

Khodadadi, Abolfazl; Poudineh, Rahmatallah

**Working Paper**

## Contracts for difference - CfDs - in the energy transition: Balancing market efficiency and risk mitigation

OIES Paper: EL, No. 56

**Provided in Cooperation with:**

The Oxford Institute for Energy Studies, Oxford

*Suggested Citation:* Khodadadi, Abolfazl; Poudineh, Rahmatallah (2024) : Contracts for difference - CfDs - in the energy transition: Balancing market efficiency and risk mitigation, OIES Paper: EL, No. 56, ISBN 978-1-78467-250-8, The Oxford Institute for Energy Studies, Oxford

This Version is available at:

<https://hdl.handle.net/10419/301913>

**Standard-Nutzungsbedingungen:**

Die Dokumente auf EconStor dürfen zu eigenen wissenschaftlichen Zwecken und zum Privatgebrauch gespeichert und kopiert werden.

Sie dürfen die Dokumente nicht für öffentliche oder kommerzielle Zwecke vervielfältigen, öffentlich ausstellen, öffentlich zugänglich machen, vertreiben oder anderweitig nutzen.

Sofern die Verfasser die Dokumente unter Open-Content-Lizenzen (insbesondere CC-Lizenzen) zur Verfügung gestellt haben sollten, gelten abweichend von diesen Nutzungsbedingungen die in der dort genannten Lizenz gewährten Nutzungsrechte.

**Terms of use:**

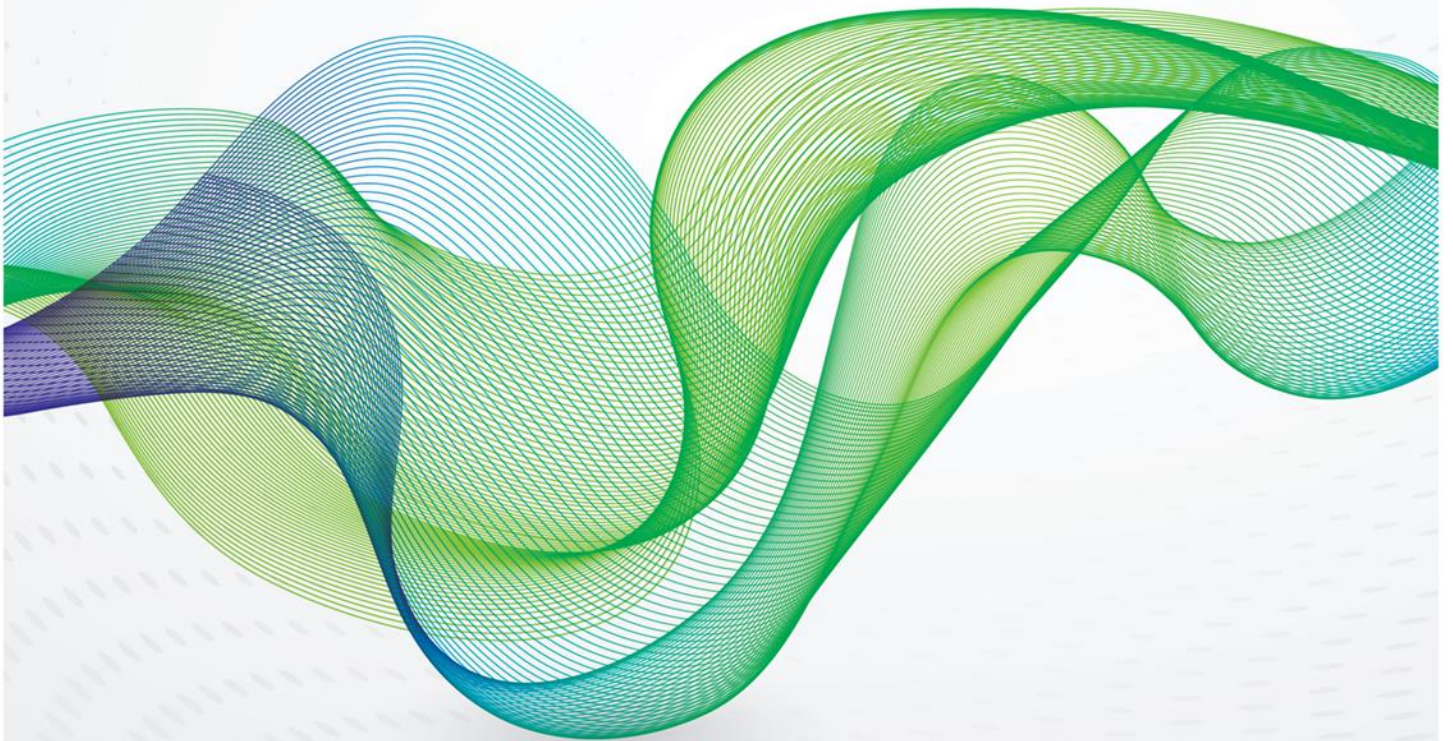
*Documents in EconStor may be saved and copied for your personal and scholarly purposes.*

*You are not to copy documents for public or commercial purposes, to exhibit the documents publicly, to make them publicly available on the internet, or to distribute or otherwise use the documents in public.*

*If the documents have been made available under an Open Content Licence (especially Creative Commons Licences), you may exercise further usage rights as specified in the indicated licence.*

July 2024

# **Contracts for difference – CfDs – in the energy transition: balancing market efficiency and risk mitigation**





The contents of this paper are the authors' sole responsibility. They do not necessarily represent the views of the Oxford Institute for Energy Studies or any of its members.

*Copyright © 2024*  
***Oxford Institute for Energy Studies***  
(Registered Charity, No. 286084)

This publication may be reproduced in part for educational or non-profit purposes without special permission from the copyright holder, provided acknowledgement of the source is made. No use of this publication may be made for resale or for any other commercial purpose whatsoever without prior permission in writing from the Oxford Institute for Energy Studies.

ISBN 978-1-78467-250-8



## Abstract

Contracts for Difference (CfDs) have emerged as a key policy instrument to incentivize renewable energy investments by mitigating revenue volatility. However, conventional CfDs, while effective in fostering growth in renewable energy sources, can introduce market distortions. These distortions arise from misaligned incentives, particularly the 'produce-and-forget' mentality, where generators prioritize maximizing production without considering market signals. To address these challenges, in recent years, alternative CfD designs have been proposed in the literature with the aim of enhancing market integration by decoupling payouts from real-time generation, and aligning generator incentives with market outcomes. However, the challenge is that these modified CfDs introduce basis risk, where discrepancies between *reference* prices and output, and *actual* prices and output, can lead to financial volatility. This is however unavoidable because the purpose of CfDs is to mitigate risks for renewable energy generators, while market efficiency relies on participants bearing some level of risk through price exposure, so as to incentivize optimal decision-making. This challenge underscores the complex trade-off policymakers face between market efficiency and risk mitigation, necessitating a balanced approach to the design of CfDs. Additionally, the impact of increased basis risk on various stakeholders, including generators, the government, consumers and financial institutions, highlights the need for a nuanced understanding of financial volatility and regulatory implications of alternative CfD designs.





## Contents

<b>Abstract</b> .....	<b>ii</b>
<b>Contents</b> .....	<b>iii</b>
<b>Figures and boxes</b> .....	<b>iii</b>
<b>Tables</b> .....	<b>iii</b>
<b>1. Introduction</b> .....	<b>1</b>
<b>2. Conventional CfD contracts: Key design parameters</b> .....	<b>3</b>
2.1 Reference market considerations ( $\lambda h$ ) .....	4
2.2 Reference price considerations ( $Rh$ ) .....	4
2.3 Reference volume consideration ( $q_i, h$ ) .....	7
2.4 Strike price design considerations .....	7
<b>3. Addressing distortions in conventional CfDs</b> .....	<b>8</b>
3.1 Benchmark case .....	8
3.2 Main proposed methods .....	13
<b>4. Discussions</b> .....	<b>22</b>
<b>5. Conclusions</b> .....	<b>24</b>
<b>References</b> .....	<b>25</b>

## Figures and boxes

Figure 1: Two-sided vs. one-sided CfDs with a strike price set at 50 €/MWh .....	2
Figure 2: Basis risk in hourly vs. monthly average reference pricing CfD design .....	5
Box 1: The calculation of market reference price in the UK .....	6
Figure 3: Standard strike price versus cap and floor strike price .....	8
Figure 4: Flow of the money in the CfD contract in the case of positive reference price .....	9
Figure 5: Flow of the money in the CfD contract in the case of negative reference price .....	11
Figure 6: Intermittent reference prices for two years .....	12
Figure 7: Histogram of the negative intermittent reference prices .....	12
Figure 8: A hypothetical market price curve .....	14
Figure 9: Comparison of subsidy metrics by location .....	16
Figure 10: Forecast capacity factor for the three assumed locations .....	17
Figure 11: The effect of Yardstick output on generator's revenue .....	18
Figure 12: Comparison of actual power output with different reference outputs .....	21

## Tables

Table 1: Details of the payment and energy prices in the case of positive reference price .....	9
Table 2: Details of the payment and energy prices in the case of negative reference price (€/MWh) ..	11
Table 3: Specifications of the three different locations in the yardstick locational CfD .....	17
Table 4: Money flow for the b-FCfD contract in three different locations .....	19



## 1. Introduction

Contracts for Difference (CfDs) are a critical mechanism used in the United Kingdom (UK) and the European Union (EU) to encourage investment in low-carbon energy generation. CfDs offer a way to stabilize revenues for producers of renewable energy by hedging against volatile wholesale prices. This mechanism can make renewable energy projects more financially viable and attractive to investors.

The European Commission recognises CfDs as a useful tool to support the deployment of renewable energy sources, including wind, solar, and increasingly, hydrogen and other low-carbon technologies. The UK, on the other hand, has been a pioneer in the use of CfD schemes, especially after the Electricity Market Reform (EMR) of 2013. Since its implementation, CfDs have significantly contributed to the growth of the renewable energy sector in the UK (Welisch, and Poudineh, 2019). By 2023, CfD auctions had successfully contracted over 20 GW of renewable capacity, covering technologies such as offshore wind, onshore wind, solar photo-voltaic (PV), and biomass. The scheme has driven down the costs of renewable energy, particularly offshore wind, which saw strike prices fall from £119.89/MWh in the first allocation round in 2015 to as low as £39.65/MWh in the 2019 round.

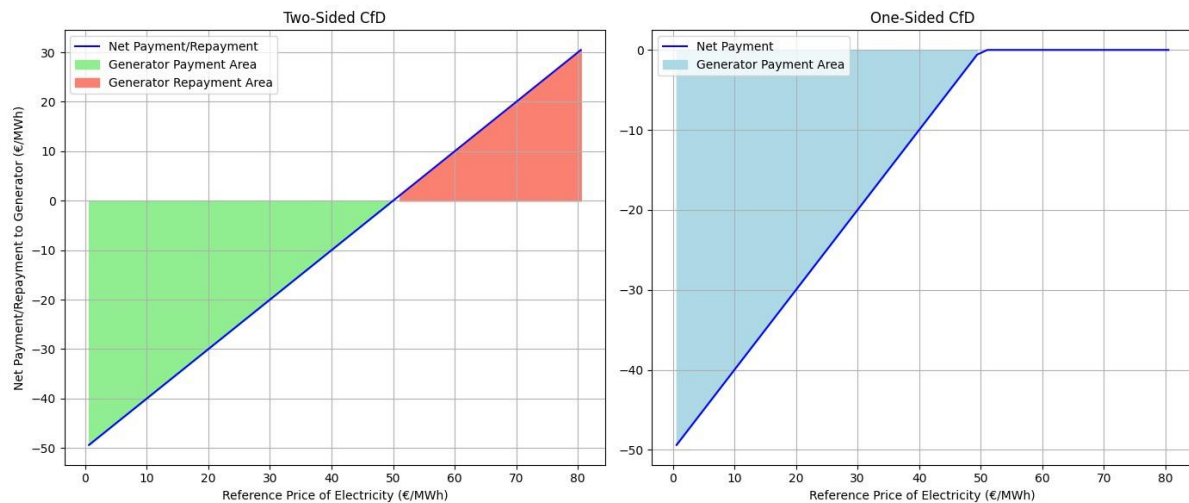
When formulating CfDs, policymakers and regulators generally aim to achieve two primary objectives: (1) to provide economic incentives for investments in renewable energy sources in alignment with predetermined political deployment targets; and (2) to facilitate the seamless integration of renewable energy into power markets, minimizing any potential distortions in market dynamics (European Commission, 2023). The most commonly used remuneration schemes in Europe include the one-sided CfD contract in Germany and the Netherlands, and the two-sided CfDs used in the UK and Denmark. These schemes guarantee producers a minimum support price equivalent to the strike price in the support auction. However, the rules regarding excess revenues when the electricity price exceeds the support price differ between the one-sided and two-sided CfDs. Under the UK two-sided CfD, owners of renewable energy assets are guaranteed a fixed price (£/MWh) for the electricity they generate over a fixed contract period, for example a 15-year contract (Kell et al., 2023). Once a renewable producer and the government have entered into a CfD contract, the producer can continue selling their power on the day-ahead market or any other market of their choice. The CfD payments are determined through a separate financial settlement, which takes into account the relative levels of the floating (reference) market price and the fixed strike price. If the strike price exceeds the reference market price, the government or CfD party pays the difference to the renewable producer as a payout. Conversely, if the strike price falls below the reference market price, the renewable producer must pay the difference between the two prices to the government as a clawback.

