ENTSO-E Position Paper

Sustainable Contracts for Difference (CfDs) Design

February 2024

entsoe

Foreword

ENTSO-E, the European Network of Transmission System Operators for Electricity, is the association of the European transmission system operators (TSOs). The **40 member TSOs, representing 36 countries,** are responsible for the secure and coordinated operation of Europe's electricity system, the **largest interconnected electrical grid in the world.**

Before ENTSO-E was established in 2009, there was a long history of cooperation among European transmission operators, dating back to the creation of the electrical synchronous areas and interconnections which were established in the 1950s.

In its present form, ENTSO-E was founded to fulfil the common mission of the European TSO community: to power our society. At its core, European consumers rely upon a secure and efficient electricity system. Our electricity transmission grid, and its secure operation, is the backbone of the power system, thereby supporting the vitality of our society. ENTSO-E was created **to ensure the efficiency and security of the pan-European interconnected power system** across all time frames within the internal energy market and its extension to the interconnected countries.

ENTSO-E is working to secure a carbon-neutral future. The transition is a shared political objective through the continent and necessitates a much more electrified economy where sustainable, efficient and secure electricity becomes even more important. **Our Vision: "a power system for a carbon-neutral Europe"**[1] shows that this is within our reach, but additional work is necessary to make it a reality.

ENTSO-E is ready to meet the ambitions of Net Zero, the challenges of today and those of the future for the benefit of consumers, by working together with all stakeholders and policymakers.

1 https://vision.entsoe.eu/

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1 Executive Summary

In order to attain the required massive expansion of Renewable Energy Sources required for the energy transition, public support schemes will likely continue to play a role. Two-sided Contracts for Difference have become increasingly popular in recent years, particularly for offshore wind tenders. In the wake of increased energy prices as of 2021, two-Sided CfDs may also be used to reduce consumer costs, as also reflected in draft legislative proposals for the Electricity Market Design Reform.

In this context, system operators cannot ignore the possibility that the design of such support schemes significantly impacts system operations. It is in ENTSO-E's view crucial to account for this in order to ensure a cost-efficient, sustainable and secure energy transition. This paper aims to inform policy makers and other relevant stakeholders of the potential impact of two-sided CfD on system operation, and how an improved design can help mitigate such risks.

The paper describes several designs, which are assessed according to four main criteria:

- **Bidding behaviour and dispatch:** to what extent efficient incentives are provided for participation in the day-ahead, intraday and balancing market.
- **Asset design and siting:** to what extent efficient incentives are provided to maximise the market value of electricity rather than maximise production volume to earn higher return from subsidies.
- **Risk hedging:** to what extent price and volume risks for generators can be hedged.
- **Regulatory risk:** to what extent changes in the design of support schemes/instruments bring about changes for market parties.

From a system operator point of view, the first criterion carries the most weight. Good performance in this aspect ensures efficient behaviour by the generator, which should make such assets valuable contributors to a secure and cost-efficient system. Designs that do not satisfy this criterion will require counter measures, that may be costly and must ultimately be paid for by consumers.

The design of the Contract for Difference with the supported generator is the foremost element in this regard. It constitutes a difference payment between the state issuing the support and the generator subject to it. The amount is determined by the difference between an agreed strike price and a reference market price multiplied by a reference volume. Whereas the strike price should be the outcome of a competitive tendering, both reference volume and reference price are important design elements to consider before the tender. This paper makes a first and foremost distinction on the reference volume between production based CfDs and non-production based CfDs.

Production based CfDs take the actual injection of the supported generator as reference volume. It is the most common metric for existing support schemes. Within this category, it is possible to further distinguish based on reference price calculation. However, any of the options retain important market distortions. For an hourly reference market price definition, the quantitative analysis in appendix shows an occurrence of conflicting incentives close to 20 % of the time for the considered period and reference market. For a yearly reference price determined ex-ante, the quantitative analysis in appendix shows an occurrence of conflicting incentives over 90 % of the time for a high price shock between years. For more normal price differences between years in the considered respective periods and reference market such conflicts occurs around 5 % of the time. Since all assessments were based on historical prices, they can be considered realistic scenarios. Therefore, those CfD designs are not scalable to preserve efficient market functioning with high amounts of RES subject to CfD in the system. The CfD with monthly/yearly reference market price determined ex-post is expected to mitigate such distortions, but not to avoid them exhaustively.

The paper also investigated strike price, and revenue cap and floor models. It concludes no tangible advantage for a strike price cap and floor. The revenue cap and floor might avoid market distortions, but seems complicated to put in place as it requires an exhaustive view on revenues for each generator. This is expected to come at a high regulatory risk. In addition, it will not incentivise efficient asset design or siting.

Non-production based CfDs use a counterfactual reflecting the potential production as a reference volume, which can be estimated in several ways. Since this makes dispatch independent of the CfD payments, it should avoid distorted bidding behaviour and dispatch altogether. For this reason, a non-production based design is strongly preferable going forward. A first way to determine the potential for production is the Capability-Based CfD, where the maximum possible production of the individual asset, reflecting the active power output under normal conditions (i. e. without any curtailment), is used. Because it is calibrated to the specific conditions of the asset, it scores well in terms of risk coverage for the generator, which should lower costs associated to risk in the strike price tender. On its own, it doesn't incentivise efficient asset design and siting (though this might be resolved by limiting the operating hours during which support/payback applies). While it is a new mechanism, ENTSO-E considers the regulatory risk as limited, as there appear to be eligible metrics to assess capability (e. g. Available Active Power). A second way to determine potential for production is via a more generic "reference generator", which is the approach of the Financial RES CfD (a generalisation of "Financial Wind CfD"). Since there can be a mismatch between the generic reference and the individual asset, it is likely to cover risk to a lesser extent. On the other hand, it does not reward volume maximisation and can therefore incentivise system-friendly asset design and siting. From a regulatory point of view, the model seems more complicated as the definition of the reference generator is a point of discussion. The assessment thus shows a trade-off between both models, but gives a significantly better rating overall compared to production-based designs. Therefore, ENTSO-E recommends a move towards non-production-based designs, though further discussion is needed around the detailed design of capability/the reference generator.

Criterion	Production-Based CfDs					Non-Production-Based CfDs	
	Hourly Price	Yearly Price Ex-Ante	Yearly Price Ex-Post	Cap/floor Price	Cap/floor Revenues	Capability-Based	Financial RES
Dispatch	− −	− −	−	−	+ +	+ +	+ +
Asset Design & Siting	− −	+ −	+	−	− −	−	+ +
Risk Hedging	−	− −	+ −	−	+ −	+	+ −
Regulatory Risk	−	−	+ −	−	− −	+ −	− −

Table 1: Summary of CfD design assessment

Secondary to the CfD design, reallocation of CfD cost and benefits (which in first instance fall to the state issuing the CfD) to consumers can also have important impacts on system operation and market functioning. In particular, if it affects consumer prices directly, they no longer reflect the true value of electricity and could hamper demand side response. Secondly, if a high share of generation is under a CfD, this might reduce supply on the forward market (since such generators are already hedged under a CfD). The paper first considers an administrative reallocation, whereby the state fully determines the level of cost/benefit allocated to consumers. From a TSO perspective it is important cost/benefit will not distort the incentives for consumers and hence non-consumption based reallocations are preferred (i. e. not increasing/reducing the cost per MWh consumed). A second model, referred to as "market-based" whereby the state would conclude consumer CfDs in accordance with generator CfDs, can increase supply in the PPA market where there is a shortage. The potential impact of such a model on existing PPA/forward markets is yet unclear and should be investigated further.

Finally, the effect CfDs have on forward markets can also be reduced by providing an opportunity for commercial Power Purchasing Agreements in a CfD tender. That way, consumers with an interest in such hedging products have the opportunity to establish them before the developer enters into a long-term CfD with the state and this volume is excluded from the commercial PPA market. The paper presents two possible models for coexistence: the Carve-Out and the Two-Stage Tender. Both should inherently favour volumes developed under commercial PPAs, but either option should carefully assess the end goal of the tender as well as potential gaming risks (which is a matter of the detailed design). Volume developed under commercial PPAs should not lead to bidding/dispatch distortions and incentivise efficient asset design, since the full cost of inefficient choices falls on commercial actors. The latter is, however, an essential prerequisite. If the project continues to receive some form of support (even though it is branded as a commercial PPA), elaborate consideration on potential distortions is required, as for the two-sided contracts for difference design discussed in this paper.

In light of this, ENTSO-E recommends:

- **To move away from production-based CfDs and towards non-production based CfDs**

  Justification: as increased amounts of renewable/low-carbon is introduced into the system and we cannot know whether they will be supported or not, support schemes need to be designed so that such assets follow market price signals (and therefore system needs) at true marginal cost. Such a move seems best aligned with the principles in article 19b of the approved proposal 2023/0077 of the electricity market reform.

- **Where injection-based continues to be applied despite the above recommendation, to at least make them as least-distortive as possible accounting for the detailed considerations in this paper (e. g. technology-specific yearly/monthly reference price determined ex-post, definition on full-load hours…)**

- **To continue with an open discussion on the precise definition of the capability of capability-based CfDs and the reference generator of the financial RES CfDs**

- **Not to allocate CfD costs and benefits on the basis of actual MWhs consumed, but rather look for non-consumption based allocation mechanisms**

- **To further investigate the potential impact on existing forward/PPA markets of the market-based reallocation concept prior considering its implementation**

- **To integrate options for fully commercial (i. e. without any form of support) PPAs into CfD tenders**

- **To appropriately assess the implications of Carve-Out and Two-Stage Tender mechanisms in the specific context of a CfD tender (particularly for gaming risks and desired outcome)**

2 Introduction

A key enabler to complete the energy transition is the market and system integration of renewable energy. They would ideally be less reliant or even not in need of renewable support in the long run. However, the need for a massive and rapid expansion of RES together with uncertain market conditions shed doubt about whether the market integration of RES can be timely achieved or deliver it within the required timeframe. In this context, support schemes for RES investments may be a necessity to drive the energy transition, at least until commercial markets and decarbonisation goals are fully aligned. The starting point of this paper is that there are policy decisions to use CfD support schemes to deploy RES. The validity of these decisions is not within the scope of this paper, but take them for granted.

To this end, system operators cannot ignore the possibility that the design of such support schemes significantly impacts system operations. In the end, well-functioning markets align with efficient system operation, which is why the former is essential. This paper aims to provide a Transmission System Operator (TSO) perspective on design of support schemes to ensure that the market can function in an efficient way, whether the reliance on support is in the end substantial or negligible. Since Contracts for Differences (CfDs) are a central element in the European Market Reform of 2023, the scope is limited to this type of support scheme. Nevertheless, the overall principles put forward for consideration apply to any type of support scheme. The paper also often discusses CfDs in relation to Power Purchasing Agreements (PPAs), which are both concepts defined in draft European market design reform legislative proposals as follows:

"two-way contract for difference" means a contract signed between a power generating facility operator and a counterpart, usually a public entity, that provides both minimum remuneration protection and a limit to excess remuneration;

"power purchase agreement" or "PPA" means a contract under which a natural or legal person agrees to purchase electricity from an electricity producer on a market basis;

This paper identifies three main topics to consider when setting up a CfD scheme to ensure efficient market functioning:

1. Non-distortive Contract for Difference design:

The contract with generators benefiting from a CfD should ensure that they retain incentives to be dispatched and designed in the interest of the market.

2. Cost-/benefit allocation to consumers:

CfDs generate costs as well as revenues for member states issuing them, depending on real market prices in the end. Allocation to electricity consumers can also influence their behaviour, which impacts demand side response development. In addition, they may impact forward market liquidity.

3. Coexistence with Power Purchase Agreements (PPAs)

Minimising the reliance on support requires models where commercial PPAs can also develop alongside CfDs.

This note elaborates key design principles for all three topics, with a key focus on topic 1. Before diving into the topics themselves, it is important to elaborate the potential impact on market functioning, as well as delineating the objectives of CfD design from a system operator perspective.

3 Impact of support schemes on markets and system operation

Support schemes aim at achieving policy goals that commercial markets alone are not able to deliver. Typically, the goal is to push forward a development that either wouldn't have happened or would have taken longer time. For instance, support schemes have been used by governments to deploy renewable energy sources (RES) by reducing their market risks and/or increasing expected return from the investment to attract developers. This has been done to speed up investments in RES, where there is uncertainty that the European Emissions Trading System (EU ETS) will have sufficient and timely impact to attract necessary investments, or to promote the political preference for a certain technology (i. e. targeted support schemes). Therefore, support schemes constitute regulatory intervention, which has an impact on markets and system operation.

The design of support schemes influences the way RES respond to market conditions and hence, may have a distortive impact on the market price signals. This could materialise in day-ahead- (DA), intraday (ID)- or balancing market and subsequently propagate to existing forward, futures and PPA markets. Since market prices govern the dispatch of the asset, it has an impact on power system operation as well. For example, depending on the design, support schemes may distort electricity generators' bidding behavior in day-ahead, intraday and balancing markets if they give incentives to produce regardless of the market price development ("produce-and-forget effect"). Such distortions affect prices in the markets and the TSO's ability to operate the system in a secure and reliable way, leading to higher system costs.

These considerations are important to keep in mind when designing support schemes to ensure they are designed in an efficient way minimising market and system distortions. It is furthermore important that CfD design does not limit participation of resources in ancillary services. To this end, any support scheme should provide system-beneficial investment incentives for RES generation and flexibility (generation, storage, flexible demand response). They should incentivise RES to respond to market signals (e. g. increasing the contribution of RES to ancillary and balancing services) as well as allow market prices to signal/reflect profitable investments in flexibility thus, facilitating the accommodation of large volumes of RES in the electricity system.

In light of recent policy discussions, Contracts for Differences are an important support scheme going forward. In this paper, ENTSO-E will cover a broad range of possible CfD designs and how they could be implemented. However, the considerations can be extrapolated to other types of support schemes.

4 Objectives of robust CfD design

From a system perspective it is important that the CfD is designed in a way that incentivises efficient dispatch and system-beneficial investment decisions that match the system needs.

This should allow for the efficient integration of RES (or nuclear) into the markets and grids. Moreover, the design choices for CfD implementation are of great importance for developers and financiers as well. The CfD design can have an impact on the degree that risks (price, volume, liquidity) can be hedged and may bring about changes for market parties which might need to adapt their bidding strategies and financing structures accordingly.

Therefore, a set of objectives have been defined, that will subsequently be used as criteria to assess the various CfD designs:

› Bidding behaviour and dispatch (operational phase): to what extent efficient incentives are provided for participation in short-term markets (day-ahead, intraday) and the balancing market. The market price, and not the CfD pay-out, should be the relevant incentive.

Application to cross-zonal capacities:

Cross-zonal capacities are essential to foster trade in the internal European electricity market and subject to strong competition. The regulatory framework is continuously evolving to ensure a maximum of cross-zonal capacity is given to the market for competitive trade. However, if the CfD design would create distortions in bidding, cross-zonal capacities are in the end not allocated based on effective marginal costs (thus fostering the most cost-effective deployment of resources across Europe), but rather based on arbitrary levels of subsidy. On a large scale, this could severely compromise a cost-efficient market. This can be avoided by non-distortive CfD designs that ensure market behaviour based on marginal cost.

