Oxera

Assessment of draft Contracts-for-Difference strike prices and contract terms

Analysis to inform DECC's consultation on the draft Electricity Market Reform Delivery Plan

Prepared for ScottishPower

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Executive summary

In introducing the feed-in tariffs with Contracts for Difference (CfDs), the government needs to design a risk and reward package to support the investment needed to deliver the objectives of its Electricity Market Reform (EMR). This means ensuring that the terms of the CfD present a 'bankable' investment instrument, while setting appropriate strike prices. In this context, Oxera has analysed the government's current draft proposals for strike prices and CfD terms, as set out in the Department of Energy and Climate Change (DECC) Consultation on the draft EMR Delivery Plan and the draft CfD terms.[1] In particular, we have analysed discounted cash flows for both onshore and offshore (Round 2 and Round 3) projects. Results from this analysis are presented in two ways:

– as **CfD strike prices** calibrated to deliver an internal rate of return (IRR) equal to the IRR available to the same project under the Renewables Obligation (RO), adjusted for DECC's assumed hurdle rate reduction;

– as the **IRR** using DECC's draft CfD strike prices, which are then compared with the hurdle rates published by DECC.[2]

Oxera has broadly replicated DECC's draft strike prices using DECC's assumptions. We then tested the sensitivity of the results to different assumptions, including power price forecasts, inflation expectations, and cost degression pathways. Subsequently, we analysed the impact of the proposed CfD terms on value and expected returns (principally, capacity adjustment mechanism and change in law provisions) that DECC has seemingly not factored into its assessment of the draft strike prices.

Finally, we modelled the impact of indexing the strike price to the retail prices index (RPI) rather than the consumer prices index (CPI), and extending the term to 20 years from 15 years.

Are the RO and CfD schemes comparable?

We computed strike prices under the 'RO – X' methodology based on DECC's assumptions about the economics of wind projects for a project commissioning in 2016/17. These strike prices have been developed taking account of the £2.5/MWh tolerance created by the policy of rounding to the nearest £5/MWh.

We estimated necessary strike prices and tested the sensitivity to different modelling assumptions for power price forecasts, inflation, and the treatment of risk, based on the draft CfD contract terms—for example, if investors are expected to make investment decisions without the five-year foresight constraint on power prices. This results in a forecast of increasing power prices, which widens the gap between returns under the RO and under the CfD. Furthermore, conventional investment appraisal may be expected to assume that costs and revenues will increase according to RPI rather than CPI, which would also widen the gap between RO and CfD returns when the CfD strike price is indexed to CPI. In assessing project hurdle rates and net present value, investors would be expected to account for wholesale power price risk after the end of the CfD term.

[1] DECC (2013), 'Consultation on the draft Electricity Market Reform Delivery Plan', July; DECC (2013), 'Electricity Market Reform: Contract for Difference - Allocation Methodology for Renewable Generation', August 5th; draft Contract for Difference published by DECC on August 7th 2013. Available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/227071/CfD_contract__amended.pdf

[2] DECC (2013), 'Electricity Generation Costs', July.

Using alternative assumptions for power price forecasts, inflation and the treatment of risk suggests that developers seeking parity with the RO would expect a price around £9/MWh higher than the draft strike price for onshore wind. Prices lower than this could lead to developers opting for the RO in preference to the CfD.

Factoring in the expected impact of the capacity adjustment mechanism and the change in law provisions increases the required strike price for onshore wind by a further £6/MWh, resulting in a strike price of around £114/MWh based on the current terms.[3]

The impact of modifying contract terms has also been modelled. Indexing the CfD strike price to RPI instead of CPI and extending the CfD term to 20 years instead of 15 years reduces the required onshore strike price almost to the level of the published draft strike price. As the cash flows associated with these modified support payments occur relatively late in project lifetimes, these modifications would not be expected to create significant additional pressure on the Levy Control Framework. Further work to improve both the capacity adjustment mechanism and the change in law provisions could achieve risk-adjusted parity with the RO.

For offshore wind (Round 2), the cumulative impact of alternative assumptions for power price forecasts, inflation and the treatment of risk suggests that developers seeking RO parity would expect a price around £8/MWh higher than the draft strike price for offshore wind. The strike price impact of adopting the alternative assumptions is lower for offshore than onshore projects. This is because the higher revenue under the RO from removing the five-year foresight assumption is discounted at a higher hurdle rate than for onshore projects and so has a lower present value, as reflected in a smaller increase in the required CfD strike price.

Factoring in the expected impact of the capacity adjustment mechanism and the change in law provisions increases the required strike price for offshore wind by a further £7/MWh, resulting in a strike price of around £163/MWh based on the current terms.

Mitigating these effects by indexing the CfD strike price to RPI instead of CPI and extending the CfD term to 20 years instead of 15 years would more than offset these impacts and deliver a level of support broadly comparable to the RO at a strike price of £143/MWh. While this is lower than the draft strike price of £150/MWh, this needs to be viewed alongside the analysis of return rates (presented in section 4 of the report), which accounts for a wider set of factors and suggests that the current draft strike price and terms would, if extended to 20 years and RPI-indexed, deliver an IRR marginally below the offshore wind (Round 2) hurdle rate for projects commissioning in 2016/17.

Will CfDs incentivise investment?

The draft CfD strike prices and contract terms can be used to compute the IRR on onshore and offshore wind investment. The sensitivity of IRR to different modelling assumptions has been assessed.

Based on the draft strike prices, the average onshore wind project has an IRR of 6.8% after taking into account the cumulative impact of removing the five-year foresight assumption from the wholesale electricity price forecast (which would increase expected revenues once the CfD comes to an end), modelling costs and post-CfD power prices as being indexed to RPI rather than CPI, and assuming lower values for Levy Exemption Certificates (LECs). Factoring in the expected impact of the capacity adjustment mechanism and the change in law provisions further reduces the IRR of the average project to 5.9%, which is significantly below the 7.9% hurdle rate put forward by DECC. Amending the contract terms by indexing the strike price to RPI and extending the CfD term to 20 years would increase the IRR to 7.4%, which is almost enough to incentivise the planned level of deployment based on

[3] This report presents strike prices rounded to the nearest £1/MWh, and therefore individual elements may not sum to the cumulative impact presented.

2016/17 costs. However, the strike price degression from £100/MWh in 2016/17 to £95/MWh in 2017/18 would reduce returns to 6.7% for projects commissioning in 2017/18, based on current evidence that costs are unlikely to decrease over this time period.

The average offshore wind project (Round 2) has an IRR of around 8.1% after taking into account the cumulative impact of removing the five-year foresight assumption from the wholesale electricity price forecast, modelling costs and post-CfD power prices as being indexed to RPI rather than CPI, assuming lower values for LECs, and assuming power purchase agreement (PPA) discounts comparable to onshore. Factoring in the expected impact of the capacity adjustment mechanism and the current change in law provisions further reduces the IRR of the average project to 7.1%, which is significantly below the 9.6% hurdle rate put forward by DECC. Factoring in the uncertainty around the costs of offshore wind (Round 2) projects suggests that only the lowest-cost projects would be able to achieve an IRR equal to the hurdle rate, and even for these the investment decision would be finely balanced. The gap of around 440bp between the 9.6% hurdle rate and the 5.2% IRR for the highest cost offshore (Round 2) projects suggests that these projects may not be developed even if significant learning effects could be realised.

Under current proposals, the draft strike prices would be unlikely to incentivise any offshore (Round 3) projects to be developed under any scenario for costs.

Amending the contract terms for offshore wind by indexing the strike price to RPI and extending the CfD term to 20 years increases the IRR of the average Round 2 project to 9.4%, which is almost enough to incentivise the planned level of deployment based on 2016/17 costs. However, the strike price degression from £150/MWh in 2016/17 to £135/MWh in 2018/19 would reduce returns to 7.3% for projects commissioning in 2018/19. This reflects the use of a shallower cost-reduction pathway than assumed by DECC, which is more consistent with the level of offshore wind deployment envisaged in the draft EMR Delivery Plan. Restoring the IRR to the hurdle rate would require the strike price to be increased by approximately £15/MWh, which would effectively mean maintaining the 2016/17 level of £150/MWh throughout the five-year Delivery Plan period.

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1 Introduction

In this report Oxera assesses the impact of the draft strike prices of the Department of Energy and Climate Change (DECC) and contract terms for feed-in tariffs with Contracts for Difference (CfDs) on the economics of onshore (>5MW) and offshore wind (Round 2 and Round 3) projects over the first five-year Electricity Market Reform (EMR) Delivery Plan period.[4]

Specifically, Oxera has undertaken analysis to address the following questions.

– **Do the proposals meet DECC's stated objective of setting support under the CfD at 'a comparable level to that provided by the Renewables Obligation (RO) scheme taking into account the differences between the two support schemes'?**[5] Given that CfDs and the RO are anticipated to operate in parallel over the period 2014/15–2016/17, these support mechanisms will need to be broadly consistent in terms of their economic and financial attractiveness to developers and investors. In particular, achieving comparable support under these mechanisms is important to ensure a smooth transition to CfDs and reduce the risk of an investment hiatus for projects at various stages of development.

– **Do DECC's proposals deliver levels of expected return broadly equal to the technology-specific investment hurdle rates published by DECC, based on an assessment of project costs, revenues, and risks?** Given that two of the government's objectives for EMR are to 'ensure sufficient investment in sustainable low-carbon technologies' and to 'maximise benefits and minimise costs to taxpayers and consumers', expected returns to investments in low-carbon generation will need to meet the assumed hurdle rates in order to incentivise sufficient investment.[6] If expected returns are lower than those required to compensate investors for the risks of undertaking such investments, this could jeopardise the delivery of the UK's renewable energy objectives.[7] Conversely, if expected returns materially exceeded hurdle rates, the result could be over-delivery and excessive cost to consumers.

To address these questions on the economic *comparability* of the RO and CfD and the *viability* of renewable generation under the CfD, this report has analysed the impacts of both the proposed strike prices—a key driver of project revenues—and selected contract terms that would be expected to have a significant impact on the allocation of risks to developers, investors and other stakeholders. Specifically, this report has focused on the CfD term, strike price indexation, capacity adjustment proposals, and change in law provisions.

The report is structured as follows:

– section 2 describes the methodology and key assumptions;
– section 3 presents evidence on whether support under the RO and CfD schemes is comparable;

[4] DECC (2013), 'Consultation on the draft Electricity Market Reform Delivery Plan', July.

[5] DECC (2013), 'Consultation on the draft Electricity Market Reform Delivery Plan', July, p. 24.

[6] DECC (2013), 'Consultation on the draft Electricity Market Reform Delivery Plan', July, pp. 11–12.

[7] A driver of whether this target is met is what proportion of available low-carbon generation projects is economically viable at the level of DECC's proposed CfD strike prices and with the proposed CfD contract terms. Given that strike prices are currently set for specific technologies and that individual projects may differ in terms of their development costs, load factors and risks, not necessarily all projects for all technologies would need to be viable to meet the UK's energy policy objectives. In the absence of information on the distribution of costs and other relevant characteristics for the entire population of potential low-carbon generation projects, in this report we focus on analysing the expected returns to 'average' onshore and offshore (Round 2 and Round 3) wind projects.

– section 4 presents evidence on whether the CfD scheme would be expected to incentivise investment.

Appendix 1 provides further detail on the specific modelling assumptions used.

2 Methodology

The analytical approach adopted for this report is described in section 2.1, with a summary of Oxera's key modelling assumptions in section 2.2.

Summary

Oxera has analysed discounted cash flows for both onshore (>5MW) and offshore wind (Round 2 and Round 3) projects. The results from this analysis are presented in two ways:

– as CfD strike prices calibrated to achieve an internal rate of return (IRR) equivalent to that available to a similar project under the RO, adjusted for DECC's assumed hurdle reduction.

– as IRRs using DECC's proposed CfD strike prices, which are then compared to the hurdle rates published by DECC.

Oxera has broadly replicated DECC's draft strike prices and tested the sensitivity of the results to different assumptions, including power price forecasts, treatment of inflation, and cost degression pathways. We then included the impact on value and expected returns of contract terms (specifically, capacity adjustment mechanism and change in law provisions) that DECC has not factored into its analysis of draft strike prices.

Finally, we modelled the impact of indexing the strike price to the retail prices index (RPI) rather than the consumer prices index (CPI) and extending the term to 20 years from 15 years.

2.1 Analytical approach

The analysis presented in this report is based on a discounted cash-flow (DCF) model for onshore (>5MW) and offshore wind (Round 2 and Round 3) projects.

To the best of Oxera's knowledge, DECC has not published the full working models it used to calculate the proposed strike prices. Therefore, Oxera first developed a 'baseline' model to reproduce DECC's strike price proposals, using DECC's own assumptions wherever possible.[8] The baseline model was then used to test the impact of different assumptions concerning revenues, costs, and CfD contract terms.

Separate cash-flow statements were produced for representative onshore and offshore wind farms supported by either the RO or with CfDs, and a common set of cost assumptions was used.

Throughout the report, the results from Oxera's DCF model are presented in the following ways:

– as **CfD strike prices** calibrated to deliver an expected return (ie, the IRR) equal to the IRR available to the same project under the RO, adjusted for DECC's assumed hurdle reduction (to account for presumed lower risk under the CfD). This is consistent with the 'RO – X' approach outlined in DECC's draft EMR Delivery Plan consultation;[9]

– as **IRRs** using DECC's proposed CfD strike prices. Real IRRs were calculated using pre-tax cash flows expressed in constant 2012 prices to enable comparisons with DECC's published hurdle rates for onshore and offshore wind projects.

[8] Oxera's model of onshore and offshore wind CfD strike prices differs from DECC's proposed strike prices by around 1%, or approximately £1–£2/MWh. DECC's policy was to round strike prices to the nearest £5/MWh (see also Box 2.2).
[9] DECC (2013), 'Delivery Plan consultation and EMR implementation program', July 31st, slide 19.

