Department for
Energy Security
& Net Zero

Market signals and renewable investment behaviour

Final Report

DESNZ research paper number: 2023/049

March 2023

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Glossary

BEIS	Department for Business, Energy & Industrial Strategy
CAPEX	Capital expenditure
CAPM	Capital Asset Pricing Model
CfD	Contract for Difference
Cost of capital	See 'WACC'
DESNZ	Department for Energy Security and Net Zero
EMR	Electricity Market Reform
GB	Great Britain
Hurdle rate	The minimum rate of return (over a project lifetime) required for investors to invest in a project
LMP	Locational marginal pricing
LRMC	Long-run marginal cost
OPEX	Operating expenditure
REMA	Review of Electricity Market Arrangements
RES	Renewable Energy Source
RO	Renewables Obligation
ROC	Renewables Obligation Certificate
TNUoS	Transmission Network Use of System
WACC	Weighted average cost of capital (WACC), incorporating the cost of debt, equity and debt-to-equity ratios

Executive Summary

Project context and objectives

Meeting the 2035 commitment to decarbonise the GB electricity sector (subject to security of supply) means delivering a significant amount of new low-carbon electricity capacity. Market arrangements need to ensure that this transition happens at least cost to society and energy consumers.

If generators bear the full range of costs (and benefits) associated with their actions (i.e. not just their own technology costs, but also the wider impacts they impose on the system), then private decisions regarding which technologies to invest in, where to build them and when/how to operate them will tend to minimise costs for the system. This should, over the long run, reduce costs to consumers.

Currently, in the GB market, the combination of wholesale market price signals, capacity market revenues, grid access charges and grid balancing revenues and costs, broadly reflect generators' wider system impacts. The REMA consultation also considers options for making such signals (in particular, locational and temporal signals) even more reflective of the costs and benefits of generators' actions. Greater exposure to these market signals can therefore help reduce wider system costs.

Low-carbon capacity under the current Contract for Difference (CfD) support arrangements is exposed to some signals (such as grid access charges), but is largely insulated from wholesale market price signals. This is since their revenues (wholesale and support) per MWh generated are broadly stable, at a level around the 'strike price' in their CfD (which is typically determined in a competitive auction). This was a conscious decision taken when the CfD arrangements were introduced. Reducing price risk was assessed to be an important factor in reducing the financial rate of return investors in renewables would require. Lower rates of return required by investors in turn reduce the required support levels for investments to break even, reducing support costs borne by energy consumers. This effect was thought to be more significant than the potential cost (in terms of wider system impacts) resulting from reducing generators' exposure to market signals.

Given developments in the GB electricity sector over the past decade, it makes sense to re-evaluate the optimal allocation of risk between investors and consumers. DESNZ is considering a range of different possible options for reform to the renewable support arrangements that may introduce varying degrees of market risk for investors. Broadly, these options would increase generators' exposure to wholesale market prices, though some could also reduce investors' exposure to the risk that average levels of output are lower than expected ('volume risk').

Therefore, DESNZ has commissioned Frontier Economics and Cornwall Insight to develop a conceptual framework for understanding the implications of introducing a greater degree of exposure to market signals in renewable support arrangements:

- on overall system benefits i.e. how could it drive greater efficiency in investment and operational decisions of plants; and
- on investors, i.e. how might it affect the required rate of return.

Our focus is on intermittent plants, such as solar and wind (both onshore and offshore). Our assessment is supported by a literature review, engagement with investors, and some illustrative quantitative analysis to demonstrate some of the concepts that we identified. Given the largely qualitative review and given some detailed design questions remain, it is challenging to set out firm conclusions (for example, in terms of a ranking of options). However, we set out the key factors that could influence the system impacts and the required rate of return, as well as the potential trade-off between them.

Impacts on system benefits

Broadly, options that involve a higher degree of market exposure are more likely to minimise wider system costs.[1] This is because, as noted above, investors will then be more likely to internalise the trade-off between their own private costs and wider impacts on the system. In particular, greater market exposure ensures stronger incentives for generators to produce when wholesale prices are higher (including at times of scarcity), i.e. when output is more valuable for the system. The precise impacts will depend on the extent to which investors are actually able to influence system impacts through their actions (e.g. whether they can opt for a different technology, siting or configuration) and require further study.

We describe the impacts qualitatively below for each option.

Longer reference price periods

CfD payments are equal to the difference between a reference price in a given hour of production and a strike price, typically multiplied by the volume of production in that hour.[2] Under the current CfD for intermittent plants, the reference price is the hourly day-ahead price.

The reference price could instead be set as a (time-weighted) average of forward prices over a longer period (e.g. week, month, season – the case for baseload CfD plants currently – or year). Given the intermittent output of wind and solar plants, they are unlikely to achieve a

[1] This is subject to the caveat that none of the options considered would directly recognise differences in the values of different technologies in terms of capacity adequacy (i.e. ensuring there is sufficient capacity on the system to cope with periods of system stress). It would, however, be possible to recognise these differences indirectly (e.g. in the design of the auction).

[2] Except that under current contractual terms, no CfD payments are made in periods during which the hourly day-ahead price is negative.

reference price averaged over a longer period (as this would require generating a flat output profile).

This means that, other things equal, unlike the current CfD, plants that expect to generate a higher proportion of their output at times when wholesale prices are higher during the reference price period will expect to ‘capture’ higher revenues. In other words, projects that are better able to produce at times of higher prices (i.e. when power is more valuable for the system) will be financially better rewarded. The longer the reference price period, the greater the exposure generators will have to variation in wholesale prices, and so the greater potential for differences in expected earnings, given differences in generators’ output profiles.

Similarly to the current CfD, since payments are based on metered output, generators’ incentives to provide (downward) balancing or network curtailment services to the system operator may be distorted. Turning down generation involves limited incremental cost to the system. However, CfD generators may be more reluctant to reduce output since this would involve foregoing CfD payments.

Strike price range

Under a CfD with a strike price range, we assume that the CfD payments are evaluated against a strike price maximum (cap) and minimum (floor) as follows:

- When the reference price is above the strike price cap, the generator pays back the difference between the reference price and the strike price cap, multiplied by the output during that half-hour.
- When the reference price is below the strike price floor, the generator receives a top-up equal to the difference between the reference price and the strike price floor, multiplied by the output during that half-hour.

When the reference price is between the strike price cap and floor, we assume there are no CfD payments and that the generator simply receives the market wholesale price on all output sold. This similarly results in a greater reward for plants able to produce when power is more valuable for the system. Impacts will be internalised to a greater extent:

- the wider the strike price range; and
- if variation in wholesale prices tends to be within the strike price range (i.e. if neither the cap nor floor bind for significant periods of time).

Similarly to the current CfD and longer reference price option, this option may distort incentives for plants to provide services to the system operator, whenever the cap or floor bind.

Payment on deemed output

It would also be possible to de-couple CfD payments from actual output, and instead link payments to a ‘deemed’ level of output over the reference period. The impacts may depend on how this option is configured.

As an example, the level of deemed output could be flat across reference periods. In this case, the deemed output payment would be akin to a payment on a constant level of availability, with the 'availability' price varying between reference periods depending on movements in the reference price. Generators would be exposed to full variation in wholesale prices within reference periods on their metered output.

In addition, since CfD payments would not be linked to metered output, this would avoid distortions to short-term markets (e.g. the balancing mechanism) that may arise under the above options. Operational signals under this option would be efficient (guided by wholesale price and balancing market price signals, and not by support payments).

Revenue cap and floor

Under this option, generators receive a top-up when reference revenues (derived, for example, by multiplying a reference wholesale price by actual metered output) are below a revenue floor, and pay-back when reference revenues are above a revenue cap. When reference revenues in the reference period are between the cap and floor, generators do not pay back or receive top-up payments, and so simply earn revenues based on their output and the wholesale market price.

The wider the range between cap and floor, the greater the reward for CfD holders better able to produce at times of higher wholesale prices (to the extent that neither the cap nor floor are binding).

However, this option also has the potential to lead to inefficient operational signals, the extent of which would depend on the detailed design features (e.g. level of cap and floor, availability incentives, potential revenue sharing arrangements for revenues above the cap).

Design variations – extended contract length and green power pool

Currently, generators default onto merchant arrangements once the original term of their CfD ends. This results in a period of full exposure to wholesale price signals (until the asset retires).

For options that do not involve full exposure to wholesale price movements, a longer contract duration will reduce the degree to which wider system impacts are internalised by generators. A similar point applies to the green power pool option, given this option envisages the possibility for generators to move to new (albeit potentially shorter-duration) contracts following the end of the initial contract term.

Impacts on risk exposure for investors

Investors will not be able to predict with certainty the cash flows that a plant will generate over its lifetime. Greater uncertainty in the profitability of an investment will tend to lead to a higher required rate of return ('cost of capital'), for investments to go ahead.[3] However, there is no

[3] Investor feedback also lends some anecdotal support for this.

consensus on which types of risk matter most for investors' cost of capital and how to estimate the impact on the cost of capital of a given forecast increase in specific aspects of risk.

Our analysis has therefore focussed on the impacts of each option on different components of unpredictability in revenues ('revenue risk'). This is consistent with anecdotal feedback from investors received as part of the project.

Generators' revenues will depend on how much they generate (their output, or volume) and the price at which they sell this output. Both volumes generated by intermittent plants and market prices are unpredictable. Revenue risk will therefore primarily be a function of price risk (the extent of unpredictability in market prices) and volume risk (unpredictability in average levels of production), and the interactions between them.

For example, if when output for a plant tends to be lower, prices tend to be higher, and vice versa (i.e. prices and volumes are negatively correlated), it is possible that revenues may exhibit less variation than either prices or volumes individually. This may become increasingly the case for intermittent renewable plants, as the level of intermittent renewable deployment on the system increases (e.g. a wind farm will tend to be generating when other wind farms are generating, and the resulting high levels of generation will tend to put downward pressure on market prices).

Since prices are largely stabilised under the CfD[4], volume risk is the main driver of revenue risk under the current CfD. Compared to the current CfD:

- A **CfD with a longer reference price period** exposes generators to an incremental risk (which we term 'profile risk') that the average price they are actually able to achieve differs from the baseload price implicit in the reference price, driving some unpredictability in returns, though volume risk will remain the main driver of revenue risk;
- A **deemed output CfD** may involve some additional profile risk (depending on the length of the reference price period). However, since CfD payments are de-coupled from output, the change in revenue that arises from variation in output will not be equal to the CfD strike price (as is the case for the current CfD), but will instead relate to the level of wholesale prices. To the extent that wholesale prices are expected to remain below the strike price on average (i.e. the CfD is expected to provide a degree of subsidy), then revenue volatility will be lower under our assumed version of a deemed output CfD, compared to the current CfD. This effect will be reinforced if prices and volumes are negatively correlated; and
- To the extent that prices and volumes are negatively correlated, options that introduce exposure to market price risk (such as the **CfD with strike price range and the revenue cap/floor**) may actually result in revenues being more stable (the extent of this impact will depend on precise design, e.g. width of strike price range).

Above, we have set out how increased exposure to market signals need not always lead to an increase in revenue risk (where prices and volumes are negatively correlated). In some

[4] The exception relates to periods of negative pricing as highlighted in footnote 2.

situations, therefore, there may not be a trade-off between wider system impacts and revenue risk. However, this trade-off is more evident where prices and volumes are positively correlated (i.e. prices tend to be low when output is low, and vice versa) or weakly correlated.

The correlation between prices and volumes may also depend on the time horizon over which it is assessed. For example, over a longer time horizon, the correlation between an individual plant's volumes and its average capture prices may be weaker than over a shorter time horizon. This is because, over a longer horizon, the influence of factors exogenous to the individual plant (such as the overall level of renewable capacity) will be relatively more important than over a shorter time period (e.g. within-year).

The relative importance of shorter-horizon vs. longer-horizon price risks requires further assessment. However, our illustrative quantitative analysis (based on historical data) shows that the removal of volatility in average prices from one reference period to the next is relatively more important than the removal of exposure to within-reference period price movements. That said, all options analysed could significantly reduce price risk compared to merchant operation.

Overall conclusions

As we have set out above, while greater exposure to market signals clearly increases price risk, it is less clear whether it is associated with a higher cost of capital. However, the correlation between prices and volumes may be weaker over a longer time horizon: investors may value protection from longer-term movements in prices.

To the extent increased market exposure does lead to a higher cost of capital, the key question (in terms of the overall costs of decarbonisation to consumers) is whether any increased system benefits are likely to be sufficiently material to offset the impact of a higher cost of capital.

Broadly, increased market exposure is more likely to result in material reductions in system costs if investors have scope to take actions that would help them capture higher wholesale prices and more generally respond to price signals. Where competition for support is between projects of the same technology, investors will have some ability to respond to market signals (e.g. via siting decisions). But investors will have more scope to contribute to reduce costs through their actions if they can choose between different technologies (i.e. if technologies compete for support).

Without a full system cost analysis, it is difficult to quantitively assess the best balance between increasing system benefits and the cost of capital. Once further work has been carried out to develop the design of preferred options in greater detail, quantitative analysis could shed further light on the impacts of the different options. In addition, further work will be required to engage existing and potential investors throughout any transition period.

1 Introduction

Project context

Meeting the 2035 commitment to decarbonise the GB electricity sector (subject to security of supply) means delivering a significant amount of new low carbon electricity capacity. Government is consulting on a range of options for supporting the deployment of mass low-carbon power, as part of the wider Review of Electricity Market Arrangements (REMA).[5]

The precise design of support mechanisms can affect the degree to which generators (and in turn, investors) are exposed to not just their own technology costs, but also to the wider impacts they impose on the system, such as their impacts in the wholesale market, on the costs of ensuring capacity adequacy, in balancing and ancillary service markets and on electricity networks.[6] If support arrangements do not internalise these wider impacts, then competitive processes for awarding support may result in an inefficient (i.e. higher cost to society) choice of projects and/or technologies, and in sub-optimal operational signals.[7]

The degree of exposure to market risk under alternative support mechanisms could also affect investor hurdle rates (i.e. cost of capital). The actual cost of capital required by investors will determine the revenues required to invest[8], and so will affect the level and nature of support and, in turn, costs borne by energy customers (in other words, the cost of capital will affect distributional impacts).[9]

Under a current style Contract for Difference (CfD) (introduced as part of Electricity Market Reform (EMR) in 2014), a low carbon plant receives a 'top-up' payment equal to the difference between the reference price and the contract 'strike price'. If the reference price is above the strike price, the plant must pay-back the difference. As long as the plant sells its power at the reference price, it will tend to earn the strike price for its power. DESNZ is of the view that CfDs have been effective in driving down the cost of capital.[10]

[5] BEIS (2022), 'Review of Electricity Market Arrangements Consultation Document', Chapter 6
[6] For a description of these 'wider impacts', see BEIS (2020), 'Electricity Generation Costs 2020', Section 7.
[7] The materiality of any impacts of support mechanism design will depend on how significant wider system impacts are, and how their magnitude compares to differences in technology costs between projects/technologies. The precise design of support mechanisms may have less of an effect on the technology mix if the degree of competition between projects and/or technologies is limited (for example, through the use of separate allocation 'pots', differentiated by technology, and the use of technology maxima and/or minima).
[8] The level of support will need to be set just high enough so that the net present value of cash flows (i.e. sum of cash flows, discounted at the cost of capital) is zero.
[9] It may also be helpful (if carrying out a societal cost-benefit analysis) understand the impact of support mechanisms on the cost of capital. This is because, as recommended by Green Book guidance, when calculating the net costs to society, the cost of capital is used as a proxy for the risk to society associated with investment in these technologies. However, to ensure it is a good proxy for the risks to society from technology investment, the cost of capital should ideally reflect the intrinsic risk associated with investment (for example due to technical operational risks) rather than the degree of market risk exposure under a given support mechanism design, so it is important to be able to strip out the impact of support mechanism design on risk faced by investors from the estimated cost of capital. For a discussion of this, see Frontier Economics (2018) 'Assessing the value for money of electricity technologies: A report for the Energy Technologies Institute', Section 2.5.
[10] BEIS (2022), 'Review of Electricity Market Arrangements Consultation Document', p.78.

Some changes have already been made to increase the price exposure under CfDs.[11] However, as part of its REMA consultation, DESNZ wants to understand better the implications of increasing exposure to market prices for investors, and overall system and customer benefits.

Increasing price exposure involves a potential trade-off with regard to minimising overall system and customer costs:

on the one hand, increasing CfD generators' exposure to expected wholesale revenues provides a higher financial reward for those generators better able to capture higher wholesale prices (i.e. generate when most beneficial for the system either by displacing higher-cost generation or by helping to contribute towards periods of scarcity). This should increase the likelihood that CfD auctions select technologies or projects that are least cost from an overall system perspective, which should, over the long run, reduce costs to customers;

on the other hand, increased market risk could increase the cost of capital (and hence increase overall investment costs) and, in turn, increase required support levels (the costs of which would be passed onto customers).

This potential trade-off was understood during EMR[12]. Wholesale price exposure was not completely removed from investors: e.g. baseload renewable plants (e.g. biomass) are settled against an (average) seasonal price on the basis that this provides stronger incentives to schedule maintenance when wholesale prices are lower within the reference period. However, in general, reducing price risk (and hence the cost of capital) was given more weight in the choice of support arrangement in EMR. While there was a clear logic for this approach at the time, given developments in the GB electricity sector over the past decade, it makes sense to re-evaluate the optimal allocation of risk.

Project objectives

As set out in its REMA consultation, DESNZ is considering a range of different possible options for reform to the renewable support arrangements that may introduce varying degrees of market risk e.g. changes to the current CfD, payments on deemed output, or a revenue cap and floor. Therefore, DESNZ has commissioned Frontier Economics and Cornwall Insight to develop the evidence base regarding the implications of introducing a greater degree of market price exposure in the renewable support arrangements on investors and then overall system benefits.

At a high-level our overall approach to this project is to:

First, consider conceptually the implications of the different renewable support options for different categories of risk and hence identify (qualitative) implications for overall earnings

[11] For example, from CfD Allocation Round 4 (AR4), no payment is made during any hour when the day ahead price is below zero. This builds on an earlier policy (for AR2 and AR3) to make no payment when the day-ahead price is negative for six or more consecutive hours.

[12] See DECC (2014) 'Impact Assessment: Contracts for Difference', Table 5.

volatility and cost of capital. Our analysis has focussed on intermittent plants such as solar and wind, these being the renewable technologies most likely to be deployed at scale in GB. This conceptual analysis has been supported by a review of relevant literature.

Second, engage with a range of existing and potential investors to understand the current landscape for investment in GB renewables and gain insights into how it could change as a result of the options being considered, including investor views on their implications for the cost of capital.

Third, qualitatively consider the potential implications of the new options for overall system benefits, taking into account the conclusions regarding cost of capital.

Options assessed for increasing exposure to market signals

We consider the implications of the following options, listed in the REMA consultation document:[13]

- Two variations to the current CfD arrangements:
  - CfD with a longer reference price period;
  - CfD with a strike price range;[14]
  - Payment based on deemed output; and
  - Revenue cap and floor.
- We also consider two additional variants of these options:
  - The implications of a longer contract length (i.e. beyond the existing 15 years); and
  - The implications of a 'Green Power Pool' in which it is likely different contractual structures between generators and the 'pool' could be embedded.

Where applicable, we discuss how these design variations could apply in conjunction with the support mechanisms listed above.

While at a high level these options can be reasonably well-defined, there remains a large degree of uncertainty in the precise design choices which will ultimately be important for the final implications for investors and wider system impacts. Where feasible we have identified the implications for our analysis of different key design choices, but in general set out clearly any assumptions that we make regarding design choices.

13 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1098100/review-electricity-market-arrangements.pdf, see page 78 onwards.

14 This option would expose generators to wholesale prices when the reference price is within a defined range. If the reference price is above the upper end of the range ('cap'), generators pay back the difference to the cap price, while if the reference price is below the lower end of the range ('floor'), generators get topped up to the floor price.

Structure of this report

The remainder of this report is structured as follows:

- in section 2, we consider how the different options and design variations above affect the revenue risks faced by generators;
- in section 3, we present an illustrative quantitative analysis of the impacts of the different options on the distribution of earnings
- in section 4, we assess the extent to which the options under consideration would lead to wider system impacts being internalised by investors;
- in section 5, we summarise our understanding of the current landscape for investment in GB renewables and the insights gained from interviews with investors regarding the options considered; and
- in section 6, we set out our conclusions.

In the Annexes we:

- consider the implications for the nature of the locational signal, and hence locational risk, of the different support options being considered as part of REMA, based on:
    - wholesale market arrangements as today (i.e. with a national electricity wholesale price, with locational signals included in Transmission Network Use of System, or 'TNUoS', charges faced by generators);
    - an alternative market structure based on locational marginal pricing (LMP); and
- summarise the findings of our review of the literature regarding the impact of support mechanism designs on risks and cost of capital faced by investors.

2 Revenue risk exposure under REMA options

Approach to evaluating risk exposure under REMA options

The Capital Asset Pricing Model (CAPM) is a theoretical approach linking systematic risk associated with an asset (risk that cannot be diversified via other investments) to required rates of return to support efficient investment. It is commonly used by economic regulators[15] to set the allowed cost of equity (part of the overall cost of capital) for regulated businesses. CAPM suggests that investors do not need to be compensated for risks which can be mitigated through diversification within a portfolio.

However, views on exactly what types of risk may be diversifiable may differ. For example, NERA (2013 and 2015) considered that certain risks (market price risk) may be non-diversifiable, while others (volume risk) may be diversifiable. There may be a certain logic for this, in that differences in output profiles could be diversified through diversification across different technologies or geographical dispersion of assets, while electricity market prices are more closely correlated with the stock market. However, diversification, in the context of CAPM, relates not just to other investments in the energy sector but also to investments across the economy.

In addition, NERA (2013) also suggested that the CAPM framework does not address fully two aspects of real-world risk for which investors do require compensation:

- the existence of material asymmetric risk, referring to: '…*a situation where the 'base case' for revenues / costs chosen by the regulator (e.g. on the basis of the median or mode) is more optimistic than the expected case ('mean'). In that context, regulatory / governmental choice can lead to expected under-recovery of cost…*'; and
- the existence of real option value (where investors need to be compensated for investing now, because in doing so they give up the opportunity to 'wait and see', in order to inform forecasts using improved information sets).

Further, the CAPM framework does not lend itself to estimating how a forecast increase in volatility (even if it can be shown to be non-diversifiable) affects the cost of equity. To quantify the impacts in detail would require relevant comparator companies operating under the different regimes with no other differences (or differences whose effect can be controlled for), and such comparators are unlikely to exist. This is confirmed by our literature review (see Annex B): none of the papers considered adopted the standard CAPM framework to estimate the impacts of different support mechanisms on the cost of capital.

