Schlecht, Ingmar; Maurer, Christoph; Hirth, Lion

Working Paper

Financial Contracts for Differences

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The problems of conventional CfDs in electricity markets and how forward contracts can help solve them

Ingmar Schlecht[a,b], Christoph Maurer[c], Lion Hirth[a,d]

[a] Neon Neue Energieökonomik GmbH, Berlin, Germany
[b] ZHAW Winterthur, School of Management and Law, Winterthur, Switzerland
[c] Consentec GmbH, Aachen, Germany
[d] Hertie School, Berlin, Germany

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Abstract **–** Contracts for differences are widely discussed as a cornerstone of Europe's future electricity market design. This is a paper on CfD contract design. We summarize the dispatch and investment distortions that conventional CfDs cause, the patches that are used to overcome these shortcomings, and the problems these fixes introduce. We then propose an alternative contract that we dub "financial" CfD. It is a hybrid between conventional CfDs and forward contracts that mitigates revenue risk to a very large degree while providing undistorted incentives and avoiding margin calls. Like traditional CfDs, these contracts are long-term and tailored to technology-specific (wind, solar, nuclear) generation patterns but, like forwards, decouple payments from actual generation. We also propose to mitigate volume risk and to accept physical assets as collateral to avoid margin calls.

1. Introduction

Contracts-for-differences. In the ongoing debates on reforming the electricity market design in Europe, contracts for differences (CfDs) are in the center of discussions. Many commentators have suggested that CfDs should become a cornerstone of the EU's future electricity market. CfDs are financial contracts that specify payments from a buyer to a seller if the price of an underlying is below the agreed-upon strike price and a reverse payment otherwise. CfDs are financial derivatives used in many foreign exchange, security and commodity markets, along with other derivatives such as forwards, futures, options and swaps. Like these other derivatives, CfDs are usually traded between commercial entities.

Electricity CfDs. In electricity markets, commercial contracts for difference exist, e.g. to trade the price spread between two bidding zones; also financial futures and forward contracts are essentially "contracts for differences". However, the term is usually used to refer to long-term contracts between an electricity generator and a government ("public CfDs"); this is also how the European Commission uses the term. Such CfDs use the hour-by-hour day-ahead spot price as the underlying. The payment is calculated as the spread between strike and spot price, multiplied with the electricity produced by a specific asset, such as a wind park. This "weighting" of price spreads with fluctuating volumes sets electricity CfDs apart from those used in security and commodity markets, but also from electricity future contracts. It also makes these contracts more complicated than many realize.

Goals. The goal of public CfDs is to increase long-term price stability both for producers and for consumers, intermediated by the state. With price risk mitigated, generation investors have lower cost of capital and hence lower levelized energy costs. In Europe the use of CfDs became widespread with the UK electricity market reform of 2014.

CfDs as support schemes. CfDs are maybe best understood not as a part of the design of the electricity market, but as a support scheme for renewable (and sometimes nuclear) energy, very much like other support policies including feed-in-tariffs, feed-in-premiums, and renewable portfolio standards. Compared to these alternatives, CfDs have several benefits, which is the reason their use has increased across Europe in recent years. The fact that they, unlike many other support schemes, generate public income in times of high electricity prices has made them attractive to policymakers since the onset of the energy crisis. In the current reform debate, CfDs are increasingly discussed as electricity market design rather than as a support policy, the likely reason is more legal than economic: support schemes constitute state aid and need to be notified with the European Commission. If CfDs are declared a component of electricity market design, EU member states could implement them more freely.

Problems. In this paper, we identify three problems that arise from CfDs as they are used in electricity markets. First, CfDs provide "produce-and-forget" incentives in the sense that they mute electricity price variation: generators have no benefit of producing electricity when it is needed most. Second, they distort short-term intraday and balancing markets. Finally, while they mitigate price risks, they do not reduce volume risks. To address some of these shortcomings, first-generation CfDs have been modified, e.g. by replacing the hour-by-hour spot price with a monthly average price. These tweaks have brought new problems which triggered additional modifications.

Financial CfD. To address these problems more fundamentally, we propose a new type of contract that we dub "financial CfD". It combines properties from three different kind of contracts: CfDs, financial forward and futures contracts, and mortgages. Forwards and futures have been used for many years by conventional power generators to hedge their positions and mitigate price risk. The core innovation of our proposal is to decouple payments from the physical production of an individual asset. The financial CfD comprises of two hourly payments, a fixed payment from the government to the generator. In turn, the generator pays spot market revenues to the government. These are not, however, the actual revenues, but benchmark (or yardstick) revenues that are independent from the actual generator's dispatch. For wind energy, the benchmark revenues could be derived from a reference turbine, weather models, or the average generation of a country's fleet of turbines. (This is why we call the contract a "financial CfD", despite the fact that any CfD is a financial contract.) To avoid margin calls, we propose to use the physical generation asset as collateral, like a mortgage.

Benefits. Compared to traditional CfDs, the proposed financial CfDs have the benefits of mitigating volume risks (and thus reduce risk premia further) and avoiding distortive effects. Compared to futures/forwards, the instrument has the benefits of reducing basis risk through a better profile, avoiding margin calls, and longer maturities. This working paper presents preliminary thoughts; it should not be read as a comprehensive assessment or a policy proposal ready for overnight implementation.

How / if. This paper is not a "pro CfD" piece, it discusses instrument design: *how* should long-term contracts between generators and governments be designed to avoid distortions? It does not address the bigger question *if* governments should engage in long-term contracts in the first place, or if such contracts are better left to private firms and markets. This is a complicated question that involves fundamental trade-offs and this paper should not be understood as a recommendation of public long-term contracts. In other words, we do not discuss if governments should mitigate investor risk, but outline how, if they wish, they can do so in a way that avoids distortions. Thoughts presented here on instrument design could even be valuable for commercial contracts – a financial CfD could also be signed between a generator and an industrial consumer.

Voluntary. Independent of their design, we believe public contracts should be an option, not an obligation. Others have suggested to introduce mandatory CfDs (Greece in 2022; Spain and France in 2023) or to punish generators who are not signing CfDs by capping their revenues (Fabra, 2022). Making public contracts (of any kind) mandatory essentially means banning merchant investments. It would have adverse effects on investments and would reduce, rather than foster, investment and renewables deployment.

Downstream side. If the government engages in long-term contracts with electricity generators – financial CfDs, conventional CfDs, or feed-in-tariffs – it essentially takes a financial position. The profit or loss from this position are passed on to taxpayers or electricity consumers (see Figure 1). The way the financial obligation is passed through will have important consequences for price risk mitigation of consumers, but also incentives for demand-side flexibility and energy savings. In this paper, we focus on the contract between generator and government but briefly comment on the "downstream" side of public long-term contracts.

