 2 shows, CfD wind generation rose from 2.62 TWh in 2017-18 to 29.12 TWh in 2025-26. CfD payments to wind farms also increased, from £296 million in 2017-18 to £1,678 million in 2020-21, but became more volatile thereafter because payments depend on the gap between strike prices

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[7] The auction system in the UK electricity market originated from the Non-Fossil-Fuel Obligation (NFFO) auctions, which operated from 1990 to 1998 before being replaced by the RO scheme.

and wholesale electricity prices. In 2021-22, wind farms made a small repayment to the LCCC (-£3 million), while in 2022-23 payments to wind farms were positive (£104 million) but total scheme-wide CfD payments were only £9 million, because of repayments from other technologies. In 2025-26, CfD payments to wind farms reached £2.38 billion, out of total CfD payments of £2.97 billion.

Table 2. The annual generation from CfD wind farms from 2017-18 to 2025-26. Source: National Energy System Operator, Elexon, and LCCC.

Financial year	Total wind generation (GWh)	Wind generation from non-CfD wind farms (GWh)	Wind generation from CfD wind farms (GWh)	CfD payments to Wind farms (£million)	Total CfD payments (£million)	CfD payments to wind farms (%)
2017-18	48,328	45,707	2,621	295.85	543.97	54.39%
2018-19	52,319	46,681	5,637	598.85	979.97	61.11%
2019-20	65,142	53,641	11,500	1365.76	1809.48	75.48%
2020-21	64,312	49,445	14,867	1677.71	2267.82	73.98%
2021-22	66,107	50,345	15,761	-2.98	289.27	-
2022-23	78,006	60,638	17,369	103.45	8.96	-
2023-24	80,207	61,091	19,116	1757.76	1769.98	99.31%
2024-25	79,649	55,122	24,527	1734.89	2238.29	77.51%
2025-26	92,757	63,642	29,115	2377.35	2966.22	80.15%

Negative electricity prices arise when excess supply leads market participants to pay to dispose of electricity rather than sell it. This can occur when intermittent renewable output is high during periods of low demand, creating a surplus in the system. This phenomenon has been examined in markets such as Germany (Valitov, 2019; Aust and Horsch, 2020). In the UK context, two features of the CfD scheme are particularly relevant for interpreting generator incentives: the treatment of curtailment and the treatment of negative prices. First, CfD payments are generally linked to eligible metered output rather than forgone generation, so curtailed electricity that is not generated and exported is not automatically compensated. Realised output therefore remains important for revenues even under price stabilisation. Second, the treatment of negative prices depends on contract design. Under the UK CfD scheme, payments are suspended during periods of negative day-ahead prices, with earlier contracts applying this rule only after six or more consecutive hours and later contracts applying it to any negative-price hour (DESNZ, 2024). CfD support therefore reduces, but does not eliminate, exposure to market conditions.

These institutional features matter for interpreting the empirical results. Relative to the RO scheme, CfD contracts weaken generators' exposure to wholesale price fluctuations, but because support depends on metered output and may be withdrawn during sustained negative-price periods, market-related incentives remain. Any stronger price effect associated with CfD wind generation should therefore be understood as reflecting reduced price exposure rather than a complete absence of market discipline.

3.3 Generators under the RO scheme and the CfD scheme in the market

Generators supported under the RO scheme are considered first. Under this scheme, generators sell their electricity in the competitive wholesale market and receive revenue from the certificates awarded to them. The profit of an RO generator i, π_i^{RO}, is

$$\pi_i^{RO} = \left(p_i^w - c_i^{RO}\right)q_i^{RO} + p_i^{roc} r_i \tag{1}$$

where c_i^{RO} denotes operating costs, p_i^w is the market price (i.e., wholesale electricity price), q_i^{RO} is the quantity of electricity supplied, p_i^{roc} is the certificate price, and r_i is the number of certificates sold. The first term on the right-hand side represents revenue net of operating costs from electricity sales, while the second term captures additional revenue from certificate sales. As Eq. (1) shows, the market price is directly relevant to the profit of a generator supported under the RO scheme.

Next, consider generators supported under the CfD scheme.[8] Like RO-supported generators, generators holding CfD contracts sell their electricity in the competitive wholesale market. CfD generators effectively receive a fixed price per MWh of eligible electricity, receiving top-up payments when the market price falls below the strike price and paying back the difference when it rises above the strike price. The profit of a CfD generator i, π_i^{CFD}, is

$$\pi_i^{CfD} = \left(p_i^w - c_i^{CfD}\right)q_i^{CfD} + (p_i^s - p_i^w)q_i^{CfD} \tag{2}$$

where c_i^{CfD} denotes the operating costs, p_i^s is the strike price, and q_i^{CfD} is the quantity of electricity supplied. On the right-hand side of Eq. (2), the first term is the revenue from selling electricity to the market, and the second term is the transfer to or from the LCCC depending on the difference between the strike price and the market price. The profit function can be rewritten as

$$\pi_i^{CfD} = \left(p_i^s - c_i^{CfD}\right)q_i^{CfD} \tag{3}$$

Eq. (3) shows that, in this stylised representation, the CfD scheme removes the wholesale market price from the profit function, making profit less directly sensitive to wholesale price outcomes than under the RO scheme.

This is a stylised simplification rather than a complete description of realised revenues. In practice, CfD insulation from market prices is incomplete, since payments depend on eligible metered output and may be limited during negative-price periods. Eq. (3) is therefore intended to highlight the price-stabilising feature of the CfD mechanism. CfD contracts may strengthen incentives to secure sales volume, especially when the strike price exceeds operating costs, and these incentives may become more important in competitive or crowded market conditions. The support regime may also influence project planning and siting, with the RO scheme favouring locations with higher market value and less

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[8] For comparison, the profit functions of generators under the FIT and FIP schemes are illustrated in Appendix A2.

congestion, while the CfD scheme may place greater weight on maximising output and thus favour more crowded locations.