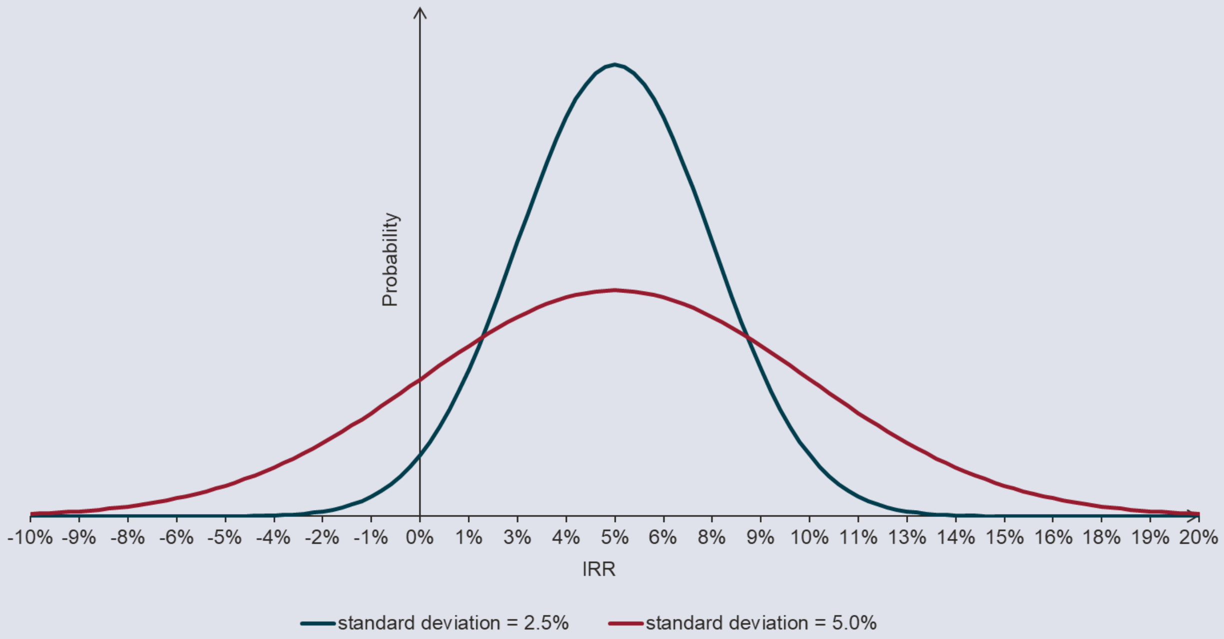
To the extent a given option leads to an increase in the distribution of returns, and that incremental risk is non-diversifiable, then, under CAPM, this would lead to a higher required

[15] UKRN (2022) 'Cost of Capital – Annual Update Report', page 24.

cost of equity (and, in turn, cost of capital). Therefore, in this report, we focus on assessing the implications of the change in the nature of the support on the distribution of returns (over the investment horizon) for a renewables investment decision (though the extent to which incremental risks are ultimately diversifiable would need to be eventually considered to come to a view regarding the impacts on the cost of capital).

Box: Illustration of the concept of the distribution of returns

Consider two hypothetical investments, each with an expected (i.e. mean) internal rate of return (IRR) over the lifetime of the investment of 5%. Returns on both investments are unpredictable: the realised (i.e. outturn) IRR could end up being higher or lower than the mean, but the probability distribution of IRR outcomes (i.e. the probability attached to different IRR outcomes) is known. However, the two investments differ in the standard deviation of returns – returns for one are more widely dispersed around the mean than the other. This is illustrated in the figure below.



In the rest of this section, we:

- discuss the categories of revenue[16] risk we consider (price, volume and profile risk);
- describe the key design features of each REMA option and consider the degree of exposure to the sub-categories of revenue risk (price, volume and profile) under each; and

[16] Since our focus is on intermittent plants, whose costs are largely fixed (and therefore will not substantially change under different options), the effects of the options on the distribution of returns will be essentially the same as their effects on the distribution of revenues.

- explore how different degrees of exposure to the sub-categories of revenue risk may affect the distribution of expected earnings for investors.

We carry out a similar analysis in respect of locational risk (the degree to which investors are exposed to unpredictability in the locational signal that they face) at Annex A.

Categories of revenue risk

Revenue risk refers to the degree to which investors are exposed to unpredictability in wholesale revenues over the lifetime of their investment under the different renewables support options. To facilitate our analysis of the impacts of different support mechanism design features, we break down revenue risk into the following components (we later consider possible interactions between these components).

Price risk refers to the part of revenue risk related to unpredictability in the **wholesale market price.** Different support mechanisms can expose generators to greater or lower price risk.

- For example, under the Renewables Obligation (RO) scheme (which closed to new capacity on 31 March 2017[17]), generators receive a (broadly stable) premium payment per MWh generated, in addition to the wholesale price. RO generators therefore are exposed to the variation in wholesale prices.[18]
- In contrast, the current CfD insulates investors from much of the price risk (over the CfD term). However, as we go on to discuss, price risk can be introduced into the CfD framework in various ways, such as by exposing generators to:
    - price movements within certain bounds (e.g. a strike price range); or
    - movements in spot prices relative to those implied by the forward contract on which a CfD reference price may be set (e.g. a CfD with a longer reference period)

Volume risk refers to the unpredictability in generator revenues driven by the **differences in average load factors compared to expected average load factors**. This could be driven by variation in solar radiation or wind conditions (for intermittent plants) or variation in plant reliability.[19] We initially assess the degree of volume risk holding the price earned per MWh constant, but later consider the effect of a potential correlation between volume and price.

Profile risk is relevant only under options that involve a reference wholesale price which is a forward price (such as the CfD with a longer reference price period), which expose generators

[17] https://www.ofgem.gov.uk/environmental-and-social-schemes/renewables-obligation-ro

[18] Price risk includes the risk that wholesale prices may be low because of the influence on the wholesale electricity price at times of high output from intermittent, weather-driven generation such as solar, onshore wind and offshore wind (sometimes referred to as ‘price cannibalisation’).

[19] If there is excess supply of intermittent generation relative to demand, prices may fall to zero (or below), and economic curtailment (a deliberate reduction in output below what could have been produced in order to balance energy supply and demand) may result. For the purposes of this analysis, we consider this as a subset of price cannibalisation risk (i.e. under price risk, as described in footnote 18), rather than as a volume-related risk.

to within-reference period wholesale price variation due to the shape of a generators output. It refers to the unpredictability in earnings related to variation in the difference between:

- the reference wholesale price; and
- the average wholesale price actually achievable by generators due to the variability in a plant's profile over the period which the reference price is set (e.g. 1 hour, 1 week, 1 month), even if average load factors were to remain constant across reference periods.

Strictly, profile risk also applies to the current CfD for intermittent plants, in the sense that the day-ahead reference price can be said to be a forward price. However, given all options we consider would leave investors exposed to the risk of forecasting errors following the day-ahead stage (which may also include exposure to imbalance charges, sometimes referred to as 'imbalance risk'), we focus in our analysis on profile risk up to and including the day-ahead stage.

Where the reference price can be achieved with 100% certainty by generators producing a **flat output profile** (i.e. a constant load factor) in the reference period, there is **no profile risk**. In practice, given our focus is on intermittent technologies there **will always be profile risk**, even if generators were able to perfectly hedge their expected profile at the start of the reference period (which they will typically not be able to, given the more limited granularity of products traded in the forward market[20]). This is because generators are exposed to variations in the difference between:

- the (baseload) reference price (which, as noted above, implies a flat output profile); and
- the price actually captured (which depends on the outturn profile of output).[21]

This is illustrated in Figure 2 below. To be clear, profile risk exists even if forward prices and spot prices remain entirely aligned. If prices also move during the reference period, then this represents an additional price risk (that we noted above when describing price risk). The profile risk is also likely to be enhanced by forecast errors regarding the amount and profile of the generation during any reference price period.

It can be challenging at times to disentangle the different risks, and there is no standard approach or definition.[22] To help understand the particular allocation of risks that we have set out above it is helpful to consider an example.

- Imagine an intermittent plant with a CfD contract, for which the reference period is one month, and the reference price is based on the month-ahead baseload contract.
- Even if the plant could perfectly foresee its output profile for the month ahead, and outturn spot prices do not change from those implied by the forward price (i.e. average

[20] For example, half-hourly products are not typically traded until the day-ahead stage.
[21] For intermittent generators, this will primarily be driven by variations in weather conditions. For baseload generators it will be driven by variations in plant reliability (i.e. unplanned outages).
[22] For example, NERA (2013) describes 'basis risk', which it defines as 'the inability of generators to achieve the reference price under the contract'.

prices remain unchanged), it is clear that, due to its profile, the plant is unlikely to achieve the reference price on average for its output.

- In this example, the fact that the plant does not achieve the reference price is entirely driven by the deviation in the profile from a baseload plant. The extent of these deviations will be unpredictable from period to period.
- In addition to profile risk, the plant faces a price risk within the reference period. If outturn spot prices deviate from that used to set the reference price, the impact of the profile risk will also change.

It is important to note that the categories of risk shown above are not the only drivers of investor risk related to renewables support. However, they represent the fundamental features that differentiate the support mechanism options being considered from each other, given the differences in how each mechanism supports a plant's revenue. Other risks, such as counterparty risk and allocation risk, are important, but can be considered as independent design considerations separate from the core features of any mechanism related to revenue risk.[23]

Impact of REMA options on categories of revenue risk

This sub-section outlines our understanding of the design of each renewable support option being considered by DESNZ under REMA, and the exposure to revenue risk categories associated with each. As noted in section 1, our analysis focuses on the implications for intermittent plants, such as solar and wind.

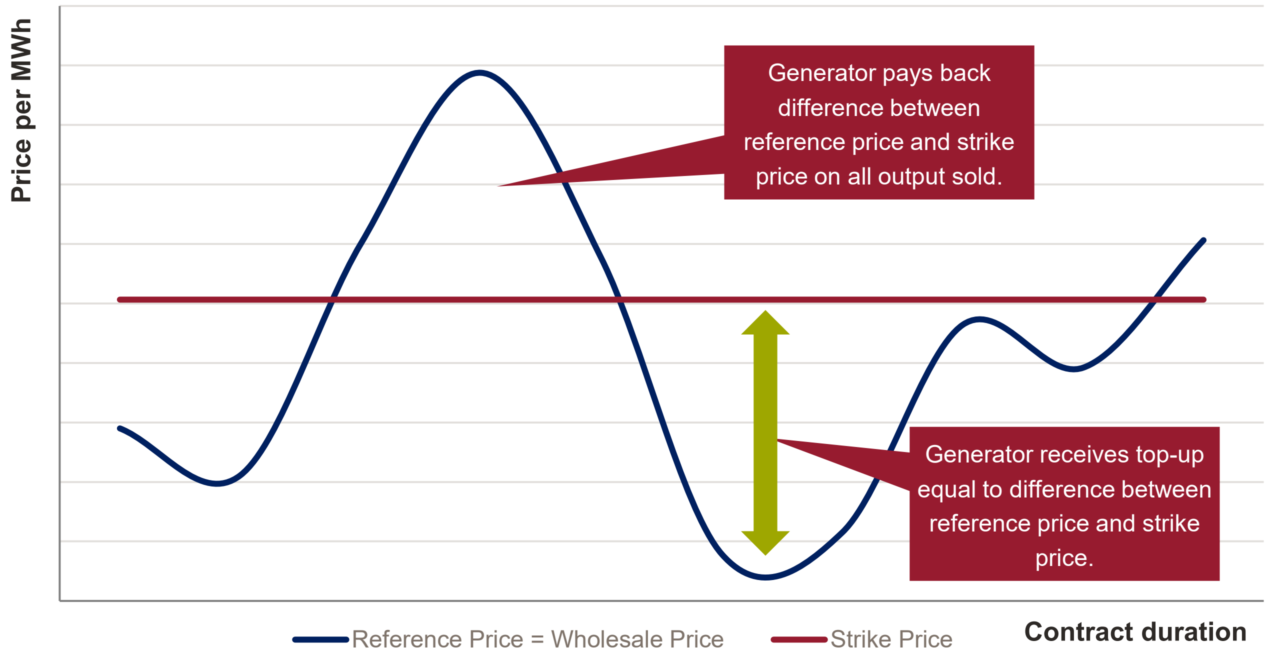
Current (AR4) CfD

The CfD for intermittent plants sets the reference wholesale price for all hours of the contract as the hourly price traded on the day ahead market. The CfD payment for a given hour is then set as the difference between the strike price and the reference price, multiplied by the output sold in that hour. [24] Typically, generators receive top-ups on output sold in hours where the reference price is below the strike price and pay back the difference between the reference price and the strike price in hours when the reference price is above the strike price. As long as the price at which the plant sells its power (the 'capture price') is the same as the reference price, it will earn the strike price for its power. Figure 1 provides an illustration of the top-up/pay-back mechanism in the current CfD.

[23] Our analysis implicitly assumes a wholesale market structure similar to today based on a national wholesale price, with locational signals sent through locational transmission charges (TNUoS). The locational TNUoS charges faced by investors may represent an additional source of earnings volatility, however, because TNUoS charges represent a part of fixed cost for plants this source of volatility is not affected by the different options. Similarly, support mechanisms may vary in the degree of construction risk left with investors, but given the focus of our report, we assume no changes to construction risk compared to the current CfD, across all options considered.

[24] With the exception that (as mentioned in footnote 11) generators do not receive top-ups on output sold in hours where the reference price is at or below zero.

Figure 1 Illustration of current CfD operation



Source: Frontier Economics

The sources of revenue risk under the current CfD can be described as follows:

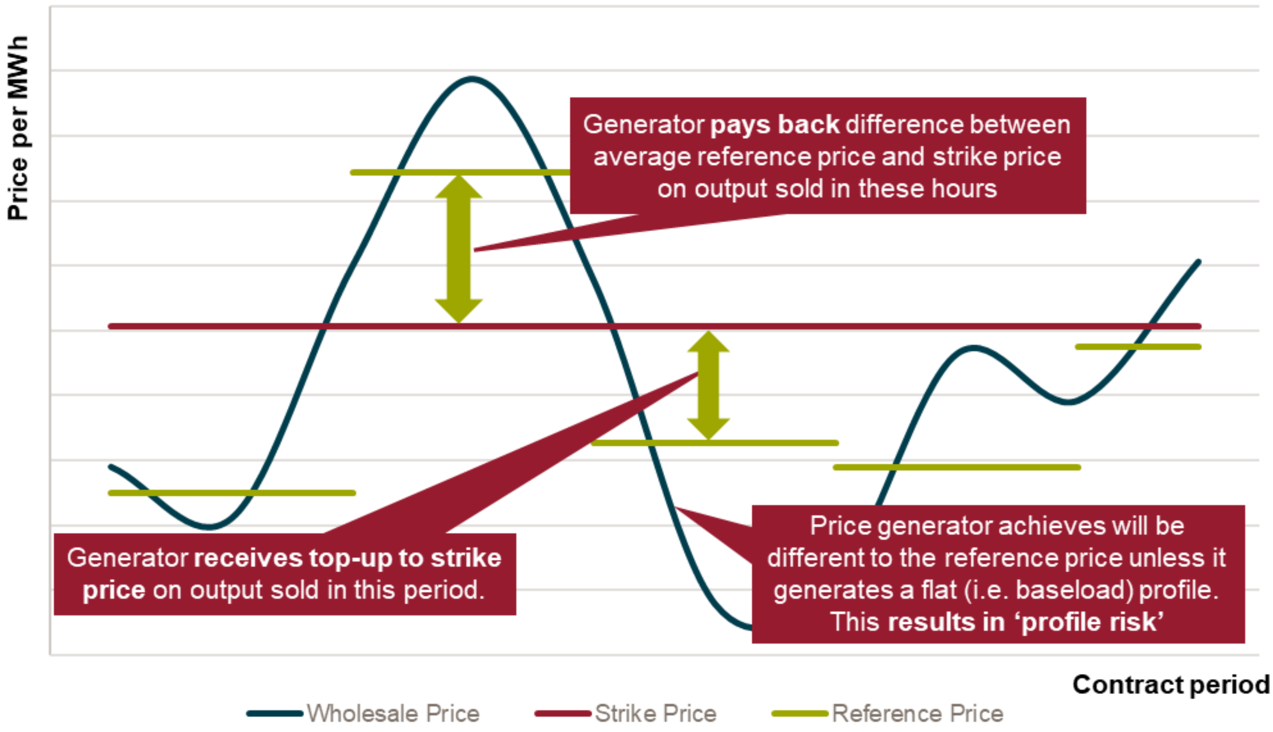
- **Price risk** – When originally introduced, the CfD fixed a strike price (in real terms) for the duration of the 15-year contract, which ensured that investors faced no exposure to volatility in wholesale prices. Subsequently (see footnote 11), the CfD has introduced a further degree of wholesale price risk as generators do not receive top-ups on output sold in hours when the wholesale price is zero or negative (i.e. generators are exposed to wholesale market prices in these hours). We have assumed a rule to ensure a similar effect would apply across all options we consider in this analysis.
- **Profile risk** - for intermittent generators, the reference price is the hourly day-ahead price and therefore profile risk (before the day-ahead stage) is essentially nil.
- **Volume risk** - all volume risk is left with the investor since CfD payments are not made in hours when the generator does not produce.

Option 1 - CfD with longer reference price periods

In a CfD with a longer reference price period, the reference price is set as a function of the wholesale prices over a pre-defined reference period. CfD payments are then evaluated in the same way as under the current CfD where payments are equal to the difference between the reference price and the strike price in any given hour of production, multiplied by the volume of production in that hour.

For the purposes of the risk categorisation exercise, we assume that the reference price is set in advance of each period as an average of forward market prices across all hours in the reference period[25], similar to the case today for the 'baseload CfD' i.e. we assume that investors are aware of the reference price prior to each reference price period. We make no assumption about the length of the reference periods over which the average is drawn to create the reference price (i.e. how often does the reference price change). Figure 2 provides an illustration of the top-up/pay-back mechanism with this CfD design.

Figure 2 Illustration of a CfD with longer reference price periods



Source: Frontier Economics

When participating in auctions, bidders will form a view regarding any average difference between the average capture price and the reference price[26] and reflect this in the strike price bid. However, generators are exposed to the risk of changes in capture prices and output profile, the extent to which will depend on the length of the reference period:

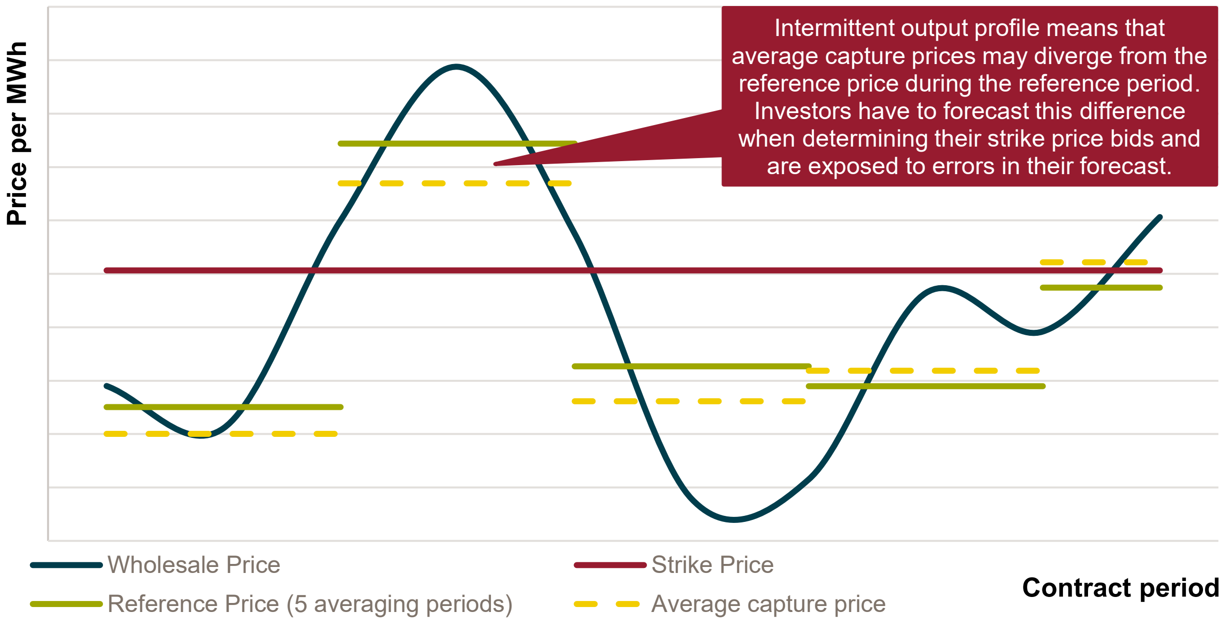
- **Price risk** - the level of exposure to price risk is similar to the price risk exposure under the current CfD. However, the plant is exposed to the risk that wholesale prices during the reference period deviate from the forward prices used to set the reference price. There is no wholesale price risk from reference period to period.
- **Profile risk** – the variable output profile of an intermittent plant creates a new risk relative to the existing CfD. Even if we assume no change to market prices between the prices used to set the reference price and the outturn half-hourly market prices during the reference price period, the variable output profile of an intermittent generator during

[25] We note that there may be alternative methods for constructing the reference price which could affect the degree of revenue risk exposure.
[26] For intermittent plants, investors might expect the capture price to (on average) be below a baseload reference price.

a reference price period means it is unlikely to achieve the reference price. The divergence in the price at which generators sell their output and the reference price will be unpredictable and will vary by reference period. This in turn means that the final revenue per MWh (combination of wholesale revenues and CfD payments) may vary across reference periods. Figure 3 illustrates the scope for profile risk.

- **Volume risk:** as with the current CfD, all volume risk is left with the investor since CfD payments are not made in hours when the generator does not produce.

Figure 3 Profile risk under a CfD with longer reference price periods



Source: Frontier Economics

The degree of price and profile risk is likely to increase with a longer reference price period for two reasons:

- There is greater potential for deviations (in either direction) between the forward market prices used to set the reference price and capture prices, leading to increased price risk; and
- Moving to a longer reference period, the size of an intermittent plant’s forecast error in relation to its output profile is likely to grow (at least initially, though there is a limit as to how large the forecast error can get as the reference period duration increases). A plant will decide whether or not it hedges its expected profile through forward sales and on the optimal strategy for doing so based on its risk preferences and the information available to it at the time. Errors in forecasting output profile will require a deviation from this optimal hedging strategy, which, to the extent the plant decides to engage in forward trading, implies some risk related to price movements.

There is an increased likelihood of profile forecast errors by plants (i.e. because a plant is more likely to incorrectly forecast its output profile over a longer reference period) and as a result plants are more likely to incorrectly anticipate the difference between the revenue its output shape would earn at reference prices and average capture prices.