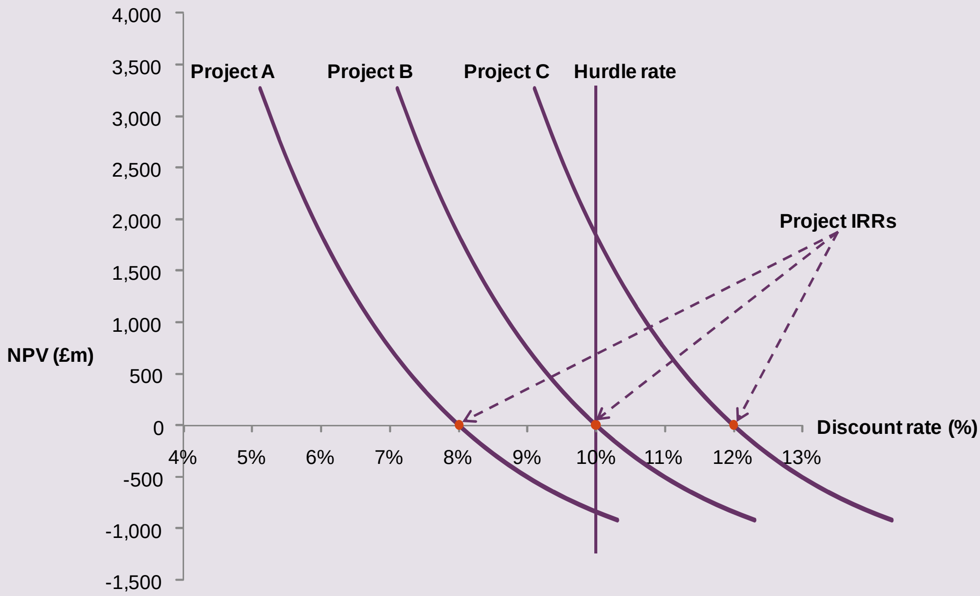
Box 2.1 provides background information that can be useful when interpreting the results shown in section 3.

Box 2.1 Illustration of results from a discounted cash-flow model

A DCF model typically includes forward-looking projections for revenues and costs that are used to calculate expected cash flows. A discount rate that reflects the rate of return required by investors to invest in a project can then be used to calculate the net present value (NPV) of the cash flows. The NPV therefore represents the value of the modelled cash flows at a given point in time. The IRR is defined as the discount rate at which the NPV of the project is zero.

In investment appraisal, a project with a NPV of zero or more would typically be considered economically viable, since this would imply that the revenues generated by the investment would at least cover its costs, including the required return on invested capital. Equivalently, any project with an IRR equal to or greater than the 'hurdle rate' (ie, the rate of return required by investors) would also be economically viable.

The relationship between NPV, IRR, the discount rate, and the hurdle rate is illustrated in the figure below. This shows three hypothetical projects with different cash flows and different IRRs; projects A, B, and C have IRRs of 8%, 10%, and 12%, respectively.



As can be seen, each point on the curved lines depicting the three projects in the above figure represents the NPV for a given discount rate. For the hurdle rate shown in the figure (in this case 10%), only projects B and C are viable since they have expected returns (IRRs) greater than or equal to the hurdle rate. Equivalently, at a discount rate of 10%, the NPVs of projects B and C are both either equal to or greater than zero, thereby confirming their viability. At a discount rate of 10%, the NPV of project A is roughly –£1,000m, indicating that this project would not be viable.

If it is assumed that the three projects depicted in the above figure differ only in their CfD strike price, it can be seen that increasing or decreasing the strike price shifts the curves (and the resulting IRRs) to the right or the left, respectively. In this way, Oxera's DCF model can be used to identify the strike price necessary to achieve a target hurdle rate.

Using the approaches described above, Oxera has analysed the sensitivity of CfD strike prices and project IRRs to a range of low-carbon generation project parameters, including assumptions on:

– factors such as wholesale power prices that affect the viability of projects under the RO and the CfD regimes differently, and hence would affect the calculation of strike prices under the RO – X approach (which was developed to ensure that risk-adjusted support available under the RO and CfD schemes was comparable);

– factors such as the inflation measure applied to costs or the pricing of Levy Exemption Certificates (LECs), which affect the economic viability of projects under both the RO and the CfD schemes equally. These factors imply that the IRR would be affected without necessarily affecting the RO–X calculation;

– the strike price degression pathway and changes in costs (eg, due to 'learning effects') that can affect the economic viability of projects under both the RO and the CfD, and which may require a higher strike price, or less aggressive degression, in order to secure investment.

Oxera's DCF modelling was also used to measure the impact on CfD strike prices and IRRs of specific CfD contract terms, including:

– penalties as a result of adjustments to plant capacity after a CfD has been granted;
– compensation for qualifying changes in law.

We also modelled the sensitivity of CfD strike prices and IRRs to changes in contract terms that could enhance the attractiveness of the risk and reward package for investors, including:

– indexation of the strike price to the RPI instead of the CPI;
– extension of a CfD contract term to 20 years instead of 15 years.

The analysis has been undertaken for both onshore and offshore wind projects (using both Round 2 and Round 3 cost assumptions). It has focused on the period from 2016/17 onwards, which is towards the end of the transition period when both the RO and CfD schemes would operate in parallel (ie, 2014/15–2016/17) and when there is the greatest practical scope for projects to exercise choice of support mechanism.

Throughout this report, 2012 prices are used and pre-tax IRRs are calculated from cash flows expressed in constant 2012 prices (unless stated otherwise), which is consistent with DECC's approach.

It is important to note that the results presented in this report need to be considered in light of DECC's strike price rounding assumptions, as explained in Box 2.2 below.

Box 2.2 Impact of rounding strike prices to the nearest £5/MWh

DECC's approach is to round strike prices to the nearest £5/MWh, and it has justified this approach by reference to the 0.1 increments/decrements used in the banding of Renewables Obligation Certificates (ROCs) (which are estimated to be worth approximately £5/MWh). This policy has two consequences.

– The unrounded strike price could be up to £2.5/MWh higher or lower than the published price. This is equivalent to around ±35 basis points (bp) on project IRR for onshore wind and ±30bp on project IRR for offshore wind (Round 2), based on Oxera modelling.
– There is a steep annual 'degression' (ie, reduction) of £10/MWh in the offshore wind strike price between 2016/17 and 2017/18. If this reduction were magnified as a result of DECC's rounding approach, project IRRs would be approximately 60bp lower than if the annual reduction was £5/MWh.

These estimates also imply that a £1/MWh change in the strike price affects the IRR by more than 10bp.

The rounding of strike prices therefore has a material impact on project IRRs, introducing uncertainty over whether marginal projects would be delivered. Moreover, from the consumer cost perspective, rounded strike prices could mean (assuming that the strike price calculation was otherwise correct) that there could be cases where materially more support is being provided than is strictly required.

Source: DECC (2013), 'Delivery Plan consultation and EMR implementation program—Annex B: strike price methodology', July 31st, and Oxera analysis.

2.2 Baseline model assumptions

Several categories of assumptions are outlined below for operational parameters, prices and revenues, costs and inflation measures used in the development of Oxera's DCF model. Additional assumptions are given in Appendix 1.

2.2.1 Operational parameters

Operational parameters relate to the timing of the projects, output, and market discounts on prices available to developers of renewable generation for ROCs, LECs, and electricity through power purchase agreements (PPAs). Although pre-development and construction times were different between onshore and offshore wind projects, all project timelines were adjusted to match a 2016 calendar year commissioning date, unless otherwise stated. The operational life for projects also follows assumptions outlined by DECC.[10]

Capacity for onshore wind projects is calculated based on DECC's notional capacity of 71.8 MW.[11] Offshore wind models use representative values of 400 MW for offshore Round 2 projects and 1,000 MW for offshore Round 3 projects based on information supplied by ScottishPower. Load factor values taken from DECC's consultation are used to generate a projected operating capacity for each plant based on a DECC assumption of 1% transmission losses (relevant for projects supported by a CfD), and no capacity adjustment factor in the baseline model.[12]

The PPA discounts for wholesale energy, ROC, LEC and CfD strike price revenues are based on the National Grid assumptions used by DECC; discounts were applied to revenues earned from the operating capacity of a plant.[13]

2.2.2 Price and revenue parameters

Price parameters relate to the projections of wholesale power, ROC, LEC values and Capacity Mechanism (CM) revenues.

In our analysis of the proposed CfD strike prices, we used three power price projections. Figure 2.1 shows the wholesale power price projections.

– The baseline model follows DECC's five-year foresight assumption, whereby real (CPI-indexed) wholesale prices are assumed to be constant from 2018/19 onwards.[14]

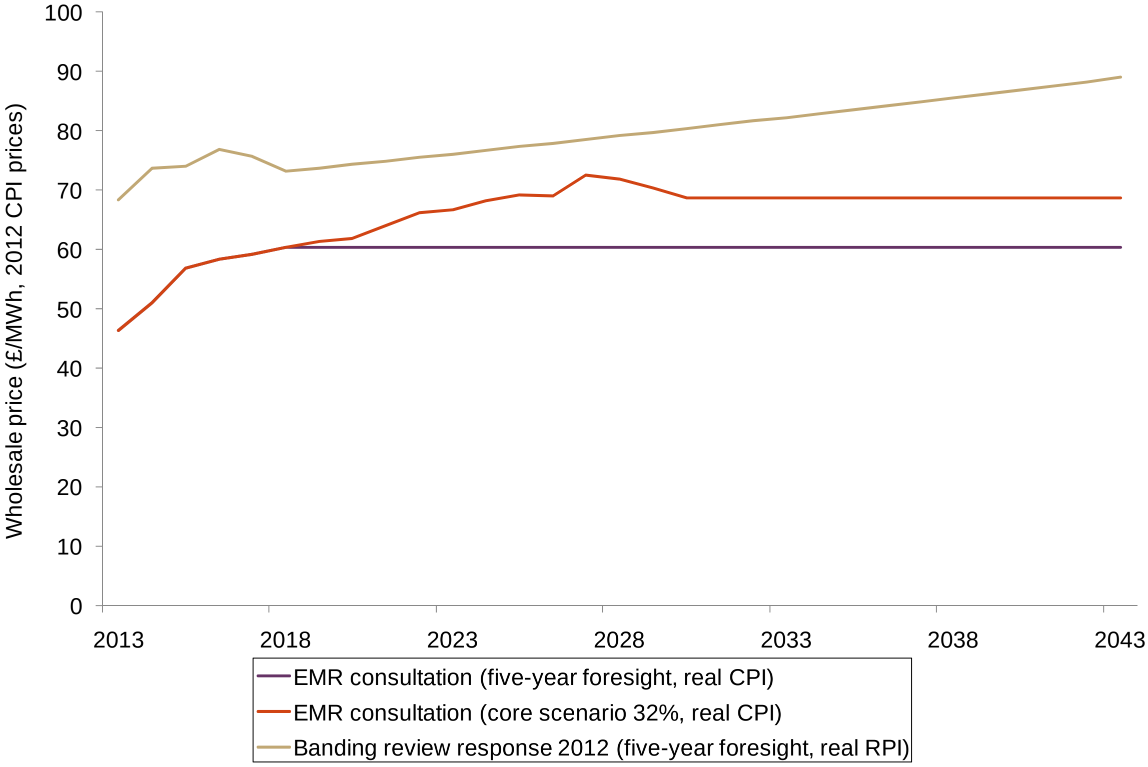
– We tested the sensitivity of the baseline to changes in the five-year foresight assumption by using DECC's own projections of rising real power prices from the '32% core renewable scenario' until 2030, with constant real (CPI-indexed) prices thereafter.[15] These projections appear themselves to be based on constant real (CPI-indexed) gas costs as a key input assumption.[16]

– A further modelling sensitivity was tested using the power price projections originally used in the RO Banding Review (ROBR), which also included a five-year foresight

[10] DECC (2013), 'Electricity Generation Costs', July.
[11] DECC (2013), 'Delivery Plan consultation and EMR implementation program', July 31st, slide 41.
[12] DECC (2013), 'Delivery Plan consultation and EMR implementation program', July 31st, slide 46.
[13] National Grid (2013), 'National Grid EMR Analytical Report', July, Annex table 7.
[14] DECC (2013), 'Delivery Plan consultation and EMR implementation program', July 31st, slide 51.
[15] National Grid (2013), 'National Grid EMR Analytical Report', July, p. 42.
[16] DECC (2012), 'DECC Fossil Fuel Price Projections', October.

assumption, but were, we understand, indexed to RPI.[17] Wholesale energy revenue is calculated based on power prices, operating capacity and a PPA discount.

Figure 2.1 Wholesale power price projections



Note: Power price forecasts for the EMR consultation were indexed to the CPI inflation measure. Power price forecasts used in the Banding Review response are assumed to have been indexed to the RPI inflation measure. The figure therefore reflects the real price effect resulting from the differences between RPI and CPI.
Source: National Grid (2013), 'National Grid EMR Analytical Report', July, Annex section 6.1.5 (underlying data was supplied in spreadsheet 'NG_Report_Data_2020_for_website.xls'); DECC (2012), 'Government response to the consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013-17 and the Renewables Obligation Order 012—Impact assessment', July 25th; Oxera analysis.

ROC values were derived from Ofgem's 2013/14 buy-out price of £42.02 per ROC, and were assumed to be held constant in real (RPI-indexed) terms.[18] The total value of a ROC was assumed to be equal to the sum of the buy-out price and the value of payments that are recycled through the ROC buy-out fund. Accordingly, ROC prices were rebased to 2012 prices using RPI and then adjusted to account for the additional 10% 'headroom' applied by the government when setting the annual level of the RO. Projects are assumed to receive ROC revenues for 20 years that were calculated based on the prevailing ROC banding level in 2016/17 (ie, 0.9 for onshore; 1.8 for offshore wind), plant operating capacity, and projected nominal ROC prices.

In Oxera's baseline model, LEC values follow DECC's assumption of £5/MWh, increasing by RPI.[19]

[17] DECC (2012), 'Government response to the consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013-17 and the Renewables Obligation Order 2012—Impact assessment', July 25th; DECC (2012), 'DECC Fossil Fuel Price Projections', July.
[18] Ofgem (2013), 'Information Note: the renewable obligation buy-out price and mutualisation ceiling 2013-2014', February 13th.
[19] DECC (2013), 'Consultation on the draft Electricity Market Reform Delivery Plan, Annex B: Strike Price Methodology', July, Box 1.

CM revenue assumptions match DECC's Delivery Plan consultation; that is, CM revenue is calculated in years in which no RO or CfD support is available for projects, based on a 22% de-rating assumption and capacity market clearing price of £25/kW.[20]

2.2.3 Costs

Baseline cost assumptions include pre-development, construction, fixed and variable OPEX. Pre-development and construction times follow DECC assumptions.[21] The phasing of pre-development and CAPEX follows DECC assumptions.[22] In scenarios where capacity is adjusted after securing a CfD (see section 3.1.4), the reduction is applied to CAPEX but not to the pre-development costs.