3.4 Two propositions

The preceding discussion suggests that the observed empirical pattern may reflect not only behavioural differences in market participation, but also differences in costs and project siting, raising a potential endogeneity concern. Accordingly, the propositions below are derived from the different profitability structures of the RO and CfD schemes, and the empirical results should be interpreted as reduced-form evidence associated with support design rather than as evidence of bidding behaviour alone.

Because wholesale electricity prices directly affect the profits of non-CfD generators but are less directly relevant for CfD generators, CfD generators may be less sensitive to realised wholesale price outcomes. They may therefore place greater emphasis on securing eligible output, which could strengthen the downward effect of CfD wind generation on wholesale electricity prices.

Proposition 1: Compared with wind generation from non-CfD wind generators, which are mainly RO wind generators, wind generation from CfD generators has a larger negative impact on the wholesale electricity price.

This mechanism may become more important when the market is more crowded, that is, when wind generation is higher and electricity demand is lower. Under these conditions, competition among wind farms to secure sales becomes more intense. Since CfD generators are less directly exposed to wholesale price fluctuations, they may be more willing than non-CfD generators to accept lower market prices to secure eligible output.

Proposition 2: When the market is more crowded, the negative impact of wind generation from CfD wind farms on the wholesale electricity price is stronger because the need to secure maximum sales volume becomes more pressing.

Figure 1 summarises the analytical framework of the study. It links the coexistence of RO- and CfD wind farms to the empirical strategy for identifying differences in wholesale price effects, the mechanism test based on market crowdedness, and the broader implications for regulatory spillovers across renewable asset cohorts.

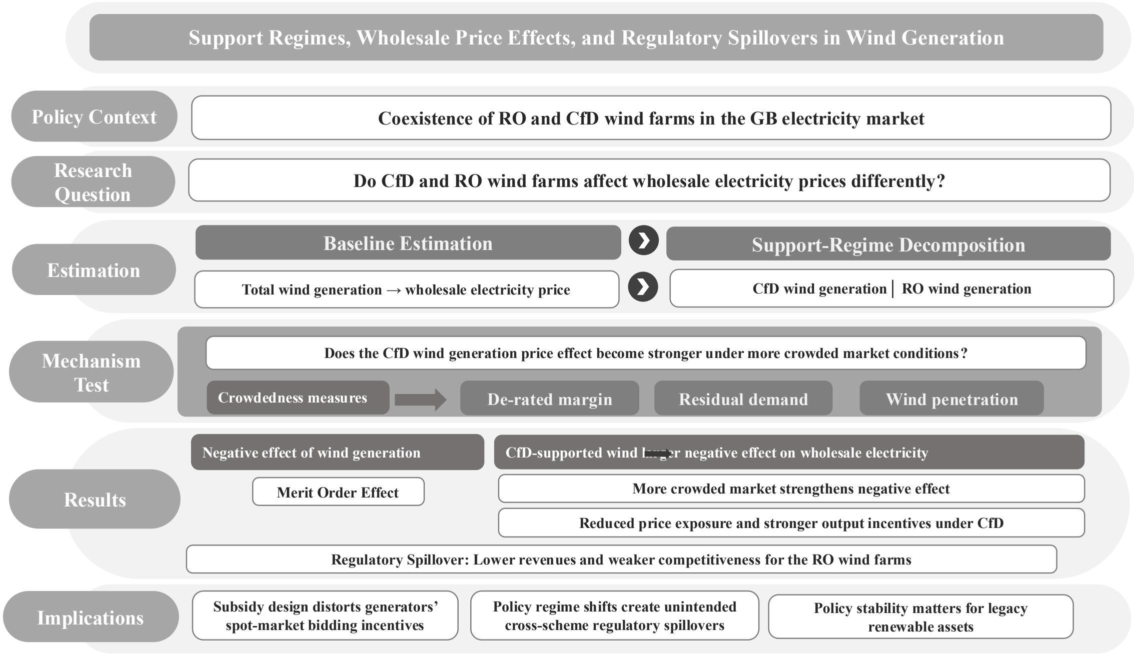

Figure 1. Conceptual framework and analytical flow of this study.

4. Data and model specifications

4.1 Data

The data used cover the period from 11 April 2017, when CfD wind generators became operational, to 31 December 2025. The GB wholesale electricity price is measured by the Market Index Price (MIP) from Elexon (Elexon, 2019).[9] This half-hourly series represents a weighted average price relating to qualifying contracts from intraday trading, which is particularly relevant to short-term adjustment (hours ahead) for wind generation characterised by intermittency and unpredictability (Soman et al., 2010). Although intraday trading accounts for only a small share of total electricity transactions, the MIP is widely used as a reference wholesale price for Great Britain (Elexon, 2019).

The analysis also uses half-hourly data on national demand, wind generation, and solar generation for Great Britain. First, national electricity demand is constructed from two components from National Energy System Operator (NESO): (i) measured national demand, defined as the sum of metered generation, and (ii) estimated embedded wind and solar generation. For the system operator, embedded generation is indistinguishable from reduced demand, since it is connected to low-voltage regional electricity networks. Second, wind generation is constructed using (i) wind generation from large wind farms with capacity above 100 MW connected to the Transmission Network and (ii) estimated embedded wind generation. Third, solar generation is measured using the estimated embedded solar generation. All half-hourly data are converted into daily average hourly values, i.e.,

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[9] The monthly average MIP aligns with the monthly average electricity price for day-ahead contracts provided by Ofgem. Similarly, Bunn and Zachmann (2010) find high correlations between exchange and OTC prices in the UK between 2002 and 2005.

daily observations obtained by averaging the half-hourly values within each day, to reduce high-frequency noise (Gelabert et al., 2011; Clò et al., 2015).