› Asset design and siting (investment phase): to what extent efficient incentives are provided to maximise the market value of electricity rather than maximise production volume to earn higher return from subsidies. Efficient incentives are needed for choosing a system-beneficial location and asset design whose feed-in profile matches system needs (e. g. east or west facing solar panels, wind turbines with longer rotor blades and higher towers, so that more electricity is produced in hours with lower solar/wind and higher demand).

› Risk hedging (price and volume): to what extent price and volume risks for RES operators can be hedged. The volume risks are referred to the RES not being dispatched due to negative prices. The revenues of RES developers depend on the frequency at which negative prices occur, which is not in their control.

Application for offshore wind:

Offshore bidding zones[2] (OBZs) although this market design maximises social welfare, might increase price/volume risks for offshore wind farms (OWFs) connected to offshore hybrid assets. For instance, given that there is no offshore demand, offshore generation may face a risk of not being dispatched due to constraints of the onshore grid. This risk is not exclusive for OBZs, albeit that the impact might be higher in case of OBZs compared to onshore bidding zones. There are also onshore bidding zones that face substantial excess supply or demand and therefore, they are highly dependent on interconnector capacity. If these risks are assessed as detrimental to the business case of the RES, these should be revealed in a transparent way e. g., through auctions and could be addressed by the CfD design.

› Regulatory risk: to what extent changes in the design of support schemes/instruments bring about changes for market parties. In order for the support scheme to be effective, it is important that market participants (especially project developers, financiers, operators) are able to adapt their bidding and financing structures to these changes.

2 For more information on offshore bidding zones, see ENTSO-E's position paper on market and regulatory issues for offshore (ENTSO-E, 2020 [3])

5 Suitable Technologies

The assessments presented mostly pertain to technologies with limited flexibility. In essence, a CfD on the Day-Ahead market dampens the price difference at different times of delivery (though the degree varies, as is apparent from e. g. the comparison of financial wind CfD to capability-based CfD). Even in the least degree, it does not seem suitable as a concept for technologies which are flexible, as the key value for many of them (e. g. batteries or flexible thermal generation) is to capitalise on price variability.

Intermittent renewable energy sources (Photovoltaic [PV] and wind) have limited control on when they deliver their energy. Other technologies with limited flexibility, such as certain nuclear plants, rely on running continuously at low marginal cost. A CfD scheme could also finance their business case, but the incentive to make such installations flexible in the future is removed under such a scheme. If this is not desired then CfDs should not be considered a viable option. There may be a reference plant definition for the financial RES CfD (see corresponding section) that would retain incentives for flexibility, but this requires further investigation.

Most other technologies (in particular storage) obtain a lot of value from being exposed to variable prices and are not suitable for a CfD. For projects combining technologies (e. g. RES + battery), a CfD could be considered for the underlying renewable assets, but do not seem appropriate to be considered on the whole.

Finally, it should be noted that, especially for renewable energy sources, a lot of capacity is expected to be commissioned in the coming years. It is uncertain what share of this will be under CfDs, but it could be significant and then poor CfD design would compromise efficient markets and system management. Hence it is crucial to ensure non-distortive CfD design going forward.

6 Topic 1: Non-distortive CfD Design

6.1 CfD concept description

Especially for offshore projects, Contracts for Differences (CfDs) have become a popular mechanism (Jansen, et al., 2022 [5]). A "one-sided" CfD compensates the generator for market prices below the so-called strike price (see Figure 1). The strike price is normally determined in an auction, where bidders with the lowest strike prices are awarded the right to realise their projects. On the other hand, if the market price exceeds the strike price, this represents an additional upside for the generator with one-sided CfDs. If developers expect high revenues compared to costs during the lifetime of their project, they may be willing to accept a low strike price with one-sided CfDs. If the developer expects this to be the case for a long time, he may be willing to accept a strike price even at zero, i. e. no support is required. Indeed, there have been auctions for offshore wind in Europe resulting in a strike price of zero. This is no guarantee that RES will continue to develop at the politically desired rate without support schemes. Either way, it is key to have competition in CfD tenders to achieve low cost.

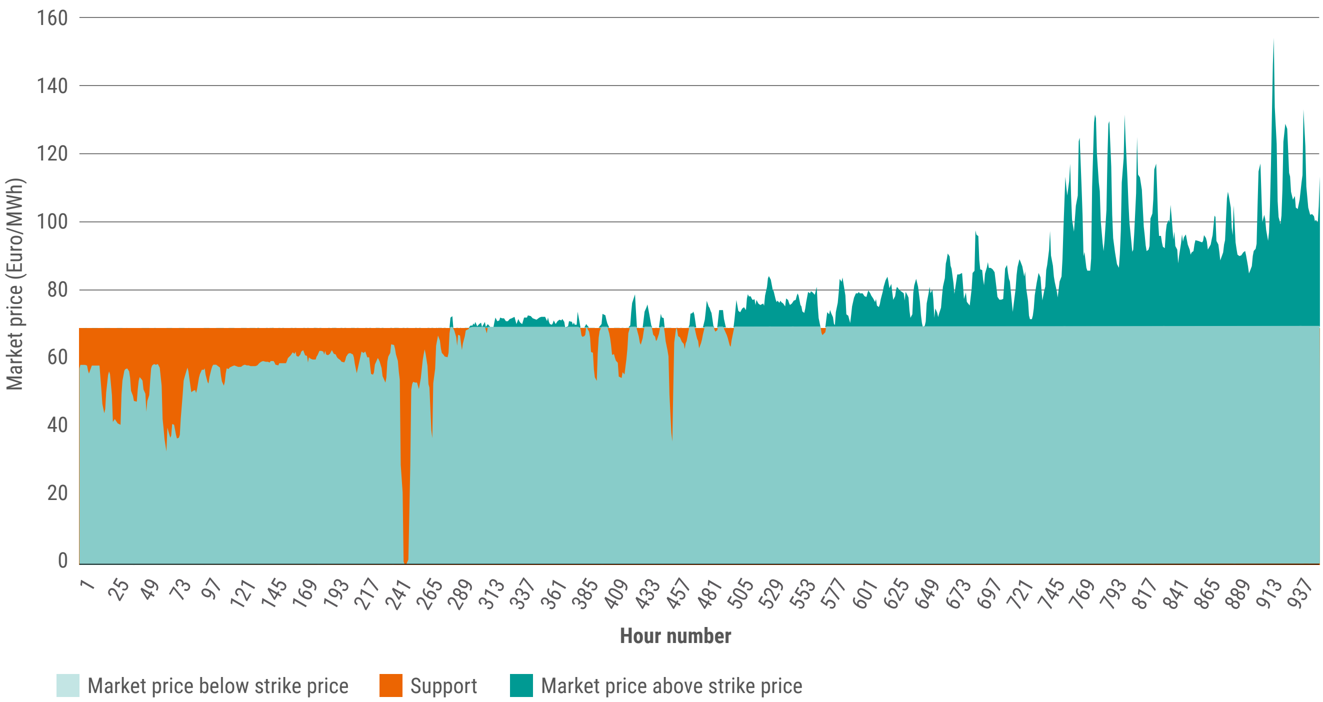

Figure 1: Illustration of CfD with strike price of 70 €/MWh for a period of 1,000 hours in NO_2 in 2021 (assuming hourly reference, see below)

Additionally, real market prices could exceed considerations in bidding in the CfD tender. As such, member state issuing a CfD may want to recover funds from supported generators at times of high prices. By the design of CfD, these revenues can be reallocated to protect consumers (see TOPIC 2). In particular, there seems to be an interest to protect consumers at time of high prices in the of mid-2021. One way to enable this is to oblige developers to return revenues in excess of the strike price (i. e. the dark green area in Figure 1). This is what happens with a two-sided CfD: the generator receives support when the market price is **below** the strike price and pays back excess revenues when the strike price is **above** the strike price. On the other hand, ceteris paribus, developers will bid a higher strike price for a two-sided than for a one-sided CfD, because of the reduced upside. Presently, this appears not to be a concern, but this should also be considered. The strike price then becomes the price the developer is willing to accept for the power sold by the project, subject to the other design elements.

6.2 CfD Key design element

This section presents several design elements of CfDs that are highly relevant for the effectiveness and impact of the respective instrument. The most distinguishing design option is the distinction between **production based CfDs** and **non-production based CfDs**. The reference volume in production based CfDs is the actual injection of the asset. The reference volume for the non-production based CfDs is a counterfactual reflecting the potential production, which can be estimated in several ways. Within these two main categories there are further distinctions.

The **reference market price** refers to the spot price on the wholesale market with which the strike price is compared and therefore determines the CfD payments. It is often determined based on the hourly Day-ahead (DA) market price or the average of DA market prices over a longer reference period e. g. monthly or annually. The average market prices are often adjusted by technology-specific value factors for the respective RES technology (technology-specific volume weighted average). Moreover, the calculation of the payments (positive or negative) can take place ex-ante based on past electricity prices in the previous reference period or ex-post when the average market price over the reference period is known.

The **duration of the contract** can be defined in time i. e. number of years or it can be volume-based i. e. determined based on a number of full load hours (MWh/MW) over the lifetime of the project. The latter means that the support is the same in all relevant locations and paid for the same number of MWh, thus, incentives for placing installations in high energy yield locations in response to a higher payment per MWh could be dampened (Newberry, 2023 [8]). This design choice can serve as a locational steering of onshore RES investments in order to contribute to a better coordination of market investments with grid expansion and ultimately a more balanced system. Moreover, it could address volume risks for RES developers i. e. not being dispatched due to negative prices or as a result of market coupling, or less wind than expected (see next section).

In the past, CfD implementations allowed for a **payout at times when market prices were negative** leading to market distortions and high system costs. Some implementations stop the support at negative prices after a threshold is reached[3]. It is furthermore prohibited under article 123 of the State Aid Guidelines. Most recent CfD implementations do not allow for a payout when market prices are negative, avoiding at least this type of distortion in Day-Ahead. Nonetheless, other disortions may remain.

6.3 Production based CfDs

The CfDs discussed in this section use the measured injection[4] to determine the volume which receives the CfD premium (i. e. the difference between the strike price and reference price). Different designs use a different definition for the reference price. The last two designs discuss the possibility to cap/floor the level of support in different ways.

3 E. g. in Germany where a sliding premium/one-sided CfD is implemented RES installations stop receiving the premium if the prices were negative for four consecutive hours. From 2027 there will be a complete phase out of support at times of negative prices (§ 51 EEG 2023).

4 It should be noted that, as the common reference price is according to Day-Ahead and the CfD volume is a tele-measurement of real-time injection, there is an inherent mismatch between the volumes bid in that timeframe and the volume used for the CfD. However, it is expected that this is an acceptable risk for the benefiting generator, supported by the real-life application of such CfD contracts.

6.3.1 CfD with hourly reference market price

In the past CfDs have been implemented, like in the UK, with the hourly DA price as reference market price including support at times that market prices are negative (Department of Energy & Climate Change, 2014 [1]). Such a CfD design creates significant market and system distortions which might become even more severe as higher share of RES enter into a CfD.

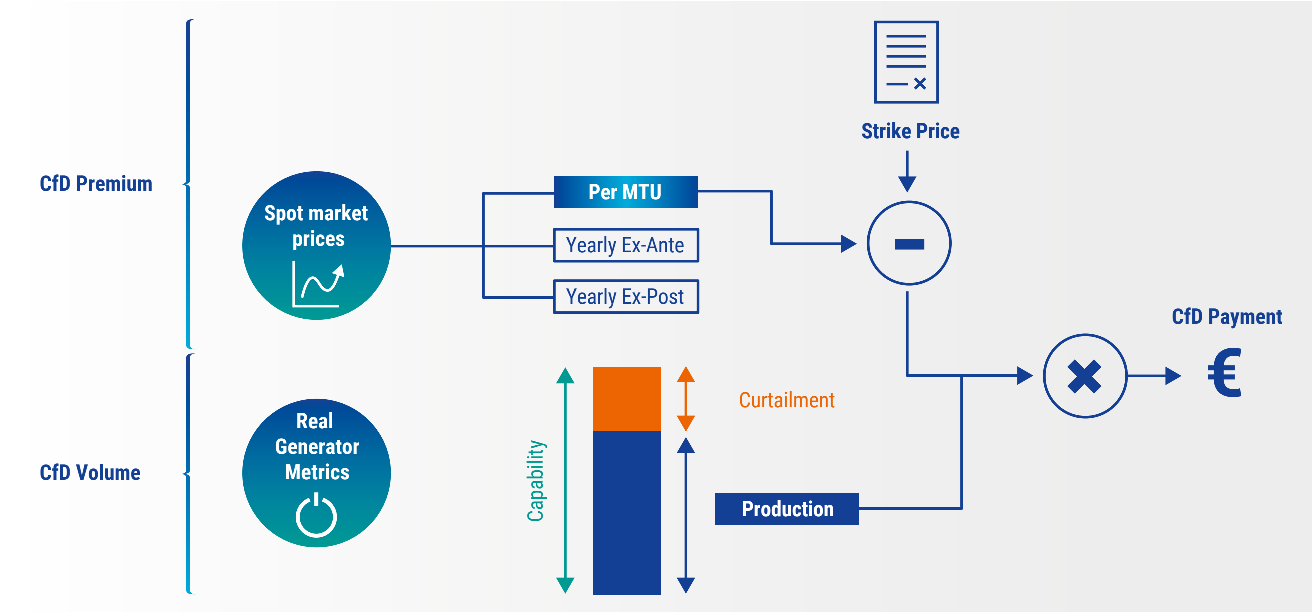

Figure 2: Conceptual illustration of production-based CfD with hourly reference market price

Dispatch (operational phase)

Under such a CfD design, RES generators effectively receive a fixed price every hour and therefore, the only incentive they have is to maximise production regardless of the value of the market price to maximise their income guaranteed via the subsidy ("produce-and-forget" effect). Even during hours with negative electricity prices, RES producers are incentivised to continue bidding into the market even up to the negative market cap in Day Ahead (as the subsidy will cover for this) and the negative of the subsidy in later market timeframes (intraday and balancing), which means below their marginal costs. The effect for Day-Ahead can be mitigated if no subsidy is paid for negative market prices, but such distortions then remain for intraday and balancing timeframes. This also means that TSOs will have to accept an artificial cost for downwards flexibility to compensate for the loss of subsidy. Furthermore, there are no incentives to schedule maintenance when the residual demand is low and prices are low because the generator receives the same price regardless. The CfD payment (positive or negative) is known after the DA market clearing (ex-post) and constitutes an opportunity cost meaning that the RES generators price it in when bidding in ID and balancing market e. g. if they expect a negative payment (clawback, i. e. payment from the generator back to the government), as long as the market price in ID or balancing is below the clawback level, the RES generators have an incentive to cease their production to avoid the payment to the state. This means they will be incentivised to bid at prices higher than their marginal costs (relative to the situation without CfD) in order not to be selected in the clearing leading to an upward pressure on ID and balancing prices because clawback payments are generating an "artificial" marginal cost. The quantitative analysis in appendix shows an occurrence of conflicting incentives close to 20 % of the time for the considered period and reference market.