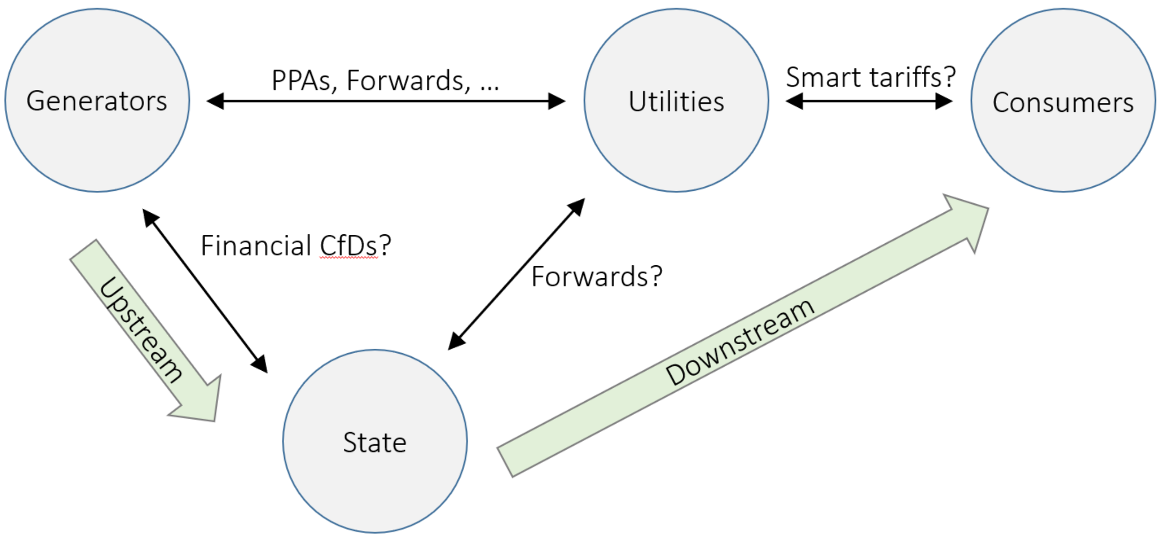

Figure 1: Possible long-term contractual relationships.

Newbery. A recent and timely paper by David Newbery (2023) discusses CfD design with a focus on avoiding the distortive incentives of conventional CfDs. His conclusions are similar to ours, yet he puts a greater emphasis on locational incentives arising from different specifications. He proposes what he calls a "yardstick CfD", which also decouple CfDs payments from an asset's production. However, the details of the proposed contract differ in significant ways from our proposal: the yardstick CfD relies on site-specific production forecasts, similar to a recent proposal by Elia Group (2022, unpublished, discussed in section 3.3), reducing incentives to increase the value of electricity through technology and siting choices. Also, the yardstick CfDs only addresses price risk, unlike our proposal which also addresses the weather-related volume risks faced by wind and solar plants. But the fundamental idea of decoupling payments from actual production we share with both Elia Group (2022) and Newbery (2023).

2. Objectives of CfD Design

The main reason for introducing CfDs is to provide financial stability for both contractual parties, i. e. generators and governments.

De-risking low-carbon investments. Renewable and nuclear plants are most relevant for the decarbonization of the electricity system. But these technologies are capital intensive: they come with high investment costs and low or almost zero variable cost. As a consequence, following the initial investment only minor parts of the total cost of those plants can be controlled by owners. At the same time, they will remain fully exposed to revenue risks from electricity price development and, in case of variable renewable plants, meteorological conditions (volume risk). The reason why the long-term electricity price development is a difficult risk to take for investors is that long-term prices are driven to a large extent by energy policy decisions, from hydrogen support schemes to technology phaseout incentives. While this holds true for all kinds of power plants, there are nevertheless important differences between renewable/nuclear and non-nuclear thermal power plants. For the latter, variable costs are not only much more relevant, but may also determine electricity prices, often resulting in a correlation of costs and revenues. In addition, being exposed to revenue risks can trigger efficient decisions like reduction of generation, fuel switches, temporary mothballing or even decommissioning. For renewable and nuclear plants, instead, once plants are built, being exposed to revenue risks from long-term price development and variations in meteorological conditions will typically not result in better decision making. De-risking such investments, provided that they are desirable in a first place, leads to lower capital costs and thus makes them cheaper. From a risk perspective a one-off payment at the time of investment would be best. A stable and guaranteed (i. e. with negligible counterparty risk) revenue stream over longer periods would be a close second, though.

Fiscal means to protect consumers. Whilst Europe's energy crisis showed no evidence of market failures in short-term markets, it can be reasonably argued that insufficient hedging by consumers (or the lack of possibilities thereof) exacerbated the consequences of the crisis, thus firing market interventions. Governments urged to support vulnerable consumers, but being themselves subject to fiscal constraints, also introduced revenue caps for generators to, at least partially, recover costs for subsidies and support measures. It cannot be discussed in detail here whether governments should engage in direct compensation of high electricity prices for consumers instead of providing favorable conditions for private hedging (like liquid long-term markets and intelligent design of retail tariffs). But being hedged against electricity price developments by long-term contracts would allow governments to support vulnerable consumers during high price periods and provide a stable revenue stream to renewable/nuclear generators with a relatively stable total level of expenditures. This could help to overcome fiscal concerns and would allow them to refrain from short-term market interventions which might have detrimental effects on the long run.

Efficient incentives. Whereas limiting risk exposure with regard to non-controllable factors might be most relevant from generators' perspective, CfDs should at the same time be duly designed not to distort any decisions by plant operators which can be relevant for efficient design and operation of a plant. This refers to decisions during the investment stage as well as the operational stage.

- **Optimal utilization (operational stage).** CfDs should incentivize plant owners to utilize their asset efficiently (i.e., system-friendly). The incentive should be to always produce when the price is above, and never when the price is below short-term variable costs. This should not only hold on day-ahead stage, but also in real time. Plant owners should make the efficient choice, driven by price signals, between selling at different markets (day-ahead, intraday, balancing). Also, power plant owners should be incentivized to schedule maintenance of power plants according to price signals, so that they try to avoid maintenance during periods of high prices and schedule them to lower-price periods instead.
- **Optimal design and siting (investment stage)**. Investors should be incentivized to design plants so that they optimize the generation profile of the plant, balancing the investment costs of system-friendly design choices with their lifetime benefits. Hourly electricity prices are not only useful to guide the utilization of assets, but also transport a rich set of information about the investments needed from a system perspective
- **Optimal retrofit and repowering (re-investment stage).** Throughout the lifetime of the asset, plant owners should face the efficient level of retrofit, maintenance investment and repowering incentives. The strengths of such re-investment signals should correspond to longer term price levels, so that the incentive for output-maximizing retrofits is stronger during high-price scarcity times compared to low-price oversupply periods.

Price signals remain relevant. These considerations show that price signals are highly relevant to guide efficient decision-making also for renewable and nuclear plant operators. With efficiently designed short-term markets, prices will reflect the power system's needs. Hence, if the price signal is not muted for investors, they are incentivized to make system optimal choices rather than simply maximizing total output. A well-designed long-term contract should therefore reduce/eliminate exposure towards non-controllable risks like long-term price developments and, in case of variable renewables, volume risks, but preserve price signals to incentivize decision-making aligned with system needs.

3. Contracts for difference to date

In this section, we define traditional CfDs, outline the problems they bring, and discuss how contract design has evolved to address these very problems. We conclude with a comparison of CfDs to forward contracts.

3.1. The conventional CfD

Conventional CfD. There are many ways contracts for differences are specified in electricity markets. We discuss more advanced types in Section 3.3 below but first discuss a basic "plain vanilla" specification that we use as a point of reference. In the simplest contract, which we refer to as the "conventional CfD" and which resembles the contracts introduced in the UK in 2014, it is specified as follows:

- the strike price is fixed,
- the underlying is the hourly day-ahead spot price,
- the CfD is linked to a specific physical asset, and
- volumes are "as produced" in every hour.

The hour-by-hour payment obligation is calculated as

$$\text{Payment}_t = (\text{strike price} - \text{spot price}_t) \times \text{produced volume}_t$$

If the strike price exceeds the spot price, governments make a payment to generators, and vice versa. The fact that it is physical production that determines the payments is the reason these CfDs are also called "injection-based". Figure 2 shows the spot price during five hours. The payment in each hour is calculated as the price difference (arrows) multiplied with the production (width of the boxes). While this results in stable prices, revenues remain uncertain because of the fluctuation in production.