A key distinction in the analysis is between CfD and non-CfD wind generation. CfD wind generation is calculated from the daily generation series published by the LCCC for individual CfD generators. Daily generation is aggregated across all CfD wind farms and divided by 24 to obtain a daily average hourly measure. Non-CfD wind generation is then defined as the difference between total wind generation and CfD wind generation. This category mainly consists of wind farms supported under the earlier RO scheme.

The analysis further includes daily data on fuel prices, carbon costs, and net electricity imports. Fuel and carbon price data are obtained from DataStream. The natural gas price is measured in pence per therm at the UK National Balancing Point, while the coal price is proxied by the API2 index and converted into £/tonne. To capture the carbon cost faced by fossil-fuel generators in Great Britain, an effective carbon price is defined as the sum of the EU ETS allowance price and the UK Carbon Price Support, expressed in £/tonne of CO_2.[10] Because fuel and carbon markets do not trade on weekends, weekend observations are set equal to the preceding Friday's value. Net electricity imports, obtained from Elexon, are included to reflect the increasing integration of the GB electricity market with neighbouring European markets. All non-sterling prices are converted into pounds sterling using daily exchange rates.

Table 3 reports summary statistics for the variables used in the analysis. The time-series properties of the data are also examined using the Augmented Dickey–Fuller and Phillips–Perron tests. Most variables are found to be stationary in levels at the 5% significance level. For gas prices, coal prices, and the effective carbon price, the unit root null cannot always be rejected. Accordingly, month and weekday dummies are included in the regressions, and the stationarity of the regression residuals is also assessed as an additional check on the validity of the estimated relationships.

Table 3. Statistics of variables related to the wholesale electricity market.

Variable	Obs	Mean	Min	Max	Data source
Wholesale price, £/MWh	3,215	82.24	-11.35	666.90	Elexon
National demand, GWh	3,215	30.76	22.50	43.31	NESO
Wind generation, GWh	3,215	9.46	0.85	27.31	NESO
Non-CfD wind generation, GWh	3,215	7.73	0.82	21.61	NESO, LCCC
CfD wind generation, GWh	3,215	1.74	0.00	6.57	LCCC
Solar generation, GWh	3,215	1.50	0.04	4.91	NESO
Natural gas price, pence/therm	3,215	85.08	8.50	570.00	DataStream
Coal price, £/tonne	3,215	90.76	30.92	341.10	DataStream
Effective carbon price, £/tonne	3,215	60.89	22.04	103.67	DataStream
Net imports, GWh	3,215	3.45	-5.69	13.61	NESO

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[10] The UK Government introduced the Carbon Price Support mechanism (CPS) for fossil-fuel generation on 1 April 2013.

4.2 Model specifications

This section outlines the empirical strategy for testing whether wind generation under different support regimes has different effects on wholesale electricity prices, and whether any differences are consistent with output-securing incentives, cost-based explanations, project selection, or regulatory spillover. The analysis proceeds in three steps: first, it estimates a baseline model using total wind generation to identify the aggregate merit-order effect in Great Britain; second, it separates wind generation into CfD and non-CfD generation to test whether support arrangements are associated with different marginal price effects; and third, it examines whether the effect of CfD wind is amplified under crowded market conditions, using de-rated margin, residual demand, and wind penetration as indicators.

4.2.1 Baseline and support-regime regression models

The dependent variable is the daily average hourly value of the wholesale price (*wp*) measured by the Market Index Price. Following Shao et al. (2022), in the first specification, the independent variables include daily average hourly national demand (*nd*), daily average hourly wind generation (*wind*) and solar generation (*solar*), gas price (*gasp*), coal price (*coalp*), effective carbon price (*carbonps*), and net imports (*netimp*). As suggested by Würzburg et al. (2013) and Cludius et al. (2014), daily electricity consumption is price-insensitive and inelastic, making daily average hourly national demand an exogenous variable. Wind and solar generation are assumed to be exogenous and mainly influenced by weather conditions. In addition, prices of natural gas and coal are included in the model. Gas, coal, and carbon prices from international markets are assumed to be exogenous to the GB wholesale electricity price. Effective carbon prices (*carbonps*) charged on GHG emissions from electricity generation increase the costs of fossil-fuelled plants and should also affect electricity prices. Finally, as the GB electricity network is interconnected with neighbouring countries, net imports (*netimp*) from interconnectors are also included in the model. To control for seasonal effects, we include a vector of time dummies (*D*), including eleven dummies indicating the month and six dummies indicating the days of the week. The first specification does not distinguish wind generation from different wind farms and is given as

$$\begin{gathered} wp_t = \beta_0 + \beta_1 \cdot nd_t + \beta_2 \cdot wind_t + \beta_3 \cdot solar_t \\ +\beta_4 \cdot gasp_t + \beta_5 \cdot coalp_t + \beta_6 \cdot carbonps_t + \beta_7 \cdot netimp_t + \gamma D_t + \varepsilon_t \end{gathered} \tag{4}$$

As discussed in Section 3.3, due to the design of support schemes, wind generation from CfD wind farms may have a different effect on wholesale electricity prices than wind generation from non-CfD wind farms. Therefore, the second specification considers wind generation from non-CfD wind farms ($wind_{nc,t}$) and CfD wind farms ($wind_{c,t}$), separately,

$$\begin{gathered} wp_t = \beta_0 + \beta_1 \cdot nd_t + \beta_{2a} \cdot wind_{nc,t} + \beta_{2b} \cdot wind_{c,t} + \beta_3 \cdot solar_t \\ +\beta_4 \cdot gasp_t + \beta_5 \cdot coalp_t + \beta_6 \cdot carbonps_t + \beta_7 \cdot netimp_t + \gamma D_t + \varepsilon_t \end{gathered} \tag{5}$$

4.2.2 Measuring market crowdedness

The price effect of CfD wind generation may differ across market conditions, particularly between relatively crowded and less crowded conditions. To capture this possibility, three indicators of market crowdedness are considered: the de-rated margin, residual demand, and wind penetration, each of which reflects the balance between available supply and demand from a different perspective.

