Department for
Business, Energy
& Industrial Strategy

EVALUATION OF THE CONTRACTS FOR DIFFERENCE SCHEME

[Phase 1: Allocation Rounds 1 & 2]

Final Report

June 2019

Contents

List of Abbreviations

ACT	Advanced Conversion Technologies
AR	Allocation Round
CfD	Contracts for Difference
CHP	Combined Heat and Power
CMO	Context Mechanism Outcome
CAGR	Compound Annual Growth Rate
DDM	Dynamic Dispatch Model
EMR	Electricity Market Reform
FC	Financial Close
FiT	Feed-in-Tariff
FIDER	Final Investment Decision Enabling for Renewables
HLQ	High Level Evaluation Question
LCCC	Low Carbon Contracts Company
LCOE	Levelised Cost of Electricity
MDD	Milestone Delivery Date
OFTO	Offshore Transmission Owners
PPA	Power Purchasing Agreement
REA	Rapid Evidence Assessment
RO	Renewables Obligation
RQM	Renewable Qualifying Multiplier

Introduction

Background to the CfD scheme

The Department for Business, Energy and Industrial Strategy (BEIS) commissioned Technopolis Group Ltd, in partnership with LCP Ltd and Dr Gregor Semieniuk, University of London to undertake a process and impact evaluation of the Contracts for Difference (CfD) scheme. This report presents findings from Phase 1 of the evaluation, which assessed the extent to which the CfD Allocation Rounds 1 and 2 met their intended objectives.

Policy Background

The Energy Act (2013) implemented regulations to enable the CfD scheme to meet a range of Electricity Market Reform (EMR) programme objectives. The strategic objectives for the EMR include:

- Ensure a secure electricity supply by providing a diverse range of energy sources, including renewables, nuclear, CCS equipped plant, unabated gas and demand side approaches; and ensuring we have sufficient reliable capacity to minimise the risk of supply shortages
- Ensure sufficient investment in sustainable low-carbon technologies to put us on a path consistent with our EU 2020 renewables targets and our longer-term target to reduce carbon emissions by at least 80% of 1990 levels by 2050
- Maximise benefits and minimising costs to the economy as a whole and to taxpayers and consumers - maintaining affordable electricity bills while delivering the investment needed. EMR minimises costs compared to the current policies because it seeks to use the power of the markets and competition and reduce Ministerial intervention and support over time.

The CfD scheme supports delivery of the latter two objectives above in particular. CfDs aim to give developers a higher level of confidence and certainty to invest in low carbon electricity generation, by agreeing to a fixed price for the sale of electricity. Generators are awarded a 15-year CfD and a set of obligations to deliver the contracted capacity within a specified timeframe. The contract guarantees additional revenue to developers when the wholesale market price, the “reference price”, is below the “strike price”, which is a measure of the cost of investing in a renewable electricity technology. The CfD scheme aims to reduce developers’ risks by providing more certainty in revenue and to support investment in a wide range of renewable technologies with different levels of maturity.

The first two Allocation Rounds (held in 2014/15 and 2016/17) have awarded contracts to 38 projects in total. This number includes three projects which did not sign their contract after it was awarded. Prior to this, eight other projects were awarded a CfD through bilateral negotiation in the Final Investment Decision Enabling for Renewables (FIDER) process. The FIDER CfDs process has been evaluated separately[1], and these projects were therefore outside the scope of this evaluation.

Brief Overview of CfD scheme Design

A brief overview of the key design features of Allocation Rounds 1 and 2 is provided below. Annex C (Theory of Change) provides more description of the design features of the CfD scheme.

- **Budget Notice and Allocation Rounds:** Allocation Rounds are announced by BEIS via publishing a "Budget Notice". This sets out the budget available for specific years of electricity generation delivery and the technologies eligible for the allocation round. The first Allocation Round (AR1) took place in 2014/15. The following Allocation Round 2 (AR2) was opened in April 2017. The third CfD allocation round (AR3) was opened in May 2019.

  In AR1 and AR2, the Budget has been allocated to different technology 'Pots' at the discretion of BEIS, with the Allocation Regulations allowing BEIS to set maximum or minimum budget reservation (in MW or £s) to a specific technology or group of technologies. The total budgets for these allocation rounds fall under the Levy Control Framework and Control for Low Carbon Levies, which are government frameworks designed to control the costs of supporting low carbon electricity. The source of funding for the CfD scheme comes from payments from electricity suppliers, via the Supplier Obligation, which is ultimately paid for by consumers through their energy bills.

- **Delivery Years and Administrative Strike Prices** are typically announced around five months before auctions open. The Administrative Strike Price (ASP) sets out the maximum support, presented on a price per MWh basis, that the Government is willing to offer developers for each technology in each delivery year, otherwise known as the reserve price.

- **Pot Design**: In previous auctions, technologies have been divided into two pots[2]:

  - Pot 1 'Established' technologies: Onshore Wind (>5 MW), Solar Photovoltaic (PV) (>5 MW), Energy from Waste with Combined Heat and Power (CHP), Hydro (>5 MW and <50 MW), and Landfill Gas and Sewage Gas, and Biomass Conversion

[1] Independent evaluation of FID enabling investment for renewables. Grant Thornton on behalf of DECC. 2015

[2] When the CfD scheme was announced in 2014, Biomass Conversion technologies were initially listed under a separate "Pot 3". However, Biomass Conversion technologies were then merged with Pot 1.

- Pot 2 ‘Less established’ technologies: Offshore Wind, Wave, Tidal Stream, Advanced Conversion Technologies, Anaerobic Digestion (>5 MW), Dedicated Biomass with Combined Heat and Power (CHP) and Geothermal

The central offer to successful bidders is to be awarded a 15-year contract for difference (CfD), with payments indexed to inflation, and a set of obligations to deliver the contracted capacity within a specified timeframe. The contract guarantees additional revenue to developers when the wholesale market price, the “reference price”, is below the “strike price”, which is a measure of the cost of investing in a low-carbon technology. When the reference price is higher than the strike price, developers are required to make payments back to the counterparty (LCCC). As illustrated in Figure 1 below.

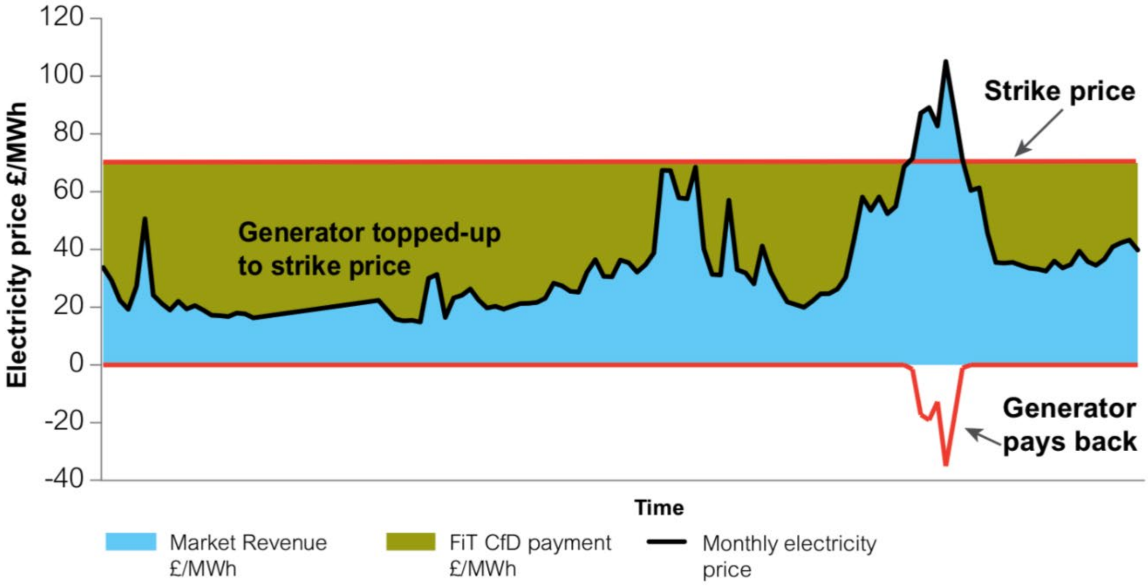

Figure 1 CfD Payment mechanism. Source: Planning Our Electric Future White Paper. DECC 2011

Evaluation Methods

The overall aim of this evaluation was to assess the extent to which the CfD scheme is on track to meet its objectives. In addition, it aimed to assess the effectiveness of processes for delivery to help inform policy development around ways in which delivery processes may be improved for future allocation rounds. The evaluation answers five high-level questions:

1. To what extent, how and why is the CfD scheme contributing to its intended objectives, and do its outcomes, both intended and unintended, differ for different groups (project developers, investors, technology types)?

2. Are the design parameters of the CfD scheme and auction allocations appropriate for achieving the intended objectives?

3. Is the CfD scheme being delivered as intended?

4. Does the CfD scheme present good value for money?

5. What are the implications of the findings for the future contribution of renewable technology to the Electricity Market?

In addition, the evaluation addressed a longer list of over 30 more specific sub-questions in relation to the five high level evaluation questions above. These are listed as part of the Evaluation Framework Annex G, which describes the data sources used to address each question.

Addressing these questions requires a mix of impact, process and economic evaluation. The evaluation is theory-based, adopting principles of realist approaches to address questions around how differences in context influence how developers respond to the scheme. This is combined with quantitative data collection and analysis, including modelling of forecast electricity generation and economic cost benefit analysis to address questions around whether the scheme represents good value for money in comparison to a modelled counterfactual scenario of continued Renewables Obligation (RO) policy.

The evaluation is split over three main Phases, as follows:

- Phase 1 – evaluating the first and second Allocation Rounds (summer 2018 – spring 2019), which is the focus of this report
- Phase 2 – evaluating the third Allocation Round and the operational experiences of AR1 and AR2 projects (spring 2019 - summer 2020)
- Phase 3 – the evaluation will end with a final synthesis phase that combines the findings from all workstreams undertaken in Phases 1 and 2, including an assessment of overall impacts to date (by end 2020).

Theoretical Approach to the Evaluation

The evaluation is theory-based. This started with developing a detailed Theory of Change (ToC) for the CfD scheme to set out (pre-fieldwork) understanding of the flow of cause and effect between how inputs and activities (e.g. government legislation, budget allocation, publications and actions by delivery bodies to administer the scheme) lead to their expected outputs (such as number of new contracts signed to deliver renewable projects), outcomes (increased renewable electricity generation) and longer-term impacts (such as more cost-effective clean electricity supply and reduced carbon emissions). See Annex C for details.

Adopting principles of a *realist* approach, the ToC was refined to explore not only what overall outcomes and impacts are expected to be achieved, but to understand the causal pathways of *how* they will be achieved, and *why* this may be driven by differences in contexts. This was key to assessing the extent to which the scheme is on track to deliver its objectives, and if not, why not.

Realist evaluation is concerned with unravelling the inner mechanisms at work in different contexts. As described by Barbara Befani (2016[3]), this entails refining the ToC into one or more **Context-Mechanism-Outcome (CMO)** configurations, where **Contexts** are made of resources, opportunities and constraints available to the beneficiaries; **Mechanisms** are choices, reasoning or decisions that individuals take based on the resources available in their context; and **Outcomes** are the product of individuals' behaviour and choices. Annex C refines the overall programme's ToC into a series of CMO configurations.

Not all of the Evaluation Questions in this mixed methods study required a realist approach. For example, economic analysis and statistical modelling techniques were used to estimate the overall costs and benefits of the scheme compared to a modelled counterfactual scenario of continued RO (see Annex B for more details).

In addition, some of the more exploratory **process evaluation** questions did not require development of pre-defined theories, or CMOs, in advance of fieldwork and then testing. Here respondents were asked open ended questions to discuss their experiences of the scheme to share their unprompted views. The analysis of findings was based around a 'bottom-up' approach to coding and grouping the range of emerging themes and then exploring how these varied by context (rather than a top-down assessment of whether the findings confirm or refute a pre-defined CMO configuration about the application process). This approach to addressing such questions may be considered more *constructivist* than *realist* (see Annex A for more details).

Where a realist approach added value was in addressing the high-level questions around the extent to which the scheme is meeting its objectives, why and in which contexts. When comparing the CfD and RO schemes, the realist approach explains the factors that have led to estimated cost reduction impacts for consumers

The project was arranged around delivering a series of Work Packages (WP), as briefly summarised below.

CfD scheme Composition Analysis – This work package analysed the levels of electricity generation that CfD contracted projects are forecast to deliver. This provided an initial assessment of the sub questions of high-level evaluation question 1 around:

(a) What capacity is on track to be delivered within agreed milestones, and how much has been invested in it?

(b) To what extent has CfD contributed to meeting the 2020 renewables target?

Analysis of renewable energy investment trends in the UK – This work package analysed trends in renewable investment over time, since 2004-2018 to assess whether

[3] Choosing Appropriate Evaluation Methods: A Tool for Assessment and Selection, October 2016. Bond.

different types of firms have begun investing more or less in different technologies since the CfD scheme was introduced.

Rapid Evidence Assessment (REA) – The REA was used to consolidate existing evidence on the extent to which the CfD is delivering against its objectives, or ways in which processes for delivery may be improved. This strand reviewed international literature to give examples of how the design of renewable energy auctions has influenced the type of outcomes obtained. The REA addressed the following two research questions:

- *What does existing evidence tell us about how renewable energy auction design affects intended outcomes: encouraging investment in and increasing supply of renewable electricity; and lowering technology and support costs?*
- *What implications do wider international trends in renewable energy investment and technology cost have on the continued use of auctions in the future?*

Reports of the results from the three Scoping Stage strands have been provided separately as Annexes. Key findings have been incorporated as supporting evidence within this report.

Following this desk review of existing evidence, Phase 1 fieldwork interviews with groups of key stakeholders began, as outlined below.

Interviews with CfD delivery partners – Prior to the main fieldwork with project developers, an initial round of face-to-face interviews was carried out with CfD scheme policy leads and representatives of delivery partner organisations. The organisations included for these interviews were BEIS, Ofgem, LCCC and (EMR) Delivery Body, Electricity System Operator, National Grid [4]. This stage was used to refine the theories of change before testing whether these align with the views of scheme participants, scheme non-participants, and also the outcomes achieved.

Interviews with Round 1 and 2 project developers – The aim was to carry out semi-structured telephone interviews with representatives of the developers of the 38 projects which were successfully awarded contracts in AR1 and AR2. The interview data was used to test the programme theories of change described in the CMOs and inform assumptions in the economic modelling.

Due to non-responses, interviews were achieved with developers of 23 CfD projects. Where developers held contracts for more than one CfD generation unit interviews were

[4] LCCC is the designated counterparty to Contracts for Difference (CFDs). Its role is to manage CfDs, as well as to manage the Supplier Obligation Levy that funds CfD payments. National Grid is the designated Delivery Body. It runs the application, qualification and allocation processes for CFDs. Ofgem determines outcomes of disputes with regards to certain eligibility criteria. Ofgem also manages Fuel Measurement and Sampling (FMS) processes to ensure that fuelled technologies comply with CfD Sustainability obligations.

used to gather information on more than one project per interview. Hence, the interviews covered 31 individual CfD generations units.

As outlined in Table 2 those interviewed reflected a good spread of different types of CfD participants, in terms of types of technology, stage of project development and allocation round. Interviews with developers that had been successful at auction but refused their contracts, due to the strike price offered, or had their CfD terminated due to inability to meet Milestone Delivery Dates were also included. Further information on the interview methodology and the topic guide can be found in the Annexes.

Technology	AR 1 Projects covered through interviews (Total awarded projects in brackets)	AR 2 Projects covered by interviews (Total awarded projects in brackets)	Total projects covered by interviews (Total awarded projects in brackets)
Advanced Conversion Technologies	1 (3)	4 (6)	**5 (9)**
Dedicated Biomass with CHP	0 (0)	0 (2)	**0 (2)**
Energy from Waste with CHP	0 (2)	0 (0)	**0 (2)**
Offshore wind	2 (2)	3 (3)	**5 (5)**
Onshore wind	10 (15)	0 (0)	**10 (15)**
Solar-PV	3 (5)	0 (0)	**3 (5)**
Total development projects covered through interviews	16 (27)	7 (11)	**23 (38)**

Table 1. Overview of interviews with CfD developers

Interviews with non-participating renewable energy developers – 17 semi-structured telephone interviews were carried out with wider developers of renewable electricity generation units in GB who do not have a CfD contract (either because of failure at auction or because they had not applied to the CfD scheme). These were sampled from the Renewable Energy Planning Database[5] to select a sub-group of projects that have gained planning permission over the last 5 years but did not have a CfD. This group was selected to reflect a similar profile to those awarded CfD schemes in terms of types of technologies and generating capacity. The aim was not to use this as a direct control group to compare outcomes. Rather, the purpose of these interviews was to gain insight into the experiences of unsuccessful CfD applicants, or reasons why they did not apply for a CfD contract.

Unlike the interviews with developers of CfD projects, these interviews did not primarily focus around their experience of developing one specific project (as they did not own a CfD project). The developer firms all had a portfolio of multiple projects that had been developed under the RO. In addition, most had experience of developing, or investing in, renewable energy electricity projects of different technology types. The table below shows the count of how many different types of technologies the 17 developer firms represented. The total adds to more than 17 because most firms had been involved in developing more than one type of technology.

	ACT	Biomass and CHP	EfW and CHP	Hydro	Offshore	Onshore	Solar-PV	Tidal Power
Types of technologies covered by the 17 interviewed companies	2	5	2	1	4	9	10	2

Table 2. Profile of developers without a CfD by technology

All interviews were audio recorded (with the respondent's consent) and then transcribed. Nvivo (a qualitative data analysis software) was used to highlight and code the range of different responses arising on each topic explored in interviews. A 'bottom-up' analysis was carried out to explore the range of themes emerging themes from the text, as well as a 'top-down' analysis of whether previously developed theories of change hold true. For example, to test whether the assumed linkages between our CMOs are valid, or whether there are more salient types of contextual factors that are associated with outcomes of interest.

Quantitative online survey with CfD developers and investors – An online survey was sent to developers to capture detailed standard information to inform our estimates of costs of debt and equity for different technologies, and the minimum rate of return required

[5] Renewable Energy Planning Database. Managed by Eunomia on behalf of BEIS.

to make a project viable (hurdle rates). This was sent to all 34 CfD developers, although we had relatively high non-response rates to certain questions, as discussed below.

Cost-effectiveness analysis – This addressed the HLQ4 evaluation question *"Does the CfD scheme represent good value for money*?" The analysis compared outcomes of the current CfD scheme with a modelled counterfactual scenario of subsidising the same level of generation under the RO. The rationale for using a scenario whereby the RO continued as the counterfactual was primarily that it is reasonable to assume that if the CfD scheme had not been introduced then the RO would likely to have continued (rather than a "do nothing" scenario of no form of support). This approach to counterfactual comparison was taken in DECC's pre-implementation Impact Assessment to estimate the Net Present Value of the CfD scheme.

The modelling required developing estimates of the cost to consumers per MWh of electricity produced, by each technology. This was used to compare overall support costs to a counterfactual scenario assuming the CfD scheme had not been introduced and the RO continued out to 2050. The BEIS Dynamic Dispatch Model was used as the basis of this modelling work (see Chapter 6 for details).

Limitations of data collected

When forming conclusions on the evidence gathered, the following limitations of the underlying data were taken into account:

Interviews with CfD developers

Overall, respondents reflected a good range of most of the different types of technologies developed under AR1 and AR2. However, developers of CfD projects with Energy from Waste with CHP and Dedicated Biomass with CHP were not included due to non-response. That said, the interviews with developers of ACT projects included firms that had also developed projects with these technologies under the RO. In addition, interviews with unsuccessful applicants to the CfD scheme included developers of Dedicated Biomass and Energy from Waste with CHP projects. Therefore, representatives from these bio-energy technology sectors had some coverage within the wider sample.

Interviews with developers of renewables without a CfD

The 17 interviews with developers of renewable electricity projects without a CfD aimed to gather insights from experiences of unsuccessful CfD applicants, and developers who may, in principle, have been eligible to apply to the CfD scheme but chose not to. Whilst these groups were covered, it is not known how representative they are of the wider population of unsuccessful applicants, because data on the number and profile of unsuccessful applicants is kept confidential. In addition, the relatively small number of interviews included in this qualitative sample should not be considered statistically representative of the wider population of firms who develop renewable electricity across GB. More details on approach to sampling, recruitment and profile of respondents for this group are provided in Annex A.

Online survey

The survey was sent to all 34 CfD developers, achieving 20 responses in total. Respondents represented 15 separate CfD projects, because for some projects, more than one member of the project's consortium of developer firms responded. There was a higher proportion of respondents representing Offshore and Onshore wind projects, and a relative under-representation of other technologies (See Annex A for profile). There was a high rate of non-response to certain questions. Findings from the survey have been included in this report if the questions were answered by at least 50% of respondents. Some questions, for example around hurdle rates, received very few responses which was likely to be due to commercial sensitivity. Findings from these questions have not been included in the analysis.

The economic modelling of CfD costs and benefits was therefore based upon estimates of project development costs and the latest hurdle rate estimates in BEIS's 2018 reference case. The telephone interview data was used to provide further validation of ranges used for estimating the impact of CfDs on hurdle rate reduction. Estimates of the impact of the scheme on hurdle rate reduction that were given by telephone interview respondents were within the range assumed by BEIS's 2018 reference case.