Asset design and siting (investment phase)

When the CfD payments are determined on an hourly basis there are no incentives for system-beneficial investment choices but rather incentives for maximising production and minimising costs. RES generators do not have any incentive to choose system-beneficial locations or invest in installations such as wind turbines that produce more electricity at low wind speeds, when production might overall be low, or east/west facing solar panels that produce more at morning and evening peaks when demand is typically high, since they will not benefit from higher electricity prices at those moments.

Risk hedging (price and volume)

A CfD with an hourly reference market price removes any price risks in day-ahead, reducing financing costs for project developers. However, volume risks are not addressed by this CfD implementation which might have a negative impact on the profitability of the project.

Regulatory risk

CfDs with hourly reference market price have been implemented already in some countries like the UK and market parties have already gained experience with this design. Therefore, such a CfD implementation could be perceived as less complex, requiring limited adjustments with regard to bidding and financing structure for developers and financiers.

6.3.2 CfD with yearly reference market price determined ex-ante

More recent CfD implementations addressed the distortive effects of the hourly based CfD design by adjusting certain design elements e. g. using a longer reference period, granting no support when electricity prices are negative, etc. Such a CfD design applied in Denmark for the Thor tender where the reference price is fixed for a period of 12 months, it is calculated as a simple average of the hourly spot prices in the previous calendar year and the support is discontinued in hours with negative spot prices[5]. The total subsidy in a given hour is the product of the price premium and the output measured for that same hour. The total premium from the state or total payment from the concession owner is settled on a monthly basis. In addition, in order to reduce the risk for the state and the concession owner payments have been capped for both. The cap on total payment from the generator to the Danish state, in the Thor case was set at DKK 2,8 billion. When the cap is reached the generator will run the wind farm on purely commercial terms, without support and thus, will receive full income from selling electricity to the market. The Thor tender also included a cap from the state to the generator at DKK 6,5 billion although it turned out not to be relevant due to zero bids[6].

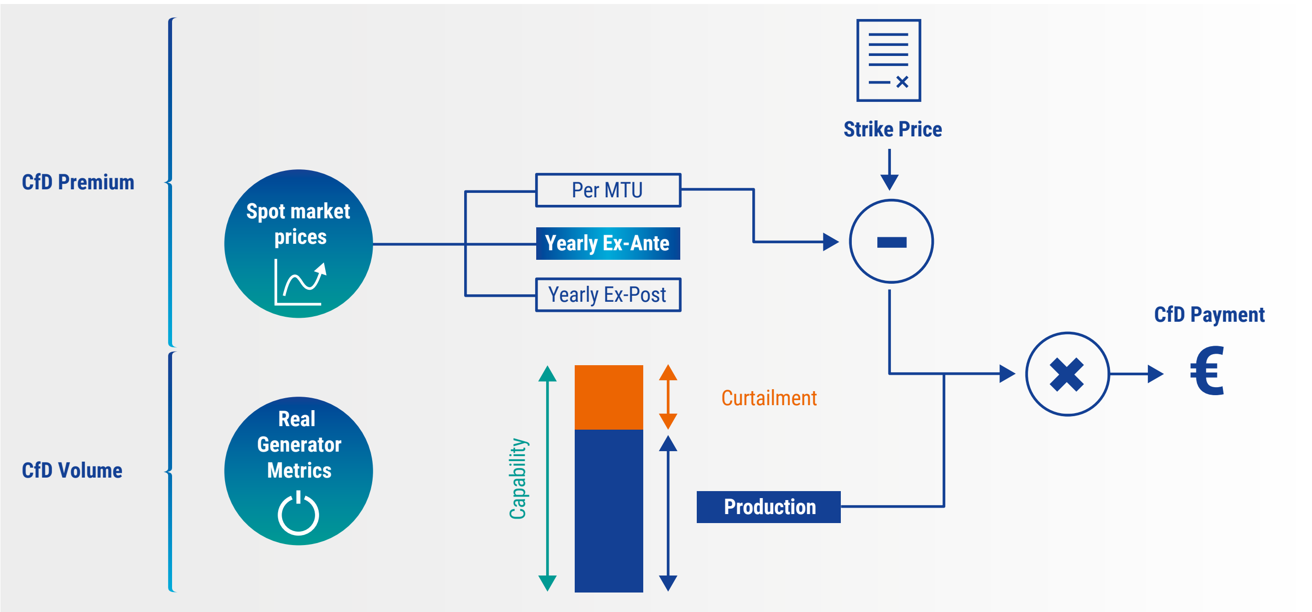

Figure 3: Conceptual illustration of production-based CfD with yearly reference market price determined ex-ante

5 https://ens.dk/sites/ens.dk/files/Vindenergi/subsidy_scheme_and_other_financial_issues_31march2020.pdf
6 https://ens.dk/en/our-responsibilities/wind-power/ongoing-offshore-wind-tenders/thor-offshore-wind-farm/news-about

Dispatch (operational phase)

In principle, with a longer reference market price (in this case yearly reference market price) RES producers are exposed to the market price within the reference period, and they have a greater incentive to dispatch efficiently compared to the hourly settlement (though for such a design, exemption of support during hours of negative price should mitigate this in the day-Ahead stage). However, since the reference market price is based on historical spot prices the CfD payment (positive or negative) is known before the DA timeframe and this can lead to dispatch distortions in DA market. This is the case in years when the RES producer has to pay back to the state. Their cost for generating a MWh of electricity is now artificially inflated by the premium to the state and hence, they will bid at this cost rather than the true (close to zero for RES) marginal cost. This reduces the payback the government can make and also makes prices artificially higher during that period. In order to mitigate this effect, the clawback is discontinued in hours in which the spot price is lower than the size of concession owner's payment to the state. An alternative could be that the clawback is limited to a maximum amount that includes the marginal operational costs so that there is still an incentive to produce. However, both of these options reduce clawback possibilities for the state. In addition, dispatch distortions in ID and balancing market timeframe remain unresolved since the CfD payment is known ex-ante. Moreover, not granting support in hours with negative spot prices minimises distortive bidding behaviour in DA market avoiding that RES producers continue to produce even at times when electricity prices are below their marginal costs. This also means that TSOs will have to accept an artificial cost for downwards flexibility to compensate for the loss of subsidy. Finally, a yearly reference market price provides seasonal incentives for planning maintenance at times when the value of electricity is low i. e. during times of low wind. To clarify, this is because periods of high wind don't necessarily coincide with high value for electricity. Making the generator under CfD indifferent to this would instead remove the possibility to make this trade-off. The quantitative analysis in appendix shows an occurrence of conflicting incentives over 90 % of the time for a high price shock between years and around 5 % of the time for low price differences between years in the considered respective periods and reference market.

Asset design and siting (investment phase)

The longer reference period provides more incentives for system-beneficial investments in terms of design and location of assets allowing for an easier integration of RES into the system and markets. With longer averaging periods, RES producers are exposed to the volatility of the market prices and could consider projections of future electricity price developments in their investment decisions. Therefore, they are incentivised to choose asset designs and locations that match the system needs hence, maximising the market value of electricity especially at times of low wind or solar and being awarded by potentially higher electricity prices.

Risk hedging (price and volume)

Unlike with the hourly-based CfD, a yearly averaging period exposes project developers to further price risks since the reference market price deviates from the actual price they achieve in the market. This might impact the financing costs for project developers. Volume risks are not covered by this CfD implementation. In addition, the simple average may not reflect the time of delivery of the benefiting generators, meaning that the reference price is different than what they typically captured. Volume-weighting of the prices is possible, but the residual risk will differ depending on the level at which this is done (i. e. generator-specific or aggregated per technology).

Regulatory risk

CfDs with yearly reference market price has been implemented already in some countries like Denmark and Germany and therefore, less effort by developers and financiers is expected for adjusting their bidding and financing structure.

6.3.3 CfD with monthly/yearly reference market price determined ex-post

Inspired by the sliding premium/one-sided CfD in Germany[7], there is considered a two-sided CfD with a reference market price defined as a technology-specific weighted average of DA market prices, determined on a monthly or yearly basis and calculated ex-post i. e. after the end of the reference period. Moreover, the CfD design excludes support payments in times of negative prices and the duration of the contract is based on a maximum number of full load hours (FLH) over the lifetime of the project. The possible effect of such a CfD design is described below.

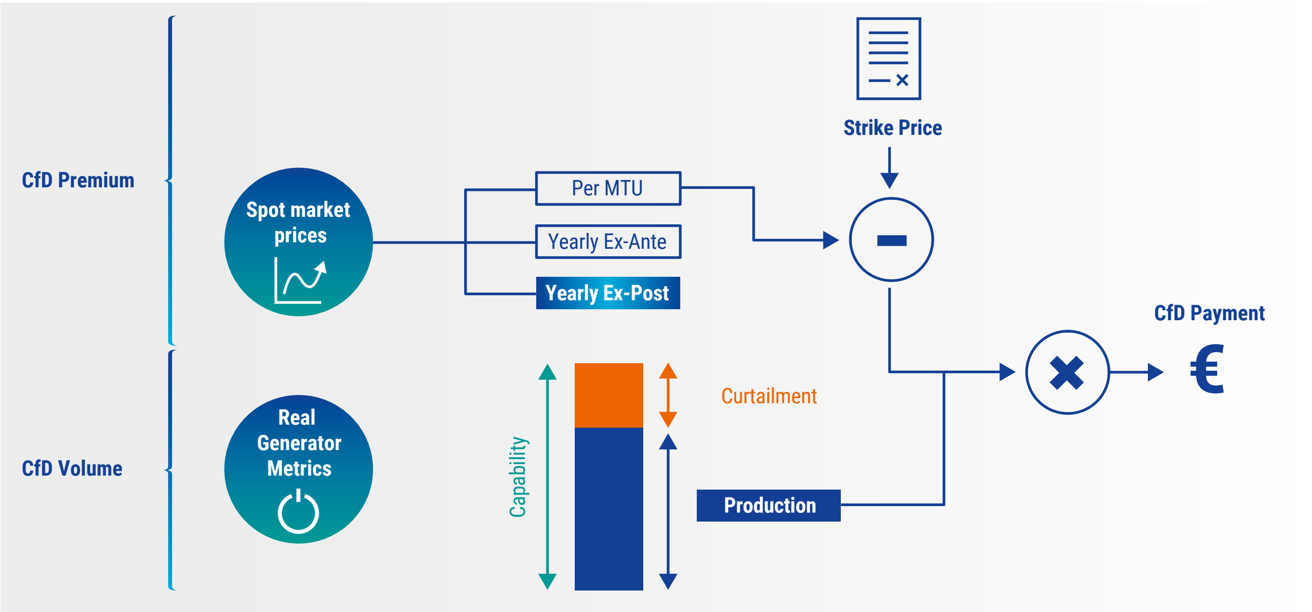

Figure 4: Conceptual illustration of production-based CfD with yearly reference market price determined ex-post

Dispatch (operational phase)

The longer averaging period and especially the fact that the reference market price is only known ex-post increases the incentive for efficient dispatch in all market time frames. However, distortive dispatch incentives will be observed towards the end of the reference period when the CfD payment can be estimated with increasing accuracy and thus, producers can adjust their bidding behavior according to the expected CfD payment. Market parties will still have the incentive to cease production at times of negative day-ahead prices, since they will not receive any support. However market parties have still an incentive to produce when the expected difference between the strike price and the reference price is higher, than the expected revenue from ceasing production in intraday or imbalance markets. The risk of manipulating the dispatch/market and subsidy payout in a small bidding zone e. g. an offshore bidding zone with limited numbers of generators, is higher, but there is regulation in place to counter specific cases of market manipulation. In addition, planning maintenance at system-optimal times within the reference period i. e. when demand and potentially prices are low is incentivised. Especially if the reference price is determined on a yearly basis incentives for optimising maintenance across seasons are created.

Asset design and siting (investment phase)

Designing a CfD with a monthly or yearly reference period and based on the production of all plants of the same technology category (e. g. solar, wind onshore, wind offshore) creates more incentives to invest in system-beneficial asset designs that produce at times with higher electricity prices enabling producers to achieve higher average market prices than the rest of the plants of the same technology, compared to hourly reference prices. Furthermore, limiting the length of the contract by a maximum number of full load hours leads to a better locational steering of the (onshore) RES investments. The payout is the same everywhere and paid for the same number of MWh therefore, the incentive to choose locations with higher capacity factors in the expectation of higher subsidies is reduced.

7 This CfD design is inspired by the sliding premium in Germany which is a one-sided CfD, meaning that there is no clawback and the producers only receive the difference between the strike price and the so called "market value of the electricity". This is defined as the monthly (and since 2023 yearly) average electricity market value of plants in the same technology category calculated ex-post. EEG 2023 https://www.gesetze-im-internet.de/eeg_2014/anlage_1.html

Risk hedging (price and volume)

A certain cash flow risk is introduced due to the fact that the reference market price and the actual price that the producer achieves in the market can deviate. In this case, the longer the reference period and thus, further away from actual achievable market prices the CfD is settled, the higher the price risk exposure for the producer. In addition, by defining the duration of the contract based on a number of full load hours over the lifetime of the project, volume risks are partly hedged, since the support does not depend on the energy produced in any individual hour. Therefore, lost revenues from not being dispatched due to negative prices or as a result of market coupling, would be made up for at a later point in time.

Regulatory risk

Many of the aforementioned CfD design elements have been used in existing support schemes like in the sliding premium in Germany and the SDE++ in the Netherlands. Therefore, it is deemed feasible for market parties to adjust their bidding and financing structures.

6.3.4 Price cap and floor

General concept description

Under a cap and floor CfD, a generator is guaranteed a maximum and a minimum price per MWh production, with exposure to the market price within that range. In this type of CfD the single strike price is replaced by the cap and floor prices.

With a cap and floor CfD the cap and floor prices would typically be higher and lower respectively compared to a similar classical two-sided CfD. In a classical two-sided CfD the revenue of the generator is fixed by the strike price. With a cap and floor CfD a generator can capture some additional revenue if the market prices increase, up to the cap price. Therefore, the floor price may be lower compared to a classical two sided CfD.

The cap-floor price range means the generator is exposed to the market price as long as it is typically within that range. If over time the market price changes significantly and is structurally above the cap or below the floor price for extended periods, it behaves in practice as a classical two-sided CfD with the cap or floor price acting as the strike price.

Design options

The volume in this CfD is the produced volume. The main design options are the cap and the floor prices. In a tender the cap price may be fixed reflecting the accepted infra marginal rent, while the floor price is set through competitive bidding. Optionally a cost/benefit sharing mechanism could be implemented in which the generator keeps part of the revenue if the reference price is above the cap price, or pays part of the price difference if the reference price is below the floor price. This would on the one hand further limit the short-term market distortions of the CfD and incentivises generators to maximise the market value. But on the other hand also increase the risks for market parties that the CfDs aims to mitigate.

Similar to the CfD with monthly/yearly reference price determined ex-post, the cap and floor price CfD should ensure there are no payments to generators when prices are negative, in compliance with state aid guidelines[8].

Also similar to the non-production based CfD further design options may be considered to further mitigate short term market distortions, such as capping the maximum number full load hours that are covered under the CfD and using an ex-post reference price.

The properties of this CfD depend on the relation between the cap and floor on the one hand and the market prices on the other. With a low floor and a high cap, they are not binding under normal/expected circumstances and the CfD behaves very much like a market price contract mitigating the effects of a CfD, with the cap and floor acting as insurance against unforeseen developments in market prices. With a high floor and low cap, the CfD is more like a CfD with one strike price, as either the floor or the cap normally will be binding.