With one-sided CfDs (sometimes called feed in premium), however, producers can keep the excess revenues. This difference in remuneration rules leads to variations in revenue volatility during the support contract period. In other words, investors can speculate on higher electricity prices when using one-sided CfDs, while two-sided CfDs eliminate this incentive.

Figure 1 illustrates the difference between two models. The two-sided CfD model, assuming a strike price of 50 €/MWh, demonstrates dual financial outcomes: it mandates repayments from generators when reference prices exceed the strike price, and facilitates payments to generators when prices are below this threshold. Conversely, the one-sided CfD model solely necessitates payments to generators for reference prices falling below the strike price, with no repayment obligation, illustrating a less complex financial interaction and potentially higher risk exposure for the subsidizing entity.



**Figure 1: Two-sided vs. one-sided CfDs with a strike price set at 50 €/MWh**



In theory, one-sided CfDs can ensure revenue stability if they guarantee a sufficiently high floor support price. However, apart from the fact that it does not protect consumers, the auction process for one-sided CfDs may encourage certain strategic behaviours. This problem has resulted in zero bids for offshore wind projects in some cases (Đukan & Kitzing, 2021), mainly because project sponsors anticipate a rise in wholesale electricity prices in the future, coupled with expected cost reductions through the utilization of larger turbine sizes. These factors lead to lower production costs and create an expectation of increased profitability. Furthermore, the presence of zero bids incorporates a real-option element due to the significant time gaps between the auction award and the actual implementation of the project (Müsgens and Riepin, 2018). This extended timeline provides project sponsors with the opportunity to reassess market conditions and financing arrangements, allowing them to potentially cancel the awarded contract if deemed necessary. In Germany, for instance, the non-realization penalties for the initial successful zero-bid projects amounted to approximately 2.5 per cent to 3.8 per cent of the total project development costs. Consequently, bidders faced the prospect of significant earnings while bearing a comparatively smaller downside risk in the form of penalty payments (Müsgens and Riepin, 2018). Nonetheless, the issue of low non-realisation penalty payments and long lead times are not unique to one-sided CfDs; they also apply to two-sided CfDs, too.

Countries within the EU and other regions have shown growing interest in the two-sided CfDs model used in the UK due to its success in reducing investment risks while protecting consumers from market price rises. For instance, Germany has explored implementing a similar CfD mechanism to support its renewable energy expansion under the Renewable Energy Sources Act (EEG) reform (Clean Energy Wire Article, 2021). Likewise, the European Commission has acknowledged the potential benefits of two-sided CfDs in its guidelines for state aid for climate, environmental protection, and energy, suggesting their use could enhance the cost-effectiveness of renewable energy subsidies (European Commission, 2022).

The conventional CfDs (by this we refer to the two-sided model), despite their advantages in stabilizing revenues and increasing the bankability of renewable energy projects, present certain problems that need to be addressed. Traditional CfDs share aspects with financial derivatives, but their binding to specific assets is distinct. This linkage restricts secondary market trading without associated asset sales, and may lead to asset dispatch manipulation to influence payments. Notably, conventional CfDs present two main challenges: incentivising a 'produce-and-forget' mentality; and causing intraday and balancing market disruptions.

Traditional CfDs (namely, the two-sided model) encourage power generators to prioritize the maximizing of power production. These contracts are similar to the conventional feed-in tariffs that separate the generator's revenues from any market incentives. With revenues per MWh always matching the strike price, there are some distortions as follows:



- First, CfDs do not encourage the selection of system-friendly renewables, such as high-efficiency wind turbines or adaptable solar panels. Therefore, the incentive for optimal, sustainable resource utilization and plant design is lacking.
- Second, investment decisions in energy assets, encompassing maintenance, retrofit, and repowering, are influenced by conventional CfDs, which tend to suppress spot price fluctuations and thus, distort market signals. This can lead to suboptimal investment during energy crises and overinvestment during surpluses, as stakeholders might prioritize adhering to existing contracts over optimizing for current market conditions. Even in the context of wind turbine repowering, the finite nature of conventional CfDs might discourage upgrading to more efficient units to maintain the benefits of existing contracts.
- Third, the absence of incentives for generators to strategically time maintenance activities during low-demand periods may lead to suboptimal scheduling decisions, potentially exacerbating supply-demand imbalances.
- Finally, traditional CfDs do not drive generators to amplify production during high-price durations (if it is a dispatchable resource) or to curtail during low-price intervals. For instance, wind, solar, and nuclear plants should reduce outputs when prices fall beneath their operational costs. But with conventional CfDs, they might continue production, even when prices go negative. This is especially problematic for technologies with fluctuating variable costs. Thermal power plants, reservoir hydropower, and storage plants are especially vulnerable. These adaptable generators need price-driven operation for viability. Encouraging consistent electricity production can nullify their worth as adaptable resources. This problem magnifies when CfDs dominate more of the market.

There are also arguments that CfD may impact the forward market with implications for consumer welfare. A study by Simshauser (2019) finds that with the entry of variable renewable generation and the exit of coal plants, on-market firm hedge contracts traditionally provided by coal plants are increasingly replaced by off-market CfDs. This creates a shortage of primary issuance hedge contracts in the forward market, likely leading to higher forward contract price premiums and exposing price-sensitive customers to undesirable spot market risks.

This paper reviews conventional CfD contracts, highlights their shortcomings, and analyzes suggested models in the literature for improving these contracts. We show the strengths and weaknesses of the main proposed approaches and then discuss why there is no perfect CfD contract (in that, policymakers always face a trade-off between market efficiency and risk mitigation) and highlight the implications of this trade-off for players – including generators, government, consumers and financial institutions who finance CfD-based assets.

The next section discusses conventional CfDs and their key design parameters. Section 3 reviews the key methods proposed to address distortions in conventional CfDs. Section 4 presents discussions and policy implications. Concluding remarks are provided in Section 5.

## 2. Conventional CfD contracts: Key design parameters

In order to better understand the reasoning behind different distortions introduced by conventional CfDs, it is helpful to look deeper into the basic calculations of payment under these contracts.

Let's assume  $q_{i,h}$  is the physical selling quantity of a unit  $i$  at hour  $h$ ,  $\lambda_h$  is the spot price of the market at hour  $h$ ,  $c_{i,h}$  is the marginal cost of the production of unit  $i$  at hour  $h$ ,  $R_h$  is the reference price for CfD contract at hour  $h$ , and  $SP$  is the strike price of the CfD contract. Given the above notation, the net revenue of the unit  $i$  at hour  $h$  is as follows:

$$\begin{aligned} Rev_{i,h}^{Tot} &= Rev_{i,h}^{energy} + Rev_{i,h}^{CfD} \\ &= q_{i,h}[\lambda_h - c_{i,h}] + q_{i,h}[SP - R_h] \end{aligned} \quad (1)$$





Where,  $Rev_{i,h}^{energy}$  is the revenue from selling energy in the market with the day-ahead energy market price and  $Rev_{i,h}^{CfD}$  is the compensation through the CfD mechanism which could be positive, where the strike price is above the reference price or negative, vice versa. In the  $Rev_{i,h}^{energy}$  calculation the marginal cost of energy production is deducted from the payment. This value is negligible in most cases of the renewable assets.

Equation (1) captures the essence of the generator's revenue under a CfD support scheme. There are four key parameters in this formula (namely,  $\lambda_h$ ,  $R_h$ ,  $q_{i,h}$  and  $SP$ ) that determine how the risk is allocated between generators and government. They also influence generators' behaviour in the market with consequences for market price formation and efficient dispatch. In what follows we analyze these key parameters.

## 2.1 Reference market considerations ( $\lambda_h$ )

The selection of a reference market, in which market price ( $\lambda_h$ ) is determined, is a critical decision that significantly impacts generator behaviour, risk exposure, and market integration. The reference market determines the reference prices against which the CfD payments are calculated. The choice can vary from solely using day-ahead prices to incorporating prices from intraday, balancing markets, or a mixed index of several market segments.

Day-ahead wholesale markets are a frequent choice in the EU and the UK due to their liquidity and established role in price formation. Day-ahead prices tend to be less volatile than intraday or balancing market prices, providing a measure of predictable revenue for renewable generators that promotes investment. While generators still face the risk of imbalances between forecasted and actual generation, the day-ahead market helps keep this risk within reasonable bounds.

When CfDs use day-ahead market prices as a reference, this design choice can significantly impact the behaviour and strategies of renewable energy generators in relation to intraday and balancing markets. The potential distortions introduced by such a configuration arise mainly from the misalignment between the fixed nature of day-ahead CfD settlements and the dynamic conditions of subsequent market segments.

If the day-ahead reference price is high, leading to a clawback situation where renewable energy producers need to pay back part of their earnings, and if intraday prices are lower but still positive, producers might be incentivized to buy back their commitments on the intraday market rather than generate power. This behaviour is encouraged to avoid the higher clawback costs and could lead to under-utilization of renewable resources when they are actually needed, contradicting the goals of market efficiency and carbon reduction.

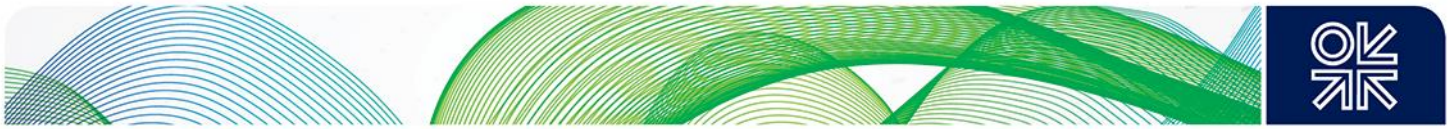
When day-ahead prices are very low or negative, leading to CfD payouts to compensate producers, if intraday prices remain higher (but still negative), there might be an incentive to continue producing to secure CfD payouts as long as the positive payout is higher than the intraday price (Kitzing et al., 2024). This can result in over-generation during times when demand is low, contributing to grid instability and inefficiencies.

Another point is that CfD payouts or clawbacks known in advance can alter how producers bid on intraday and balancing markets. For example, knowing that they will receive a payout might lead producers to offer power at lower prices on intraday markets than they would otherwise, potentially driving prices down artificially. Conversely, the need to cover a clawback might push them to demand higher prices, which can distort the true supply-demand equilibrium.

Finally, the ability to predict CfD settlements based on day-ahead prices can lead to strategic bidding where producers might manipulate their production or market engagement to maximize financial returns rather than aligning with market needs or efficiency cues.

## 2.2 Reference price considerations ( $R_h$ )

The choice of reference period aggregation level in CfD schemes plays a critical role in balancing market integration with financial risk management for renewable energy generators. Shorter periods promote



responsiveness but at the cost of greater administrative complexity and lower risk exposure. In contrast, longer periods simplify revenue calculations and stabilize income but at the expense of reduced market responsiveness and increased exposure to prolonged market volatility.