Estimates of impact of CfD scheme on cost reduction

As with all modelling of future outcomes, there is a significant degree of uncertainty in the projections. To understand this uncertainty, variations in the key assumptions that drive the differences between the costs of the two regimes, such as hurdle rate differences and wholesale price levels, have been tested.

However, several uncertainties remain. This analysis has focused on estimating the changes in cost of supporting a fixed level of low-carbon deployment under the two regimes. The level of deployment, and the mix of technologies deployed, has been held constant, in line with BEIS's 2018 reference case. The magnitude of the savings under the CfD scheme would likely vary materially under a different level and mix of low-carbon deployment.

1. Delivery of CfD Generation Units

Key findings:

The majority of projects awarded a CfD contract are currently on-track to be delivered. This equates to a generation capacity of 5.26 GW, meaning **96% of initially awarded capacity is currently on track to be delivered**.

Out of the 38 projects that were awarded a CfD in the two Allocation Rounds, four had their contracts terminated and three did not sign the contract offered. These projects were all in the Solar-PV and Bioenergy sector. Of the seven projects which did not go forward, all but one were relatively small projects; each with an initial estimated capacity below 50 MW.

The capacity from the first two Allocation Rounds is estimated to provide around 6% of the UK's total electricity generation by 2025. The UK is currently on track to meet 2020 targets on the proportion of electricity generated from renewable sources. CfD projects will contribute around 1.3% to all electricity generation by 2020 (given the majority of capacity will come on stream after 2020).

Introduction

This chapter provides an assessment of the overall status of CfD projects, the timing of their delivery, and their overall contribution to the renewable electricity generation targets.

Project status and capacity on track

Table 3 below provides an overview of all projects awarded a contract, their proposed generating capacity, capacity reductions, and the extent to which projects are currently on track or have been terminated.

Allocation Round / Technology	AR 1 Projects Awarded (Capacity in MW)	AR 2 Projects Awarded (Capacity in MW)	AR 1 & 2 Combined (Capacity in MW)
Advanced Conversion Technologies	3 (62)	6 (64)	9 (126)
Dedicated Biomass with CHP	-	2 (86)	2 (86)
Energy from Waste with CHP	2 (95)	-	2 (95)

Allocation Round / Technology	AR 1 Projects Awarded (Capacity in MW)	AR 2 Projects Awarded (Capacity in MW)	AR 1 & 2 Combined (Capacity in MW)
Offshore wind	2 (1,162)	3 (3,196)	5 (4,358)
Onshore wind	15 (749)	-	15 (749)
Solar-PV	5 (72)	-	5 (72)
Total Projects / Capacity awarded	**27 (2,139)**[6]	**11 (3,346)**[7]	**38 (5,485)**
Projects / Capacity not proceeding	3 (45)	4 (108)	7 (153)
Capacity Reductions	69 MW	0	69 MW

Table 3 Overview of CfD project and capacity status

Table 4 below gives a summary of the total numbers of projects that are on track, and their capacity, by Allocation Round.

CfD Status	AR 1 on track	AR 2 on track	AR 1 & 2 Combined on track
Projects on track (Share of originally awarded projects)	24 (89%)	7 (64%)	31 (82%)
Capacity (MW) on track (Share of originally awarded capacity)	2,025 (95%)	3,238 (97%)	5,263 (96%)

Table 4 Total share of CfD projects and capacity on track of initially awarded capacity

Out of 27 projects awarded in AR1, two of the Solar-PV projects (Wick Farm Solar-PV & Royston Solar-PV Farm) declined to sign their contracts and one had their contract terminated (Netley Landfill Solar-PV Park).

Out of the 11 CfD projects awarded a contract in AR2, the ACT project 'Redruth EfW' did not sign the contract and three other projects 'Drakelow Renewable Energy Centre' (ACT), 'Station Yard' CFD 1 (ACT), and 'Grangemouth Renewable Energy Plant' (Dedicated Biomass with CHP) had their contracts terminated.

[6] There were 29 individual CfD generation units in AR1 since East Anglia One is a phased project with 3 separate CfD units but one contracted 'project'.

[7] Hornsea Project 2, Triton Knoll, and Moray Offshore had 3 phased individual generation units each. Overall the second allocation round had 17 CfD units awarded.

According to the January 2019 CfD Register, the list for all currently contracted CfD units from AR1 and AR2 have a combined total generation capacity of 5.26 GW. This compares to 5.48 GW total capacity which was initially awarded in AR1 and AR2 (2.14 GW in AR1 and 3.35 GW in AR2)[8].

Therefore, 96% of initially awarded capacity is currently on track to be delivered with around 222 MW not being delivered due to permitted capacity reductions or contract terminations.

Delivery timescales

Regarding the delivery of the progressing projects, as shown in Figure 2, the majority of CfD capacity are expected to begin generating in the year 2022 (Generator's Expected Start Date), when Offshore wind projects with a total capacity of around 2.5 GW are set to become operational.

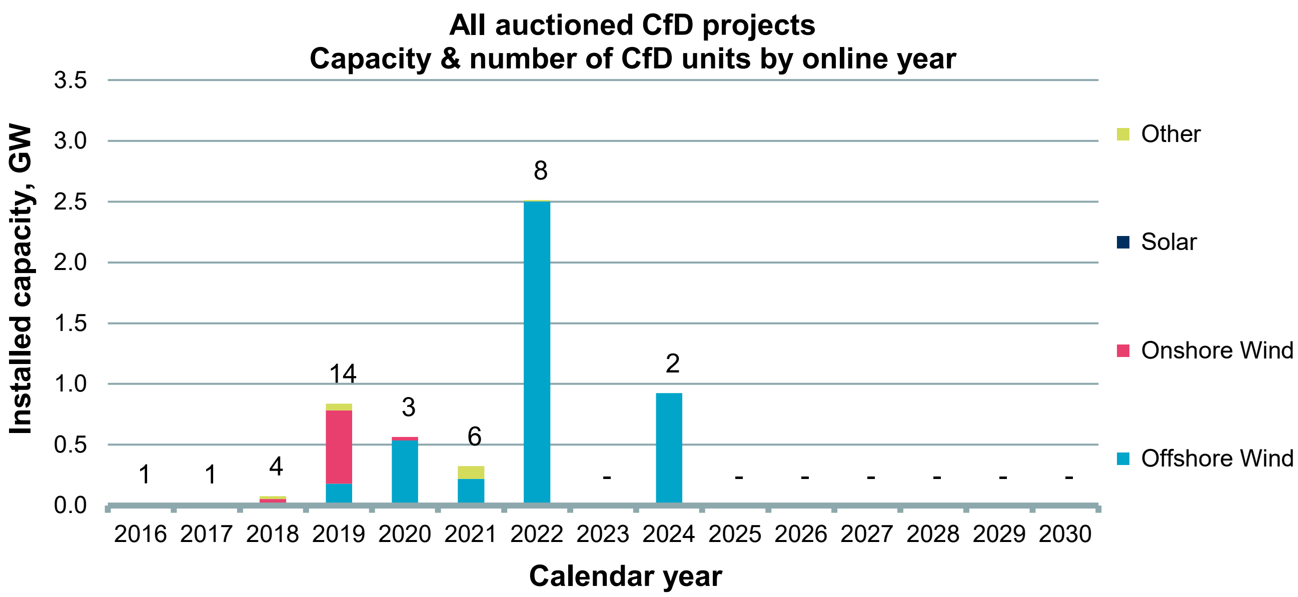

Figure 2 All auctioned CfD projects capacity per delivery year & number of units (phased projects treated as multiple units). Source: CfD Register. LCCC 25/01/2019

The cumulative CfD capacity from AR1 and AR2 will surpass 5 GW in 2024 when the last two Offshore wind projects are delivered. As shown in Figure 2 below, Offshore wind will account for more than 4 GW of the cumulative CfD capacity.

[8] Due to rounding the totals presented for AR1 and AR2 do not add up to 5.48 GW

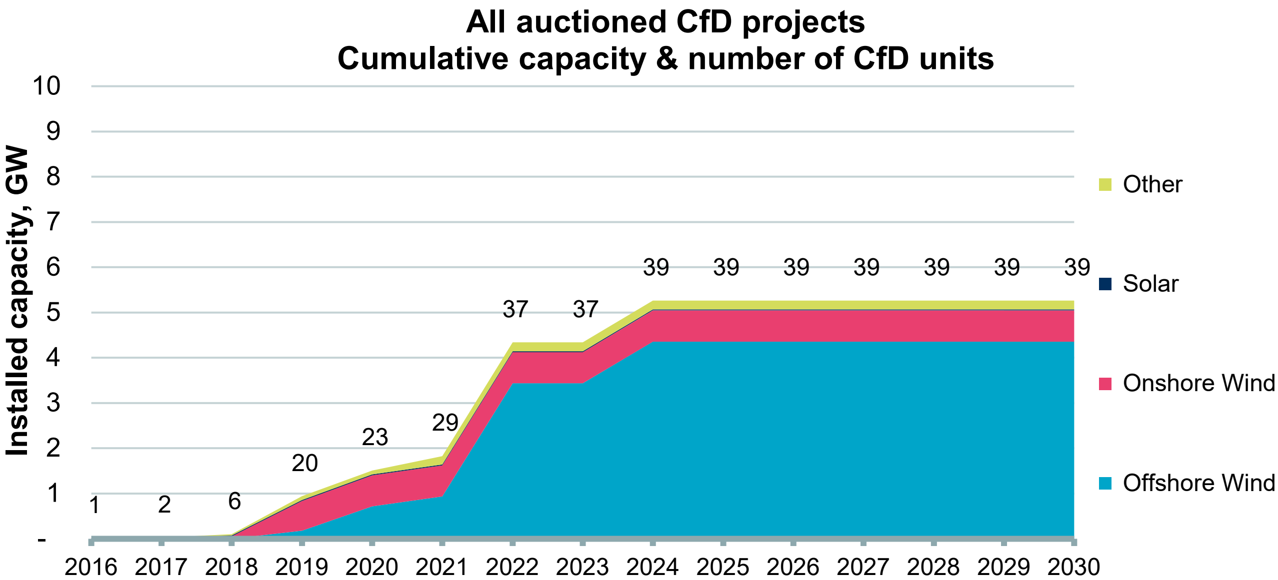

Figure 3 All auctioned CfD projects cumulative capacity & number of units (phased projects counted as multiple units). Source: CfD Register. LCCC 25/01/2019

Contribution to 2020 renewable electricity targets

The UK is currently forecast to meet the Government's aim of generating 30% of electricity from renewable sources by 2020. This aim is a UK set sub-target of the legally binding EU 2009 Renewable Energy Directive to deliver 15% of final energy consumption - across electricity, heat and transport, from renewable sources by 2020. By 2020 CfD projects will provide around 1.3%[9] of the UK's total electricity generation (as most units will come on stream after this date).

By 2025 the auctioned CfD generation will, in a central commodity price scenario[10], will account for around 6% of all electricity generation in GB. This corresponds to 21.6 TWh which is enough to power around 5.8 million British homes for one year[11]. From the second Allocation Round, Offshore wind alone will provide 13TWh or 60% of all CfD auctioned generation by 2025.

[9] Based on the January 2019 CfD Register
[10] See Chapter 6 for details of assumptions used.
[11] Based on a 2017 domestic electricity consumption of 3,729 kWh per meter. Data from BEIS (2018). Sub-National Electricity and Gas Consumption Statistics. Available at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/767027/Sub-national-electricity-and-gas-consumptio-summar-report-2017.pdf

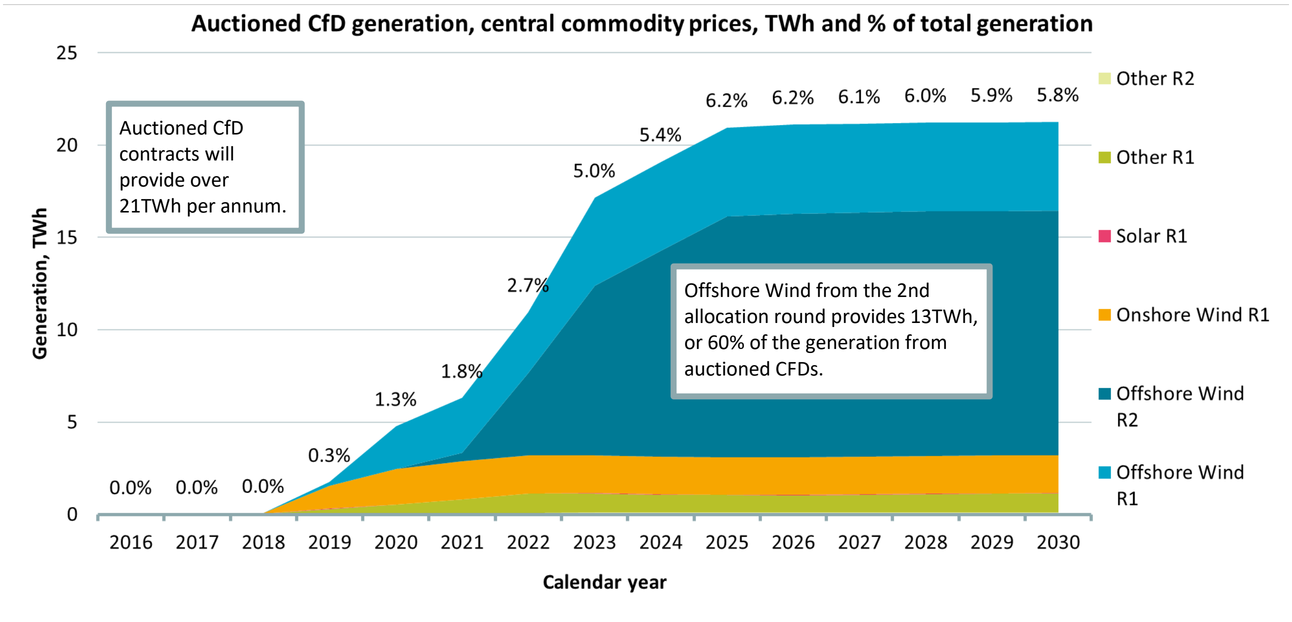

Figure 4. Auctioned CfD generation, central commodity prices, TWh and % of total electricity generation. Source: LCP analysis based on CfD register and BEIS assumptions

2. Impact of CfDs on Attracting Finance

Key findings:

Responses from developers suggest that the core feature of the CfD which attracts investors is its 15-year price stabilisation mechanism. Responses support the theory of change that this provides more certainty over future revenue, reduces risks for investors, and leads to lowering the costs of capital for developers. Overall, this was considered to reduce total project costs in comparison to similar projects under the Renewables Obligation (RO).

The CfD has seen a slight shift towards more international utility backed developer companies investing in UK renewables development, compared to the RO. This is primarily driven by the profile of Offshore wind developers.

The strike prices for Offshore wind fell by around a half between AR1 and AR2. This reduction in prices for Offshore wind was faster than historical or international trends, suggesting the auctions supported cost reduction.

The lack of a further allocation round for Pot 1, 'Established Technologies', in Allocation Rounds since AR1 has been followed by a relative fall in investment for these technologies. Most developers expected the market for Corporate PPA or subsidy-free development for new build generation units to remain relatively small for the foreseeable future.

Impact of CfD scheme on attracting new investment to UK renewables development

This chapter presents findings on what impact the CfD scheme has had on attracting finance, de-risking investment decisions and lowering the costs of capital for projects. Findings are primarily based on responses from the interviews with developers. The section also discusses how these findings are supported by secondary data sources such as the investment trend analysis of Bloomberg Terminal data and the Rapid Evidence Assessment (REA)[12]. The chapter provides an overview of developers' views on the potential for 'subsidy-free' renewable generation units, covering the role of corporate Power Purchase Agreements (PPAs) and co-located battery storage.

[12] See Annexes.

Background on need for new investment

The Government's Clean Growth Strategy[13] and supporting analysis from the Committee on Climate Change[14] have highlighted the need for attracting high levels of additional investment in order to meet carbon reduction targets and ensure a secure supply of clean and affordable electricity. The Clean Growth 'Grand Challenge' of the Industrial Strategy White Paper (2017) also sets out a strategy to shift investment towards clean energy technologies, with the aim of "leading the world in the development, manufacture and use of low carbon technologies, systems and services that cost less than high carbon alternatives". The CfD scheme supports delivery of these aims to shift investment towards clean and cost-effective energy technologies.

Renewable energy power plants are characterised by high upfront capital expenditure and cost of finance which are gradually recovered over the project's economic lifetime[15]. Conversely, operating expenditure is low, especially for wind and Solar-PV technologies with costless fuel. For example, the International Energy Agency (IEA 2017a, p. 50)[16] estimates that for an Offshore wind power plant, about one third of the Levelised Cost of Energy (LCOE) comes from capital expenditure[17], and one half from the cost of financing this capital. As these 'costs of capital' account for a high proportion of overall project costs, policies aimed at reducing risks for investors will reduce the interest rates they apply, and hence reduce overall project costs for developers. The CfD aims to attract new investment by protecting generators from uncertainties in future wholesale price fluctuations, through its 15-year price stabilisation contract.

Background on falling strike prices

When looking at auction outcomes, it is evident that implementation of Allocation Rounds 1 and 2 contributed to trends in falling project costs (for Pot 2 technologies), as reflected by their clearing strike prices.

[13] HM Government (2017). The Clean Growth Strategy: Leading the way to a low carbon future.
[14] Reducing UK emissions – 2018 Progress Report to Parliament. Committee on Climate Change.
[15] Responses to the survey of developers indicate that the economic lifetime of most CfD generation units range from 15 to 25 years (the period over which the investment case is assessed over).
[16] See List of References section
[17] Of this capital expenditure, about 40-60% go towards the wind turbines, the rest to Offshore wind foundations (15-30%) and installation costs (10-25%) (IEA 2017, p. 50).

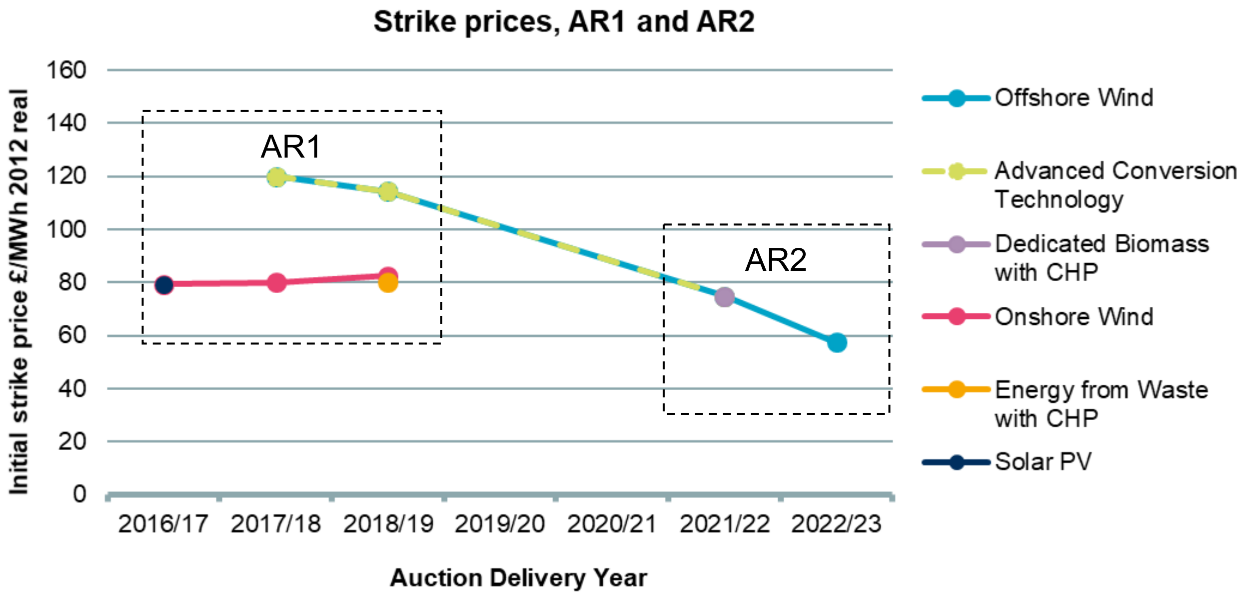

Figure 5. Clearing strike prices by delivery year. Source: BEIS, AR1 and AR2 outcomes (excluding terminated contracts)

As shown in Figure 5, the strike prices for Offshore wind in Allocation Round 2 has reduced by around a half, in comparison to Allocation Round 1. In addition, Advanced Conversion Technology (ACT) prices fell on average by 37% between rounds 1 and 2.

This rapid drop in prices cannot be attributed to the CfD Scheme alone. Other global trends were also at play as contributing factors to reducing the overall Levelised Cost of Electricity (LCOE) for various technologies[18]. In particular the industrialisation of Offshore wind turbine manufacturing in Germany and Denmark has contributed to lower supplier costs. Furthermore, existing evidence suggests there have been cost reductions from technology advancements, such as larger rotor diameters of wind turbines (a cost-effective way of increasing capacity) plus technological learning from previous projects. For example, the UK's first Offshore wind farm, which was commissioned in year 2000 at Blyth, off the coast of Northumberland[19], comprises two 2MW turbines, with a rotor diameter of 66 meters. Whereas, the currently planned East Anglia Two Offshore wind farm is proposing to install wind turbines with a rotor diameter of up to 250m and generating capacity of up to 19MW[20] each.

