Banding scenarios: impacts on onshore wind deployment

Prepared for ScottishPower and ScottishPower Renewables

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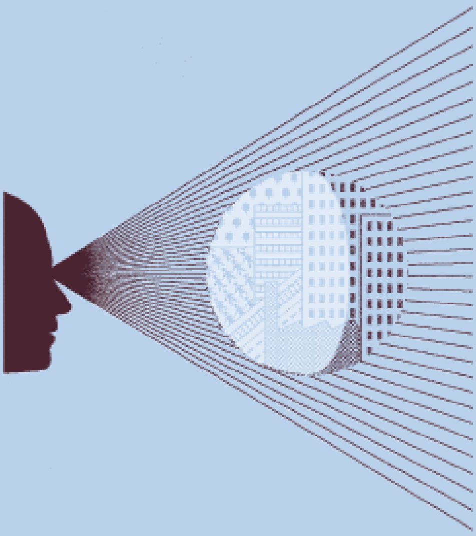

Executive Summary

DECC's accelerated Banding Review is due to consult on proposed renewable technology support levels within the Renewables Obligation (RO) in July 2011. This Review is one year earlier than originally planned, in order to provide investors with greater certainty over future banding levels, and to promote investment and the ability to meet the UK's target for 15% of energy to come from renewable sources by 2020.[1]

This report provides an analysis of onshore wind economics and possible deployment levels in order to contribute to DECC's Review. The analysis is based on discounted cash flow models that are used to examine potential project returns under updated electricity price expectations and a range of banding sensitivities, as well as the resulting deployment levels and associated costs of meeting the UK's renewables target.

In particular, the analysis examines the extent to which the introduction of Carbon Price Support (CPS) may increase electricity price expectations, and hence the returns to potential projects. The analysis also examines the effect that alternative onshore banding levels could have on onshore wind returns and deployment, and considers the cost implications of replacing onshore wind deployment with more costly, but nevertheless abundant, offshore wind. As set out below, a reduction in banding from 1 ROC/MWh to 0.9 ROC/MWh in a scenario with CPS could create additional costs of around £70m–£84m per annum by 2020,[2] while a reduction to 0.75 ROC/MWh could increase costs by over £200m per annum.

While the introduction of CPS alone might be expected to increase wholesale electricity prices and hence the returns to onshore wind, its effects should arguably be evaluated alongside the other proposed reforms within DECC's Electricity Market Reform (EMR) package and, in particular, the potential adverse effect of the proposed capacity mechanism on onshore wind economics.[3] Without further clarity over the full package of reforms, it would be inefficient to link revisions to the current banding levels to the additional revenues associated with CPS alone, if other elements of the reform package might act to worsen project economics.

Summary of findings

The key findings of the analysis are that:

– the introduction of CPS is likely to increase onshore wind revenues by less than 2%, and improve returns to onshore wind projects by around 30 basis points;

– a reduction in banding from 1 ROC/MWh to 0.9 ROC/MWh or 0.75 ROC/MWh in a scenario with CPS could reduce project returns by around 70 or 180 basis points respectively, and lead to an additional 10% or 25% of potential onshore wind projects being uneconomic to develop (of which around 70% are expected to be in Scotland);

– if a reduction in onshore wind deployment associated with banding changes were to be replaced by offshore wind, there would be likely to be an associated increase in support costs, alongside a relatively small decrease in required onshore transmission costs;

[1] See DECC (2010), 'Press release: Faster review of renewable electricity to provide investor certainty', December 8th.

[2] The effective level of support under large-scale renewable feed-in-tariffs that may ultimately replace support under the RO from 2017 is assumed to be similar to that within the revised banding levels in the analysis.

[3] The proposed capacity mechanism would be likely to have the effect of lowering wholesale electricity prices by reducing the scarcity component of prices in peak periods. Onshore wind economics could therefore be adversely affected if it were ineligible to receive additional capacity payments.

- a reduction in onshore banding from 1 ROC/MWh to 0.9 ROC/MWh in a scenario with CPS could lead to an overall net increase in support and transmission costs of around £70m–£84m per annum by 2020;
- a reduction in onshore banding from 1 ROC/MWh to 0.75 ROC/MWh in a scenario with CPS could lead to an overall net increase in support and transmission costs of around £219m–£256m per annum by 2020.