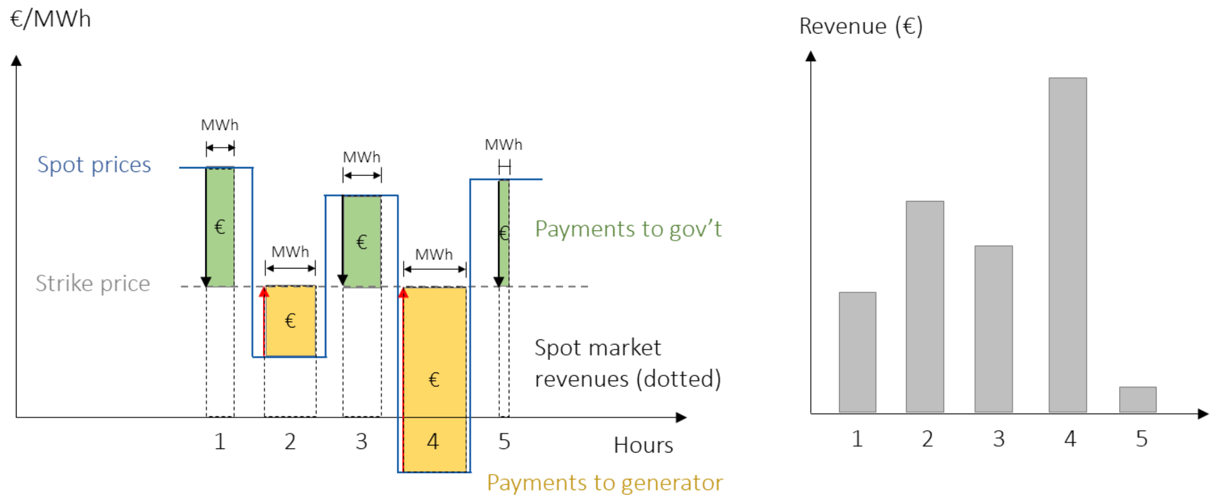

Figure 2: Payments (left) and revenues (right) under the conventional CfD.

Asset-specificity. While the conventional CfD is in some ways similar to a financial derivative such as a futures or a forward contract, the fact that it is linked to a specific asset makes it different. Not only does this make it impossible to trade CfDs on secondary markets (without selling the asset, too), but more importantly it entails that CfDs provide incentives to adjust the dispatch of the asset in order to affect payments.

3.2. Problems with the conventional CfD

Three problems. The conventional CfD design comes with three problems: produce-and-forget incentives, distortion on intraday and balancing markets, and the fact that volume risks remain unhedged. We discuss each in turn.

Produce-and-forget. The conventional CfD provides a simple incentive to the generator: maximize production. Because the revenues across all hours of production equal the strike price, there is no incentive for the generator to increase output at times of high prices (scarcity), to schedule maintenance at periods of low demand, to reduce output at times of low/negative prices (abundance), or to invest in power plants that reap above-average market prices (flexible or system-friendly plants). This has a range of adverse consequences:

- *Investment choices*. When selling to the spot market, wind and solar investors can maximize their revenues by investing into what is sometimes called "system-friendly renewables": wind turbines with higher towers and larger rotors that produce electricity more continuously; tracking solar panels with higher capacity factors; or west-facing solar that contribute more to high demand during late afternoons. The conventional CfD provides no incentives for such system-friendly plant design. For hydroelectric and thermal power plants, the incentive to simply maximize production results in plants being optimized for base load operations and a lack of flexibility including load-following capabilities, ramp rates, and part-load efficiency.

- *Retrofit and repowering choices.* Investments are not only one-off decisions. Maintenance, retrofit, and repowering investments are decided on during an asset's lifetime. Conventional CfDs often distort such choices, because they mute the electricity price, the core scarcity signal of power markets. This means that under such contracts, in an energy crisis, where every kWh matters, too little would be invested into maintenance and retrofitting, and in an electricity glut too much, just to cling on to an old contract. The same applies for repowering of wind turbines, i.e. replacing older, less productive wind turbines with larger, new ones. Since an existing CfD ends with the life of the asset, an old wind turbine might not be replaced by a newer, more productive one just to keep the payments of the old contract.
- *Maintenance scheduling*. Under the conventional CfD, generators have no incentive to schedule maintenance at times of low demand. Nuclear power generators may instead schedule maintenance when engineering teams are cheapest, which is often in the winter. Intermittent renewables, where imbalance settlement costs are correlated with spot prices, have an incentive to schedule maintenance in the hours with the highest spot prices to avoid high imbalance costs – which is the opposite of what they should do.
- *Dispatch*. Under the conventional CfDs, generators have no incentives to increase production in high-price hours or decrease it periods where prices are below their production costs. Wind, solar and nuclear plants should curtail output whenever prices drop below their variable costs, but under the conventional CfD they keep producing – even when prices turn negative. This distortion is even more damaging for technologies with higher variable costs and/or if these costs change over time. This includes all fossil, hydrogen, reservoir hydroelectricity and storage plants, for which the conventional CfD is particularly ill-suited. These flexible generators must follow prices, they need to be dispatched according to the demand and supply balance. Providing an incentive to continuously generate electricity would obliterate their economic value as a flexible asset. Such distortions tend to become more damaging if larger volumes of the market are covered by CfDs.

Problematic fixes. Some (but not all) of the "produce-and-forget" issues of the conventional CfD are fixed in more advanced CfD specifications that have been proposed or implemented by European countries in recent years, in particular monthly reference periods, as we discuss in Section 3.3. However, these resolve only part of the misaligned incentives, reduce the quality of the hedge, and come with their own problems.

Intraday / balancing distortion. A second problem is the distortion on intraday and balancing markets. The conventional CfD uses the hour-by-hour day-ahead price as the underlying. After that auction has cleared, the price of the hourly CfD payment is fixed and known to the generator. From this moment on, it constitutes an opportunity cost and will be priced in, just as any other variable cost component. This has implications for the subsequent market stages, the intraday and balancing markets. The effect has different directions in high-price and low-price hours:

- If, say, the strike price is 80 €/MWh and the day-ahead price was 200 €/MWh, generators must pay 120 €/MWh for every MWh they produce in that hour. If the intraday or imbalance price drops to 119 €/MWh, it is rational for the generator to curtail output to avoid the payment. This implies the waste of low-cost (and low-carbon) energy, an upward pressure on intraday prices, which arbitrage trading will transmit back to day-ahead prices.
- The opposite effect occurs in low-price hours, when governments pay generators. In such hours, plant owners deduct the payment from their optimal intraday bids, which means they inefficiently bid into intraday markets below their own variable costs. CfDs hence put downward pressure on prices that had been low anyway.

Possible fixes. There are two ways to address this issues, one of which is used in practice, according to our knowledge. First, you could anchor the payment on volumes other than the physical production, something we propose below. Alternatively, you could use real-time balancing prices as underlying, rather than day-ahead prices. This would, however, make generators dump all production into the system imbalance, which would compromise operational system security.