However, as discussed in the Annexed report on Investment Trends in UK Renewable Electricity, prices between AR1 and AR2 fell at a much faster rate than previous global

[18] See Annex Investment Trends in UK Renewable Electricity.
[19] Based on E.ON overview of Blyth Offshore wind farm: https://www.eonenergy.com/About-eon/our-company/generation/our-current-portfolio/wind/offshore/blyth
[20] ScottishPower Renewables (SPR): https://www.scottishpowerrenewables.com/userfiles/file/SPR_Exhibition_Panels.pdf

rates of reductions in LCOE. IRENA (2018[21]) estimates that Offshore LCOE fell by 18% between 2010 and 2017, which corresponds to a Compound Annual Growth Rate of (CAGR) of less than -3%, whereas the reduction in clearing prices for Offshore between AR1 and AR2 represents a CAGR of -28%. It appears that prices in recent auctions reduced at rates much faster than historical learning curves.

The evidence gathered from the interviews with developers supports the theory of change that the CfD revenue stabilisation had an impact on attracting investment and reducing project costs. The estimated reduced cost to bill payers of developing renewable electricity projects under the CfD scheme (see Chapter 6), in comparison to the RO scheme, is primarily driven by the reduced cost of capital available for CfD projects. Developers of most technology types clearly expressed that the price stabilisation mechanism of the CfD made it more attractive to investors than the RO. As one respondent from a company who has invested in both RO and CfD projects explained:

We apply two different discount rates; one for contracted revenues, taking into account the sale price of electricity and the subsidised rate, and one for the future merchant rate for selling electricity on the market without a contractual arrangement (in the case of a CfD project, this would be for the period after the 15-year contract ends). We then use this to create one overall blended discount rate. Because of the time preference of money, the revenue in the first few years will have a much bigger effect than those long into the future. So, in comparison to a project with a RO, if a similar project had a CfD then we would be prepared to accept lower overall interest rates.

The precise hurdle rate figure depends on each project, but overall, the effect of having a CfD could reduce rates by up to 2 percentage points
(Solar-PV and Onshore wind investor)

Both the survey and telephone interviews with developers asked respondents to provide estimates of the extent to which CfD reduced costs of capital, in comparison to the RO, asking the hurdle rates[22] they would apply to their project under each scheme. The majority of respondents were not willing to provide quantitative estimates due to the commercially sensitive nature of this information. Thus, aggregate estimates of the impact of the CfD scheme on reducing hurdle rates could not be provided from the interviews or survey data.

However, there was a general consensus, through the qualitative explanations that, **overall, the 15-year price stabilisation contract offered by the CfD reduced risks for investors, in comparison to the RO**. Only a relatively small number of respondents (six) provided quantitative estimates of the impact of the CfD in lowering hurdle rates in

[21] IRENA 2018c. Renewable Power Generation Costs in 2017. Abu Dhabi: International Renewable Energy Agency.

[22] A hurdle rate is the minimum rate of return on a project or investment required by a manager or investor. The hurdle rate denotes appropriate compensation for the level of risk present; riskier projects generally have higher hurdle rates than those that are less risky (Investopedia)

comparison to the RO. Estimates of the impact of obtaining a CfD on hurdle rate reduction for investors were generally in the range of 1-2%. This range is in line with estimates provided in previous studies[23] to inform Government estimates of hurdle rate reduction used in the BEIS Cost of Electricity Generation report. Developers of Offshore wind, Onshore wind and Solar-PV projects all offered similar views:

There was a huge reduction in the cost of capital for Offshore wind. It allows pension fund managers to invest. For a typical Offshore wind project, the CfD would knock off around 2% of the overall project cost in comparison to the RO.
(Offshore wind developer)

Broadly speaking, the best scenario for low hurdle rates is CfD, then RO in the middle and then no subsidy as the worst option. This is due to the volatility of the income of those different scenarios. As an estimate, there is around a 2% difference in hurdle rate between the best (CfD) and worst (no subsidy) subsidy scenarios.
(Onshore wind developer)

Some developers explained that the falls in strike prices witnessed cannot solely be attributable to the price stabilisation contract. A mix of other factors were also at play, including:

- **competition between developers** to win contracts through auctions
- increased **competition between manufacturer** firms to supply a growing market for larger Offshore wind farms
- the **response from supply chain manufacturers** to the reduced levels of total subsidy available through the CfD as compared with the RO.

The RO did have its own cost inefficiencies. The suppliers of wind turbines and Solar-PV panels knew very well what level of subsidy was available to the developer and would price their products according to what they estimated was affordable. Once RO was taken away, all of a sudden, the price of wind turbines came down! The competitive nature of the CfD has also pushed the turbine manufactures to come up with more innovative ways of reducing costs e.g. through larger rotor diameters to gain better performance.
(Offshore and Onshore wind developer)

Some respondents also explained that the falling prices of many technologies was in part also attributable to the years of support provided under the RO, which enabled high-cost renewable technologies to be deployed earlier than would have been the case otherwise and for those initial applications to be further developed and commercialised.

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[23] NERA (2015). Electricity Generation Costs and Hurdle Rates Lot 1: Hurdle Rates update for Generation Technologies. Available at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/566809/NERA_Hurdle_Rates_for_Electricity_Generation_Technologies.pdf

The RO may get some bad press now, in terms of cost-effectiveness, but it achieved what it set out to do. It gave the level of subsidy support needed to foster early growth of the renewables industry. This helped technologies develop and attract more investment. So this provided a platform that made the CfD Scheme possible. (Offshore and Onshore wind developer)

Implications for attracting investment relating to Pot 1 Technologies

Since Allocation Round 1 there has not been another allocation round for Pot 1 technologies (which includes Onshore wind and Solar-PV). Government recognise that Onshore wind and Solar-PV costs had already fallen dramatically and so support was scaled back in those areas. The policy aim was to see a competitive electricity market, operating as independently as possible, so the priority was to focus support on Pot 2 technologies, in order to drive costs down costs of less established renewables.

Developers interviewed were almost unanimous in their view that the lack of further auctions for Pot 1 technologies has been met with a relative drop in investment in all Pot 1 technologies.

The impact on investment in Onshore wind has been dramatic. RenewableUK have reported that investment in Onshore wind is down 80% year-on-year.[24] *(Developer of multiple technologies)*

Now that the RO is gone, there is a pipeline of Onshore projects sitting in the development phase but they're just not going to come forward. (Developer of multiple technologies)

We [Solar-PV company] have stopped developing in the UK altogether now because without a support mechanism, projects were not financially viable and do not look to be viable in a reasonable time frame. There is a strongly growing international market, so we're now focused on that. (Solar-PV developer)

Other secondary data sources lend support to this claim. The House of Lords Select Committee report[25] on investment in clean energy quotes analysis of Bloomberg data to suggest that the drop in support for Onshore wind and Solar-PV had a negative impact on confidence and reduced the number of new build projects going ahead in those sectors since 2016. The analysis of Bloomberg data carried out as part of the Investment Trends scoping phase report[26] suggests that new build Solar-PV projects that came online in 2016

24 Quote refers to RenewableUK Press Release: *New Onshore wind installations plummet* 18 January 2019

25 Green finance: mobilising investment in clean energy and sustainable development. Environmental Audit House of Commons Select Committee. 2018. Available at: https://publications.parliament.uk/pa/cm201719/cmselect/cmenvaud/617/61702.htm

26 See Annexed report: Investment Trends in UK Renewable Electricity

had a combined generating capacity of 2.4 GW, whereas by 2018, the capacity of added new build Solar-PV projects dropped to around 400 MW.

Several developers (of both Pot 1 and Pot 2 technologies) commented on the implications of not re-running Pot 1 for meeting CfD objectives around supporting increased generation of renewable technologies in the most cost-effective way.

> *If the main objective of the scheme was to support deployment of renewables in the most cost-effective way, then frankly I don't think it has met that objective, because it's really just focused on one technology (Offshore wind). The most cost-effective way would be to allow Onshore wind and Solar-PV to compete as well. (Developer, multiple technologies)*

The implications of Pot design, and the frequency of Allocation Rounds on developers' investment strategies are discussed further in Section 4, Scheme Design Features.

Has the Scheme attracted investment from a greater pool of sources?

Based on the investment trend analysis using the Bloomberg Terminal[27] for this study, the most noticeable difference in the profile of companies participating in the CfD scheme appears to be the slight shift towards more multi-national utility backed developer companies, compared to the RO. This appears largely to be driven by the opportunities presented by the CfD Scheme from 2014 to **invest, at large scale, in the growing UK Offshore wind industry**.

Profile of Onshore wind developers

Using Bloomberg Terminal records on the parent companies of equity owners of renewable projects (at the time of financial close of the project), the companies were grouped into broad categories depending on their industry, ownership and function. Figure 6 below shows the application of this classification of equity owners to the first round CfD Onshore wind farms, and Onshore wind farms financed under the RO scheme in a comparable time frame. Under the RO scheme around 20% of projects are sponsored by firms whose main activity is the development of renewable energy projects in the energy sector. These firms are labelled "energy firms". Another 20% is sponsored directly by utilities, and smaller shares are owned by non-bank financial institutions (FIN) such as asset management firms, and non-energy, non-utility and non-financial firms (NFF), such as retailers or manufacturing firms. A quarter of developers cannot be classified because details of who the parent companies are for all equity owners is not publicly disclosed in all projects.

One difference with the CfD scheme appears to be the larger share of energy firms participating in CfD projects. However, the relatively small sample of Onshore wind projects with a CfD (15) and the fairly high proportion of RO projects where the parent companies of equity owners was unclassified (28%) make it difficult to draw reliable

[27] See Annexed report: Investment Trends in UK Renewable Electricity.

conclusions on whether the CfD attracted a different profile of developer firms for Onshore wind.

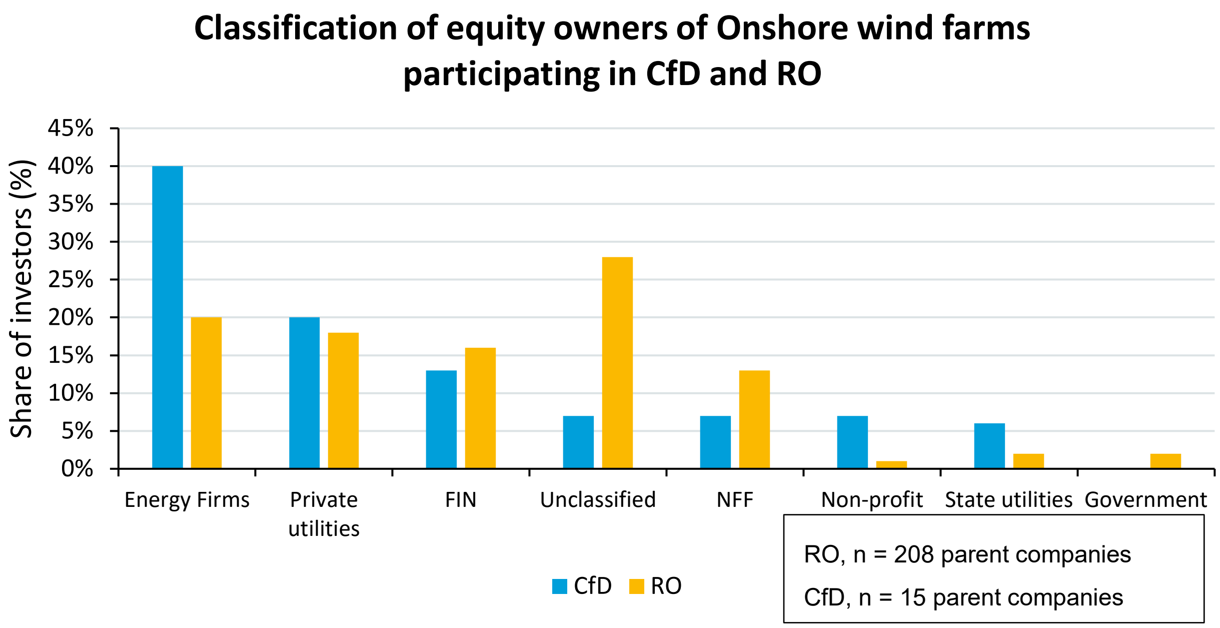

Figure 6. RO Onshore windfarm equity providers with Financial Close (FC) estimated in 2014-early 2018, and CfD Onshore windfarm equity providers (all in round one, with FC typically in 2017-2018). NFF = non-financial, non-energy firms, FIN = non-bank financial firms, (classification as in Mazzucato and Semieniuk 2018). Source: Bloomberg Terminal as of February 2018.

Offshore wind is developed by a relatively small set of types of firms, including a high share of energy companies and other utility firms. Where project finance data allows insight into debt financing sources, the data shows that state sponsored banks are often involved in the lender consortium. Given the high upfront costs of developing Offshore projects (and potential allocation risk of not being awarded a CfD) the development phase is more feasible for a consortium with capacity to self-finance from their own balance sheet, or with access to low interest loans from state sponsored banks or utilities.

Consequently, the type of companies with capacity to develop Offshore wind projects is more limited, and the profile of types of investors in the CfD scheme appears relatively similar to the RO. However, as shown in Figure 7, there does appear to be a slightly higher proportion of utility companies investing in the CfD.

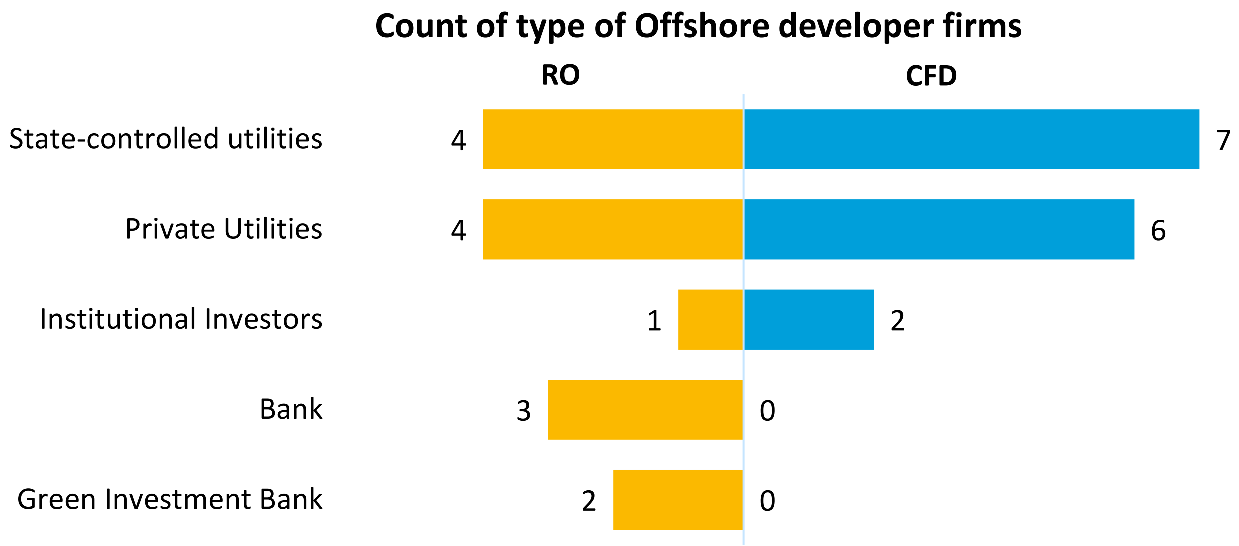

Figure 7: Project involvement count of Offshore developer types (one project can have more than one company in the consortium). Sources: Bloomberg Terminal, 4C Offshore. Siemens grouped with banks (has a banking license). One of two institutional investors is a sovereign investment fund. Statoil grouped with utilities.

Post contract award acquisitions and refinancing

Some of the CfD Offshore wind projects went through major or full ownership changes via post-auction acquisitions of shares, as visible in Bloomberg reports. Not all equity deals are published, but out of the five Offshore wind farms awarded a CfD, it is known that:

- EDF Energy bought Neart Na Gaoithe from the developer Mainstream Renewable Power
- Large shares of the Moray East Offshore wind project have been sold to multiple buyers by developer EDP Renewables
- Innogy divested 41% of its shares of the Triton Knoll Offshore wind farm to two Japanese utility companies.

Once projects become operational, they may attract more finance from investors with a lower appetite for risk (such as pension fund managers), as development phase risks have been overcome. The majority of auctioned CfD projects are currently not yet operational, so Phase 2 of the evaluation will explore how the financial structure of projects has changed over time.

CfD Scheme specific risks

The CfD has some unique associated risks compared to the RO, such as the 'allocation risk' of not being awarded a contract through a competitive auction and the milestone delivery risk. The milestone delivery risk refers to not achieving the Milestone Delivery Date (MDD) requirement to have either spent 10% of pre-commissioning project costs or evidencing key commitments such as signing key contracts within 12 months of signing the CfD. This may lead to termination of the contract by LCCC.

Developers explained that they incur substantial costs for planning consent and securing grid access before bidding, which are sunk costs if they do not receive a CfD and cannot reach Financial Close (FC) to implement the project. As there are no guarantees of being successful at auction, the cost of capital from any third-party finance for this stage is high. Smaller developers described this as a barrier which is likely to have deterred some from bidding.

In comparison with the RO there was no allocation risk back then. If the project was designed in a way that it complied with the RO rules, you could develop it whenever you were ready…But with the CfD you need to get planning consent which costs you around £250,000, plus around a year of work. Also, you need the grid connection, which also costs you significantly. All of this needs to be done before you can enter the auction and you might not even get it then.
(Developer, multiple technologies)

The effects of the MDD risk are described further in Chapter 5, Impact of CfD Scheme Design Features.

The online survey asked respondents to consider the relative importance of different project development risks. Respondents were asked to rank each type of risk on a scale of 1 (no risk) to 10 (very high risk) for developing a generation unit under the CfD Scheme, and then to rank these risks considering a scenario where the same project was being developed under the RO.

Only ten out of 20 respondents completed this question, so these results should be treated as only indicative, rather than statistically significant. Although the ten still represent around a third of all CfD developers.

As shown in Figure 8 below, the results reflect the explanations given in the telephone interviews on impact of the CfD Scheme on project risks. For example, the risks associated with volatility of income were ranked lower for a CfD project compared to the RO (on a scale of 1 to 10). Although risks associated with unexpected project construction delay were ranked higher under the CfD (due to implications for missing MDD or the project's Target Commissioning Window dates).

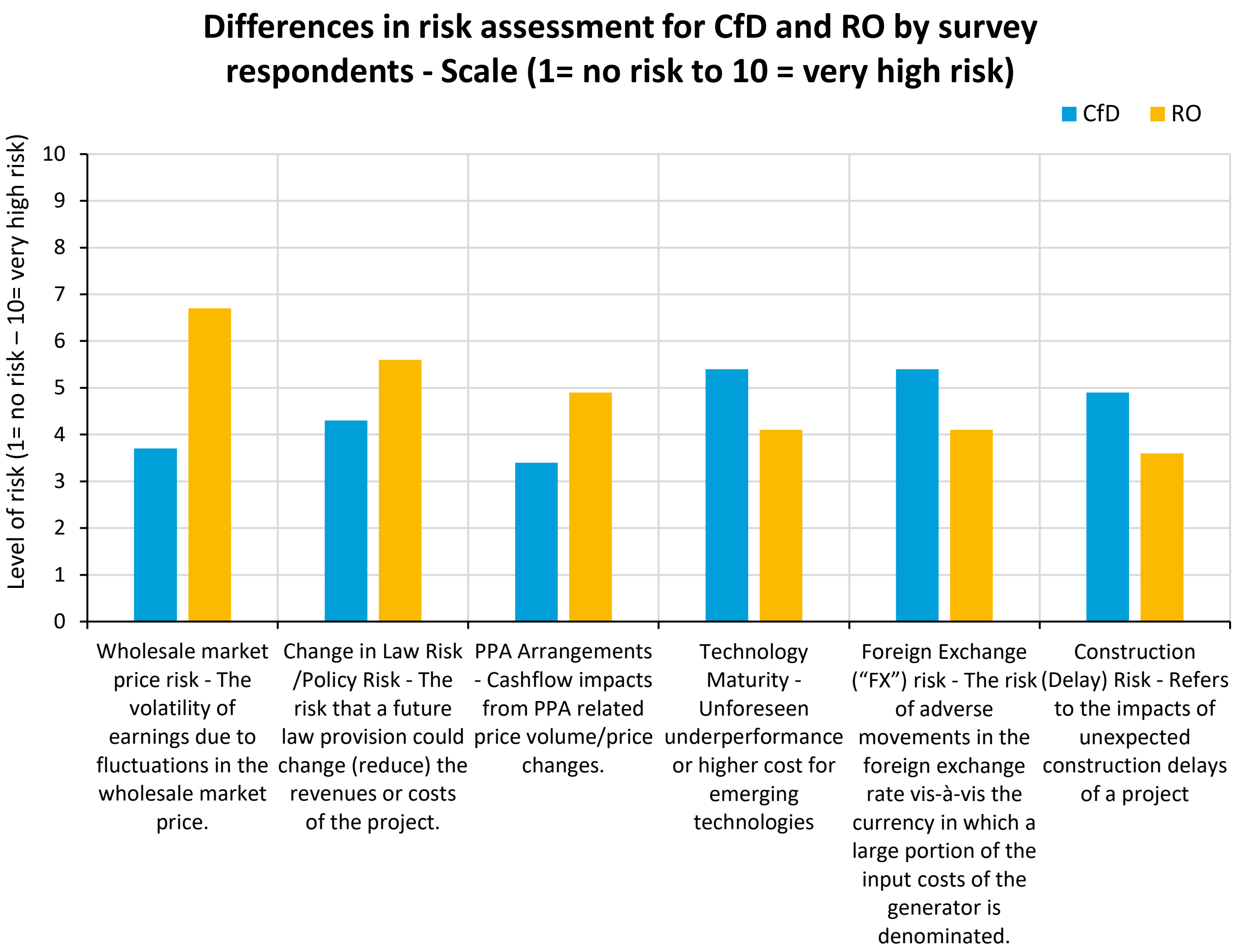

Figure 8. Survey respondents' risk assessment for CfD and RO Schemes

Developers' outlook towards subsidy-free development

This sub-section addresses the evaluation question; *What evidence is there that the CfD Scheme supports trends towards subsidy-free deployment*?