8 In any case, the European State Aid Guidelines do not permit payments for production under negative prices, so such support schemes should be fased out.

Qualitative assessment: objectives/risks

Dispatch (short-term market)

A cap/floor price CfD is very similar to the improved two-sided production based CfD in terms of mitigating short term market distortions. But there is a further incentive for the generator to optimise their dispatch on the market price and mitigating short term market distortions, by exposing the generator to the market price within the cap floor price range. Similar market distortions remain, however, once the cap or floor is attained.

Investment (system-beneficial design & operation/maintenance)

The cap/floor price CfD is very similar to the improved two-sided CfD in terms of system beneficial design and operation/maintenance.

Risk hedging (price risk; incl. reference period + volume risk and impact on financing cost)

Generators are exposed to market price risk but this is limited to the range of the cap and floor price. The price range gives reasonable assurance for debt, and some additional upside for equity compared to a classical two sided CfD.

Similar to other production based CfDs, with this CfD generators are exposed to the volume risks incurred by weather variations, and maintenance and outages. The generator is also exposed to the volume risk incurred by market congestion, when the interconnection capacity of a bidding zone limits the production within a bidding zone resulting in market curtailment of generation.

Regulatory risk

The cap/floor price CfD is simple and transparent and does not rely on external benchmarks. There are risks, particularly with regard to short term market distortions.

6.3.5 Revenue cap and floor

General concept description

The CfD with revenue cap and floor has some similarities with the price cap and floor. But instead a generator would be guaranteed a minimum revenue per MWh production. They can act on all market segments, and if in a period they do not meet the minimum revenue they would be paid up to the minimum revenue. If in a period they exceed a maximum revenue they would have to pay back a proportion of that revenue.

Design options

The volume in this CfD is the produced volume.

The main design option is the cap and floor revenue per MWh. In a tender the cap revenue may be fixed reflecting the accepted infra marginal rent, while the floor revenue is set through competitive bidding. Optionally a sharing mechanism could be implemented when the market price is outside of the cap and floor range. The generator then keeps part of the revenue above the cap or pays part of the price difference below the floor. This further limits the short-term market distortions of the CfD and to incentivise generators to maximise the market value.

The reference period is another key design option, similar to the classical two sided CfD with similar considerations.

A longer reference period would mitigate short term market distortions. A shorter reference period would mean that if the market conditions are below the floor revenue the generator would disregard the market incentives for dispatch decisions, resulting in short term market distortions.

Similar to the improved CfD, the cap and floor revenue CfD should ensure there are no payments to generators when prices are negative, in compliance with state aid guidelines[9].

Also similar to the improved CfD further design options may be considered to further mitigate short term market distortions, such as capping the maximum number full load hours that are covered under the CfD and using an ex-post reference price.

9 In any case, the European State Aid Guidelines (cf. article 123) do not permit payments for production under negative prices, so such support schemes should be fased out.

Qualitative assessment: objectives/risks

Dispatch (short-term market)

A cap/floor revenue CfD is very similar to the cap/floor price CfD in terms of mitigating short term market distortions. But may limit distortions further by considering all revenues, rather than only a price benchmark for one market segment (in which case distortive effects may occur in subsequent market segments, e. g. intraday and balancing).

Investment (system-beneficial design & operation/maintenance)

The cap/floor revenue CfD is very similar to the cap/floor price CfD in terms of system-beneficial design and operation/maintenance.

Risk hedging (price risk; incl. reference period + volume risk and impact on financing cost)

Generators are exposed to market risk but this is limited to the range of the cap and floor revenue. The revenue range gives reasonable assurance for debt, and some additional upside for equity compared to a classical two sided CfD.

Similar to other production based CfDs, with this CfD generators are exposed to the volume risks incurred by weather variations, and maintenance and outages. The generator is also exposed to the volume risk incurred by market congestion, when the interconnection capacity of a bidding zone limits the production within a bidding zone resulting in market curtailment of generation.

Regulatory risk

The cap/floor revenue CfD does not rely on external benchmarks. However there are risks, particularly with regard to short term market distortions. Moreover the inclusion of balancing services revenues and the potential distortive effects on either the balancing mechanism or market behaviour carry a significant risk on the functioning of those markets, and are less well understood.

The revenue cap and floor CfD requires elaborate and complex accounting of revenues, resulting in a high administrative burden. This is an intensive process, similar to the inframarginal rent clawback, with a high administrative burden. Furthermore portfolio balancing further complicates the accounting of revenues, particularly if revenues from balancing services were to be included. How those could be earmarked is unclear, and may pose risks to the functioning of balancing markets.

6.4 Non-production based CfD

Production-based CfDs risk important distortions, which negatively impact dispatch behavior and asset design while retaining important risks for the generator. Whereas the CfDs in the previous section attempt to resolve these issues in the timing of measuring of the injection or changing the reference price, the core idea of CfD designs in this chapter is that the actual output of the generator benefiting from a CfD does not directly influence the payments to or by the generator. In other words, the reference volume to determine the amount of MWh for which the generator is compensated is not the injection of that asset. Rather, it is a metric for the "potential for injection" at any given time. Capability-Based CfDs, Financial RES CfDs[10] (Schlecht, Mauer, & Hirth, 2023 [8]), Deemed CfDs (Baringa, 2023) and Yardstick CfDs (Newberry, 2023) all represent concepts adhering to this "non-production based CfD" design. This paper shortly introduces various concepts and summarises the different options under Capability-Based CfDs, Financial RES CfDs, and Yardstick CfDs.

An important consideration for all models is when to use real production and when to use an estimation according to a model. The estimation should be used in all cases where it otherwise would be optimal from a system perspective to deviate from maximum potential for production based on marginal cost, cf. the Use Cases in the Appendix. Moreover, it should be used in cases where the assets are used for downward regulation. More complex cases arise when onshore grid constraints limit the output of RES assets, e. g. in the case of Offshore Bidding Zones. A further discussion on this topic is outside the scope of this paper but should certainly be considered in relevant contexts. An obvious case where support would not be based on an estimation of potential production is where the relevant assets are not operating due to outages or planned maintenance. It should further be noted that the normal situation will be that potential production equals real production, and only during special conditions may this not be the case, and estimation of capability becomes important.

A final issue is that when support is not based on physical production, it reduces the incentives to maximise production, which seems to be in contradiction with the wish to maximise emission-free generation. However, the incentives in the proposed models are aligned to maximise production whenever it can be utilised, and as such when market value is the highest. Zero or negative prices indicate a situation where there is too much production. If certain sources continue to produce, others will be curtailed. Either the power that is not produced in the proposed models or other power would be curtailed in the case of production based support. Such excess production might also be harmful by reducing system security.

10 The original paper refers to "Financial Wind CfDs". Here we generalise the concept to also include e. g. solar

6.4.1 Capability-Based CfDs

General Concept description

The distinguishing feature of Capability-Based CfDs, compared to the other concepts, is that the potential for injection (or "capability") is defined at the level of the individual asset: it defines the amount of MWh the generation facility could have produced as an individual estimation based on weather conditions and parameters specific to the asset. This means, for example, that in case production is reduced due to unprofitable (i. e. negative) market prices, the CfD will continue to pay out the price difference for the energy the generator could have injected instead of actual injection.

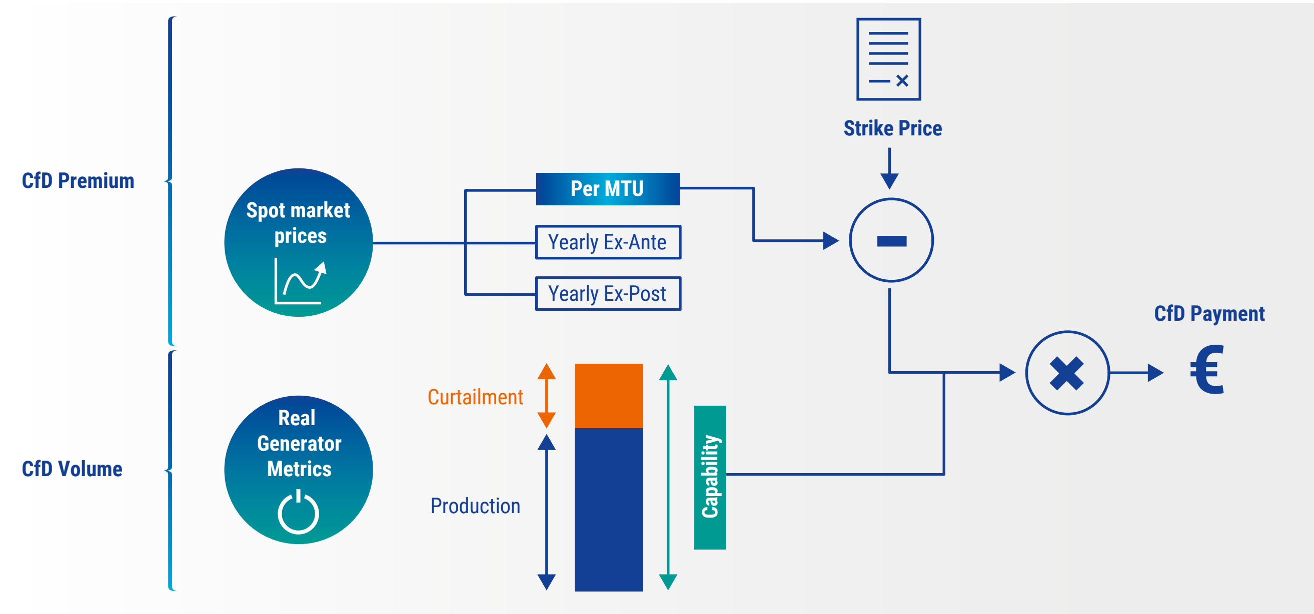

Figure 5: Conceptual illustration of capability-based CfD

The metric used for capability is a key design feature and falls under the discussion of the design options. In order to ensure a reliable and non-discriminatory measure for capability, it should adhere to the following principles:

- It is able to continuously and accurately determine the generator's potential for injection
- It cannot be manipulated; auditing the data should be possible
- It should be accessible to all generator developers

Options for estimation of capability

For illustration we describe three approaches for the estimation of capability. Other approaches may also be developed.

Available Active Power

The first metric considered to define capability is Available Active Power. (AAP) It is a real-time stream of data provided to renewable park operators (possible for both wind and solar PV), providing the maximum possible output of the assets at any given moment, taking into account a.o. local weather conditions and topology of the park. It is generated by a built-in module performing the calculation of this metric and provided by the manufacturer of the asset, and it is becoming standard on all new wind turbines. The calculation itself is normally intellectual property of the manufacturer and is not customised for the specific operator. This should make it hard for the asset owner to manipulate such data.

Moreover, the data is produced continuously, and can thus be compared with actual production data to ensure their correctness.

Elia's baselining study (Elia, 2021 [2]) shows variations between different methods of determining AAP. At high output and for certain methodologies across the board, inaccuracy is estimated consistently below 5 %. This type of module is more or less standard with new wind turbines.

This metric was originally assessed by Elia as a baseline methodology for the provision of TSO services. In general, determining the potential for injection is very similar to establishing a baseline for a generator.

Power curves based on local weather observations, operated by a central entity

In this case, the capability is determined by a central entity (on behalf of whichever institution that pays for or receives the contributions from the CfD). Estimations are based on the power curves of the relevant turbines, which are known. The advantage of this approach is that the estimation is independent of the asset owner. On the other hand, it is less accurate, because it will be hard to take into account all relevant parameters that are used in a more physical mode, e. g. the topology of the wind park and how this affects airflow and potential output[11].

Market bidding (for systems with per-unit bidding)

In markets that have per-unit bidding, the entity operating the CfD could have bidding information of individual generators. This allows for the CfD to be matched exactly with the price of the corresponding market (Day-Ahead and/or Intraday) and volume, providing a "perfect" hedge on the considered market(s). These bids translate into a balancing position if the bid is selected. In other words, if the asset ends up not delivering the sold volume, they are liable to imbalance costs. These costs usually exceed the gains from the wholesale markets and so there is an incentive to only sell volumes the bidding party can deliver. With the CfD, however, the gains in day-ahead are fixed, meaning that if price expectations and the cost to resolve a short system imbalance are low, there might be an incentive to "overbid" in markets. The imbalance cost is generally hard to predict and such a strategy would remain risky, but the potential for such a strategy should be investigated further before applying this metric. In addition, there are advantages to not restricting the market to per-unit bidding (e. g. notably for demand side response aggregators) and so they should not be forced to change towards per-unit bidding for CfDs alone. Nevertheless, a scheme resembling this approach currently exists in Spain (the "REER" scheme[12] [MITECO, 2020] [6]), providing a practical application.

Qualitative assessment: objectives/risks

Dispatch

The CfD payments are not directly related to the actual output of the asset and there is therefore no benefit in deviating dispatch from what is optimal under market prices. As an example, if a BSPs position is in excess of it day-ahead commitments and there is overproduction in the system in general, the asset is causing a cost for the BRP, and there is an incentive to reduce production until the BRP is balanced. Under the capability-based CfD, this reduction of output will not influence CfD revenues, and the asset gains by aligning their output with market price signals. This also means that the CfD pay-out is not negatively affected by down regulation for e. g. TSO services. Capability-based CfDs therefore avoid dispatch distortions. In the case of "market bidding" model, there might be an incentive to "overbid" in markets, which can be a risky behaviour as imbalance prices are generally hard to predict.

Investment and maintenance

The capability-based CfD aims to fix the price for any MWh the asset could produce when using an hourly DA price as a reference. Therefore, the time of delivery to potentially inject a MWh does not influence revenues. While this does not influence dispatch, the asset owner will have no incentive to consider time of delivery in the design or maintenance planning of the asset[13]. Indeed, whether the asset can deliver more energy under high or low prices does not change overall revenues. Since every MWh is valued equally, the asset owner will maximise the MWhs the asset can deliver overall. A reference price based on a longer period (year, month) would reduce this problem, but has other challenges (e. g. individual generator risk).

11 In Germany, this method is used to calculate the compensation for RES in case of redispatch (it is called "Spitzabrechnungsverfahren"). It is common to use a correction factor to take the specific conditions of the wind turbine into account (e. g. local vegetation, wake effects by other WTs).

12 The Remuneration Regime for RES was approved in 2020 by Real Decreto 960/2020, and since then 4 auctions have taken place, but still no units under this regime have been integrated in the Spanish electricity market. This regime includes as a novelty the possibility of an additional element of market exposure, through a parameter called percentage of market adjustment (which the paper has not analysed in detail). More information can be found on https://www.miteco.gob.es/es/energia/renovables/regimen-economico-energias-renovables.html

13 The design becomes less of an issue with the other models described below.

As an example, it is then more advantageous to construct south-facing solar panels, as this maximises output, even if the system could use more east-/west-facing solar panels. In addition, since the revenues per MWh are the same under high- or low-price periods, the asset owner has an incentive to plan maintenance when the volume potential is the lowest, but not when the energy is needed the least. Insofar maintenance and asset design can have a significant impact on the value to the system, this is a disadvantage of the capability-based design. Maintenance is probably less of a problem for offshore wind, where maintenance in any case must be done during the summer and will depend on availability of maintenance crews.