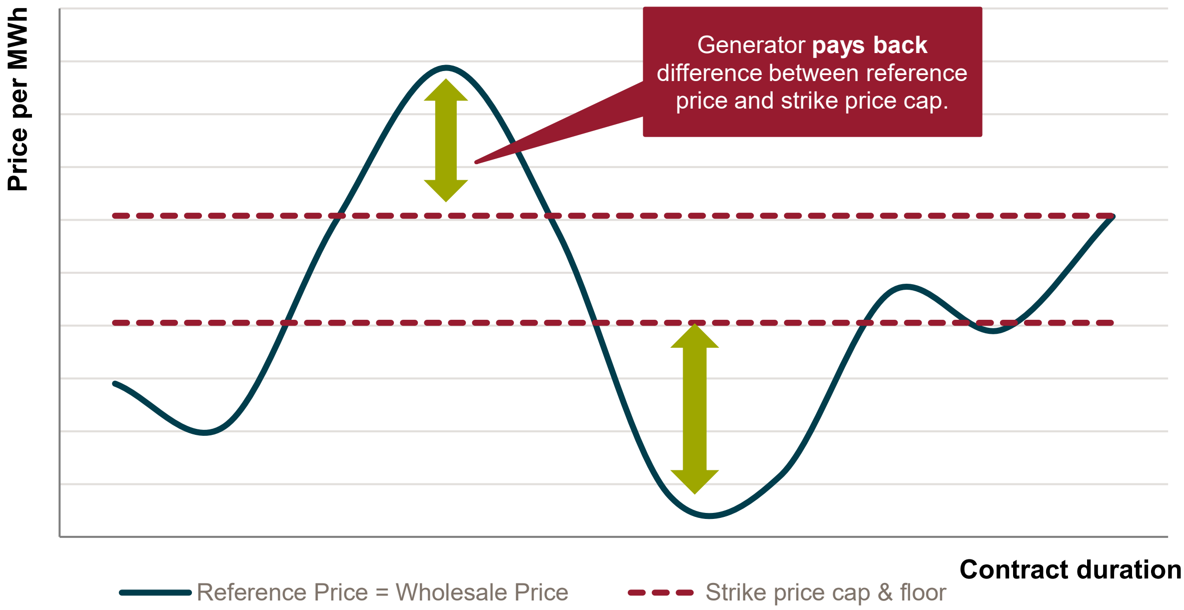
Option 2 - CfD with strike price range

Under a CfD with a strike price range, the CfD payments are evaluated against a strike price maximum (cap) and minimum (floor) as follows:

- When the reference price is above the strike price cap, the generator pays back the difference between the reference price and the strike price cap, multiplied by the output during that half-hour.
- When the reference price is between the strike price cap and floor, there are no CfD payments and the generator is exposed to the market wholesale price on all output sold.
- When the reference price is below the strike price floor, the generator receives a top-up equal to the difference between the reference price and the strike price floor, multiplied by the output during that half-hour.

Figure 4 provides an illustration of the top-up/pay-back mechanism under a CfD with a strike price range.

Figure 4 Illustration of a CfD with a strike price range



Source: Frontier Economics

Note: The diagram above illustrates the case where the reference price is hourly as the standard CfD, although a strike price range could also be introduced in combination with a longer reference period.

The sources of revenue risk under a CfD with a strike price range can be described as follows:

- **Price risk** - the CfD strike price range introduces a degree of wholesale price risk greater than the level experienced under the current CfD, to the extent that variation in wholesale prices is expected to lie mainly within the strike price range (i.e. the degree of risk depends on the size of the range between strike price cap and strike price floor relative to the expected distribution of wholesale prices). When prices are at the cap or floor, price risk (within reference period) is introduced if we assume a longer reference price.

- **Profile risk** – there is no profile risk when prices are within the strike price range, but profile risk (assuming a longer reference price period than under the current CfD) remains with regard to achieving the cap or floor price e.g. the risk that the actual price a generator is able to achieve for its output may be below the floor, but reference price is above.
- **Volume risk** - as with the current CfD, all volume risk is left with the investor since neither CfD payments nor the wholesale price are paid (or received) in periods during which the generator does not produce.

Option 3 - Payment on deemed output

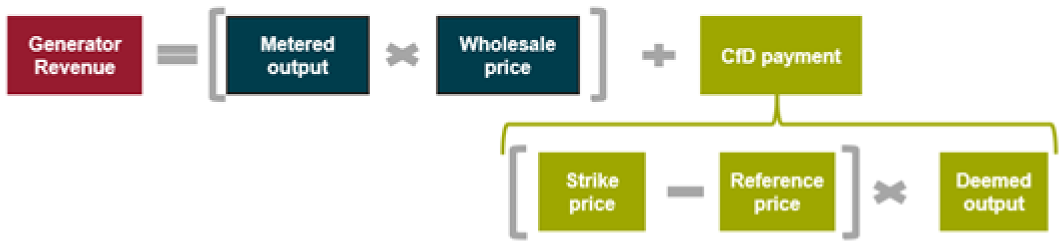
In this support mechanism, we assume that a plant's output is 'deemed' administratively based on factors such as location and generation technology for a pre-defined reference period (e.g. week, month, year), assuming a constant load factor over the reference period (though the estimated load factor may vary between sites).

For the purposes of this assessment, we assume that the period over which the deemed output is set is equal to the longer reference price period from option 1 above. As a result, this option builds on option 1 by not only fixing the reference price for the next reference period, but also by fixing the volume on which the top-up payment is calculated. Therefore, when combined with the strike price in the contract, investors have full visibility of the deemed output payment they will receive in the next period.

In this respect, the deemed output payment is equivalent to a varying availability payment fixed prior to the start of each deemed output period (assuming wholesale prices are typically below strike prices). In the case where the reference price is above the strike price then the generator will pay back to the counterparty for the next period, but the size of the pay-back will be fixed. During the reference period the plant earns revenues based on its wholesale market sales.

Figure 5 describes a generator's revenue within a reference period under this support option.

Figure 5 Generator revenues with payment on deemed output

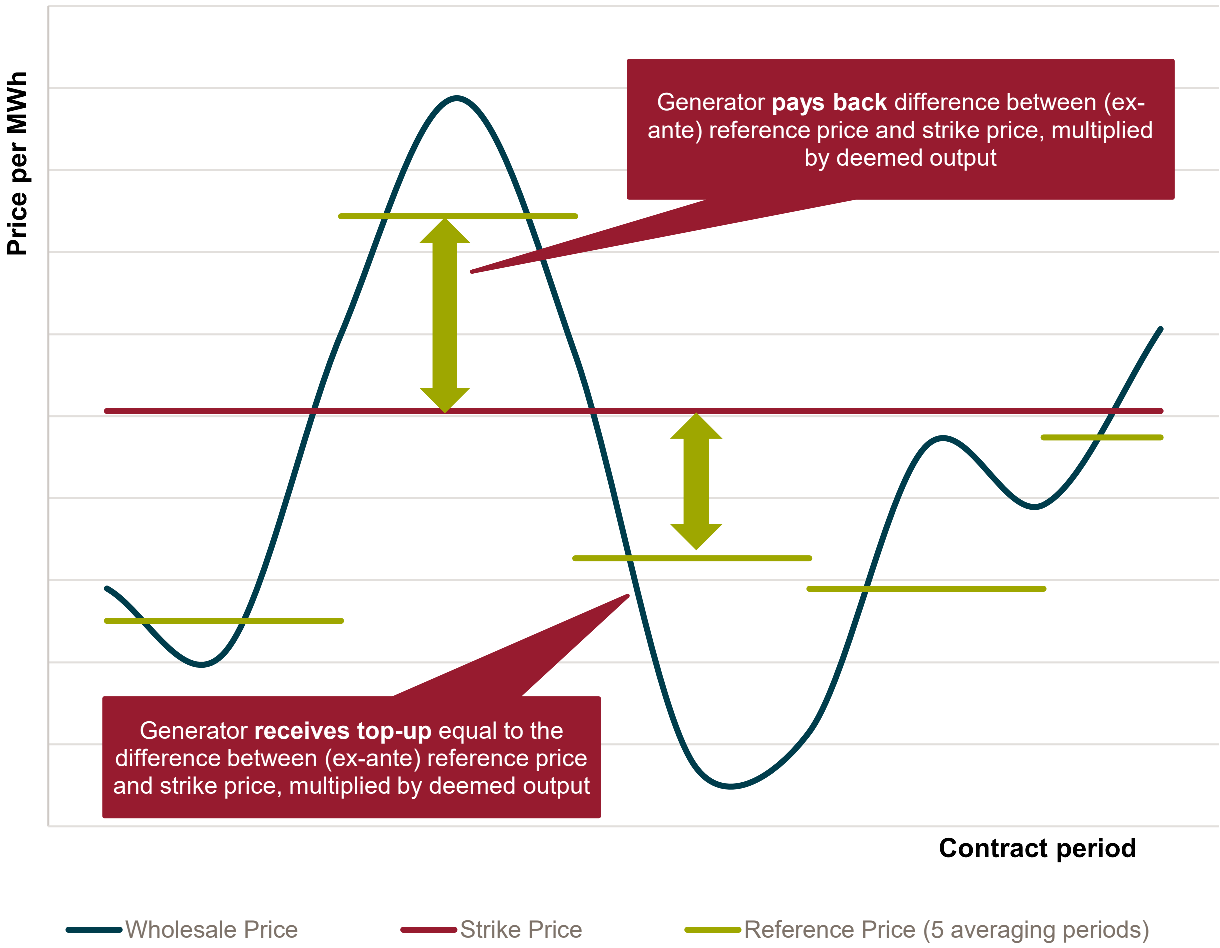


Source: Frontier Economics

Under this arrangement, generators sell any output at wholesale prices and make/receive the same support payment irrespective of actual output. If a generator's output is equal to its deemed output and it is sold at the reference price, the support scheme results in the generator receiving the strike price on all of its output. This is analogous to the outcome under the current CfD. In cases where the generator's output is different to the deemed output, the deemed output payment is likely to result in an effective price per unit of output sold that is different to the strike price. If the generator's output is below the deemed output, the top-up (assuming reference prices below the strike price) results in an effective price per unit of output which is above the strike price. When output is above deemed output, the effective price on that output is below the strike price.

Figure 6 provides an illustration of when generators make/receive support payments on deemed output.

Figure 6 Illustration of payments based on deemed output



Source: Frontier Economics

- **Price risk** – wholesale price exposure is limited to within the reference price period i.e. investors are exposed to the risk that prices during the reference period deviate from the forward prices used to set the reference price[27]. There is no wholesale price risk from reference period to period on deemed output, though generators are exposed to price risk in relation to variations in output from deemed output (as we note below under volume risk). This is similar to the CfD with longer reference price as above.

[27] Price risk would be limited if the reference price was the hourly day-ahead price.

- **Profile risk** – profile risk applies only to deemed output, and depends on the length of the reference period. Assuming the same reference period as for Option 1 (CfD with longer reference price period), the profile risk will be similar to Option 1, and therefore greater than the current CfD.
- **Volume risk** – generator fully exposed to variations in its output in relation to wholesale earnings, but there is no volume risk with respect to the support payments which are de-coupled from actual output.[28] Viewed in isolation, volume risk is therefore reduced compared to the current CfD, but we discuss later that the effect of this (compared to the current CfD) is ambiguous (see Figure 10) once the interaction with prices is considered.

Option 4 - Revenue cap and floor

As with a CfD with longer reference price periods and the payment on deemed output options, a revenue cap and floor requires a reference period to be set. We do not make assumptions in this report about the level of any cap and floor, but there are examples to draw on from elsewhere in the electricity sector (for example, electricity interconnectors currently, and under consideration for pumped hydro storage). A typical approach might be to base a floor on some minimum level of revenues required to service an investor's debt and a cap based on a revenue that would avoid 'excessive' returns. Clearly the precise range chosen will be critical for investor risks.

To provide some incentive for intermittent plants to forecast their output and actively manage their sales in the market (rather than simply selling power very close to delivery), we assume payments under a cap and floor option would be evaluated against a reference wholesale revenue[29] figure (either day-ahead as for the current CfD or a longer reference price period). We assume a 'notional' revenue is calculated for each plant (e.g. by multiplying a reference wholesale price by actual metered output) for the reference period.

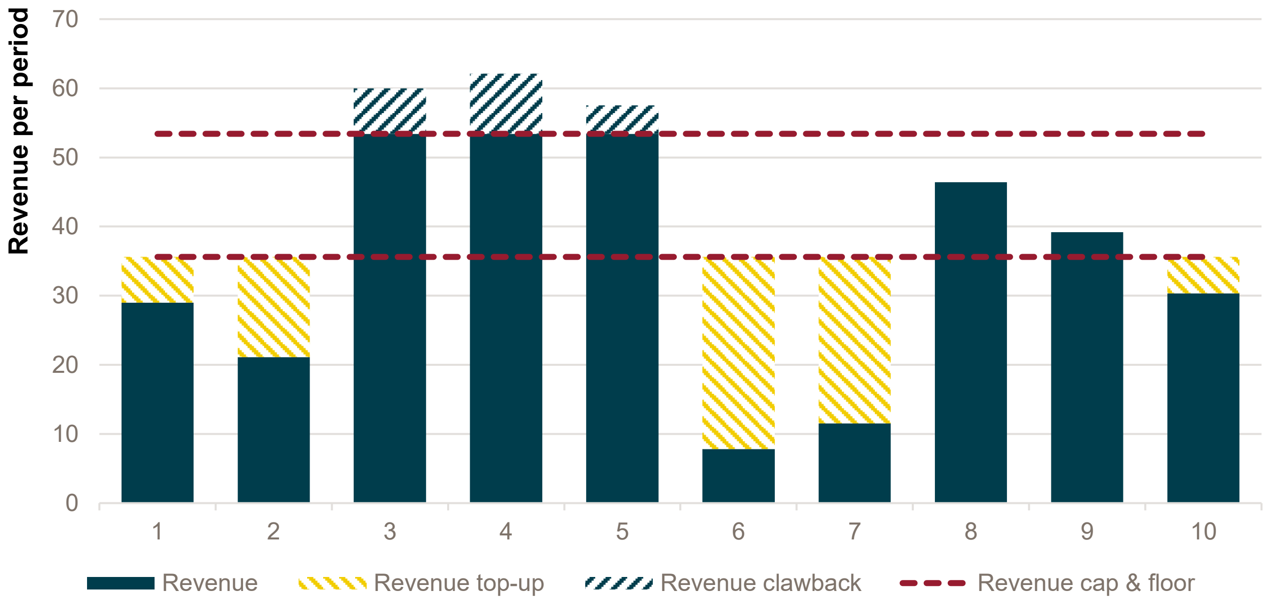
Generators then receive a top-up when reference revenues are below the revenue floor, and pay-back when reference revenues are above the revenue cap. When reference revenues in the reference period are between the cap and floor, generators do not pay back or receive top-up payments. We also assume that support payments are only made if the plant is available in a given period[30]. In this way, the revenue cap and floor differs from an availability payment (which pays irrespective of actual output). Figure 7 illustrates the payments under a revenue cap and floor mechanism.

[28] Under this option, we assume support is paid even during times of negative prices. This is because the fact the payment does not depend on dispatch already means that support payments do not affect generators' dispatch incentives.

[29] Our analysis focuses on wholesale market revenues. However, the extent to which other sources of revenue (e.g. from providing balancing services) are covered by the revenue cap/floor arrangement would also need to be considered.

[30] Exactly how availability would be measured (e.g. by testing, reaching a minimum level of generation within a given period) is not in scope of this report.

Figure 7 Illustration of a revenue cap and floor support mechanism



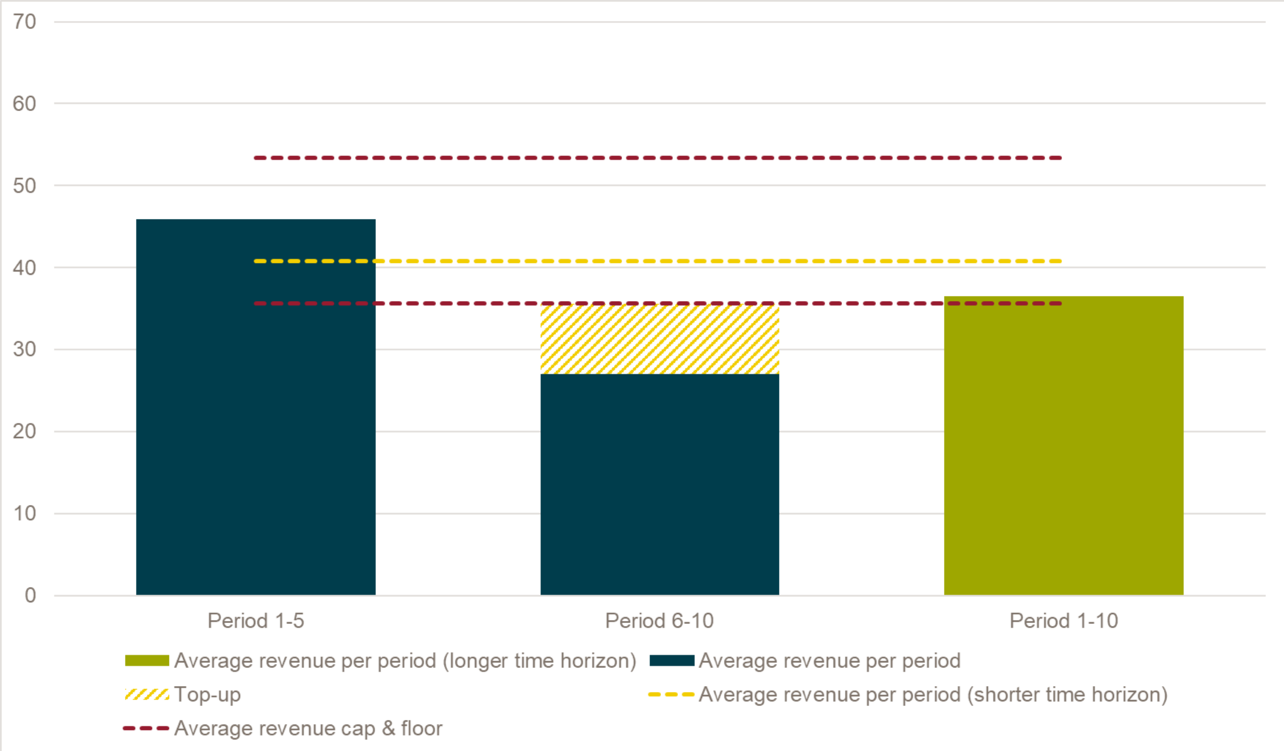
Source: Frontier Economics

For a revenue cap and floor, it is not possible to make a precise distinction between price and volume risk. For this option, we instead consider revenue risk (as a combination of both price and volume risk) and profile risk:

- **Revenue risk** - in a scenario where investors receive a guaranteed revenue (i.e. without any cap or floor) all investor price and volume risk would be removed. Introducing a revenue cap and floor leaves investors with some revenue risk.
  - The size of this risk will depend on the extent to which either the cap or floor is expected to bind (i.e. how wide the cap and floor range is, and whether wholesale price variation is largely within this range).
  - The frequency with which revenues are evaluated (i.e. the length of the reference period) relative to the revenue cap and floor also matters for the amount of risk. Figure 8 illustrates this point, showing that for the same total amount of revenue generated over the whole ten intervals (from Figure 7), the level of top-up is different if all ten periods are evaluated as a single block or in two separate blocks of five periods:
  - Defining two reference periods (intervals one to five, and six to ten) results in a top-up payment in the second reference period, but not the first. This is illustrated via the two blue bars in Figure 8 below.
  - Defining one reference period (intervals one to ten) results in no top-up payments. This is illustrated via the light green bar in Figure 8 below.
  - The average revenue across the ten intervals in this example, marked with a yellow dashed line, is therefore higher with shorter reference periods.

- **Profile risk** - the potential for profile risk depends on the definition of the reference revenue: only if the reference revenue based on a forward price does this introduces the potential for profile risk before the day-ahead stage (equivalent to the profile risk in the CfD with longer reference price periods).

Figure 8 Illustration of revenue risk with varying reference period length



Source: Frontier Economics

Design variation – Green power pool

A green power pool is a co-ordinated pool for renewable electricity which operates in parallel to the wholesale market. Generators agree to long-term contracts to sell all output to the 'Pool'. The price received by the generators is determined via auction and with generator bids reflecting their long-run marginal cost ('LRMC').

Larger customers (e.g. retail suppliers or industrial customers) purchase power from the Pool via long-term contracts, priced at the weighted average of the LRMC of available generation in a given period. Contracts are standardised such that they could be tradeable (i.e. industrial customers could sell them on if their demand changes). We note that detailed policy decisions in relation to design may affect the counterparty risk faced by generators in the pool, but here we simply assume counterparty risk is the same as under the current CfD.

From the perspective of generators, we consider the Pool as a framework in which contractual arrangements between the pool and generators (e.g. a CfD or revenue cap and floor) could be set. For example, under a CfD a generator would receive a strike price (effectively as a single payment without profile risk) on all of its actual volume. Under a revenue cap and floor the volume risk for revenues outside of the cap and floor range would also be removed. In practice the green power pool is unlikely to work with some of the options, such as the CfD with strike price range.

The main distinguishing characteristic of the pool, as regards revenue risk, is that beyond the initial term, generators may be able to opt into new (potentially shorter duration) contracts. This means that generators do not bear full wholesale price risk following the initial term (though they do face price risk, related mainly to uncertainty regarding the LRMC of future RES capacity).

Design variation – Extended contract length

The length of the contract is a design decision which applies to all of the REMA options above, as well as the green power pool. The current generic CfD term is 15 years, while renewable power asset lifetimes can extend to 20-25 years and potentially beyond. This means that investors are currently exposed to full merchant risk for a period of time following the end of the CfD term. A longer term would extend the protections offered under each of the options, compared to the standard duration, but would also extend risks associated with a support contract (i.e. profile risk). However, any reduction in the dispersion of lifetime returns will not be proportional to the increase in contract length:

- on the one hand, cash flows 15 or more years into the future will be heavily discounted by investors, which will reduce the contribution of such cash flows returns to expected returns (and, in turn, the dispersion of returns); and
- on the other hand, the expected distribution of wholesale price may increase further out in the future.

Summary of risks under each REMA options

Figure 9 provides a qualitative summary of the degree of price, volume and basis risk exposure for each of the REMA options, as well as the green power pool.

Figure 9 Summary of revenue risk exposure

Risk Category	Current CfD	Longer reference price periods	Strike price range	Payment on deemed output	Revenue cap and floor
Price risk		(depends on length of reference period)	(depends on range)	(assumed same as longer reference period)	(depends on level of cap/floor and length of reference period for evaluating revenues)
Volume risk				(no volume risk on support payments)	
Profile risk		(varying by technology and depends on length of reference period)	(potentially higher depending on reference price option)	(assumed same as longer reference period)	(depending on definition of reference revenue)

Low degree of risk   High degree of risk exposure

Source: Frontier Economics

From this exercise, we conclude that the likely changes in revenue risks in each option, **compared to the current CfD** are as follows:

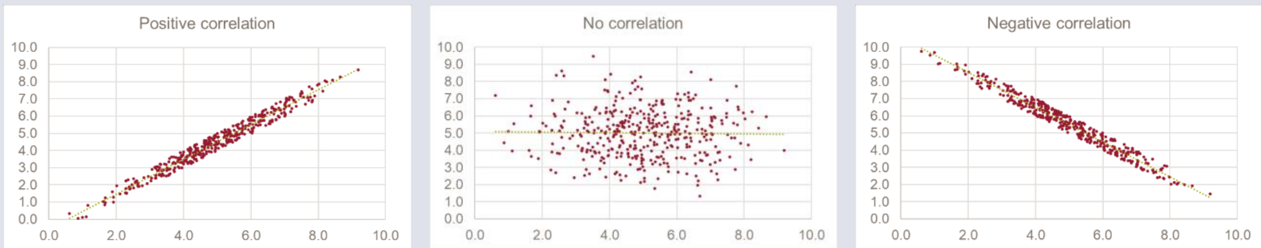
- **Longer reference price periods** – additional price and profile risk as there is increased unpredictability of deviations between forward prices and outturn prices, and whether the plant's capture price matches the reference price.
- **Strike price range** - additional wholesale price risk linked to the size of the range between strike price cap and strike price floor. Potential for additional profile risk, subject to how reference prices are defined.
- **Payment on deemed output** – as the case for the longer reference price period option, additional price and profile risk as there is increased unpredictability of deviations between forward prices and outturn prices, and whether the plant's capture price matches the reference price. However, volume risk related to the support payments is removed.
- **Revenue cap and floor** – not possible to distinguish between price and volume risk inherent in this option and therefore comparison to the current CfD is difficult. The revenue cap and floor mechanism allows revenue risk (as a combination of price and volume) with the size of the revenue risk dependent on the range between cap and floor, the degree of overlap between the distribution of wholesale market revenues and the cap/floor range, and the frequency of evaluation of payments under the cap and floor contract.
- **Green power pool**: within the contract term, the exposure to revenue risk depends on the precise contractual arrangements between the pool and generators (e.g. a CfD or revenue cap and floor). Beyond the initial term, the key distinguishing feature of the green power pool is that generators may be able to opt into new (potentially shorter duration) contracts as a way of reducing merchant tail risk.