A recent report by the International Renewable Energy Agency (IRENA 2018[28]) describes a global trend towards reduced costs and subsidies for renewable energy technology. For example, the report estimates that, globally, the LCOE from Solar-PV decreased by 69% between 2010 and 2016 – coming well into the cost range of fossil fuels. The IRENA study estimates that by 2020, the renewable power generation technologies that are now in commercial use are expected to fall within the fossil fuel-fired cost range, with most at the lower end or undercutting fossil fuels. This trend coincides with an increase in competitive auctions, which have replaced supporting deployment through quota-based targets and

[28] IRENA (2018) Renewable Power Generation Costs in 2017

Feed-In-Tariffs. Evidence from existing literature[29] suggests that competitive auction mechanisms play an important role in bringing down the cost of subsidies.

Whether this points to a future for renewables which does not need additional support payments, is not feasible to answer from the evidence gathered here; partly because the very existence of a subsidy can influence the cost of renewables. However, evidence from the interviews with developer companies suggests that whilst most commercialised technologies are on a trajectory towards reducing subsidy, the current potential for development without additional support payments is viewed as a niche market, which is not likely to expand at sufficient scale in time to meet the requirements of future clean energy demand, or carbon budget targets, based on market forces alone.

Recent BEIS national statistics suggest the large majority of renewable electricity projects are accredited with government support schemes, indicating that levels of generation without having additional government support are currently small. For example, BEIS statistics (March 2019[30]) suggest that by 2018, Solar-PV deployment in the UK has a combined generation capacity of over 13 GW. Among this, over 12 GW is generated from projects accredited to either the RO, FITs or CfD scheme. From the remainder of currently unaccredited projects (accounting for less than 1 GW), the statistical release notes that some may be new projects that are yet to be recorded on the RO register.

There was some discussion in the interviews around what exactly constitutes "subsidy-free" as there appears to be no commonly accepted definition of the term. Some projects which are currently viewed as subsidy-free, in terms of not receiving a CfD, were described as extensions to previous RO projects, having benefited from grid connections put in place under previous subsidy regimes.

> *We do not see Onshore wind going subsidy-free in the next few years, it is very challenging and will depend a lot on market prices. The problem is that banks are not comfortable with merchant risk and are concerned about price cannibalisation[31]. Current projects which try to develop subsidy-free had grid access and infrastructure paid by RO. So, it is possible for them to benefit from the strong cashflows from existing RO projects which underpin "subsidy-free" approaches.*
> *(Onshore wind developer)*

New build renewable electricity projects that receive neither RO support nor CfD payments may be considered as constituting subsidy-free electricity generation. In this definition, one respondent raised the example of Clayhill Solar-PV Farm in Milton Keynes. This had considerable press coverage on opening in 2017 as the UK's first subsidy-free Solar-PV

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[29] See Rapid Evidence Assessment Annex

[30] National Statistics. Solar Photovoltaics deployment: https://www.gov.uk/government/statistics/solar-photovoltaics-deployment

[31] Price cannibalisation – Times of high output from intermittent, weather-driven generation such as solar, onshore and offshore wind can reduce wholesale electricity prices. However, this reduction in prices can reduce overall revenue generation for the project, which poses a risk for investors.

farm. However, some reports[32] suggest the co-location of the site with a 6MW battery storage facility may have strengthened their business case. This will enable the owners to be eligible to bid for ancillary services from National Grid. Whilst ancillary service payments are not a form of government subsidy for renewables, it illustrates that planned additional income streams may be required for projects such as this to reach Financial Close.

The role of corporate Power Purchase Agreements (PPAs) for subsidy-free development

Another potential route towards subsidy-free deployment is corporate PPAs. There are emerging examples of these agreements between a generator and a private customer that can give enough revenue security to drive new-build subsidy-free development.

However, most developers expressed views that the corporate PPA market for new build projects is currently relatively small. For new-build projects, developers and lenders will need a long-term guaranteed price to finance the project, for example, around 10-15 years such as with a CfD. However, developers felt that corporate companies, may be reluctant to sign long-term (more than 3-5 years) contracts.

> *Everyone is talking about corporate PPAs but hardly anyone is doing them. There are many reasons for that. It is difficult for a corporate client to agree to terms that are in any way comparable to a government backed CfD. Large corporates may be used to buying electricity in two or maybe three-year-in-advance deals at most. But they are not going to agree to a 15-year price. There is a big difference between the appetite for risk that corporate energy users have, and what level of contractual assurance a developer needs to get their investment agreed.*
> *(Onshore and Offshore wind developer)*

Some developers also felt that promoting corporate PPAs may not be an equitable way of spreading the costs of renewables across wider consumers.

> *If corporate PPAs do progress, then a consequence of this will be that we have a two-tiered energy costs system. Because Onshore and Solar-PV cannot get CfDs, they are looking for niche private deals to supply to industrial firms. This means that energy using industries get the cheapest form of electricity, whereas the rest of the bill paying public are left to subsidise the more expensive Pot 2 renewables, at higher cost. This is not the most equitable way of paying for renewables deployment.*
> *(Onshore and Offshore wind developer)*

One ACT developer reported that the existence of the CfD deters investors from supporting corporate PPAs with their technology, since their usual investors are now

[32] *Inside Clayhill, the UK's first subsidy-free Solar farm*. Solar-PV Power Portal report. 2017.

waiting for winners of the next CfD allocation round to look for a safer investment opportunity.

The potential for CfDs with low net top-up payments

Some developers explained that if previous trends in falling strike prices between CfD Allocation Rounds continue in the future, then the agreed strike prices will come close to the reference price. This suggests that whilst the CfD may be needed to mitigate against risks of future wholesale price fluctuations, in practice the level of top-up subsidy payments may be very low.

> *From an Offshore perspective, we may well get to a point in future where the CfD strike price is effectively subsidy-free and projects will be viable. However, we are not there yet. The offer of subsidy (e.g. that top-ups will be made available when the reference price drops) is still necessary to make Offshore wind developments viable. It may be that in practice that subsidy is not used, and the projects become subsidy-free by default (if reference prices remain high) but to give investors the confidence they need to mitigate risks of price drops, we need that assurance there.*
> *(Offshore wind developer)*

The role of co-located battery storage for subsidy-free development

As described in BEIS and Ofgem's 2017 Smart Systems and Flexibility Plan[33], electricity storage, such as battery technologies, can bring a number of benefits to the electricity system. It can reduce curtailment of electricity from renewable sources (turning down generation when supply is greater than demand) and mitigates the intermittency of renewable electricity generation. Storage offers the service of price arbitrage (i.e. shifting power from a time of low demand to a time of high demand). In addition, battery storage can provide ancillary services to the Electricity System Operator and help to reduce the need for expensive improvements of the grid.[34]

When co-located with renewables, storage can also increase site cost efficiency by sharing grid connection costs (and maximising the use of a grid connection). In terms of how payment for storage services may interact with CfD payments, storage is not considered part of the CfD facility. Storage must be metered separately, unless the generator can demonstrate to the LCCC's satisfaction that the meter ensures that their storage technology only stores electricity generated by the CfD project and does not store electricity imported from any other source. Further details on regulations around the metering of storage under the CfD Scheme were set out in Government's response to consultation on changes to CfD regulations in February 2017[35]. Given co-located storage technology must be metered separately, sites can be eligible to participate in the ancillary service markets run by the Electricity System Operator.

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[33] Upgrading our energy system: smart systems and flexibility plan. BEIS and Ofgem. 2018.
[34] Upgrading our energy system: smart systems and flexibility plan. BEIS and Ofgem. 2018.
[35] Government response to the consultation on changes to the CFD contract and CFD regulations. Feb 2017

Developers were asked in interviews (and the online survey) whether they currently have co-located battery storage or are planning to develop storage facilities in future. Some developers felt that there was not currently a strong enough business case for using co-located battery storage solely to store on-site generated capacity. This was due to a perception that batteries at the scale are currently too expensive to install in comparison with their expected revenue.

> *The bigger point for batteries is to support the national grid with frequency response or to take over spillovers for extra generation. Times with negative pricing for Solar-PV will be relatively small and will not be the reason why you have the battery. In any support scheme, battery storage should be available to do grid response. Batteries are just too expensive to store generation and even if there is a negative price you can still just dump the electricity. If batteries can only be co-located if they are solely used for storing power, nobody will install batteries.*
> *(Solar-PV Developer)*

Some developers were more positive that there will be a business case in the near future. Respondents to the online survey were asked “*Has your company considered investing in co-located electricity storage alongside CfD supported generators?”* 13 out of 20 respondents answered this question, so results should be considered as only indicative of CfD developers’ views. Only one respondent stated their site currently has co-located storage. However, the majority of respondents (nine) suggested they might consider investing in storage in the future, to be ready as new business models emerge.

3. CfD Scheme Delivery Processes

Key findings:

The majority of applicants (both successful and unsuccessful) felt the information and guidance provided in advance of application was clear and sufficient to understand the requirements of participation.

Some difficulties were reported around requirements to demonstrate certain eligibility criteria - for example, for Supply Chain Plan reports.

There was some variation in response according to experiences of applying to Allocation Round 1 (AR1) or Allocation Round 2 (AR2). This was considered a learning curve, and in cases where the developer had also applied in AR2, the application requirements were reported as being more straightforward the second time as they knew what to expect.

The 12-month Milestone Delivery Date window is considered too short to complete sufficient development work to demonstrate 10% of spend. This was reported to have led to procurement practices that were not cost-effective. For example, paying sub-contractors for the costs of construction work in advance.

Smaller firms, which cannot pay for costs of initial development work until they reach Financial Close can struggle to meet the required MDD spending target.

For larger firms (e.g. Offshore wind developers) challenges were linked to the large scale of construction works required in the 12-month period and the administrative challenge of collating financial information to demonstrate 10% had been spent.

Introduction

This section explores developers' experience of participating in the scheme, across the journey from gathering information to understanding the application process, through to signing the contract and meeting milestone delivery dates. The section summarises developers' views on what worked well, in terms of working with delivery bodies to meet the requirements of scheme participation, as well as where improvements could be made.

Delivery Processes

Views expressed on delivery processes are based on the experiences of participants in Allocation Rounds 1 and 2. Some of the findings discuss administrative requirements that may have subsequently changed (particularly since AR1) and do not necessarily reflect how the scheme was administered by delivery partners for Allocation Round 3. Indeed, a common view expressed was that as these competitive auctions were being delivered for the first time in AR1, some 'teething problems' were to be expected and subsequently addressed for AR2.

This section summarises the experiences of developers in working through the following nine stages of participating in the scheme, as summarised in Figure 9:

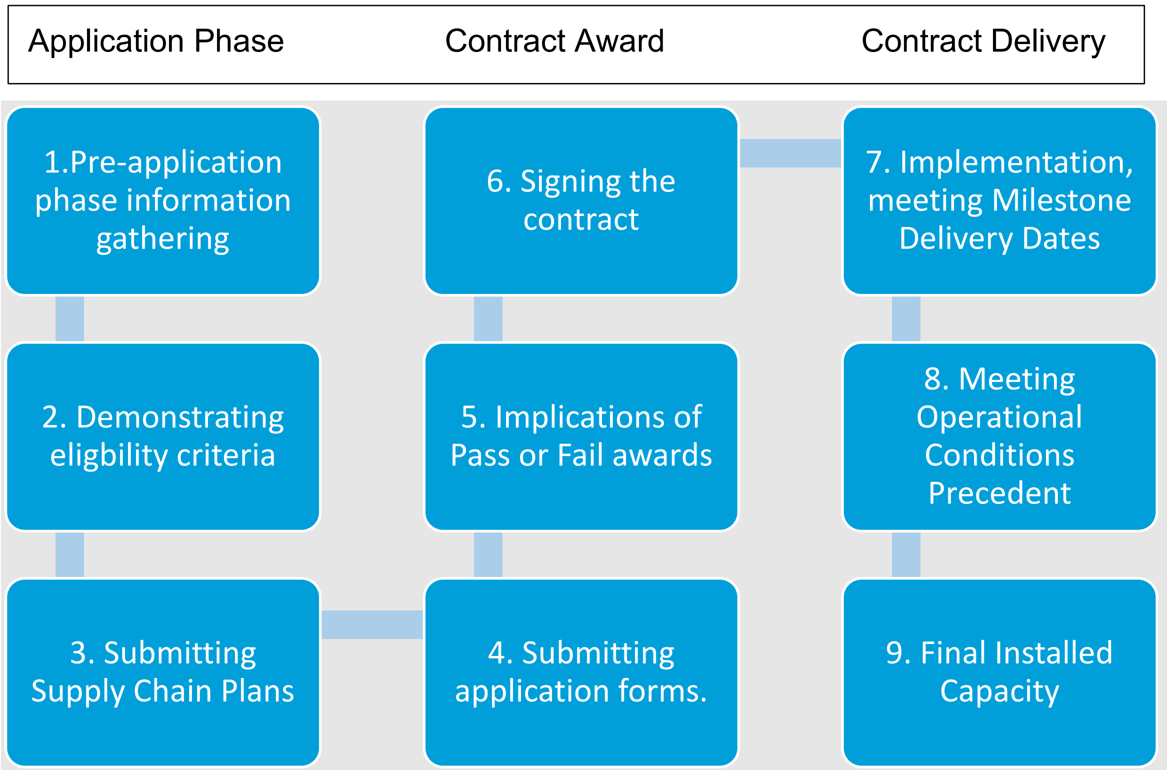

Figure 9. Stages of CfD Participation

Pre-application phase information and guidance

Prior to applying to the scheme, developers gather information and guidance around its regulations, design rules, application processes and eligibility requirements. This stage includes digesting official Government publications such as the Allocation Framework, the Budget Notice and supplementary guidance on requirements of specific strands such as Supply Chain Plans. Although not compulsory, it may also entail attending pre-application workshop events led by the delivery partners to present and explain these requirements.

Overall, the majority of applicants (both successful and unsuccessful) felt the guidance provided in advance of application was very clear and gave them sufficient information to understand the requirements of participation. This view was commonly expressed across developers of different types of technology. **Where there was some variation, the main difference was around whether the respondent was reporting experiences in relation to AR1 or AR2**. For AR1, there was some uncertainty over exactly what level of information was required to demonstrate certain eligibility criteria. This was considered a learning curve, and in cases where the developer had also applied in AR2, these requirements were reported as being more straightforward the second time, as they knew what to expect.

We attended most seminars and received a very good grounding regarding what information we needed to provide. No real surprises in the application process, auction process and award of the contracts. Everything was clearly set out; the National Grid did a very good job administering these stages of the process.
(ACT developer)

Ofgem's annual report[36] on EMR Delivery Body performance notes that results from the first CfD Customer and Stakeholder Satisfaction Survey (2018) suggest that, overall, participants have been positive on the Delivery Body's approach to delivering CfD application process.

In the interviews some of the published official guidance was reported by developers as being complex and legalistic, but this was generally viewed as necessary given the complexity of the scheme and the scale of investment that CfD contracts relate to. Although the guidance required some considerable time and resource to consider in advance of application, this was generally considered to be proportionate.

Because of the scale of our investment ambition, it was in our interest to make sure we had a very clear understanding of all details of the application process and scheme design rules.
(Offshore wind developer)

Demonstrating eligibility and submitting an application

Through the process of applying to the scheme, to award and sign off of a contract, an applicant may have to communicate with four separate delivery authorities individually:

- BEIS - for overall Scheme guidance and submitting Supply Chain Plans,
- (EMR) Delivery Body, Electricity System Operator, National Grid - for pre-application stage guidance and to submit applications to
- Ofgem - on appeals for unsuccessful applicants, and;
- LCCC - for award and ratification of the contract, and ongoing contract management.

Particularly for AR1, some developers reported some uncertainty over which delivery body to turn to for advice, with some instances of inconsistencies in advice given by different bodies (particularly where these queries related to specific changes to eligibility criteria between the RO and CfD). It was suggested that the process would have run more efficiently if applicants had one single 'CfD relationship manager' to engage with

[36] Annual report on the Delivery Body's Performance of its functions in relation to the Capacity Market. Ofgem. 2018

throughout, and/or one single website for information, with a portal for submission of all application and contractual information.

> *For AR1, the national online portal hadn't been set up, so all information had to be provided by sending spreadsheets and different documents to different delivery bodies individually. This was a bit of a hassle, but I think it should be rectified now with the new online portal.*
> *(Offshore wind developer)*

For biomass conversion projects, there was some perceived inconsistencies between how Ofgem and LCCC interpreted rule changes between the RO and the CfD over what proportion of fuel burned would be eligible for payments. The objective of sustainability requirements under both the RO and the CfD is that only electricity that has been produced through burning fuel from renewable sources (not fossil fuels) is eligible for payments. Hence, the Renewable Qualifying Multiplier (RQM) takes into account what proportion of fossil fuel a plant has used to calculate its level of CfD payments. One respondent highlighted some perceived inconsistencies between Ofgem and LCCC in precisely how this is calculated, with some significant implications for the amount of payment they will be eligible for. This developer explained that the LCCC interpretation assumes that all fossil fuel used on-site results in the generation of electricity. However, after an outage, a gasification facility will need to bring the gasifier up to temperature from a cold start by burning some fossil fuel to stabilise temperature and raise steam in the boiler.

> *The LCCC said that fuel use in these circumstances does result in the generation of electricity… we would advocate that LCCC, like Ofgem, excludes fossil fuel use that does not result in generation from the calculation of the Renewable Qualifying Multiplier (RQM).*
> *(Biomass conversion developer)*

LCCC observes that the RO and CfD have different scheme mechanics for the treatment of fuelled technologies. The CfD scheme has specific contractual drafting on fuelling criteria and fuel, measurement and sampling (FMS) requirements that differs from the RO. The resulting operation would result in a different approach to calculate the level of eligible generation.

Other instances where application guidance, and the application forms themselves, were felt to be less clear were due to a perceived "one size fits all" approach to the templates, which do not account for technology-specific differences between projects and their sites. For example, in determining the precise geographical location of an Offshore wind farm.

> *The template states you have to provide 4 grid coordinates of the development area, yet most Offshore sites aren't defined by 4 coordinates. The legal framework of the contract says that you can't have overlapping areas, but the way they ask for information does not allow an accurate description of the area. A 4-coordinate footprint could cause some*

development areas to appear to overlap when in fact they do not.
(Offshore wind developer)

Issues were raised around the pass or fail nature of submitting an application, without having an opportunity to correct perceived minor faults such as specification of grid coordinates or whether the Company Director had added their signature to all required sections of the form. These errors could result in applications being rejected, with some projects that had spent years in the development phase being cancelled or postponed until the next Allocation Round.

We had some bad experiences when bidding in Round 1 but by Round 2 it was far better. The rules on eligibility criteria make total sense but it is the system for demonstrating that you are eligible which was a bit messy. Nobody wanted to give you any feedback about whether the application gave the required information.
(Developer, multiple technologies)

We participated in Round 1 and the application failed. It was the same project that was awarded a contract in Round 2. Nothing had changed about the project, just changes to its description in the forms.
(Developer, multiple technologies)

In the run up to AR2, National Grid introduced a pre-application accreditation service, whereby applicants could submit their forms to check whether all required information had been submitted correctly, or identify any errors, in advance of the dates for submitting the final application. However, this service was not available prior to AR1. Few respondents discussed having used the pre-application accreditation service at AR2, although those who did generally found it a helpful and important check. However, others reported that the timescales for submitting an application, receiving comments and then making adjustments were still considered to be too short.

Supply Chain Plans

In order to qualify to take part in a CfD Allocation Round, applicants proposing a generation unit with a capacity of 300MW or more are required to provide National Grid with a statement by Secretary of State for BEIS confirming approval of their Supply Chain Plan. The aim of the Supply Chain Plan policy is to encourage the development of open and competitive supply chains, growth of supply chain industries and the promotion of innovation and skills.

Representatives of all CfD generation units where Supply Chain Plans were required were interviewed (five large Offshore wind farm developments), in addition to one Offshore wind farm developer whose Supply Chain Plan was rejected and was therefore not eligible to apply for a CfD, however it is not known if the developer resubmitted their Supply Chain Plan for approval. Responses to questions around their experiences of submitting Supply Chain Plans were mixed, including:

- Whether or not they felt the guidance on requirements of what information was required to be submitted was clear and well understood
- Whether or not they felt the time and resource required to develop and submit a Supply Chain Plan was proportionate and justified or whether it was overly burdensome
- Whether or not the stated requirement to submit the Plans led to positive or negative impacts on wider supply chains in the Offshore wind industry.