Deciding on the appropriate level of aggregation involves considering the specific characteristics of the energy source, the typical market conditions, and the financial resilience of the generators. It's a strategic decision that impacts not only the financial health of renewable energy projects, but also the overall efficiency and stability of the energy market.

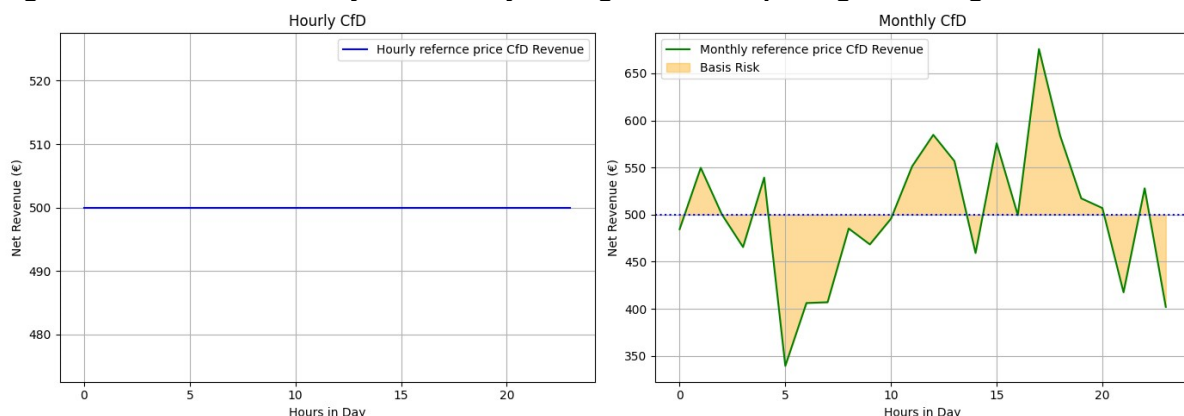
The fundamental tension lies between how finely you slice time when setting the reference price. A fine-grained (for example, hourly) reference price would be one where generators receive the precise difference between the strike price and the hourly spot market price, largely shielding them from market volatility but with consequences for market integration. The 'produce-and-forget' model disincentivizes generators from adjusting production based on short-term price signals, hindering responsiveness to grid needs. Also, in this model the emphasis is on predictable revenue to encourage investment, not on optimizing how the generator interacts with the market.

On the other hand, an aggregated reference price (for example, monthly or quarterly) increases the risk exposure of a renewable energy generator – but improves market integration and incentivizes flexible operation. By averaging the reference price across longer periods, short-term price fluctuations within that period impact the generator's revenue. This increases risk exposure. Generators thus have incentives to adjust their production and maintenance schedules for value maximization, aligning them more closely with market dynamics.

The side-by-side graphs in Figure 2 shows the core difference in risk exposure between hourly and monthly average reference pricing in a typical CfD. For simplicity we assume a constant production of 10 MWh at each hour, a normal and positive distribution of hourly market prices and a strike price of €50/MWh. The hourly reference CfD plot shows a relatively flat line at the level determined by the strike price. This stability reflects the generator's insulation from market price volatility, as the hourly reference price mirrors the spot price closely. Conversely, the monthly average reference price CfD plot reveals a fluctuating revenue line. These oscillations illustrate the basis risk: the generator's net revenue deviates from the constant strike price-based income due to discrepancies between the hourly spot prices and the monthly average. The shaded area between the lines quantifies the potential for revenue to be either higher or lower than the strike price-based expectation over the month.

The hourly model offers maximum risk reduction and predictable revenue for renewable generators. This stability is crucial for attracting investment in new renewable capacity - but distorts generators' incentives to respond to market signals. The monthly model introduces basis risk, making generators responsive to market signals. Their revenue is directly affected by price fluctuations, encouraging them to adjust production or maintenance schedules to maximize value. This alignment with market dynamics promotes flexibility and supports grid stability as renewable penetration increases.

**Figure 2: Basis risk in hourly vs. monthly average reference pricing CfD design**





The choice of aggregation level carries significant weight as renewable energy sources become more dominant. Traditionally, hourly models might have sufficed to stabilize revenue and attract investment. However, as grids prioritize flexibility to deal with the variability of renewables, mechanisms that encourage flexible and responsive generation become essential. Averaging promotes generators who can ramp up/down production or manage maintenance schedules strategically in response to market signals. This is critical for balancing grids with high renewable penetration.

#### Box 1: The calculation of market reference price in the UK

The UK uses an hourly approach to set the reference price for intermittent renewable energy resources. Here, we investigate two cases in the intermittent renewable generation domain: Positive and Negative Intermittent Market Reference Prices (IMRP).

##### Positive IMRP

The calculation of CfD generator payments hinges on the difference between the market reference price (MRP) and the CfD's strike price. There are two types of MRPs: the Baseload Market Reference Price (BMRP) and the Intermittent Market Reference Price (IMRP). The applicable MRP and the prices for electricity sales are determined by the CfD contract.

The BMRP is seasonally calculated using a traded volume weighted average of forward season data, provided daily by the London Energy Brokers' Association (LEBA). The resultant BMRP is published biannually on the EMRS website.<sup>1</sup> In contrast, the IMRP for intermittent technologies is derived from the GB day-ahead hourly price calculated by the weighted average of the two market price indexes, EPEX Spot and N2EX as follows:

$$IMRP_h = \frac{\sum_{i=1}^{N_s} \lambda_{i,h} V_{i,h}}{\sum_{i=1}^{N_s} V_{i,h}}$$

Where the  $\lambda_{i,h}$  is the day-ahead hourly price for trading hour  $h$  and price source of  $i$ ,  $V_{i,h}$  is the day-ahead hourly volume traded on hour  $h$  and price source of  $i$  and  $N_s$  is the number of price sources: EPEX Spot and N2EX. If there is only one published price for the day-ahead market through each of the resources, the published price would be the final reference price.

##### Negative IMRP

Negative Pricing terms apply to both baseload and intermittent generators under the CfD contract, but not every CfD includes these provisions. The contract determines one of two versions of negative pricing. In the first version, negative IMRP occurs when the IMRP falls below £0/MWh for six consecutive hours or more. In the second version, negative IMRP is defined as the IMRP being below £0/MWh for one hour or more. For these hours, the pricing difference is limited to the strike price.

When the IMRP is negative based on the second version, the CfD payment for each contract is calculated as follows:

$$Rev_{i,h}^{CfD} = \min(SP - IMRP_h, SP) \times q_{i,h}$$

The  $\min$  operator in the above equation limits the CfD revenue to the strike price when the negative IMRP scheme is activated.

The negative price rule introduces a challenge due to increased balancing costs when all CfD units react identically and simultaneously<sup>2</sup>. If all CfD units exit the system at once in response to negative pricing rules, it not only causes operational problems, but also substantially increases the costs associated with maintaining system balance.

<sup>1</sup> <https://www.emrsettlement.co.uk/settlement-data/settlement-data-roles/>

<sup>2</sup> <https://www.current-news.co.uk/eso-addresses-market-distortions-created-by-cfd-scheme/#:~:text=%E2%80%9CThe%20current%20CfD%20design%20disincentivised,scheme%E2%80%9D%20noted%20Keay%2DBright.>





## 2.3 Reference volume consideration ( $q_{i,h}$ )

The choice of reference volume design in CfD schemes is critical in determining how well renewable energy integrates into the energy market and how generators manage risk.

The common approach is energy-based volume. In this approach payments are based on actual electricity generated, therefore, there is a direct incentive for generators to maximize output whenever market prices are favourable, aligning closely with market demand. However, this can lead to negative market distortions, such as overproduction during times of low demand if the market price is still above the cost of production. Furthermore, generators can be exposed to volume risk from operational inefficiencies (such as missing forecast output), or unplanned outages.

There are alternative approaches under consideration that are proposed to hedge price risks while avoiding dispatch distortions typically associated with generation-based CfDs. These approaches require linking payments to capacity or an estimated potential output that reflects realistic operational scenarios instead of actual generation to encourage more market-aligned generation practices. In Section 3, where we discuss proposed solutions in the literature, we analyze the two primary models in this category: Newbery's yardstick locational CfD (Newbery, 2023) and Schlecht et al.'s benchmark-based financial CfD (Schlecht et al., 2024).

## 2.4 Strike price design considerations

The strike price within a CfD contract plays a pivotal role in shaping the incentives faced by renewable energy generators and defining their risk profile. It dictates when generators receive support payments and when they are required to repay revenues to the counterparty, often a government entity.

A fixed strike price provides high certainty and low risk concerning market price fluctuations. Producers know exactly the amount they need to pay or receive, which can significantly reduce the financial uncertainty associated with variable market prices. Nonetheless, as explained earlier, the certainty of revenue irrespective of market conditions can dampen the incentive for renewable energy producers to respond to market signals, potentially leading to less efficient market integration.

The decision to use fixed strike prices versus a flexible approach hinge on the policymaker's prioritisation of risk reduction versus market integration. Fixed strike prices offer the highest level of investor certainty, attracting capital needed for the renewable energy transition. Conversely, cap-and-floor systems introduce some market exposure for generators, encouraging them to engage with the market and support grids in balancing supply and demand.

Figure 3 below explores two different configurations of a CfD contract mechanism: the standard strike price and a cap-and-floor system. We assume the standard strike price is fixed at €50/MWh, but for the flexible strike price the floor price is set at €20/MWh, and the cap price at €80/MWh. In the standard approach when the reference price is below the strike price of €50/MWh, the area is shaded green, indicating that the generator receives a payment. Conversely, when the reference price exceeds the strike price, the area turns salmon pink, showing that the generator must make a repayment. The transition at the strike price is a critical threshold where the financial obligation flips from a credit to a debit.

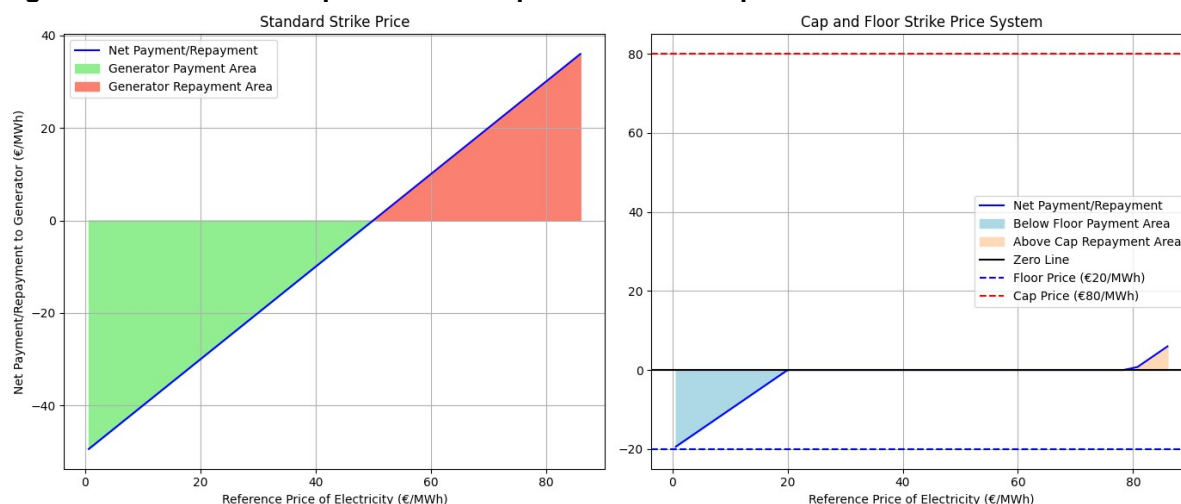
In the cap and floor model, below the floor price (€20/MWh) and above the cap price (€80/MWh), payments and repayments are capped respectively. The areas are shaded light blue and peach-puff to indicate payments and repayments, respectively. Between the floor and cap, no payments or repayments occur, representing a stability zone for both the generator and the market.