Implications for revenue unpredictability under different REMA options

In this sub-section, we discuss how exposure to the components of revenue risk described in section above for each REMA option may translate into unpredictability in revenues from an investment. Before we do so, it is important to recognise that the overall impact of a particular option on revenue risk may be different to the sum of the incremental risks identified in the previous section. The combined effect on overall dispersion of revenues of the individual revenue risk components depends on how correlated each of the components are with each other, which we have not assessed as part of this work.

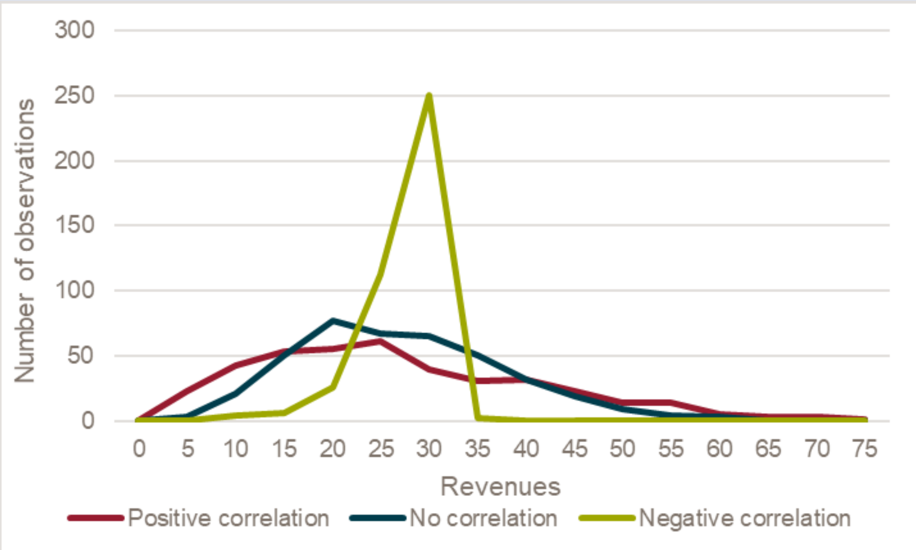
Box: illustrating the correlation between two random variables

The three charts below illustrate two variables (say, price and volume), both randomly distributed (in this case, normally distributed with a mean of 5 and standard deviation of 1.5), for a sample of 400 observations. The difference in each case is the correlation – whether prices are positively, negatively or not correlated with volumes.



Given revenue is the product of price and volume, how widely distributed revenues are will depend on whether prices tend to be high or low when output is high (and vice versa). Revenues will be much more tightly distributed when prices and volumes are negatively correlated.

The chart below illustrates the distribution of revenues corresponding to each of the three charts above. In each case, average (mean) revenues are the same (approximately equal to 25), although the distribution (e.g. size of tails) is clearly wider in the cases of positive and no correlation.



This is likely to be particularly important when considering the interaction of price and volume risks:

- Under the current CfD, prices are, to a large extent (as discussed above) stabilised. The distribution of overall earnings for a CfD generation is primarily driven by the distribution of volume. The choice of CfD was based on a key assumption made at the time of EMR that removing price risk reduces earnings volatility because a significant source of revenue unpredictability related to long-term gas prices was removed from investors.

- Without a CfD, revenues are equal to the wholesale price, multiplied by volume:
  - If a generator tends to produce at higher load factors at times when wholesale prices are higher (i.e. there is a positive correlation between prices and an individual generator's volumes), revenues will be more widely distributed than either prices or volumes individually. In other words, revenues will be more widely distributed than under the CfD.
  - If a generator tends to produce at higher load factors at times when wholesale prices are lower (i.e. there is a negative correlation between prices and an individual generator's volumes),[31] revenues could be more narrowly distributed than either prices or volumes individually. In other words, merchant revenues could be less widely distributed than under a CfD.

Therefore, different conclusions can be reached regarding the effect of mechanisms such as the CfD on earnings volatility depending on the assumption made regarding the correlation between wholesale prices and volumes. The extent of any correlation between price and volume (and the distribution of each individually) is an empirical question, and will vary by technology and location of the asset. The symmetry (or otherwise) of the distributions of prices and volumes may also have an influence.

It may also be the case that these different views on the correlation are not mutually exclusive, and may be relevant over different timescales. For example, while investors may view the negative correlation between prices and volumes for intermittent plants an increasingly important feature of risk as renewables deployment expands, investors are still likely to be exposed wholesale price movements driven by variation in gas and carbon prices (uncorrelated with intermittent plant output), as long as gas-fired generation plays a significant role in wholesale price formation.

The correlation between prices and volumes may also depend on the time horizon over which it is assessed. For example, over a longer time horizon, the correlation between an individual plant's volumes and its average capture prices may be weaker than over a shorter time horizon. This is because, over a longer horizon, the influence of factors exogenous to the individual plant (such as the overall level of renewable capacity) will be relatively more important than over a shorter time period (e.g. within-year).

In this assessment we make no assumption regarding these factors, and instead describe below how either assuming a positive or negative correlation between wholesale prices and volumes might affect overall revenue volatility relative to the current CfD.

[31] This is particularly relevant to intermittent renewable generation: wind and solar plants tend to produce at the same time (due to weather patterns in GB) meaning that an individual wind/solar plant may face relatively lower prices when its output is high and higher prices when its output is lower. This 'negative correlation' could become more important as renewable penetration increases.

Option 1 - CfD with longer reference price periods

This option introduces incremental price and profile risk over the current CfD. Generators must forecast the gap between expected capture and reference prices when setting their strike price bid, which is a function of:

- the difference between forward prices that set the reference price and outturn half-hourly prices; and
- the difference the baseload price implicit in the forward reference price and the plant's variable output profile.

With regard to the first of these, our expectation is that the market's expectation of spot prices embedded in forward prices is unbiased and therefore, from reference period to reference period, deviations between forward and spot prices are equally likely to be positive or negative. Therefore, the impact of this change on the distribution of expected earnings over an investment horizon is likely to be limited.

However, investors are exposed to unpredictability in the extent to which their output profile will differ from the flat profile implicit in the baseload reference price. This is an additional source of unpredictability relative to the current CfD. As a result, the expected distribution of earnings is likely to widen, compared to the current CfD.

Option 2 - CfD with strike price range

The strike price range introduces additional wholesale price risk compared to the current CfD, linked to the size of the strike price range. The overall impact of this additional risk on earnings volatility depends on the correlation between wholesale prices and a generator's individual volumes (as well as the size of the strike price range):

- Positive or no correlation between wholesale prices and a generator's volumes: greater price risk results in greater earnings volatility.
- Negative correlation between wholesale prices and a generator's volumes: greater price risk results in lower earnings volatility. The strike price range protects against extreme movements in prices, and when prices within the strike price range, the negative correlation between prices and volumes drives greater earnings stability.

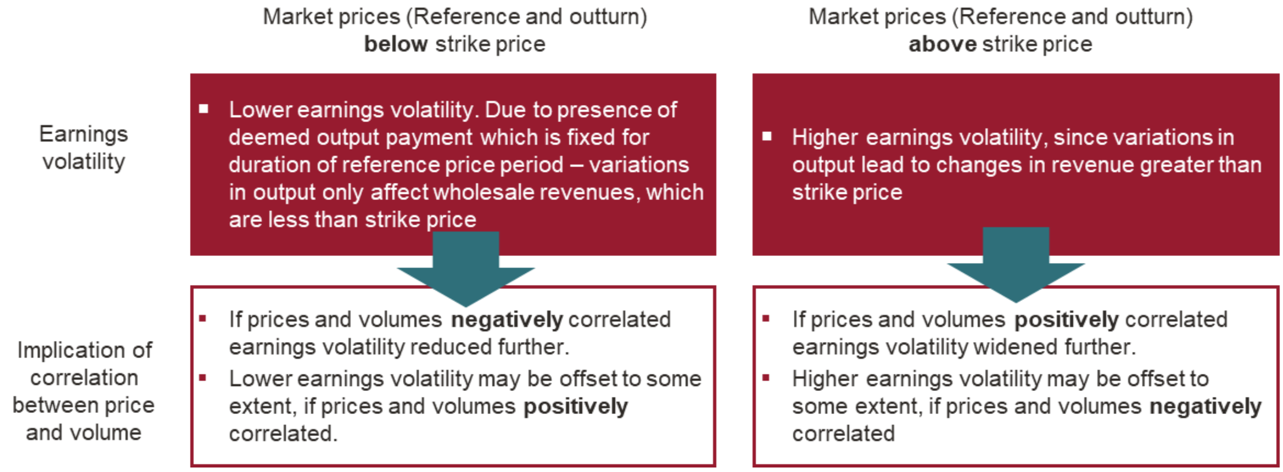
Option 3 - Payment on deemed output

For payments on deemed output, there are a number of changes to risks relative to the current CfD to consider:

- The increased price and profile risk during the reference price period - as noted above in relation to the CfD with an extended reference price period, the impact of the profile risk is likely to add to overall earnings volatility.
- With regard to the change in volume risk due to the support payment being decoupled from actual output, the impact is ambiguous with the direction of impact likely to relate to

whether support payments are expected to be positive or negative during the course of the contract. We discuss this in Figure 10 below.

Figure 10 Impact of change in volume risk on earnings volatility



Source: Frontier Economics

To the extent that wholesale prices are expected to remain below strike prices during the course of a contract, then it is difficult to determine the overall impact on earnings volatility of this option, with an increase in volatility due to profile risk, but a reduction due to decreased volume risk. However, if prices are expected to be above then this option is likely to increase earnings volatility relative to the current CfD.

Option 4 – Revenue cap and floor

The impact of a revenue cap and floor is likely to be closely linked to the size of the range between the cap and floor revenues. At one extreme, with a narrow range, it is likely to reduce earnings volatility relative to the current CfD (irrespective of the correlation of prices and volumes), due to the removal of volume risk, in addition to the removal of wholesale price risk under the CfD. A similar conclusion holds if the cap and floor range has little overlap with the distribution of wholesale market revenues – i.e. if either the cap or floor are expected to bind most of the time.[32] However, increased earnings volatility may result still from any potential profile risk with a longer reference price period.

However, with a large range between the cap and floor prices, exposure to price and volume risk is more likely to be increased relative to the CfD. This means (similarly to the strike price range option) the impact on overall revenue risk will be closely linked to the correlation between prices and volumes:

- When prices and volumes are negatively correlated, this creates additional revenue stability within the cap and floor range; but

[32] For high-cost technologies, there will be a large ‘subsidy’ component, so the mechanism may tend to stabilise revenues around the floor level. Similarly, for technologies that are very profitable with merchant revenues alone, the mechanism will tend to stabilise revenues around the cap level.

- When they are positively correlated, earnings volatility is likely to be increased, increasing likelihood that the revenue cap and floor are binding.

Design variations – Extended contract length

The impact of an extended contract length on earnings volatility will depend on the extent to which each design option mitigates earnings risk relative to full merchant tail exposure (i.e. a counterfactual without any support mechanism in place). This in turn depends on the correlation between wholesale prices and an individual generator's output:

- If prices and output are positively correlated, then earnings absent a support mechanism are likely to be more volatile than either price or output individually. Since all options reduce either price risk or overall revenue risk, compared to merchant operation, an extension of the contract length will reduce overall earnings volatility.
- If prices and output are negatively correlated, revenues will be more predictable than either prices or output individually. Any support mechanism which then serves to reduce wholesale price risk exposure only (e.g. the current CfD, a CfD with strike price range and a CfD with longer reference price) may actually introduce greater earnings volatility, compared to a counterfactual with full merchant risk exposure. As a result, any extension of the contract length for these options could increase overall earnings volatility.

Ultimately, as explained above, any change in earnings volatility (and associated change in cost of capital) will not be proportional to the increase in contract length.

Design variations – Green power pool

As noted above, the key distinguishing feature of the green power pool is that generators may be able to opt into new (potentially shorter duration) contracts as a way of reducing merchant tail risk. The effects of the green power pool on the cost of capital are therefore similar to the effects of a longer contract (see above). One difference compared to the simple option of longer contracts is that the price of any new contracts will be unpredictable at the time of entering into the original CfD. However, the price of a new contract will be linked to the LRMC of renewable power, which is likely to be more predictable than the wholesale price 15+ years out from commissioning.

Summary of earnings volatility relative to the current CfD

Table 1 below summarises the likely impact on the level of earnings volatility relative to the current CfD, noting where our conclusions depend on the correlation wholesale prices and an individual generator's output or particular design considerations. Red-shaded cells indicate a likely increase in revenue risk, compared to the current CfD, green a likely reduction in risk and amber an ambiguous or unclear effect.

Table 1 Earnings volatility under each of the REMA options

<table>
<tr><th colspan="2" rowspan="2">Support option</th><th colspan="2">Likely impact on earnings volatility, compared to current CfD</th></tr>
<tr><th>Positive correlation between prices and volumes</th><th>Negative correlation between prices and volumes</th></tr>
<tr><td colspan="2">Longer reference price periods</td><td colspan="2">Greater earnings volatility due to increased profile risk. Extent depends on length of reference period.</td></tr>
<tr><td colspan="2">Strike price range</td><td>Greater earnings volatility</td><td>Lower earnings volatility</td></tr>
<tr><td rowspan="2">Payment on deemed output</td><td>Wholesale prices expected to be below strike price</td><td>Uncertain impact, reduction in volume risk but increased profile risk depending on reference price period.</td><td>Volume risk further muted by negative correlation.</td></tr>
<tr><td>Wholesale prices expected to be above strike price</td><td>Increase in earnings volatility, with effect enhanced by positive correlation of prices and volume</td><td></td></tr>
<tr><td rowspan="2">Revenue cap and floor</td><td>Narrow range</td><td colspan="2">Impact subject to the range between revenue cap and floor. Narrow range likely to reduce volatility due to reduced volume risk.</td></tr>
<tr><td>Wider range</td><td>Wide range leaves price and volume risk with investors and therefore impact linked to correlation. Positive correlation will create greater propensity for revenue cap/floor to apply.</td><td>Negative correlation will create more stable revenues within cap and floor range.</td></tr>
<tr><td colspan="2">Variation: Contract length</td><td>Longer contracts for all options likely to reduce earnings volatility</td><td>Longer contracts for CfD options likely to increase earnings volatility.</td></tr>
<tr><td colspan="2">Variation: Green Power Pool</td><td>Similar effects as for longer contract</td><td></td></tr>
</table>

Source: Frontier Economics.

3 Illustrating the impact of changes in risk exposure on the distribution of earnings

In this section, we present an illustrative quantitative analysis of the impacts of the different options on the distribution of earnings. Specifically, we compare the standard deviation of revenues[33] for hypothetical new-build wind (onshore and offshore) and solar plants, under the following options:

- merchant operation;
- the current CfD scheme;
- the CfD with a longer reference period;
- the CfD with a strike price range;
- the CfD with payment on deemed output; and
- a revenue cap and floor.[34]

The aim of this analysis is not to draw definitive quantitative conclusions regarding the impacts of each of the options on the cost of capital. It is instead intended to provide:

- a quantitative illustration of the impacts of the options on risk exposure analysed qualitatively in the previous chapter, to aid understanding of the qualitative analysis; and
- a framework for how future analysis could be done in this area with different option design assumptions and market price and RES production data.

After setting out our approach and the results, we discuss how the framework we set out could be further developed.

Approach

The analysis consists of the following steps:

- **Step 1:** For each type of plant, we assume a production profile based on historical data for 2021.[35]

[33] Note, our analysis focuses on revenues from the wholesale market and (where relevant) under the support mechanism being analysed. It does not therefore capture variation in returns due to variations in capacity mechanism revenues (potentially relevant under merchant operation, or beyond the initial term of any support arrangement) or to variation in balancing and ancillary service revenues. However, we expect such revenues to account for only a small share of revenues for intermittent renewable plants, and therefore for only a small share of variation in revenues.

[34] We do not model volatility of earnings for the green power pool and extended contract length design variations. However, comparing the other options to merchant operation could provide some insight on the effect of extending contract length.

[35] Based on BMRS data. We choose 2021 as it is the most recent year for which we have data for all technologies, which does not appear to be affected by certain anomalies in the data (e.g. abnormally low load factors).

- **Step 2:** For a given support option (but not for merchant operation) and for each type of plant, calculate support levels (e.g. CfD strike price) required for the investment to break even, given:
  - assumptions regarding policy parameters (summarised in Table 2 below);
  - assumed technology costs, lifetime and cost of capital;[36]
  - wholesale prices over 2012-2020; and
  - the annual output profile (Step 1) repeated each year.
- **Step 3:** Generate a ‘synthetic’ distribution of hourly price profiles covering a 5-year period. Each profile is based on selecting 5 years at random from the period 2012-2020[37], in a random order.[38]
- **Step 4:** Holding the support level fixed at the level calculated in Step 2, calculate cash flows and the IRR over the 5-year period for each of the synthetic price profiles generated in Step 3.
- **Step 5:** Calculate the resulting coefficient of variation[39] of the IRR.
- **Step 6:** Repeat Steps 3 to 5 for each support option.

The analysis requires making certain assumptions regarding the design parameters of each option (for example, for the CfD with strike price range option, to solve for the strike price range in Step 2 above, we need to make an assumption regarding the width of the range). The results will be sensitive to the assumptions made regarding design parameters, which we summarise in Table 2 below.

[36] Values for CAPEX, OPEX and the WACC for each technology are taken from the BEIS electricity generation costs report (2020). We use central CAPEX and OPEX values for projects commissioning in 2025. Given the restriction of the analysis to a 5-year period, we incorporate CAPEX and a return by using an annuitized value. For this calculation, we use a cost of capital of 5.2% (the BEIS assumption for onshore wind, which we also use for solar PV) and an asset lifetime of 25 years. In practice the cost of capital and asset lifetime may differ between technologies.

[37] For the purposes of this illustrative analysis, we have excluded 2021 and 2022 from our analysis. Prices in those years tend to be significantly higher than in other years, which makes drawing conclusions more challenging.

[38] With nine years of wholesale price data (2012-2020), this gives 15,120 possible permutations of 5-year profiles.

[39] The coefficient of variation is defined as the standard deviation divided by the mean. The coefficient of variation is a unitless measure of the dispersion of a distribution. The higher the coefficient, the greater the dispersion in returns.

Table 2 Summary of assumptions regarding design parameters for each option

Option	Assumed design parameters
Current CfD	Reference price equals hourly price. No payment when hourly price is negative.
CfD with longer reference price period	Reference price calculated as average of hourly price over reference period. Reference period of 1 month considered (sensitivities of 6 months and 12 months). No payment when hourly price is negative
CfD with strike price range	Reference price equals hourly price. Upper and lower bound set equal to ‘central’ value, +/- X%. Value for X% of 5% considered (10% as sensitivity). No payment when hourly price is negative
CfD with payment on deemed output	Similar to CfD with longer reference price period, reference price calculated as average of hourly price over reference period, and reference periods of 1 month, 6 months, and 12 months considered. Deemed output for each hour set equal to average output during the reference period.
Revenue cap and floor	Calculate the annual notional revenue required to obtain an average return of 5.2%, Calculate the 'cap' and 'floor' as notional revenue +/- X%. Value for X% of 10% considered. If annual merchant revenues are below annual floor revenues, revenues are ‘topped up’ to the floor level. If annual merchant revenues exceed annual cap revenues, the generator pays back the difference. If annual merchant revenues are within the cap/floor range, annual revenues equal merchant revenues. No adjustment to the cap and floor for the number of hours of negative prices in a given year.

Source: Frontier Economics

Our approach is similar to that used by NERA (2013). In their report considering the impact of a CfD on the cost of capital, NERA undertook an analysis of historical revenue volatility for onshore and offshore wind technologies, comparing the standard deviation of historical revenues under the RO to hypothetical CfD cash flows.[40] Other quantitative studies also essentially focus on volatility in cash flows or returns, although the metric they consider may differ. For example:

[40] While NERA did not use their historic volatility analysis to directly calculate the cost of capital, it was used to support their conclusions regarding the effect of the CfD on reducing revenue volatility and that the impact of the CfD would be relatively larger for onshore wind compared to offshore wind.

Some (e.g. Redpoint (2010) and Bunn and Yusupov (2015)) focus on 'value-at-risk' – the difference between the mean earnings expectation and an extreme (e.g. 95th percentile) downside case[41]; and

Blyth et al (2021) similarly focus on downside risk. Their analysis is based on forward-looking modelling. For each option, the authors calculate, across different scenarios, the change in discount rate required to achieve the same net present value as in a base case scenario ('discount rate impact'). A positive discount rate impact indicates downside risk. If an option leads to positive discount rate impacts being more limited, the authors conclude it is associated with a lower cost of capital.

We highlight a few additional caveats regarding the analysis:

- **Holding output profile fixed (while allowing for different price profiles):** We hold the output profile for each hypothetical plant fixed[42] while simulating the returns under different synthetic price profiles. The analysis presented here therefore cannot be used to draw inferences regarding the impacts of the different options on volume risk, and does not model any correlation between prices and volumes. This means that it could (if prices and volumes are negatively correlated) overestimate the increase in the volatility of earnings arising from options that expose generators to greater wholesale risk (or vice versa if prices and volumes are positively correlated).[43]
- **Use of historical prices:** While the analysis is not strictly a backward-looking analysis, it does use historical price volatility as a proxy for the future. To the extent that future capture prices for renewables may be more volatile (for example due to increased dependency of prices on weather conditions), the analysis may under-estimate volatility of merchant revenues (and so under-estimate the impact of different options in addressing volatility).
- **No representation of forward prices:** For options that involve a reference price, in practice, the reference price is likely to be set using a forward price. As we have described in section 2, this introduces some price risk due to variation in the difference between forward and spot prices. For simplicity, we calculate the reference price as being equal to the observed average spot price over the defined reference period. The analysis therefore considers the differences in prices captured by the hypothetical generator due to its output profile not being flat in each period, but does not capture price risk related to differences between forward and spot prices.[44]

[41] In the Redpoint analysis, the value at risk figure was used as an input to determine the cost of capital, based on an assumed relationship between gearing (i.e. the ratio of debt to equity) and the value at risk.

[42] In addition, the assumed wind and solar profiles are based on publicly available data for the aggregate wind and solar plant park in GB. As a consequence, the resulting output profile is likely to be smoother than that of an individual plant.

[43] There is a small positive correlation between hourly wholesale prices over 2012-20 and volumes for the corresponding hour in 2021 for our modelled plants. The correlation coefficients are 0.08 for onshore wind and 0.01 for solar.