Risk hedging (price risk; incl. reference period + volume risk and impact on financing cost)

Since the capability-metric is at the level of the individual asset, it provides a near-perfect hedge and thus minimal risk for the asset owner. This should result in a low strike price in a CfD tender. The estimated capability will deviate from the day ahead forecast that is the basis for the asset owner's bidding in the day ahead market, and they will therefore face an imbalance risk. This is however not different from a normal situation where the asset is operated at its physical capability. In addition, inaccurate centralised methods (e. g. applied wind curves/forecast by CfD entity) could increase the risk. Lastly, there is a risk that the overall potential for wind production is lower than expected. Overall, the risk under a well-designed capability-based CfD should be low compared to other CfD designs, and there could be ways to deal with the remaining risks in the design.

Regulatory risk

There are currently no known capability-based CfDs in operation and hence there is no operational experience with this design. Nevertheless, capability-based CfDs using AAP should be relatively easy to implement, since the metric is already in use by RES asset operators. Other metrics may need additional regulatory consideration and assessment of potential strategic bidding. In addition, capability-based CfDs should be more robust to regulatory changes such as new configurations of bidding zones, since the revenues do not depend on the deployment of the asset in the market (i. e. dispatch), cf. the introduction to this section about non-production based CfDs.

6.4.2 Financial RES CfDs

General concept description

The Financial RES CfDs (Schlecht, Mauer, & Hirth, 2023) are similar to the capability-based CfDs described above, as the model is designed to decouple payments from the actual production of individual power-generating assets. However, instead of relying on the output of a specific asset, payments are based on benchmark revenues calculated from a reference generator (reference, generation multiplied by DA-price), providing a partly hedge against volume and price risk. This contract model basically involves a dual payment system (see also the mathematical description below):

1. The government pays a fixed hourly remuneration to the generator for each installed MW. This payment is determined through a competitive auction and remains constant throughout the contract's duration, unaffected by production levels or market prices.

2. The generator, in turn, pays the government the calculated hourly profits of a reference generator and not the subsidised asset itself.

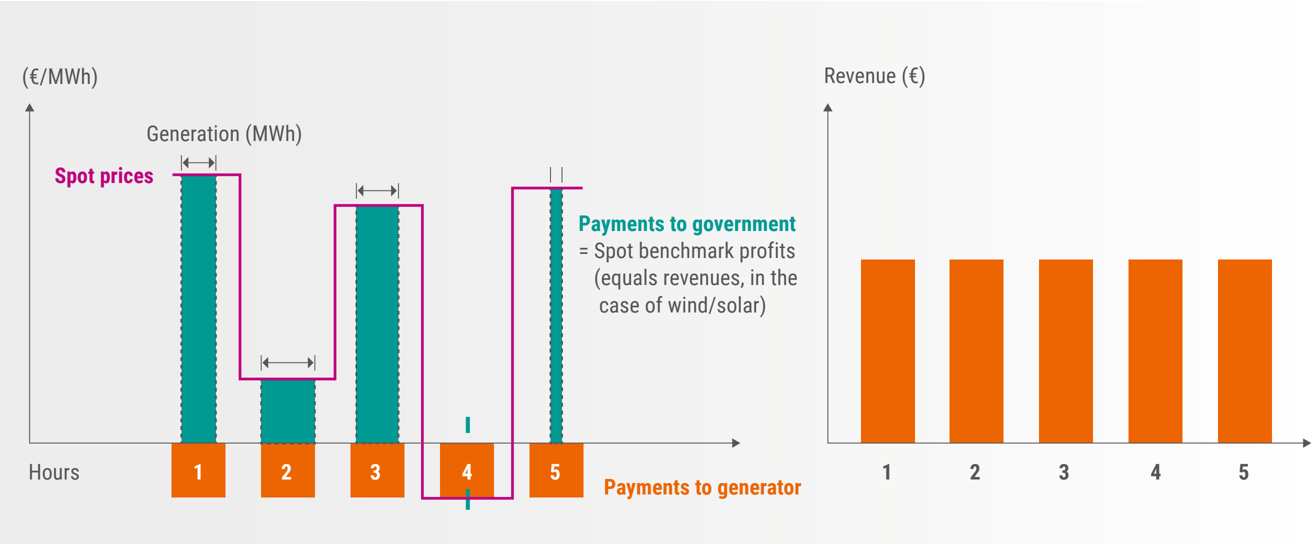

Figure 6: Conceptual illustration of Financial RES CfDs (Schlecht, Mauer, & Hirth, 2023)

None of the two flows are affected by the generator's actual production, and the generator can maximise income from its generation over multiple timeframes. This also implies that this model has some characteristics of an investment subsidy where the generator receives a fixed subsidy for each installed MW. The generator is left with the financial risk from the difference between actual generation and the reference generation[14].

Example for offshore wind in an offshore bidding zone

Such wind capacity is particularly sensitive to competition on grid capacity and allocation of scarce grid capacity as a whole. If the reference generator does not take this into account, the risk remains with the wind farm. On the other hand, such a risk is very location-specific and would in other words be hard to reflect in a generic reference. A Financial RES CfD might therefore end up not covering this risk.

Mathematical description

S	Fixed hourly remuneration
$Q_A(i)$	Asset production in hour i
$Q_R(i)$	Reference production in hour i
$p(i)$	Spot price in hour i
N	Number of hours in the year
Y	Set of hours in actual year

Hourly revenue of asset: $R_A(i) = S + Q_A(i) \cdot p(i)$

Hourly cost of asset: $C_A(i) = Q_R(i) \cdot p(i)$

Net annual operating revenue: $OR_A = N \cdot S + \sum_{i \epsilon Y}[Q_A(i) - Q_R(i)] \cdot p(i)$

The sum expression illustrates that if $Q_A(i)$ and $Q_R(i)$ are perfectly correlated, the sum become zero and the net operating revenue is the fixed payment from the state.

14 Such risks could be mitigated by e. g. a stop-loss function on the clawback, which at least limits the generators exposure in extreme cases. However, this means the generator may retain additional inframarginal rent in practice. This reduces the potential clawback revenues for the state issuing the support and is for them to consider.

Figure 7: Costs and revenue for a hypothetical 10-hour period

Figure 7 illustrates the costs and revenue for a hypothetical 10-hour period. The data assumed a rather strong negative correlation between the spot price and generation, which results in low generation of both asset and reference when prices are high, and high generation when prices are low. A positive correlation between the asset and reference generation is assumed. We see that the asset and reference revenues are of similar size, but not equal. The resulting net revenue is thus not constant, but relatively stable, and of course much more stable when aggregated over longer periods.

Design Options

The reference generator is a crucial component of the proposed Financial RES CfDs, as it serves as the standard against which the actual performance of the contracted asset is assessed and benchmark income is calculated. The authors suggest three different approaches to define the reference generator: a model that derives reference output from weather data (such as the EPEX wind index), a sample of actual assets, and the aggregation of wind/solar generation over a larger region (a country or a bidding zone). Each of these options come with some risks, for instance when the sample of physical assets that is used is small there might be a financial incentive to manipulate the dispatch of these reference plants. Furthermore, using a too granular aggregation would result in individual assets becoming too important.

In general, having a more generic reference creates more incentives for investments in system-beneficial assets that can produce at times with higher prices and so optimise their market revenues. This is particularly relevant for onshore assets. There is not perfect solutions, there will always be a trade-off between risks/financings costs and system/market integration of assets.

Qualitative assessment: objectives/risks

Dispatch

The Financial RES CfD is aimed at incentivising generators to match their production with the demand needs of the electricity market. The model mitigates the “produce-and-forget” issue as well as other dispatch distortions associated with production based CfDs by making the generator’s payment to the government dependent on the reference generator’s performance instead of the asset’s actual production. Nevertheless, as the definition of the reference generator has a significant influence on dispatch decisions, it will be crucial that the benchmark meets a number of objectives, such as to be transparent and unbiased, reflective of average conditions and representative of the technology among others.

Asset design and siting (investment phase)

The Financial RES CfD incentivises a system-beneficial asset design and locational choices, as payments are not directly linked to the output of a specific asset, but rather based on benchmark revenues calculated from a reference generator. This could create more incentives to invest in system-beneficial asset designs that produce at times with higher electricity prices enabling producers to achieve higher average market revenues than the reference generator (incentive to “beat the market”). However, similar to other non-production based CfDs, it is not clear to what extent this CfD design incentivises optimising capacity at the expense of generation efficiency (lower feed-in per capacity), especially if the policy goal is to support electricity generation (MWh).

Investment and Risk Hedging

The Financial RES CfD provides a semi-fixed, stable income stream for developers, and could be an attractive proposition for developers seeking stable returns in the renewable energy sector. Additionally, it also offers a robust mechanism to hedge against both price and volume risks. The use of a physical generation asset as collateral, like a mortgage, adds another layer of risk mitigation. However, depending on how the reference generator is defined the financial CfD introduces a basis risk compared to capability-based CfD.

Regulatory risk

The Financial RES CfD concept includes several aspects that need to be assessed carefully before implementation. For instance, the already highlighted challenges defining a reference generator and the detailed accounting needed for the dual payments may add operational complexity compared to other options.

6.4.3 Yardstick CfD

The Yardstick CfD is a concept proposed by David Newberry (Newberry, 2022) where the payments of the CfD are defined as the difference between the strike price and reference price, multiplied by the product of the RES capacity and a "forecasted" capacity factor, and adding the average difference in hourly generation between the actual site and the bidding zone average.

The added proposition to this design is to also consider locational siting considerations, which can be handled through suitable market or grid pricing/tariffs (the paper mentions Locational Marginal Pricing with financial transmission rights or Transmission Network Use-of-System charges). The paper states that a cap on the number of full load operating hours for which the CfD is paid out should then largely remove preference for sites with higher annual generation. In absence of locational prices, locational incentives, and incentives to deploy energy with low correlation to assets of the same class could be added by providing an additional remuneration component proportional to the difference of the asset's capacity factor at a given time and a "system" capacity factor of the same technology class (or "yardstick VRE"). In that sense, it could resolve some of the shortcomings under the "Investment" criterion for capability-based CfDs. On the other hand, this adds to the complexity of the mechanism (e. g. requiring to define the system capacity factor and appropriate cap on running hours).

This model may be relevant if auctions are held over large geographical areas. In cases where they are limited to one particular site the additional elements concerning localisation are not needed and only add complexity. The linking of support to a number of full load hour is however a property that can be relevant also for other models, as it removes some uncertainty related to future generation.

Mathematical description

s	strike price
$p(i)$	hourly spot price
$f_{r,i}$	regional relative forecast generation in hour i
$f_{S,i}$	bidding zone relative forecast generation in hour i
f_{vi}	asset relative metered output in hour i
K	capacity of asset
N	contract length in full load hours
H	number of hours in one year

Hourly revenue of asset: $R_A(i) = \big(s - p(i)\big) \cdot f_{r,i} \cdot K + a_i \cdot K$

where support is limited to T hours and T satisfies $\sum_1^T f_{vi} = N$

and where a_i is the average annual difference between the biddings zone average generation and the generation on the actual site:

$$a_i = \sum_1^H (f_{S,i} - f_{r,i}) \cdot p_i / H$$

Dispatch

Efficiency requires that the asset will offer at its avoidable cost in the day-ahead auction and into the balancing market for constrained down actions. The strike price and revenue paid do not depend on a generator's actual hourly output inducing truth-telling bids. Bidding according to the true avoidable cost is a dominant strategy for a competitive generator unable to influence the market price.

Asset design and siting (investment phase)

The limit of full operating hours reduces the incentive to locate solely because of high capacity factors, while the correction term takes into account geographical differences and guides efficient locational decisions.

Investment and Risk Hedging

In principle the model can a provide sufficient hedge when the strike price is based on an auction, there is no unrealistically low limit and the number of full load hours for which the subsidy is given is acceptable. Similar as for the Financial RES contracts, there remains some risk related to the correlation between the forecasted generation of the asset and the regional reference. Authorities can reduce the risk by providing good statistical data for the reference.

Implementation

As for the other models propose in this group, further analysis is needed to gain a full understanding of the properties and effects of the model.

6.5 Importance of retaining balancing responsibility

The previous sections present the CfD as a vehicle to provide income certainty to developers of generator projects. While it indeed stabilises revenues in wholesale (in particular in the considered designs, relative to Day-Ahead), it does not eliminate all revenue/cost uncertainty for the generator. It should be clear however, that such support should never provide a hedge for imbalance costs. The exposure of grid users (directly or indirectly via a designated balance responsible party) to the full extent of imbalance prices is essential to ensure balance responsibility and the most efficient use of resources to keep the grid balanced. This principle is also cemented in article 5 of Regulation 2019/943, where the first paragraph states:

"All market participants shall be responsible for the imbalances they cause in the system ('balance responsibility'). To that end, market participants shall either be balance responsible parties or shall contractually delegate their responsibility to a balance responsible party of their choice. Each balance responsible party shall be financially responsible for its imbalances and shall strive to be balanced or shall help the electricity system to be balanced."

It should be clear that the imbalance price in the end enforces that earlier commitments (such as in forward or day-ahead markets) resulting in schedules are respected. Trading electricity entails taking a position in the BRPs overall balance and failure to deliver that energy results in an imbalance, which is subject to the imbalance price. Reducing deviations from schedules resulting from traded electricity reduces the "penalty" for not delivering on a commitment – imbalance settlement costs. If extensive shares of the imbalance costs are compensated by a support scheme, this provides a "risk of overselling" (i. e. selling more than what a party expects to be able to deliver) lucrative. This risk must be mitigated by a suitable incentives through the imbalance settlement scheme on national level in the framework of EB Regulation. The basic principle that each balance responsible party shall be financially responsible for its imbalances and obligation to strive to be balanced or to help the electricity system to be balanced remains untouched. This can be supported by short-term trading possibilities via intraday markets to balance imbalances resulting from long-term trade and uncertainties of real available generation. Any financial incentive to stress the system through intentionally open positions must be avoided. For these reasons, retaining full balancing responsibility remains a crucial principle which should be supported by support schemes as well.