OPEX is based on DECC estimates, and calculated according to the operating capacity of the plant.[23]

2.2.4 Inflation

Annual RPI and CPI values were derived from several sources:

- historical values—CPI and RPI values prior to 2012 were taken from the Office for National Statistics (ONS);[24]
- medium-term forecast—CPI values from 2012 to 2016 were taken from the March 2013 Office for Budget Responsibility forecasts used by DECC, and RPI values were taken from HM Treasury;[25]
- long-term forecast—values for 2017 onwards are assumed to be constant at the Bank of England's target rate of 2% for CPI.[26] An assumption of 2.8% was used as the annual RPI inflation rate that corresponds to the 2% CPI target.[27]

In the baseline model, ROC and LEC revenues are indexed by RPI, while wholesale power prices, CM revenue, pre-development, CAPEX and OPEX are indexed by CPI.

[20] DECC (2013), 'Delivery Plan consultation and EMR implementation programme', July 31st, slide 49. These revenues are unclear owing to uncertainty over the level of capacity payments as well as plant eligibility.
[21] DECC (2013), 'Electricity Generation Costs', July.
[22] DECC (2013), 'Delivery Plan consultation and EMR implementation programme', July 31, slides 41–42.
[23] DECC (2013), 'Electricity Generation Costs', July.
[24] ONS (2013), 'Consumer Price Inflation Time Series Dataset', June, tables 5.a and 20.
[25] HM Treasury (2013), 'Forecasts for the UK Economy', May, p. 18.
[26] Bank of England (2013), 'Inflation Report', August.
[27] the differences between the RPI and CPI measures are reviewed in Miller, R. (2011), 'The long-run difference between RPI and CPI inflation', Office for Budget Responsibility working paper no. 2, November.

3 Is support under the RO and CfD schemes comparable?

As highlighted in the introduction to this report, a key question concerning DECC's draft EMR Delivery Plan is whether the draft CfD strike prices and contract terms together provide a level of support that is comparable to that provided by the RO. This section sets out Oxera's analysis of this issue in relation to onshore and offshore wind projects.

Summary

Oxera has computed strike prices under the 'RO – X' methodology based on DECC's assumptions on the economics of onshore and offshore wind projects. Strike prices estimated by Oxera are within the £2.5/MWh tolerance related to the approach of rounding draft strike prices to the nearest £5/MWh.

We estimated necessary strike prices and tested the sensitivity to different modelling assumptions for power price forecasts, inflation and the treatment of risk, based on the draft CfD terms. Investors are likely to make investment decisions without constraining their view to the five-year foresight assumed by DECC on power prices, which widens the gap between returns under the RO and under the CfD. Investors are also more likely to reflect the fact that a significant proportion of the input factors behind power prices will increase according to RPI rather than CPI, which further widens the gap between RO and CfD returns, since the CfD strike price is indexed to CPI. Moreover, when assessing hurdle rates, investors would be expected to take into account their increased exposure to wholesale power price risk after CfD expiry.

Onshore wind

Using alternative assumptions for power price forecasts, inflation and exposure to wholesale market risk suggests that investors would require a strike price £9/MWh higher than the draft strike price for onshore wind for a project commissioning in 2016/17. Prices lower than this could lead to developers opting for the RO in preference to the CfD.

Factoring in the expected risk of the proposed capacity adjustment mechanism and the change in law provisions requires a further increase in the strike price for onshore wind of £6/MWh, resulting in a strike price of around £114/MWh based on the current terms. This overall uplift on the proposed strike price is needed to deliver RO equivalence.

Offshore wind

For offshore wind (Round 2), the cumulative impact of alternative assumptions for power price forecasts, inflation and the treatment of risk suggests that developers (seeking RO equivalence) would expect a price £8/MWh higher than the draft strike price for offshore wind for a project commissioning in 2016/17.

Factoring in the expected risk of the proposed capacity adjustment mechanism and the change in law provisions requires a further increase in the strike price for offshore wind of £7/MWh, resulting in a strike price of around £163/MWh based on the current terms. This overall uplift on the proposed strike price is needed to deliver RO equivalence.

Taking account of the Levy Control Framework, Oxera has also modelled the impact of modifying contract terms. Indexing the CfD strike price to RPI instead of CPI and extending the CfD term to 20 years instead of 15 years offsets the required uplift in the onshore wind strike price almost to the level of the published draft strike price for 2016/17. For offshore wind (Round 2), these modifications to contract terms would deliver a level of support broadly comparable to the RO at a strike price of around £143/MWh. While this is lower than the draft strike price of £150/MWh, this needs to be viewed alongside the analysis of IRRs in section 4, which accounts for a wider set of factors and suggests that, even with RPI indexation and a 20-year term, the current draft strike price and terms would deliver an IRR marginally below the offshore wind (Round 2) hurdle rate for projects commissioning in 2016/17.

As the cash flows associated with these modified support payments occur relatively late in the project lifetimes, these modifications would not create significant additional pressure on the Levy Control Framework to 2020.

3.1 Analysis of CfD strike prices

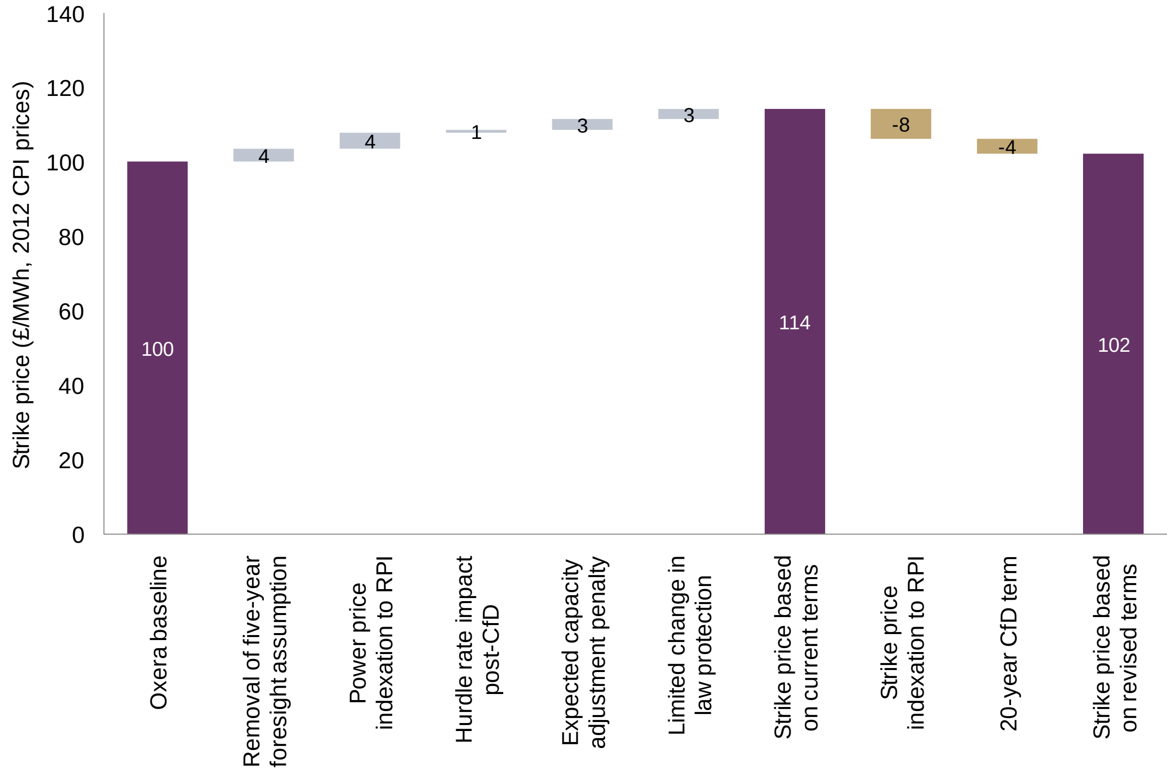
DECC has drawn on a variety of evidence to form the assumptions behind the published draft strike prices. As the available evidence supports a range of modelling assumptions, some judgement must be exercised to settle on a particular set of values from which the final strike prices can be calculated. Accordingly, Oxera's analysis has tested the impact of key assumptions used by DECC, as well as the proposed CfD contract terms on strike prices.

Figures 3.1 and 3.2 show the CfD strike prices required for projects commissioning in 2016/17 to deliver expected returns equal to those available to the same project under the RO (adjusted for DECC's assumed hurdle rate reduction owing to the presumed lower investment risk under the CfD). As described in section 2.1, this approach is consistent with DECC's RO – X methodology.

Specifically, Figure 3.1 indicates that DECC's draft strike price for onshore wind is not expected to achieve a comparable level of support to the RO, particularly after taking into account the wider differences between the two support schemes. The Figure shows that varying DECC's assumptions and allowing for the impact of the proposed contract terms on capacity adjustment and change in law (not considered by DECC in its own strike price calculations) would result in an 'RO-comparable' CfD strike price of around £114/MWh, compared with the current draft strike price of £100/MWh. The Figure also shows that if DECC were to index the strike price to RPI (rather than to CPI as currently proposed) and extend the CfD to 20 years (compared with the current proposal of 15 years), a strike price of £102/MWh would be required to meet DECC's objective of offering a level of support comparable to that available under the RO.

Figure 3.1 therefore suggests that investors considering whether to support an onshore wind final investment decision in the transition period would not be expected to view the combination of DECC's current draft strike prices and contract terms as offering support that is comparable to the RO—unless accompanied by changes to the CfD terms to mitigate their impact. This is because DECC's assumptions on power prices and inflation are not likely to be consistent with those adopted by renewable generation investors (especially those already familiar with the RO). Furthermore, DECC's proposed contract terms on capacity adjustment and change in law would act to reduce expected returns under the CfD, and these effects have not been included in DECC's strike price calculations.

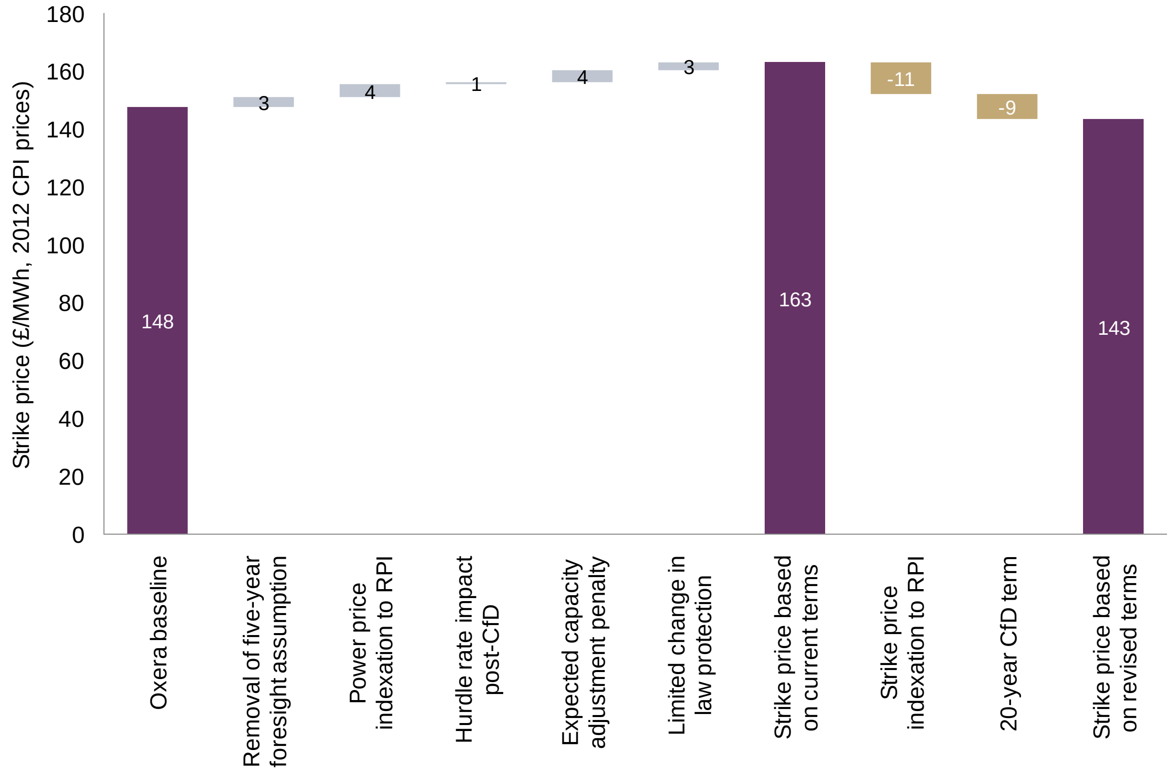
Figure 3.1 CfD strike price to ensure comparability of RO and CfD schemes for onshore wind (2016/17 commissioning)



Note: Oxera's baseline model of the CfD strike price is based on DECC's proposed CfD terms, uses DECC assumptions wherever possible, and its calculations are consistent with DECC's RO – X methodology. Oxera's baseline estimate is consistent with DECC's proposed CfD strike price of £100/MWh for onshore wind for 2016/17, given rounding assumptions (see Box 2.2). Individual elements may not sum to the totals because they are presented to the nearest £1/MWh.
Source: Oxera analysis.

Figure 3.2 supports a similar conclusion for offshore wind (Round 2). Once DECC's draft strike prices are adjusted to take account of alternative power price and inflation assumptions, as well as the financial impact of proposed CfD contract terms, the Figure shows that CfD strike prices would need to be around £163/MWh compared with the current draft strike price of £150/MWh. The Figure also shows that indexing the strike price to RPI and extending the CfD to 20 years would offset these impacts and deliver a level of support broadly comparable to that of the RO at a strike price of £143/MWh. While this is lower than the draft strike price of £150/MWh, this needs to be viewed alongside the analysis of IRRs in section 4, which accounts for a wider set of factors and suggests that the current draft strike price and terms would, if extended to 20 years and with RPI strike price indexation, deliver an IRR marginally below the offshore wind (Round 2) hurdle rate for projects commissioning in 2016/17.

Figure 3.2 CfD strike price to ensure comparability of RO and CfD schemes for offshore wind (Round 2; 2016/17 commissioning)



Note: Oxera's baseline model of the CfD strike price is based on DECC's proposed CfD terms, uses DECC assumptions wherever possible, and its calculations are consistent with DECC's RO–X methodology. Oxera's baseline estimate is consistent with DECC's proposed CfD strike price of £150/MWh for offshore wind for 2016/17 given rounding assumptions (see Box 2.2). Individual elements may not sum to the totals because they are presented to the nearest £1/MWh.
Source: Oxera analysis.