In the empirical analysis, market crowdedness is represented by a dummy variable, d. For each indicator, the dummy is defined by comparing the daily average hourly value with the corresponding quarterly average hourly value. It takes the value of one when the market is classified as more crowded, and zero otherwise. This binary specification is intended to identify whether the price effect of CfD wind generation differs across market regimes, rather than to estimate a continuous response to system tightness. A continuous specification related to market crowdedness is less suitable because the de-rated margin, residual demand, and wind penetration are closely related to other control variables already included in the model, particularly national demand and generation variables. Including them directly would therefore create substantial multicollinearity and make the interaction effects harder to interpret.

The first measure is the de-rated margin, an official indicator of system tightness (DECC, 2013), defined as the difference between available de-rated capacity and forecast demand. Higher values indicate greater excess supply and, in our interpretation, a more crowded market. It is defined as

$$drm_t = T_t + wind_t^f - nd_t^f \tag{6}$$

where T_t is the generation capacity of conventional generators, $wind_t^f$ is forecasted wind generation, and nd_t^f is forecasted demand. The de-rated capacity margin measures the amount of excess supply above peak demand. As higher (forecasted) wind generation and/or lower (forecasted) national demand lead to a higher margin, the market is more crowded if the de-rated margin is higher than its quarterly average value,

$$\begin{aligned} d^{drm} &= 0 \; if \; drm_t < \overline{drm} \;\; \leftrightarrow \;\; market \; is \; less \; crowded \\ d^{drm} &= 1 \; if \; drm_t > \overline{drm} \;\; \leftrightarrow \;\; market \; is \; more \; crowded \end{aligned} \tag{7}$$

The second measure is residual demand, defined as demand net of wind generation. Lower residual demand indicates that a larger share of demand is already met by wind generation and therefore corresponds to a more crowded market. It is defined as

$$rd_t = nd_t - wind_t \tag{8}$$

where higher wind generation and/or lower national demand lead to lower residual demand. Therefore, the market is more crowded if residual demand is less than its quarterly average value,

$$\begin{aligned} d^{rd} &= 0 \; if \; rd_t > \overline{rd} \;\; \leftrightarrow \;\; market \; is \; less \; crowded \\ d^{rd} &= 1 \; if \; rd_t < \overline{rd} \;\; \leftrightarrow \;\; market \; is \; more \; crowded \end{aligned} \tag{9}$$

The third measure is wind penetration, defined as the ratio of wind generation to national demand. Higher values indicate that wind generation accounts for a larger share of demand and therefore correspond to a more crowded market. It is defined as

$$wpen_t = \frac{wind_t}{nd_t} \tag{10}$$

where higher wind generation and/or lower national demand lead to higher wind penetration. Therefore, the market is more crowded if wind penetration is greater than its quarterly average value,

$$\begin{aligned} d^{wpen} &= 0 \; if \; wpen_t < \overline{wpen} \quad \leftrightarrow \quad market \; is \; less \; crowded \\ d^{wpen} &= 1 \; if \; wpen_t > \overline{wpen} \quad \leftrightarrow \quad market \; is \; more \; crowded \end{aligned} \tag{11}$$

In the baseline crowdedness analysis, observations are classified into less crowded and more crowded regimes using dummy variables based on the three measures. Table 4 reports summary statistics for key wholesale market variables under these two conditions, showing that wholesale electricity prices are consistently higher in less crowded markets, in line with periods of higher demand and/or lower wind generation.

Table 4. Summary statistics under three alternative measures of market crowdedness.

	De-rated margin		Residual demand		Wind penetration	
Variables	Less crowded	More crowded	Less crowded	More crowded	Less crowded	More crowded
Wholesale price, £/MWh	93.34	70.07	94.27	69.35	92.48	70.38
National demand, GWh	31.17	30.31	31.41	30.07	30.79	30.73
Wind generation, GWh	6.46	12.75	6.18	12.97	5.89	13.60
Non-CfD wind generation, GWh	5.28	10.40	5.05	10.60	4.80	11.11
CfD wind generation, GWh	1.18	2.35	1.14	2.38	1.09	2.49
Observations	1681	1534	1663	1552	1726	1489

4.2.3 Interaction models, estimation strategy, and diagnostics

To examine whether the price effect of CfD wind generation varies with market crowdedness, the baseline model is extended to include a market crowdedness dummy and an interaction term between this dummy and CfD wind generation,

$$\begin{aligned} wp_t = \beta_0 + \beta_1 \cdot nd_t + \beta_{2a} \cdot wind_{nc,t} + \beta_{2b} \cdot wind_{c,t} + \gamma_1 \cdot d_t + \gamma_2 \cdot d_t \cdot wind_{c,t} \\ + \beta_3 \cdot solar_t + \beta_4 \cdot gasp_t + \beta_5 \cdot coalp_t + \beta_6 \cdot carbonps_t + \beta_7 \cdot netimp_t + \gamma D_t + \varepsilon_t \end{aligned} \tag{12}$$

where d_t is a dummy variable, equalling to one when the market is more crowded and zero otherwise, and D_t denotes the set of calendar dummies. In this specification, β_{2b} measures the impact of CfD wind generation on the wholesale price in a less crowded market, while $(\beta_{2b} + \gamma_2)$ measures the corresponding effect in a more crowded market. The coefficient of the interaction term, γ_2, therefore captures how the price effect of CfD wind generation changes with market crowdedness. A negative coefficient indicates that CfD wind generation has a larger downward effect on wholesale prices when the market is more crowded.