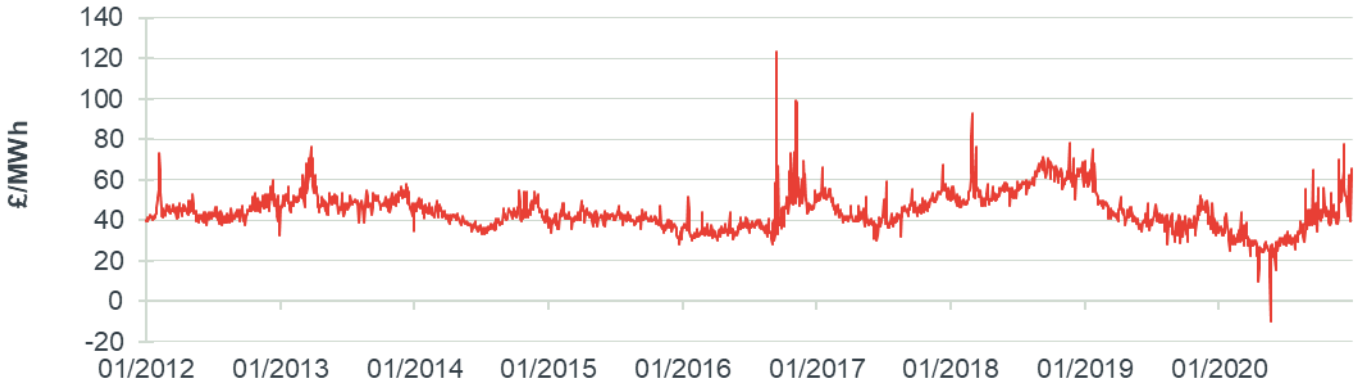
[44] It may be possible to introduce this to a similar type of analysis. For example, if assuming that forward prices are unbiased estimates of future spot prices, then one approach may be to set the reference price equal to average spot prices, plus a random error (symmetrically distributed around zero).

Results

Merchant revenues

Figure 11 shows day-ahead baseload prices (i.e. average of hourly prices for each day) for GB over 2012-20 (i.e. the price data used in our analysis).

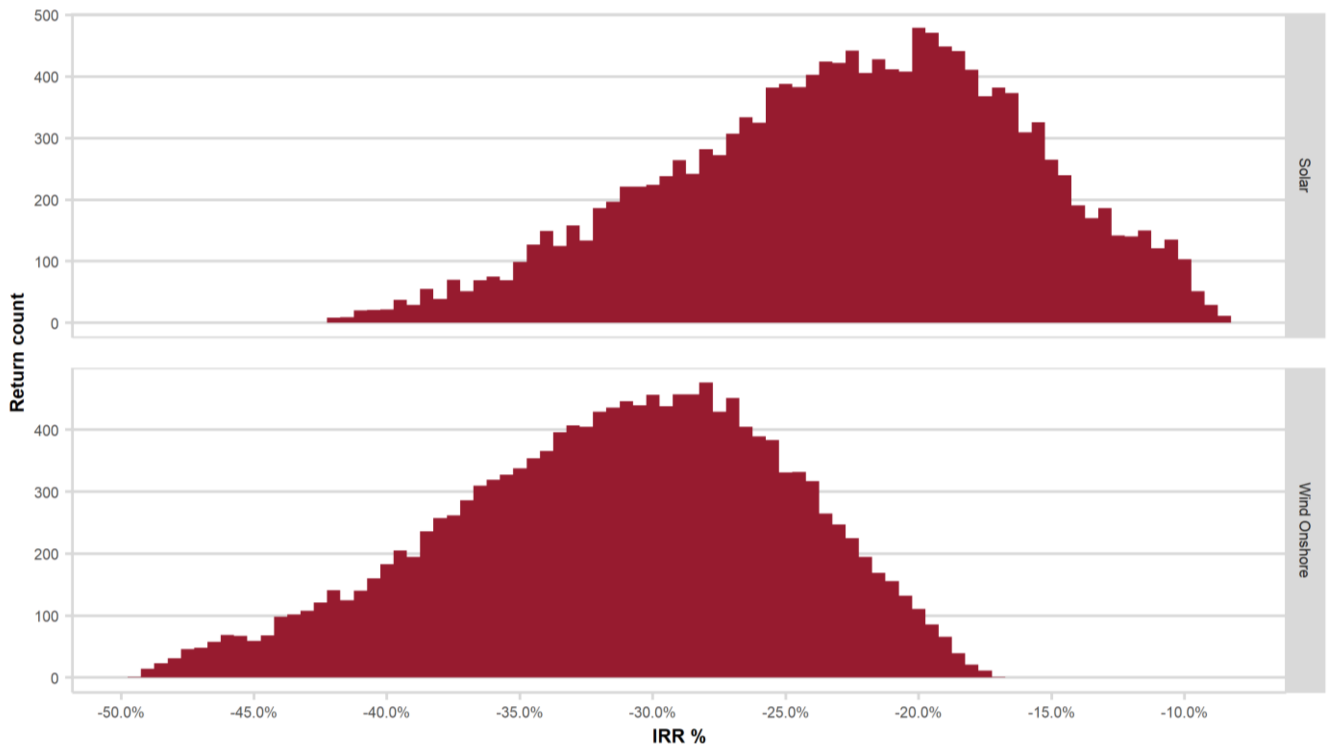
Figure 11 GB day-ahead baseload prices



Frontier Economics, based on Bloomberg data.

Figure 12 shows the distribution of merchant IRRs resulting from the different permutations of hourly price profiles, for solar and for onshore wind.

Figure 12 Distribution of merchant IRRs



Source: Frontier Economics

For both technologies, the entire range of IRR estimates is negative. In other words, none of the synthetic merchant price profiles result in a positive rate of return. This is due in part to the low observed load factors for each technology in the data used (typically between 20% and 30%). IRRs for solar are less negative given lower assumed CAPEX and OPEX. There is significant variation in merchant returns for both technologies (range in IRR estimates of around 30 percentage points).

Calculated support levels

Based on the wholesale prices over 2012-2020 and the design parameters in Table 2 above, Table 3 below shows the calculated strike prices (or notional annual revenues, in the case of the revenue cap/floor option) for each technology, under each option.

Table 3 Calculated strike prices / notional revenues under different options

	Solar PV	Onshore wind
Current CfD	£ 58.59 / MWh	£ 61.38 / MWh
CfD with longer reference price period (1 month)	£ 56.63 / MWh	£ 61.01 / MWh
CfD with strike price range (+/- 5% range)	£ 60.91 / MWh (mid-point of range)	£ 63.90 / MWh (mid-point of range)
CfD with payments on deemed output (1 month reference period)	£ 56.63 / MWh	£ 61.01 / MWh
Revenue cap / floor	£ 48.4 k (notional annual revenue, 1 MW plant)	£ 124.3 k (notional annual revenue, 1 MW plant)

Source: Frontier Economics. Figures in real 2018 prices.

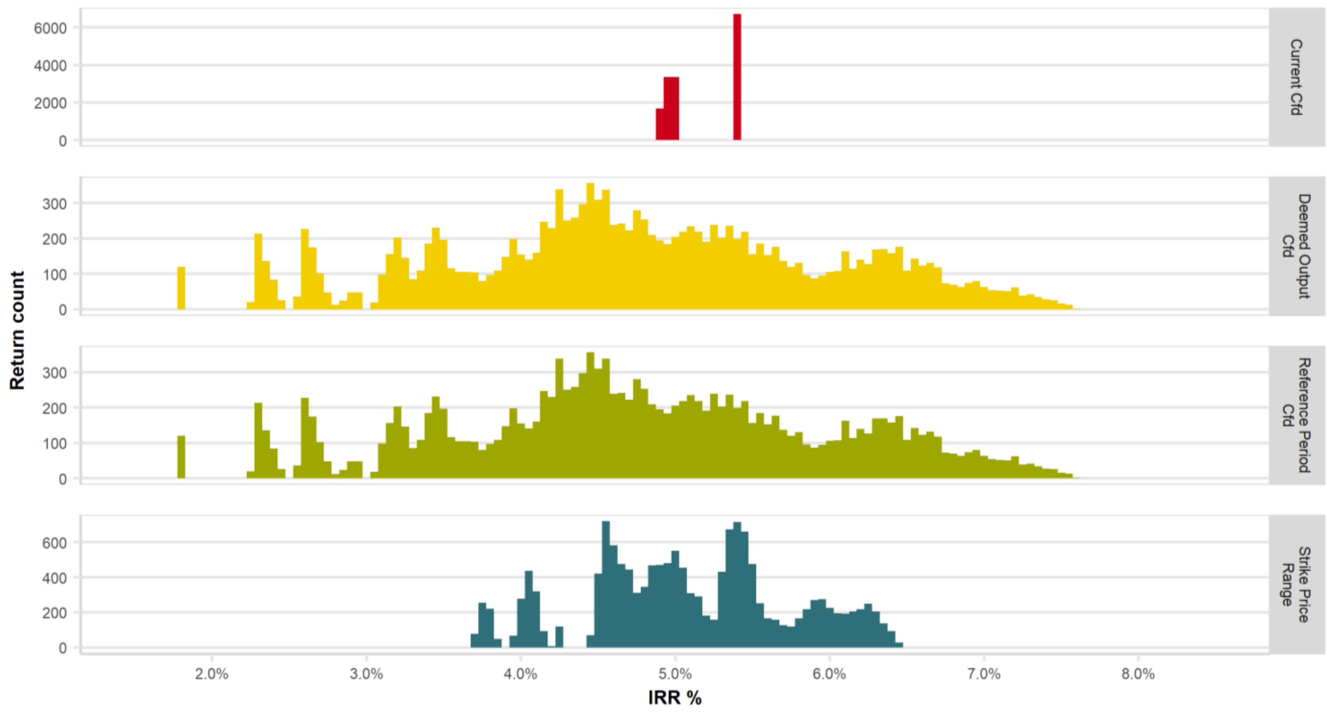
The strike prices differ across options. This is because the profile of support payments is different under each option, so the strike price needs to adjust to ensure the same expected rate of return (note that, for the purposes of deriving strike prices / required notional revenues, we have held the cost of capital constant across options).

For example, the estimated strike price for a CfD with a longer reference price period is lower than the strike price under the current CfD. This reflects the fact that, in our analysis, capture prices for wind and solar tend to be higher than baseload prices (see footnote 43). If the strike price under the two options were the same, support payments would be higher under the longer reference price period option, leading to a higher than required rate of return.

Distribution of IRR estimates under different support mechanisms

Figure 13 shows the estimated distribution of IRR estimates under the different support mechanism options considered, for solar PV.

Figure 13 Distribution of IRR estimates under different support mechanism options, solar PV



Source: Frontier Economics

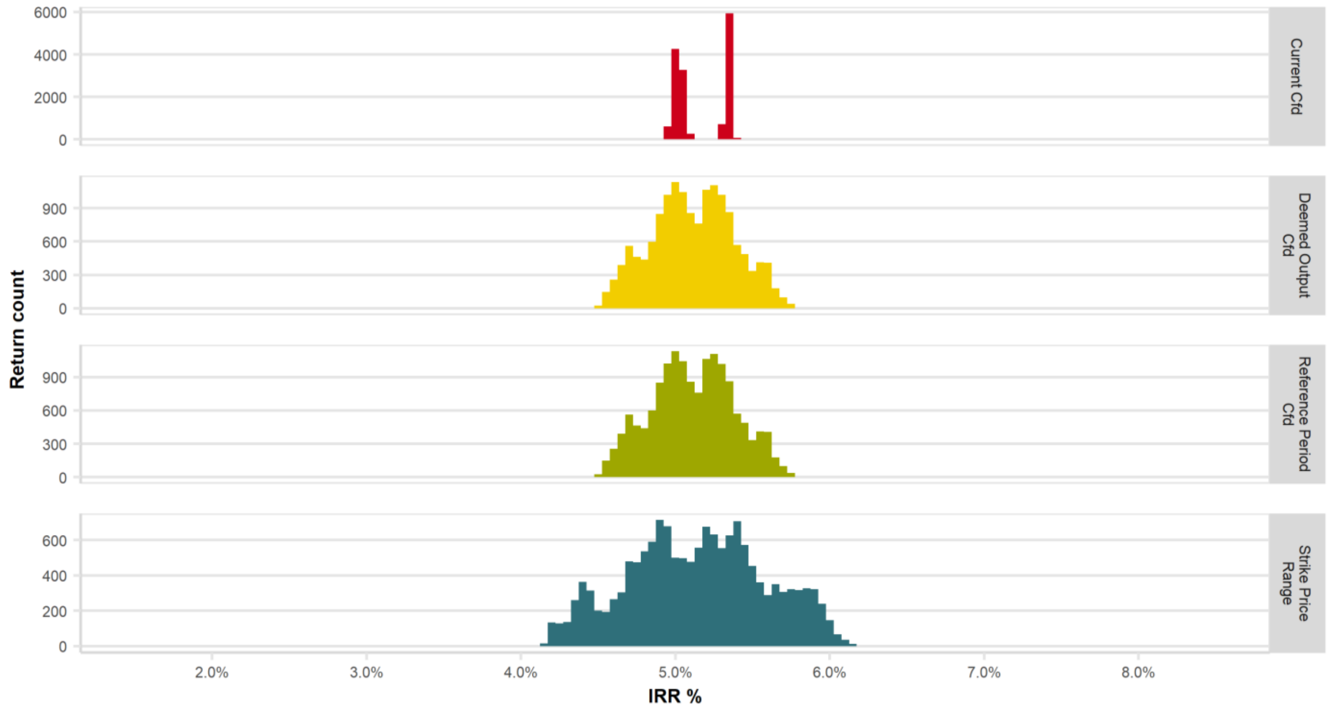
For all options, the IRR estimates vary in a positive range, with variation in returns under all significantly reduced, compared to merchant returns:

- **Current CfD:** returns are centred around the assumed WACC (5.2%). However, there is some distribution around the returns. Because prices are only ever negative in 2 hours in 2019 and 99 hours in 2020, this results in a bimodal distribution where any 5-year period that includes cash flows from 2020 results in a slightly lower IRR than the average return, and any run without 2020 cash flows results in slightly higher IRR than the average return.
- **CfD with longer reference price period:** Returns are more widely distributed than under the current CfD, reflecting greater exposure to the difference between the capture price and the baseload reference price.
- **CfD with strike price range:** Returns are more widely distributed than under the current CfD , reflecting greater exposure to price risk (as explained above, there is no volume risk in this analysis).
- **CfD with payments based on deemed output:** Returns are distributed similarly to the longer reference price period option. This is because the relatively short reference period (1 month) means that deemed output (which is set equal to average monthly volumes) closely tracks actual volumes.
- **Revenue cap and floor:** Results are not shown above. This is because, even with the cap and floor set at a wide range (e.g. 50%) either side of the notional revenue, the revenue floor always binds and there is no distribution of returns in our modelling. This

is because the entire distribution of merchant cash flows lies in a negative range. This illustrates the point made in section 2 that the impact of the revenue and floor option on the distribution of returns depends not just the size of the cap/floor range, but on the degree of overlap between the distribution of wholesale market revenues and the cap/floor range.

Figure 14 shows the estimated distribution of IRR estimates under the different support mechanism options considered, for onshore wind.

Figure 14 Distribution of IRR estimates under different support mechanism options, onshore wind



Source: Frontier Economics

The results for the current CfD and the strike price range are similar to those for solar PV. However, for the CfD with longer reference price and CfD with payment based on deemed output, the variation in returns for onshore wind is narrower than that for solar (despite the variation in merchant returns for the two technologies being similar – see Figure 12 above). This is consistent with there being less variability in the difference between the (baseload) reference price and the capture price for onshore wind, than there is for solar (based on the price and volume data we use in our analysis. We have also considered the following sensitivities for onshore wind:

- a strike price range of +/- 10% (as opposed to 5%), leads to a slightly wider distribution of returns (~3.6% to 6.7%) than a strike price range of +/- 5% (see Figure 14), reflecting increased exposure to price risk; and
- longer reference price periods (of 6 months and 12 months) lead to a wider distribution of returns (for both sensitivities, ~4.2% to 6.2%), compared to a 1-month reference period (see Figure 14), for both the CfD with longer reference price and CfD with

payment on deemed output models. This reflects increased exposure to profile risk. However, the dispersion of returns remains significantly reduced compared to merchant returns. This is because volatility in annual average prices over 2012-2020 (from which investors are insulated under a longer reference price CfD) has been similar to volatility in capture prices, based on our price and output data.[45]

Possible further development of the framework

Use of forward-looking data

It would be possible to adapt the framework above to use forward-looking projections of output and (internally consistent) price projections drawn from power market modelling. A distribution of forward-looking price profiles could be generated by assuming distributions around key parameters, such as fossil fuel prices and the capacity mix. As noted in footnote 44, it may also be possible to introduce price risk related to differences between forward and spot prices to the analysis.

Conversion of impacts to cost of capital equivalent

It might also be possible to convert the estimated impact on the standard deviation of returns of a change in regime (i.e. from CfD to one of the REMA options) to a cost of capital equivalent. The Sharpe ratio is one such approach to doing so, originally proposed by one of the developers of CAPM. It is a widely used method for measuring risk-adjusted relative returns.

The Sharpe ratio is a measure of reward (over and above the risk-free rate) relative to risk (as measured by the standard deviation of returns). In its simplest form, it is defined as:

$$Sharpe\ Ratio = \frac{r - r_f}{\sigma}$$

where: *r* is the return on investment, *r_f* is the risk-free rate, *r – r_f* is defined as ‘excess’ return above the risk-free rate, and *σ* is the standard deviation of excess returns (above the risk-free rate).

If we assume that investors wish to hold the Sharpe ratio of their investments constant, it means that faced with an increase in the standard deviation of excess returns, investors demand a proportional increase in excess returns.[46]

[45] The standard deviation of annual average (i.e. baseload) prices is £6.80/MWh, approximately 15% of the average wholesale price across the entire period (£45.90/MWh). Under the longer reference price period CfD, investors are protected from this year-to-year volatility in wholesale prices. The standard deviation of the average annual capture price is £6.52/MWh for onshore wind (£8.39/MWh for solar).

[46] An example of use of the Sharpe ratio is contained in Frontier (2022) ‘Locational Marginal Pricing – Implications for cost of capital’.

4 Effects of REMA options on wider system impacts

Low carbon support options are more likely to result in costs to society being minimised where investors are exposed not just to their own technology costs, but also to the wider impacts they may impose on the energy system (we explain these wider impacts below). This is also relevant for the criteria Government is considering in assessing REMA options[47], which include that market design should:

- lead to solutions being delivered at **least cost** to consumers[48] and sub-groups of consumers; and
- incentivise market participants of all sizes (both supply and demand side) to **act flexibly** where it is efficient to do so.

In other words, an objective of option design is to internalise the wider system impacts to investors, so that these are taken into consideration when they are choosing whether to invest.

In this section, we assess the extent to which the options under consideration would lead to wider system impacts being internalised by investors (technology own costs are borne by investors under all options). We also comment on how the significance of the impact of the different options on wider system impacts might be assessed.

DESNZ has previously described the following wider system impacts of relevance,[49] building on work by Frontier for its predecessor, DECC:[50]

- **Impacts in the wholesale market:** This category considers the fuel and carbon cost savings when incremental technology displaces higher marginal cost generation. It reflects how timely or valuable each MWh generated by a plant is and, for a small enough increment of capacity, can be proxied for by the wholesale price.[51] This impact will differ by technology type.
- **Impacts on costs of capacity adequacy:** This category considers the savings in the costs of ensuring the system reliability standard is met from the deployment of the incremental technology. It reflects how firm or reliable each MW of capacity provided by a technology is at moments of peak demand. This will differ by technology type.
- **Impacts in balancing and ancillary service markets:** This category considers how helpful or unhelpful a technology's generation is for the balancing and operability of the

[47] BEIS (2022), 'Review of Electricity Market Arrangements Consultation Document', page 46.

[48] Though, as noted earlier, there is a potential trade-off in that increased market exposure could increase risks to investors, also relevant for another REMA criterion, **investor confidence.**

[49] For a description of these 'wider impacts', see BEIS (2020), 'Electricity Generation Costs 2020', Section 7. This framework was intended to apply not just to generation, but to all resources (e.g. including interconnectors, demand-side response and storage).

[50] Frontier (2016), 'Whole power system impacts of electricity generation technologies'.

[51] Assuming that the carbon price faced by generators reflects the societal cost of greenhouse gas emissions.

system. If the incremental capacity increases the uncertainty of supply, generators in the rest of the system may be called on to help support system stability, resulting in additional costs. This impact will differ by technology type.

- **Impacts on networks:** This category considers how conveniently located a technology is, i.e. its proximity to demand centres. Incremental capacity may affect the cost of managing network constraints and/or may require investments in the grid. The impact will differ by technology type and location.

Below we consider the extent to which wholesale, balancing and network impacts would be internalised, under each of the low carbon support options.

For the purposes of the analysis, we assume that, under merchant operation, signals faced by generators are fully reflective of the costs/benefits on the system. In other words, we take the signals under merchant operation as a benchmark (while recognising that views may differ on the extent to which merchant signals are truly cost-reflective). For example:

- **Balancing:** Under current imbalance settlement arrangements in GB, penalties borne by generators (when their metered output does not match their contracted sales) should reflect the marginal costs of balancing actions taken by the system operator. Generators can provide balancing services and earn revenues for doing so.
- **Network:** Under the current TNUoS model for grid tariffs, generators face a locational (investment) signal. The REMA process is considering whether these signals may need to be reformed, including to provide operational locational signals via LMP models.[52]

We do not consider impacts on the costs of capacity adequacy since they are not borne by investors under any of the options under the contract term[53] – they can only be captured by investors after the end of the contract. In other words, technologies that make a greater contribution to capacity adequacy are only able to benefit to a limited extent from this competitive advantage in a low carbon auction.

Current (AR4) CfD

Impacts in the wholesale market – limited internalisation:

- Largely, generators receive the strike price for all output sold at the reference price, which should be achievable to a large degree (but for forecast error after the day-ahead stage, and as long as the day-ahead price is not negative). This means that there is no differentiation between generators based on the value of each MWh generated (as long as the reference price is positive).
- The negative pricing rule may distort incentives for solutions or behaviour that result in less frequent curtailment. Under merchant operation, the pay-off to carrying out

[52] We have not assessed how the REMA options might affect the degree to which locational impacts are internalised by investors under LMP models.
[53] We understand from BEIS that generators would not be allowed to combine capacity market revenues with revenues from a low-carbon support mechanism.

measures that can help shift output away from times of negative prices (e.g. investing in behind-the-meter storage or adjusting the timing of planned maintenance) depends on the cost of the measure and on the additional wholesale revenues that can be captured as a result. Under the CfD, by shifting the timing of its output, the generator stands to gain the strike price (rather than earning zero if it produces at times of negative prices). If the strike price is above the wholesale price, such measures will be over-incentivised.[54]

Impacts in balancing and ancillary service markets – partly internalised:

- The current CfD leaves forecast risk following the day-ahead stage with generators, and so would leave generators exposed to the balancing costs for the system resulting from errors in forecasting output.
- Under the current CfD, generators can provide balancing services and earn revenues for doing so. However, given CfD payments are based on output, this may mean there is, reduced incentive for generators to provide downward balancing to ESO when the day-ahead price is positive (and below the strike price).[55]

Impacts on networks – partly internalised:

- CfD holders are exposed to the full TNUoS signal, which will therefore influence siting decisions.
- Given CfD payments are made (when the day-ahead price is positive) based on output, this may distort the merit order for curtailment payments for system balancing (i.e. network) reasons. This is because bids in the balancing mechanism for curtailment for system balancing might reflect foregone CfD payments, as opposed to only reflecting the incremental costs of curtailment.