The remainder of this section elaborates on the drivers of the 'RO-comparable' strike price calculations summarised in Figures 3.1 and 3.2, namely:

– the removal of the five-year foresight assumption (section 3.1.1);
– power price indexation to RPI (section 3.1.2);
– the hurdle rate impact post-CfD (section 3.1.3);
– the expected capacity adjustment penalty (section 3.1.4);
– limited change in law protection (section 3.1.5).

We also consider:

– strike price indexation to RPI (section 3.1.6);
– the 20-year CfD term (section 3.1.7).

3.1.1 Removal of five-year foresight assumption

Power prices play an important role in determining 'RO-comparable' strike prices since the two schemes differ fundamentally in their exposure to power price risk offered to developers. Under the RO, developers have access to the upside risk from increased power prices since ROC revenues are additional (or 'premium') payments on top of the price at which electricity is sold. In contrast, the CfD strike price represents the total revenue for all electricity, regardless of changes in power prices. Put differently, the CfD removes the access to upside risk from increases in power prices while protecting developers from downside risks—indeed, this is DECC's rationale for reducing the hurdle rate for CfD-supported projects compared with those supported by the RO.

All else being equal, power prices are positively related to expected returns under the RO. The RO – X methodology also sets CfD strike prices so as to ensure that the 'marginal' project for a given low-carbon generation technology achieves a return under the CfD that is reflective of the expected return achieved under the RO. Consequently, CfD strike prices required under the RO – X methodology are positively related to expected power prices.

As explained in section 2.2.2 and shown in Figure 2.1, the DECC baseline assumes that developers forecast power prices for only five years, and that they assume that prices will remain level in real (CPI-indexed) terms thereafter. This approach seems inconsistent with practices adopted by energy market participants and indeed by DECC in other contexts. For example, companies such as Shell have developed long-term energy scenarios since the 1970s that underpin their scenario planning approach to business management.[28] Also, in its response to Ofgem's Project Discovery Energy Market Scenarios, E.ON UK confirmed that it uses long-term scenarios (alongside other modelling approaches) when evaluating policy and energy market uncertainty.[29] Moreover, it is notable that DECC's own Updated Energy Projections provide commodity price projections out to 2030, which suggests that it would be feasible for developers of low-carbon generation to make use of these and similar forecasts in the context of investment appraisal.[30]

Figures 3.1 and 3.2 therefore show the impact on strike prices if it is assumed that developers take a longer view of power prices than assumed by DECC.

It is worth noting that DECC's five-year foresight assumption is likely to be unduly conservative compared with its other power price scenario shown in Figure 2.1, for at least three reasons:

– DECC's '32% core renewables scenario' is based on its own central commodity price projections, which would suggest that the commodity prices implied by the five-year foresight scenario would largely represent a downside scenario;

– adopting a five-year foresight assumption would not be consistent with finance theory, which suggests that investments should be evaluated using future expected (ie, probability-weighted) cash flows. Thus, adopting the five-year foresight assumption would underestimate the value of projects;

– given that the hurdle rate assumption used by DECC is partly based on investors' views of both the systematic and idiosyncratic risks, this would suggest that some conservatism is already included in the RO – X methodology.[31]

As shown in Figures 3.1 and 3.2, removing DECC's five-year foresight assumption would imply that the 'RO-comparable' CfD strike price would increase by around £4/MWh and £3/MWh for onshore and offshore wind projects commissioning in 2016/17, respectively. The strike price impact is lower for offshore projects since the higher revenue under the RO from removing the five-year foresight assumption is discounted by DECC using a higher hurdle rate than for onshore projects (and therefore has a lower present value, reflected in a smaller increase in the CfD strike price).

One possible objection to removing the five-year foresight assumption is that this assumption was used in the ROBR, which set the current RO bands that the RO – X methodology is seeking to match. However, on the basis of this argument, it would also be appropriate to

[28] See http://www.shell.com/global/future-energy/scenarios/what-are-scenarios.html.

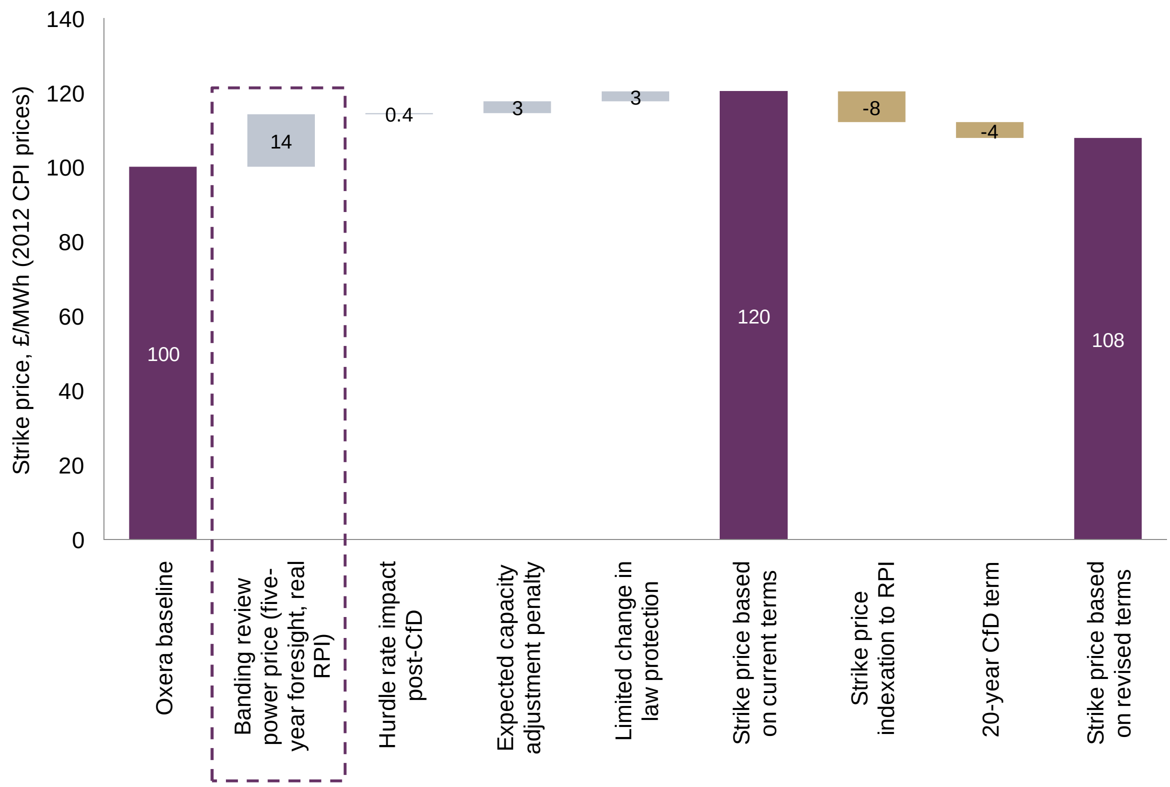
[29] E.ON UK (2009), 'Project Discovery energy market scenarios: Comment by E.ON UK', November. Available at: https://www.ofgem.gov.uk/ofgem-publications/40319/e..pdf.

[30] DECC (2013), 'Updated energy and emissions projections 2013', September.

[31] For a discussion of why the use of hurdle rates might introduce conservatism into investment appraisal, see Oxera (2011), 'Discount rates for low-carbon and renewable generation technologies', prepared for the Committee on Climate Change, April 11th, section 2.

use the fuel price assumptions of the ROBR. Accordingly, as a sensitivity, the 'RO comparable' CfD strike prices for onshore and offshore wind (Round 2) have been calculated based on replacing the EMR Delivery Plan consultation power price forecast with the forecast used by DECC in the ROBR (including the five-year foresight assumption then used). Figures 3.3 and 3.4 show the level of support under the CfD that is consistent with the power price forecast used to determine the current RO bandings under the Banding Review.[32] For example, both onshore and offshore wind strike prices based on current CfD terms would be £7/MWh higher with the ROBR forecast, which also suggests that ROC banding would need to be revised upwards if a Banding Review were carried out today. (This would also imply that CfD strike prices would need to be higher to achieve risk-adjusted returns that are comparable with those that were intended to be set at the time of the ROBR.)

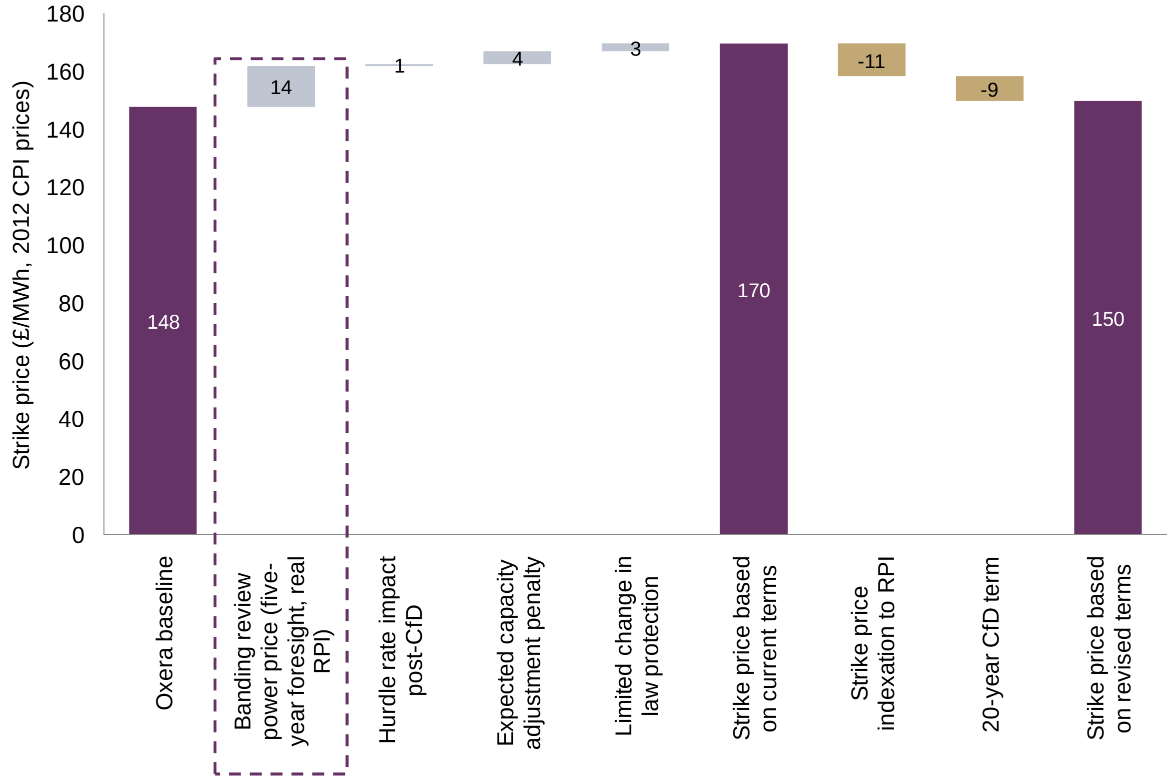
Figure 3.3 CfD strike price to ensure comparability of RO and CfD schemes for onshore wind using ROBR price forecast with five-year foresight (2016/17 commissioning)



Note: Oxera's baseline model of the CfD strike price is based on DECC's proposed CfD terms, uses DECC assumptions wherever possible, and the calculations are consistent with DECC's RO – X methodology. Oxera's baseline estimate is consistent with DECC's proposed CfD strike price of £100/MWh for onshore wind for 2016/17 given rounding assumptions (see Box 2.2). The dashed box shows the impact of using the Banding Review power price forecast (which used five-year foresight) and, we understand, constant real power prices in RPI terms beyond that point. Individual elements may not sum to the totals because they are presented to the nearest £1/MWh.
Source: Oxera analysis.

[32] As explained in section 2.2, the ROBR power price forecast included a five-year foresight assumption and, according to correspondence between DECC and ScottishPower provided to Oxera, can be assumed to have been indexed to RPI. Therefore, unlike Figures 3.1 and 3.2, Figures 3.3 and 3.4 show the combined impact of removing the five-year foresight assumption and indexing power prices to RPI (denoted by the dashed box).

Figure 3.4 CfD strike price to ensure comparability of RO and CfD schemes for offshore wind (Round 2) using ROBR price forecast with five year foresight (2016/17 commissioning)



Note: Oxera's baseline model of the CfD strike price is based on DECC's proposed CfD terms, uses DECC assumptions wherever possible, and the calculations are consistent with DECC's RO–X methodology. Oxera's baseline estimate is consistent with DECC's proposed CfD strike price of £150/MWh for offshore wind for 2016/17 given rounding assumptions (see Box 2.2). The dashed box shows the combined impact of using the Banding Review power price forecast (which used five year foresight) and, we understand, constant real power prices in RPI terms beyond that point. Individual elements may not sum to the totals because they are presented to the nearest £1/MWh.
Source: Oxera analysis.

Therefore, the implications of Figures 3.1 to 3.4 are that the current draft strike prices are too low from two perspectives:

– investors are likely to make investment decisions based on a longer view of power prices and would therefore expect a higher strike price (all else being equal) to achieve the same risk-adjusted revenue as would have been expected under the RO. The current proposed strike prices therefore make CfDs look unattractive compared with the RO;

– the decline in power price forecasts since the ROBR would be consistent with an upward revision of RO bandings for a given hurdle rate, all else being equal. As RO bandings are not currently being adjusted, setting CfD strike prices based on the existing RO bandings is, through the RO – X methodology, effectively cementing expected returns to renewable technologies under the CfD that are lower than those intended when the ROBR was undertaken.

3.1.2 Power price indexation to RPI

As indicated in section 2.1, DECC's draft strike prices were developed from a model of real costs and revenues, with both CPI and RPI inflation measures used for different cost and revenue items. Specifically, DECC assumed that revenues and costs would generally be indexed to CPI, except for those cash flows that were already indexed to RPI as a result of policy commitments or other contractual obligations. Consequently, DECC's EMR Delivery

Plan consultation assumed that ROC prices were indexed to RPI and that power prices would be constant in real CPI terms beyond the five-year foresight period.

In the case where the five-year foresight assumption is lifted, DECC continues to use CPI as the principal inflation measure for power prices. In particular, the price curve is based on a gas input projection which itself uses five-year foresight plus a real (CPI-indexed) trajectory. To the extent that RPI indexation of the flat gas price beyond the first five years is more realistic, this would be reflected in higher projected future power prices, since RPI inflation is forecast to be higher than CPI inflation.[33] Consequently, investors would expect a higher strike price (all else being equal) to achieve the same risk-adjusted revenue as would have been expected under the RO.