The results above suggest that, given the potential distribution of project economics derived in the analysis, the additional revenues associated with the introduction of CPS are unlikely to warrant a reduction in onshore banding. Any reduction in onshore wind banding is likely to reduce onshore wind deployment, and substituting this reduced onshore wind output with increased offshore wind deployment would lead to a significant increase in costs.

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1 Introduction

DECC's accelerated Banding Review is due to consult on proposed renewable technology support levels within the Renewables Obligation (RO) in July 2011. This Review is one year earlier than originally planned in order to provide investors with greater certainty over future banding levels, and to promote investment and the ability to meet the UK's target for 15% of energy to come from renewable sources by 2020.[4]

As part of the Banding Review process, DECC has commissioned work from ARUP and Ernst & Young to assess the relative costs and resource potential of different renewable technologies, in order to underpin its subsequent analysis.[5] With regard to onshore wind, ARUP has drawn the following conclusion.

> **Onshore Wind** – This still has significant deployment potential of around 17.3GW by 2030 (medium forecast), but the deployment rates are slower than previously modelled. So generally, forecast 2020 figures will only be reached on the high ambition scenario. This is mainly due to planning and grid constraints. Deployment of onshore wind in Scotland is anticipated to remain an important and increasing part of the onshore wind generation. The capex and opex data is very similar to previous studies.[6]

ARUP's work confirms that onshore wind is a relatively low-cost renewable technology, and that maximising the deployment of this resource is therefore likely to be required in order to meet the UK's renewable targets at least cost. A key consideration in determining the appropriate banding level to maximise onshore wind potential is an assessment of the distribution of potential projects in terms of their cost and operating potential, and the resulting economics.

This report provides an analysis of onshore wind economics and possible deployment levels in order to contribute to DECC's Review. The analysis is based on discounted cash flow models that use Oxera's GB power price and ROC price projections as inputs, as well as regional cost and load factor differences developed in response to Ofgem's review of transmission charging within Project TransmiT.[7] These are used to examine potential project returns under updated electricity price expectations and a range of banding sensitivities, as well as the resulting deployment levels and associated costs of meeting the UK's renewables target.

The report presents results along two dimensions. The first tests the sensitivity of project economics and deployment levels to different electricity prices. In particular, it examines the extent to which the introduction of Carbon Price Support (CPS) may increase electricity price expectations and hence the returns to potential projects. The second set of sensitivities examines the effect that alternative onshore banding levels could have on onshore wind returns and deployment. It also examines the cost implications of replacing onshore wind deployment with more costly, but nevertheless abundant, offshore wind.[8]

The report is structured as follows.

– Section 2 describes recent market developments, and the extent to which they might motivate changes to the current banding levels.

[4] See DECC (2010), 'Press release: Faster review of renewable electricity to provide investor certainty', December 8th.
[5] ARUP (2011), 'Review of the generation costs and deployment potential of renewable electricity technologies in the UK', June.
[6] ARUP (2011), op. cit., p. iv.
[7] See Oxera (2010), 'Principles and priorities for transmission charging reform', November.
[8] Banding levels for offshore wind are assumed to remain at 2 ROC/MWh.

– Section 3 sets out the modelling framework with which to assess how onshore wind economics may have changed, and uses this to model the impact that increased carbon price expectations could have on onshore wind economics. It also provides an assessment of how different onshore wind banding scenarios could affect total deployment levels.
– Section 4 considers the wider impacts of changes to onshore wind deployment, and provides an assessment of the impact on total renewable support costs and transmission investment requirements within a cost–benefit framework; and
– Section 5 concludes.

2 Market developments and their interaction with banding levels

This section considers long term market developments that have the potential to affect onshore wind economics. It focuses on recent changes that are likely to persist, rather than temporary changes, as a stable regulatory environment requires renewable support levels to be predictable in order to facilitate investment. The extent of possible effects in the following areas is considered.

– **Carbon price support**—the introduction of Carbon Price Support (CPS) as announced in the 2011 Budget has the potential to lead to higher longer-term carbon price expectations than would have been delivered under the EU ETS alone. If this were to lead to materially different power price expectations, this could increase the returns to renewables projects and either increase total deployment or reduce the support required within the RO.

– **Capital cost developments**—any significant changes in the expected engineering, procurement and construction costs of onshore wind projects since the introduction of banding in 2009 might be expected to alter the returns to future projects, and this could alter the level of support required by those projects.