These differences in views reflected difference in whether the applicant had their Supply Chain Plan approved or rejected by BEIS and whether they had applied at AR1 and/or AR2.

All respondents expressed some level of uncertainty around exactly what information was needed to meet the assessment criteria and how their Plan would be judged. **This was felt to be more problematic for AR1**, where applicants were going through the process without the precedent of knowing what a successful Plan entails. Since approved Supply Chain Plans of successful projects are published following each allocation round, it was felt this would be less of an issue over time. Respondents with more positive views of the process stated that, having been through the process at least once, they knew what to expect and felt it would be relatively straightforward to complete it a second time around.

Now we've all been through it once I think the process will be clearly understood and fairly straightforward do again in future.
(Developer, Supply Chain Plan approved)

These respondents also explained that, although the process of collating information and drafting the Supply Chain Plans is resource intensive (taking "several weeks"), they noted that as this requirement only applies to developers of projects that are 300MW or more, it will be led by large firms, with sufficient internal resource to conduct such work. It was also explained that Offshore wind developers were increasingly aware of the need to communicate the benefits of the proposed projects in terms of wider gains for communities, in addition to the benefits of clean and affordable electricity. Therefore, they are accustomed to collating the information required and presenting a case for how proposed projects will support national industries. For instance, one developer remarked that they are now used to proving the wider benefits of their projects and have that information readily to hand.

So much of the evidence needed is information that developers of large projects will already have available and be used to reporting.
(Developer, Supply Chain Plan approved)

More difficulties were expressed in relation to AR1, where some applicants felt the level of detail that they were expected to provide was unclear, or exactly how pass or fail decisions would be determined.

Not long before AR1 was launched, policy on supply chain content was under development and there was considerable uncertainty over what the requirements of the report would be…. However, our plans for developing [name of site] were quite well advanced with commitments made to groups of suppliers.
(Developer, Supply Chain Plan rejected)

For at least one Offshore wind developer, their Supply Chain Plan was not approved in AR1, as it did not score highly enough in the competition criteria. This meant that a project that had spent several years and £millions in the pre-development phase was not eligible to apply for a CfD, with frustration for the company concerned. However, at the time of AR1, the RO was still open for applications, providing another route to commissioning for Offshore wind projects at an advanced stage of development.

We submitted our supply chain plan and it failed. Which meant we could not proceed with an application for a CfD. We felt the supply chain process was like a submitting into a black box; we had no clear idea of how the report was being judged and what we needed to do to pass that test. This did not seem a transparent way for the Government to do business or make decisions on multi-million pound investments.
(Developer, Supply Chain Plan rejected)

Another contextual factor which led respondents to expressing challenges with Supply Chain Plans was developers' experiences of dealing with UK based supplier firms when tendering. At the time of AR1, the UK supply chain for Offshore wind farm components and services was in a nascent phase of development, with a relative lack of competition between firms to supply the large volume of construction products and services that were required to meet the high demand being proposed in advance of the first CfD auction.

Some developers interviewed reported confusion about whether there was a need to demonstrate commitment to supporting UK firms in their Supply Chain Plans during AR1. In 2012, the Offshore Wind Developers Forum agreed an industry led vision of achieving a minimum of 50% UK content in offshore wind supply chains by 2020. RenewableUK subsequently published guidance[37] on how to measure the UK content of Offshore wind farms to support monitoring of progress towards this goal. This was an industry led voluntary target and Government's official guidance on Supply Chain Plans **did not include a requirement to source a percentage of suppliers from UK based firms**.

Some developers interviewed said they were unclear whether they needed to support UK manufacturing capacity, and whether such an approach could lead to inflated pricing.

The other difficulty with this, was that at the time of AR1, the UK supply chain was not sufficiently big enough or advanced. There was no large turbine manufacturer for example. And some of the UK suppliers that were there, were not taking long-term strategic

[37] *A Guide to Measuring the UK Content of Offshore Wind Farms*. RenewableUK. 2015

decisions to use this opportunity to work with us in growing the Offshore industry. (Offshore wind developer)

Most of the lead developer companies of large UK Offshore wind farms are part of multi-national Groups, whose parent company is based abroad. Some developers, who reported confusion about whether there was a target for UK content[38], explained that, if there are concerns over the maturity and reliability of UK suppliers, then this raised project development risks in the construction phase, and associated costs. Some of this confusion may have arisen from the fact that the industry was setting itself UK content targets, whilst the government had no such targets.

This goes back to the point about Offshore wind investment being an international market. Multi-national firms will look at requirements like this, and the potential for high supply chain costs, when considering investment decisions. (Offshore wind developer)

Once the project has been built, generators are required to submit a Post Build Report setting out the degree to which commitments set out in the Supply Chain Plan have been implemented and the reasons for any deviation from the submitted plan. Given large Offshore wind units are typically phased into 3 or more stages over several years, developers noted that one area that is causing uncertainty is around how BEIS will judge whether the decisions to change certain suppliers was made on reasonable grounds, and whether responsibility for that change lies with the developer or the supplier company. For instance, one developer was not clear whether there was an obligation to use suppliers they had previously identified, and what would happen if that supplier ceased trading, citing lack of clear guidance from BEIS. It is important to note though that Supply Chain Plans were not designed to police the choice of suppliers.

Contract award and sign-off

National Grid notifies the Low Carbon Contracts Company (LCCC) which bids have been successful. As the CfD counterparty, the LCCC offers the contracts to developers and obtains their signatures. Developers commonly expressed views around the contract document being overly long and legally complex (with over 300 pages to review).The extent to which developers viewed the requirement to review and sign the contract as being burdensome varied according to the size of the developer company and their internal legal resource available to review contracts, and the appetite of the developer to spend time in thoroughly checking each section and raise queries on points of detail with LCCC.

[38] While there was industry led target of sourcing 50% of the suppliers from UK based firms, Government guidance on Supply Chain Plans did not include any requirement to source a percentage of suppliers from UK based firms.

Among larger firms who were making larger scale investment decisions, it was considered proportionate to spend sufficient time in reviewing the details of the contract before signing. Particularly as the terms of the contract were published in advance of the auction.

We had to spend a lot of time reviewing the terms of the CfD, around 3-4 months plus months (in advance of bidding) of interactions with the procurement team.
(Offshore wind developer)

The interviews explored whether or not reviewing the contract was considered more of a resource burden for smaller developer firms who lack in-house legal teams. However, as some felt that the contract was generally non-negotiable, in practice they spent little time on this.

We received the contract and we pretty much just signed it straight away. It was a very long contract document, but we thought it was non-negotiable so there wasn't much point going through it line by line and arguing details with them.
(Onshore wind developer, smaller firm)

Among firms who invested time in reviewing all terms of the contract in detail, some felt that this stage was not a difficult part of the journey towards implementing a CfD. Partly because the terms of the CfD had been published months in advance of Allocation Rounds opening.

Because the contract terms were published several months before the auctions, we knew exactly what the contract would look like. We paid for legal advice, but the costs of this stage are not really significant. The signing process was very smooth since everything was standardised and could not be changed. This stage did not take too much time.
(Offshore wind developer)

Some developers however, raised issues around the perceived "one size fits all" nature of the general terms of the contract, which were considered as being designed to be proportionate for large Offshore wind projects, but overly complex and risk averse for the size of investment related to small scale projects. The issue of requiring agreement to both generic and technology specific terms in one contract was also felt to have raised complications.

You've got the very complicated general agreement and then you have a specific technology agreement. The two-part contract approach really doesn't work that well. It would make more sense for the technology specific element to be part of the main body, so then it has the proper linkages through a single document. At the moment what you've got is a general thing, and then you've got the technology specific part and then you have to work out which bits apply to you. Actually, that's just a recipe for reducing understanding and increasing legal fees.
(Solar-PV developer)

Post-award contract implementation milestones

Once contracts are signed, the LCCC guide projects through various milestone checks before they become operational and can begin receiving CfD payments. These include:

- Meeting the Milestone Delivery Date (MDD) requirement to demonstrate commitment to the project by either spending 10% of pre-commissioning project costs or evidencing key commitments such as signing key contracts within 12 months, and
- Fulfilling the Operational Conditions Precedent (OCPs), which include demonstrating that the project has commissioned 80% of generation capacity before reaching the end of the Target Commissioning Window and being eligible for CfD payment.

The aim of these milestone requirements is to deter speculative bids from projects that are not deliverable and to provide a means of reallocating budget for cancelled projects to future Allocation Rounds. They also aim to ensure that projects begin generation within their contracted timescales, which is important for ensuring wider government decarbonisation objectives are met. These stages are described in more detail in the Theory of Change section (See Annex C) and illustrated in Figure 10 below.

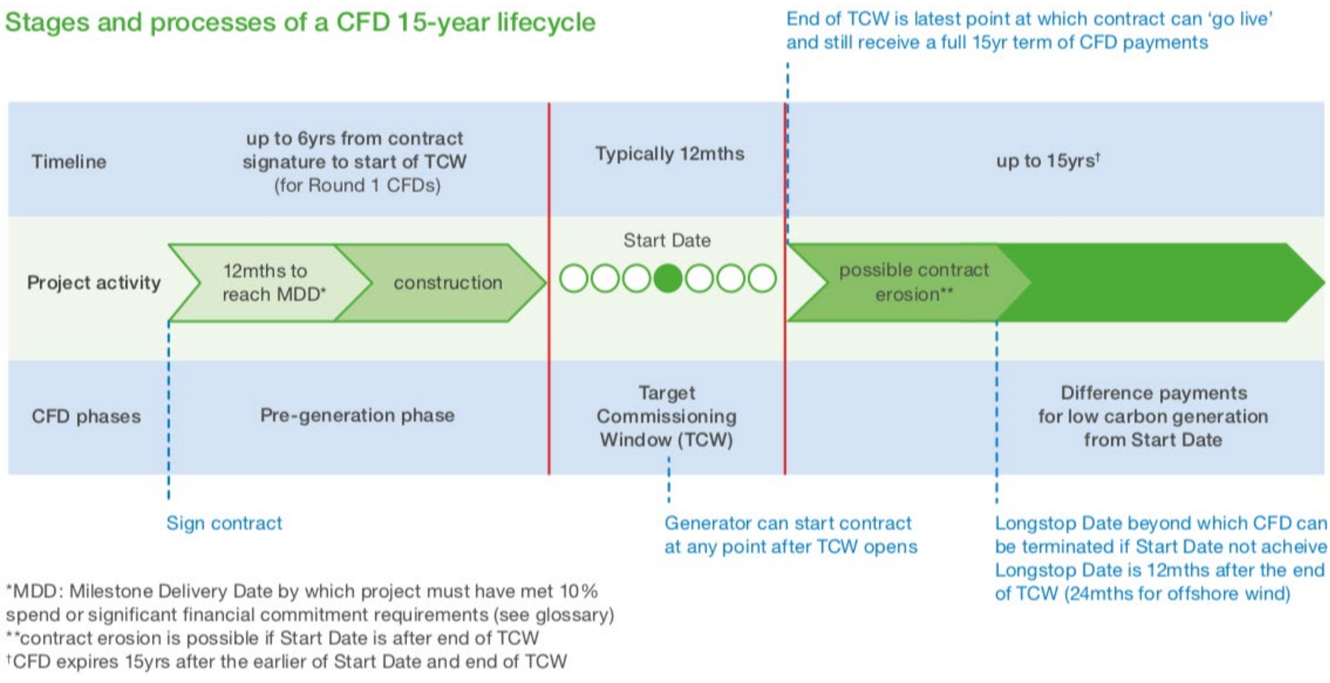

Figure 10. Stage and Process of a CfD project lifecycle. Source: LCCC Annual Report 2016/17

Meeting Milestone Delivery Dates (MDD)

Developers were asked for views on any ways in which the post-contract award delivery phase may have been improved. The most common issues raised related to the MDD requirement to demonstrate 10% total project spend within 12 months of contract signature. This raised a number of challenges, some on which there was a general consensus across developers of all technologies, whereas others were context specific to the size of the firm and the extent to which they had access to finance to pay for construction works prior to project Financial Close (FC). The issues raised are summarised below.

The 12-month window was considered too short to complete sufficient development work. This was reported to have led to procurement practices that were not cost-effective. For example, paying sub-contractors for the costs of construction work in advance. This raised risks around not being able to re-coup costs for work that is not completed to standard. It was also felt by developers to have given certain suppliers the upper hand in contract negotiations, where the supplier knew that the developer was approaching an MDD deadline, and some developers described that therefore suppliers could charge over-inflated prices as the developer would not be willing to jeopardise their CfD.

Some big projects have paid hundreds of millions of pounds to tier one suppliers as a down payment in advance of work completed, which is not an efficient use of capital. And suppliers know that projects have a 12-month window to secure MDD so they can use this to delay negotiations and demand higher prices.
(Offshore Wind developer)

Most developers explained they will not complete FC negotiations with their investors until several months after signing the CfD. This means initial development costs, prior to MDD, may have to be paid for from the developer's own balance sheet. Some smaller firms explained that taking on exposure to this level of cost was an uncomfortable level of financial risk, which they would not normally do were it not for the MDD requirement.

Reaching the first milestone was problematic because it forces developers to put more money at risk earlier on than they usually would (e.g. under RO). Developers will pay for things like planning, land rights, grid rights, and deposits on the grid prior to securing Financial Close. We would never have normally committed to that before securing finance, but we are forced to under the CfD
(Onshore wind developer).

For at least one smaller developer firm, this inability to reach FC in time and begin to spend on project construction, led to their CfD being terminated.

The MDD with the 10% spent is very restrictive. We did as much work as we could ourselves (spending from internal budget), but we had to demonstrate an overall spend of £6 million in 12 months. For us, the only way to achieve that was to reach FC and access wider investment. But negotiations with investors delayed reaching an agreement. We were granted an extension, but it wasn't long enough to raise the money and spend enough of it in time to demonstrate 10% spent. This process is much easier for a big utility backed company
(Developer of cancelled project).

Another smaller scale firm which had developed Energy from Waste with CHP projects through the RO and had been previously unsuccessful in applying for a CfD, similarly explained that the disconnect between CfD award and securing FC meant it would be difficult for them to commit to the MDD.

> *The timing of Financial Close can be difficult to predict in advance. So quite simply, the existing CfD structure requires developers to commit to project milestone deadlines which in reality cannot be guaranteed.*
> *(Energy from Waste project developer, unsuccessful applicant)*

Administrative challenges with proving 10% spend

Developers of large Offshore wind farms (often backed by international utility firms) have less problem accessing finance to meet the 10% project spend commitment. For them, the challenge was more around the large scale of construction work required, and the administrative challenge of collating financial information to demonstrate 10% had been spent.

Collating all invoices and financial information required for the LCCC's auditing process was an administrative challenge. This was explained as being more of a challenge for AR1 projects, where both the developer companies and the LCCC were working through this process for this first time, and certain aspects of the process were still being refined, such as the format templates used to collate invoices.

> *On the target to prove 10% spend by MDD - for us, this equates to somewhere between £100m and £200m, made up of literally thousands of individual invoices. So, we wanted to build in time to audit invoicing well in advance and have an interim check of spend to date by LCCC before the deadline. This would mean that when the final MDD audit check was completed, they would only have to approve spend for a dozen or so invoices since the last check. LCCC said you can do the interim audit, but for legal reasons, they would have to re-audit everything again closer to the milestone delivery date, which would make the exercise pointless.*
> *(Offshore wind developer, AR1)*

> *There were issues around the kind of information that needed to be submitted. At the beginning of the process, they said we could just submit our Excel templates. We were quite early in submitting all of our documentation, and this seemed to make LCCC realise they couldn't process all applicants in a non-standardised way, so they then came back to us and asked us to go through a standard process and created numerous spreadsheets for us to refill.*
> *(Offshore Wind developer, AR1)*

Developers also felt the standardised timing of MDD points created administrative challenges for LCCC, with a spike in workload to coordinate audits across multiple projects at one time.

All projects are awarded a contract around the same time, which means they will all be going through their MDD requirements around the same time. This means LCCC appear stretched for capacity during key milestone dates and it can be hard to get an informal or formal response from LCCC quickly.
(Offshore Wind developer, AR1)

Having been through the process in AR1, some developers felt that the renewables industry was now aware of the challenges of spending 10% of total project pre-commissioning costs in 12 months and would plan in advance to condense work within this period. However, this meant that pre-development feasibility work that would normally have been carried out in advance of putting a project forward for a CfD auction could be delayed, posing some construction risks and cost uncertainties.

It creates some incentives for risky decisions. For example, prior to CfD award the developer is aware that they will have to make a large 10% spend within the 12 months post-award. They may therefore defer some expensive costs like Offshore underwater surveys and site investigations, and more detailed engineering design work until after the contract is awarded. This means that projects are being put forward at auction which haven't been properly risk assessed. And the developer is aware of these risks, so if the engineering design work is not fully complete, then the full project costs will be uncertain. These risks will be factored into the bid price put forward.
(Developer, Offshore wind)

Exclusion criteria for the 10% spend

Some Offshore wind developers felt that the criteria around what types of costs can be included in the 10% project pre-commissioning spend were not accurate metrics for demonstrating commitment. For example, that Offshore Transmission Owners (OFTO) licencing costs are excluded from the MDD spend.

We can understand the argument that because the developer will receive repayment when the OFTO is tendered in around 7-8 years' time, then this should not be treated as an overall project cost. However, historically, developers have not been reimbursed for the full amount when OFTO is tendered. And whether or not the developer gets reimbursed should be irrelevant when considering the purpose of MDD, because if the purpose of the 10% spend requirement is to demonstrate commitment to implement the project, then OFTO costs are a form of commitment, because the developer will not receive this money

back if they don't proceed to operational phase.
(Developer, Offshore wind)

Grid connection related costs were explained as being an increasingly important element in terms of spend, because new proposed developments in the pipeline are further from shore, which means their OFTO related costs will be higher in future.

Others raised related points where they agreed with the policy rationale behind the MDD requirement, in terms of there being a need for projects to demonstrate commitment to implement the contract, and not needlessly delay the operational phase, but that spending 10% of project pre-commissioning costs was not a necessary measure to use.

As a developer of £multi-billion projects, we would expect that proving we had signed supply and construction contracts to be a sufficient sign of commitment, without also having to have made 10% expenditure against them in 12 months. Once we have undergone investment in pre-development phase, and signed a CfD contract, including its supply chain plan, I can assure you that means we are all in (committed).

The Longstop Date[39] linked to the Target Commissioning Window[40] is also a sufficient disincentive against deliberately delaying a project. The economic case for the project will be based around the 15-year CfD guarantee, so the developer will do everything in their power to ensure they don't start eroding the timescale of that CfD.
(Developer, Offshore wind)

39 **Longstop Date** – This date is specified in each contract and is the last date by which the generator's project must achieve its required minimum generation capacity. It is generally 12 months after the end of the Target Commissioning Window for onshore technologies and 24 months for offshore wind.

40 **Target Commissioning Window (TCW)** – The TCW is the period during which the generator is obliged to fulfil all its Operational Conditions Precedents, one of which is a requirement to achieve 80% of the project's required generation capacity. The generator must achieve this level before it is entitled to issue a start date notice under the CfD, triggering its entitlement to CfD payments. If the generator does not fulfil its Operational Conditions Precedent by the end of the TCW, its entitlement to CfD support payments will reduce day for day for each day of delay in fulfilling this requirement.

4. Impact of CfD Scheme Design Features

Key findings:

Developers views on pot structure differed according to a range of contextual factors, including: the type of technology they primarily develop, whether they also developed Pot 1 technologies, and whether they had previously been unsuccessful in bidding for CfD in a Pot 2 auction.

Most developers agreed with the policy rationale for having a separate Pot for less established technologies. There was support for the overall theory of change that this supported the commercial scale-up and cost reduction of certain technologies, particularly given the success of Offshore wind.

Some respondents stated that the Pot 2 structure does not take sufficient account of the different levels of development between less established technologies in Pot 2, or for other emerging technologies not yet included in Pot 2. It was therefore felt that there was a gap in subsidy provision to support commercialisation of new emerging technologies.

There was no consensus as to the best solution, but various suggestions were raised around either creating a new “innovation pot” or using the policy tools that already exist within the CfD regulations more directly to support a wider range of technologies (for example, by setting minimum and maximum MW limits for different technologies and different administrative strike prices).

Views on preference towards pay-as-clear or pay-as-bid auction bidding mechanisms were varied. Some felt that pay-as-clear offers more risk to developers, given the potential to lose out on the contract due to strategic bidding from competitors. It was also considered a risk to increasing overall levels of subsidy, given the mechanism to raise prices from those who had bid low to the clearing price. Others felt that pay-as-clear generally worked well, and that as it was now well established and understood by participants, it was not an aspect of CfD scheme design they felt should be changed.

Introduction

Developers were asked to explain what wider impacts certain aspects of the CfD scheme’s design had for the development of renewable technologies in their sector. The main design features explored were:

- Pot Structure (the types of technologies included within Pot 1 and Pot 2)

- The frequency of Allocation Rounds
- Implications of the "pay-as-clear" bidding process (in comparison to "pay-as-bid" which is used in renewable energy auctions of some other countries).