The distribution of prices around the reference price is not necessarily symmetric. The government's financial commitment can be substantial, particularly if the market price of electricity frequently falls below the strike price, necessitating continuous payments to generators. These costs can fluctuate significantly based on market conditions and could become a burden if not managed with foresight and adequate budgetary allocations.





**Figure 3: Standard strike price versus cap and floor strike price**



Incorporating indexation for inflation, commodity prices, or other economic factors can help maintain the economic viability of renewable projects over time. Adjustments like technology or siting factors can incentivize developments in less favourable locations or with specific technologies, aiding policy goals such as geographic distribution of renewable energy generation or the promotion of less mature technologies.

The method of setting the strike price, whether through administrative set-up, competitive auction, or bilateral negotiations, can impact how producers approach the market. Competitive auctions may drive prices down, potentially closer to or even below the Levelized Cost of Electricity (LCoE), encouraging aggressive market participation but possibly at the risk of financial unsustainability.

### 3. Addressing distortions in conventional CfDs

In this section, we investigate the effect of distortions on the value of CfDs and analyze the way which the two main proposals from the literature, namely Newbery's yardstick locational CfD and Schlecht et al.'s benchmark-based financial CfD, can help to address some of the distortions in the conventional CfDs.

#### 3.1 Benchmark case

To understand distortions better, we first analyze a benchmark case which is a conventional two-way CfD as the way it is implemented in the UK. The analysis is performed on a typical date with two different scenarios for electricity prices. The first one is a date with all positive prices and in the second one, some hours during the date, the prices are negative.

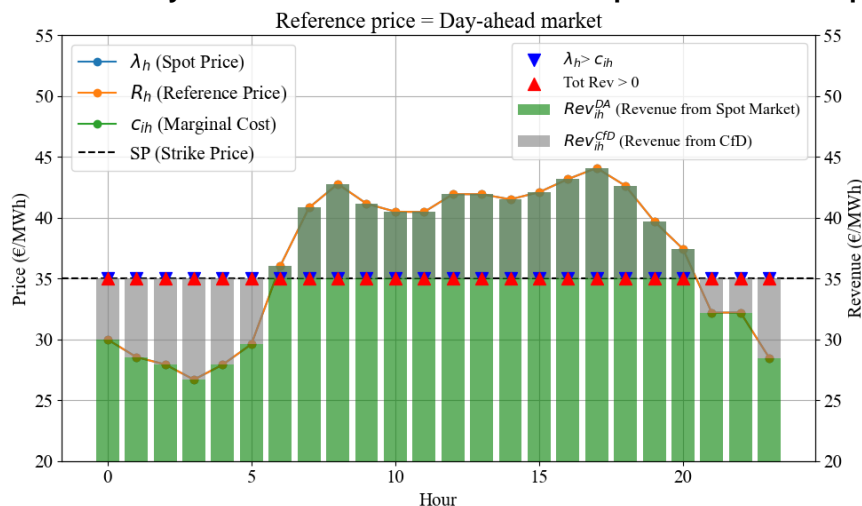
##### *Positive Price Period*

In this case study, the objective is to establish a benchmark scenario for the CfD value. We assume that the reference is the same as the hourly day ahead market price. Within the framework of a conventional CfD agreement, during periods when the reference price ( $\lambda_h$ ) exceeds the predetermined strike price (SP), there ensues a transfer of funds from the generating entity to the CfD counterparty, and conversely, when the reference price falls below the strike price. Consequently, the net revenue derived from the CfD contract remains constant across all time intervals. For the purpose of simplification in this analysis, the marginal costs associated with generation are assumed to be negligible. Figure 4 shows



the flow money between generator and CfD counter party in this case.<sup>3</sup> Table 1 below shows the details of the calculation for a single day in this scheme.

**Figure 4: Flow of the money in the CfD contract in the case of positive reference price**



**Table 1: Details of the payment and energy prices in the case of positive reference price**

Hour	Revenue from DA Market (€/MWh)	Revenue from CfD (€/MWh)	Total Revenue (€/MWh)	Reference Price (€/MWh)
1	29.99	5.01	35.0	29.99
2	28.54	6.45	35.0	28.54
3	27.94	7.06	35.0	27.94
4	26.69	8.31	35.0	26.69
5	27.92	7.08	35.0	27.92
6	29.61	5.39	35.0	29.61
7	36.03	-1.03	35.0	36.03
8	40.82	-5.82	35.0	40.82
9	42.78	-7.78	35.0	42.78
10	41.16	-6.16	35.0	41.16
11	40.5	-5.5	35.0	40.5
12	40.47	-5.47	35.0	40.47
13	41.94	-6.94	35.0	41.94
14	41.93	-6.93	35.0	41.93
15	41.51	-6.51	35.0	41.51
16	42.1	-7.1	35.0	42.1

<sup>3</sup> Also, Figure 4 shows the blue triangle as representative of the energy market price higher than the variable cost of the generator and the red one shows whether the total revenue calculated based on the Equation (1) is positive or not.



17	43.18	-8.18	35.0	43.18
18	44.09	-9.09	35.0	44.09
19	42.62	-7.62	35.0	42.62
20	39.7	-4.7	35.0	39.7
21	37.44	-2.44	35.0	37.44
22	32.2	2.8	35.0	32.2
23	32.21	2.79	35.0	32.21
24	28.47	6.53	35.0	28.47

The table clearly shows that when the reference price is above the strike price, the revenue from the CfD is negative, reflecting the payment from the generator to the CfD counterparty. Conversely, when the reference price is below the strike price, the revenue from the CfD is positive, indicating a payment to the generator. This mechanism ensures that the total revenue remains fixed at the strike price of €35.0/MWh throughout the day. For example, during the seventh hour, the reference price is €36.03/MWh, resulting in a negative CfD revenue of -- €1.03/MWh, balancing the total revenue to €35.0/MWh. This consistent revenue stream demonstrates the stability provided by CfD contracts, but also highlights how they can suppress price signals, potentially leading to suboptimal investment decisions during periods of price volatility.

#### *Negative Price Period*

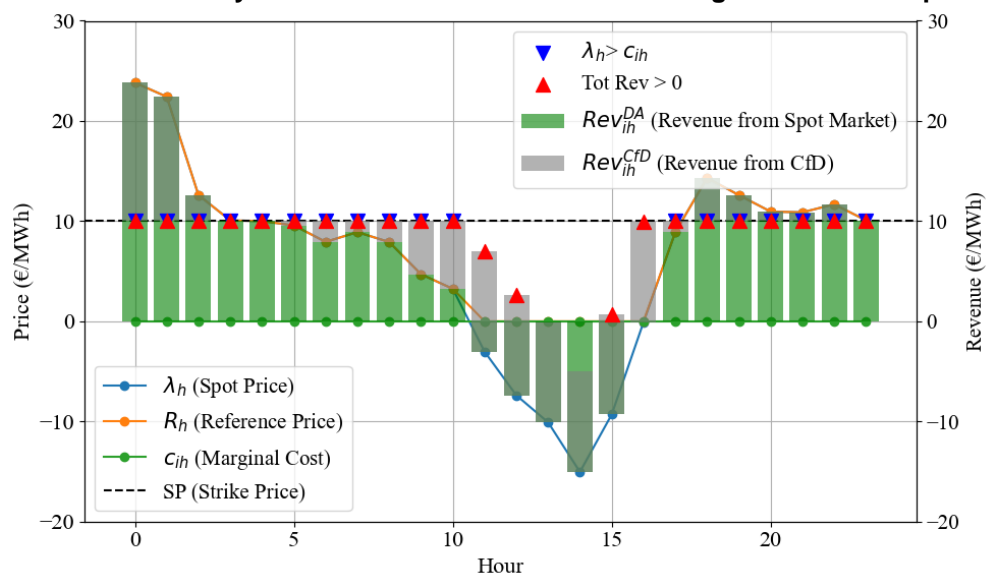
In this scenario we assume that there are instances where the market prices are assumed to have negative values for certain periods.

Negative market prices occur when there is an oversupply of electricity and limited flexibility on either the generation or demand side. This can happen due to factors like high renewable output coinciding with low demand. Traditional CfDs, designed to support generators when prices are low, inadvertently create a perverse incentive to continue producing even when it is economically inefficient, as generators still receive the difference between the strike price and the negative market price. According to prevailing regulations, should market prices remain negative for a duration of six consecutive hours, reference prices are to be treated as zero. In the case study illustrated in Figure 5, it is observed that during these intervals, the net revenue for the generating entities does not remain uniform, as the financial clawback to the government surpasses the compensation disbursed to the generator units. This may restore the incentive to reduce generation during periods of oversupply, but may create another problem: revenue instability.

Table 2 presented below elucidates the payment and revenue details for a specified sample date with some hours of negative prices. An analysis of the total revenue indicates that during periods of positive reference hours, the financial transactions are structured in such a manner that they yield a consistent revenue stream for the generators. However, during intervals of negative reference hours, the generators' revenue is not hedged if it generates (Case I), leading to scenarios where they may incur a net loss in total revenue. However, if it does not generate in hours with negative day-ahead (DA) market price (Case II), the total revenue would be zero as the CfD payment itself depends on the generation.

Therefore, while by treating reference prices as zero during negative hours generators are encouraged to behave in a way that aligns with broader market signals, this may increase revenue instability for the generator. Consequently, within this context, the CfD agreement fails to serve as an effective revenue stabilization mechanism for the generators. This highlights the need for CfD designs that can better accommodate periods of negative pricing without compromising financial predictability for renewable energy producers.

**Figure 5: Flow of the money in the CfD contract in the case of negative reference price**



**Table 2: Details of the payment and energy prices in the case of negative reference price (€/MWh)**

Hour	Revenue from DA Market– Case I	Revenue from DA Market– Case II	Revenue from CfD	Total Revenue – Case I	Total Revenue – Case II	Reference Price
1	23.82	23.82	-13.82	10.0	10.0	23.82
2	22.42	22.42	-12.42	10.0	10.0	22.42
3	12.6	12.6	-2.6	10.0	10.0	12.6
4	10.07	10.07	-0.07	10.0	10.0	10.07
5	10.0	10.0	0.0	10.0	10.0	10.0
6	9.57	9.57	0.43	10.0	10.0	9.57
7	7.93	7.93	2.07	10.0	10.0	7.93
8	8.9	8.9	1.1	10.0	10.0	8.9
9	7.91	7.91	2.09	10.0	10.0	7.91
10	4.7	4.7	5.3	10.0	10.0	4.7
11	3.24	3.24	6.76	10.0	10.0	3.24
12	-3.03	0	10.0	6.97	10.0	0
13	-7.39	0	10.0	2.61	10.0	0
14	-10.09	0	10.0	-0.09	10.0	0
15	-15.04	0	10.0	-5.04	10.0	0
16	-9.31	0	10.0	0.69	10.0	0
17	-0.1	0	10.0	9.9	10.0	0
18	8.88	8.88	1.12	10.0	10.0	8.88