RPI, having been introduced in 1947, has a much longer history than CPI, which began to become more widely used only in 2003, when it became the measure underpinning the Bank of England's inflation target.[34] As a result, it may be expected that RPI remains a more conventional measure of inflation and it continues to be used for a variety of purposes. For example, index-linked gilts are adjusted in line with RPI, as are a large number of private sector pension schemes. Utility price regulation (eg, for energy networks and water and sewerage networks) also continues to be based on RPI. Indeed, following its recent consultation on changes to the RPI designed to close the gap between RPI and CPI, the ONS decided against a key arithmetical change, citing the 'significant value to users in maintaining the continuity of the existing RPI's long time series without major change, so that it may continue to be used for long-term indexation and for index-linked gilts and bonds in accordance with user expectations'.[35]

The scale of the investment challenge associated with EMR highlights the importance of incentivising investment in low-carbon generation from multiple sources. In particular, it is widely recognised that pension and insurance funds could represent a significant source of long-term funding that might help to meet this financing gap. Given that these investors' liabilities are generally linked to RPI, this could provide further support for assuming low-carbon generation cash flows being indexed to RPI and strike prices being adjusted accordingly.[36]

Moreover, given the familiarity of many investors with the RO, it would seem natural that they might be expected to continue to evaluate the CfD on a consistent basis by using similar inflation expectations. As the RO buy-out price is set by Ofgem and is increased annually in line with RPI, this is further grounds for assuming that investors' inflation expectations are likely to be anchored in RPI.

Figures 3.1 and 3.2 therefore show the impact on strike prices if it is assumed that investors retained the use of RPI in investment appraisal. As shown in Figures 3.1 and 3.2, indexing cash flows to RPI rather than CPI would imply that the 'RO-comparable' CfD strike price would increase by around £4/MWh for both onshore and offshore wind projects commissioning in 2016/17.

3.1.3 Hurdle rate impact post-CfD

As noted in section 2.1, DECC's CfD strike price calculations assume that hurdle rates for investment in renewable generation technologies under the RO and with a CfD differ. For example, DECC's hurdle rate assumption for onshore wind under the RO is 8.3%, whereas

[33] We have modelled these effects (of gas prices and other inputs) by adjusting DECC's entire price projection upwards by the difference between RPI and CPI inflation. To the extent that some elements of that projection (eg, carbon price support) have inflation indices that are known and correctly accounted for in DECC's projection, this could overestimate the indexation impact, but the effect is expected to be small relative to the adjustment indicated.

[34] ONS (2012), 'National Statistician's consultation on options for improving the Retail Prices Index', November 14th, p. 6.

[35] ONS (2013), 'National Statistician announces outcome of consultation on RPI', press release, January 10th. Available at http://www.ons.gov.uk/ons/rel/mro/news-release/rpirecommendations/rpinewsrelease.html.

[36] ONS (2012), 'National Statistician's consultation on options for improving the Retail Prices Index', November 14th, p. 27.

under the CfD it is 7.9%, with the difference stated to be accounted for by the reduced exposure to wholesale electricity price risk under the CfD scheme.

However, projects supported by a CfD are protected from wholesale price risk only during the term of the contract, after which projects would no longer receive CfD top-up payments, and hence revenue will vary according to the wholesale price. DECC's RO – X methodology for calculating strike prices has seemingly not accounted for the increase in risk at the end of the CfD contract.

One way to estimate the average hurdle rate over the lifetime of the project would therefore be a weighted average of the hurdle rates applicable during the term of the CfD contract (as estimated by DECC) and after CfD expiry (assumed here to be equivalent to DECC's RO hurdle rate), with the weights determined by the share of a project's value (ie, the present value of cash flows) that are delivered during the periods with and without CfD.[37]

Oxera estimates that the exposure of the generator to wholesale price risk after the end of the CfD term (and therefore no longer benefiting from the CfD hurdle rate reduction) has roughly a 10bp impact, equivalent to an additional £1/MWh (approximately) on the strike price for both onshore and offshore projects commissioning in 2016/17.

3.1.4 Expected capacity adjustment penalty

The proposed CfD capacity adjustment mechanism allows for developers to make two reductions in capacity by up to 5% each after being allocated a CfD (ie, the cumulative reduction could be up to 10%). Subject to certain exceptions (such as for poor geological conditions), capacity reduction beyond this would incur a penalty of 0.5% of the strike price for every 1% of capacity reduction.[38] Capacity reductions of more than 30% provide the counterparty body with a right to terminate the CfD.

Capacity reductions of 30% are a realistic potential outcome of developers' project-optimisation decisions. The factors driving capacity reductions include the following:

– the planning process fixes an upper bound for capacity early in the pre-development phase, which developers rationally respond to by being ambitious on capacity at an early stage as upward adjustments at a late stage would be impossible or costly;
– opportunities for optimising load factors and output for a given level of capacity (eg, 2MW turbines rather than 3MW turbines) arise during the pre-construction/pre-Final Investment Decision (FID) phase;
– constraints arising from sufficient offshore transmission capacity not being available in a timely manner or at proportionate cost.

Oxera's analysis has assumed that developers are able to make full use of the two 'free' adjustments that allow a 10% capacity reduction without incurring a strike price penalty. We understand that the ability of developers in practice to use these 'free' adjustments will be constrained by the timing windows that the draft CfD terms impose when the adjustments can be made, and especially the second move which needs to be after Significant Financial Commitment (SFC). Therefore, the analysis presented below is likely to underestimate the negative impact of this mechanism on IRRs.

Figure 3.5 shows that the capacity adjustment mechanism has a material impact on project IRRs. Assuming degradation of 30%, the onshore IRR would decrease by 180bp and the

[37] This approach is conservative since it would be expected to underestimate the average hurdle rate over the investment horizon, given that the RO hurdle rate reflects only partial exposure to wholesale price risk (ie, because ROC revenues make up a significant proportion of revenues). If the post-CfD hurdle rate were higher, the RO-comparable CfD strike price would be greater than shown in Figures 3.3 and 3.4.

[38] DECC (2013), 'Electricity Market Reform: Contract for Difference - Allocation Methodology for Renewable Generation', August 5th, p. 30.

offshore IRR by 200bp. Developers would be expected to take action to minimise the adverse impact of the adjustment mechanism by:

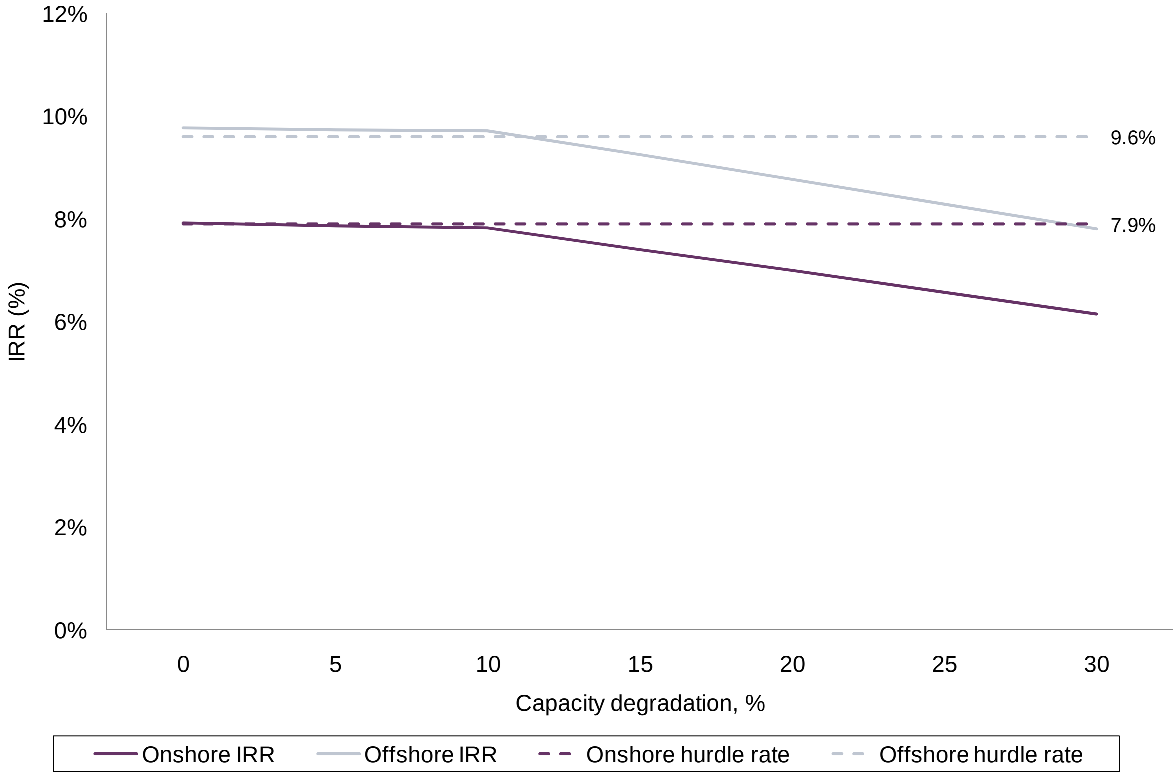
– being less ambitious with capacity when securing a CfD, which leads to sites being inefficiently underdeveloped, requiring more expensive sites to be developed at the margin to meet the renewables target;
– proceeding with non-optimised projects, which increases costs and disincentivises the supply chain competition and innovation that are necessary to generate learning effects that reduce costs over time;
– delaying the application for a CfD until sufficient wind data has been collected and a decision has been made on turbine size, which means foregoing the benefits of getting a CfD earlier in the development process;
– failing to make the deadline for SFC and triggering termination of the CfD by the counterparty, which at best delays delivery, and at worst means that projects will be foregone permanently as strike price degression renders them uneconomic.

The extent to which these actions are implemented will depend on the rate of trade-off between more costly, non-optimised projects and the strike price penalty risk. ScottishPower estimates that proceeding with a non-optimised project adds around 5% to costs.

The expected strike price penalty risk will be based on an assessment of the probability of capacity adjustments occurring, and hence the strike price penalty being applied. The expected degradation is therefore likely to lie between zero and 30% (given that the CfD for any projects with capacity degradation greater than 30% would be terminated). Assuming a 50:50 weighting of the zero and 30% adjustment scenarios (ie, expected degradation of 15%) suggests that the strike price needs to be around £3 or £4/MWh higher for onshore and offshore wind respectively, to counter the expected adverse impact of the degradation mechanism (Figures 3.1 and 3.2). The impact is larger for offshore wind as the penalty is calculated as a fixed percentage of the strike price, and the strike price is 50% higher for offshore compared to onshore wind.

The capacity adjustment mechanism will therefore on average increase costs and/or reduce the value of strike prices. Value and returns to the developer will be lower as a result of the introduction of this mechanism, and customers will face higher prices and delays as a result of lower deployment.

Figure 3.5 Impact of capacity degradation on IRRs for onshore and offshore wind (Round 2)



Note: IRRs calculated using Oxera's baseline model, which is consistent with DECC's CfD hurdle rate assumptions of 7.9% and 9.6% for onshore and offshore wind (Round 2) given rounding assumptions (see Box 2.2).
Source: Oxera analysis.

3.1.5 Limited change in law protection

The draft CfD contract terms provide limited protection against qualifying changes in law that discriminate directly between CfD-supported low-carbon generation and other plants. The proposed terms also extend limited protection to changes in law that have a 'discriminatory effect' on CfD holders, provided that the effect is 'undue and not objectively justified'.[39] However, DECC has not provided guidance on how it would define 'undue' discriminatory effects or what would be considered an 'objective justification'. CfD holders would therefore be expected to be exposed to significant regulatory uncertainty and the risks of policy changes.

Given that changes to energy policies and regulations frequently have the potential to increase generators' unit costs, this would imply that conventional generation and plants supported by the RO would have more protection than CfD holders against adverse changes in law that apply generally to the sector. This is because such plants, unlike CfD holders, may be able to 'pass through' some or all of the additional cost arising from the change in law via the wholesale market. For example, a general tax on electricity generation would be likely to increase unit costs for all generators, with non-CfD generators able to recover some or all of the consequent increase in costs through higher power prices. In contrast, CfD-supported plants would not be able to recover any of the cost increase until after the end of the CfD term, since payments are effectively capped by the strike price. Scenarios around taxes of this kind can therefore illustrate the magnitude of exposure to risks not covered by the change in law provision.

[39] Clause 22 of the draft Contract for Difference published by DECC on August 7th 2013. Available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/227071/CfD_contract__amended.pdf

Figures 3.1 and 3.2 therefore show the impact on the required strike price for RO parity based on assuming a 25% probability of a notional £10/MWh tax on generation being introduced from 2016 onwards (ie, at the start of the next Parliament). Such a tax could raise approximately £3 billion per year, based on total GB generation of approximately 300TWh. Figures 3.1 and 3.2 highlight that, to protect against that scenario, developers would require a strike price approximately £3/MWh higher than DECC's draft strike prices to make the expected returns under the CfD equivalent to risk-adjusted returns available under the RO.

Other scenarios for the impact of change in law could also be considered, and investors would be expected to form a view about the extent to which these scenarios are symmetrical or skewed towards higher or lower outcomes for power prices, costs and spreads. The required strike price would be higher to the extent that changes in law are likely to increase downside risks to profitability and constrain upside risks.

3.1.6 Strike price indexation to RPI

Inflation measured according to the RPI is likely to be higher than with the CPI for a variety of reasons, including the different composition of the indices and calculation methods.[40] This is reflected in current forecasts for the short and the long term, where inflation is predicted to be significantly higher if measured by RPI than by CPI. ROCs values are effectively indexed to RPI, whereas the current proposal is for the CfD strike price to be indexed to CPI. This policy choice is a key driver of value and, hence, the strike price.

Figure 3.1 shows that indexing the strike price to RPI instead of CPI reduces the required strike price for onshore wind by around £8/MWh.

Figure 3.2 shows that indexing the offshore wind (Round 2) strike price to RPI instead of CPI decreases the 'RO-comparable' strike price by £11/MWh. The impacts are larger than for onshore wind because of the higher offshore wind strike price.

Indexing the strike price to RPI affects the cash-flow profile of CfD support payments over time compared with CPI indexation. Support payments are lower in the early part of the project lifetime, with higher support payments occurring later. RPI indexation therefore provides a mechanism for increasing project returns without creating significant additional costs on the Levy Control Framework budget set to 2020/21.