The evolution of project costs was examined in the 2011 ARUP study commissioned by DECC as part of its Banding Review.[9] The study highlights that there has been relatively little movement in expected onshore wind costs:

> The capex and opex data is very similar to previous studies.[10]

For this reason, the remainder of this section considers the impact of the introduction of CPS on onshore wind economics. The assessment is based on Oxera's forward-looking commodity and power price projections, and compared to the results from using DECC's electricity price projections.

While the introduction of CPS alone might be expected to increase wholesale electricity prices and hence the returns to onshore wind, its effects should arguably be evaluated alongside the other proposed reforms within DECC's Electricity Market Reform (EMR) package, and in particular, the potential adverse effect of the proposed capacity mechanism on onshore wind economics.[11] Without further clarity over the full package of reforms, it may be inefficient to link revisions to the current banding levels to the additional revenues associated with CPS alone if other elements of the reform package may act to worsen project economics.

2.1 Carbon Price Support

The 2011 budget announced the introduction of an annually adjusted input tax in order to create a carbon price floor.[12] The floor is to take effect from April 2013, starting at £16/tCO_2, and increase linearly to £30/tCO_2 by 2020 and is planned to increase to £70/tCO_2 by 2030.[13]

[9] ARUP (2011), 'Review of the generation costs and deployment potential of renewable electricity technologies in the UK', June.

[10] ARUP (2011). op. cit., p. iv.

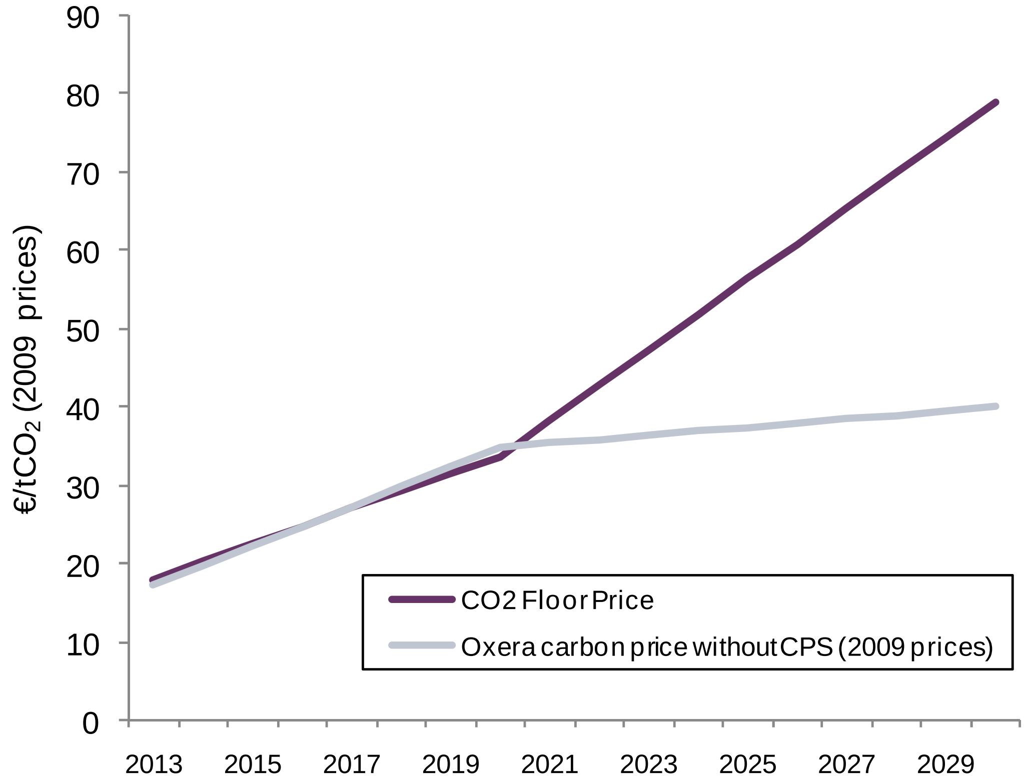
[11] The proposed capacity mechanism would be likely to have the effect of lowering wholesale electricity prices by reducing the scarcity component of prices in peak periods. Onshore wind economics could therefore be adversely affected if it were ineligible to receive additional capacity payments.

[12] HM Treasury (2011), 'Budget 2011', March.

[13] HM Treasury and HM Revenue and Customs (2011), 'Carbon price floor consultation: the Government response', March.

Figure 2.1 shows the carbon price floor in the period to 2020, alongside Oxera's carbon price projection for the same period.