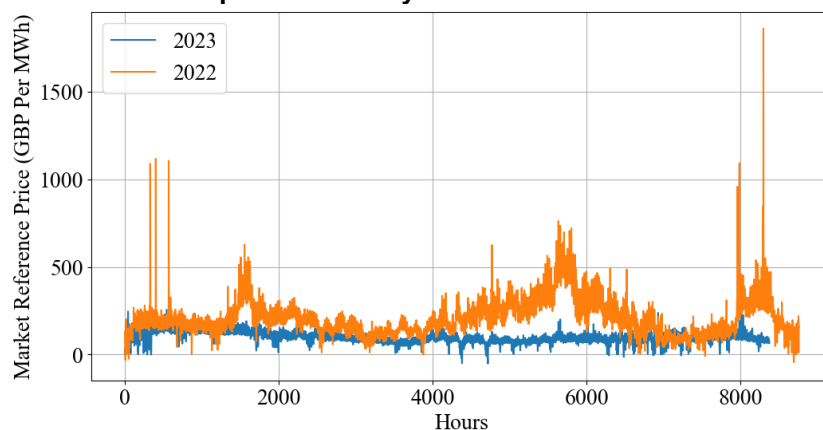




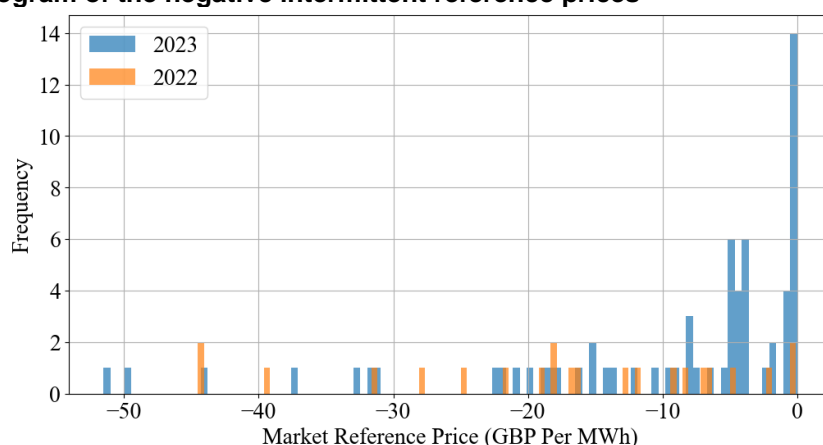
19	14.32	14.32	-4.32	10.0	10.0	14.32
20	12.6	12.6	-2.6	10.0	10.0	12.6
21	10.95	10.95	-0.95	10.0	10.0	10.95
22	10.88	10.88	-0.88	10.0	10.0	10.88
23	11.68	11.68	-1.68	10.0	10.0	11.68
24	10.08	10.08	-0.08	10.0	10.0	10.08

This means that generators need to make prediction of negative pricing frequency. Figure 6 illustrates the fluctuating reference price data over a span of two years in UK electricity market<sup>4</sup>. A histogram of negative prices during this period is presented in Figure 7. These two figures reveal that for the majority of the time, prices remained above zero, indicating that the impacts of the hours with negative prices are generally insignificant. Nevertheless, it is noteworthy that there were approximately 100 hours during the last two years where the reference price dipped below zero. In the absence of flexibility and with the growth of share of variable renewables in the system, the frequency of occurrence of negative prices may rise. Thus, the current CfD frameworks may need significant adjustments to handle these changes effectively.

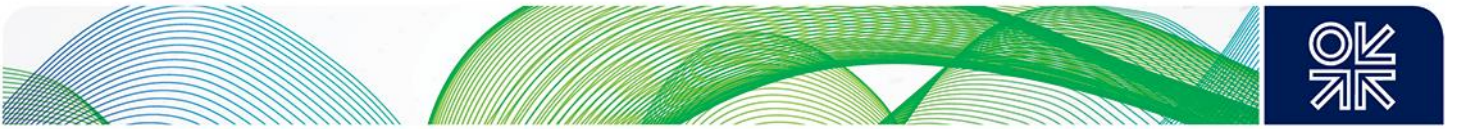
**Figure 6: Intermittent reference prices for two years**



**Figure 7 : Histogram of the negative intermittent reference prices**



<sup>4</sup> Settlement Data for CfD Generators - EMR Settlement Limited [WWW Document], n.d. URL <https://www.emrsettlement.co.uk/settlement-data/settlement-data-cfd-generators/> (accessed 3.3.24).



## 3.2 Main proposed methods

Some key methods have been suggested in the literature to reform the CfD scheme, each aiming to address specific shortcomings of the traditional CfD model. Notable among these are Newbery's Yardstick Locational CfD (Newbery, 2023) and Schlecht et al.'s benchmark-based financial CfD(b-FCfD) (Schlecht et al., 2024, 2023). Focusing on Newbery's Yardstick Locational CfD and Schlecht et al.'s benchmark-based financial CfD in this paper makes sense for two reasons. Both models address significant limitations of traditional CfDs, particularly the issues of economic inefficiency and revenue instability under varying market conditions. Second, these two methods to some extent cover the main features proposed in the literature and have similar strength and weaknesses.

### 3.2.1 Yardstick Locational CfD

Newbery (2023) advocates for an auction-based approach to determine the minimum necessary premium to attract investment while minimizing the cost of subsidies (Yardstick Locational CfD). The key aspect of his model is that it pays out based on the contracted terms regardless of whether the generator is actually producing electricity at any given moment. This is fundamentally different from traditional CfDs or feed-in tariffs, where payments are typically dependent on actual electricity production. Also, the new CfD structure shifts from time-based to volume-based incentives, focusing on the amount of energy produced rather than the duration of operation. This specification ties the financial compensation to a quantifiable amount of energy provision rather than merely time, aligning payments more closely with actual energy contributions.

The volume in this model is not based on the actual output but a benchmark. As we discuss later, by setting the yardstick volume at the system-wide average or local average output, the model introduces a basis risk. This risk is a strategic choice to incentivize efficient behaviour.

Also, the efficiency of the proposed model relies significantly on pairing the CfD with a transmission contract priced based on future output-weighted Locational Marginal Prices (LMPs). This pairing aims to mitigate locational distortions by encouraging renewable energy installations in locations where they deliver the most value during higher-priced hours.

In what follows we show the way which Yardstick Locational CfD tries to maintain the incentive for renewable energy generators within the spot market.

#### Efficient dispatch

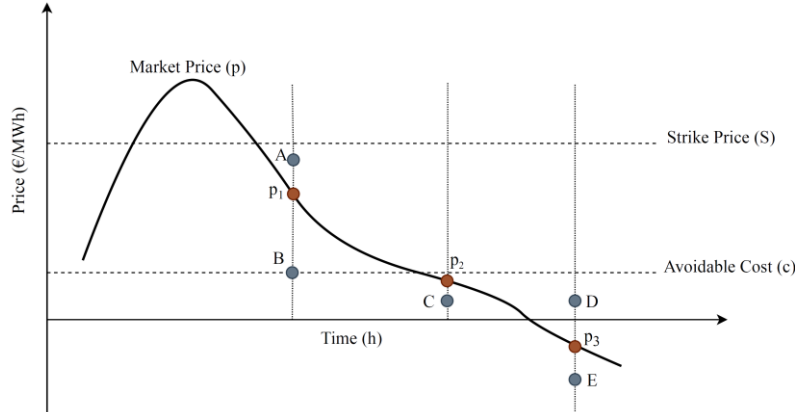
The fundamental premise of the Yardstick Locational CfD is that payment is calculated as (2), irrespective of the generation status:

$$(s - p_{rh})\theta_{rh}k \quad (2)$$

In this formula,  $s$  is the strike price,  $p_{rh}$  is the reference price which is the wholesale day-ahead market for location  $r$ , hour  $h$ ,  $\theta_{rh}$  is the capacity factor of the unit in location  $r$  and hour  $h$ , and  $K$  is the installed capacity of the unit.

Let's consider the scenario illustrated in Figure 8. It shows the market price variation, the level of strike price and avoidable costs. We assume here that the market price and the reference price are the same. Based on the interplay of strike price, avoidable cost, and market price levels, various outcomes are conceivable. A unit intending to bid under these diverse scenarios is hypothesized:

**Figure 8: A hypothetical market price curve**



**Point A:** At this point, the bid value is higher than the market price – thus, if an asset bids in this value, it will not be dispatched. In this case, only the CfD payment would be paid to the unit; hence, bearing in mind that in this model CfD payment is not tied to actual generation, the total payment is:

$$Rev_A = (s - p_{r,1})\theta_{r,1}k.$$

**Point B:** At this point, the bid value is lower than the market price and the total revenue of the unit would be:

$$Rev_B = Rev_B^{DA} + Rev_B^{CfD} = (p_{r,1} - c)\theta_{r,1}k + (s - p_{r,1})\theta_{r,1}k = (s - c)\theta_{r,1}k$$

which is higher than  $Rev_A$ . Thus, it shows that the generators are incentivized to bid based on the true cost ( $c$ ) using the financial CfD contract.

In Point A, the CfD payment compensates for market exclusion, while in Point B, the combined revenue from market participation and CfD payments maximizes economic returns for cost-efficient production. This outcome not only incentivises the generator to bid based on its true cost but also rewards it for doing so. By bidding lower than the market price and closer to its actual production cost, the generator maximizes its total revenue through both market sales and CfD compensation. This strategy aligns the generator's incentives with market efficiency, promoting cost-effective dispatch.

**Point C:** There are two situations in this point as the market price is below the avoidable cost of the unit:

- **Do not generate:** In this case, there is no revenue from the day-ahead (DA) market and the total revenue would be from the CfD:  $Rev_c = Rev_c^{CfD} = (s - p_{r,2})\theta_{r,2}k$

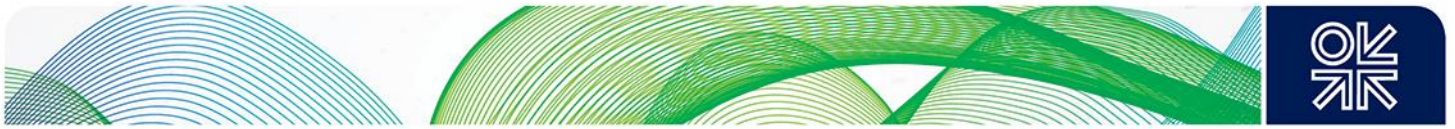
Choosing not to generate in this situation aligns with merit-based dispatch principles, where generating units are expected to operate only when it is economically sensible. The CfD payment ensures that the generator receives compensation for the capacity readiness, offsetting potential losses from market inactivity and supporting the financial stability of renewable energy sources.

- **Generate:** In this case, the revenue would be

$$Rev_c = Rev_c^{DA} + Rev_c^{CfD} = (p_{r,2} - c)\theta_{r,2}k + (s - p_{r,2})\theta_{r,2}k$$

in which  $Rev_c^{DA} \leq 0$  and the unit has the risk of losing  $(p_{r,2} - c)\theta_{r,2}k$  if it generates. In other words, if the generator decides to operate despite the market price being below the avoidable cost, it will incur a loss on each unit of electricity produced because the sales revenue is less than the production cost. Thus, it has no incentive to generate, which is aligned with merit-based dispatch when the market price is lower than the avoidable cost of the unit.

**Point D:** In this point, the generator bid is higher than the market price and it will not be dispatched (like point A). Also, based on the CfD payment regulation, if the reference price is negative, it will be considered as zero. Thus, the revenue in this case is:



$$Rev_D = Rev_D^{CfD} = s\theta_{r,3}k.$$

**Point E:** There are two situations in this case based on the dispatch decision of the generator:

- **Do not generate:** In this case, the revenue would be same as for point D.
- **Generate:** In this case, the total revenue would be:

$$Rev_E = Rev_E^{DA} + Rev_E^{CfD} = (p_3 - c)\theta_{r,3}k + s\theta_{r,3}k$$

which is lower than in the case that the unit does not generate because the first term is negative ( $(p_3 - c)\theta_{r,3}k < 0$ ). Thus, there is no incentive for the unit to generate – which is compliant with the system need in the case of very low market prices. Point E thus illustrates a critical aspect of the yardstick CfD mechanism – encouraging or discouraging generation based on real-time market conditions and economic rationality.

These cases show that the proposed CfD contract will provide efficient dispatch signals for the units and that the system would benefit from cost-effective dispatch.

### Locational distortions

In this section, we analyse how Newbery's method can be used to remove locational distortions. To illustrate this, let's assume there are two possible locations for the deployment of a wind farm: 'Central' and 'Windy'. The illustration in Figure 8 visually represents the comparison between two types of locations in terms of their subsidy-related metrics, using the following assumptions.

- The analysis assumes that the subsidy limit is defined as a fixed amount of energy production in MWh per MW of capacity (MWh/MW) (as suggested by the Yardstick CfD model). In this case, it is set to 30,000 MWh per MW. This assumption implies that once a location produces this amount of energy, the subsidy ends.
- We also assume that the Central and Windy locations have different annual energy production rates. The Central location produces 2,000 MWh per MW per year, while the Windy location produces 3,000 MWh per MW per year. This differential reflects the varying efficiency or potential of different locations, with windy areas typically generating more power due to stronger or more consistent winds.
- The duration for which the subsidy is available differs between locations and is directly tied to how quickly they reach the subsidy limit. The Windy location reaches this limit faster due to its higher production rate.
- A discount rate of 3.5 per cent is used to calculate the present value of the total subsidy for each location. This rate is critical in determining the present value of future cash flows, reflecting the time value of money. The discount rate chosen reflects a moderate assumption about the cost of capital or the opportunity cost of investment.