Pot Structure

In previous auctions, technologies have been divided into two pots:

- **Pot 1** - 'Established' technologies including: Onshore Wind (>5 MW), Solar-PV (>5 MW), Energy from Waste with CHP, Hydro (>5 MW and <50 MW), and Landfill Gas and Sewage Gas
- **Pot 2** - 'Less established' technologies, including: Advanced Conversion Technologies, Anaerobic Digestion (>5 MW), Dedicated Biomass with CHP, Geothermal, Offshore Wind, Tidal Stream, and Wave.

Interviews with developers asked questions around; to what extent and how have Pot 2 auctions led to greater developments in the less established technologies?

The response from developers differed according to a range of **contextual factors**, including: the type of technology they primarily develop, whether they also developed Pot 1 technologies, and whether they had previously been unsuccessful in bidding for CfD in a Pot 2 auction.

Success of Offshore wind

First, **most developers agreed** with the policy rationale for **having a separate Pot in which emerging technologies** do not have to compete with mature technologies. There was support for the overall theory of change that this supported the commercial scale-up and cost reduction of certain technologies. Support for the design of Pot 2 was greater among developers of Offshore wind projects.

The way that it was designed at the start makes sense. The Pot 1 and Pot 2 split made sense in terms of allowing more subsidy for emerging technologies. (Offshore wind developer)

It (Pot 2) has been very successful in terms of stimulating investment in Offshore wind, and that's the main success story of CfDs. (Offshore wind developer)

While the Pot 2 structure was almost unanimously viewed as being beneficial for supporting the earlier deployment of Offshore wind, points were raised around the implications of previous periods of uncertainty over how frequently Pot 2 Allocation Rounds were expected to be run. The third CfD Pot 2 Allocation Round was opened in May 2019, with the intention to hold Allocation Rounds every two years thereafter.

Looking retrospectively over the past few years, there have been periods of uncertainty for Offshore wind as well. For example, after AR1 there wasn't much certainty over when the next allocation round would be or how frequent they would be thereafter. We operate in a global market for investing in Offshore wind. So, our company board will look at which countries have the best forward visibility over their regulatory framework and where the best support levels are likely to be. During periods of uncertainty in the UK, decisions can be taken to prioritise investment elsewhere.
(Offshore wind developer)

Extent of support for other less established technologies
Certain CfD scheme design features also impacted on supporting or inhibiting other emerging market technologies. In particular, the case of marine technologies can be highlighted.

In AR1, there was a ringfence for up to 100MW for marine technologies. Representatives from the marine technologies sector that were interviewed explained that the industry expected a similar level of ringfenced support, with a higher administrative strike price, in AR2, as a replacement for the enhanced RO banding[41]. At the time of AR2, marine technologies such as Tidal Stream were not as cost competitive as Offshore wind. However, respondents claimed they offered wider benefits (a more stable form of supply than intermittent Offshore wind), as well as potential cost reductions, and therefore it was felt that there was merit in continuing additional subsidy in the shorter term.

In AR1, we did not bid for the CfD because the project was not quite ready, and because it was assumed the next Allocation Round would include a similar ringfence for marine technologies. It never occurred to us that there would be a complete reversal on policy on support for marine technology. We had ten years of support through innovation grants, loans and ROs. This helped the UK become the world leader in development of marine energy. The sector was becoming successful, so it didn't occur to us that subsidy support would end, but then they suddenly just dropped all support from CfD AR2.

There have been absolutely no new projects developed since the ringfence was dropped in CfDs, and a large number of players have left the market.

This also had impact on investment in innovation. There was a potential for large cost reduction in tidal technologies and the UK was a world leader, who could export this technology, but this opportunity has been lost.
(Developer, marine technologies)

Tidal Stream projects were still eligible to compete in AR2, but no longer received a ringfenced budget allocation. The BEIS policy position is to consider responsibility to

[41] A ROC is the certificate issued for eligible renewable electricity generated within the UK and supplied to customers in the UK. The initial default was that one ROC is issued for each megawatt-hour (MWh) of eligible renewable output. Banding was introduced in 2009 to provide differing levels of support to groups of technologies depending upon their relative maturity, development cost and associated risk.

billpayers; they are paying for an energy system that is secure, affordable and clean. At the time of AR2, Wave and Tidal Stream projects had an estimated strike price around three times higher than Offshore wind and projections suggested they would remain significantly above other renewables through the next decade and as such could not be considered affordable.

Another respondent from a large utility-backed developer explained the effect of this on their investment decisions.

> *We had previously been active in marine technologies (Wave and Tidal) but don't invest now because they are in the same Pot as Offshore wind and can't compete. Tidal technologies were really at the pre-commercialisation stage, whereas Offshore wind had already been proven and commercialised. So, they weren't competing at the same stage of the innovation and cost reduction curve. There wasn't enough diversification within the Pot 2 structure to take account of that.*
> *(Developer, multiple technologies)*

CfD eligibility and interaction with other R&D support for innovation

One of the eligibility criteria for obtaining a CfD is that the generation unit is not receiving funds under another government support scheme (the Non-Fossil Fuel Order, Capacity Market, RO, Feed-in Tariff (FiT) and, in the case of Energy from Waste with CHP projects, Renewable Heat Incentive). Once the CfD is signed, generators are required to pay back any other forms of State aid received in relation to the project costs before it can receive any CfD payments.

While respondents agreed with the rationale that projects should not be double-supported from RO or FiTs alongside CfD payments, some issues were raised around how receiving a past small scale grant for innovation work to support technology development could block projects being implemented.

> *The eligibility criteria exclude projects which have had other forms of public grants. But emerging innovative technologies need public grants to support them to develop. There are lots of projects that will have had some form of innovation grants from the EU, or the Scottish Government or other types of Government innovation funding at some stage. It doesn't make sense that projects which were successful in securing public funding for innovation, were then excluded from the CfD and effectively blocked from being implemented. (Marine technologies developer)*

Several respondents raised points around how the current Pot 2 structure does not take sufficient account of the **different levels of development** between technologies within Pot 2, or for other new emerging technologies not yet included. It was therefore felt that there was a gap in subsidy provision to support commercialisation of new technologies. There was no consensus as to the solution, but various suggestions were raised around either creating a new “innovation pot” or to use the policy tools that already exist within the CfD rules to support a wider range of technologies. For example, by setting minimum and maximum MW limits and differences in administrative strike prices.

The Pot designs do not facilitate the strategic development of the diverse technologies required for future security of supply. They cause competition between technologies with very different cost structures and levels of development, which disadvantages the less developed technologies in the Pot and limits innovation (and consequently the diversity of our future energy mix.
(Non-CfD developer, Solar-PV)

Yes, there has been an impact (on company investment in R&D). There is no support mechanism for technology which is at an earlier TRL stage (Technology Readiness Level). So, there is no business case for us, as it is very difficult to justify investment in early-stage technologies.
(Developer, multiple technologies)

Is the chosen auction type (pay-as-clear) effective in driving competition and achieving cost reductions?

Background on pay-as-clear vs pay-as-bid auction design

An important part of the auction design is the decision whether to use a 'pay-as-clear' mechanism or a 'pay-as-bid' mechanism. In a pay-as-clear mechanism, which is currently used in the CfD auction, all bidders receive the highest strike price that clears the budget. In a pay-as-bid mechanism, the bidder receives the strike price they bid. Both mechanisms have been used in other renewable energy auctions internationally. The Rapid Evidence Assessment (REA) conducted as part of the scoping phase of this study reviewed existing literature on what difference in outcomes the different approaches have achieved internationally.

Developers interviewed were asked whether they believed a pay-as-clear or pay-as-bid mechanism is preferable. They were also probed to explain whether they felt either bidding mechanism is more likely to result in strategic bidding.

Most of the successful Offshore wind developers stated they do not believe that strategic bidding was widespread in CfD auctions:

Speculative bidding is quite unlikely in Offshore wind projects – being large infrastructure projects they are very involved in community, society and government, and so are accountable to a range of stakeholders. Our business case and bid price is approved at company Board level. A strategy based on bidding low and pinning our hopes on gaining a high clearing price just would not be accepted.
(Offshore Wind developer, AR2)

Pay-as-clear has worked for Offshore Wind. I don't believe that strategic bidding is a huge concern. Most developers will not bid much below the reference price
(Developer, multiple technologies, AR1 and AR2)

However, some respondents (particularly unsuccessful applicants) indicated that concern over competition, and/or the pay-as-clear mechanism, led to submission of bids which were priced unrealistically low and the award of contracts to projects that are not financially viable to deliver:

In theory, in a perfect market, pay-as-clear and pay as bid, should give the same result. But what we've seen, particularly for solar, is that some developers have bid too low in the hope of getting a higher price at clearing, and then projects are being cancelled. I can see benefits of pay-as-clear, but perhaps there needs to be a tightening of non-delivery disincentives e.g. financial penalties like a bid bond, rather just been banned from developing on the site for a couple of years
(Investor in Solar-PV projects)

We bid at a real price that was assessed as being financially viable for the project to proceed. However, because of the way the pay-as-clear competitive auctions are run, other biomass and ACT companies bid in strategically lower. This means that they were awarded the contracts and we lost out. But they bid too low and were not viable, so many of them are now being cancelled
(Unsuccessful applicant, AR1)

Further analysis and discussion of how developers' response to the pay-as-clear auction design may have influenced bidding strategy is included in Annex C. The evidence suggests that pay-as-clear has not resulted in strategic bidding for larger projects in the Offshore wind sector. However, it may have influenced strategic bidding for smaller scale and other emerging technologies. By placing downward pressure on prices, it has also seemingly led to some project failures, with a few examples of projects either not signing contracts at the strike price offered or having been terminated due to being unable to reach FC.

The developer's perception of how severe an impact Non-Delivery Disincentives (NDD) are may also be a factor in influencing likelihood of strategic bidding. Some developers have viewed the NDD penalty as being an insufficient deterrent to their longer-term implementation plans (e.g. being excluded from developing on the site proposed for a period of 13 months[42]). For example, one proposed 15 MW Solar-PV project which was offered a CfD in AR1, declined to sign at clearing price offered and was subject to NDD penalties. However, the developer later went on to build the project by splitting it into three 5MW generation units, so that it was eligible for FITs.

Other developers with an international portfolio commented that the NDD in the CfD scheme is a relatively weak penalty in comparison to other renewable electricity auctions in other countries. This point is explored further in the REA, which gives an overview of the non-delivery disincentives that have been used in auctions internationally (such as bid

[42] 13 months was the exclusion period for AR1, which has since been amended to 24 months.

bonds or financial deposits)[43]. There was some evidence from the international review to suggest that renewable energy auctions which run pay-as-clear pricing mechanisms can achieve lower strike prices, but have higher rates of non-delivery, due to the “winners curse” of not being able to the implement the project at the strike price offered.

[43] See Rapid Evidence Assessment Annex for review of non-delivery disincentives used in other countries.

5. Value for Money

Key findings:

Based on our modelling estimates, the CfD scheme will reduce the impact of renewables deployment on consumer bills under all scenarios, as compared with the RO policy that preceded it.

The reduction in costs to the consumer due to the CfD projects auctioned in AR1 and AR2 is estimated at around **£3bn** (in present value terms) in comparison with supporting the same projects under the RO. The scenarios tested produced upper and lower bound estimates of **£1bn** and **£4bn**[44].

The lower support costs under the CfD regime are primarily driven by the lower hurdle rates assumed compared to under the RO. With projected future CfD projects (excluding nuclear and CCS) also included, the potential consumer cost savings of the CfD regime through to 2050 are estimated at around **£9bn** compared to the RO scheme, with a range of £4bn to £14bn in the scenarios tested.

Introduction

This section addresses the evaluation question *"Does the CfD scheme represent good value for money*?" To answer this question, the analysis uses the BEIS Dynamic Dispatch Model (DDM)[45]. The analysis compares the costs of supporting low-carbon deployment through the CfD regime to a counterfactual assuming the RO scheme had continued.

Approach and key assumptions

The modelling covers the period from 2016 (when the first CfD project came online) to 2050, and considers two groups of CfD supported generators:

- Generators allocated CfDs via allocation rounds 1 and 2 **(primary focus)**

[44] In Phase 2 of the CfD Evaluation this analysis was repeated to include AR3 projects based on updated 2019 assumptions of potential future wholesale electricity prices under a scenario which is consistent with the Government's commitments to Net Zero. Phase 2 analysis found a saving of around £3bn for AR1, AR2 and AR3 projects with a range of £2bn to £5bn in scenarios tested. See the CfD Phase 2 evaluation report for the full analysis: https://www.gov.uk/government/publications/evaluation-of-the-contracts-for-difference-scheme

[45] The DDM is BEIS's inhouse electricity market model used to model the GB power market over the medium to long term.

- Generators projected to be allocated CfDs in the future, based on BEIS's 2018 reference case of the DDM

Nuclear and potential future Gas CCS CfD contracts are considered outside the scope of this analysis[46], and no variation in their support is modelled.

Generators allocated a CfD contract under the FIDER (Final Investment Decision Enabling for Renewables) were assumed to have been supported under the RO scheme in the counterfactual modelling, but these projects were not a focus of the analysis as they are outside the allocation process.

The modelling **assumes that BEIS policy objectives would have remained the same** as if the RO scheme had continued. This includes the same target level of renewable deployment and the same supported technologies. As a result, the analysis focuses on the **costs of supporting the same level of deployment** under the RO scheme**,** rather than seeking to model any differences in deployment.

With the same level of deployment, **the same project costs for the supported plant** under the two regimes was also assumed. Falls in capital costs, as has recently been observed for offshore wind, are assumed to be due to the level of deployment (and wider global factors), rather than the type of low-carbon support regime.

These and other key assumptions that feed into the modelling can be found in Annex B.

Overview of Scenarios

Six comparison scenarios have been explored to understand the sensitivity of the results to key assumptions. Each of the scenarios includes a CfD baseline run and an RO counterfactual run. The scenarios are:

1. CfD baseline vs RO counterfactual under central assumptions[47]
2. CfD baseline vs RO counterfactual under low commodity prices
3. CfD baseline vs RO counterfactual under high commodity prices
4. CfD baseline vs RO counterfactual with lower hurdle rate differences (-0.5%)
5. CfD baseline vs RO counterfactual with higher hurdle rate differences (+0.5%)
6. CfD baseline vs RO counterfactual where RO support levels are higher due to lack of price discovery & competition (equivalent to a 5% rise in strike price)

[46] Nuclear have a bilateral CFD outside of the allocation process, and Gas CCS is likely to need a different form of support due to the correlation between its fuel costs and the wholesale price.

[47] Central assumptions as per BEIS 2018 reference case. Note that under central assumptions projects supported under RO were assumed to have higher hurdle rates than under CfDs

Commodity prices

Commodity prices (gas, coal and oil) are a key input assumption for the modelling. They are an important driver of wholesale electricity prices, with the gas price currently the largest single component. Commodity prices are therefore particularly important when calculating the required levels of support (RO bandings and to a lesser extent CfD strike prices), and when modelling the support payments over the course of a project's contract.

Under the CfD baseline runs commodity price projections only have a small impact when determining required strike prices, as generators are only exposed to wholesale prices after the end of their 15-year contracts. However, under the RO scheme, commodity price projections are crucial when determining the required level of support, as generators are exposed to wholesale prices throughout the contract period.

In addition, with contracts assigned, commodity prices are an important driver in the support payments modelled under the CfD regime, which vary based on fluctuations in the wholesale price (whereas support under the RO scheme is more certain).

As a result of this importance, two scenarios for variations in commodity prices have been tested. Under **Scenario 2** BEIS's low commodity price projections are used for both the CfD baseline and RO counterfactual, and under **Scenario 3** BEIS's high commodity price projections are used.

When calculating the required levels of support under these scenarios, it is important to base these calculations on what would have been a "best view" at the time the support was set. This means simulating scenarios where support levels are determined based on different prices to the prices that out-turned. For example, if calculating the required RO banding for a plant in 2020 in the low commodity price scenario, the best view would not be that the low-price projection occurs – there has not yet been enough evidence to be confident that low prices will persist. However, when calculating support levels in 2040 within the low scenario, we have now had over 20 years of low prices so would expect this trend to continue.

To deal with this problem, a blend of results from a central commodity price run and a relevant low or high commodity price run are used to form a "best view" of wholesale income in calculating support levels. The weighting of the central run in this view decreases over the years. This was parameterised using historical BEIS commodity price forecasts, which were used to analyse the correlation between changes in short-term commodity prices and changes in the long-term projections. More detail can be found in Annex B.

Hurdle rates

The hurdle rates are a key modelling assumption. In particular, it is important how they differ between the two support regimes. Lower hurdle rates are assumed under the CfD regime because of the reduced risk to investors. This is the primary driving factor in the CfD regime representing value for money relative to the RO. Evidence from the interviews corroborated the BEIS assumptions that CfD-supported plant are given lower hurdle rates than similar projects under the RO (within a range of up to 2 percentage points lower). The interviews and surveys do not provide sufficiently representative quantitative evidence to form the basis of these assumptions (though the ranges broadly align with the assumptions used). As a result, we use the latest assumptions in the 2018 BEIS reference case, and test the sensitivity of results to changes in these assumptions.

Hurdle rate changes are tested under two scenarios. Under **Scenario 4** hurdle rate differences between the two regimes are reduced by 0.5% and under **Scenario 5** they are increased by 0.5%.

Reduced price discovery and reduced competition under the RO

In addition to reduced price risks for investors that result in lower required support levels, another benefit of the CfD regime to the consumer is that competition in the auctions can allow for price discovery and drive support levels down to the true project costs.

The base-case runs do not account for this potential benefit, so this was tested under **Scenario 6**. This scenario models an increase in RO support to represent the fact that support levels may have been higher due to this reduced competition. In the base case modelling it was determined that CfD strike prices could be up to 5% higher with reduced competition. So, in this scenario a sensitivity was tested where RO banding levels are increased in the RO counterfactual so that each plant's overall income (wholesale income plus support payments) is 5% higher.

To determine the 5% assumption used in this sensitivity, an assessment was undertaken to identify the maximum increase in support levels that could be implemented in the modelling without incentivising materially more new CfD capacity (i.e. Offshore wind). This provided a scenario that was consistent with our counterfactual assumption that the same level of new capacity is procured under the RO. To do this, the difference in the strike prices required in the modelling between the last unit built and second to last unit built was assessed (as a proxy for difference between last unit and next unit that would be built). This averaged 5%. The main driver of these differences is the supply curve assumed in the 2018 BEIS reference case for capital costs – this means in any given year there may be, for example, a range of new offshore wind projects available that require between £50/MWh and £60/MWh of support.

Calculated support levels

The support levels (CfD strike prices and ROC bandings) are a key input to each run. They are calculated for each run based on model outputs of a previous run. The support levels are set to a level where the generator achieves its required hurdle rate, considering all revenues and costs over the lifetime of the project. Model runs were iterated to achieve alignment between the support levels assumed in the run and those calculated from the model run outputs.

Example of support level calculation for an illustrative Offshore Wind plant

Cashflows for an illustrative 650MW CfD-supported Offshore wind farm are shown below. It has a calculated strike price of £56.8/MWh, which allows it to cover its hurdle rate of 6.3%. Note that upfront construction costs have been excluded due to their scale.

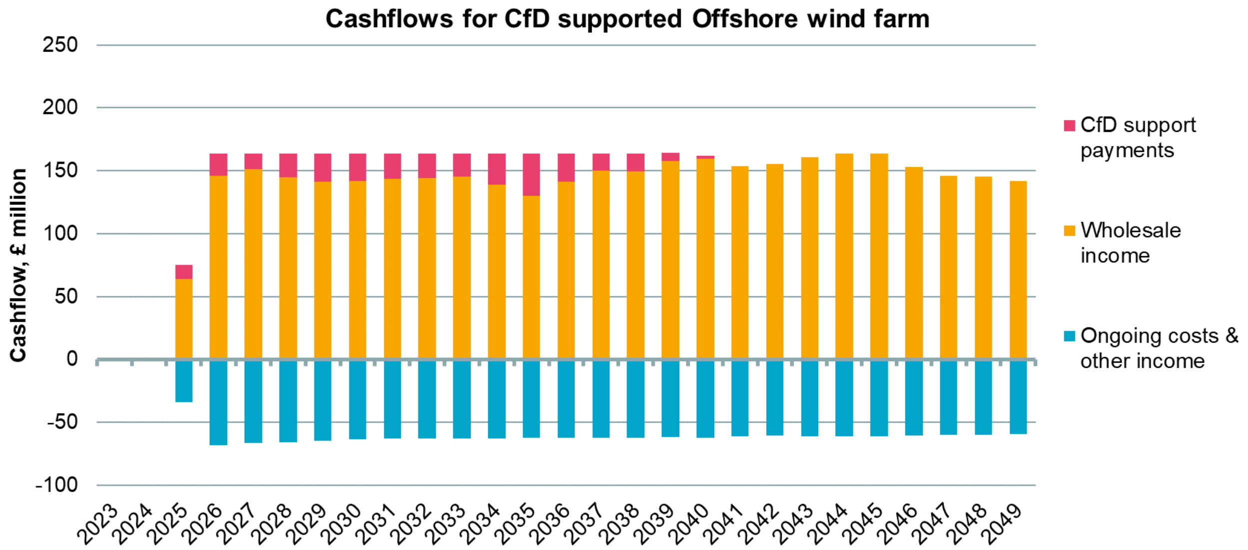

Figure 11. Cashflows for CfD supported Offshore wind farm Source: LCP analysis from DDM outputs

For the project to achieve the higher hurdle rate of 7.7% under the RO scheme, it was calculated that it would require 0.19 ROCs/MWh. The cashflows with this level of support are shown below. The support payments are significantly higher than under the CfD regime: £647m vs £282m with no discounting, and still more than double (£447m vs £215m) with a 3.5% social discount rate applied.