Option 1 - CfD with longer reference price periods

Impacts in the wholesale market – partly internalised (extent depends on reference period):

- On the one hand, this option introduces greater wholesale price exposure within the reference period, and so provides a greater financial reward to generators that produce when power is relatively more expensive within the reference period. If generators compete against each other for support, other things equal, those that expect higher wholesale market revenues within each reference period will be able to submit lower bids for support, and therefore will be more likely to be successful in auctions. Wholesale market impacts will be internalised to a greater extent, the longer the period over which the reference price is averaged.

[54] In addition, the negative pricing rule, as currently formulated, does not eliminate the possibility of inefficient dispatch. It is possible that day-ahead prices could be positive, resulting in a CfD payment, which might distort dispatch if intraday or balancing prices turn out to be negative.
[55] This is the case in theory, although in practice generator behaviour may depend on a range of factors.

- Similarly to the current CfD, the negative pricing rule may distort incentives for solutions or behaviour that result in less frequent curtailment, though the nature of the distortion will be different if CfD strike prices and resulting CfD payments are different.

Impacts in balancing and ancillary service markets – partly internalised:

- As with the current CfD, forecast risk following the day-ahead stage is left with generators, so generators remain exposed to the system balancing costs resulting from errors in forecasting output.
- Similar to the current CfD, since payments are based on output, this may mean there is reduced incentive for generators to provide downward balancing to ESO when the day-ahead price is positive. Compared to the current CfD, the extent of the distortion will be different, since the profile of CfD payments will be different (whether or not there is a more material distortion under this option would need to be examined empirically).

Impacts on networks – partly internalised: As with the current CfD:

- generators are exposed to the full TNUoS signal, which will therefore influence siting decisions; and
- similar to the current CfD, given CfD payments are based on output (when the day-ahead price is positive), this may distort the merit order for curtailment payments for network reasons. Compared to the current CfD, the extent of the distortion will be different (and the extent would need to be examined empirically), since the profile of CfD payments will be different.

Option 2 - CfD with strike price range

Impacts in the wholesale market – partly internalised (extent depends on width of strike price range):

- This option introduces complete wholesale price exposure within the strike price range. Therefore, wholesale market impacts will be internalised to a greater extent, compared to the current CfD, the wider the strike price range (relative to variation in the reference price). This provides an incentive to invest in technologies with a higher value in the wholesale market or to adjust behaviour (e.g. timing of planned maintenance) to maximise wholesale market revenues.
- As with the current CfD, to the extent the reference price lies outside of the strike price range, the negative pricing rule may distort the incentive for solutions or behaviour that avoid curtailment for overall energy balancing reasons.

Impacts in balancing and ancillary service markets – partly internalised:

- As with the current CfD, forecast risk following the day-ahead stage is left with generators, so generators are exposed to the system balancing costs resulting from errors in forecasting output.

- Similar to the current CfD, given payments are based on output, this may mean there is reduced incentive for generators to provide downward balancing to ESO when the reference price is positive. However, CfD payments will only be made when the reference price is outside the strike price range, so this distortion will occur less frequently, depending on the width of the strike price range (though the size of CfD payments may differ, compared to the current CfD).

Impacts on networks – partly internalised: As with the current CfD:

- generators are exposed to the full TNUoS signal, which will therefore influence siting decisions; and
- given CfD payments are based on output (when the reference price outside the strike price range), this may distort the merit order for curtailment payments for network reasons. Compared to the current CfD, this may happen less frequently (CfD payments will only be made when the reference price is outside the strike price range), but as noted above, the size of CfD payments may differ, compared to the current CfD.

Option 3 - Payment on deemed output

Impacts in the wholesale market – partly internalised (extent depends on reference period and profile of deemed output):

- As with Option 1, wholesale market impacts will be internalised to a greater extent compared to the current CfD. The extent will depend on the profile of deemed output.
  - One approach could be to allow deemed output to vary between reference periods (e.g. according to a forecast ahead of the start of each reference period), while being kept constant (i.e. constant load factor) within reference period. To an investor, this would appear similar to the CfD with a longer reference price period (with some possible differences since operational signals would differ, as payments are not linked to output). Wholesale market impacts will therefore be internalised to a greater extent, the longer the period over which the reference price is averaged.
  - If deemed output is constant across reference periods, wholesale market signals are fully internalised, regardless of the reference price period.
- Given payments are not linked to metered output, generators have efficient incentives (i.e. linked to the wholesale price signal) to avoid generating at times of negative prices.[56]

Impacts in balancing and ancillary service markets – fully internalised:

[56] Under this option, there is no need for a separate negative pricing rule.

- As with the current CfD, forecast risk following the day-ahead stage is left with generators, so generators are exposed to the system balancing costs resulting from errors in forecasting output.
- Compared to both the current CfD and to Option 1, given CfD payments are not based on metered output, there is an incentive for generators to provide downward balancing to ESO.

Impacts on networks – fully internalised:

- As with the current CfD, generators are exposed to the full TNUoS signal, which will therefore influence siting decisions; and
- Compared to both the current CfD and to Option 1, given CfD payments are not based on metered output, there is no distortion to the merit order for curtailment payments for network reasons.

Option 4 – Revenue cap and floor

Impacts in the wholesale market – partly internalised (extent depends on reference period and cap/floor range):

- Overall, the effects of this option will depend on the width of the cap/floor range (relative to expected wholesale price variation) and the length of the reference period.
- If the range is very wide, the signals faced by generators will be more akin to merchant generation and impacts in the wholesale market will be largely internalised by generators (and vice versa).
- The longer the period over which the reference price is averaged, the greater the exposure generators will have to price differences within the reference period, which will lead to impacts in the wholesale market being partly internalised, as described above for Option 1.
- The effects may also depend on the design of the availability incentive (e.g. if receiving any payment for a given period requires a threshold level of generation over the period, then this provides an incentive to achieve at least the threshold level of dispatch, to ensure at least that floor revenues are captured).
- Similarly, the revenue cap may also distort dispatch incentives: if a generator anticipates the cap is likely to be binding in a given period, this may disincentivise further generation, even if this might be beneficial for the system.[57] The extent of this distortion would depend on the level of the revenue cap relative to merchant revenues achievable

[57] It may be possible to reduce this distortion through introducing a sharing factor at the cap allowing generators to keep part of the benefit from increased sales over the cap. Expectations of the potential for additional profits beyond the cap may also reduce the distortion at the investment stage.

in a given period, and the frequency with which revenues are evaluated (i.e. the length of the reference period) relative to the revenue cap and floor.[58]

Impacts in balancing and ancillary service markets – partly internalised:

- As with the current CfD, forecast risk following the day-ahead stage is left with generators, so generators are exposed to the system balancing costs resulting from errors in forecasting output.
- As discussed above, the revenue cap and floor may distort dispatch incentives, which may affect balancing and ancillary service costs, depending on the level of the cap/floor.

Impacts on networks – partly internalised:

- As with the current CfD, generators are exposed to the full TNUoS signal, which will therefore influence siting decisions; and
- As discussed above, the revenue cap and floor may distort dispatch incentives, which may also affect curtailment costs, depending on the level of the cap/floor.

Design variations – Extended contract length and green power pool

The precise impacts of a longer contract will depend on the option. In general, to the extent that a given option results in less internalisation of wider system impacts compared to merchant operation, a longer contract duration will further reduce the degree to which wider system impacts are internalised by generators. A similar point applies to the green power pool, given it envisages the possibility for generators to move to new (albeit potentially shorter-duration) contracts following the end of the initial contract term.

Summary

Figure 15 summarises the analysis above. The impacts of some options (such as the strike price range and revenue cap and floor) are highly dependent on scheme design. This uncertainty is not fully captured visually in Figure 15 below.

[58] It may be possible to alleviate this distortion by determining notional revenues based on deemed, rather than actual, volumes, though we have not considered how this might work in practice in this report.

Figure 15 Degree to which different options expose generators to wider system impacts

System impact category	Current CfD	Longer reference price periods	Strike price range	Payment on deemed output	Revenue cap and floor
Wholesale market		(depends on length of reference period)	(depends on range)	(depends on length of reference period and profile of deemed output)	(depends on cap/floor range and design of availability incentive)
Balancing and ancillary services					
Network					

Low degree of internalisation of impacts

Wider impacts fully internalised

Source: Frontier Economics

Overall, we conclude that the main impacts of each option on the degree to which wider impacts are internalised by investors, **relative to the current CfD,** are as follows:

- **Longer reference price periods** – the longer the reference price period, the greater the reward for CfD holders better able to produce at times of higher wholesale prices;
- **Strike price range** – the wider the strike price range, the greater the reward for CfD holders better able to produce at times of higher wholesale prices;
- **Payment on deemed output** – as is the case for the longer reference price period option, if deemed output varies by reference period, then the longer the reference price period, the greater the reward for CfD holders better able to produce at times of higher wholesale prices. Impacts will be fully internalised if the deemed output profile is flat across reference periods. In addition, distortions to short-term markets (energy balancing and network curtailment) are avoided since payment is not linked to metered output; and
- **Revenue cap and floor** – the wider the range between cap and floor, the greater the reward for CfD holders better able to produce at times of higher wholesale prices. Compared to the current CfD, impacts on balancing and network curtailment markets are uncertain, and may depend on the design of any availability incentive, as well as the levels of the cap and floor.

As noted above, none of the options address the extent to which options internalise the impacts on capacity adequacy of different technologies. However, a given technology may (for example) have a higher value in terms of impacts in the wholesale market but a lower value in terms of capacity adequacy. It may be possible to recognise differences in capacity adequacy value in the auction design (e.g. the auctioneer could adjust the strike price bids submitted to reflect differences in capacity adequacy values between technologies). But if only a subset of differences between technologies (and locations) in wider system impacts are recognised by the combination of support arrangement and auction design, total system costs may not be minimised.

Significance of impacts

In the above discussion, there is some uncertainty as ranked how options might perform, as this is largely an empirical question. The extent to which differences in support mechanism design could lead to materially different auction outcomes will depend on:

- **the extent to which options expose investors to their wider system impacts** (which will need to take account of the final agreed design parameters[59]);
- **the ability of investors to influence system impacts through their actions** (which will be greater where auctions are across technologies, rather than being specific to individual technologies). Under technology-specific auctions, all categories of system impact above can be affected by siting decisions and operational decisions (e.g. timing of maintenance). Under technology-neutral auctions, the categories of system impact above can also be affected by choice of technology;
- **the incremental cost of system-beneficial behaviour:** in other words, what are the additional costs (CAPEX and OPEX) to investors associated with, for example, alternative siting or configurations of existing technologies or investing in alternative technologies? Assessing this may require a combination of engineering and stakeholder input; and
- **Interactions between new and existing capacity:** we have focussed in our analysis on the implications of different support mechanism options on new investors, largely ignoring how new capacity might interact with existing capacity on the system, and the incentives under which existing plants operate. Whether or not a CfD payment materially distorts the merit order (e.g. for system balancing) might depend on what other distortions are in place. For example, existing RO plants receive a relatively stable payment per MWh (in addition to the wholesale price), at levels that differ depending on technology and time of commissioning, and it may be some time before such plants exit current arrangements.

The significance of any impacts could be quantitatively assessed using power market modelling.

The modelling approach would first simulate auction outcomes under each options of interest (and the current CfD, as a baseline). The analysis could consider outcomes under both the current CfD auction structure (pots, clearing price mechanisms, budgets, capacity minima/maxima, etc.) and one with a greater degree of inter-technology competition (e.g. offshore wind competing against solar and onshore wind).

The approach would then model the impacts on total system costs (including network and balancing costs), given the different auction outcomes in the first step, and holding other aspects of the optimisation (e.g. any grid emissions intensity target, electricity demand,

[59] It would also require the mechanics of how each option could be made to work with competitive allocation, which we have not considered as part of this report.

baseline technology mix) constant. Plant short-run marginal cost assumptions could be adjusted to reflect any payments under support mechanisms linked to output.

5 Feedback from investors

As part of our work with DESNZ, Cornwall Insight engaged with a range of existing and potential investors to:

- understand the current landscape for investment in GB renewables; and
- gain insights, using interviews with current investors, into how it could change as a result of the options being considered.

In this section, we summarise the findings from the work carried out by Cornwall Insight.

Current investor landscape

Cornwall Insight, working with Frontier Economics, have developed an understanding of how investors may respond to changes in the market against current behaviour. Observations in this section are based upon analysis of markets, commercial arrangements and industry news.

Cornwall Insight identified key investor types in the current GB renewable energy market. Archetypes are intentionally not limited to those investing in existing Contracts for Difference (CfD) schemes. To the extent that there are typical or reoccurring characteristics, these have been summarised for each investment vehicle and investor type (Table 4).

Table 4 GB renewable generation investor archetypes

Type	Investor	What they are	Typical scale of investment in renewable generation projects	Investment objectives	Deal characteristics
Finance	Institutional	Insurance companies and fund managers.	>£100mn	Generally stable returns over the long-term	Bonds or equity investments – huge variety Some limited CfD experience observed
	Infrastructure	Sub-type of institutional	>£50mn (can be low as £15mn)	Long-term stable returns	Seeking income during holding period Some stated interest in CfD type investments

Type	Investor	What they are	Typical scale of investment in renewable generation projects	Investment objectives	Deal characteristics
	Venture capital	Private equity focusing on new companies with high growth potential	<£5mn	Short-term growth and sale to new investors; high risk/ high returns	Short-term/ time-limited investments, seeking value on exit Low interest observed in CfD-type investments
	Project financing	Bank debt injected to project specific SPVs	>£15mn	Certain returns over defined periods	10–25-year terms, large pot sizes, low interest rates Utilised in development of renewable generation assets, including some successful CfD schemes
Utility	Traditional utility company	Asset heavy utility company, owns significant energy related assets	>£50mn	Long-term stable returns	Medium to long-term investments Significant presence in successful CfD support schemes, although not all investors of this category have a stated interest in renewable generation assets
	Newer utility company	Asset light utility company, owns little generation	>£1-5mn	Medium-term growth	Invest smaller amounts and target medium risk projects Power Purchase Agreements (PPAs) may be more popular for parties with

Type	Investor	What they are	Typical scale of investment in renewable generation projects	Investment objectives	Deal characteristics
					smaller asset portfolios
	Traditional oil and gas company	Has/had, operations in oil and gas industry	>£100mn	Long-term stable returns	Medium to long-term investments Strong presence in existing CfD schemes
Other	Water or telecoms company	Companies operating in water and sewage companies	>£5-50mn	Long-term stable returns	Large capital, medium to long-term investments No activity observed in existing CfD schemes, although significant activity in PPAs and co-located renewable generation and storage
	Public sector	Local authorities and councils	Very varied. From <£1mn to >£10mn	Long-term stable returns	Varying types of deals No activity observed in existing CfD schemes, although significant activity in PPAs and co-located renewable generation and storage
	Crowd funding	Appealing to the public to invest small amounts	<£1mn in total (Individual investments of <£1,000)	Short-term growth with medium risk. Raising capital through public funding	Short-term/ time-limited investments No observed activity in existing CfD schemes

Source: Cornwall Insight

Looking ahead, methods of investment are undergoing global changes. Interest rates rose in 2022, linked to increasing inflation in the wake of Russia's invasion of Ukraine and energy prices rises. A common refrain since then has been that 'the era of cheap money is over'. `However, the expansion of ESG (Environmental, Social and Governance) themed investment funds potentially opens new avenues for investment in renewable generation.

The US Inflation Reduction Act includes over $60 billion to stimulate domestic clean energy manufacturing. In light of this, and the EU and UK policy response, investors in RES may be re-considering international opportunities. An emphasis across jurisdictions on the development of local supply chains may have knock-on implications for future investment in RES.

Investor interviews

Cornwall Insight conducted eight interviews with different organisations (representing a mix of finance and utility-type investors) over December 2022. Interview candidates were selected from parties who had indicated their interest via the REMA consultation process, along with other funders identified from public records and Cornwall Insight's market contacts. A variety of funder types were sought, representing interest in different technology types and funding gearing.

During the interview stage, the top-level investor attributes, and secondary characteristics about the organisation and the interviewee, were captured, to help identify and classify emerging themes. Interviewees were asked to describe their existing portfolio and future investment plans, to reveal:

- Financing used: balance sheet, project, subsidies, Power Purchase Agreements (PPAs)/Corporate PPAs (CPPAs);
- Where GB subsidies have been used, which scheme(s), e.g. prior CfD rounds;
- Technology focus (e.g. offshore wind, solar, unproven technologies);
- Preferred investment stage (e.g. development, construction, operation);
- Investments beyond supported GB renewables (e.g. merchant assets, infrastructure, approaches internationally); and
- Risk/return appetite.

Varying risk appetites are displayed by different types of investor. The majority of the investment types that were profiled in the initial phase had a low or medium risk appetite, with only private equity, venture capital and peer-to-peer investments showing the potential for higher tolerance for risk.

Interviewees were shown simplified diagrams of the market design options considered, and invited to share their views in a semi-structured interview via online video interview.

The following is a summary of the views provided by the parties:

- Several interviewees expressed support for the current (AR4) CfD model, given the price certainty provided and (in the views of some interviewees) its relative simplicity.
- However, several interviewees also recognised that the wider landscape was changing (given increasing penetration of renewables and Government's policy commitments), which might be a driver for changes to support mechanism design.
- None of the alternatives to the current CfD emerged as being universally popular among interviewees.
- Some comments provided support for the view that greater market risk would add risk to investors (or that required returns may temporarily increase until the market is able to find investors able to manage additional risks). For example, one respondent, commenting on the CfD strike price range option, noted that a wider range may provide reduced certainty regarding revenues.
- There were mixed views regarding options such as the CfD based on deemed output and a revenue cap and floor, which also reduce the extent to which investors are exposed to volume risk. Some existing investors/operators were cautious about the benefit of reducing volume risk, as this is where they see their operation having the potential to outperform the market (given the context in which these comments are made, we interpret 'volume risk' to refer to profile risk as we have defined it above). Some investors were confident these concerns would not be an issue if the resulting schemes were properly designed.
- Many participants commented that alternatives to the current CfD may involve additional complexity, which could deter investment, either due to perceived risks, or due to administrative burden.

Possible further research

It is possible that uncertainty regarding wider market design changes (given the ongoing REMA consultation) may have influenced the level of detail provided by respondents. Interviewees noted the difficulty in commenting on incremental or granular changes when more fundamental market features were perceived to not be fixed.

In addition, not all investors currently have a detailed understanding of the energy market. Interviewees were concerned some investors could be put off by a modest, or even favourable, change in risk, because of the time and resources required to explain the change.

Further engagement with investors on the impacts on risk and cost of capital of the different options, therefore, has the potential to yield additional insights, provided that:

- the detailed design parameters (e.g. deemed output level, any safeguards in place to minimise gaming risks) of the options are known, as is the governance process around them (e.g. dispute resolution processes)
- there is clarity regarding wider electricity market design; and

- sufficient time is taken to explain the above to investors.

6 Conclusions

As we noted in the introduction, increasing price exposure involves a potential trade-off with regard to minimising overall system and customer costs:

- on the one hand, increased exposure of CfD generation to expected wholesale revenues of the different technologies should increase the likelihood that competitive CfD auctions select technologies or projects that are least cost from an overall system perspective (which should, over the long run, reduce costs to customers); but
- on the other hand, increased market risk could increase the cost of capital (and hence increase overall investment costs) and, in turn, increase costs to customers.

Broadly, options that involve a higher degree of market exposure are more likely to minimise wider system costs. This is because this will encourage investors to internalise the trade-off between their own private costs and wider impacts on the system, in particular ensuring stronger incentives for investors to produce when wholesale prices are higher (including at times of scarcity), i.e. when output is more valuable for the system. The precise impacts will depend on whether investors actually have options to influence system impacts through their actions and the costs of such options (e.g. change in technology, siting or configuration). In addition, how options rank in this regard will depend on their eventual design:

- **Longer reference price periods** – the longer the reference price period, the greater the incentive for CfD holders to produce at times of higher wholesale prices;
- **Strike price range** – the wider the strike price range, the greater the incentive for CfD holders to produce at times of higher wholesale prices;
- **Payment on deemed output** – as is the case for the longer reference price period option, if deemed output varies by reference period, then the longer the reference price period, the greater the incentive for CfD holders to produce at times of higher wholesale prices. Impacts will be fully internalised if the deemed output profile is flat across reference periods. In addition, distortions to short-term markets (energy balancing and network curtailment) are avoided since payment is not linked to metered output; and
- **Revenue cap and floor** – the wider the range between cap and floor, the greater the incentive for CfD holders to produce at times of higher wholesale prices (provided that wholesale prices lie within the cap/floor range). Compared to the current CfD, impacts on balancing and network curtailment markets are uncertain, and may depend on the design of any availability incentive, as well as the levels of the cap and floor.

The cost of capital will tend to be higher under options that result in a wider distribution of returns (to the extent that incremental risks cannot be diversified via other investments). As well as depending on their precise design, how the options affect the distribution of returns will depend on the correlation between wholesale prices and plant volumes.

The trade-off between wider system impacts and the distribution of returns is perhaps most evident where prices and volumes are positively correlated (i.e. prices tend to be low when output is low, and vice versa). In this case, merchant revenues will be more widely dispersed than either prices or volumes individually. It is also relevant where prices and volumes are only weakly correlated. In both cases, a higher degree of market exposure will generally also mean more widely dispersed returns. Compared to the current CfD:

- a revenue cap/floor model with a narrow range could reduce risk compared to the current CfD, due to reduced volume risk;
- a longer reference price period introduces some additional profile risk;
- assuming the same reference price period, a deemed output model may also introduce additional profile risk, but this may (if wholesale prices are expected to be below strike prices) be offset by reduced earnings volatility due to the deemed output payment; and
- options that introduce price risk exposure, such as the CfD with a strike price range and the revenue cap/floor with a wide range) have the potential to introduce greatest unpredictability of returns (depending on precise design, e.g. width of strike price range).

Investor feedback lends some anecdotal support for higher required returns where exposure to market risk is greater.

However, greater market exposure need not always lead to an increase in the distribution of returns. If wholesale prices and plant volumes are negatively correlated (i.e. prices tend to be low when output is high, and vice versa), then merchant revenues might be less widely dispersed than either prices or volumes individually. With negative correlation, compared to the current CfD:

- options that introduce price risk exposure (such as the CfD with strike price range and the revenue cap/floor) have the potential to reduce unpredictability of returns (though their impact will depend on precise design, e.g. width of strike price range);
- a deemed output model may involve some additional profile risk, although (if wholesale prices are expected to remain below strike prices) unpredictability of returns should be less than that of volumes alone (volume risk is the main driver of revenue risk under the current CfD); and
- a longer reference price period – assuming the same reference price period as the deemed output model – similarly involves additional profile risk but revenue risks are still primarily driven by volume risk as is the case for the current CfD.