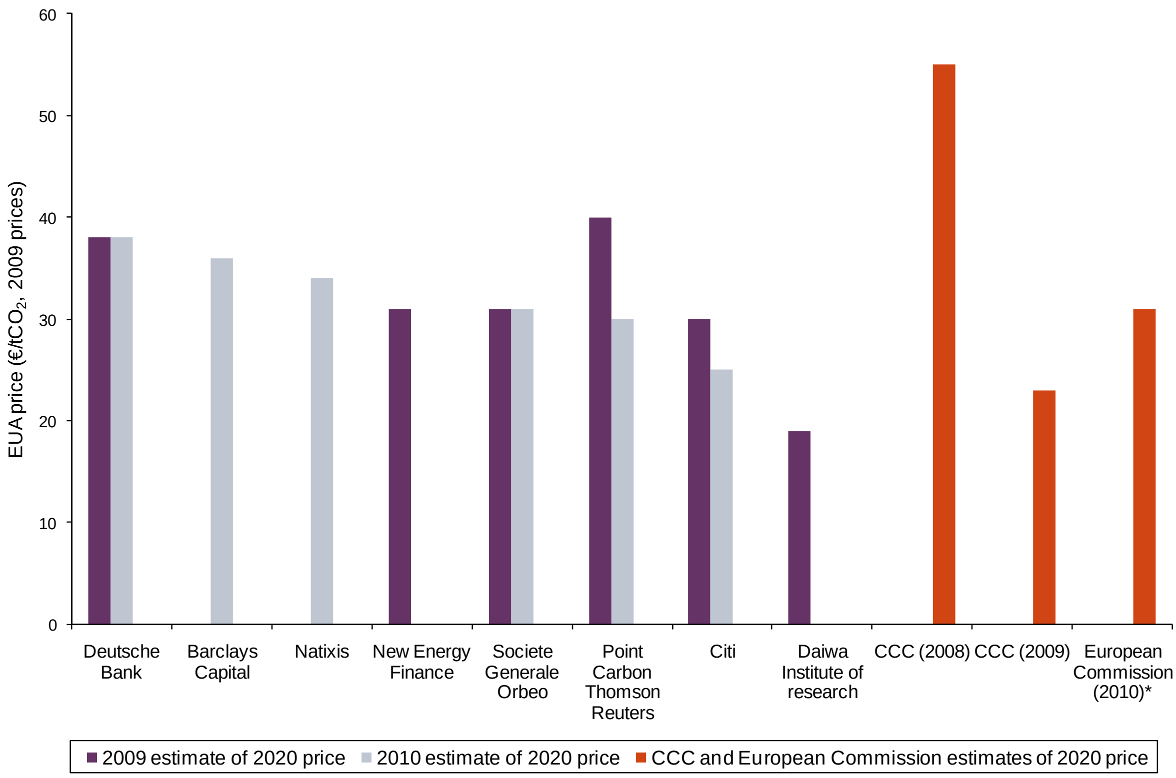
Figure 2.1 Carbon price floor and Oxera's ETS projection



Source: HM Treasury and Oxera analysis.

Oxera's central carbon price projection rises from current levels to around €35/tCO_2 (in 2009 prices) by 2020. This is consistent with other independent projections, as reported by the Committee on Climate Change (CCC), and illustrated in Figure 2.2. The consistency between independent forecasts suggests that EU ETS prices may be close to the level of the carbon price floor by around 2020.

Figure 2.2 Independent projections of carbon prices in 2020



Note: Estimates are as reported by the Committee on Climate Change (CCC), and either taken from published sources or supplied directly by analysts. Nominal forecasts were converted to real 2009 prices using an assumed annual inflation rate of 2%. *The European Commission estimate is based on a 30% Greenhouse Gas (GHG) reduction target, with a reduction of 25% made within the EU, and 5% through the use of international offsets. The Thomson Reuters Point Carbon estimate is a probability-weighted Phase III average. Underlying data: Deutsche Bank (July 2009 and April 2010); Barclays Capital (April 2010); Natixis E&I (July 2009 and May 2010); New Energy Finance (July 2009); Société Générale and Rhodia: Orbeo (May 2009 and April 2010); Thomson Reuters Point Carbon (July 2009 and June 2010); Citi Investment Research and Analytics (July 2009 and April 2010); Daiwa Institute of Research (February 2009); Committee on Climate Change (2008), 'Building a low-carbon economy – the UK's contribution to tackling climate change', December; Committee on Climate Change (2009), 'Meeting Carbon Budgets – the need for a step change', October; European Commission (2010), 'Analysis of options to move beyond 20% greenhouse gas emission reductions and assessing the risk of carbon leakage'. Source: Committee on Climate Change.