The empirical models are first estimated by OLS, and the residuals are then examined using standard diagnostic tests. The Breusch–Pagan test indicates heteroskedasticity, while the Durbin–Watson test and, where reported, the Breusch–Godfrey test indicate first-order serial correlation. Because such serial dependence is common in daily electricity price data, the disturbance term is modelled as an AR(1) process:

$$\varepsilon_t = \rho\varepsilon_{t-1} + \omega_t, |\ \rho\ | < 1 \tag{13}$$

where ω_t is a white-noise error term. The coefficients are therefore estimated using Prais–Winsten regression, which is a feasible GLS estimator for linear models with AR(1) disturbances. To assess specification adequacy, post-estimation diagnostic tests are conducted on the transformed residuals, including tests for remaining serial correlation and residual stationarity. These checks support the validity of the estimated regression relationships.

5. Estimation results and discussion

This section presents the empirical results and discusses their implications. Section 5.1 reports the Prais-Winsten estimates and examines whether the wholesale price effect of wind generation differs between CfD and non-CfD wind farms, as well as across market conditions. Section 5.2 then interprets these findings in four areas: generation costs of wind farms, output-securing incentives under alternative support schemes, investment and project selection, and regulatory risk under changing policy regimes.

5.1 Estimation results

Table 5 reports the empirical regression results. The models are first estimated by OLS and then re-estimated using Prais-Winsten regression to account for first-order serial correlation, with heteroskedasticity-robust standard errors reported throughout. The post-estimation diagnostics suggest that residual serial correlation is substantially mitigated in most specifications, as the Breusch-Godfrey tests in columns (1)–(5) fail to reject the null hypothesis of no first-order autocorrelation. In addition, the residual-based Augmented Dickey–Fuller and Phillips–Perron tests reject the null hypothesis of a unit root in all specifications, supporting the stationarity of the estimated relationships.

The results from the first specification, Eq. (4), based on total wind generation, are presented in Column 1 of Table 5. The coefficient of national demand is positive and significant, showing that a marginal increase of 1 GWh in daily average hourly national demand increases the daily average hourly electricity price by £1.595/MWh. Meanwhile, the coefficient of wind generation is negative and significant, showing that a marginal increase of 1 GWh in daily average hourly wind generation reduces the wholesale electricity price by £2.579/MWh. This negative effect of wind generation on wholesale price is consistent with the findings of Shao et al. (2022).

Column 2 shows the results for the second specification, Equation (5), in which total wind generation is separated into CfD and non-CfD wind generation. The results suggest that a marginal increase of 1 GWh in non-CfD wind generation reduces the price by £2.148/MWh, while the same increase in CfD wind generation is associated with a substantially larger reduction of £4.381/MWh. This large difference supports Proposition 1 in Section 3.4, namely that wind generation from CfD generators has a larger negative impact on the wholesale electricity price than wind generation from non-CfD generators, most of which are supported under the RO scheme. Possible explanations for this difference are discussed further in Section 5.2.

Table 5. Results from the Prais-Winsten estimation. Dependent variable: wholesale electricity price.

	(1)	(2)	(3)	(4)	(5)
Variables	Total wind	Separated wind	De-rated margin (D)	Wind penetration (D)	Residual demand (D)
National demand	1.595***	1.594***	1.715***	1.722***	1.889***
	(0.317)	(0.316)	(0.323)	(0.319)	(0.324)
Total wind generation	-2.579***				
	(0.118)				
Non-CfD wind generation		-2.148***	-2.345***	-2.531***	-2.643***
		(0.183)	(0.195)	(0.218)	(0.214)
CfD wind generation		-4.381***	-2.704***	-2.109**	-2.132**
		(0.597)	(0.852)	(0.905)	(0.855)
Dummy of market crowdedness			5.885***	7.948***	10.22***
			(1.108)	(1.216)	(1.152)
CfD wind * dummy			-2.373***	-3.039***	-3.263***
			(0.600)	(0.678)	(0.634)
Solar generation	-5.445***	-5.368***	-5.455***	-5.178***	-5.532***
	(0.723)	(0.723)	(0.724)	(0.719)	(0.726)
Gas price	0.641***	0.640***	0.639***	0.639***	0.637***
	(0.027)	(0.027)	(0.027)	(0.027)	(0.027)
Coal price	0.210***	0.202***	0.205***	0.206***	0.204***
	(0.028)	(0.029)	(0.029)	(0.029)	(0.029)
Effective carbon price	0.355***	0.405***	0.410***	0.410***	0.435***
	(0.040)	(0.045)	(0.047)	(0.045)	(0.047)
Net imports	0.064	0.087	0.132	0.152	0.126
	(0.188)	(0.187)	(0.186)	(0.186)	(0.184)
Constant	-33.13***	-35.86***	-41.84***	-41.91***	-48.25***
	(12.01)	(11.97)	(12.27)	(12.15)	(12.23)
Observations	3,215	3,215	3,215	3,215	3,215
R-squared	0.783	0.782	0.784	0.785	0.786
Breusch-Godfrey test	0.665	0.662	1.42	1.271	1.97
	(0.415)	(0.416)	(0.233)	(0.260)	(0.161)
Durbin-Watson Statistic	2.044	2.044	2.048	2.048	2.048
ADF test on Residual	-7.258	-7.24	-7.271	-7.283	-7.295
Perron test on Residual	-5.832	-5.811	-5.819	-5.834	-5.832
Robust	Yes	Yes	Yes	Yes	Yes

Standard errors are reported in parentheses. For the Breusch-Godfrey test, parentheses report p-values for the null hypothesis of no first-order serial correlation.