Volume risk unhedged. A third shortcoming of conventional CfDs is that they do not fully mitigate revenue risk. This is because they leave generators fully exposed to volume risk, e.g. the variation of wind speeds between years. To make things worse, they even delete a natural hedge that is otherwise implicit in power markets: When selling to spot markets the negative correlation between prices and wind availability mitigates the volume risk – years with little wind output tend to have higher prices. In a CfD context, a low-wind year comes with particularly low revenues, because the lower volume is no longer balanced out by above-average prices. An more complete hedge would account for volume risk, too.

3.3. Tweaks of the conventional CfD

Tweaks. We are not the first to observe these problems. Therefore, some existing and proposed CfD designs aim at tweaking the contracts such that some of these problems are addressed. However, most of these tweaks themselves introduce new problems, some of which are fixed in follow-up fixes. Table 1 below outlines various fixes and their problems solved and introduced.

No support payments at negative prices. Some support schemes address the problem of incentives for generators to produce even at electricity price levels below their variable cost at least for situations with negative prices. This is achieved by setting CfD payments to 0 €/MWh for electricity produced during negative price periods. Although eliminating the incentive to produce during such periods, this fix also comes at a cost. In particular, it creates significant revenue uncertainties for generators. Their lifetime revenues will to a large extent depend on the frequency of negative prices, a factor beyond their control. To mitigate this risk, in some countries the fix is only applied if negative price periods prevail for several hours. In Germany, the minimum length of the negative price period was set to 6 hours first, later reduced to four hours and will be reduced to one hour from 2027 onwards. But again, there is a downside. Such rules create a bidding uncertainty as generators will have to guess the occurrence of negative prices and the length of negative price periods already at bidding stage and guessing wrong can turnout costly.

Longer reference period. Some of the CfDs applied in practice use a different underlying. Instead of the hourly spot price they use a reference price. The reference price is usually the monthly or yearly weighted or unweighted average spot prices, e.g. the average capture price of a wider set of wind turbines. This is for example done in the German market premium (a one-sided downside-cap CfD) or in the Danish hybrid CfD. The period along which prices are averaged is often called a “reference period”. The payment is then calculated as follows.

$$\text{Payment}_t = (\text{strike price} - \textit{reference price}_{year}) \text{ x produced volume}_t$$

By calculating the CfD payment based on longer reference periods, intra-period price differences are no longer muted for the generator and create incentives again. Therefore, dispatch and maintenance incentives within these periods are optimized to capture the highest prices again and design choices at investment are done with a view to producing at the highest priced hours within the reference periods. While yearly reference periods also provide seasonal incentives, monthly reference periods do not, as reference periods only provide incentives to optimize production timing within but not across the periods.

Day-ahead distortion as a result. Longer reference periods introduce new problems, however. The most important new problem introduced is that bids on the day-ahead market are distorted. This is because the CfD payment can be forecasted with reasonable accuracy at the day-ahead stage, and it is mostly independent of the day-ahead price. Consequently, generators optimize their bidding behavior against the CfD payment. If they know they will have to pay 30 €/MWh due to a CfD in a clawback (high price) period, they will no longer produce at spot prices below that threshold. Likewise, if generators know they will get a CfD payment of 30 €/MWh during a support (low price) period, they will produce even if spot prices are below variable costs by less than 30 €/MWh, because the CfD payment would compensate operating losses. These incentives are distortive and decrease overall welfare. They also lead to shifts in the merit order where low-carbon generators not producing (despite prices being above their variable costs) while fossil generators might continue to produce.

Suspending distortive payments. To avoid such distortive dispatch incentives, more advanced CfD designs such as the Danish hybrid CfD (on which the Thor offshore wind farm tender's support scheme is based) introduce further fixes. Here, CfD clawback is limited to just below the spot price. This ensures incentive compatibility in the day-ahead market. This incentive fix, however, results in discontinuities in the resulting merit-order on the intraday market, because whether support payments are made depends on the day-ahead price surpassing the zero threshold, which could cause unintended dispatch consequences on intraday markets.

Capability-based CfDs. A different approach is taken by capability-based CfDs, an idea put forward by ENTSO-E (2023, forthcoming). It suggests to decouple payments from an asset's production and instead relying on the asset's potential to produce, its capability:

$$\text{Payment}_t = (\text{strike price} - \text{spot price}_t) \times \textit{production potential}_t$$

This removes the dispatch inefficiencies with respect to intraday and balancing markets. In decoupling payments from an asset's production, it shares features with the financial CfD that we introduce in section 4. As the approach, however, continues to rely on an individual asset's production potential, it still mutes the price signal on the investment and re-investment time horizon. Also, relying entirely on the production potential for CfD payment calculation assigns a high commercial relevance to the production potential calculation model, which might be difficult to objectively establish. While such production potential estimates have been used in the past for the calculation of remuneration in case of downward redispatch, relying on them entirely for CfD payments even under normal circumstances significantly increases the stakes and the incentive for manipulation. Unlike the other tweaks, the production potential approach, however, addresses the root of the dispatch distortions, the link between payments and the production of the asset.

Remaining problems. None of the existing tweaks to CfDs addresses all problems of the conventional CfD. While none of the tweaks addresses the volume risk and the inefficient retrofit and repowering choices, they differ in which other risks they address and do not address. Even the most sophisticated tweaks for production based CfD, relating to longer reference periods and negative price periods, solve system-friendliness incentives but, for fundamental reasons, fail to address the intraday and balancing distortion. In addition, as a consequence of the incentive compatibility fixes introduced, generators are no longer fully hedged against the price level, and forecasts regarding how often the triggers for the respective incentive fixes will be met have to be made at the investment stage. Thus, increasing incentive compatibility runs against the primary objective of CfD to minimize investment risks. These are significant shortcomings remaining (see Table 1).

Table 1: Tweaks relative to the conventional CfD, problems addressed, and new problems introduced.

Tweak	Problems addressed	New problems introduced
No support payments if negative prices prevail for several hours	Non-curtailment at negative prices	Bidding uncertainty: negative prices need to be anticipated at the bidding stage already. Revenue uncertainty: Lifetime revenues depend on the frequency of negative prices.
Longer reference period	System-friendliness incentives Intra-reference period maintenance scheduling	Day-ahead-distortion
Suspending distortive payments: clawback limited to just below the spot price.	Curtailment at low prices during clawback	Revenue uncertainty: Lifetime revenues depend on the frequency of low prices.
Capability-based CfDs – Using potential to produce, rather than actual production, to calculate difference payments.	Intraday & balancing distortions	Difficulty of objective production potential data for individual assets, danger of manipulation.

3.4. Forward contracts

Forward contracts. Financial forward and futures contracts have been a core feature of electricity markets for many years. Utilities use them on large scale to hedge price risks. While they carry a different name, financial forwards are also contracts for differences. They are contracts for differences for a specified amount of energy during a specified settlement period. The same holds for futures contracts, the exchange-traded equivalent to the over the counter-traded forward contracts.

Asset-independence. The most fundamental difference between the conventional CfD and forwards / futures is that the latter are asset-independent: payments are due regardless of any individual asset's production. In other words, they are financial derivatives. Asset-independence has the crucial advantage that – while fulfilling its purpose to provide long-term financial stability for both counterparties – they do not distort investment and operation decisions. Both counterparties continue to react to the power market's short-term scarcity as they remain exposed to spot price incentives, while at the same time being financially hedged. This is more important than ever in a system composed of variable renewables which create many new short-term dynamics factoring into price patterns and new types of assets (from battery storages to heat pumps) to both benefit from and mitigate such price volatility.

Shortcomings. Forward and futures contracts have three major shortcomings limiting their use as an instrument to provide investment stability for low-carbon generators.