The correlation between prices and volumes may also depend on the time horizon over which it is assessed. For example, over a longer time horizon, the correlation between an individual plant's volumes and its average capture prices may be weaker than over a shorter time horizon. This is because, over a longer horizon, the influence of factors exogenous to the individual plant (such as the overall level of renewable capacity) will be relatively more important than over a shorter time period (e.g. within-year).

The relative importance of shorter-horizon vs. longer-horizon price risks requires further assessment. However, our illustrative quantitative analysis (based on historical data) shows that even if exposed to profile risk under the longer reference price period and deemed output models, the removal of volatility in average prices from one period to the next is more significant.

The extent to which either price risk or volume risk is ultimately diversifiable requires further assessment. Similarly, the nature of the correlation between prices and volumes is an empirical question (and the result may differ by technology or location). We have set out (and illustrated) a framework that could be used to provide indicative quantitative estimates of the impact of different options on the variation in returns and, in turn, the cost of capital.

The impacts of options on total system costs will depend on the extent to which investors are actually able to influence system impacts through their choices. Investors will be more able to do so where technologies compete against each other for support in auctions. We have described an approach that could be used to quantitatively assess the possible impacts on wider system costs.

Some potential investors expressed concerns that changes to the CfD scheme would deter investment in new schemes, requiring re-assessment of compatibility with the funder’s risk appetite. DESNZ will need to engage existing and potential investors throughout any transition period.

Annex A – Locational risk exposure under REMA options

In this Annex we consider the implications for the nature of the locational signal, and hence locational risk, of the different support options being considered as part of REMA.

It is helpful to separate out locational risk into locational price and volume risks:

- **Locational price risk** is the degree to which investors are exposed to changes in the value of the locational signal i.e. the value of locational TNUoS charge, or in the case of LMP, the spread between the local and system price.
- **Locational volume risk** is the degree to which investors are exposed to the network not being able to physically accommodate their power i.e. whether plant's are compensated for being curtailed for system reasons as is the case under current arrangements.

However, the implications of the locational risks for investors will not only depend on the design of the support arrangements, but will also depend on the wider wholesale market structure in which the plants operate. REMA is considering the potential to move from the current national wholesale price to LMP, alongside other options for improving the efficiency of locational signals. We therefore consider the implications for locational risks under different wholesale market structures (focussing on LMP) and support arrangements.

National wholesale price with TNUoS charges

Under the current CfD (AR4) regime investors are exposed to a form of locational price risk but not volume risk:

- **Locational price risk** - The locational price signal relates to the value of the locational network charge (TNUoS) and therefore investors are exposed to errors in their forecasts of the charges which change annually.
- **Locational volume risk** – Under 'Connect and Manage' if there are local transmission network constraints which imply that energy cannot be physically accommodated, investors can bid into the balancing mechanism in a way which will ensure that they still receive their strike price despite not producing at full capacity.[60] As a result, investors are not directly exposed to errors in their forecasts of their curtailment, which depend on

[60] Investors are still exposed to being out of merit for energy balances when the wholesale prices are negative. However, they can still inform ESO of an intention to generate, and submit negative price bids (as long as the day-ahead price is positive and below the strike price) to the balancing mechanism for system curtailment reasons. In the event the transmission network cannot accommodate their energy, they would agree to 'buy back' their energy provided ESO pays them and be paid for so doing.

forecasts of the pattern of new generation and new load connections or network developments in their local area.

This characterisation of the different risks holds for each of the support options discussed in this report. While uncertainty about the value of TNUoS directly affects the distribution of expected returns for investors (it is a component of a plant's fixed costs), it does not affect a plant's revenues and therefore the nature of the locational signal is not affected by any of the price or revenue support options in scope.

Locational marginal pricing (LMP)

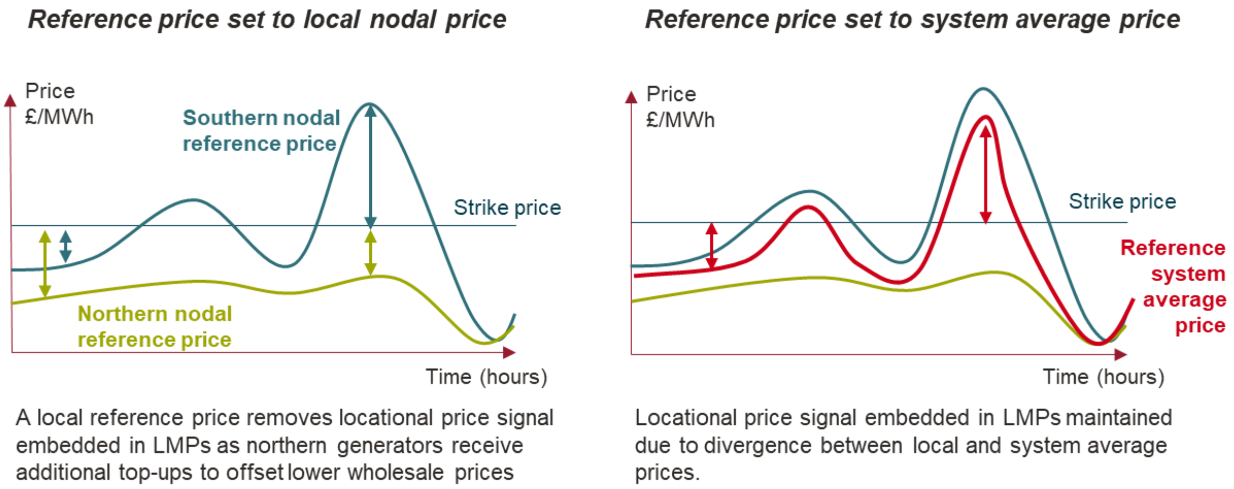
Under LMP the nature of the locational risk will change relative to the current arrangements, as well as being dependent on the particular design of the support scheme.

With regard to the **locational price risk**, each of the support mechanisms we go on to discuss relies on an explicit (e.g. CfD) or implicit (e.g. revenue cap & floor) reference price. The value of the locational price signal faced by investors is dependent on whether the reference price is a system average price or local (nodal or zonal) price. In other words, for each of the options there is a design choice about the degree to which investors are exposed to a locational price signal as described in Figure 16 below:

- If the reference price is based on a local price then they are effectively insulated from locational price risk; and
- If the reference price is based on a system average price, then investors are exposed to locational price risk, and hence errors in their forecasts of the locational price spread, which is highly dependent on the location of other parties' investments (generation, load and networks).

Therefore, for each of the options we will consider the implications for locational risk of LMP with support mechanisms based on either local or system average reference prices.

Figure 16 Implications of approach to reference price for locational price signal under LMP



Source: Frontier Economics

Note: We refer to a Southern zone as indicative of a region with excess demand where prices are typically higher than average, and a Northern zone as indicative of a region with excess supply where prices are typically less than average.

In principle, LMP introduces a new **locational volume risk** for investors. If local low-cost generation is too high relative to the available transmission capacity, the network may not physically be able to accommodate their production. However, in contrast to the current approach (TNUoS regime + 'Connect and Manage'), under an LMP regime, investors will receive no compensation. In other words, they will not earn their strike price on such 'curtailed' volumes.

Investors will therefore have to forecast the likely extent of such curtailment over the investment horizon, and will be exposed to errors in their forecasts. The level of curtailment will be highly dependent on the location of other parties' investments and production relative to the pace of network and local load development. As a result, delays in the commissioning of new transmission lines, or shifts in the spatial pattern of generation and demand relative to expectations may have a material impact on returns.

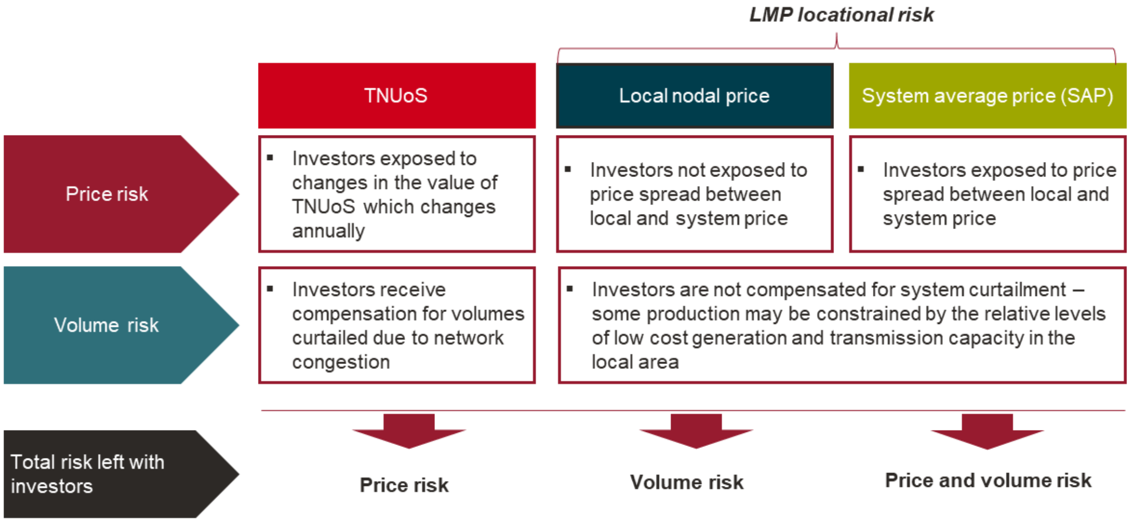
However, the nature of this new risk and degree of exposure for investors will vary under the different support options.

In the following sections we therefore discuss how locational risk, and hence the distribution of expected returns for an investor, is affected by the different support options (assuming both approaches to the reference price) under LMP. For each option we also compare the impact relative to the current status quo approach with TNUoS.

Current CfD and CfD with longer reference price periods

Under the current CfD with TNUoS, investors are only exposed to locational price risk. In contrast, under LMP a new volume risk is introduced irrespective of the approach to reference prices, but investors are only also exposed to price risk if the reference price is a system average price. This comparison of risks is also relevant for a CfD with a longer reference price period. While a longer reference price period changes the profile risk faced by investors, the nature of the locational risks remains the same.

Figure 17 Locational risk summary under current CfD



Source: Frontier Economics

With regard to the implications for the distribution of expected earnings, under both TNUoS and LMP (with SAP) investors must forecast the locational price which in both cases is volatile and uncertain. As noted in Frontier's separate report, which compared the predictability of the locational price signal under LMP with TNUoS, there are good reasons to believe that an LMP signal would be more unpredictable.[61] However, if LMP with a local price is introduced, then price risk is removed meaning locational price risk is reduced relative to TNUoS as specified today.[62]

As noted above, under LMP, the new volume risk means that investors need to forecast system curtailment and are therefore exposed to errors in those forecasts. The level of curtailment will be highly dependent on other parties' investments and production relative to the pace of network and local load development.

CfD with strike price range

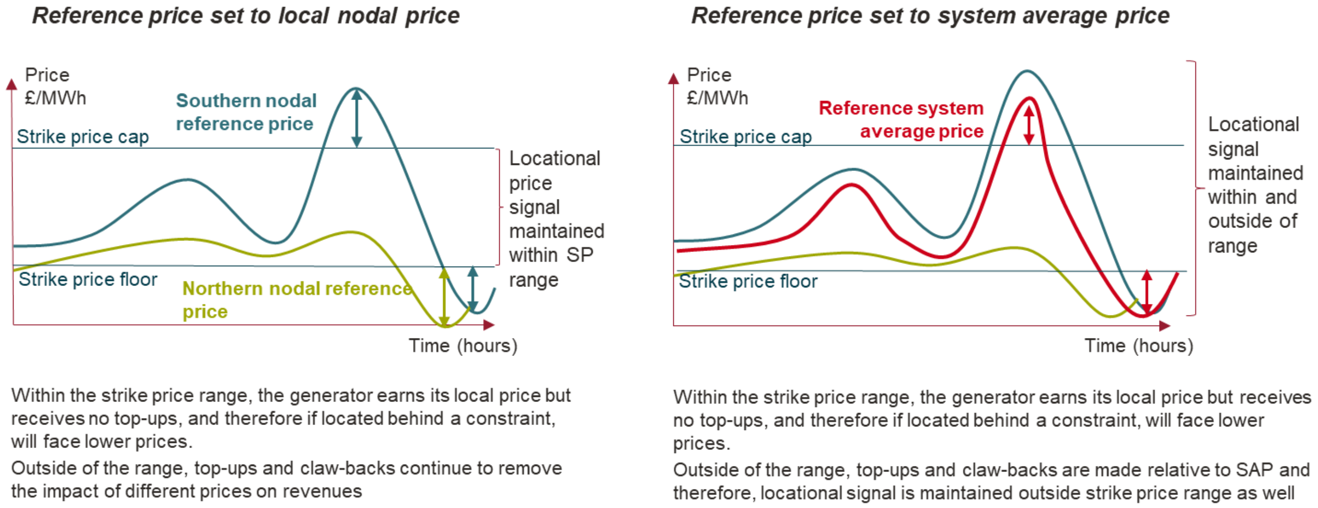
A strike price range introduces some locational price risk irrespective of the approach to the reference price. Whereas under the current CfD a local reference price removes locational price risk entirely, with a strike price range locational price risk remains for wholesale prices

[61] This is a topic of debate in the industry and will be considered in detail by Ofgem. However, as we noted in a recent report ('Locational Marginal Pricing – Implications for cost of capital', Frontier Economics, October 2022), because the LMP signal is impacted by a greater number of factors which are difficult for investors to predict, and more likely to be in flux in coming years. These include the level and location of spare capacity on the system, which itself is likely to be driven by a wide variety of non-market factors such as government energy policy, the application of marine and land spatial planning.

[62] We note that locational price risk under TNUoS could also easily be removed if the TNUoS charge were to be fixed for the term of a support contract, for which there is a logic as once an investment has been made, changes in the value of TNUoS each year are unlikely to affect any locational decisions during the term of the contract.

within the range of the cap and floor prices irrespective of the approach to the reference price. With a system average price the locational signal also remains above the cap and floor.

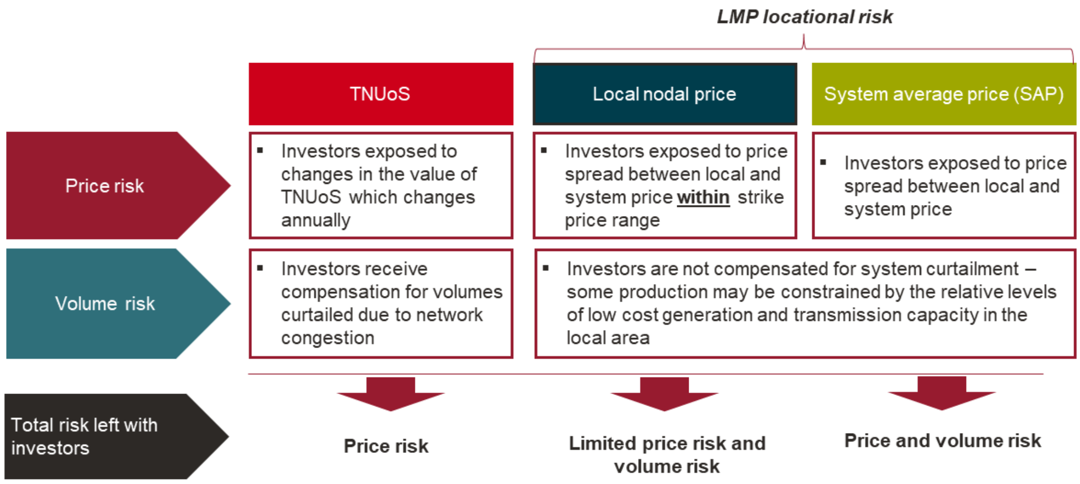
Figure 18 Implications of approach to reference price for locational price signal under LMP with strike price range



Source: Frontier Economics

With regard to the **distribution of expected earnings**, the strike price range has similar implications for locational risk under LMP as the current CfD, except for the fact that it also introduces additional price risk (depending on the size of the strike price range and expectations that prices will lie within this range) with a local reference price.

Figure 19 Locational risk summary under strike price range



Source: Frontier Economics

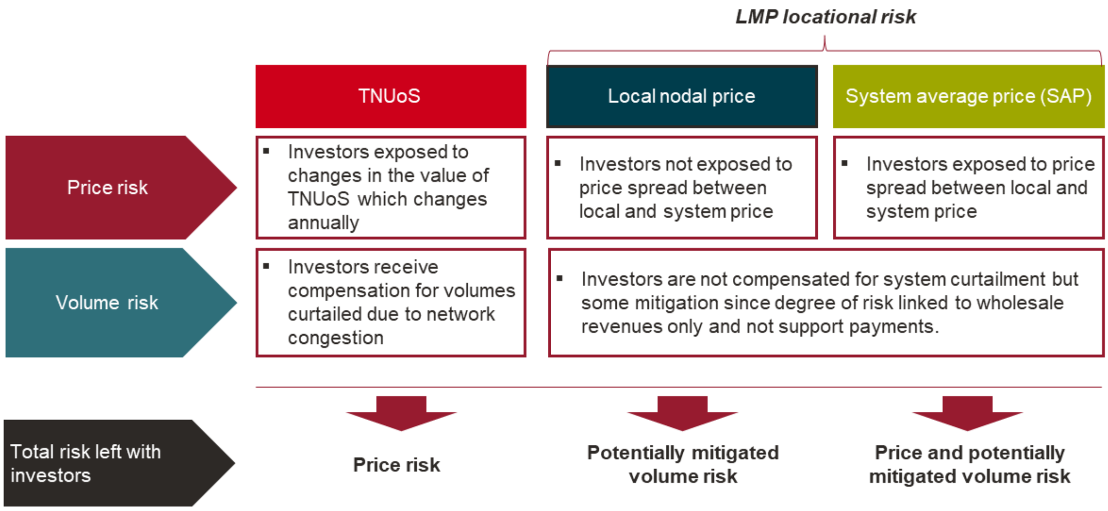
Payment on deemed output

The deemed output payment is set ex ante based on forward traded prices for the relevant period. With regard to the **locational price signal**, in the same way as for the current CfD and CfD with a longer reference price, investors are only exposed to locational price risk if the forward prices used to set the reference price relate to a system average price.

However, with regard to the **locational volume signal** under LMP, a payment on deemed output mitigates to some degree the volume risk. We assume that deemed output itself would not be capped when there is congestion, meaning the deemed output payment is de-coupled from actual output. Therefore, if a plant's output is effectively curtailed by being out of merit in the wholesale market, then its impact relates to wholesale revenues only (making the resulting locational signal more efficient than under CfD models with payment on metered output). Given wholesale prices are expected to be very low or negative in such periods, the impact of curtailment on a windfarm's revenues is expected to be very low.

As a result, with regard to the **distribution of expected earnings**, the impact of a payment on deemed output would (given our assumption that payments are not capped when there is congestion) be to reduce the impact of errors in investors' forecasts of the volume of curtailment due to congestion. Therefore, relative to the CfD options, the payment on deemed output potentially reduces uncertainty under both local price LMP and system average prices options as investors are exposed to reduced locational volume risk.

Figure 20 Locational risk summary under payment on deemed output



Source: Frontier Economics

Revenue cap and floor

Under a revenue cap and floor, as explained in section 2, we assume that the revenue on which cap and floor payments are calculated is based on a reference price multiplied by actual volumes of output from the plant. This means that investors are exposed to variations in the volume of output, and hence errors in forecasts of system curtailment, within the strike price range irrespective of the approach to the reference price.

If the reference price is a:

- **Local reference price**, an investor is exposed to variations in its actual revenues within the range of the cap and floor, based on actual volumes (i.e. system curtailment) and actual local prices.

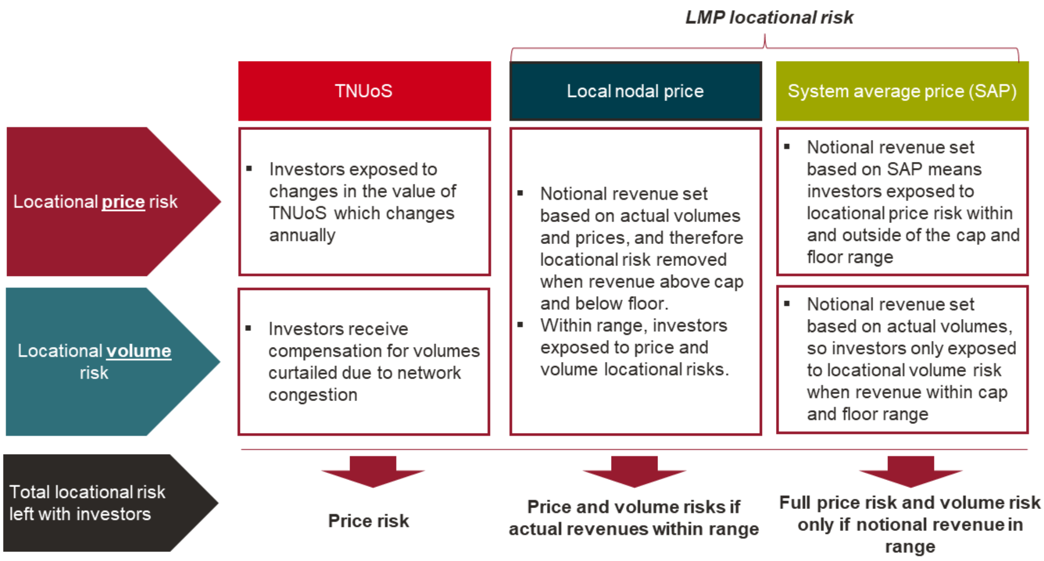
- **System average price**, an investor is exposed to additional risk. For example, if local prices are typically below SAP in the reference period for the revenue calculation, then:
  - a plant may receive no top-up even when actual revenues are below the floor; or
  - a plant may have to pay-back even when actual revenues are within the range.

Therefore, with regard to the **distribution of expected earnings** investors must forecast the price spread and volume of system curtailment to estimate where revenues will be within the range under both options for the reference price. These are both uncertain and expose investors to errors in their forecasts of the degree of congestion they will face.

With a system average price, there is an additional risk that revenues will be outside of the cap and floor range, increasing the exposure of investors to errors in their forecasts of the locational price they will face.

Relative to the CfD options, the revenue cap and floor options have the potential to mitigate some of the locational volume risks, though this is likely to depend on the size of the cap and floor range.

Figure 21 Locational risk summary under revenue cap and floor



Source: Frontier Economics

Summary of locational risk exposure under REMA options

TNUoS risk is independent of the options we consider in that its locational signal affects fixed costs, whereas all of the support arrangements in scope of this project are focused on revenues. In contrast, LMP sends a locational signal by affecting the revenues of generators in different locations. In broad terms LMP can be considered to have a locational price (i.e. the price spread between local and SAP) and volume (i.e. reduced volumes due to system curtailment) effects.

The extent to which price and volume effects pass through to investors depends on:

- The high-level nature of the support arrangement; and
- The approach to integrating the locational price signal i.e. the choice of reference price, local or SAP.