3.1.7 20-year CfD term

The proposed standard contract term for a CfD is 15 years, whereas, under the RO, support is provided for 20 years. Extending the CfD term would be expected to partially offset the shortfall in the draft strike price, while sustaining the required rate of return.

Figure 3.1 shows that increasing the onshore CfD term from 15 to 20 years reduces the 'RO-comparable' strike price for onshore wind by around £4/MWh. It is worth noting that DECC presented an £8/MWh impact from changing the term of CfD support, and this differs from the £4/MWh estimate in Figure 3.1 for two reasons:

– DECC compares 24 years (ie, lifetime support) against 15 years, whereas the comparison presented here is between 15 years and 20 years; and
– DECC's analysis is based on five-year foresight power prices—replacing this with a longer-term view of power prices makes the 20-year CfD less attractive than the RO compared with a 15-year CfD (because the generator is able to benefit from assumed higher power prices for a shorter period until the end of the project).

In the case of offshore wind (Round 2), Figure 3.2 shows that, by increasing the CfD term from 15 to 20 years, the required strike price could be reduced by around £9/MWh. The strike price impact is larger for offshore wind as the draft strike price is higher than for

[40] Miller, R. (2011), 'The long-run difference between RPI and CPI inflation', Office for Budget Responsibility working paper no. 2, November.

onshore wind, which means that the revenue benefit from receiving CfD revenues rather than the wholesale power price in years 16–20 is larger for offshore than onshore wind.

Similar to RPI indexation of the strike price, extending the CfD term provides a mechanism for increasing the viability of offshore wind (Round 2) projects without creating additional pressure on the Levy Control Framework budget set to 2020/21.

4 Will CfDs incentivise investment?

This section presents evidence on whether the CfD scheme would be expected to incentivise investment. The analysis focuses on testing whether DECC's draft CfD strike prices and contract terms would deliver expected returns that at least equal the technology-specific investment hurdle rates also published by DECC. To the extent that this is not achieved, the government's objective of securing investment in renewable generation may not be realised. Also, in order to maximise the long-term benefits of investment in technologies such as offshore wind, it would be important to enable sufficient investment at an early stage in order to facilitate future cost reductions through learning effects.

Summary

The draft CfD strike prices and contract terms can be used to compute the IRRs for onshore and offshore wind investment. The sensitivity of project IRRs to different modelling assumptions has been assessed for onshore and offshore wind.

Onshore wind

Based on the draft strike prices, the average onshore wind project has an IRR of 6.8% after modelling costs as being indexed to RPI rather than CPI, assuming lower values for LECs, and using higher wholesale price assumptions for the post-CfD period.[41] Factoring in the expected impact of the capacity adjustment mechanism and the change in law provisions further reduces the IRR of the average project to 5.9%, which is significantly below the 7.9% hurdle rate put forward by DECC. Amending the contract terms by indexing the strike price to RPI and extending the CfD term to 20 years would increase the IRR to 7.4%, which is almost enough to incentivise the planned level of deployment based on 2016/17 costs. However, the strike price degression from £100/MWh in 2016/17 to £95/MWh in 2017/18 would reduce returns to 6.7% for projects commissioning in 2017/18, based on current evidence that costs are unlikely to decrease over this time period.

Offshore wind

Based on the draft strike prices, the average offshore wind project (Round 2) has an IRR of around 8.1% after modelling costs as being indexed to RPI rather than CPI, assuming lower values for LECs, assuming PPA discounts comparable to onshore wind, and using higher wholesale price assumptions for the post-CfD period (as per onshore wind above). Factoring in the expected impact of the capacity adjustment mechanism and the change in law provision further reduces the IRR of the average project to 7.1%, which is significantly below the 9.6% hurdle rate put forward by DECC.

Considering the uncertainty around the costs of Round 2 projects suggests that only the lowest-cost projects can achieve an IRR equal to the hurdle rate, and even in these cases, the investment decision would be finely balanced. The gap of around 440bp between the 9.6% hurdle rate and the 5.2% IRR for the highest-cost Round 2 projects suggests that these projects may not be developed even if significant learning effects can be realised. The draft strike prices are unlikely to incentivise any Round 3 projects to be developed under any scenario for costs.

Amending the contract terms for offshore wind by indexing the strike price to RPI and extending the CfD term to 20 years increases the IRR of the average Round 2 project to 9.4%, which is almost enough to incentivise the planned level of deployment based on 2016/17 costs. However, the strike price degression from £150/MWh in 2016/17 to £135/MWh in 2018/19 would reduce returns to 7.3% for projects commissioning in 2018/19. This reflects the use of a shallower cost-reduction pathway than assumed by DECC, which is more consistent with the level of offshore wind deployment envisaged in the draft EMR Delivery Plan. Restoring the IRR to the hurdle rate would require RPI indexation, a 20-year term and the strike price to be increased by approximately £15/MWh, which would effectively mean maintaining the 2016/17 level of £150/MWh throughout the five-year Delivery Plan period.

[41] The higher wholesale price assumptions after CfD expiry arise from removing the five-year foresight limitation and uplifting the forward price projection to reflect the difference between the RPI and CPI inflation measures.

4.1 Analysis of CfD IRRs

As set out in section 3.1, DECC has drawn on a variety of evidence to form the assumptions behind the published draft strike prices, and so Oxera has analysed the impact of key assumptions used by DECC on the expected returns (ie, IRRs) to onshore and offshore wind projects supported by CfDs.

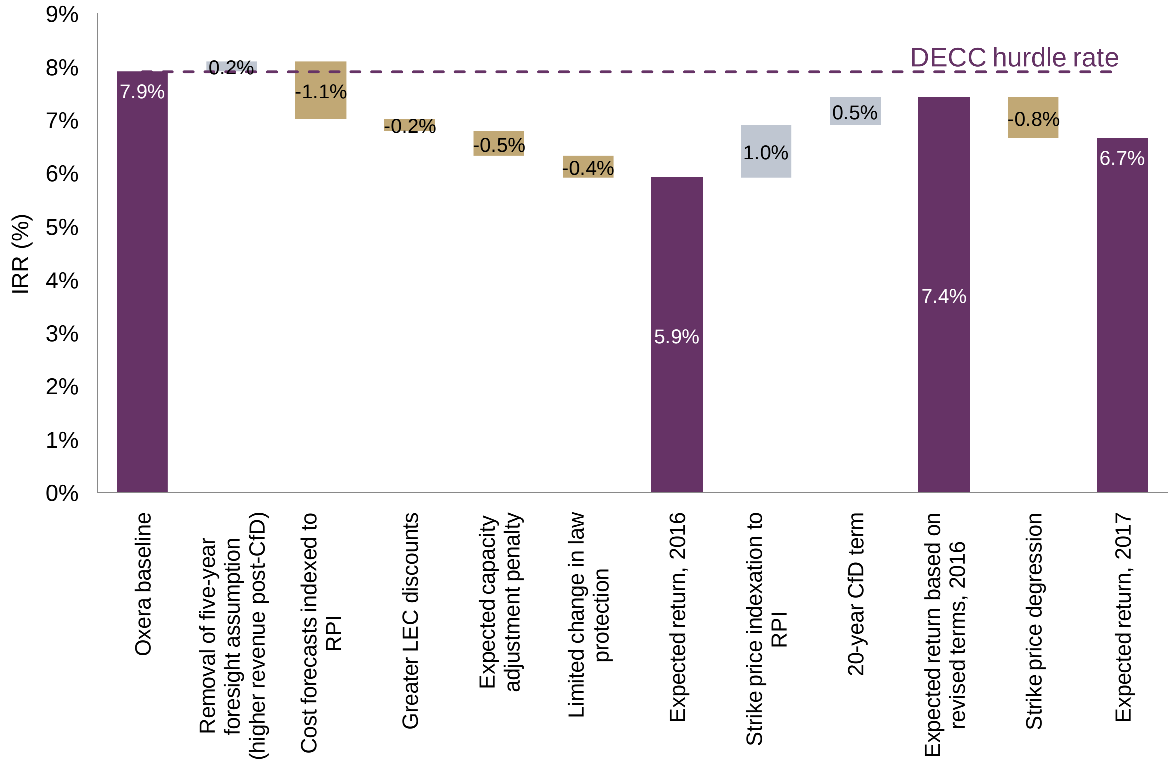
Figures 4.1 and 4.2 indicate that DECC's draft strike prices and contract terms would not be sufficient to enable onshore and offshore wind IRRs for the 'average' project to meet DECC's hurdle rate assumptions, suggesting that CfDs may not incentivise sufficient investment in these technologies from 2016/17 onwards. In particular, the degression in strike prices at the end of the transition period in 2016/17 could have a significant detrimental impact on investment incentives. These figures show CfD IRRs starting from Oxera's calculations of the strike prices under the RO – X methodology.

Thus, Figure 4.1 shows that IRRs for onshore wind projects with a CfD commissioning in 2016/17 would be expected to be approximately 5.9%, which is around 200bp lower than DECC's published hurdle rate.

Figure 4.2 shows that IRRs for offshore wind (Round 2) projects with a CfD commissioning in 2016/17 would be expected to be approximately 7.1%, or around 250bp lower than DECC's hurdle rate assumption.

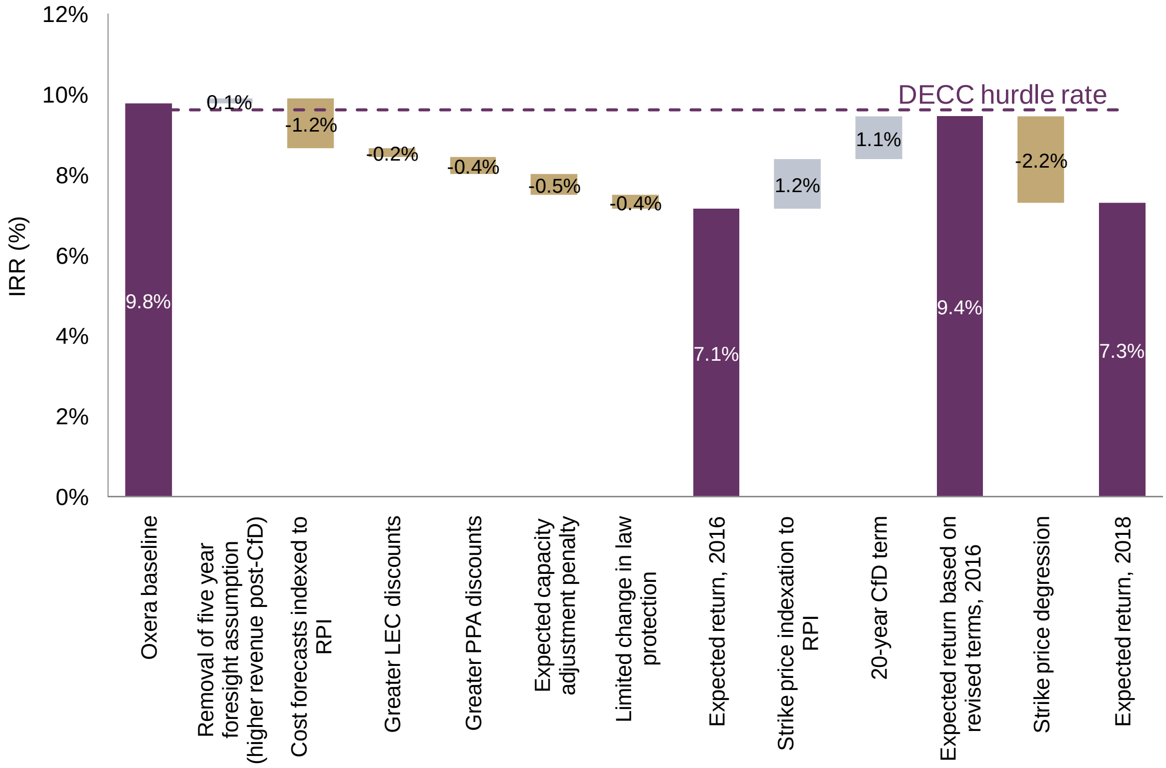
These results are consistent with Figures 3.1 and 3.2, which indicate that CfD strike prices for onshore and offshore wind (Round 2) in 2016/17 would need to rise to around £114/MWh (ie, an increase of £14/MWh over DECC's draft strike price) and £163/MWh (ie, an increase of £13/MWh over DECC's draft strike price), respectively, in order to meet DECC's published hurdle rates.

Figure 4.1 Onshore wind IRR (2016/17 and 2017/18 commissioning)



Note: IRRs calculated using Oxera's baseline model, which is consistent with DECC's CfD hurdle rate assumptions given rounding assumptions used to convert from IRRs to strike prices (see Box 2.2). Individual elements may not sum to the totals because they are presented to the nearest 0.1%.
Source: Oxera analysis.

Figure 4.2 Offshore wind IRR (Round 2, 2016/17 and 2018/19 commissioning)



Note: IRRs calculated using Oxera's baseline model, which is consistent with DECC's CfD hurdle rate assumptions, given rounding assumptions used to convert IRRs to strike prices (see Box 2.2). Individual elements may not sum to the totals because they are presented to the nearest 0.1%.
Source: Oxera analysis.

The differences between DECC's hurdle rates and Oxera's estimates for onshore and offshore wind (Round 2) IRRs are driven by the following:

– removal of the five-year foresight assumption, which affects income in the period after CfD expiry (see section 4.1.1);
– indexation of costs and post-CfD power prices to RPI (see section 4.1.2);
– greater LEC and PPA discounts (see section 4.1.3);
– expected capacity adjustment penalty and limited change in law protection (section 4.1.4).

We also consider:

– strike price indexation to RPI and the 20-year CfD term (see section 4.1.5);
– onshore wind strike price degression (see section 4.1.6);
– offshore wind cost uncertainty and strike price degression (see section 4.1.7).

The remainder of this section discusses each factor in turn. It is important to note that several of these factors operate in a quite different way to how they do in the RO – X analysis discussed in section 3. This is because section 3 focuses on differences in revenues over the CfD period between the RO and CfD regimes (and costs are not relevant to the assessment), whereas the analysis in this section takes the income under the CfD as fixed while still considering non-CfD income (mainly after the CfD has expired), as well as costs.

4.1.1 Removal of five-year foresight assumption

As discussed in section 3.1.1, DECC's draft strike prices assumed that investors base their investment decisions on forecasting power prices over a horizon of five years, with prices remaining constant in real (CPI-indexed) terms thereafter.