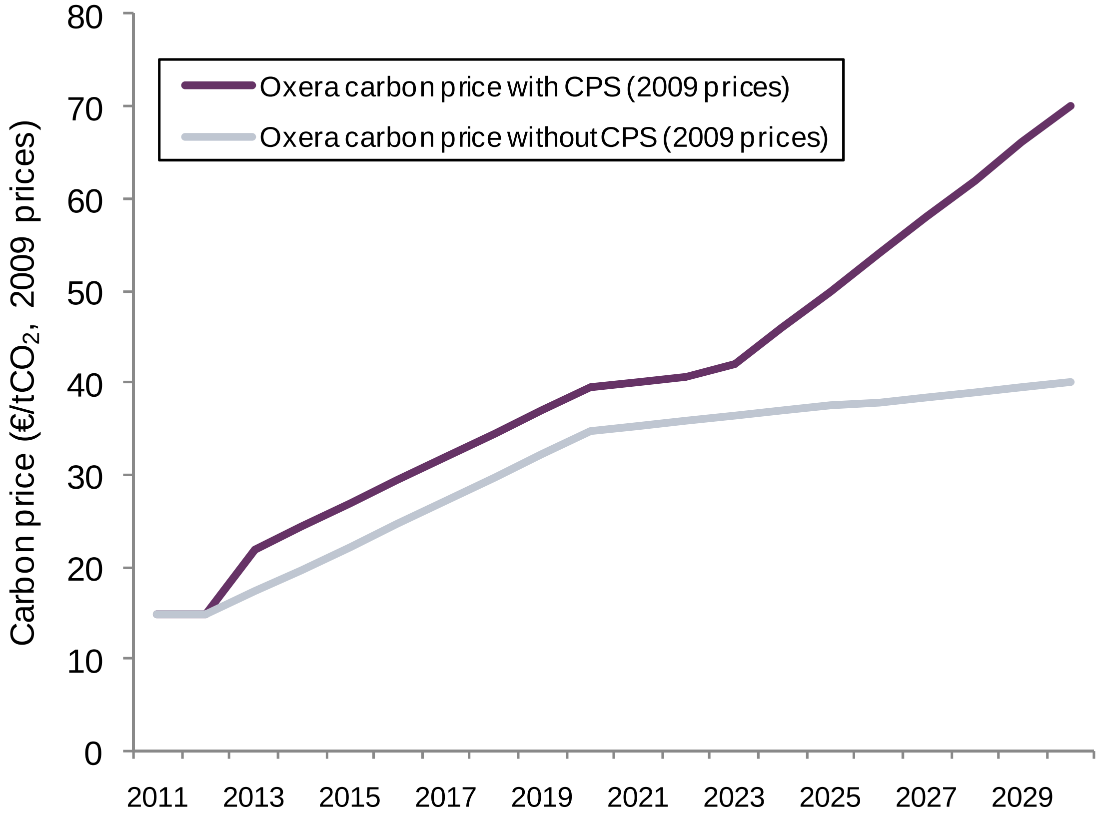
The carbon price floor is to be put in operation through levying 'carbon price support rates'—calculated as the difference between the carbon target/floor price and the futures market price in the EU ETS. A one-year average of ICE-ECX index daily settlement prices has been used to calculate the 2013 support rate of £4.94/tCO_2 (nominal), and preliminary estimates for 2014–15 and 2015–16 of £7.28/tCO_2 and £9.86/tCO_2 respectively.[14]

Carbon allowance (EUA) forward prices represent observed traded prices, but are not necessarily a forecast of future prices. Longer-dated prices in particular are less frequently traded, and tend to reflect near-term prices. The lack of a robust benchmark for prices beyond the next few years is consistent with the approach adopted by the government to set support rates just two years in advance. There are also fiscal and competitive impacts surrounding the level of the tax. For these reasons, and given Oxera's and other independent projections that carbon prices are likely to rise close to the carbon floor by 2020, the analysis below assumes that the impact of CPS on the effective carbon price, and hence electricity prices, is to increase prices by the higher of £5/tCO_2, or the difference between the floor price and Oxera's carbon price projection.