Key recommendation on CfD design – Production-Based CfDs

Criterion	Production-Based CfDs				
	Hourly Price	**Yearly Price Ex-Ante**	**Yearly Price Ex-Post**	**Cap/floor Price**	**Cap/floor Revenues**
Dispatch	⊖ ⊖ > Regular distortions expected in Intraday and Balancing > Risks overproduction, curtailment and artificial price increases	⊖ ⊖ > Regular distortions expected in Day-Ahead, Intraday and Balancing > Risks overproduction, curtailment and artificial price increases	⊖ > Distortions are mitigated by not revealing the value of the CfD premium > Distortions may persist towards the end of the settlement period when the premium is more predictable	⊖ > Allows margin of undistorted dispatch/bidding within price bounds > Distortions persist when either price is exceeded > Higher cap and lower floor reduces likelihood of distortions	⊕ ⊕ > Exact difference payments on revenues made in each timeframe could avoid distortions > Any "shortcuts" in implementation can allow distortions to persist
Asset Design & Siting	⊖ ⊖ > Incentivises volume maximisation	⊕ ⊖ > Reference is unaffected by individual asset > Incentivises revenue maximisation accounting for the premium	⊕ > Reference is unaffected by individual asset > Incentivises revenue maximisation	⊖ > Margin between cap and floor incentivises capturing higher prices therein > Unless cap/floor are very high/low, margin is limited	⊖ ⊖ > Incentivises volume maximisation > Equalises price across all timeframes, also Intraday and Balancing
Risk Hedging	⊖ > Volume risk is not covered (option does not include yearly full load hours) > Uncertainty on production under negative prices/ curtailment at high prices	⊖ ⊖ > Yearly full load hours can cover CfD volume risk > Volume risk in market remains > Uncertainty on production under negative prices/ curtailment at high prices > CfD premium is backward-looking	⊕ ⊖ > Yearly full load hours can cover CfD volume risk > Volume risk in market remains > Uncertainty on production under negative prices/ curtailment at high prices > Price weighting cannot correspond to individual asset to avoid distortions	⊖ > Yearly full load hours can cover CfD volume risk > Volume risk in market remains > Uncertainty on production under negative prices/ curtailment at high prices > Cap/floor still allows volatility	⊕ ⊖ > Guarantees revenues across timeframes > Uncertainty remains between cap and floor
Regulatory Risk	⊖ > Similar to existing schemes > Not robust due to risk of distortions, necessitating changes later on	⊖ > Similar to existing schemes > Not robust due to risk of distortions, necessitating changes later on	⊕ ⊖ > Similar to existing schemes > Not robust due to risk of distortions, necessitating changes later on > Distortions may be mitigated to an extent	⊖ > Similar to existing schemes > Not robust due to risk of distortions, necessitating changes later on > Administrative setting of the price cap	⊖ ⊖ > Distortions may be limited > Requires visibility on revenues across all timeframes > Administrative setting of the price cap

Table 2: Key recommendation on CfD design – Production-Based CfDs

Key recommendation on CfD design – Non-Production-Based CfDs

Criterion	Non-Production-Based CfDs	
	Capability-Based	**Financial**
Dispatch	⊕⊕ > Removes conflict between dispatch and CfD premium in DA, ID and balancing timeframes	⊕⊕ > Removes conflict between dispatch and CfD premium in DA, ID and balancing timeframes
Asset Design & Siting	⊖ > Incentivises volume maximisation > Could be mitigated by weighting the CfD premium calculation according to generic reference > Schemes to promote hybrid units (as e. g. applied in Spain) are a subject for further investigation	⊕⊕ > Incentivises revenue maximisation, accounting for design and siting benefits > Siting benefits most flexible for Yardstick
Risk Hedging	⊕ > Both volume and price risk is covered > Performance measured relative to specific asset > Risk can remain under generic reference premium	⊕⊖ > Both volume and price risk is partly covered > Uncertainty on performance relative to reference asset
Regulatory Risk	⊕⊖ > Use of new metric > Robust for the future against distortions	⊖⊖ > Definition of reference power plant/yardstick may be a complex/contestable process > Robust for the future against distortions > Appropriate payment exceptions should be defined (e. g. long outages)

Table 3: Key recommendation on CfD design – Non-Production-Based CfDs

The CfD design influences the way RES respond to market conditions and in many cases has a distorting impact on price signals and the power system operation. With higher shares of CfDs in the future distortive effects such as producing electricity when prices are negative (i. e. below marginal costs) would proliferate in a high-RES system impacting significantly the price formation and thus, system operations. Therefore, from a system perspective is of high importance that CfDs are designed to incentivise efficient dispatch in all market timeframes (i. e. day-ahead, intraday, balancing) as well as investments in system-optimal asset designs and siting that maximise the value and not the volume of electricity. To this end, non-production based CfDs, where the CfD volume is settled based on a reference and not the actual production of the asset, can remove dispatch inefficiencies on day-ahead, intraday and balancing. They are further subdivided into two types[15]:

- Capability-based CfDs are settled on the maximum possible production of the asset reflecting the active power output under normal conditions (i. e. without any curtailment).
- Financial RES are settled on the production of a "reference generator"

Capability-based CfDs could offer a better risk and financial coverage compared to financial RES CfDs. On the other hand, the financial RES CfDs could create more incentives for system-beneficial investment decisions, resulting from a global reference electricity production profile. – If an installation deviates from this average production profile and operates at times of higher market prices, developers will profit from the correspondingly higher revenues per MWh. In any case, attention is needed when defining the reference volume. This should be done in a robust and transparent way to prevent possible inadvertent behaviour. Although non-production based CfDs can avoid dispatch distortions as described above, there is no practical experience yet with these CfD designs. Finally, it is noted that the solution will be a trade-off between several concerns like optimal dispatch, siting and maintenance incentives and risk minimisations, and the chosen solution will depend on technologies and national preferences. In the end, ENTSO-E recommends a move towards non-production-based designs, though further discussion is needed around the detailed design of capability/the reference plant.

If policy makers decide to implement production-based CfDs, these should at least be designed to minimise market distortions. To this end, a CfD with a reference market price defined as a technology-specific weighted average of DA market prices, determined on a yearly basis and calculated ex-post i. e. after the end of the reference period could provide better incentives for efficient dispatch and system-optimal investment decisions compared to other production based CfD variants. Moreover, defining the duration of the contract based on an number of full load hours over the project lifetime could serve as a certain level of locational steering of onshore RES investments to contribute to a better coordination of market investments with grid expansion and ultimately a more balanced system. Such a design choice could also cover volume risks for RES developers e. g. not being dispatched due to negative prices or as a result of market coupling. Finally, introducing a cap and floor price rather than a single strike price could further mitigate distortive effects. Nonetheless, non-production-based CfDs are expected to provided a mores exhaustive prevention of market distortions.

To conclude, ENTSO-E recommends:

- **To move away from production-based CfDs and towards non-production based CfDs**

  Justification: as increased amount of renewable/low-carbon is introduced into the system and we cannot know whether they will be supported or not, support schemes need to be designed so that such assets follow market price signals (and therefore system needs) at true marginal cost.

- **Where injection-based continues to be applied despite the above recommendation, to at least make them as least-distortive as possible accounting for the detailed considerations in the higher-mentioned paragraph (e. g. technology-specific yearly/monthly reference price determined ex-post, definition on full-load hours…)**
- **To continue with an open discussion on the precise definition of the capability of capability-based CfDs and the reference generator of the financial RES CfDs**

15 Yardstick CfD could align with either of these categories, depending on if the detailed design considers a more asset-specific (capability-based) or generic (financial RES) reference

7 Topic 2: Cost-benefit allocation to consumers

A state supported Contract for Difference is constituted to provide revenue adequacy and investment security to a generator owner. The counterparty to ensure this is the state government issuing the subsidy or a competent authority designated by them. Either way, the state needs to dispose of funds to supplement developer revenue at times of low prices and may receive revenues at times of high prices. It therefore needs to decide how to allocate both costs and benefits of a CfD scheme. Two options for doing so are elaborated and assessed further in this paper: an administrative allocation and a more market-based allocation.

While allocation of costs and benefits should primarily concern the member state issuing the CfD, the specific implementation can still distort the market on the demand side. In particular, if it affects consumer prices directly, they no longer reflect the true value of electricity and could hamper demand side response. For this reason, it is also of concern for TSOs that policy makers avoid such effects in the allocation of costs/benefits. Secondly, if a high share of generation is under a CfD, this might reduce supply on the forward market (since such generators are already hedged under a CfD). Accounting for this effect is of importance to preserve liquid forward market trade and consumer hedging options.

It should be clear that, for either model, the effects are marginal if the share of CfDs in the system is low. The financial flows will be relatively small and therefore potential impact on market functioning cannot be substantial. If CfD shares/volumes are high, on the other hand, the cost-benefit allocation could have impact on short-term price formation and forward market liquidity. While ENTSO-E continues to support fully commercial development of RES where possible, we cannot know whether the share of CfDs in the future will be high or low. Given the emphasis in the European market design reform on CfDs (particularly for renewable energy sources and nuclear), a non-distortive cost-/benefit reallocation may become key for efficient market functioning going forward. Hence, it is important to discuss a good design for cost-benefit allocation from a market functioning perspective. It should be no-regret to implement a robust method for high CfD shares, since it covers this case and the impact of low CfD shares will be limited anyway.

7.1 Administrative allocation

The most obvious way to allocate costs and benefits would be for the state to assess and decide which entities should bear the costs and receive the benefits respectively. It can of course decide on different shares for different entities. The costs would then be allocated via an appropriate tax instrument or levy and benefits can be allocated via a variety of financial pay-outs towards the target entities.

7.1.1 Design Options

A link between the cost-benefit allocation and the price for/use of electricity should be avoided in order to minimise the impact on short-term market prices/functioning. Under these circumstances and taking the administrative distribution as a starting point, there is then no reason for TSOs to be concerned with how the allocation is done.

On the cost side, this can, for example, be achieved by funding through existing, non-energy related taxation instruments or lump-sum payments by grid users that do not scale with consumed MWh over a period. On the revenue side, they could be used to supplement government budget or provide lump-sum support payments to grid users. Neither method should have an impact on electricity market prices. The distribution among tax payers/grid users is a political choice, but could be for example according to shares in energy consumption for different types of consumers. These more generic metrics should be less impacting on electricity price signals than direct €/MWh adders/reductions. For assessment purposes, this option is further referred to as the **non-consumption-based administrative allocation.**

Alternatively, if the allocation does relate in some form to electricity price or usage, this impacts the exposure of grid users (and particularly consumers, since they are likely to be targeted for CfD costs/benefits) to market prices and could have negative effects depending on the design. TSOs therefore see the need to discuss good practices to ensure that market distortions are avoided. This is important to ensure that electricity prices reflect their true economic value and consequently enable the right incentives for demand side response to develop. For assessment purposes, this option is referred to as **consumption-based administrative allocation.**

The negative effects under such a scheme most obvious if there is a direct pass-through of CfD costs/benefits as a per MWh tariff on electricity and with very precise time granularity. As an example, if CfD costs/benefits for a given market time unit on the Day-Ahead market are directly translated in to a per MWh tariff (positive or negative respectively) on consumption during that market time unit, this artificially inflates/deflates electricity market prices for every market time unit and hence distort incentives which leads to artificial high consumption when prices are high and low consumption when they are low.

At low market prices, consumers will be charged an additional cost to fund the CfD. This reduces the incentive to shift consumption to such a period or offtake electricity for storage purposes, whereas low market prices often indicate a high presence of renewable energy at that time. At times of high prices, market prices will be reduced for consumers, which undermines the incentive for demand response to reduce consumption during such times. Since at high prices, non-renewable energy sources are often at the margin, this could lead to increased fossil fuel generation over demand side response. Averaging the costs out over longer periods may mitigate this issue.

7.1.2 Qualitative assessment: Objectives/risks

Dispatch (short-term market)

Under non-consumption-based administrative allocation, impact on short-term market functioning should be limited/non-existent, since deviating from market-optimal consumption will not affect CfD cost/benefit allocation to the consumer. Under consumption-based administrative allocation, there may be significant distortions if consumers' exposure to the real value of electricity is reduced. This may cause demand not to respond to market prices, but to the CfD costs/benefits, necessitating flexibility from other resources and thus unnecessarily increasing the total cost for electricity. Averaging costs and benefits over large, shifted periods on total consumption can mitigate this to some extent.

Investment (system-beneficial design & operation/maintenance)

If the administrative allocation is designed to dampen price spikes for all consumers, it can significantly inhibit the interest to develop demand side flexibility, which is a significant risk.

Risk hedging (price risk; incl. reference period + volume risk and impact on financing cost)

From the consumer side, it is likely difficult or very expensive to source price hedging (e. g. via PPA or other forward contracts) from assets under a CfD, since such assets are already hedged and take extra risk on another forward commitment. Consumers may have ample alternatives if the share of CfDs is low, for high amounts of CfDs their options may be limited. The administrative redistribution might provide such a hedge, but it is also clear that the more it dampens electricity price volatility for consumers, the more it is distortive and the more it negatively impacts the growth of demand side response. Therefore, a consumption-based administrative allocation has a conflicting trade-off between market distortions on demand side and price risk hedging for consumers.

Regulatory risk

Implementation-wise, the administrative allocation is not very disruptive. Member states can likely integrate it in existing financial instruments or create a new, but similar to existing ones. However, there is a risk that administrative allocation affects competition in the internal European market, as Member States with a more consumer-favourable regime could attract more energy-intensive industry and artificially lower their cost. On the other hand, excluding such consumers does not provide them with price hedging from the administrative allocation and, as discussed above under high shares of CfDs, their options in the market may be limited or expensive. Secondly, there is a risk of instability of the allocation rules. While CfD contracts might run up to 20–25 years for new assets, the allocation of costs/benefits could always be revised by the member states. If it is not perceived as firm to larger consumers, this uncertainty poses a risk for them.

7.2 Market-based reallocation

Another way to allocate costs and benefits would be through a market-based reallocation approach. This concept is built around the state, or a delegated authority, being active in the forward market. The state resells previously bought renewable CfD volumes to consumers, and hence might enhance hedging opportunities for consumers.

For example, the state buys a 20 years CfD from a RE developer in a tender and subsequently sell the same amount of MW as 5 year contracts 4 times. In other words, the state acts a broker, to enhance hedging opportunities for consumers in the concerning bidding zone and then takes on a role of central counterparty for CfDs with generators and consumers. **This concept is here referred to as the back-to-back CfD.**

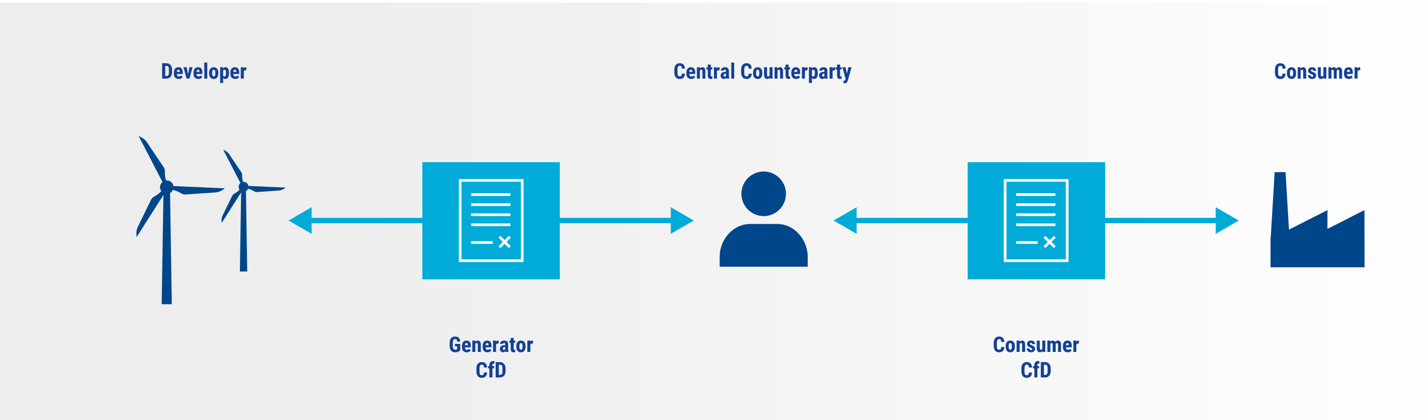

Figure 8: Conceptual illustration of market-based reallocation

Since the state or designated authority already has Contracts for Difference with generation assets, they could realise this by also signing CfDs with consumers. Like for generators, the CfDs would be allocated in a competitive tender. Since the revenues and expenses on either side at any given settlement period are unlikely to be matched, there remains a budgetary risk for the state as in the previous section. This depends very much on the chosen design (cf. next section), which determines the allocation of risks to either the central counterparty or the consumer.