Assuming the CfD strike price calculated by Oxera under the RO – X methodology and all else being equal, removing the five-year foresight assumption would result in higher expected returns to projects supported by CfDs. This is because the project would benefit from higher expected revenue after the end of the CfD term.

As shown in Figure 4.1, removing the five-year foresight assumption would imply that expected returns for onshore wind projects with a CfD commissioning in 2016/17 would increase by around 0.2%. Figure 4.2 shows that IRRs for offshore wind (Round 2) projects with a CfD commissioning in 2016/17 would increase by around 0.1%.

4.1.2 Cost and post-CfD power price forecasts indexed to RPI

As discussed in section 3.1.2, DECC's draft strike prices were developed from a model of real costs and revenues, where DECC generally assumed that cash flows would be indexed to CPI except for cash flows that were already indexed to RPI as a result of policy commitments or other contractual obligations. DECC's analysis assumed that low-carbon generation costs (eg, OPEX, CAPEX) were indexed to CPI. The assumption that costs are linked to CPI is contrary to the fact that a significant proportion of generation OPEX and CAPEX is indexed to RPI (eg, TNUoS charges and construction contracts).

Assuming the CfD strike price calculated by Oxera under the RO – X methodology and all else being equal, indexing all cash flows—specifically project costs and the wholesale electricity price—to RPI rather than CPI would result in lower expected returns to projects supported by CfDs. This is because the costs would increase throughout the life of the project, while revenues increase only after the end of the CfD term.

As shown in Figure 4.1, indexing costs and post-CfD revenues to RPI rather than CPI would imply that expected returns for onshore wind projects with a CfD commissioning in 2016/17 would fall by around 1.1%. Figure 4.2 shows that IRRs for offshore wind (Round 2) projects with a CfD commissioning in 2016/17 would fall by around 1.2%. These results imply that strike prices for onshore and offshore wind (Round 2) projects would need to be higher by approximately £11/MWh and £12/MWh respectively to mitigate the impact of forecasting costs and post-CfD revenues based on CPI rather than RPI.

4.1.3 Greater LEC and PPA discounts

This section considers two sets of assumptions about revenue streams that affect value and IRRs under both the RO and the CfD regimes; namely, the value of LECs and PPA discounts. Because these revenue streams affect the RO and CfD cases throughout, they were not relevant to the analysis in section 3 of 'RO-comparable' strike prices.

DECC has assumed that the value of LECs will remain constant in real terms. There are good reasons to believe that this results in unrealistically high values that increase project IRRs.

The value of LECs is dependent on both the Climate Change Levy (CCL) tax rate set annually by the Chancellor of the Exchequer of the day, and by the supply–demand balance for LECs. Whereas the CCL is expected to increase with inflation, the supply of LECs is also expected to increase faster than demand, which would put downward pressure on the value of a LEC.

The CCL discount for consumers with Climate Change Agreements (CCAs) increased from 65% to 90% from April 2013. Therefore, LEC demand comes primarily from companies in the commercial sectors that are not covered by these agreements. In 2012 approximately 78TWh of demand was from commercial sectors and hence liable to pay the CCL at the full rate.[42] Recent projections from DECC forecast a decrease in electricity demand from

[42] DECC (2013), 'Electricity: chapter 5, Digest of United Kingdom energy statistics (DUKES)', July 25th, Table 5.2. https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65820/dukes5_2.xls

commercial sectors between 2012 and 2020.[43] Therefore, LEC demand in 2020 is likely to be 78TWh or less.

Given that technologies which qualify for ROCs also qualify for LECs at the rate of 1LEC/MWh, the ‘core 32% renewables scenario’ modelled by National Grid implies that there will be 89TWh of LECs in 2020.[44]

On the basis of current forecasts there would be an excess of 11TWh (approximately 15%) of supply over demand for LECs in 2020. In this situation, the price would be set by customers with CCAs at the discounted value of the CCL—that is, the price would be £0.5/MWh, which is 10% of the current value assumed by DECC.

To reflect this expected decline over time in the value of LECs, DECC’s 10% PPA discount assumption has been replaced with a 35% discount.

The IRRs for both onshore and offshore wind are 20bp lower in this alternative scenario for the value of LECs. As a £1/MWh change in the strike price affects IRR by approximately 10bp, which suggests that strike prices would need to be around £2/MWh higher in this alternative scenario for LEC values.

DECC has assumed that the PPA discount on wholesale energy is lower for offshore than onshore wind (5% compared with 10%). There appears to be no justification for the difference in PPA discount assumptions made by DECC, and, given the similiarity in generation profile between the two technologies, there would appear to be no reason for PPA providers to offer a lower discount for offshore generation. The assumption used by DECC of a lower discount for offshore wind increases the expected IRR for offshore wind projects and reduces the required value of support.

Figure 4.2 shows that if the onshore wind discount of 10% is applied to offshore wind, the IRR decreases by 40bp. Under this scenario, the ‘RO-comparable’ strike price would need to be around £4/MWh higher.

4.1.4 Expected capacity adjustment penalty and limited change in law protection

As described in sections 3.1.4 and 3.1.5 the draft contract terms contain both a mechanism for adjusting the strike price in response to changes in capacity that occur after a CfD has been allocated, and provisions regarding compensation due to CfD holders in the event of a change in law.

Section 3.1.4 discussed why the capacity adjustment proposals lead to a combination of higher costs and lower revenues for developers, and hence lower returns. Figures 4.1 and 4.2 show that the expected reductions in project IRR is 50bp for both onshore and offshore wind as a result of the introduction of this penalty mechanism.

Section 3.1.5 considered how the change in law provisions affects value relative to the RO. Under the CfD there would be an impact on returns to the extent that investors consider the provisions leave projects exposed to changes in law that affect generation costs. If scenarios for changes in law are, on average, expected to increase costs, the expected impact on returns would be negative since the revenue stream will be fixed for the term of the CfD. Figures 4.1 and 4.2 show the impact on expected IRRs of these concerns, assuming that investors would assess them as having an impact equivalent to a £10/MWh tax being introduced in 2016 with a 25% probability. The expected IRR is estimated to reduce by 40bp for both onshore and offshore wind in this scenario.

[43] DECC (2013), ‘Updated Energy and Emissions Projections 2013’, September, Annex C.

[44] National Grid (2013), ‘National Grid EMR Analytical Report’, Annex E to the EMR consultation, July, section 6.1.4. The calculation excludes the value of generation by ‘Other renewable (incl. small scale FITs)’.

4.1.5 Strike price indexation to RPI and 20-year CfD term

Sections 3.1.6 and 3.1.7 assessed the additional value that would be available to developers from changing the strike price inflation index from CPI to RPI, and from extending the CfD term from 15 to 20 years. The value was expressed in terms of a reduction in the required strike price under the RO – X methodology.

Figures 4.1 and 4.2 show the impact on expected IRR of these two potential contract amendments. Indexation to RPI increases the IRR by 100bp and 120bp for onshore and offshore wind (Round 2), respectively. Extension of the CfD term to 20 years increases the IRR by 50bp and 110bp for onshore and offshore wind respectively. Term extension has a larger impact on offshore wind as the higher strike price for offshore wind makes the difference between the strike price and the forecast wholesale electricity price larger than for onshore wind.

4.1.6 Onshore wind strike price degression

Evidence presented during DECC's Onshore Wind Call for Evidence suggested that onshore wind costs were unlikely to decrease over the next five years, and potentially would increase.[45] In the subsequent government response, DECC decided that the evidence did not suggest a significant change in onshore costs, and therefore maintained the 0.9 ROC banding assumption for the ROBR period.[46] This is consistent with the costs published by DECC as part of the EMR Delivery Plan consultation, where the costs for 2017/18 are broadly the same as those for 2016/17 aside from a £10/MW/year increase in the insurance cost. Despite this, the published strike price for onshore wind falls to £95/MWh in 2017/18.

Figure 4.1 shows the expected IRR for onshore wind from combining the £95/MWh strike price for 2017/18 with the 2017/18 costs published by DECC. The IRR decreases by 80bp and falls significantly below the hurdle rate of 7.9% that DECC has published for onshore wind. This suggests a scaling back of the delivery of onshore wind projects beyond 2016/17. There will also be an incentive to bring forward projects to 2016/17 where possible, which could create supply chain challenges, as well as testing constraints, such as the allocation of CfDs under the Levy Control Framework in 2016/17.

4.1.7 Offshore wind cost uncertainty and strike price degression

There are two sources of uncertainty for offshore wind:

– the range of uncertainty around costs in a particular commissioning year, using DECC's low-, medium-, and high-cost estimates from its Electricity Generation Costs report;[47]
– an alternative cost degression pathway, based on the Crown Estate's Offshore Wind Cost Reduction Pathways study.[48]

Cost uncertainty

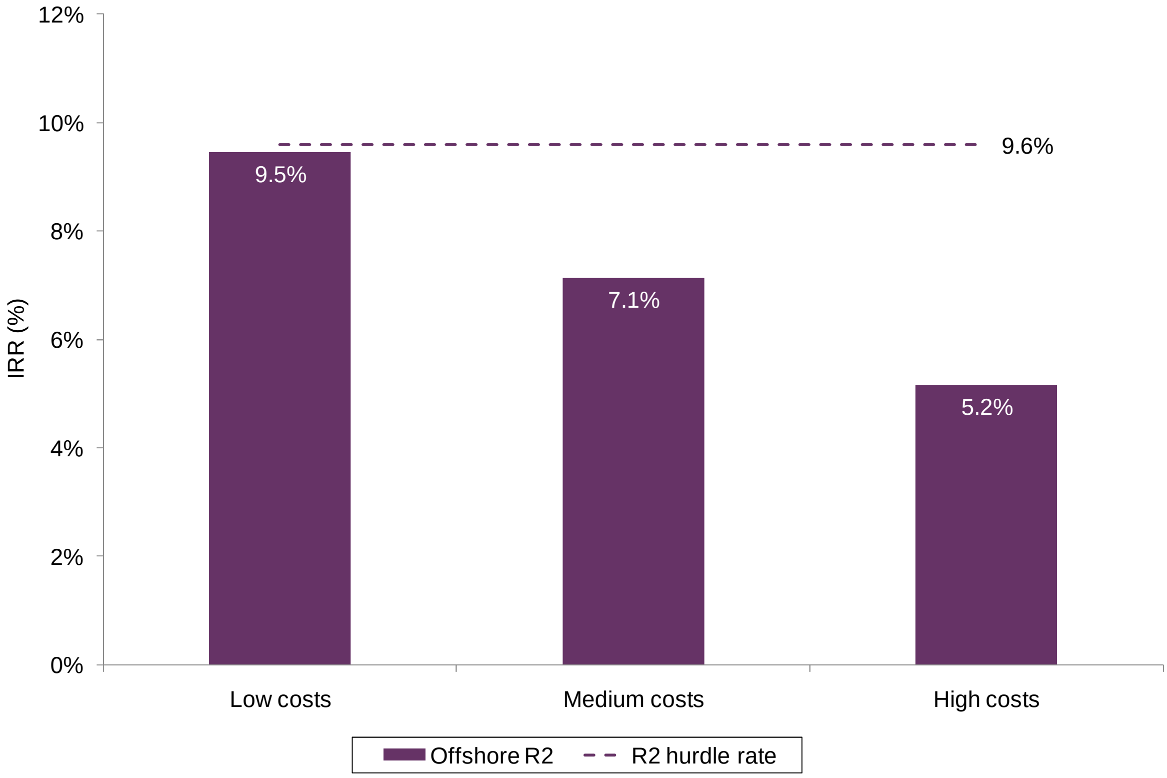
The range of uncertainty around costs in a particular commissioning year is larger for offshore wind than onshore wind, as it is a relatively less mature technology and because there is greater scope for variation in project characteristics across sites. This cost uncertainty translates into significant uncertainty around project IRR.

For example, Figure 4.3 shows that, for offshore wind (Round 2) projects, the impact of cost uncertainty could result in a change in IRR relative to Oxera's baseline expected return by around ±220bp, with IRRs ranging from 5.2 to 9.5%, compared with the DECC hurdle rate of 9.6%. This suggests that the investment case for even the lowest-cost projects is marginal.

[45] Oxera (2012), 'Outlook for onshore wind—analysis to inform DECC's Call for Evidence: Onshore wind – costs', prepared for Scottish Power, December.
[46] DECC (2013), 'Onshore Wind Call for Evidence: Government Response to Part A (Community Engagement and Benefits) and Part B (Costs)', June, p. 39.
[47] DECC (2013), 'Electricity Generation Costs', July.
[48] The Crown Estate (2012),' Offshore Wind Cost Reduction Pathways Study', May.

The gap of around 440bp between the highest- and lowest-cost projects suggests that these projects may not be developed, even if significant learning effects can be realised.