Introducing LMP to:

- **AR4 CfD or CfD with a longer reference price** increases the locational volume risk relative to a regime with a national price. The locational price risk is likely to increase with a system average reference price, and decreases with a local price (assuming TNUoS charges continue to vary annually as they do today);
- **CfD with strike price range** ensures that there is locational price and volume risk irrespective of the approach to the reference price within the strike price range;
- **payment of deemed output** similarly, to the AR4 CfD or CfD with a longer reference price, locational price risk may increase with a system average reference price. However, this option potentially reduces some of the volume risk related to system curtailment, assuming support payments are not linked to output (i.e. that variations in output only affect wholesale revenues); and
- **revenue cap & floor** reduces some of the locational volume risks relative to the AR4 CfD as plants are only exposed to volume risks within the revenue cap and floor range.

Annex B – Literature Review: Market signals and renewable investor behaviour

Introduction

The objective of the literature review is to support the development of the conceptual framework in assessing investor impacts. Specifically, it aims to help:

- identify implications of the REMA options for investor risks;
- understand qualitatively how changes in investor risks can flow through to the cost of capital; and
- identify any relevant quantitative estimates of cost of capital impacts.

Approach

In order to identify a long list of potentially relevant papers, we searched relevant databases, such as Google Scholar and Science Direct, as well as relevant websites, such as Google, using the key search terms set out in Table 5.

Table 5 Key search terms

Support arrangements	Market risks		Cost of capital
Renewables support	Revenue risk	Return volatility	Debt finance
CfDs/AR4	Price risk	Revenue volatility	Gearing
[Various] REMA support options	Volume risk	WACC	Non-diversifiable risks (Beta)
	Basis risk[63]	Cost of capital	Institutional investor
	Merchant risk	Investor risk profiles/ preferences	Multilateral lending agency

Source: Frontier Economics

Based on the keyword search, we complied a long list of more than 50 publications. We then reviewed the abstracts and/or summaries of the publications in the long list, and eliminated

[63] 'Basis risk' refers to the inability of generators to achieve the reference price index under the contract. It is a term used by NERA (2013) and by DECC when analysing the impact of different reference price options for the CfD during the EMR process. While we do not adopt the term in our analysis (its effects being caught under price risk and profile risk), we nevertheless adopted it in our search, given it was a recognised term.

publications we deemed not to be relevant. This resulted in a short list of 17 papers, which we then analysed in depth.

Summary of short-listed papers

The existing literature can be divided into three broad strands.

- papers that use regression methods to assess the impact of support scheme design on the risk premium required by investors;
- papers that analyse conceptually the impact of support scheme design on cost of capital; and
- papers qualitatively considering the impact of support scheme design on volatility of revenue and the resulting impact on cost of capital.

Regression-based approaches

May and Neuhoff (2021) estimate the effect of onshore wind power support scheme designs across 23 EU countries on the ‘wind power risk premium’, which they define as being equal to the WACC minus the country-specific risk-free rate. Information on financing costs was obtained from 53 stakeholder interviews conducted by Noothout et al. (2016). Under their Ordinary Least Squares (OLS) regression approach, feed-in tariffs and sliding premia (i.e. a market premium or a CfD) are associated with the same risk premium for investors. Tradable green certificates are associated with an average increase in the risk premium by 1.2 to 1.3 percentage points (27-33%), implying that some of the power price risk remains with investors.

These results are in line with Roth et al. (2021), who find that support schemes that decrease market risks tend to reduce the WACC. The authors empirically assess the impact of auctions and other renewable energy policies on the WACC, accounting for macro-, meso- and project-level risks. Revenue risk is measured as the percentage share of renewable electricity generation for a given country (Eurostat). According to the authors, the variable serves as a proxy for cumulative experience of actors in RES projects, which had been shown in the literature to reduce the WACC. The measure for market risk comes from the Aures Auction dataset and reflects the remuneration type (feed-in tariff, feed-in premium, quota, etc.). Remuneration types are grouped into three dummy variables (high market risk, low market, no remuneration scheme), depending on the level of support provided. Capital market risk is measured as bank concentration and bank interest margin. Information on the WACC comes from interviews with 93 stakeholders across the EU.

Using a 2-level cross classified random effects model, the results show a negative and significant effect of auction presence on the WACC, which disappears when controlling for market risks. While market risk does not have a significant effect on the WACC by itself, its impact on the auction presence variable indicates that policies that decrease exposure to market risks of generators have a dampening effect on the WACC.

It is important to note that May and Neuhoff (2021) and Roth et al. (2021) rely on a relatively small sample of observations (less than 100) from across the EU. Both papers further obtained at least part of their data from investor interviews.[64] Proxying revenue risk as the share of renewable energy generation across countries as in Roth et al (2021) might additionally bias the results. A high share of renewable electricity generation could have a different impact on risk for the individual investor, depending on what that renewable electricity is. Relying on an imperfect measure for revenue risk might thus bias the coefficients by introducing measurement error.

Conceptual approaches

Huntington et al. (2017) discuss design elements of RES-E support schemes outside of the traditional classification based on labels with a focus on market compatibility.

The authors compare various production-based and capacity-based schemes and argue that capacity payments with ex-post compensation based on reference plants are best suited as they allow a large degree of integration while mitigating investor risk (given the capacity payment would allow for a minimum periodic income). While certificate schemes are commonly perceived as the most market compatible support schemes, the authors argue that they could lead to potentially ‘unacceptably high’ (p.478) financing costs, without elaborating further on the underlying drivers.

Regarding production-based schemes, the authors discuss the design of a CfD. They note that the duration of the settlement period for the reference price is a critical factor for investor behaviour and risk exposure. The authors argue a shorter averaging period, e.g. calculating the premium on an hourly basis, would be equivalent to a flat feed-in tariff in shielding the investor from market risk, while basing the reference price on a long-term average exposes investors to more market volatility and price risk, similar to a fixed premium.

Newbery (2021) focuses on design options for subsidies that mitigate locational and dispatch distortions. Experience from the UK has shown that increased exposure to market risk, and policy risk with regard to future level of subsidies, has resulted in a 3% higher required WACC (in real terms) under the premium feed-in tariff (PFiT) scheme than under the feed-in tariff (FiT) scheme in the UK (Newbery, 2016). To address the locational and dispatch distortions and their financial implications, the author proposes a purely financial yardstick CfD. Under that scheme, the contracted volume in any hour would be deemed (rather than based on metered output). Specifically, it would be deemed proportional to the technology-specific area output per MW capacity, with a duration specified in MWh/MW capacity (i.e. x full operating hours). By determining the strike price of the CfD as the difference between the average RE revenue per MWh and the spot price, the author argues their proposed yardstick CfD scheme maintains efficient dispatch properties of normal CfDs for conventional generators. While providing certainty on the amount of the subsidy, limiting the total amount of the subsidy provides the right locational incentives. Assuring revenue by a government-backed counterparty would reduce the financing costs for the investor, while decreasing the subsidy cost.

[64] We note the possibility that investor responses may be subject to bias.

Schlecht et al. (2022) develop a so-called ‘financial wind CfD’. The authors propose to introduce auctions for financial contracts, so called ‘financial wind CfDs’. The contracts involve hour-by-hour payments between the government and the generators, spanning 20 years. The generator receives a fixed, inflation-indexed remuneration per hour, which is independent of the actual production in these hours and is determined competitively in the procurement auction. Generators can bid for multiples or fractions of a standardised contract size of a 1 MW reference turbine. Generators pay the government the hourly revenue of a reference turbine, defined as the product of the day-ahead spot price (zero if negative) and the hourly output of a reference turbine.

The price differences will result in net payments from the government to the generator in periods with low prices and/or low wind and, the opposite, in net payments to the government in periods with high prices and/or high wind. The authors argue that the financial wind CfD therefore mitigates against both the price and the weather risk and thus against the generator's total revenue risk. Given the independence of payments from the asset's production, dispatch, investment and repowering are able to follow price signals. The authors further argue that capital costs are reduced compared to traditional CfDs as financial risk for generators decreases.

The authors acknowledge that one potential shortcoming of the mechanism is that it introduces a new basis risk. As revenues from the reference turbine and from the asset can deviate, so can payment obligations from the actual revenues. As a result, income for the generator can be higher or lower than expected. While the risk is symmetric, it is correlated to electricity price levels, which makes underperforming relative to the reference turbine costly during periods of high prices. However, the authors argue that the removed volume risk likely outweighs the new basis risk, which lowers overall financing costs compared to conventional CfDs.

Approaches that quantify impacts on revenue volatility

Finally, the third strand of literature looks at volatility of revenue and its impact on investor risk. While some of the studies reach slightly different conclusions, they follow a common approach in how volatility of earnings affects financing costs

Bunn and Yusupov (2015) assess whether FiTs (CfDs) in the UK offer lower investment risks for wind energy projects than the Renewable Obligation Certificates (ROC) scheme that preceded it, as low carbon penetration increases towards the targets by 2030 and beyond. The authors argue that the interaction between intermittency of wind energy and price risk results in an investment risk metric that favours ROCs over FiTs as decarbonisation progresses.

Using detailed simulations, the authors first show that with increasing penetration of renewables, the price formation of wholesale electricity prices changes and introduces an increasingly negative correlation between market clearing prices and renewable outputs. An underlying assumption of the analysis is that ROCs and FiTs are both set in a way that provides the same average remuneration per MWh of output across years.

Following these findings, the authors simulate what the changing price distribution means for the impact of policies on future investment risk. The latter is defined as not meeting the critical value of the capital coverage ratio, which is determined by using the so-called P95 criterion, a proxy for value-at-risk.

The results show that if wind investments are exposed to wholesale market prices and are supported by supplementary green certificates, the revenue risk can be lower than if it was shielded from the price risk by a fixed feed-in tariff. This is because the negative correlation between prices and output acts as a hedge against investment risk under the ROC mechanism. The simulations further show that the investment risk changes over time. While the investment risk is initially lower under a feed-in tariff (CfD) than under the ROCs mechanism in 2012, the increasing negative correlation between prices and output equalises the investment risk for both support mechanisms by 2020 and leads to ROCs being less risky as of 2025, all else equal.

The authors conclude that removing market price risk from the investment case for new wind will not necessarily make it more attractive, as the investment decision also takes into account relative attitudes toward regulatory risk. The (in the authors' view) upside potential of the ROC mechanism, i.e. the lower revenue risk compared to CfDs, and its obligation on retailers to forward contract with RES-E producers seem to outweigh the benefits of protecting investments form the downside market risk via CfDs.

Boomsma and Linnerud (2015) reach a similar conclusion as Bunn and Yusupov (2015) when comparing investor risk for schemes with tradeable green certificates, fixed feed-in tariffs and fixed feed-in premium schemes.

They formulate the investment decision as a real option problem, where investors choose to invest either today or to wait based on threshold revenues. The threshold revenue function is the outcome of two price processes, which may be correlated. That is, if the electricity and subsidy prices are not perfectly correlated (or even random as under tradeable green certificates), combining the two prices will eliminate some of the individual risks through diversification.

Using data for Sweden and Norway, the numerical results show that risk diversification eliminates a significant part of investor risk even in instances where the electricity and certificate prices are not correlated. While fixed feed-in tariffs always carry the lowest investor risk, the difference compared to a green certificate scheme is small. For fixed feed-in premium schemes, the investor risk may even be higher compared to green certificate schemes. This is especially the case when prices of electricity and of certificates are negatively correlated, resulting in investors requiring a strictly lower threshold revenue under tradable green certificates than under feed-in premiums.

The authors conclude that investors should not be completely protected from market risk. More market-based RES-E support schemes such as tradeable green certificates are better suited than fixed feed-in tariffs as investors are better placed to deal with the remaining market risk than governments.

The results by Boomsma and Linnerud (2015) and Bunn and Yusupov (2015) are supported by Newbery (2016). While he calculates that the WACC for onshore wind energy projects in the

UK has fallen by 3% (real) due to the change from the ROCs scheme to the FiT scheme, he agrees that the ROC scheme might provide a better hedge than CfDs for portfolio utilities.

Various other papers have aimed at quantifying the impact of different support schemes on financing costs for the UK (Redpoint Energy, 2010; Cepa, 2011; Nera, 2015), Ireland (Cornwall Insights, 2022), the EU (Noothout et al., 2016), Germany, or the UK and the US (Frontier Economics, 2022).

Redpoint Energy (2010) calculate hurdle rates for different technologies by varying the cost of equity and the level of gearing. The impact of market risk on hurdle rates is taken into account via its impact on gearing following an ‘earnings-at-risk’ approach. Under this approach, a reduction in risk represents a similar increase in the proportion of ‘secure’ earnings, which enables an equivalent increase in the proportion of potential debt financing. That is, a decrease in revenue risk by 10 pp is assumed to increase gearing by the same amount. Hurdle rates are calculated for a Baseline scenario, modelling the development from 2010 to 2030 under the existing policy, and five alternative decarbonisation options: Carbon Price Support (£50/t) (CPS50), Strong Emissions Performance Standard (EPS), Premium Payments (PP), Fixed Payments (FP), and CfD.[65] The resulting hurdle rates for onshore wind range between 8.1% in the baseline, CPS50, EPS and PP scenarios and 7.8% under FP and CfD. For established offshore wind, hurdle rates lie between 10.1% for baseline, CPS50, EPS and PP and 9.6% for FP and CfDs. For emerging offshore wind, hurdle rates are 12.1% for baseline, CPS50, EPS and PP; 11.4% for FP and 11.5T% for CfDs.

Cepa (2011) builds on Redpoint Energy (2010) when assessing the impact of various support schemes on the WACC of onshore and offshore wind energy. Consistent with Redpoint Energy (2010), the model the impact of a five-percentage point increase in gearing under a CfD FiT for offshore wind and a maximum increase in gearing of 2.5% for onshore wind. They estimate that the WACC for onshore and offshore wind decreased by 0.4 and 0.8 percentage points, respectively, under a CfD compared to the RO and Premium FiT schemes. In addition, the authors argue that a well-designed CfD might reduce the need for the scale of discounts under PPAs compared to the ROC scheme. This is because the CfD scheme would reduce both the long-term price risk and the ‘cannibalisation risk’, i.e. the risk that the power price on the day might be reduced by a high supply of wind energy.

The results by Cepa (2011) are consistent with the findings by Noothout et al. (2016), who analyse the cost of capital for wind onshore projects across the EU under different policy designs. Using financing parameters from a small sample of stakeholder interviews (n=14), the WACC for a sliding feed-in premium is estimated between 5-6%, while the WACC for under a FiT scheme is between 4.4-5% for the EU average.

Prior to the introduction of the CfD support mechanism in the UK, Nera (2013) assessed how the change from the previous RO system would affect hurdle rates. The study relies on various sources, including literature reviews and investor interviews, to identify relevant risks for hurdle

[65] Detailed information on the baseline scenario and the alternative policy options considered can be found in sections 3 and 4 of Redpoint Energy (2010).

rates that would change with the implementation of the CfD regime. The main risks identified are

- Volatility of earnings, i.e. the risk related to volatility of the wholesale market price;
- Allocation risk, i.e. uncertainty around eligibility of support and the level of support eventually provided. The risk only applies to the predevelopment phase. For example, interview respondents stated that the risk of not receiving support under the CfD scheme would increase compared to the RO scheme. They expected that some eligible projects would not receive support under the CfD scheme as certain features (e.g. the Levy Control Framework) would constrain the allocation.
- Construction delay risk, i.e. risks related to unexpected construction delays of a project
- Duration risk, i.e. risks related to changes in the earnings risk exposure (volume and price risk) , associated with the length of the subsidy period. Uncertainty especially towards the end of the lifetime of the project (in years 16 to 20).
- Novelty premium, i.e. the risk related to uncertainty around the practical implementation of the new support scheme. That is, investors may prefer to observe how the new framework functions in practice before they make their investment decision. The risk is also known as the premium of foregoing the value they receive from holding a real option.

In order to quantify the impact of these risks, the authors build an extended CAPM framework that allows to cover other relevant risk categories, such as option values and asymmetric risk. Hurdle rates are estimated to decrease by between 50-175 bps, depending on the technology, due to reduced earnings volatility under the CfD scheme compared to the RO scheme. The impact on hurdle rates is dampened by increases in the allocation and construction risks, resulting in hurdle rates being 0-170 bps lower under the CfD scheme. NERA argues a novelty premium might slow down the decrease of hurdle rates in the early phase of the new scheme until investors have more visibility of the practical details of the news scheme. While the existence of such a premium could not be verified, the authors agree that there are sensible reasons that such a premium would affect hurdle rates.

Importantly, the impact on hurdle rates moving to the CfD scheme varies across technologies and across maturity levels of such. The authors caveat that ‘it may not be safe to assume an across-the-board reduction in hurdle rates for onshore wind, offshore wind and biomass conversion immediately’ (p. 60). Estimated hurdle rates decrease most in the long run for mature technologies as they were exposed to greater earnings volatility under the RO scheme, receiving a smaller share of revenue from policy support. For emerging technologies with longer pre-construction phases, hurdle rates may decrease or remain unchanged in the short term compared to an RO system.

Nera (2015) presents technology-specific hurdle rate ranges for generation projects at the appraisal stage in 2015 and estimates for hurdle rates until 2030 for different scenarios. Information on hurdle rates was collected in investor interviews and was cross-checked against a range of market data.

The authors develop a CAPM framework to assess selected hurdle rate risks that affect the various technologies (allocation, development and, to a lesser extent, construction risk). As neither volatility of revenues (except for coal, gas and waste), nor basis risk were ranked as the key risks by investors, their effect on hurdle rates was not assessed. Survey responses further showed that RES-E projects tend to be developed with equity finance, rather than debt finance, and that developers 'would expect to earn a multiple on the project development cost, rather than work in terms of hurdle rates ' (p.38).

Ranges for 2015 hurdle rates are estimated for each of the technologies using the standard deviation around the reference point. For solar, full lifecycle hurdle rates are estimated to range between 6.5-9.4%. For onshore and offshore wind, whole project hurdle rates are 6.1-10.3% (2015 reference point 8.2%) and 8.3-12.4% (2015 reference point 10.4%), respectively.

Hurdle rates for 2030 are intrapolated for three scenarios (high, medium, low risk), which are determined by investors' expectations of the future risk-free rate and by specific levels of allocation risk, revenue volatility, policy risk and fuel and carbon price volatility for each scenario. In the medium risk scenario, hurdle rates are higher than the 2015 reference point, which likely reflects the assumption that the risk-free rate will return to long term levels. The estimated hurdle rates are 8.5% for solar (8% reference point in 2015), 8.7% for onshore wind (8.2% reference point in 2015) and 10.9% for offshore wind (10.4% reference point in 2015).

Blyth et al. (2021) analyse the impact of different market design options on investment risk and financing costs for new offshore wind projects in the UK. The core question assessed in the report is whether 'cost savings from low cost of capital through de-risking policies outweigh the potential system cost benefits that might arise from exposing renewables projects to greater levels of market price risk' (p. 8).

To that end, the authors first model future electricity prices using four National Grid ESO Future Energy Scenarios for 2040 and an open-source electricity system model, Antares, to assess the impact of different electricity system configurations on electricity price formation. Their results show that wholesale prices on their own are insufficient to recoup investment costs for new projects, and that additional revenue sources may be needed to bridge the gap between the capture price and levelised cost of wind.

In a next step, the study looks at the impact of different policy regimes, providing additional revenue sources, on investment risk. The policy options considered are a 2-way CfD that fixes prices for the first 15 years of a new-build, a 2-way CfD that fixes prices but does not pay out when prices go negative, and a 1-way CfD that fixes a price floor but allows plant to profit from upside risks. In addition, the authors assess two simplified representations of the additional market revenues that could be envisaged to procure long-term power from renewable sources.

The impact on investment risk is quantified as the discount rate impact (calculated as the change in the discount rate required to get back to the same net present value expected in the base case), resulting from differences in returns of projects' returns under each scenario compared to the Consumer Transformation (CT) scenario. The 2-way CfD and 1-way CfD options are found to have the highest degree of risk reduction (with increases in discount rates

– an indicator of downside risk - limited to around 1%), while the CfD with a negative price rule exposes projects to higher levels of downside risk (up to 3%). The latter is due to uncertainty regarding the extent of periods of oversupply. The two wholesale market scenarios are associated with significant exposure to downside risk (2-6% or more), particularly relating to risk of lack of investment in major flexibility infrastructure (electrolysis and interconnectors). The authors state that downside risks help give an indication of the extent to which investors will need to be compensated, though state that the cost of capital impact will be lower than the discount rate impact because different types of investor will value risk differently and some will also take into account the upside risk.

The final part of the study investigates the potential impact on the cost of delivering the offshore wind target foreseen in the Consumer Transformation scenario (80 MW installed capacity, producing 350 TWh by 2040). The authors estimate that every percentage point increase in the cost of capital would translate into an additional £1 bn to the cost of delivering the full fleet of offshore wind expected to be needed.

Cornwall Insight (2022) evaluate different types of risks for bidding behaviour in RES-E auctions and possible mitigation measures. In a second step, the impact of those mitigation measures on consumer costs is assessed using a CBA, which considers, among others, the impact on the WACC. Their results show that decreasing merchant tail risk by extending support length by five years to 20 years would reduce the required WACC by c.17% for onshore wind projects and by c.19% for offshore wind projects.

May and Neuhoff (2022) explore how falling technology costs affect financing costs and electricity prices under different support mechanisms. Cost savings through lower technology costs in principle allow investors to fund a larger proportion of the project via electricity market revenues, requiring less funding via support mechanisms. However, exposing the investor to uncertain electricity prices increases the financing risk for investors.

The authors develop an analytical model to quantify the impact of increasing financing risk on the levelized costs of electricity under various support mechanisms for solar energy, as well as for onshore and offshore wind energy. The results show that similar levels of financing costs are required under CfDs and sliding market premium, when technology costs are high relative to wholesale price levels, while fixed market premium schemes are associated with higher overall costs per MWh. In scenarios with low technology costs (relative to wholesale price levels), premia-based mechanisms such as sliding premia and fixed premia function similar to a situation without any support mechanism. This is because with falling technology costs, the bid strike price approaches zero, exposing the investor to higher wholesale price risk. Consequently, a significant share of equity is required for financing, increasing financing costs.

Using data from Germany, the authors provide numerical results of LCOE and total annual costs for solar energy, onshore and offshore wind energy. For all three technologies, annual costs for fixed premia are significantly higher than under CfDs, almost reaching levels of scenarios without any support mechanism for solar and onshore wind energy by 2030. The difference in annual costs between sliding premia and CfDs is smaller, albeit still large for solar and onshore wind energy (EUR 370m and EUR 500m, respectively). For offshore wind energy, annual costs under a sliding premium and under CfDs are equivalent.

The authors conclude that while mechanisms may play a lower role in reducing technology costs, they serve as important instrument to keep financing costs low.

Frontier Economics (2022) focus on the impact of introducing Locational Marginal Pricing (LMP) on cost of capital. Using historic data from GB and the US, the study shows that LMP signals can be substantially more volatile than those in the existing TNUoS regime.

Considering the impact on CfD supported wind farms, the authors argue that two types of risk increase for investors when moving to LMP. Due to a changed definition in valuable production, investors will not receive the strike price on volumes that were curtailed due to generation being too high relative to the available transmission capacity. As a result, investors will face a much wider distribution around expected earnings compared to TNUoS.

The second risk relates to the LMP locational signal, which is more difficult to predict relative to TNUoS and will thus increase investor uncertainty around expected earnings.

As investors will seek a higher return on their capital to compensate for the increased risk, they might require a higher return to compensate for the increased risk. Using the Sharpe ratio as a measure of reward relative to risk, the authors estimate that the required cost of capital would increase by 2-3 percentage points when introducing LMP.

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