*** p<0.01, ** p<0.05, * p<0.1

Next, we consider the results for the third specification, Eq. (12), which distinguishes between less crowded and more crowded market conditions. Columns 3-5 introduce interaction terms to examine whether the price effect of CfD wind generation becomes stronger under more crowded market conditions. Column 3 reports the results when market crowdedness is defined using a dummy variable based on the de-rated margin. The coefficient on CfD wind generation indicates its impact on price in a less crowded market, suggesting that a marginal increase of 1 GWh reduces the wholesale price by £2.704/MWh. The interaction term for CfD wind generation is negative and statistically significant at the 1% level, with a coefficient of -£2.373/MWh, suggesting that the negative effect is significantly larger in a more crowded market. This implies that, in a more crowded market, the price-reducing effect of a 1 GWh increase in CfD wind generation is £5.077/MWh.

A similar pattern appears in Columns 4 and 5, where market crowdedness is measured by wind penetration and residual demand, respectively. The interaction coefficient is -3.039 in Column 4 and -3.263 in Column 5, both significant at the 1% level, indicating a stronger negative price effect in more crowded markets. For wind penetration, the corresponding price-reducing effect in more crowded markets is £5.148/MWh, while for residual demand it is £5.395/MWh. These results support Proposition 2: the price-reducing effect of CfD wind is stronger in more crowded market conditions, consistent with the view that the shift from the RO to the CfD scheme changed wholesale market competition and may have created adverse spillovers for RO-supported wind farms.

5.2 Discussion

5.2.1 The generation costs of wind farms

One possible explanation for the different price effects of CfD and non-CfD wind generation reported in Table 5, Column (2) is that the two groups differ in their underlying generation costs. In particular, CfD wind farms tend to be more recently commissioned than non-CfD wind farms, and may therefore benefit from technological progress and lower operating costs. Since the RO scheme was implemented between April 2002 and April 2017, while the CfD scheme began delivering generation from April 2017, it may be argued that non-CfD projects are, on average, older and potentially less efficient.

This interpretation is partly supported by evidence on the evolution of wind generation costs in the UK. Table 6 reports levelised cost estimates for onshore and offshore wind projects commissioning from 2012 and 2018 (DECC, 2012). The total levelised costs declined for both onshore wind and offshore wind. A similar downward trend is also observed in operation and maintenance (O&M) costs, which may be especially relevant to pricing strategy in the wholesale market. Therefore, for a given technology type, these patterns suggest that more recently commissioned projects may enjoy cost advantages over earlier projects.

However, the cost-based explanation is unlikely to be sufficient on its own. The composition of projects under the two support schemes differs significantly. Most RO wind farms are relatively lower-cost onshore projects (65.1%), whereas the majority of CfD wind farms are offshore projects (88.7%), which are generally more expensive. As shown in Table 6, even offshore wind projects commissioning in 2018 remained more costly than onshore wind projects commissioning in 2012. It is therefore not convincing to conclude that CfD wind farms necessarily had lower generation costs than RO-supported wind farms simply because they were commissioned later. The descriptive evidence suggests that cost differences may contribute to the observed price effects, but are unlikely to provide a complete explanation for why CfD wind generation is associated with a larger negative impact on wholesale electricity prices than RO wind generation.

Table 6. Levelised cost estimates (£/MWh) for wind projects commissioning from 2012 and 2018 (R2 and R3 represent designated areas for offshore wind projects). Source: Electricity generation costs 2012, DECC

	2012			2018		
	Onshore >5MW	Offshore R2 Zone	Offshore R3 Zone	Onshore >5MW	Offshore R2 Zone	Offshore R3 Zone
Pre-development costs	2	4	6	2	4	6
Capital costs	71	81	91	68	71	76
Fixed O&M	17	32	37	17	28	31
Variable O&M	3	1		3	1	
Total levelised costs	93	118	134	90	103	113

5.2.2 Output-securing incentives under the CfD scheme

The second explanation for the different impacts is that, because the CfD scheme stabilises revenues at the strike price and weakens exposure to realised wholesale prices, CfD wind farms may have stronger incentives than non-CfD generators to secure eligible output, particularly when market conditions are crowded. The results from the third specification provide further evidence consistent with stronger output-securing incentives among CfD wind farms. When more crowded and less crowded market conditions are examined separately, the price-reducing effect of CfD wind generation is found to be significantly stronger in more crowded markets. If pricing were determined solely by the operating costs of wind farms, the effect of otherwise similar CfD generation on market prices should not differ substantially across these scenarios. Instead, the stronger effect under crowded conditions suggests that differences in generation technology or cost alone cannot fully explain the pattern. It is more consistent with incentive-based behaviour becoming more important when competition among low-marginal-cost generators intensifies. This interpretation is also consistent with the broader literature on the market value of intermittent renewables, since more crowded conditions are precisely those in which additional wind output is likely to face lower market value and stronger competitive pressure.

Two counter-arguments could be made against the interpretation that CfD wind farms have stronger output-securing incentives. The first argument is that renewables have dispatch priority, making it unnecessary to reduce prices to secure eligible sales. However, although the UK has strong support mechanisms for wind power, there is no specific policy that gives wind power dispatch priority over other sources of electricity generation. The second argument is that the near-zero marginal costs of wind guarantee its position at the left end of the merit order. Nonetheless, the wholesale price data used in this study are derived from continuous intraday trading, where trades are executed when orders match. In this context, it is possible for CfD and non-CfD wind farms to compete for sales while no fossil fuel generators are participating in the market. These findings therefore require careful interpretation.