- **Liquidity and horizon**. In most markets, commercial forwards are only traded for a relatively short time horizon of 1-3 years – insufficient to hedge investment risk of assets with a lifetime of decades.

- **Products and profile.** Existing futures products (such as "base" or "peak" contracts) do not match typical wind/solar generation profiles. Thus, they are a poor hedge for wind and solar generators; significant basis risk remains.

- **Margining.** Futures require margin payments to be deposited, which can become very large in times of large price changes. This is a problem for liquidity-constrained generation firms in offering their production on futures markets especially in periods of volatile market prices.

Addressing the shortcomings of existing futures contracts. Below, we present an idea that addresses these shortcomings. It does so by combining features of financial forwards with CfDs.

4. Financial CfD

In this section we introduce and discuss a new contract design and compare it to existing CfDs.

4.1. The instrument

A novel contract. In the following, we introduce a novel instrument we call "financial CfD". It is meant to avoid dispatch, investment, and repowering decisions, while mitigating revenue risks that power plant investors face. The essential difference to conventional CfDs is that the contract is financial rather than asset-dependent. That means, payments are independent from the asset's production. As a second and independent innovation, we suggest to hedge not only price risk, but also volume risk. Essentially, the instrument is designed around two objectives:

- Hedging revenue risk (both price and volume risk)
- Full price structure exposure (for efficient dispatch, investment, and repowering incentives)

The instrument in short. The contract comprises of two payments between the government and a power generator, say a wind farm. The government provides a fixed hourly payment to the generator. In turn, the generator pays the government the hourly spot market revenues (in the case of wind and solar). These revenues are not, however, the actual revenues of any given asset, but benchmark (yardstick) revenues calculated from a reference generator. In the case of technologies with variable costs greater than zero (e.g. nuclear), benchmark hourly profits are paid back instead. We will elaborate on the details in turn.

Procurement auction. The government sets up an auction to procure financial contracts called "financial CfDs". The auction volume, i.e. how many such contracts are procured, can either be set ex-ante, or a demand curve for the auction can be set. A demand curve reduces market power and would lead to the government buying more such contracts if there is plenty of supply at low prices and less if there is only few supply at high prices.

Contract size. The contract size is standardized for a 1 MW reference generator. The contract is a homogenous product because it does not depend on an individual asset's production. Generators can freely choose the desired contract size, subject to collateral requirements.

Contract duration. Contracts run for a long time, roughly reflecting the technical lifetime of power generators, say 20 years for wind and solar energy.

Payments. For each hour, a payment between the government and the contracting generator is made. The hourly net payment is the difference between:

1. **Payment to generator**: The government pays a fixed hourly remuneration to the counterparty, independent of production or prices. The level of the hourly remuneration is determined

competitively in the initial procurement auction but then does not change during the lifetime of the contract. It could be inflation-indexed.

2. **Payment to the government**: The generator pays the hourly profits (contribution margin) of a reference generator to the government. These benchmark profits are defined as the day-ahead spot price minus benchmark costs (if the difference is positive, otherwise zero) multiplied with the hourly output of a reference generator. For wind and solar, which have essentially zero production costs, profits equal revenues. The reference generator is discussed in more detail below. Importantly, it is *not* the hourly output of the specific asset that is serving as collateral to the contract. This second payment is essentially a one-sided upside-cap CfD (also called financial call option) with a strike price of benchmark costs (zero in the case of wind and solar). Figure 3 illustrates both payments (left) and the resulting revenue stream (right).

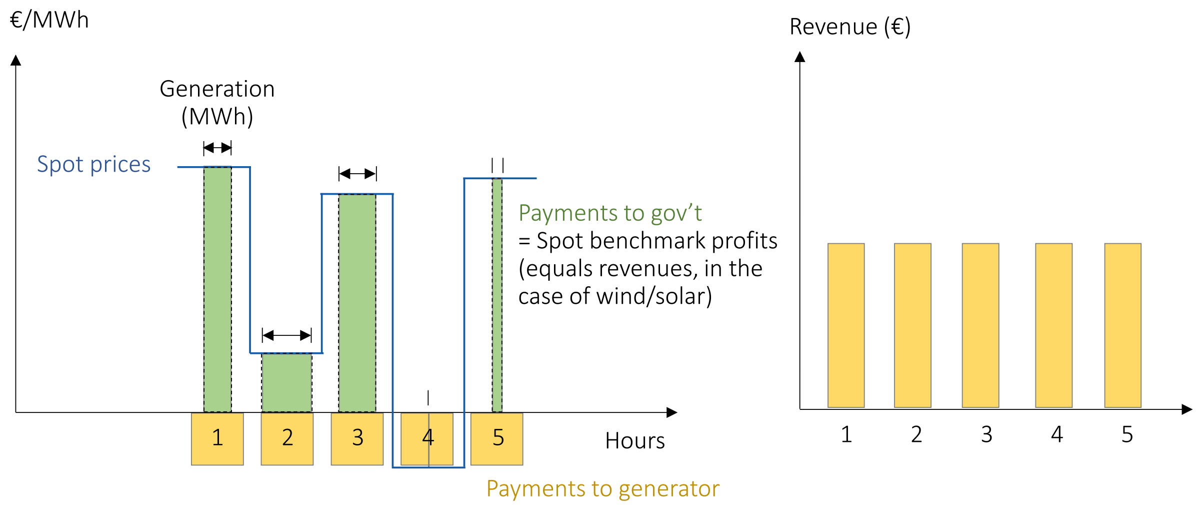

Figure 3: Revenue stream in a financial CfD for a wind or solar park (with benchmark costs of zero). Generators get a fixed hourly payment (yellow) but must pay the revenues of a reference generator (green) to the government.

Production cost. For technologies with very low generation costs, including wind and solar energy, a cost of zero is assumed. The payment to the government hence is the entire benchmark revenue. For technologies with very stable generation costs, such as nuclear power, a constant strike price could be determined ex ante in the contract, say 10 €/MWh. For other technologies, variable and opportunity cost would need to be estimated and frequently adjusted, which means the financial CfD would be ill-suited.

Net payments. In hours of high prices and/or high wind speeds, there will be a net payment from the wind farm to the government. In times of low prices and/or little wind, there will be a net payment from the government to the wind farm. By being a hedge for both the price and weather risk, the instrument helps to stabilize the generator's total revenue. Depending on the evolution of spot prices during the duration of the contract, the net present value of the contract could be positive or negative for the investor. Even if the *expected* NPV is negative ex-ante, the contract might be beneficial for investor to sign because if the value risk hedging has to them.

Parameters. Two key parameters of the instrument merit further discussion: the reference generator and the collateral.

4.2. Reference generator

Reference generator. The reference generator essentially is a method to determine an hour-by-hour generation profile that matches the production of contracted assets closely, without being the actual output of the contract party. By separating payment obligations from physical production, the distortive incentives are avoided that come with asset-pegged CfDs. At the same time, it should be highly correlated to the individual asset, so it serves as a good proxy hedge and leaves little remaining basis risk. The choice of this reference generator methodology and its hourly profile is a key parameter in the financial CfD. The closer the individual asset's own production is to the reference, the better the hedge. The only remaining source of revenue risk is the basis risk originating from the reference production profile vs. the asset's own production profile.