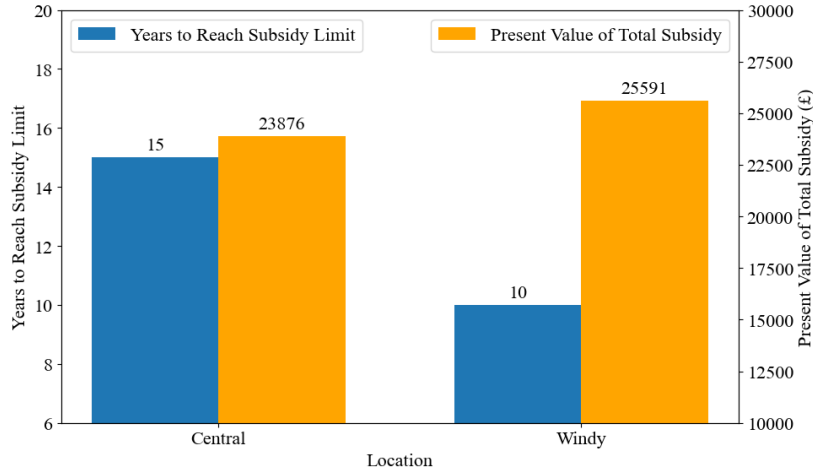
The bar chart segment – in blue – in Figure 9 displays the number of years each location takes to reach the subsidy limit. As it can be seen, the Central location requires 15.0 years, while the 'Windy' location takes only 10.0 years. In terms of the present value of the total subsidy for each location, as it is shown in Figure 9, the Central location has a present value of approximately £23,875, whereas the Windy location has a slightly higher present value of about £25,591.

The fact that the Windy location in our example reaches the subsidy limit faster, and has a higher present value of the total subsidy compared with the Central location, clearly shows why developers prefer windier locations. This issue is that total system costs per MWh renewable energy in these windy locations are sometimes higher than other regions due to congestion and the need for network reinforcement. Newbery however proposes an approach to address this problem. After limiting the contract based on a fixed number of full operating hours, he proposes removing the incentive to locate in regions of high resource while retaining the incentive to locate where the local resource has a lower correlation with the country average.





**Figure 9: Comparison of subsidy metrics by location**



In this approach a new term is added to formula (2) to address this distortion and align developers' incentives with those of system cost-minimization. Thus, the CfD compensates the generator equal to (3):

$$(s - p_{r,h})\theta_{r,h}k + a_h k \quad (3)$$

during hour  $h$  at site  $r$  over a span limited to  $T$  hours, where  $T$  fulfils the condition that the  $\sum_{h=1}^T \theta_{v,h} = N$ , and  $a_h$  is defined as the  $\sum_{h=1}^H (\theta_{s,h} - \theta_{r,h})p_h/H$ . In this equation,  $K$  represents capacity;  $\theta_{r,h}$  denotes the predicted capacity factor at site  $r$  for hour  $h$ ;  $\theta_{v,h}$  is the actual recorded output per MW at the renewable energy site during hour  $h$ ;  $\theta_{s,h}$  is the average capacity factor for the system;  $H$  refers to the total number of hours or settlement periods annually;  $N$  is the fixed length of the contract in terms of full operational hours;  $s$  is the set strike price, and  $p_h$  stands for the corresponding wholesale price.

To understand how this is effective for both the allocation of resources and location optimization, regardless of production status, consider a 10 MW wind turbine which has the possibility to be installed in three different locations with different capacity factors. The distribution of the forecast capacity factor during one year in each location is presented in Figure 10. As seen in that Figure, location A has the highest predicted capacity factor whereas location C has the lowest predicted capacity factor.

Table 3 presents the results for this example for a year with limit of full operating hours to 30,000 MWh/MW and an average system capacity factor of 0.42. The data of the electricity prices is for SE3 bidding zone (in Sweden) in 2023 taken from Nord Pool.

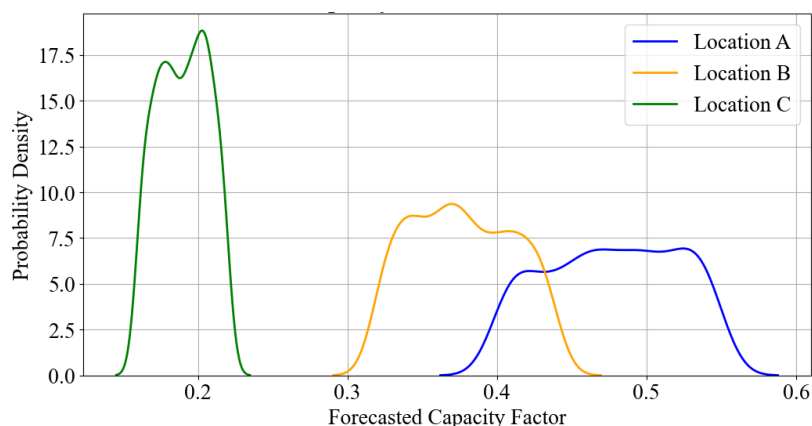
Location A, despite having a high base CfD payment (when there is no locational element as in the case of a conventional CfD) indicating high productivity or capacity factors, receives a significant negative locational incentive when the Yardstick locational CfD approach is applied. This leads to a reduction in the incentive to install additional capacity here. The CfD designer might want renewable energy developers to avoid this location because, for example, it is oversupplied or system costs are higher there.

Location B shows a moderate base CfD payment with a substantial positive locational incentive, making it an attractive option for new installations. The positive incentive could be due to strategic needs for capacity in this area or underutilization relative to its potential.

Location C initially appears less viable based on the base CfD payment alone; however, a very large locational incentive drastically increases its attractiveness. This indicates a high strategic value placed on this location, possibly due to its lower correlation with overall system production patterns or critical needs for the diversification of generation locations.



**Figure 10: Forecast capacity factor for the three assumed locations**



**Table 3: Specifications of the three different locations in the yardstick locational CfD**

	Location A	Location B	Location C
System Capacity Factor	0.42	0.42	0.42
Full operation time (h)	7507	7522	7500
Base CfD payment (€)	380976	303700	151344
Locational incentive (€)	-198122	143762	823403
Total CfD Payment (€)	182581	447461	974747

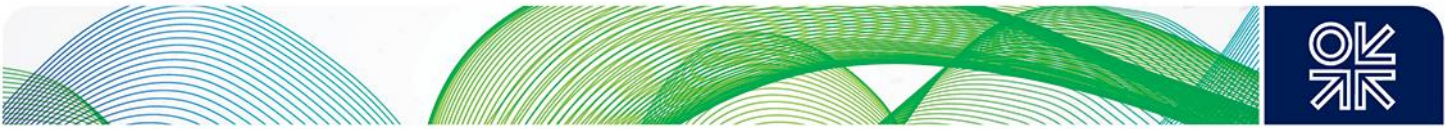
This analysis shows that normal CfD payment motivates the investors to install their units in areas with higher capacity factor and may result in extra need of transmission network in highly congested areas. But, as the new location term ( $a_n$ ) is added to the base CfD payment, it removes this distortion. As the results show, although the base CfD payment is higher in location A, the final payment after taking into account the locational incentive makes location C a more economic choice.

This approach encourages the distribution of renewable energy installations in a manner that optimizes both operational efficiency and grid reliability, moving away from traditional models that might incentivize concentration in already resource-rich or grid-congested areas. This strategic distribution aids in balancing the grid and reducing the need for excessive transmission investments or congestion management efforts.

### The effect of choice of Yardstick

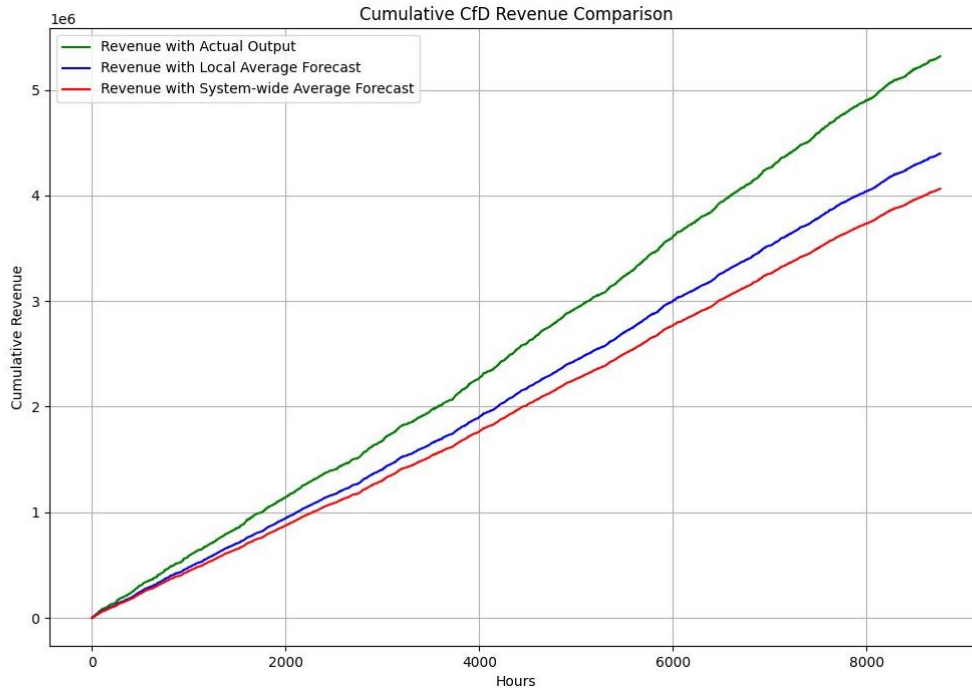
Although a Yardstick CfD, on paper, mitigates the distortions inherent to a conventional CfD, one of the biggest challenges of this approach is the choice of Yardstick and the basis risk that it introduces. In this section we explore the revenue implications of a Yardstick CfD for a renewable energy generator, under three scenarios: actual production-based payouts, local average forecast-based payouts, and system-wide average forecast-based payouts. We assume a 100 MW wind farm with a contracted volume of 200,000 MWh and a fixed strike price of €80/MWh. A fluctuating market price with a mean of €70/MWh and standard deviation of €10/MWh is simulated.

Wind speeds are modelled using a Weibull distribution, with a power curve that converts wind speed to power output. Importantly, it is assumed that the forecast capacity factors for local scenarios is correlated with the actual wind power output, with a correlation coefficient of 0.8. For the system-wide scenario this number is assumed to be 0.5. This reflects the real-world relationship between forecasts and actual production, where forecasts tend to be more accurate when data is collected from regions closer to the site.



Under these assumptions, Figure 11 shows that there is a risk that the forecast deviates from actual output, leading to missed revenue opportunities or potential losses.

**Figure 11: The effect of Yardstick output on generator's revenue**



This highlights a trade-off between market efficiency and basis risk inherent in CfD design choices. An actual output-based CfD directly links CfD payouts to the generator's actual production, ensuring revenue aligns with energy contribution but introduces market inefficiency by potentially distorting dispatch decisions and hindering market integration.

A Yardstick CfD enhances market integration by decoupling payouts from real-time generation, encouraging generators to optimize dispatch based on market signals but introduces basis risk, where the generator's revenue is exposed to the accuracy of the benchmark production forecast. This risk varies based on the forecasting methodology. Aggregated data lowers individual measurement errors or the likelihood of manipulation, but introduces the highest basis risk due to greater deviation from individual plant profiles.