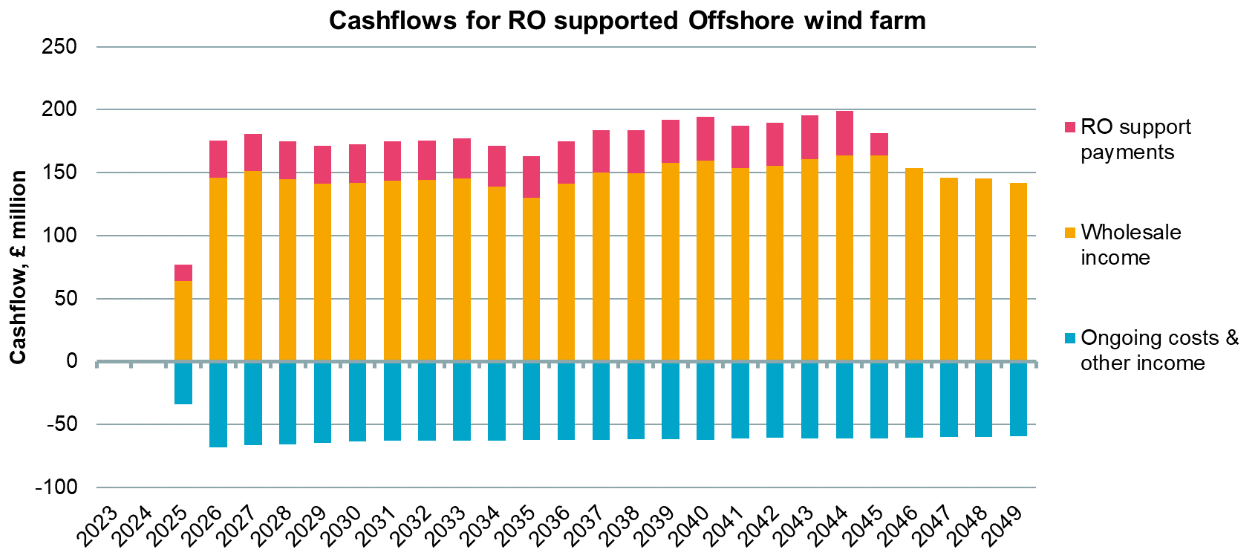

Figure 12. Cashflows for RO supported Offshore wind farm Source: LCP analysis from DDM outputs

The two sets of cashflows can also be visualised with discounting applied at their respective hurdle rates. This is shown below. The sum of these discounted cashflows is equal between the two cases (and equal to zero including all upfront construction costs which are not displayed here due to their scale).

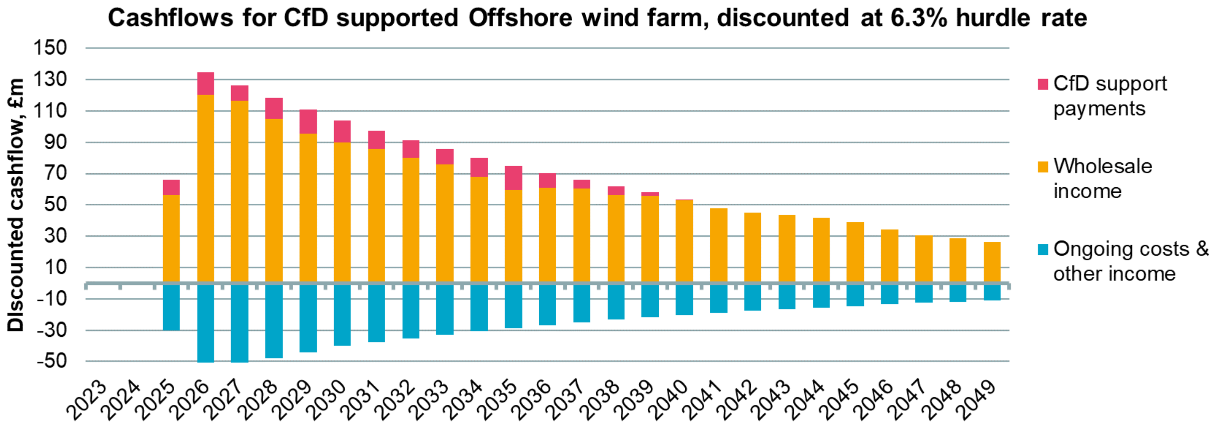

Figure 13. Cashflows for CfD supported Offshore wind farm, discounted at 6.3 % hurdle rate

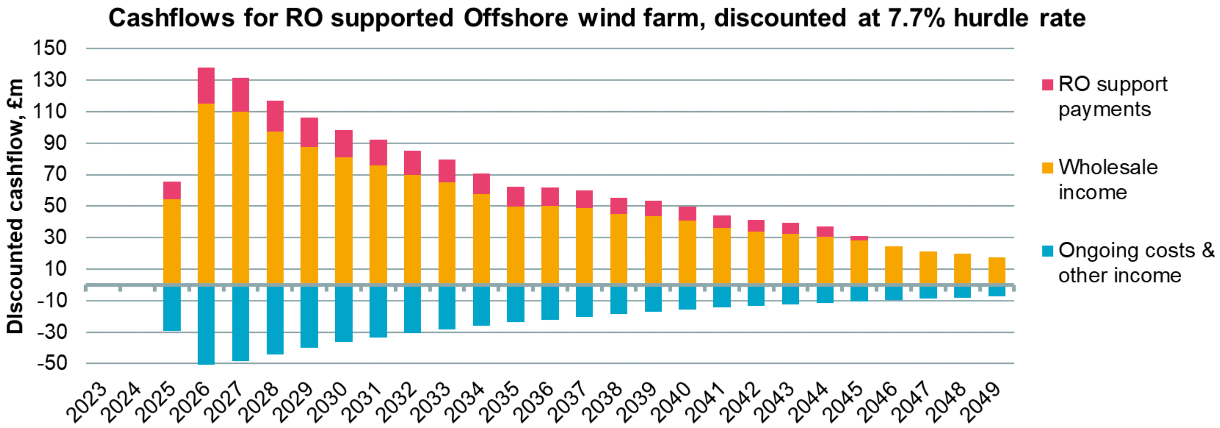

Figure 14. Cashflows for RO supported Offshore wind farm, discounted at 7.7% hurdle rate

Calculated support levels used in modelling

The calculated support levels for the CfD baseline and the RO counterfactual runs are shown below. These were calculated to incentivise an identical level of capacity in both runs.

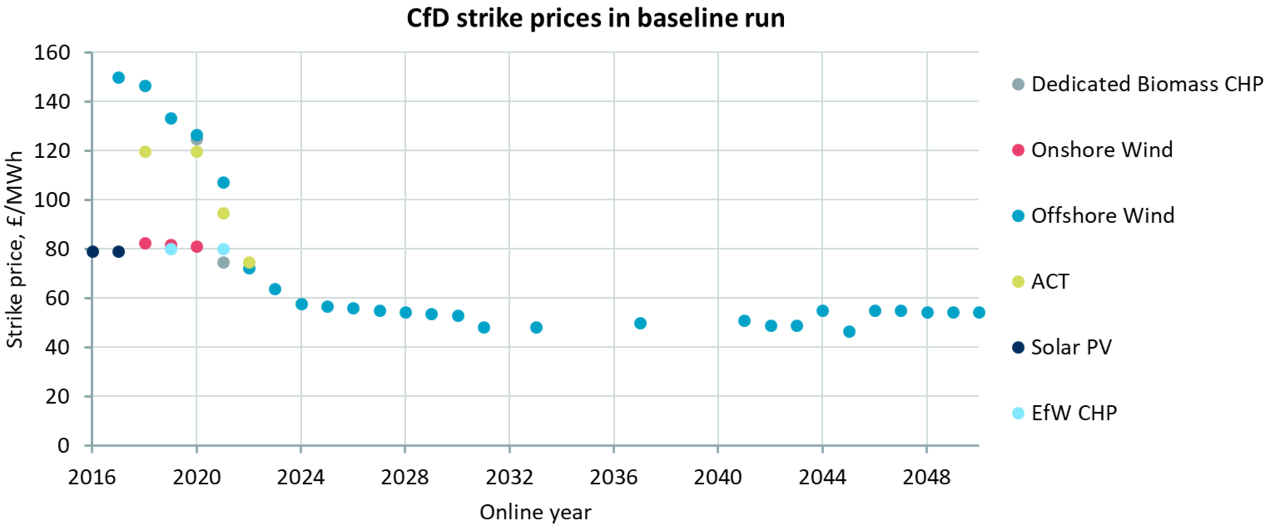

Figure 15. CfD strike prices in baseline run. Source: LCP analysis using outputs from BEIS DDM

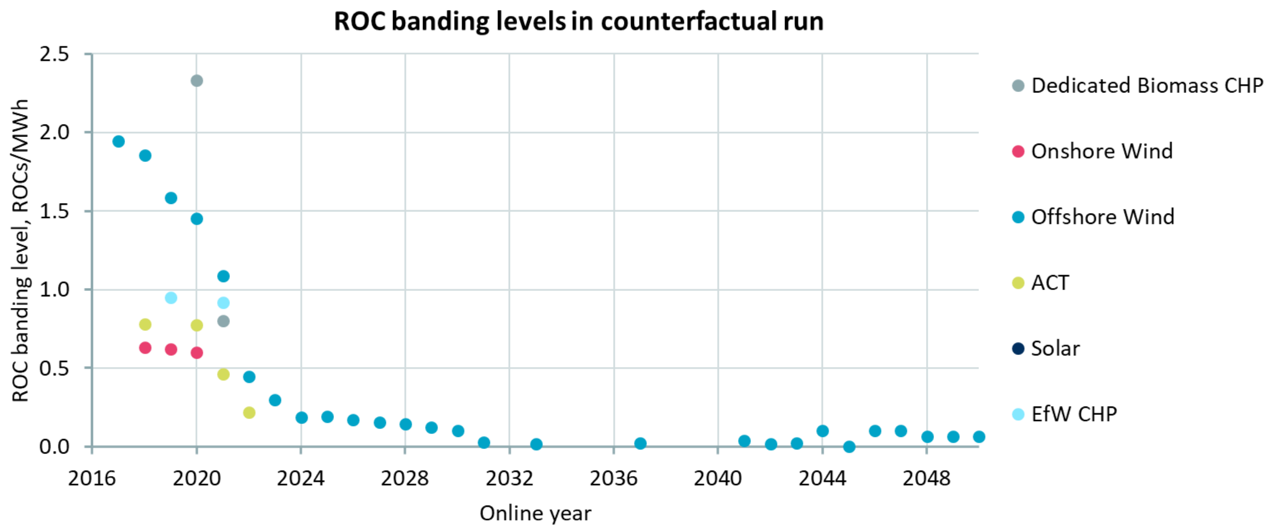

Figure 16. ROC banding levels in counterfactual run. Source: LCP analysis using outputs from BEIS DDM

Modelling results

The following sections summarise the results of the modelling. In particular, this focuses on the difference in support costs required under the two regimes.

Detailed results for Scenario 1: RO counterfactual vs CfD baseline under central assumptions

The modelling estimates that the cost of CfD support payments to the AR1 and AR2 projects under our baseline is £6bn in 2016 present value (using a 3.5% social discount rate, 2018 real). Annual support costs average about £0.6bn per year over the 2023 to 2034 period, after which costs fall sharply as projects reach the end of their 15-year contracts. Offshore wind makes up the majority of the capacity supported and is projected to make up 83% of total support costs.

These results are shown in the figure below.

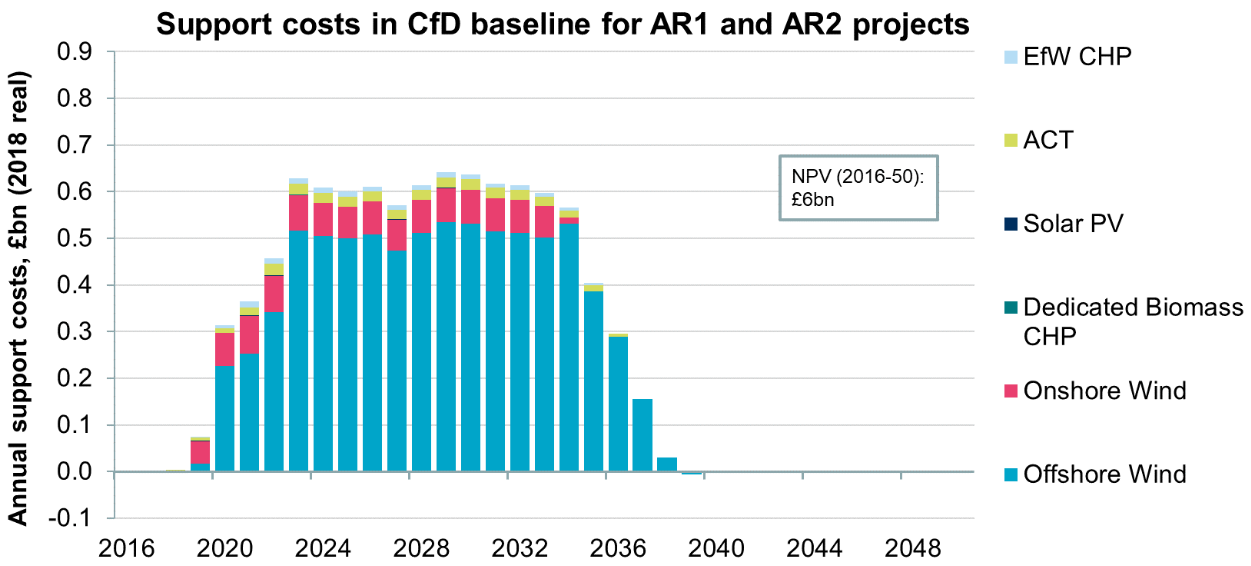

Figure 17. Modelled support costs in CfD baseline for AR1 and AR2 projects. Source: LCP analysis using BEIS DDM

Under the counterfactual scenario, where the RO scheme remains in place, support payments to the same AR1 and AR2 projects are estimated to cost £9bn (2016 present value using a 3.5% social discount rate, all in 2018 real terms). This is £3bn more than under the CfD baseline. This higher cost is driven by the higher hurdle rates assumed under the RO regime. Annual support costs are higher in most years, and occur over a longer period, due to the 20-year support contracts under RO[48]. However, it is worth noting that the RO regime protects consumers from higher subsidies if prices turn out to be lower than expected (this is explored in Scenario 3).

The two figures below show the costs under the RO counterfactual[49] and the difference in support costs to the CfD baseline.

[48] An additional benefit of the CfD regime to is that it protects consumers against higher prices, with support levels lower in these seasons/years.

[49] Note that RO buy-out prices are uprated using RPI. CPI is used for CfD strike prices and for our inflation assumption when presenting results in real terms. RPI is assumed to be higher than CPI, which is why RO support payments steadily increase over the 2025-2038 period (in real CPI terms).

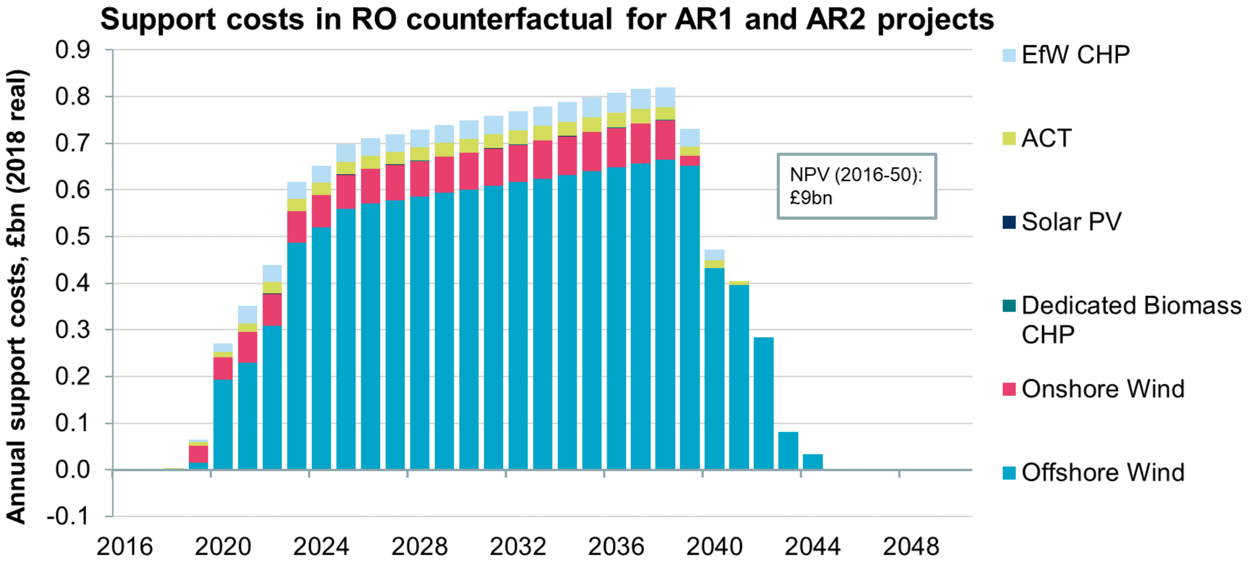

Figure 18. Modelled support costs in RO counterfactual for AR1 and AR2 projects. Source: LCP analysis using BEIS DDM

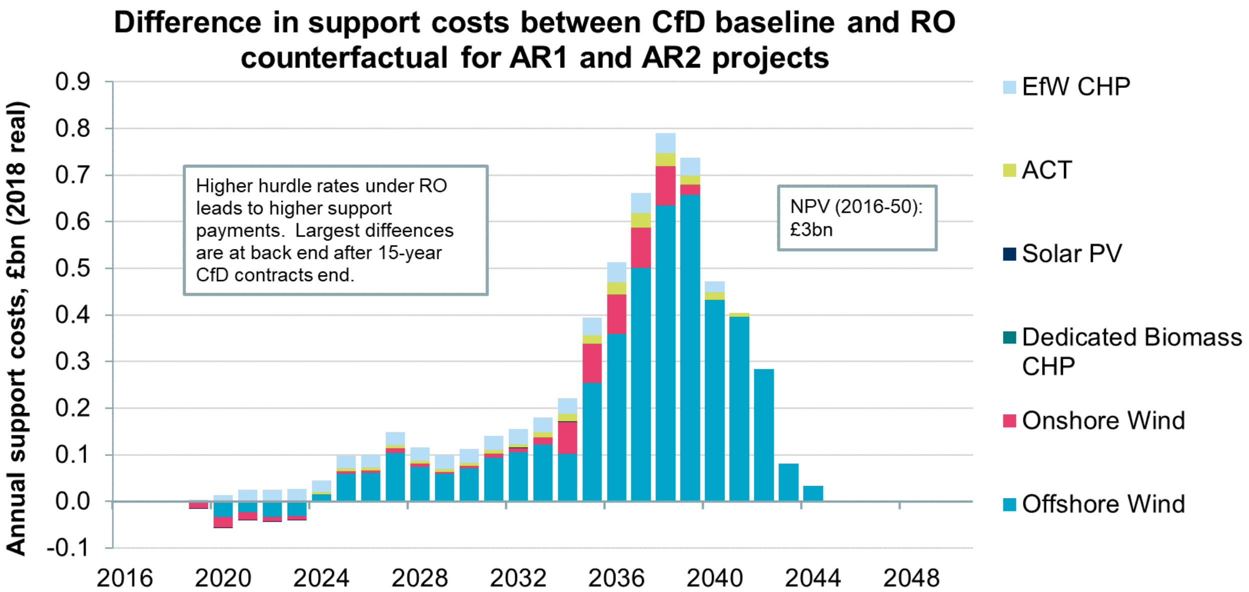

Figure 19. Difference in modelled support costs between CfD baseline and RO counterfactual for AR1 and AR2 projects. Source: LCP analysis using BEIS DDM

Note that in Figure 19 above the RO counterfactual shows lower support payments in some early years. This is due to the longer contracts (payments spread across 20 years rather than 15 years), and the RO payments trending upwards over time due to RPI indexing.

Though the projects awarded contracts under AR1 and AR2 were the main focus of the analysis, the change in support costs for future CfD projects (as projected in the latest reference case BEIS) were also assessed, under the same counterfactual where the RO scheme had continued. Assessment of the difference in support costs associated with all AR and future CfD-supported projects contained in the latest BEIS reference case (excluding nuclear and Gas CCS) are shown below.