Wind/solar. We can think of at least five different approaches, three for wind/solar and two for dispatchable plants:

- A mathematical model that derives reference output from weather data. Measured, regionally aggregated weather data could be used that is representative for the asset pool that is contracted. A similar approach was followed by energy exchange EEX when a "wind future" was introduced (now discontinued). Certainly, averaging a larger region's weather means it will not be a perfect hedge for any specific turbine, but could be a good enough hedge for many plants. Using weather data as a basis has the advantage of being independent from any individual power plant's (possibly strategic) utilization decisions but given that large money flows would depend on weather measurement then, it also poses a risk if weather measurement techniques change over time or if strategic actors try influencing weather models.

- A sample of actual physical wind / solar farms could be used. However, there would be a financial incentive to manipulate the dispatch of these reference plants, especially if the sample is small.

- A third possibility would be to use the aggregate wind / solar generation of a country or bidding zone as a reference. This would be comparable to the German concept of market value used in existing support schemes, although it would need to be defined on capacity basis (EUR of revenue per MW) rather than energy basis (EUR/MWh). For large bidding zone, the possibility to game the reference are quite limited; but that is not the case for small zones with few large generators, say offshore bidding zones.

Nuclear. For dispatchable generators, simpler references seem feasible.

- A base profile where all hours are weighted equally. The financial CfD then essentially would become a conventional financial forward contract with a very long lifetime.

- System load could be used as a profile.

Technology-neutral. One could also use base profiles for wind and solar energy. Such a technology-neutral CfDs has several benefits, including the fact that it introduces cross-technology competition, that it aligns well with existing forwards/futures and that it is much simpler to define. But a base profile comes at the expense of more significant basis (profile/shaping) risk for renewable investors.

A spectrum of options. For wind and solar, different choices of the reference generator could be placed on a spectrum, with the capability-based CfD on one end and a base profile on the other. Capability-based CfDs have very little basis risk remaining, because the profile matches potential output of the turbine very closely. This comes at the cost of having turbine-specific contracts and hence no homogenous product, and the cost of lacking any siting/technology incentives for system-friendly turbines.

4.3. Collateral

Collateral. The government should require collateral to back up the financial CfD contracts. Financial futures require cash or other liquid securities as collateral, which might trigger margin calls. In particular in times of fierce price movements and high volatility – the very crisis scenarios hedges are meant to protect against – margin calls can be dangerously large. It is an important lesson from the 2022 energy crisis that margin calls can quickly deplete even the deepest pockets, let alone those of cash-constrained project developers and smaller investors. We therefore suggest that the government could accept physical generation assets as collateral. In fact, the collateral requirement would be the only relation between the financial contract and a physical asset.

Financial collateral as an option. Accepting financial collateral as an alternative could also be considered. Should the generator wish to dismantle or repower its asset, it should be able to exchange the initial turbine that was put down as collateral for financial collateral or to transfer the contract to a new, repowered asset, while ensuring the new asset is not "overbooked".

De-rating. A possibility would be to introduce certain de-rating factors, so that e.g. a wind plant can only be counted as collateral for max. 90 percent of expected output. This ensures plant owners have enough cash in case their plant produces less than the reference plant and to pay for imbalance costs even in high price periods, despite imbalance costs being correlated to the spot price.

Incentives. Regulators should be careful in defining these collateral requirements because collateral requirements could yield incentives (during plant design and specification) to maximize the variables which the collateral requirements ask for. If the contract is profitable for investors and collateral requirements only regarded nominal capacity and ignored site-specific wind availability and potential full-load hours, they would incentivize turbine designs that maximize nominal capacity at the expense of lower full-load hours, only to be eligible as collateral for larger contract sizes of the financial CfD. Designing financial CfDs mainly as a (profit neutral) hedge, not as a support mechanism, reduces such risks, as it reduces the desire to maximize collateral eligibility.

4.4. Discussion

Four parents. The financial CfD uses and combines in a novel way properties from different types of contracts (Figure 4): it uses generation volumes tailored to specific generation types and has a long lifetime, like conventional CfDs. It is asset-independent, as financial forwards / futures. It accepts physical assets as collateral, as a mortgage loan. And it provides a hedge against volume risk, similar to capacity-based subsidy schemes such as investment tax credits.

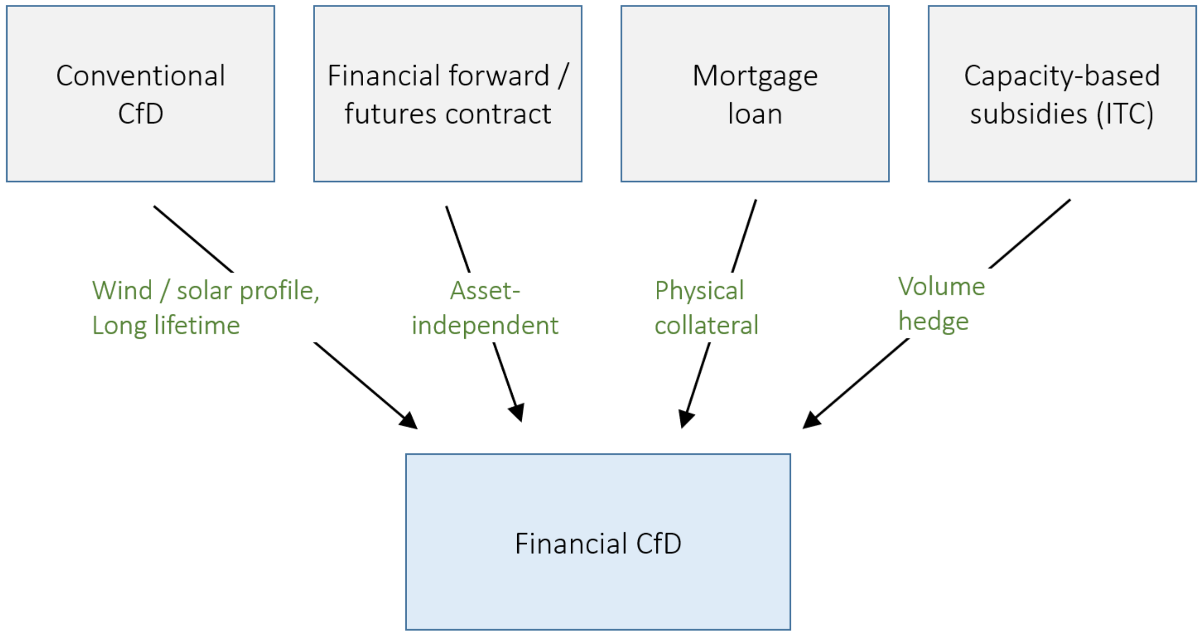

Figure 4: The financial CfD borrows and combines properties from different types of contracts.

Technologies. The financial CfD is much better suited for some generation technologies than for others. The main reason is production costs. In the following, we discuss a rough order of technologies, starting with those that are best suited for a financial CfD.

- For wind and solar energy, variable cost are constant and known quite accurately ex-ante, because they are very close to zero.
- For nuclear energy, fuel costs are quite stable; however, the opportunity cost of re-fueling introduces some inaccuracy.
- Fossil-fueled condensing plants see their production cost change every day with fluctuating fuel and carbon prices. The financial CfD strike price would need to be specified as benchmark costs, e.g. by calculating spreads from commodity price benchmarks and a reference conversion efficiency. Unobserved prices, contracts and fuel transport cost would introduce significant inaccuracy and hence additional risks.
- Plants that burn fuel for which observable commodity markets do not (yet) exist, including hydrogen and biomass, are even more difficult to parameterize.
- Generators that have unobserved opportunity costs, including cogeneration and storage plants, are even less suited for the instrument.

We think of the financial CfD as an instrument that makes sense for wind, solar and nuclear energy, but less for other generation technologies.