A natural question to raise in this context is why the state should act as a broker, through a RES-CfD, if PPA demand and supply exist from commercial market participants. The answer to this question is that particular RES deployment wouldn't have taken place without state support i. e buying CfD at a price higher than the market price an resell it to a lower market price. The back-to-back concept is relevant if there are certain risks under a commercial PPA which consumers are not willing to bear at the time the RES needs to be built and might be mitigated under a centralised system where the state takes the budgetary risk and expected loss instead.

7.2.1 Impact on existing markets

It should be clear that if the state provides hedging opportunities for consumers, it is a form of consumer support by the state. Although it could increase supply in existing PPA/forward markets, this model can therefore also have a negative impact on existing PPA-markets and commercial forward market. In both markets, RES-developers that do not rely on the state-supported CfDs could find it harder to ensure financing under the commercial market conditions, since a part of the buy side is removed via the state reallocated volumes.

In addition, the model's impact on the state's budgetary risk is uncertain. On the one hand the state removes budgetary exposure to the day-ahead price (if there is no CfD pay out cap specified in the initial CfD-tender), but on the other hand the state impacted price will most likely deviate when the state resells the CfD after the initial CfD-tender. Even if the forward prices don't change, the 20 years forward price is typically higher compared to a 5 year forward price they sell due to interest effect (interest rates are higher for 20 years fixing compared to 5 years fixing). As the state has entered into a sell contract, the risks associated with such contracts, like counterparty risk, will also be present for the member state.

This model will likely be most appealing for countries and time periods where the combination of a large share of RES capacity is under CfD's and a considerable consumer demand for PPA's is present. The state reselling CfD's is like an extra PPA supply and a competing element to the already existing market.

The potential advantages and disadvantages from this model needs to be part of a broader debate before a more detailed assessment is in order. However, the following preliminary considerations regarding some key design features are important.

› **Contract length**

Consumer contracts could present periods shorter than the underlying CfD. The counterparty to the CfD would then periodically close contracts at different prices, depending on market circumstances at the time. Shorter contract lengths could also appeal to different consumer types. Collaterals with respect to contract length will also be an important factor, as the commitment should on the one hand be firm, but on the other hand could pose a barrier to entry.

› **Volume risk**

The CfD follows a certain profile related to the output of the underlying generator (cf. Topic 1). If the counterparty to the CfD would offer consumer contracts with different profiles (e. g. baseload) instead, it would significantly augment the risk on the counterparty and present a considerable subsidy, putting a disadvantage on fully commercial forward contracts. However, aggregate volumes over generators subject to CfDs to offer a more uniform product to consumers should allow better pricing, secondary trading and increase interest.

7.3 Key recommendations on cost-/benefit allocation

State-supported Contract for Difference generate costs/benefits, depending on actual market prices in the end, to the state issuing the subsidy. The state needs to allocate funds to supplement developers' revenue at times of low prices and receives revenues from the developer at times of high prices. We are considering two options in this paper:

› **Administrative allocation: ENTSO-E recommends non-consumption based allocations to preserve incentives for consumers to respond to market conditions and foster flexibility**

› **To further investigate the potential impact on existing forward/PPA markets of the market-based reallocation concept prior considering its implementation**

8 Topic 3: Coexistence with PPAs

Contracts for Difference entail a financial involvement of the state to provide sufficient certainty on the business case of the developer counterpart. On the other hand, similar security can be obtained on commercial terms under a PPA (subject to it's own obstacles, as reflected in the electricity market reform).

Developing renewable energy sources this way would be beneficial as there is no need to involve state funding and also from the perspective of limiting market interference and distortions (as in the end, a commercial party is bearing the cost of inefficient choices in the PPA's construction[16]). In a purely commercial contract, both developer and consumer can have an interest in entering into a long-term fixed-price purchasing agreement. For the developer, it provides certainty on the business case for their investment. For the consumer, it locks in the price of purchasing electricity.

However, the conditions change if the developer has already been contracted under a CfD. The developer already has sufficient certainty on the business case by the CfD. Entering into another fixed price contract for the same volume is possible, but puts extra risk on the developer as it is speculative trading (i. e. trying to beat expectations on future spot market prices). This is possible, but the details considered outside of the scope of this paper. However, it is important to note that this developer is no longer willing to offer fixed price PPAs at commercial prices.

While CfD payments by the developer to the government could also provide some protection against high prices, the actual cost-benefit reallocation is subject to government policy. Hence, from the perspective of an electricity consumer, the cost and benefit of a CfD is less firm than a PPA. Furthermore, risks sharing may be more symmetrically distributed in a PPA than in a CfD and, therefore, it seems of interest to the system as a whole to retain a space for commercial PPAs where possible. This section explores ways of coexistence.

16 As a PPA is typically a long-term contract which fixes price and volume definitions over time, it could lead to a loss in opportunity (e. g. the spot price is more favourable) or additional costs (e. g. cost of injection under negative price, if the PPA incentivises it). This is the case when the PPA does not match the reality of the market. Therefore, commercial actors are incentivised to appropriately assess the market reality at the stage of signing the PPA as they bear the full loss if it doesn't.

8.1 Carve out

A first model was suggested in the approved principles for an upcoming offshore tender in Belgium (Van Der Straete, 2023 [9]). Therein, a candidate bidder can choose to apply the CfD only to a certain percentage of the capability of the wind park. This frees up a part of the park's potential output for a commercial PPA: as the difference under the CfD is only settled on part of the volume, the remainder can also be sold at a fixed price to hedge the full output. The margin on the commercial part can lead to strike price reductions in the CfD tender, allowing the strike price to continue to be used as a primary selection criterion. This can be shown in a simple example:

Example:

In preparation for a competitive CfD tender, a candidate developer needs to determine the price per MWh they need to earn under the strike price in order to ensure the business case of the project (CAPEX, OPEX, pricing of risks and financing costs). Based on this exercise, a first candidate bidder decides that a strike price for the full volume of 80 €/MWh and put this in as an offer in the tender for 100 % of the volume. A second bidder also considers 80 €/MWh to be sufficient, but also has an interested consumer counterparty which would be willing to buy 40 % of the volume. More so, that party is willing to offer 86 €/MWh. Hence, for 40 % of the volume, the generator is making 6 €/MWh more than strictly needed to secure the business case[17]. The remaining 60 % of the volume would still need to be covered by the CfD, but they can afford to offer a lower price than 80 €/MWh because of the margin on the PPA part.

This is determined as follows: $$0{,}4 * 86\frac{€}{MWh} + 0{,}6 * Strike\ Price \geq 80\frac{€}{MWh}$$

Solving for Strike Price gives: $$0{,}6 * Strike\ Price \geq \frac{80\frac{€}{MWh} - 0{,}4 * 86\frac{€}{MWh}}{0{,}6} = 76\frac{€}{MWh}$$

In other words, this candidate would be willing to go to 4 €/MWh lower on the CfD contract taking into account the margin of the commercial contract.

Of course, the percentage of carve-out volume is a degree of freedom and depends on consumer interest. If the consumer would be willing to buy an unlimited volume at the listed price, the bidder would prefer to have no CfD at all (i. e. carve-out volume of 100 %). If there is appetite for a higher carve-out, but not 100 % on consumer side, the bidder could offer an even lower strike price. However, a carve-out bid with a lower percentage, but higher margin on the contract, might give a lower strike price still (of course, the lower the percentage, the less the margin will make a difference). It is therefore not guaranteed that the highest carve-out percentage wins in case the strike price is the primary selection criterion. However, the counterparty will be guaranteed the lowest strike price per MWh.

If, on the other hand, the objective of the CfD tender would be to minimise the cost of the support scheme, it becomes a much more complex exercise. This would entail projections of future prices, since only then can the height of the strike price and carve-out percentage be traded off correctly. However, predictions may be wrong and there will be no firm guarantee that one bid is in the end less costly in total than the other. However, the cost per MWh for the counterparty will no longer necessarily be minimal. More qualitative criteria could represent a simplified preference of authorities to have a higher carve-out percentage (e. g. bonus points for carve-out percentages), however, this quickly becomes arbitrary and hence difficult to assess in value. The two-stage tender forces a solution where the maximum commercial volume is allocated, but also doesn't guarantee the selection of the least-cost solution for the support scheme and faces additional considerations (cf. next section).

One key advantage of the carve-out is that it should enhance the potential of attracting commercially developed generation volumes. A fully commercial project can offer at a strike price of 0 €/MWh (for 0 % of volume) and hence can still be part of, or the full solution. In addition, a single project can make use of advantages of scale in developing a larger volume for both CfD and commercially developed shares. Integrating it in a single selection step should ensure that a cost-efficient decision can be made and avoids that the result of a first step limits the solution space for the second step, which is a risk for the two-stage tender. On the other hand, it requires careful assessment of undesired cross-subsidy effects between the CfD and PPA part.

17 It could be that the risk under a commercial contract is perceived as higher than under a government-issued CfD, which means that part of the margin presented here is needed to cover that risk. However, this is ignored for simplicity's sake in this example.

8.2 Two-stage tender

Another way of gauging the interest in commercial projects would be to hold a CfD tender in two rounds: one for commercial projects only (which can be done based on concession payments[18] as has been the case in the past) and a second round for CfD tender to ensure the political targets are reached[19]. In that sense, CfDs would only complete the volume up to the political target for which there were no candidate commercial projects.

Also here, in the case of concession payments, the margin on a commercial contract can be captured, representing a net reduction of cost (or income in case there is no more CfD volume). However, there is no direct trade-off between commercial and subsidised projects. This means that the first stage would select all commercial offers up to the target volume (unless caps are applied) and the second stage takes the remaining volume.

It is unclear, however, to which extent volumes can be segmented in such a way in practice. It is subject to how the physical development space can be segmented into separate spaces upon which separate bidders could build (and likely also with a separate connection). This will be subject to a certain granularity. Secondly, may be a risk that the remaining space after the first tender stage attracts little interest for other candidates and only those that were victorious in the first tender stage retain an interest. This could result in high strike prices for that tender. This might be mitigated by regulating the bid volumes (e. g. only certain discreet bid volumes are permitted), but are a practical case-by-case consideration.

8.3 Key recommendations on Coexistence with PPAs

As already stated in the introduction, a key enabler to complete the energy transition is the market and system integration of renewable energy sources by reducing or even making unnecessary the need for investment support. For this reason, CfD tenders should be designed in such a way that the market is able to first deliver the envisaged volumes (e. g., the models introduced in this section). Non-subsidised projects should be fully exposed to undistorted market prices[20], incentivising efficient dispatch. Furthermore, allocating volumes for the forward market allows electricity buyers and sellers to interact freely, fostering a competitive market. Where the market appetite is insufficient to meet political targets, CfDs can fill the gap. This dual approach may ensure a balance between market forces and government intervention, facilitating a more efficient and cost-effective transition to renewable energy sources.

To summarise, ENTSO-E recommends:

- **To integrate options for fully commercial (i. e. without any form of support) PPAs into CfD tenders**
- **To appropriately assess the implications of Carve-Out and Two-Stage Tender mechanisms in the specific context of a CfD tender (particularly for gaming risks and desired outcome)**

18 For tenders at specific locations, candidates could offer a fixed sum to the government for the right to develop RES at that location, if the expected commercial return is high enough.

19 As an example in Germany, there are so-called "centrally pre-investigated sites" where the bidders (among other qualitative criteria) need to market their production via PPAs and the "non pre-investiagted sites" for which the bidders are eligibe for support - in case of several zero bids a second acution round takes place.

20 It should be noted that any form of support changes this assumption. If support is issued by the state to establish PPAs, it depends on the design of the support, much like CfDs, to which extent distortions materialise.

9 Conclusion

The assessment under CfD design shows a clear advantage with respect to incentivising correct bidding behavior and dispatch towards non-production based CfDs and provides tangible starting points as well as relevant references for the detailed design of such schemes. A trade-off remains between Capability-based and financial RES CfDs, particularly regarding design incentives vs. generator and regulatory risk. Nevertheless, ENTSO-E recommends a move towards non-production-based designs and further discussion needed around the detailed design of capability/ the reference plant.

Non-consumption based reallocation under an administrative allocation should preserve efficient market price signals for consumers and hence not hamper the growth of demand side response, whereas consumption based reallocation should be avoided. Market-based reallocation can provide additional PPA volumes in the forward market, but the impact on existing PPA/forward markets is as yet unclear and should be investigated further.

CfD tenders should provide the opportunity for purely commercial projects to deliver the volumes first. The Carve-Out and Two-Stage Tenders provide two potential vehicles to deliver this, but the detailed design should be considered carefully to avoid gaming or undesirable outcomes of the tender. It is furthermore imperative that such commercial PPAs are entirely free of subsidy; otherwise the preference with respect to CfDs has no clear justification and other forms of support can perpetuate similar or new distortions.

In light of this, ENTSO-E recommends:

- **To move away from production-based CfDs and towards non-production based CfDs**

  Justification: as increased amounts of renewable/ low-carbon is introduced into the system and we cannot know whether they will be supported or not, support schemes need to be designed so that such assets follow market price signals (and therefore system needs) at true marginal cost. Such a move seems best aligned with the principles in article 19b of the approved proposal 2023/0077 of the electricity market reform.

- **Where injection-based continues to be applied despite the above recommendation, to at least make them as least-distortive as possible accounting for the detailed considerations in this paper (e. g. technology-specific yearly/ monthly reference price determined ex-post, definition on full-load hours…)**

- **To continue with an open discussion on the precise definition of the capability of capability-based CfDs and the reference generator of the financial RES CfDs**

- **Not to allocate CfD costs and benefits on the basis of actual MWhs consumed, but rather look for non-consumption based allocation mechanisms**

- **To further investigate the potential impact on existing forward/PPA markets of the market-based reallocation concept prior considering its implementation**

- **To integrate options for fully commercial (i. e. without any form of support) PPAs into CfD tenders**

- **To appropriately assess the implications of Carve-Out and Two-Stage Tender mechanisms in the specific context of a CfD tender (particularly for gaming risks and desired outcome)**

Appendix: Quantitative Analysis

In order to illustrate the concepts discussed in this paper, quantitative analysis was done for several cases, to quantify conflict situations, where the support creates incentives that result in inefficient operation in the Day-Ahead or balancing markets[21].

Modelling setup

The analyses are done based on Day-Ahead and balancing prices in the Netherlands for the years 2020-2023 (to date). These data have some interesting characteristics that are expected to be representative for future years:

- Significant price **increase** from 2020 to 2021
- Significant price **decrease** from 2022 to 2023
- High number of negative prices in 2023

Two different models are analysed that were presented in the main text (cf. TOPIC 1), one based on hourly calculated support based on the DA market price ("UK model") and the other based on the average price the year before ("DK Thor model"). We then use the Dutch prices to identify the number of "conflict hours" to estimate the size of the problems.