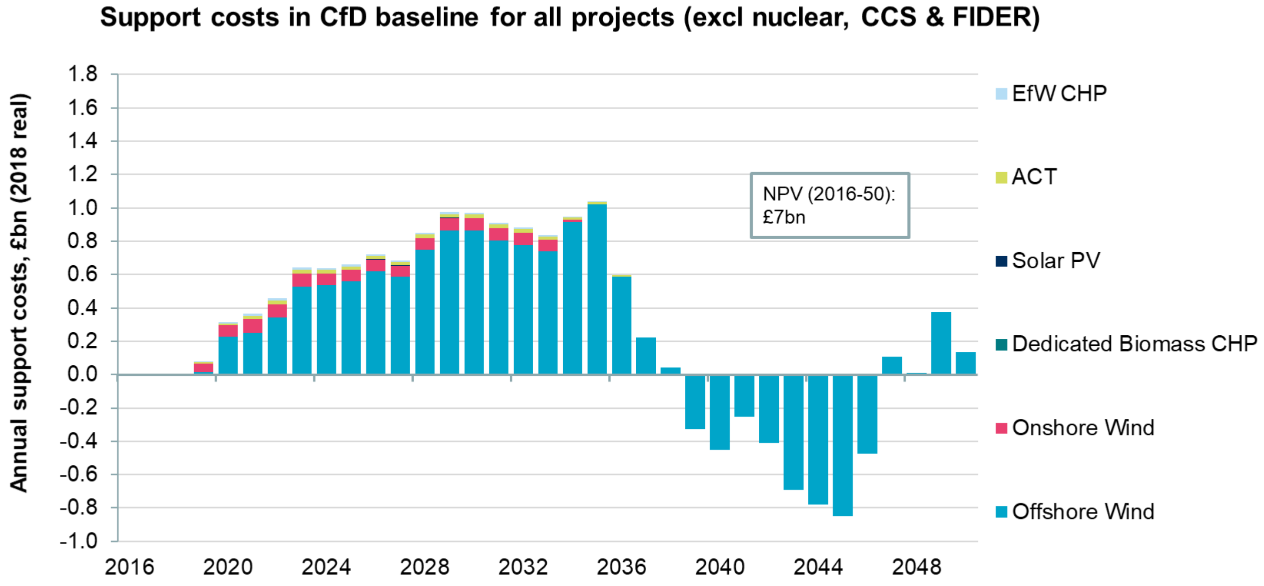

Figure 20. Modelled support costs in CfD baseline for all supported projects (excl. nuclear, Gas CCS and FIDER). Source: LCP analysis using BEIS DDM

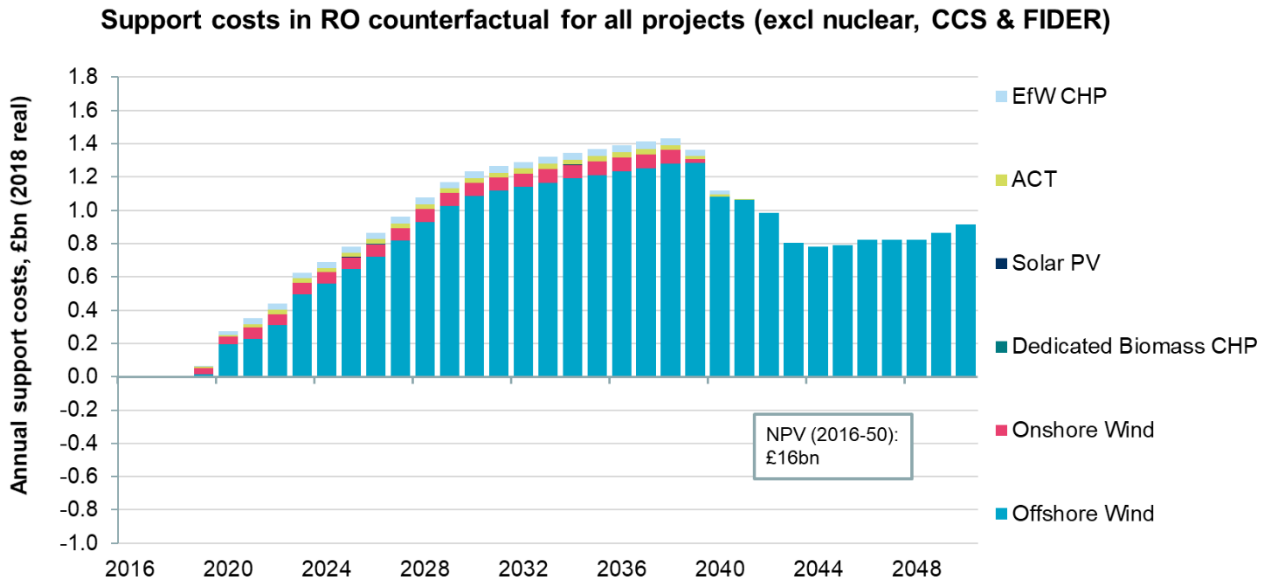

Figure 21. Modelled support costs in RO counterfactual for all supported projects (excl. nuclear, Gas CCS and FIDER). Source: LCP analysis using BEIS DDM

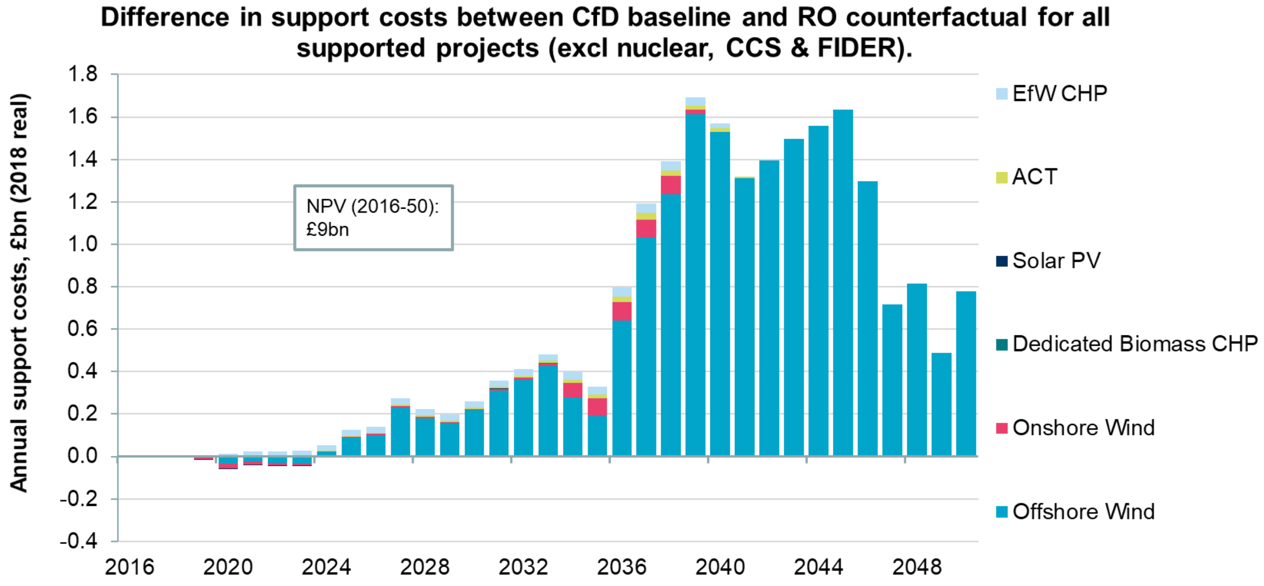

Figure 22. Difference in support costs between CfD baseline and RO counterfactual for all supported projects (excl. nuclear, Gas CCS and FIDER). Source: LCP analysis using BEIS DDM

Given the lower hurdle rate assumptions, the **modelling shows lower support costs under the CfD regime than under the RO, with £9bn in savings over the 2016-2050 period** (discounted to 2016 at 3.5%). Under the CfD regime, support costs for offshore wind in the 2040s fall below zero in some years, as strike prices are lower than their captured wholesale prices.

It is assumed that plant are still willing to take these strike prices as they provide the plant with a greater risk-adjusted return than operating with no support due to the lower assumed hurdle rates.

Summary of results for all scenarios

The table below summarises the results of each of the six scenarios. It shows the change in support costs associated with moving from the baseline (with CfD regime in place) to a counterfactual under which the RO scheme had continued. These changes are represented as £bn NPV figures for the 2016-2050 period (using a 3.5% social discount rate) in real 2018 terms.

All six scenarios show an increase in support costs under the counterfactual where the RO had remained in place, indicating that the CfD regime represents value for money. The main reason for this is the higher hurdle rates assumed under the RO regime.

NPV £bn real 2018 (2016-2050)	Scenario					
	1	2	3	4	5	6
Baseline run	CfD central	CfD high commodity prices	CfD low commodity prices	CfD central	CfD central	CfD central
Counterfactual run	RO central	RO high commodity prices	RO low commodity prices	RO +0.5% hurdle rate	RO -0.5% hurdle rate	RO reduced competition
AR1 support cost	2	2	1	2	1	2
AR2 support cost	1	1	0	1	1	2
AR1+AR2 support cost	**3**	**4**	**1**	**3**	**2**	**4**
Future projects support cost (excl. FIDER, Nuclear & CCS)	6	10	3	8	4	10
Total support cost impact	**9**	**14**	**4**	**12**	**6**	**14**

Table 5. Scenario results: Change in support costs under RO counterfactual. NPV for 2016 to 2050 period in £bn 2018 real. Note: All figures have been rounded to the nearest £bn, so the figures presented may not add up precisely to column totals. Source: LCP analysis using BEIS DDM

AR1 and AR2 – consumer cost impact

Support payments to AR1 and AR2 projects are higher under the RO counterfactual by between £1bn and £4bn across the scenarios, with an increase of £3bn in the central scenario.

The lowest increase is in the low commodity price scenario, where lower wholesale prices mean CfD top-up payments are higher. Conversely, the highest increase (£4bn) is in the high commodity price scenario, were CfD top-up payments are lower. Scenario 6 also shows an increase of £4bn, showing the impact of an increase in RO support (equivalent to a 5% increase in strike price), that may occur due to decreased competition under the RO regime in comparison to the CfD regime.

Total consumer impact – all projects

The increase in support costs in the counterfactual where all CfD projects through to 2050 (excluding FIDER, nuclear and CCS) are supported under the RO scheme ranges from £4bn to £14bn across the six scenarios.

Future projects (£3bn to £10bn) make up the majority portion of the cost increase, but this is relatively low compared to AR1 and AR2 on a per MW basis. This is partly due to effects of discounting and partly due to some payments to these projects occurring beyond the 2050 modelling horizon. However, the main reason is that the future projects plants require lower levels of support under both regimes, and this reduces the magnitude of the differences between the two regimes.

Comparing scenario 1 with scenarios 2 and 3 highlights the issues associated with price uncertainty under the different regimes. In the high prices scenario, CfD savings are higher than in the central scenario by £5bn (£14bn - £9bn), while in the low prices scenario, CfD savings are £5bn lower than the central scenario (£9bn - £4bn), but still represent a saving compared with the RO. This is because CfD support costs are higher under the low price scenario and lower under a high price scenario. There is less variation in RO support costs across the price scenarios, and consumers more exposed to unanticipated wholesale price movements under the RO regime.

Limitations of this analysis

As with all modelling of future outcomes, there is a significant degree of uncertainty in the projections. To understand this uncertainty, variations in the key assumptions that drive the differences between the costs of the two regimes, such as hurdle rate differences and wholesale price levels have been tested.

However, several uncertainties remain. This analysis has focused on estimating the changes in cost of supporting a fixed level of low-carbon deployment under the two regimes. The level of deployment, and the mix of technologies deployed, has been held constant, in line with BEIS's latest reference case. The magnitude of the savings under the CfD scheme would likely vary materially under a different level and mix of low-carbon deployment.

7. Conclusions

As this evaluation forms part of a 5-year Post Implementation Review of the EMR and CfD scheme regulations, the overarching aim was to assess the extent to which the CfD scheme is on track to meet its objectives. Five high-level questions have been used to assess this:

1. To what extent, how and why is the CfD scheme contributing to its intended objectives, and do its outcomes, both intended and unintended, differ for different groups?

The core objectives of the CfD scheme include: giving investors the confidence they need to invest in UK renewable energy projects; and to attract greater investment at a lower cost of capital and from a wider pool of sources. This aims to support increased supply of renewable electricity, whilst delivering value-for-money for consumers.

When comparing the CfD with the RO, the evidence from this study suggests the scheme is meeting the above objectives. From interviews with developers, there was strong support for the scheme's theory of change that the **offer of a 15-year price stabilisation contract reduced risks for investors** by reducing exposure to wholesale price volatility, which lowered hurdle rates for developers. This was reported to have increased access to the provision of finance from a **wider pool of investors**, resulting in competition among lenders and more attractive interest rates being offered.

The resulting lower cost of capital is a key driver behind estimates that the CfD scheme will reduce costs of AR1 and AR2 capacity to consumers by **around £3bn** (in present value terms) up to 2050, in comparison with a counterfactual scenario where the RO continued. The scenarios tested show a range of £1bn to £4bn in this estimate. Therefore, the scheme is on track to meet its objectives of **delivering value for money for consumers**.

Reductions in costs of capital were reported as being one of the contributory factors from the schemes' design that led to the significant reduction in strike prices between Allocation Rounds 1 and 2 (in addition to international trends of reduced LCOE for these technologies). Other CfD drivers of cost reduction (in comparison to the RO) identified in the evaluation include:

- The competitive pressure generated by auctions, which encourages developers to bid at the lowest prices they can afford to deliver in order to increase the likelihood of winning contracts
- The effect of reducing risks to investors encouraged multi-national developers of Offshore wind projects to scale-up their investment in the UK. This has attracted interest from developers / investors around the world, increased competition overall,

causing bidders to search for the most cost-effective combinations, innovative solutions and improved productivity in general
- The response from manufacturers in the wider supply chain (particularly Offshore wind) to support developers in winning contracts for larger scale Offshore projects at competitive prices, encouraged innovation and drove further cost reductions.

The impact of the CfD scheme in supporting investment and cost reduction in Offshore wind was described by developers as its main success story. Developers of other technologies reported similar positive outcomes in terms of reducing project costs of capital, among those who had won a CfD. However, the extent to which the CfD scheme has increased investment in other technology sectors varied according to the level of opportunity available to those technologies to be allocated a contract. For example, there have been no opportunities for technologies in Pot 1 to win a contract since AR1.

Certain aspects of the scheme's design have led to different outcomes for different groups, such as the separation of different technologies into different Pots, as well as the frequency of Allocation Rounds. This closely relates to the second high-level question:

2. Are the design parameters of the CfD scheme and auction allocations appropriate for achieving the intended objectives?

For Allocation Round 1, there was strong support for a separate Pot with higher administrative strike prices for emerging technologies. This was considered to be key in supporting the commercial scale-up and cost reduction of Offshore wind. However, this led to differences in outcomes for developers of other technologies, as summarised below.

Lack of allocation rounds for Pot 1 – Implications for cost effective deployment

The lack of allocation rounds for Pot 1 "Established Technologies" since 2015 has been followed by a **relative fall in investment for these technologies,** such as Onshore wind and Solar-PV. Some developer companies of Pot 1 technologies reported they were still actively developing projects in the UK (albeit at reduced scale) through takeover of generation units previously awarded ROCs or by exploring alternative ways to deploy without subsidy support, such as Corporate PPAs. Other companies (with a multi-national portfolio) had ceased operations in the UK and refocused investment in countries where subsidies for more established renewable technologies are still available.

It is not certain the extent to which the expected outcome was that LCOE of Solar and Onshore wind would continue to drop and they would be developed subsidy-free at the same rate without CfDs or ROC. However, this has not yet happened at any large scale for new build renewable projects, and the years since AR1 and closure of RO have been followed by a drop in investment for solar and onshore wind in the UK (it is not known how long this drop will continue, or if the Solar/Onshore sector in UK may pick up again in future).

Implications of competitive auctions for supporting innovation and future cost-reduction

Within Pot 2 "Less Established Technologies" there are differences in the extent to which they are ‘emerging’, in terms of how far each technology has progressed along the innovation and cost reduction curve. Developers of technologies that are not as advanced as Offshore wind (particularly marine technologies) reported that being grouped together in the same pot meant they could not win contracts, as they needed a higher strike price in order to deliver their project.

Several organisations reported that having been unable to win CfD contracts, they were no longer able to secure investment to support deployment and had to put their development efforts on hold. This may not necessarily be considered an “unintended outcome”, given a priority was to reduce the costs of renewables to consumers through competitive allocation that brought forward the most cost-effective technologies.

Developers of most technologies reported that the design parameters of the scheme were not conducive to supporting investment in R&D and technologies at the pre-commercialisation stage, given they have higher costs and are less likely to win CfDs under the current Pot structure. This was reported to have led to a de-prioritisation of spend for innovation in less developed technologies, with the scheme not providing a pathway for their commercialisation.

The focus on awarding contracts to projects with lowest costs in AR1 and AR2 has supported delivering value for money for consumers, in the short term at least. However, developers felt that there was a current gap in subsidy provision to support commercialisation of newer emerging technologies, with the potential greater cost reduction in the future, possibly undermining opportunities to secure even greater value for money in the longer term.

Stakeholders’ suggestions included either creating a new “Innovation Pot” or using the policy tools that already exist within the CfD regulations more directly to support a wider range of technologies. For example, by setting minimum and maximum MW limits and different administrative strike prices.

3. Is the CfD scheme being delivered as intended?

CfD contractual obligations ensure that developers deliver their contracted generation capacity within a specified timeframe.

Milestone Delivery Dates – effects on procurement practices

Meeting the Milestone Delivery Date (MDD) requirement raised a number of challenges; some of which had general consensus across developers of all technologies, and others were context specific to the size of the firm and the extent to which they had access to finance to pay for construction works prior to project Financial Close (FC).

The purpose of MDD requirements is to deter speculative bids from bed-blocking LCF funds and ensure that CfD projects begin generating within their contracted timescales. However, the 12-month window was generally considered too short to complete sufficient development work to have reached 10% of total costs. The threshold was considered too high and could lead to inefficient procurement practices that could reduce quality and or value for money. For example, several developers report paying contractors large sums for the costs of construction work in advance.

The first 12 months of the contract period is still part of the preparatory phase. Most developers will not complete project FC negotiations with their investors until months after signing the CfD.

In addition to the problems with the required expenditure profile, the MDD can pose financing problems for smaller developers. For smaller firms with less internal capital, it can be difficult to fund the scale of the development work required by the MDD from their own balance sheets. Using debt finance to pay for this work was also problematic as the loans need to be secured and interest rates can be prohibitive. Particularly when considering the implication of not meeting the MDD, which may ultimately lead to contract termination and the loss of the future revenue stream that was used to justify the loan. For developers of Offshore wind farms, a challenge was to deliver the large scale of development work required within 12 months, and the administrative burden of collating financial information to demonstrate 10% had been spent during auditing.

Another potential unintended consequence of the MDD is that some developers reported it may result in planning to condense development work within this 12-month period. However, this means that pre-development feasibility work may be delayed until after contract award (such as expensive offshore underwater surveys and more detailed engineering design work), posing some construction risks and cost uncertainties.

Despite such challenges, the majority of projects awarded contracts through AR1 and AR2 are currently on track to be delivered. Seven projects that were initially awarded contracts have failed to proceed either through refusal to sign the contract (due to the strike price offered) or having their contract terminated as a result of missing the MDD target. However, these projects represent around only 4% of the total generation capacity of awarded contracts. Therefore, **most projects are currently progressing to implement their contracts as intended.**

4. Does the CfD scheme present good value for money?

The BEIS Dynamic Dispatch Model (DDM) was used to model the costs of supporting low-carbon deployment through the CfD regime in comparison to continuing the RO scheme from 2016.

It is estimated that the CfD scheme will reduce costs of AR1 and AR2 projects, to consumers by **around £3bn** (in present value terms) up to 2050, in comparison a counterfactual scenario where the RO continued. The scenarios tested show a range of £1bn to £4bn in this estimate.

With projected future CfD projects (excluding nuclear and gas CCS) also included, consumer cost savings from the CfD regime are estimated at **£9bn** compared to the RO scheme, with a range of £4bn to £14bn in the scenarios tested. This suggests the scheme has **met its intended objectives of delivering value for money for consumers.**

5. What are the implications of the findings for the future contribution of renewable technology to the Electricity Market?

This question was not fully addressed in Phase 1 of the evaluation as this will form the basis of an overall synthesis of outcomes achieved by the CfD scheme in the third Phase of the evaluation. By 2020, the extent to which AR1 and AR2 projects are on track to delivering their intended installed generation capacity will be clearer.

However, from the January 2019 CfD Register, the list of all currently contracted CfD units from **AR1 and AR2 have a combined total installed generation capacity of 5.26 GW**. This compares to 5.48 GW total capacity which was initially awarded in Allocation Rounds 1 and 2 (2.14 GW in AR1 and 3.35 GW in AR2)[50]. Therefore, around **96% of initially awarded capacity is on track to be delivered**. Around 1GW of capacity is expected to be operational by 2019.

The UK is currently forecast to meet the aim of generating 30% of electricity from renewable sources by 2020. By then, auctioned CfD projects will provide 1.3%[51] of the UK's total electricity generation (as most units will become operational after 2020). By 2025, the auctioned CfD generation will, in a central commodity price scenario, account for around 6% of all electricity generation in Great Britain. This corresponds to over 21TWh per annum.

Next Steps

A planned Phase 2 of the evaluation will assess the experiences of participants in AR3, which opened in May 2019. A third and final Phase of the evaluation will provide an overall synthesis of evidence on impacts of the scheme across all three Allocations Rounds, in 2020.

[50] Due to rounding the totals presented for AR1 and AR2 do not add up to 5.48 GW
[51] Based on the January 2019 CfD Register

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