Bidding zone split provisions. Any CfD, including the proposed financial CfD, should be explicit about what happens to CfD payments in the case of a bidding zone split. Different options would be conceivable in this regard which each have their pros and cons and should be evaluated carefully.

4.5. Financial vs. conventional CfD

Overall welfare. The main advantage of this kind of hedge compared to traditional CfDs is that it does not distort investment and utilization decisions. Efficient plant investment and operation incentives keep overall system costs low. As all payments from the financial CfD are asset-independent, it leaves asset dispatch, investment and repowering undistorted and following price signals. But this is not the only advantage of the proposed instrument. It is also likely to reduce financial risks further both for wind generators as well as for the government, enabling to bring down capital costs further compared to traditional CfDs.

For wind/solar generators. The advantage for wind/solar generators is that this hedge targets the absolute amount of revenues, not the per-MWh revenues, so it takes out the volume risk (e.g. the windiness risk). Also, experienced developers know how to optimize their asset's generation profile, maintenance schedule, and plant operation to yield maximum profits. Given the exogenous financial nature of the hedge, any additional benefit from optimizing their asset accrues to them in full, rather than being annulled by traditional CfD difference calculation. Targeting the absolute amount of revenues independent from actual generation also helps to mitigate revenue risk for generators from not being dispatched for the sake of maximizing socio-economic welfare even if they could produce electricity in theory. Negative prices are the most obvious case here where not being dispatched and, hence, not being paid a remuneration, is a significant risk for generators largely beyond their control.

For offshore wind generators. Another scenario are offshore bidding zones currently discussed as a market arrangement for future hybrid offshore assets. While maximizing social welfare, such offshore bidding zones might result in revenue risks for offshore wind farms connected to those hybrid assets. This is because offshore wind farms within an offshore bidding zone, due to their clearly determined impact on load flows, would face significantly higher risks of not being dispatched by flow-based/advanced hybrid market coupling algorithms than wind farms connected to conventional onshore bidding zones. Here, traditional CfDs would not offer any risk mitigation as no payment will result from a traditional CfD when a generator will not be dispatched at all. Instead, the proposed financial CfDs will cover this risk and overcome opposition of wind farms against being connected to hybrid assets.

For the government. It reduces financial exposure to weather conditions. In traditional CfDs, governments lose twice in windy years. This is because windy years are (a) high volume and (b) low-price years, increasing the CfD subsidy payments or reducing the CfD income. In our proposal, they are more balanced. The government's CfD income ("the financial call option payout") is influenced by low prices (due to the windy year depressing prices) and by high volumes, two effects which to some degree balance each other out. The same goes for low-wind years, where a traditional CfD's "winning double" situation for the government is replaced by more balanced CfD income too.

Risk of unavailability now correlated to the electricity price. Given that the proposed financial CfD is a financial product that is not tied to the asset's production, its payment flows do not stop if the asset is unavailable. This is a feature, not a bug. It is important to compare the situation with traditional CfDs. In traditional CfDs, generators face the risk of plant outages, as they lead to a complete stop of revenues. In the proposed financial CfDs, that risk remains, but what's new is that the risk is now correlated to the electricity price. In times of low electricity prices, unavailability becomes cheaper now compared to traditional CfD settings and in times of high electricity prices unavailability becomes more expensive. The expected costs for an unavailability ex-ante thus stay the same compared to traditional CfDs. The fact that the unavailability risk is now correlated to power prices is a desired feature. Because it provides the correct incentives to invest into urgent maintenance. When power prices are high, generators should be incentivized to spend as much as possible to get the plant running quickly again, while in lower electricity price times they can take more time and thus spend less in maintenance.

Risk of badly performing generators. Lower than expected wind is a risk for any wind investment, even under conventional CfDs. Under financial CfDs plants are not forced to contract for 100% of expected output, but they can freely choose to use the instrument to hedge only 80% of expected output if they prefer to be on the safe side. This ensures that they are not "overhedged" through this instrument, leading to high payments in times of high electricity prices. The government's collateral requirement must account for the fact that wind farms could perform worse than expected, so it must define collateral de-rating factors.

Additional basis risk. While the proposed instrument takes away volume risks, it adds a new basis risk. This is because the underlying for the volume of the financial CfD is a reference generator and not the actual asset for which it is used as a hedge. Therefore, payment obligations from the financial CfD can deviate from actual revenues made. The risk is symmetric, which means that it can both lead to lower as well as higher than expected income for the generator, but it is now correlated to electricity price levels, which means that underperforming relative to the reference is particularly expensive during high-price times.

Summary. Overall, the financial CfD offers a likely more suited hedge than traditional CfDs because the removed volume risk likely outweighs the additional basis risk, leading to overall lower financing costs for renewables. At the same time, the financial CfD removes all distortive dispatch and design incentives of traditional CfDs, because full incentives remain to design and operate plants according to price signals – since payments are completely independent of the asset’s production, and independent payment flows do not distort.

4.6. Comparison of different CfD specifications

In Table 2, we compare the financial CfD to five other CfD specifications with respect to their producer-sided effects. We focus on two categories of effects: on incentives and on the suitability as a hedge.

Specifications. The CfD specifications we compare are the conventional CfD introduced in Section 3.1, all tweaks (cumulative from left to right) introduced in Section 3.3, Elia's suggestion of a Capability-based CfD also introduced in Section 3.3, and our proposal for a financial CfD introduced in Section 4.

Comparison. The comparison in Table 2 shows that all specifications that were already implemented by European countries so far (i.e. the Conventional CfD including all tweaks, e.g. implemented for the Danish Thor offshore tender) still distort intraday (including balancing) markets and repowering/maintenance investments, and do not provide a hedge against the volume (weather) risk. Besides the financial CfD, only Elia's proposal of a capability based CfD incentivizes efficient intraday bids. The financial CfD is the only specification that incentivizes efficient dispatch, investment, and re-investment choices and at the same time financially hedges both price and volume risk.

Table 2: Checklist for CfD designs

Incentives for…	Conventional CfD	+ no support during negative prices	+ longer reference period	+ limit clawback to below spot price	Capability -based CfD	Financial CfD
… efficient generation profile (RES) or for flexible operation (nuclear)	No	No	Yes	Yes	Yes	Yes
… efficient repowering / retrofit / maintenance investments	No	No	No	No	No	Yes
… efficient power plant maintenance scheduling	No	No	Mostly yes	Mostly yes	No	Yes
… stopping to produce at negative day-ahead prices	No	Yes	Yes	Yes	Yes	Yes
… continuing to produce at low prices in clawback times	Yes	Yes	No	Yes	Yes	Yes
… efficient intraday dispatch	No	No	No	No	Yes	Yes
Financial hedge for…						
… price risk	Almost complete	Almost complete	Almost complete	Almost complete	Almost complete	Almost complete
… volume (weather) risk	No	No	No	No	No	Mostly yes

5. The downstream side

If governments engage in long-term contracts with electricity generators, no matter what kind of contracts, they essentially take a financial position. The profit or loss from this position is passed on to taxpayers or electricity consumers. The way this is done has important consequences not only for the extent consumers are hedged against price risk, but also incentives for demand-side flexibility and energy savings, public revenues, forward market liquidity, and retail competition. In this section we aim to provide some first thoughts on these consequences and possible ways how to deal with them.

5.1. Potential problems on the downstream side

Government takes a long position. If the government engages in long term contracts with generators, regardless if those are financial or conventional CfDs or other types of contracts, the government effectively takes an unhedged long position: it buys electricity which it will not consume itself. This potentially has at least four problematic consequences: volatility in government revenues, crowding out the forward market, a muted price signal that hampers consumer flexibility, and rent seeking behavior.