5.2.3 A planning-based explanation and potential endogeneity

A third explanation for the larger negative price effect of CfD wind generation is planning-based, rather than purely operational. While the behavioural interpretation emphasises how supported generators participate in the market after commissioning, the design of a support mechanism may also influence investment decisions before projects enter operation. Policy design thus influences not only market participation incentives but also the fundamental characteristics of newly built renewable assets. Consistent with the established literature, support scheme structures alter market risk exposure, revenue arrangements and investment behaviour, ultimately determining the composition of renewable capacity deployment (Klessmann et al., 2008; Couture and Gagnon, 2010).

This selection mechanism helps explain the diverging price impacts of RO and CfD wind. Under the RO scheme, project profitability depended more directly on expected wholesale electricity prices alongside certificate revenues, which may have encouraged developers to favour projects with higher expected market value and lower exposure to crowded market conditions. Conversely, price stabilisation under the CfD framework may incentivise output maximisation. This is consistent with the broader literature showing that the value of wind generation depends not only on output volume, but also on the timing of generation and the market conditions under which output is supplied (Hirth, 2013).

Accordingly, the estimated disparity in price effects between RO and CfD wind reflects a combination of post-commissioning behavioural differences and endogenous, planning-driven variation in project composition and site selection. The results should be interpreted as reduced-form evidence capturing the broad market outcomes of the CfD regime. Although the findings are consistent with the view that CfD support reshapes market participation incentives, they also capture systematic differences in project and location selection under alternative policy frameworks. Distinguishing more sharply between these mechanisms would require more disaggregated project-level data, including information on bids, site characteristics, commissioning dates, and contractual terms, and is therefore left for future research.

5.2.4 Regulatory risk faced by RO wind farms

The results also relate to the literature on regulatory risk, policy credibility, and investment under changing support regimes. A recurring theme in this literature is that the value of long-lived energy investments depends not only on the support mechanism in place at the time of investment, but also on the extent to which subsequent policy changes alter market conditions and expected returns (Mitchell et al., 2006; Gross et al., 2010). In this context, the transition from the RO to the CfD scheme may have generated an adverse spillover for legacy non-CfD wind farms. Under the RO, generators remained exposed to wholesale electricity prices, with certificate revenues providing additional support. Before the implementation of the CfD scheme, large-scale renewable projects were primarily supported by the RO scheme. In the competition between renewable and fossil fuel generators, the former benefited from lower marginal costs in electricity generation, while the latter incurred additional costs for carbon emissions. Under these conditions, RO generators may have had limited incentives to accept lower prices to secure additional output, since wholesale prices remained an important determinant of profitability. Therefore, during the twenty-year support period under the RO, the combination of the wholesale price and the certificate price was intended to support investment in renewable projects.

The introduction of the CfD scheme reduced generators' exposure to wholesale price fluctuations through price stabilisation at the strike price, potentially strengthening incentives to secure eligible output and thereby placing greater downward pressure on wholesale electricity prices. For non-CfD wind farms, this creates a potentially adverse combination of effects. Lower wholesale electricity prices directly reduce the revenues of non-CfD projects, while stronger competition from CfD generators may further weaken the market environment in which these older assets operate. In this sense, the transition from the RO scheme to the CfD scheme may have generated an adverse spillover for investments made under the earlier policy regime. The key point is not that the original support promised a fixed return, but that the subsequent policy transition altered the competitive conditions on which those earlier investment decisions had been based. This interpretation is consistent with the broader literature showing that changes in policy design can redistribute risks across investors and affect the credibility of the investment environment for long-lived energy assets (Mitchell et al., 2006; Gross et al., 2010).

This interpretation should not be taken to imply that the CfD scheme is ineffective or undesirable. On the contrary, the scheme has generally been regarded as successful in supporting renewable deployment and reducing financing costs for new projects (Newbery, 2016). However, the results suggest that changes in support design may also redistribute market risk across renewable assets commissioned under different policy regimes. The analysis therefore connects to a broader literature showing that policy transitions can generate unintended distributional consequences and may weaken investor confidence when earlier investments become exposed to less favourable market conditions under a new regulatory environment. The implication is not to avoid support reform, but to account for its effects on existing low-carbon assets developed under earlier rules. Sustaining investor confidence requires not only effective support for new capacity, but also careful management of transition risks across successive policy regimes.

6. Conclusion

This study examines whether wind farms supported under different policy regimes have different effects on wholesale electricity prices in Great Britain. Using daily average hourly values from April 2017 to December 2025, the results show that CfD wind generation is associated with a significantly larger negative effect on wholesale electricity prices than non-CfD wind generation, most of which is supported under the RO scheme. In the specification that separates the two support types, a 1 GWh increase in CfD wind generation is associated with a £4.381/MWh reduction in wholesale electricity prices, compared with £2.148/MWh for non-CfD wind generation. However, a simple cost-based explanation is not fully convincing, since the majority of RO wind farms were onshore and relatively lower-cost (65.1%), while most CfD wind farms were offshore and generally more costly (88.7%), suggesting that CfD wind farms may not necessarily have had cost advantages.

A second possible explanation is output-securing incentives, because CfD wind farms may have stronger incentives to prioritise output and secure sales. This is consistent with the stronger negative price effect observed under more crowded market conditions. To further understand the role of these output-securing incentives, the analysis considers scenarios based on market crowdedness. Market crowdedness is measured using three approaches: de-rated margin, residual demand, and wind penetration. The results show that the negative effects of CfD wind farms on wholesale prices are significantly larger in more crowded markets than in less crowded markets.