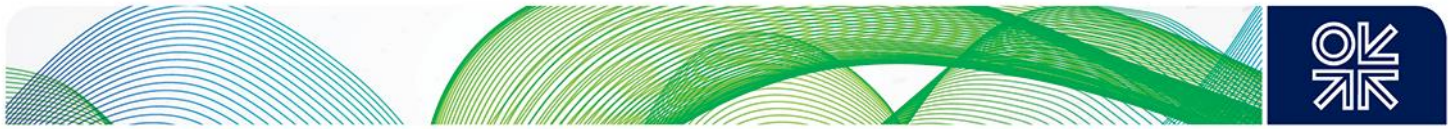
This simulation underscores the complexity of yardstick CfD design and the need for further analysis in this area to identify the optimal reference models that strike a balance between market integration incentives and manageable basis risk.

### 3.2.2 Benchmark-based Financial CfD (b-FCfD)

Schlecht et al. (2024) introduces a 'financial' CfD model, which is a hybrid between conventional CfDs and forward contracts. This model aims to mitigate revenue risks more comprehensively than the other proposed models while maintaining proper incentives for electricity generation. Similar to the Yardstick CfD discussed previously, payments in this model are decoupled from actual generation, reducing the influence of an asset's operational decisions on financial outcomes.

This model involves two distinct payments: one from the government to the generator, and another from the generator to the government, based on the performance of a reference generator. Let's assume:

- $G_h$ : Fixed hourly lump sum paid by the government to the generator, determined competitively in the initial procurement auction.
- $\lambda_h$ : Spot price of electricity at hour  $h$  (€/MWh).
- $C_{ref}$ : Benchmark variable costs of production for the reference generator (€/MWh).



- $q_{ref,h}$ : Hourly output of the reference generator at hour  $h$  (MWh).

Payment from government to generator at hour  $h = G_h$ . This is a fixed payment, independent of the generator's actual performance. Payment from the generator to the government is based on the hypothetical revenue of a reference generator, which may not be the same as the actual generator involved in the contract.

Profit of reference generator at hour  $h = (\lambda_h - C_{ref}) \times q_{ref,h}$ . However, if the profit calculation yields a negative value, it is set to zero: So we can present the adjusted profit of reference generator at hour  $h = \max\{(\lambda_h - C_{ref}) \times q_{ref,h}, 0\}$ .

The net payment for each hour is the difference between what the government pays the generator and what the generator pays back to the government:

Net Payment at hour  $h$ :  $G_h - \max\{(\lambda_h - C_{ref}) \times q_{ref,h}, 0\}$ .

This model clearly illustrates the swap nature of the financial CfD proposed by (Schlecht et al., 2024), where the generator receives a fixed sum from the government, providing stability and predictability in revenue. Simultaneously, the generator pays back to the government based on the performance of a reference generator, linking part of the contract's financial mechanics to market conditions without directly tying them to the generator's actual production.

The benefit for wind and solar power generators with this hedging strategy is that it focuses on securing their total revenue rather than revenue per MWh, thereby mitigating risks associated with production volume, such as variability in wind conditions. Additionally, seasoned developers have the expertise to fine-tune their asset's generation pattern, maintenance timing, and operational management to maximize profitability. Since the financial hedge is external, any extra gains achieved through these optimizations are fully retained by the developers, unlike in conventional CfD models where such advantages might be offset by the CfD's differential calculations.

Thus, in this contract, the total payment to the generator remains constant during the contract period. However, the locational distortion remains as different locations based on the capacity factors of the reference generator provide different incentives for the investor for the decision-making process. Table 4 shows the results of a simple case study based on the previous input data of three different locations, but considering benchmark-based financial CfD payment. As the results show, there is a different payment transaction between the unit and government agency such that the total payment would be the same for different locations. This is the nature of the model to stabilize the revenue for the different investors; hence, it does not provide a locational incentive for the market participants compared with the Yardstick locational CfD which is a negative point for the benchmark-based financial CfD.

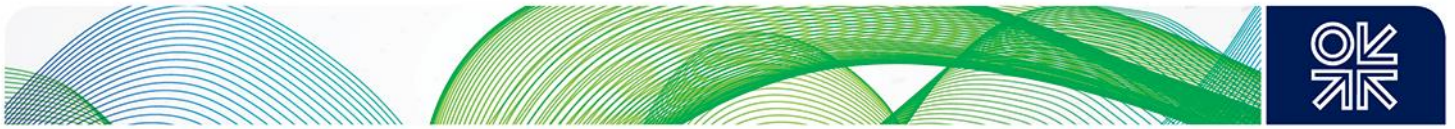
**Table 4: Money flow for the b-FCfD contract in three different locations**

	Location A	Location B	Location C
Gov-to-Gen Payment (M€)	5.52	5.52	5.52
Gen-to-Gov Payment (M€)	-2.62	-2.10	-1.04
Merchant Market Sales (M€)	2.62	2.10	1.04
Total CfD Payment (M€)	5.52	5.52	5.52

### Reference model discussion

The definition of the reference model in the b-FCfD is crucial for the opportunity and risk profile of the operator, as it directly affects the net revenue. Currently, the reference model as per Schlecht et al. (2024) is not yet detailed but describes only possible approaches for establishing a reference plant pool. This leaves a significant aspect of this contract open.





The authors present three possible methods to determine the reference energy production for wind and solar generators. One approach is to derive a theoretical energy output using regional weather data. This method, similar to one used by the European Energy Exchange, or EEX, for a now-discontinued wind future product, provides independence from individual plant operations. Another would be to use a selected group of wind/solar farms that could act as a real-world reference. Finally, aggregated wind/solar generation within a country or zone could be used as a benchmark. This method is less susceptible to manipulation in larger zones but poses risks in smaller ones with fewer generators.

To better understand the impact of the choice of the reference model, we explore the variability of power output from wind turbines under the aforementioned different reference modelling approaches. The simulation assesses three distinct reference outputs: a mathematical model based on adjusted wind speeds, a small sample of physical wind/solar farms, and a regional aggregated output. Each approach is designed to provide a perspective on how external factors and modelling techniques can influence the estimation of power output, which is crucial for determining the financial settlements under CfDs. The result of this simulation is presented in Figure 12.

The actual power output is calculated using a power curve model that simulates the power production from a wind turbine based on wind speeds. Wind speeds are modelled using a Weibull distribution, which is well-suited for wind speed data due to its ability to represent the range of wind speeds typically observed in nature. The parameters of the Weibull distribution (shape  $k=2.0$  and scale  $\lambda=10$ ) are chosen to reflect common wind conditions. The power curve is defined such that power output increases cubically with wind speed up to a rated speed of 12 m/s, beyond which it caps at a maximum output of 50 MWh, mimicking the operational characteristics of typical wind turbines.

For the mathematical model reference output, wind speeds are intentionally reduced by 5 per cent to simulate a scenario where the reference model slightly underestimates the actual wind conditions. This approach tests the resilience of the CfD framework under conservative estimates of wind speed, providing insights into how under-predictions could affect financial outcomes. The same power curve used for the actual output calculation is applied to these adjusted wind speeds.

For sample of physical wind farm output, we introduce variability by incorporating random fluctuations around the actual power output, simulating a small sample of wind farms. A normal distribution with a mean of 0 and a standard deviation of 5 per cent models the output variability, representing operational discrepancies between individual turbines within a small geographic area. This scenario examines the impact of small-scale diversity in turbine performance on the reference output, which is crucial for understanding the financial risks in CfDs when relying on data from a limited number of physical assets.

Finally, for the regional aggregated output reference model we use a similar approach to the physical sample but with significantly reduced variability (standard deviation of 1 per cent). This method simulates the averaging effect of aggregating outputs over a larger number of generators, reducing the influence of individual discrepancies and providing a more stable and representative reference output. This scenario is pertinent for large-scale CfD applications where the reference output must minimize susceptibility to manipulation *and* provide a reliable benchmark that reflects broader geographic and operational conditions.

As seen from Figure 12, the mathematical model output, calculated by applying a 5 per cent reduction to the actual wind speeds, typically underestimates the actual power output. This consistent underestimation could lead to a systematic bias where the CfD payments are higher than intended, as the reference output frequently reports lower generation than the actual. This discrepancy highlights the risk of using simplified or conservative models in CfD contracts, potentially leading to greater financial exposure for the entity responsible for making up the difference.

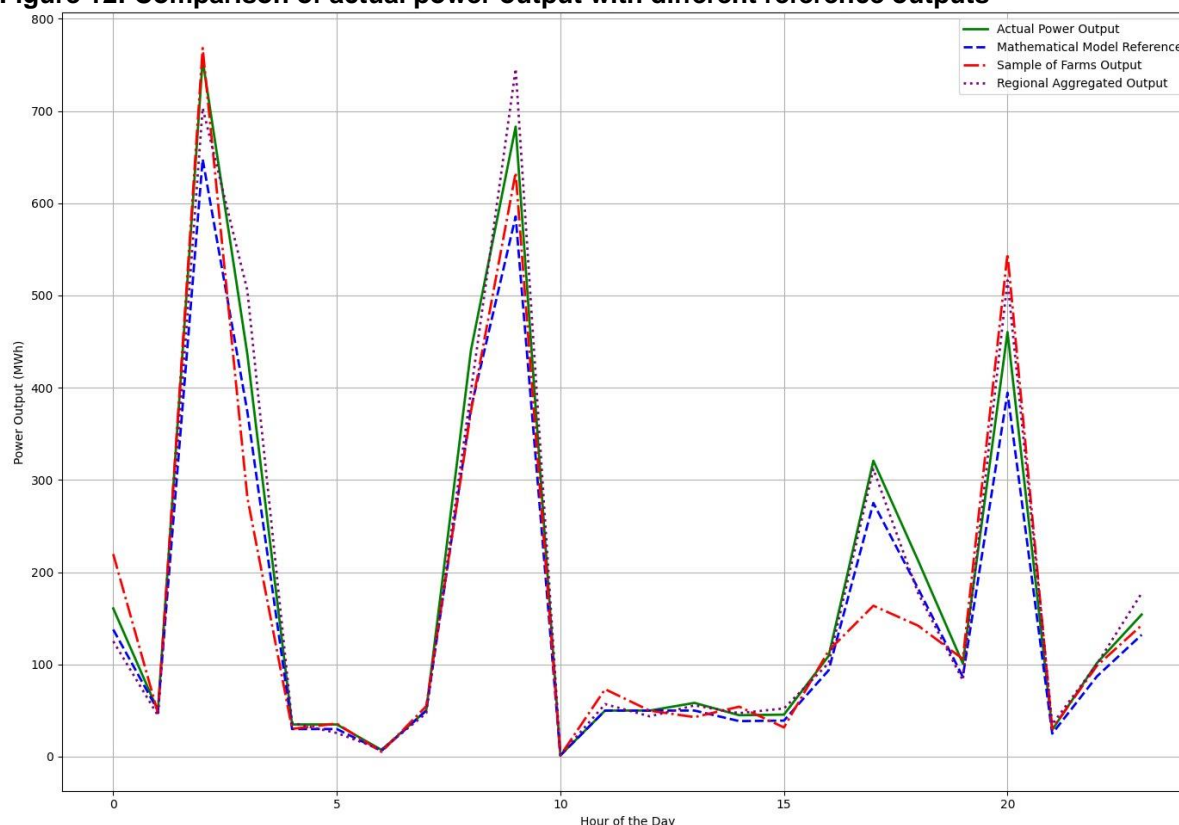
The output from a small sample of physical farms shows more variability around the actual output, reflecting operational differences between individual turbines or small groups of turbines. This variability can introduce unpredictability in CfD settlements, especially if the sample size is too small or not representative of the broader installation.



The regional aggregated output, which introduces a minimal variability (1 per cent), aligns more closely with the actual power output compared with other methods, but it is far from perfect.

These results are of course not based on reality but are simulated based on assumptions. But they clearly show that the choice of reference output significantly impacts the risk profile of CfD contracts. More stable and representative references reduce basis risk and provide more predictable financial outcomes. In contrast, models that consistently underestimate or the use of volatile samples introduce financial risks that need to be managed carefully.

**Figure 12: Comparison of actual power output with different reference outputs**



### Further challenges

An additional challenge to be addressed is whether a b-FCfD qualifies as a financial derivative, which would subject it to corresponding financial market regulation. The argument against this classification is that b-FCfDs are not directly about trading financial derivatives but about subsidy payments. This question is separate to the previously mentioned effect of the b-FCfD, which is not influenced by its characterization as a financial product. If classified as a financial derivative, the use of this subsidy instrument would be significantly more complicated, especially for smaller players.