Volatility in government revenues. The government's unhedged long position increases volatility of the government's net revenues from its CfD commitments. This either necessitate frequent collection/distribution of funds via (often distortionary) levies or subsidies from consumers, or using public debt as a buffer.

Hedging market dries up. With more of the overall market's price risk accruing to the government, it becomes harder for consumers to find appropriate hedging counterparties. Electricity generators, who are the traditional hedging counterparties, lose their natural hedge under a CfD regime and will be reluctant to take on unhedged speculative short positions on their end. This puts upward pressure on forward prices, to the disadvantage of industrial and residential consumers. Essentially, public long-term contracts crowed out commercial hedging markets.

Demand-side incentives. A naïve response to the dried-out hedging market could be "but in a CfD world, there is no need for consumers to hedge". Because the government would likely distribute income from CfD (in high price times) or collect revenue to refinance CfDs (in low price times) from consumers, effectively balancing their electricity prices. The problem is that in a renewables-dominated electricity system, the demand side must also be incentivized to react to price signals – be it by demand shifting due to daily short-term electricity price patterns, or by energy saving due to scarcity of energy supply. If the government starts subsidizing electricity whenever it gets expensive on the market and starts taxing it if it is cheap, such demand reaction is muted. The lump-sum transfer type of support payments seen during the energy crisis do not work for the longer term, because the "last year's consumption" baseline cannot be used forever without distorting incentives. Other useful baselines for lump-sum taxes/subsidies don't exist, so refinancing is always distortionary. In other words, to combine hedging with short-term incentives, liquid forward markets are crucial.

Rent-seeking. The increasing role of governments in taking a long position on electricity markets bears the risk of preferential treatment of certain groups of consumers like large or energy-intensive industries over others, creating a rent-seeking game. Therefore, in the context of European discussions going forward, it is important to shed light on this long position of governments (which is an inevitable result of any larger role of CfDs in energy policy), and transparently discuss ways how to deal with it.

5.2. Using forward markets

A partial solution. A potential part of a solution to this problem could be that the government develops its own "hedging strategy", i.e. sells its "CfD volumes" (really its financial electricity long position stemming from CfDs) not only on the spot market, but instead sells these volumes gradually on forward markets, as they become more liquid a few years before delivery. Staying fully exposed to spot prices (which governments effectively do today) is something private companies would never do, and it dries out forward markets. By using forward markets, the government (a) reduces its own revenue risk (b) helps consumers hedge their consumption (c) while keeping efficient consumer incentives alive. However, while the revenue volatility for the government could be reduced by such an approach, it is not eliminated. That means, there remains a need to refinance in case of shortfalls or to distribute funds in case of generated revenue from CfDs.

Hedging preferences. With the outlined solution, the government essentially engages in maturity transformation, i.e. it buys 20-year CfDs and sells shorter-term 4-to-1-year forward contracts. This can be efficient, because for fundamental reasons, electricity consumers often have a shorter preferred hedging time horizon than electricity generators. An industrial paper producer likes to hedge its upstream electricity costs at the same time when it signs its downstream sales contracts for its paper production. Buying electricity longer term risks being stuck to the contract even when spot electricity prices are falling, and competitors can outcompete its production on the paper market. Only few companies can afford to buy very long-term, such as IT companies. Low carbon power generators on the other hand need long-term stability.

Filling the gap. By taking on the "20-year exposure" while giving back at shorter forward horizons, governments fill the gap, reducing capital costs of low carbon generators. Given energy policy's responsibility for long-term electricity price levels, it could be argued that the risk is allocated where responsibility lies.

PPAs. An alternative to using existing organized future markets could be auctioning off PPAs. In this case, "as produced" wind / solar PPAs could be used that have the same time pattern as the financial CfDs. However, there are great benefits of using existing markets, products and trading infrastructure.

5.3. Smart retail tariffs

Fixed-price tariffs. Another question on the downstream side is how contracts between utilities and retail consumers should be specified, i.e. in what way utilities should pass on hedges to small-scale consumers. Customers on long-running electricity contracts with fixed-charge retail tariffs are better protected against large increases in electricity costs than those whose tariffs float with wholesale prices, in particular real-time pricing that essentially transmit every swing of spot prices to final consumers. The energy crisis has not only made this fact obvious to everyone but has also revealed the huge value that consumers (and policy makers) attribute to this feature.

Real-time pricing. On the other hand, fixed-charge retail tariffs mute the short-term price signal. Integrating ever larger volumes of wind and solar energy necessitates demand side flexibility in particular from electric vehicles, heat pumps, and batteries. Retail customers, or their aggregators, must be exposed to short-term price signals eventually. Also, fixed-charge retail tariffs don't provide an efficient savings incentive to consumers: when reducing electricity consumption, citizens only reap a fraction of the true economic benefits of conserving energy.

Multiple objectives. Thus, retail tariff design must try to accommodate three objectives: provide protection against electricity cost shocks while continuing to pass on the efficient short-term price signal and provide a realistic savings incentive. What seems to be a hard trade-off at first glance, fortunately does not necessarily need to be one.

Smart tariffs. To achieve both objectives, tariffs would combine real-time pricing with forward hedging. So the retail contract is more like wholesale hedging: an insurance contract to lock in a certain price level for a specified amount of energy (say, 3000 kWh) for a certain delivery period (say, one year). Similar to mobile phone contracts, where customers choose their data volume ("1 GB monthly"), for electricity they will have to choose their hedged energy volume ("1 MWh per year") when they sign a contract. Spot prices apply to any deviations (positive/negative) from the hedged energy volume. Essentially, while consumers have high certainty about the size of their electricity bill, efficient price signals prevail at the margin. The hedged energy volume should be distributed across time using a suitable reference load profile that reflects the normal or expected consumption pattern.

Literature. Similar contracts have been proposed by Borenstein (2021), Wolak (2022) and Wolak & Hardman (2022). We discuss them in more depth in (Winzer et al., forthcoming).

6. Conclusion

Problems with CfDs. Contracts for differences in the form currently used provide problematic incentives. These distortions tend to be more severe if non-zero variable cost technologies are included and/or if larger volumes of generation are contracted . The tweaks and fixes introduced to avoid such distortion often bring their own distortions, requiring further patches.

The Financial CfD. In this paper, we proposal a fundamental solution to adverse incentives by borrowing a key feature from financial forwards/futures contracts: decoupling payments from physical production. Instead, we propose to link it to an objective benchmark that is highly correlated with generation. We also discuss how such contracts could be specified to hedge not only against price risk, but also volume risk. In addition, we propose to accept physical generation assets as collateral for such contracts in order to avoid margin calls.

Two interpretations. There is different ways a financial CfD can be interpreted. One can understand it as an evolution in (renewable and nuclear energy) support schemes, advancing UK-style CfDs to avoid distortive incentives. Alternatively, one can see it as a hedging instrument, where the government provides a hedge against long-term price risks. In that sense, it is an evolution of futures/forward contracts. Following that line of thought, one could imagine financial CfDs being signed by commercial parties and even be traded on secondary markets.

Consumption side. The contract between governments and generators is only one side of public long-term contracts. The downstream side – what governments do with the financial position resulting from the contract – is equally important. Effectively, governments take long positions when engaging in CfDs that we propose to close by selling these volumes on financial markets. We hope these thoughts provide helpful input to the European policy discussion on contracts-for-difference and electricity market reform.

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