The findings are consistent with an explanation based on market incentives under different support arrangements. In particular, the negative price effect of CfD wind generation becomes significantly stronger when the market is more crowded, as measured by the de-rated margin, residual demand, and wind penetration. This difference suggests that CfD wind farms may have stronger output-securing incentives in more crowded markets. This argument is more plausible given that electricity from wind has no dispatch priority in the UK, and that the wholesale price reflects intraday trading, where orders are matched and executed continuously. More broadly, the analysis suggests that the price effect of wind generation depends not only on the quantity supplied, but also on the policy regime under which generators operate.

The results suggest a potential regulatory spillover. To the extent that CfD generation places additional downward pressure on wholesale prices, non-CfD wind farms may face lower revenues and weaker competitiveness under market conditions that differ from those anticipated when they were financed. The analysis therefore highlights how transitions between support schemes can redistribute market risk across different vintages of renewable assets. As more CfD wind farms become operational in the coming years, these spillover effects may become more important. Policymakers should therefore consider the interests of generators supported under earlier schemes during policy changes to support long-term investor confidence.

A limitation of the study is that the estimated differences between CfD and non-CfD wind generation are reduced form and may capture not only operational incentives, but also endogenous differences in project siting, technology composition, and commissioning patterns shaped by support design. Future research using plant-level bidding, locational, and contractual data could identify more clearly the relative importance of behavioural and planning-based channels.

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Appendix

A1. Abbreviations and symbol definitions

Abbreviations / Symbols	Definition
RO	Renewables Obligation
ROC	Renewables Obligation Certificate
CfD	Contracts for Difference
FIT	Feed-in Tariff
FIP	Feed-in Premium
NFFO	Non-Fossil-Fuel Obligation
DESNZ	Department for Energy Security and Net Zero
BEIS	Department for Business, Energy & Industrial Strategy
DECC	Department of Energy & Climate Change
LCCC	Low Carbon Contracts Company
EU ETS	European Union Emissions Trading System
CPS	Carbon Price Support
MIP	Market Index Price
API2	API2 coal price index
ADF	Augmented Dickey–Fuller test
PP	Phillips–Perron test
OLS	Ordinary Least Squares
GLS	Generalised Least Squares
AR(1)	First-order Autoregressive process
Prais-Winsten	Prais–Winsten regression

Durbin-Watson	Durbin–Watson First-order serial correlation test
Breusch-Godfrey	Breusch–Godfrey higher-order serial correlation test
π_i^{RO}	Profit of an RO generator *i*
π_i^{CfD}	Profit of a CfD generator *i*
c_i^{RO}	Operating cost of RO generator *i*
c_i^{CfD}	Operating cost of CfD generator *i*
p_i^{w}	Wholesale electricity price
p_i^{roc}	Price of RO certificate
q_i^{RO}	Electricity supply quantity of RO generator *i*
q_i^{CfD}	Electricity supply quantity of CfD generator *i*
r_i	Number of renewable certificates sold by generator *i*
p_i^{s}	CfD strike price
wp_t	Daily average hourly wholesale price at time *t*
nd_t	Daily average hourly national electricity demand at *t*
$wind_t$	Total daily average hourly wind generation at *t*
$wind_{nc,t}$	Non-CfD (mainly RO) wind generation at *t*
$wind_{c,t}$	CfD wind generation at *t*
$solar_t$	Daily average hourly solar generation at *t*
$gasp_t$	Natural gas price at *t*
$coalp_t$	Coal price (API2) at *t*
$carbonps_t$	Effective carbon price (EU ETS + UK CPS) at *t*
$netimp$	Net electricity imports
D_t	Time dummy vector
ε_t	Regression error term
ω_t	White-noise error term in AR(1)
ρ	AR(1) autocorrelation coefficient
$\beta_0, \beta_1 \dots \beta_7$	Regression coefficients
γ_1, γ_2	Coefficients for crowdedness dummy & interaction
drm_t	De-rated margin at time *t*
T_t	Conventional generation capacity at *t*
$wind_t^{f}$	Forecasted wind generation at *t*
nd_t^{f}	Forecasted national demand at *t*
rd_t	Residual demand at time *t*
$wpen_t$	Wind penetration rate at *t*
$\overline{drm}$, $\overline{rd}$, $\overline{wpen}$	Quarterly average of crowdedness indicators
d^{drm}, d^{rd}, d^{wpen}	Market crowdedness dummy variable; 1 = more crowded; 0 = less crowded

A2. Generators under a Feed-in Tariff scheme or a Feed-in Premium scheme

Section 3.3 suggests that generators under the CfD scheme participate in the market and may have incentives to maximise their sales, as the CfD scheme substantially weakens the direct effect of wholesale prices on their revenues. These output-securing incentives may not be observed in other price-based support schemes such as Feed-in Tariff schemes and Feed-in Premium schemes.

Under a Feed-in Tariff (FIT) scheme, electricity generators receive a fixed tariff for each unit of electricity they produce, and distribution network operators are obliged to accept this output onto their network. The profit function of generator i under the FIT scheme can be written as

$$\pi_i^{FIT} = \left(p_i^T - c_i^{FIT}\right)q_i^{FIT} \tag{A.1}$$

where p_i^T is the tariff, c_i^{FIT} is the generation cost, and q_i^{FIT} is the quantity of electricity supplied. FIT generators do not participate in the market, so they do not have an opportunity to adopt output-securing incentives.

In contrast, under the Feed-in Premium (FIP) scheme, generators sell electricity in the wholesale market and receive a premium on top of the market price. The profit function of generator i under the FIP scheme can be written as

$$\pi_i^{FIP} = \left(p_i^w - c_i^{FIP} + p_t^p\right)q_i^{FIP} \tag{A.2}$$

where p_i^w is the market price, c_i^{FIP} is the generation costs, p_t^p is the premium, and q_i^{FIP} is the quantity of electricity supplied. FIP generators may have output-securing incentives when selling electricity, but these incentives are weaker because the market price remains relevant to their profits.