Moreover, financial future products require collateral backing. For typical future products, only liquid capital is accepted as collateral. This poses significant challenges for producers, which is why future products can only be held in the portfolio to a limited extent. To circumvent this difficulty Schlecht et al. (2023) suggest creating regulations that allow the renewable energy plant itself to be used as collateral. The practical implementation of this aspect also needs to be clarified.

This situation highlights the complexity of integrating innovative financial instruments like the b-FCfD into existing regulatory frameworks. The balancing act involves providing enough flexibility for these instruments to be effective and accessible, especially for smaller entities, while ensuring that they comply with the necessary financial regulations to maintain market stability and protect stakeholders.



## 4. Discussions

Policymakers face a complex challenge in reforming CfD mechanisms to effectively incentivize renewable energy generation while ensuring market efficiency and managing financial risks. The core dilemma lies in balancing competing objectives, necessitating the careful consideration of various trade-offs.

One prominent trade-off is between market efficiency and revenue volatility. Traditional, (actual) output-based CfDs can incentivize generators to prioritise CfD payments over responding to real-time market signals, potentially hindering efficient dispatch decisions. This is not surprising. From an economic perspective, when agents are compensated based solely on output, they may maximize their own benefit at the cost of overall efficiency, leading to a classic principal-agent problem where the agent's actions do not lead to the best outcomes for the principal. In this specific case, CfD based on actual generation create a 'moral hazard' problem where generators may produce electricity even when not economically warranted (for example, during periods of low demand or when prices are below avoidable costs), because their revenue is secured irrespective of market conditions. This behaviour can lead to over-generation, requiring costly system interventions such as curtailment or storage of excess electricity, ultimately increasing costs for consumers and reducing overall market efficiency.

There are two pathways to address the incentive problem of conventional (generation-based) CfDs. One approach is to continue within the existing paradigm of generation-based CfDs but modify the reference price, as the key design parameter, while introducing solutions for negative price hours. A generation-based CfD can become incentive compatible if we move away from an hourly reference price to larger time scales and pausing pay out during the negative pricing hours. But this introduces basis risk, due to the potential deviation of the renewable market capture price from the reference price. It also increases volume risk due to lost volumes during the negative hours. On top of that, it may not address the issue of distortion in the intraday and balancing market that is introduced as a result of strategic behaviour of generators under generation-based CfDs.

An alternative approach is generation-independent CfDs to promote market integration by aligning generator's incentives with market outcomes. These models – also called Yardstick CfDs – decouple payouts from real-time generation. They use comparative performance metrics (benchmarks) to determine payouts, a concept rooted in the economic theory of yardstick competition. By benchmarking payouts to the performance of other generators or a predetermined standard, these CfDs aim to mitigate the principal-agent problem by closely aligning the financial incentives of generators with desired market outcomes.

The two approaches mentioned above can address the incentive problem, but the key issue is that in both cases generators will be exposed to basis risk. This arises when there is a mismatch between the market price and reference price, or between actual output and the yardstick output used to calculate payments in CfDs.<sup>5</sup> Basis risk is a significant concern in financial theory, particularly in the context of hedging strategies.

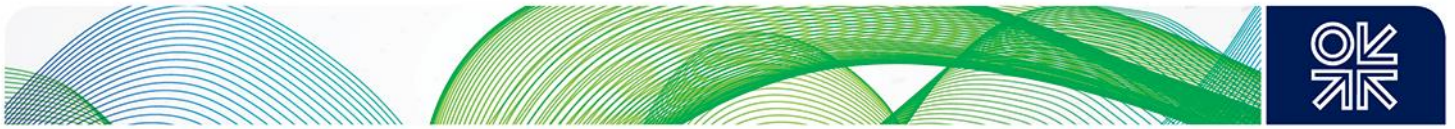
Furthermore, when it comes to Yardstick CfDs, further complexities may arise. First these schemes must be designed with an awareness of information asymmetry, where generators may have more detailed or timely information about their operational capabilities and local conditions than the CfD administrators. Effective design must therefore incorporate mechanisms to ensure that generators cannot exploit informational advantages to gain undue financial benefits. Second, in setting the benchmarks or yardsticks, careful consideration is needed to avoid adverse selection, where only those generators confident in outperforming the benchmark are likely to participate, potentially skewing the pool of participants.

The key point of this discussion is that incentivising efficient behaviour require risk exposure. This is a fundamental trade-off that CfD designer faces because the purpose of CfDs is to mitigate risks for renewable energy generators, while market efficiency relies on participants bearing some level of risk

---

<sup>5</sup> For example, in yardstick CfDs, if the forecasted output used to set benchmarks deviates significantly from actual market conditions or production levels, generators bear the financial risk of these discrepancies.





to incentivize optimal decision-making. Thus the key question is, if risk exposure is unavoidable to achieve market integration for CfDs, what are the consequences of that for various players, including generators, government, consumers and financial institutions?

From the perspective of generation, the basis risk can lead to financial volatility due to unpredictable revenue streams. For a renewable energy generator, whose operational costs and revenue models are predicated on stable financial returns, this volatility can make financial planning challenging and potentially jeopardise the economic viability of projects. The effect however is not uniform across technologies, locations, and companies.

From a strategic viewpoint for project developers, the introduction of basis risk might lead to a reevaluation of project locations, technology choices, and market engagement strategies. Decisions about where to build new capacity, which technologies to deploy, and how to interact with energy markets can be influenced by basis risk. For example, basis risk can be higher in regions with more localized price variations or grid congestion, as these factors can create discrepancies between the reference price and the actual price at the generator's location. Also project seeking CfD might favour technologies with more predictable output profiles over those with higher variability. Furthermore, if some generators are better equipped to manage basis risk (for example, those with larger portfolios or more sophisticated risk management tools), they may have a competitive advantage over smaller or less experienced developers. This may lead to a situation where larger, established developers with robust risk management capabilities might be more willing to embrace basis risk, while smaller players may favour more traditional support schemes (if available).

For government, the most direct impact of the introduced basis risk is the increased uncertainty in budget planning. With a wider range of potential outcomes due to basis risk, predicting the net cost of CfD payments becomes more challenging. In scenarios where reference prices are consistently lower than the strike price, the government might incur higher costs as it needs to make up the difference to ensure generators receive their guaranteed strike price. This can strain public finances, especially if a large portion of national energy production is covered under CfDs.

Indeed, strike price might increase in modified CfD auctions. This is because developers might adjust their bids to account for the expected basis risk. This could increase the cost of the scheme for the government but also potentially leading to less aggressive bidding and higher overall costs.

Policymakers face a delicate balancing act between promoting market integration and protecting public finances. The government needs to weigh the benefits of increased market responsiveness and flexibility against the potential costs of greater financial risk. Striking the right balance is crucial for ensuring the long-term sustainability and success of the CfD scheme.

From lenders' perspective there might be a need for more extensive due diligence to understand and mitigate the impacts of basis risk. This could involve more in-depth analysis of market dynamics, regulatory frameworks, and hedging options available to the project. The evaluation of creditworthiness for renewable projects may become more stringent. Banks might require more robust financial safeguards or higher equity commitments from project developers to mitigate the increased risk of revenue volatility due to basis risk. For some projects, lenders might charge higher interest rates to compensate for the additional risk posed by basis risk. This would increase the cost of capital for the project, affecting its overall financial feasibility.

Ultimately, much of the financial impact of managing basis risk can be passed on to consumers in the form of higher electricity rates or specific surcharges designed to stabilize renewable energy funding. Consumer support for renewable energy initiatives might be influenced by the perception of how well these systems are managed, including financial mechanisms like CfDs. If consumers perceive that CfD-related costs are leading to higher electricity prices, it could affect public support for further renewable energy policies.





## 5. Conclusions

The exploration of Contracts for Difference (CfDs) reveals their critical role in driving the renewable energy transition by providing revenue stability and encouraging investment in low-carbon technologies. Historically, CfDs have been successful, particularly in the UK, where they have significantly expanded renewable capacity and reduced costs, especially for offshore wind. However, the traditional two-sided CfD model, while stabilizing revenues, has inherent challenges including market distortions, inefficiencies, and encouraging a 'produce-and-forget' mentality among generators.

Conventional CfDs often fail to align generators' incentives with market signals, leading to overproduction and inefficient dispatch, especially during periods of low or negative market prices. This misalignment can exacerbate grid imbalances and increase system costs. In practice this means that the financial stability provided by CfDs comes at the cost of reduced responsiveness to market conditions, which is crucial for integrating higher shares of renewable energy.

The proposed reforms which decouple payout from actual generation offer promising avenues to enhance market integration and address the shortcomings of traditional models. However, these reforms introduce the basis risk, which poses financial challenges for generators and governments alike. The inherent trade-off between incentivising efficient behaviour through risk exposure and ensuring revenue stability for renewable energy projects underscores the complexity of CfD design.

Although the effect is unlikely to be uniform across generation technologies, regions and CfD types, generators, seeking predictable revenue streams, may be hesitant to embrace models that introduce basis risk. Governments, on the other hand, must balance the need for market efficiency with the financial implications of supporting renewable energy through CfDs. Financial institutions and specifically consumers also play a crucial role, as they ultimately bear the risks and costs associated with CfD mechanisms. Policymakers, therefore, must carefully navigate this trade-off, considering the diverse perspectives and interests of various stakeholders.



## References

- Clean Energy Wire Article, (2021). 'Germany eyes Contracts for Difference (CfDs) to boost renewable energy expansion', Clean Energy Wire
- Đukan, M. and Kitzing, L. (2021) 'The impact of auctions on financing conditions and cost of capital for wind energy projects', *Energy Policy*, 152, p. 112197. doi:10.1016/j.enpol.2021.112197.
- European Commission, (2023). Reform of the EU electricity market design., Online: [https://ec.europa.eu/commission/presscorner/detail/en/IP\\_23\\_1591](https://ec.europa.eu/commission/presscorner/detail/en/IP_23_1591), 14 March 2023
- European Commission (2022). Guidelines on State aid for climate, environmental protection and energy 2022. European Commission Document. COMMUNICATION FROM THE COMMISSION. (2022/C 80/01).
- Kell, N.P., Santibanez-Borda, E., Morstyn, T., Lazakis, I., Pillai, A.C., (2023). 'Methodology to prepare for UK's offshore wind Contract for Difference auctions'. *Applied Energy* 336, 120844.
- Kitzing, L., Held, A., Gephart, M., Wagner, F., Anatolitis, V., and Klessmann, C., 2024. Contracts-for-Difference to support renewable energy technologies: Considerations for design and implementation. Research Report RSC/FSR March 2024, European University Institute.
- Müsgens, F., Riepin, I., (2018). 'Is offshore already competitive? Analyzing German offshore wind auctions', in: 2018 15th International Conference on the European Energy Market (EEM). 1–6.
- Newbery, D., (2023). 'Efficient renewable electricity support: Designing an incentive-compatible support scheme'. *The Energy Journal* 44.
- Simshauser, P. (2019). On the Stability of Energy-Only Markets with Government-Initiated Contracts-for-Differences. *Energies*. <https://doi.org/10.3390/EN12132566>.
- Schlecht, I., Maurer, C., Hirth, L., 2023. Financial Contracts for Differences. ZBW - Leibniz Information Centre for Economics, Kiel, Hamburg. [https://www.econstor.eu/bitstream/10419/268370/1/Financial\\_CfD.pdf](https://www.econstor.eu/bitstream/10419/268370/1/Financial_CfD.pdf)
- Schlecht, I., Maurer, C., Hirth, L., (2024). 'Financial contracts for differences: The problems with conventional CfDs in electricity markets and how forward contracts can help solve them'. *Energy Policy* 186, 113981. <https://doi.org/10.1016/J.ENPOL.2024.113981>
- Welisch, M., & Poudineh, R. (2019). Auctions for allocation of offshore wind contracts for difference in the UK. *Renewable Energy*. <https://doi.org/10.1016/J.RENENE.2019.09.085>.