21 Ideally, we should also look at the Intraday market. However, there is not one clearing price in this market and data are not readily, which makes it a lot harder to analyse. If we assume that balancing market prices are a good proxy for the Intraday market (because market participant will estimate these prices in their bidding behavior in the Intraday market), we can interpret our results for the balancing market as be valid for the Intraday and/or balancing market.

Case 1 – Hourly reference market price

The first case looks at the production based CfD as applied in the UK (Cf. section CfD with hourly reference market price). Hourly Day-Ahead prices are set as reference market price and, therefore, the RES generators know the CfD payment after the DA market clearing. It is reasonable to assume that they will price the CfD payment in their intraday and balancing market bidding. Although support is granted even in the case of negative prices in the UK, for this analysis we assume that no support is paid under negative DA market prices, since it would be excessive to pay a difference up to the negative market cap and in any case state aid guidelines already prohibit this. Therefore, the potential distortions should be in intraday or in the balancing timeframe. To simplify, the marginal cost of the asset is assumed at 0 €/MWh (i. e. comparable to RES). Based on these assumptions, this use case counts the number of hours for which there is a conflicting incentive between the CfD premium and the imbalance price in two senses:

- **Conflict 1:** When the CfD premium is more positive than the negative imbalance price under a long system. In this case the asset will continue to run despite the market incentive to reduce production.
- **Conflict 2:** When the CfD premium is more negative than the positive imbalance price under a short system. Now the asset will be incentivised to further reduce production as it avoids more CfD payments this way and the cost of imbalance is not sufficiently high.

The results show the number of hours where conflicting incentives are observed in the balancing timeframe. Although the number of hours with a conflicting type 1 (CfD premium < positive imbalance price) accounts for a small amount (around 2 % of the time in a year), the type 2 conflicting incentive appears over 15 % of the hours in a year.

Results:	Conflict 1	Conflict 2
# conflicts	168	1,442
% conflicts	2 %	16 %

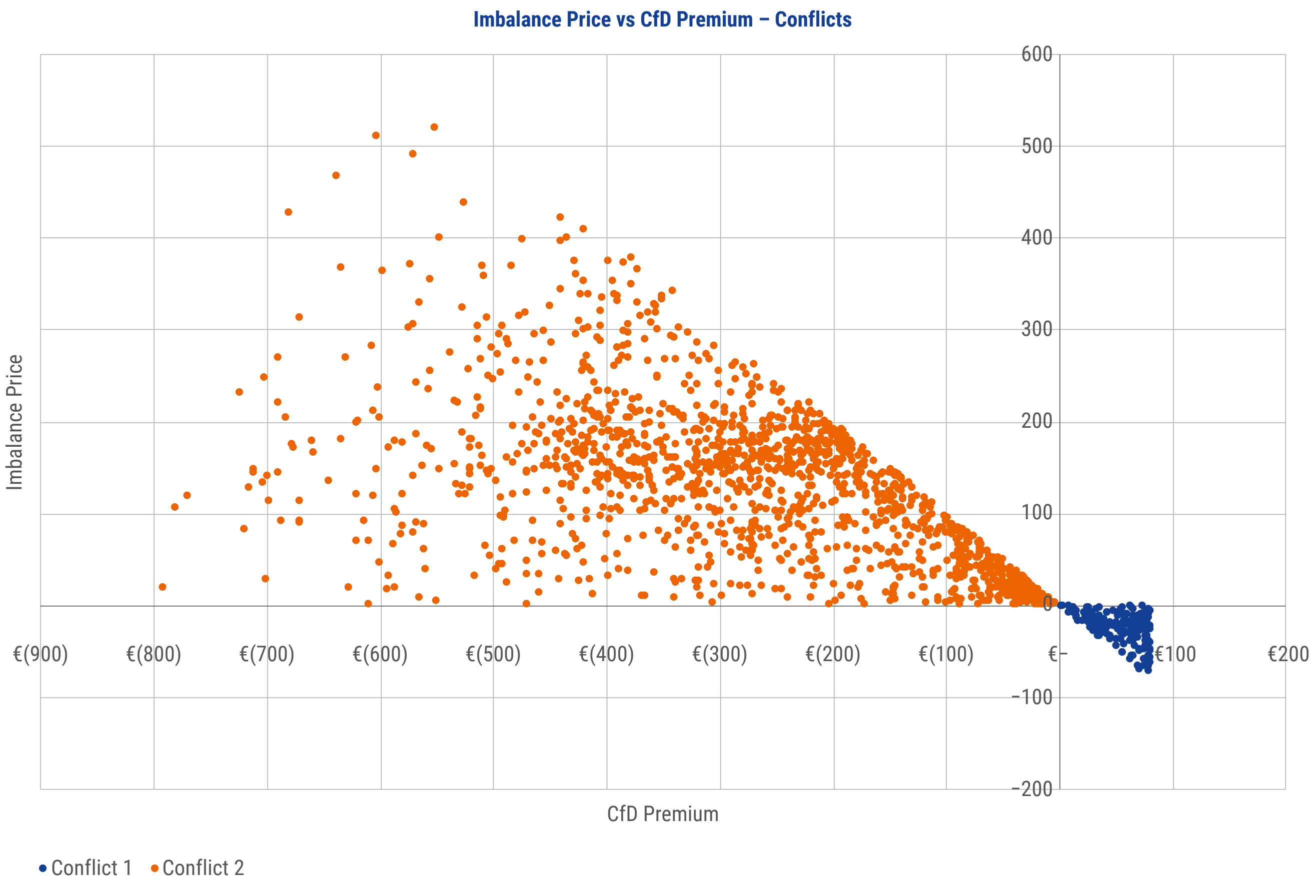

Figure 9: Distortions for production-based CfD with hourly reference price over 2022-2023 Y2D

Case 2 – yearly reference market price ex-ante

This use case resembles the production based CfD is based on the yearly ex-ante determined reference market price. The reference price is defined based on the simple arithmetic average of DA prices in the Netherlands in 2022 which are used for CfD pay-out over 2023. No support is paid under negative DA market prices. The fact that the reference market price is based on historical spot prices and thus, the CfD payment (positive or negative) is known ex-ante/before the DA timeframe, can lead to dispatch distortions in day-ahead, intraday or balancing market timeframe.

This use case counts the number of hours for which there is a conflicting incentive (i. e. number of hours where dispatch distortions occur) between the CfD premium and Day-Ahead or the imbalance price we identify the following situations:

	Day-Ahead price	Imbalance price	Consequences
Conflict 1 **Positive Premium**	< 0 >- Prem	< 0 >- Prem	No conflict, as no support is issued in such a case. Otherwise, there would be an incentive to produce as this implies a net revenue per MWh produced.
		<- Prem	No conflict, as no support is issued in such a case. Otherwise, there would be an incentive to stop pro-duction in balancing phase (or intraday).
	<- Prem	>- Prem	**Incentive to start production in balancing to receive the premium**
	> 0	> 0	No conflict as producing is the efficient solution
Conflict 2 **Negative Premium**	> 0 <- Prem	<- Prem	**Incentive not to produce as this implies a net payment per MWh produced**
		>- Prem	**Incentive to start production in balancing phase (or Intraday)**
	>- Prem	<- Prem	**Incentive to stop production in balancing to avoid paying the premium**
	< 0	< 0	No conflict, as no support would be given for negative prices and stopping is the efficient solution

Since only one value of the premium is determined, only one type of distortion is observed, depending on the value (positive or negative). We first look at the years 2022-2023. As prices were very high in 2022, there is a high negative premium in 2023. The results show the number of hours where dispatch distortions are observed in DA, balancing or both market timeframes.

Results:	**Conflict 1**			**Conflict 2**		
	DA only	**Imb only**	**Imb + DA**	**DA only**	**Imb only**	**Imb + DA**
# conflicts	0	0	0	1,298	296	3,682
% conflicts	0 %	0 %	0 %	23 %	5 %	66 %

The example shows a very negative premium (i. e.: RES would need to pay back 162 € for every MWh produced) resulting from the extremely high DA prices of the year 2022 following the energy crisis and thus, a very high number of hours where dispatch distortions are observed in Day-Ahead, balancing or both market timeframes in 2023:

› When DA prices are lower than 162 €, the wind farm will not be selected in the market clearing since the price does not cover the amount they need to pay to the CfD. Hence, it is better not to produce.

› When Imbalance Prices are lower than 162 €, it is more advantageous to suffer the imbalance price than produce, since the payment to the CfD is higher.

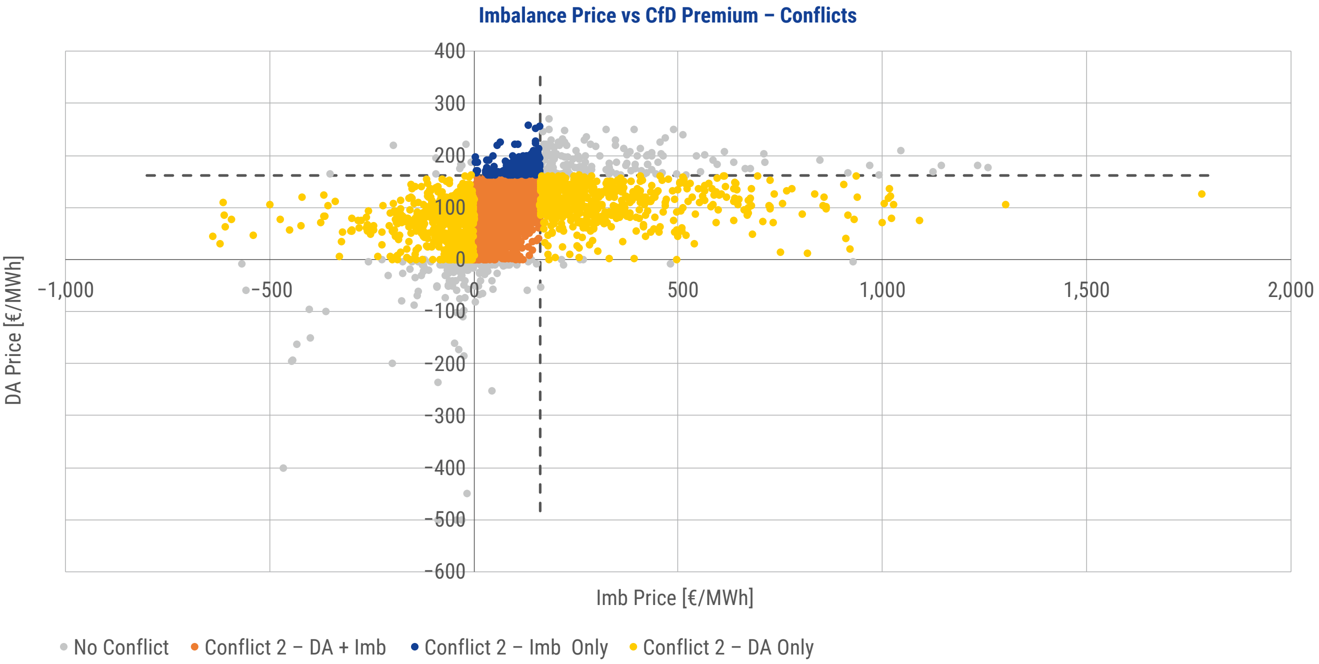

Figure 10: Conflicts caused by DA and/or Imbalance Price being lower than a large negative premium

Next, we look at the years 2020 – 2021. As prices were low in 2020, this results in a positive premium for 2021, which means that we only will see occurrences of Conflict 1.

Results:	Conflict 1			Conflict 2		
	DA only	Imb only	Imb + DA	DA only	Imb only	Imb + DA
# conflicts	0	494	0	0	0	0
% conflicts	0 %	6 %	0 %	0 %	0 %	0 %

Further comments to be added when agree on treating of prices < 0

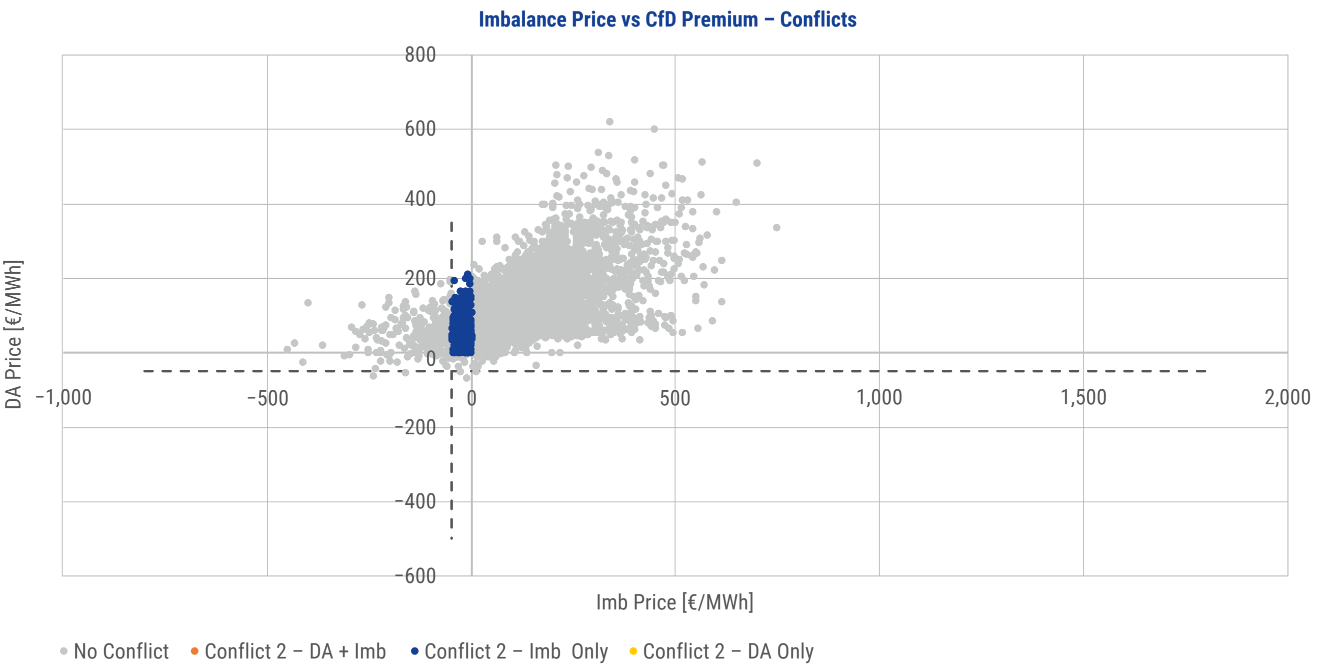

Figure 11: Conflicts caused by DA and/or Imbalance Price being negative but higher than the negative of a positive premium

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Abbreviations

AAP	Available Active Power
CfD	Contracts for Differences
DA	Day-Ahead
ENTSO-E	European Network of Transmission System Operators for Electricity
EU ETS	European Emissions Trading System
FLH	Full Load Hours
ID	Intraday
MWh	Mega Watt hour
OBZ	Offshore Bidding Zone
OWF	Offshore Wind Farms
PPA	Power Purchasing Agreements
PV	Photovoltaic
RES	Renewable Energy Sources
TSO	Transmission System Operator

Notes

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ENTSO-E AISBL
8 Rue de Spa
1000 Brussels
Belgium

www.entsoe.eu
info@ entsoe.eu

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Images

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