Figure 4.3 Impact of cost uncertainty on offshore wind (Round 2) projects

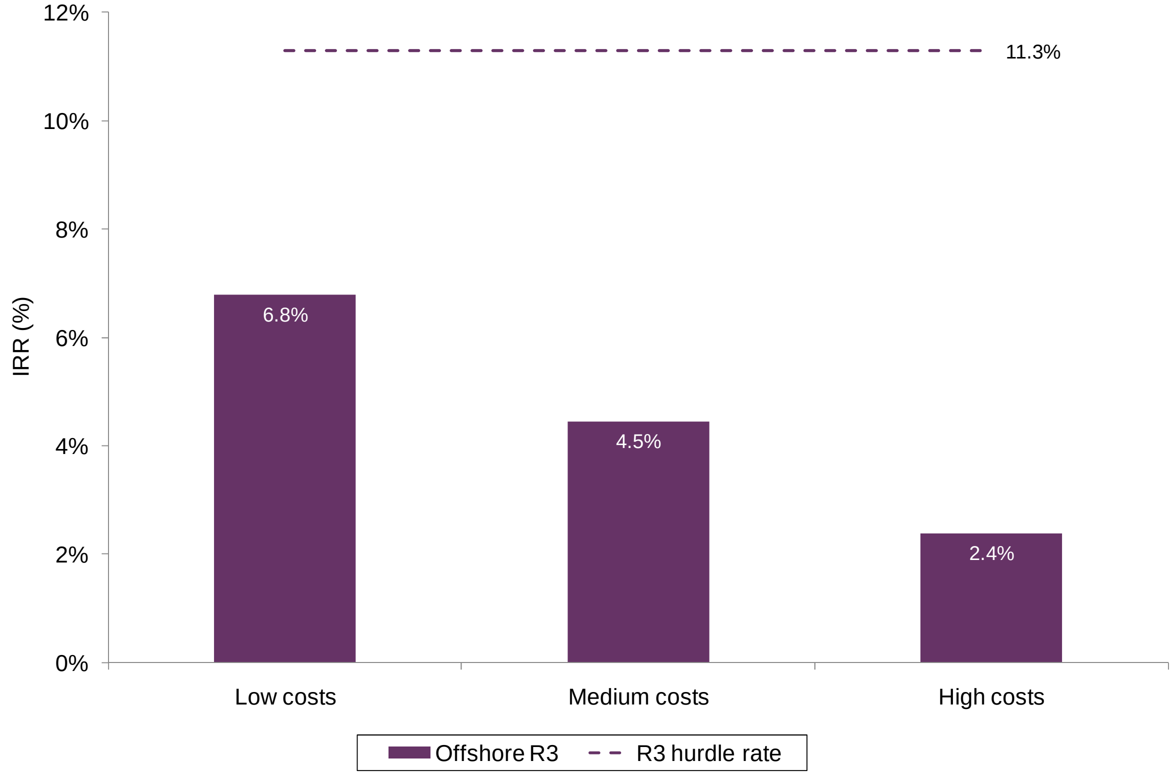


Note: IRRs calculated using Oxera's baseline model, which is consistent with DECC's CfD hurdle rate assumptions, given rounding assumptions used to convert IRRs to strike prices (see Box 2.2). Assumes projects commissioned in 2016/17. The IRR with medium costs (7.1%) corresponds to the expected return shown in Figure 4.2.
Source: DECC (2013), 'Electricity Generation Costs', July; Oxera analysis.

While the purpose of the CfD mechanism is not to ensure the delivery of all projects regardless of costs, this analysis shows that the delivery of projects is very sensitive to whether the DECC baseline used to set strike prices is representative of the costs of the marginal project. Given this sensitivity, the risk of under-delivery relative to the renewables target is significant. A higher strike price would reduce this risk, and this policy would be consistent with attaching significant weight to achieving the renewables target.

Figure 4.4 suggests that for offshore wind (Round 3) projects the impact of cost uncertainty could result in a change in IRR relative to the medium-cost scenario by around ±220bp. This Figure also highlights that offshore wind (Round 3) projects would not be commissioned in 2016/17 under any cost scenario. Put differently, the £150/MWh strike price for 2016/17 is not high enough for any Round 3 projects to be commissioned. Assuming medium costs, the 680bp gap between offshore wind (Round 3) expected returns and the DECC hurdle rate is equivalent to an additional £62/MWh (approximately) on the strike price.

Figure 4.4 Impact of cost uncertainty on offshore wind (Round 3) projects



Note: IRRs calculated using Oxera's baseline model, which is consistent with DECC's CfD hurdle rate assumptions, given rounding assumptions used to convert IRRs to strike prices (see Box 2.2). Assumes projects commissioned in 2016/17.
Source: DECC (2013), 'Electricity Generation Costs', July; and Oxera analysis.

Strike price degression pathway

The second dimension of uncertainty for offshore wind costs is the speed of cost reduction over time—that is, the 'cost degression profile'. Recognising that the rate of development and the cumulative volume of deployment are linked to the potential for cost reduction through learning effects and economies of scale, DECC has assumed significant cost reductions for offshore wind projects between 2016/17 and 2020/21, with a general £5/MWh annual reduction in strike price during this period. However, the degression profile is non-linear as there is a steep £10/MWh reduction between 2016/17 and 2017/18, which may be a result of the approach of rounding strike prices to the nearest £5/MWh.

DECC has used two sources as the basis for this cost degression profile: the modelled deployment and learning rates from the ROBR; and the Offshore Wind Cost Reduction Pathways study by the Crown Estate. DECC noted that the Crown Estate and Offshore Wind Cost Reduction Task Force profiles for offshore wind costs result in steeper degression profiles than those derived from modelled deployment and the learning rates from the ROBR. DECC applied equal weighting to the two sources of evidence when calculating strike prices.[49] However, there is no explanation for this weighting.

The study by the Offshore Wind Cost Reduction Task Force assessed four scenarios for the evolution of offshore wind, of which three predicted that levelised costs could be reduced from £140/MWh for projects reaching FID stage in 2011, to £100/MWh or less for projects reaching FID in 2020 and expected to commission by 2024. This was premised on the basis of 17 GW of capacity in the UK.[50] The exception was the 'slow progression' scenario

[49] DECC (2013), 'Electricity Generation Costs', July. p.47.
[50] The Crown Estate (2012),' Offshore Wind Cost Reduction Pathways Study', Exhibit A, May.

(assuming deployment of 12 GW), where cost reduction is limited by the reduced programme scale, which accesses fewer economies of scale and learning benefits. Costs were presented at the 2011 price level and therefore need to be increased by the 2011/12 rate of inflation to be comparable with the analysis undertaken by DECC for the draft EMR Delivery Plan.

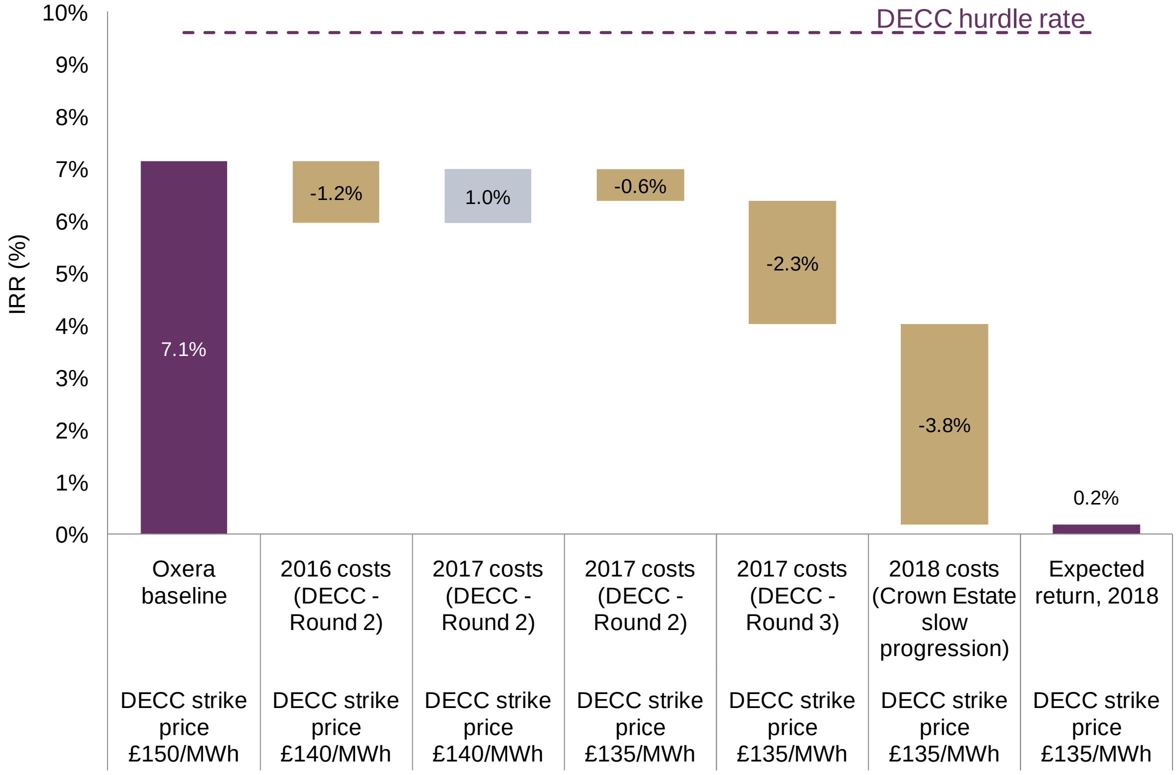
As published by DECC as part of the draft EMR Delivery Plan, offshore wind capacity of 8 GW by 2020 has been modelled as 'core scenario 32%', which compares with a minimum of 17 GW in the three Crown Estate scenarios, where costs are reduced to a maximum of £100/MWh for projects reaching FID in 2020 and commissioning in 2024.[51] Even the 'slow progression' scenario assumes higher deployment (12 GW) than envisaged in the draft EMR Delivery Plan. As the strike prices are consistent with achieving a level of deployment somewhat lower than the 'slow progression' scenario, learning effects would be smaller and occur later. This suggests that the 'slow progression' scenario now indicates the maximum cost reduction likely over the Delivery Plan period; namely, a levelised cost of energy of around £134/MWh for projects with FID 2017 and commissioning in 2021, and £115/MWh with FID 2020 and commissioning in 2024. This should be considered when assessing the strike price degression rate, albeit levelised costs are not directly comparable to strike prices.

Figure 4.5 shows the IRR for offshore wind projects commissioning in 2016/17 (Round 2), 2017/18 (Rounds 2 and 3), and 2018/19 (Round 3) based on strike prices published by DECC. Costs for 2016/17 and 2017/18 are based on those published by DECC, whereas costs for 2018/19 are based on the Crown Estate 'slow progression' scenario for projects with FID 2014.

The £10/MWh strike price degression between 2016/17 and 2017/18 combined with DECC's projected cost degression has a net impact on the IRR of around –20bp. However, as the strike price falls to £135/MWh in 2018/19 and assuming DECC's costs for Round 3 projects, the IRR decreases by 230bp, to 4.0%. As an additional step, replacing DECC's Round 3 cost assumptions with the slow progression cost assumptions from the Crown Estate study reduces the IRR by a further 380bp and makes the Round 3 IRR approximately 0.2%.

[51] The Crown Estate (2012), 'Offshore Wind Cost Reduction Pathways Study', Exhibit A, May; National Grid (2013), 'National Grid EMR Analytical Report', July, p.41.

Figure 4.5 Impact of cost and strike price degression on offshore wind (Round 2 and Round 3) projects



Note: IRRs calculated using Oxera's baseline model, which is consistent with DECC's CfD hurdle rate assumptions, given rounding assumptions used to convert IRRs to strike prices (see Box 2.2). Assumes projects commissioned with strike prices of £150/MWh, £140/MWh, and £135/MWh in 2016, 2017, and 2018, respectively.
Source: DECC (2013), 'Electricity Generation Costs', July; PwC (2012), 'Offshore wind costs reduction pathways study: finance work stream', April; and Oxera analysis.

A1 Modelling assumptions

A1.1 Model parameters

Table A1.1 Operational parameters

Parameter	Onshore wind	Offshore wind round 2	Offshore wind round 3
Commissioning year	2016	2016	2016
Operating period	24 years	23 years	22 years
Pre-development period	Four years	Five years	Six years
Construction period	Two years	Three years	Three years
Capacity	71.8 MW	400 MW	1,000 MW

Source: DECC (2013), 'Electricity Generation Costs', July; Oxera assumptions.

Table A1.2 Revenue and price parameters

Revenue source/parameter	Value
ROC price (2013/14)	£42.02/MWh
LEC price	£5/MWh
Capacity market de-rating assumption	22%
Capacity market clearing price	£25/kW
ROC banding level (ROCs/MWh)	
Onshore wind	0.9
Offshore wind	1.8

Source: DECC (2013), 'Delivery Plan consultation and EMR implementation programme', July 31st;
DECC (2012), 'Government response to the consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013-17 and the Renewables Obligation Order 2012', July; and
Ofgem (2013), 'Information Note: the renewable obligation buy-out price and mutualisation ceiling 2013-2014', February 13th.

Table A1.3 PPA discounts

	Wholesale energy revenue	ROC revenue	LEC revenue
RO			
Onshore wind	13%	10%	10%
Offshore wind	5%	5%	5%
CfD			
Onshore wind	10%	–	10%
Offshore wind	5%	–	5%

Source: National Grid (2013), 'National Grid EMR Analytical Report', July, Annex table 7.

Table A1.4 Pre-development and construction phasing schedules

	Years	Year 1	Year 2	Year 2	Year 4	Year 5	Year 6
Onshore							
Pre-development	4	25%	25%	25%	25%	–	–
CAPEX	2	67%	33%	–	–	–	–
Offshore round 2							
Pre-development	5	22%	22%	22%	22%	12%	–
CAPEX	3	30%	40%	30%	–	–	–
Offshore round 3							
Pre-development	6	16.7%	16.7%	16.7%	16.7%	16.7%	16.7%
CAPEX	3	30%	40%	30%	–	–	–

Source: DECC (2013), 'Delivery Plan consultation and EMR implementation programme', July 31st; and DECC (2013), 'EMR delivery plan consultation workshop', August 28th.

Table A1.5 Onshore wind costs

	2012 prices (£)	Unit
Pre-development costs	103	£/kW
CAPEX	1,490	£/kW
OPEX		
Fixed O&M	37.1	£/kW/yr
Variable O&M	5.0	£MWh
Insurance	3.0	£/kW/yr
Connection and Use of System	4.5	£/kW/yr

Source: DECC (2013), 'Delivery Plan consultation and EMR implementation program', July 31st.

Table A1.6 Offshore wind round 2 costs

	2016 commissioning	2017 commissioning	2020 commissioning	Units
Pre-development				
Low	50	50	50	£/kW
Medium	70	70	70	
High	120	120	120	
Construction costs				
Low	2,100	2,000	1,700	£/kW
Medium	2,500	2,300	2,000	
High	2,900	2,700	2,400	
Variable OPEX	2	2	2	£/MWh
Fixed O&M	62.9	60.5	54.6	£/MW/yr
Insurance	11,600	11,100	10,000	£/MW/yr
Connection and Use of System	45,900	44,200	39,900	£/MW/yr

Source: DECC (2013), 'Electricity Generation Costs', July.

Table A1.7 Offshore wind round 3 costs

	2016 commissioning	2017 commissioning	2020 commissioning	Units
Predevelopment				
Low	50	50	50	£/kW
Medium	105	105	105	
High	150	150	150	
Construction costs				
Low	2,200	2,100	1,800	£/kW
Medium	2,600	2,400	2,100	
High	3,100	3,000	2,600	
Variable OPEX	Included in Fixed O&M	Included in Fixed O&M	Included in Fixed O&M	£/MWh
Fixed O&M	70,900	67,000	57,800	£/MW/yr
Insurance	32,800	31,000	26,700	£/MW/yr
Connection and Use of System	60,600	57,200	49,400	£/MW/yr

Source: DECC (2013), 'Electricity Generation Costs', July.

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