[14] HM Treasury (2011), 'Carbon Price Floor Consultation: Government Response', March.

Applying an additional carbon tax on the basis of this methodology results in the carbon price impact illustrated in Figure 2.3.

Figure 2.3 Oxera carbon price trajectories with and without price support

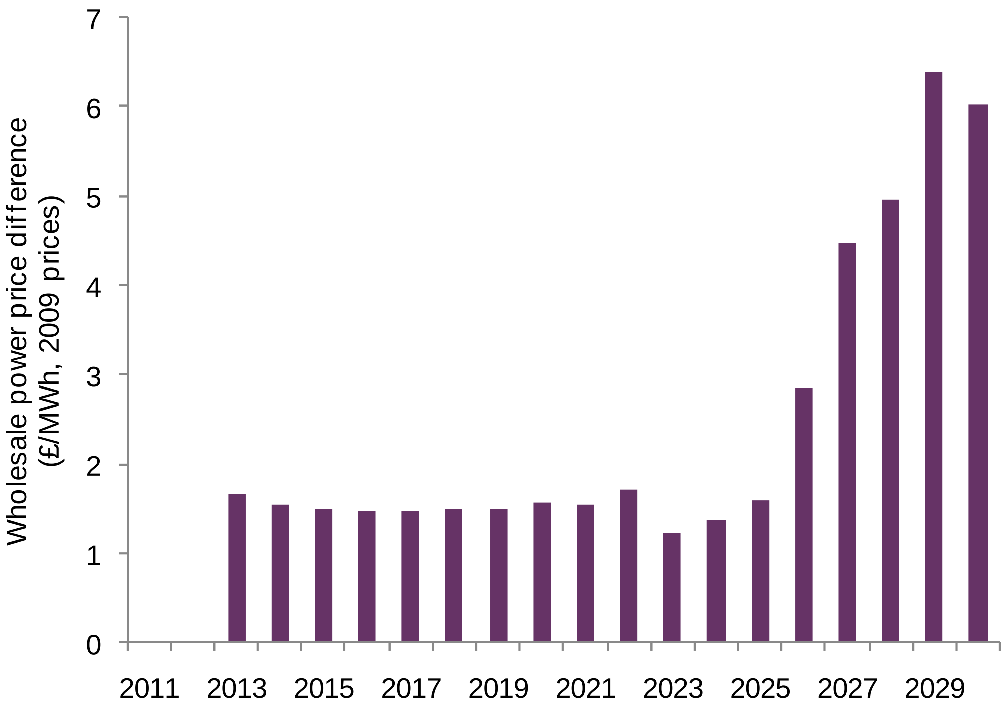


Source: HM Treasury, and Oxera analysis.

The carbon price feeds into wholesale electricity prices, and hence project returns, through its effect on the marginal cost of carbon-intensive price-setting plant. By way of illustration, an increase in the carbon price of €25/tCO_2 would increase the marginal cost of generation from a CCGT by around £9/MWh.

Figure 2.4 shows the impact that the difference in carbon price expectations in Oxera's updated projections could have on wholesale electricity prices. The figure shows that the introduction of CPS might be expected to increase electricity price projections by up to £7 by 2030; the SRMC component of prices increases by up to £9/MWh based on higher carbon costs, but the expectation of increased costs of marginal plant induces some new entry, which subsequently increases capacity margins between scenarios by up to 1 percentage point, which in turn reduces the scarcity component in peak prices.

Figure 2.4 Wholesale power price impact of the CPS



Note: Annual power price impacts depend on the carbon intensity of the generation mix as well as the carbon price difference.
Source: Oxera.

Due to the relatively small impact of CPS on power prices in the immediate future, the impact in present value terms on the economics of those projects being considered in the next few years is likely to be relatively small. Table 2.1 shows the discounted value of the increased power prices shown in Figure 2.4 on a 'representative' onshore wind plant with a load factor of 28%. At a discount rate of 10%, the revenue impact is equal to around £40/kW, or a 1.9% increase in total discounted revenues.

Compared to a discounted revenue stream from Renewable Obligation Certificates (ROCs) of around £864/kW, based on Oxera's central ROC price scenario, the table also highlights that the additional revenue associated with CPS is equal to around 5% of the expected ROC revenue stream, which absent subsequent banding adjustments might be expected to increase total deployment.

The analysis in Table 2.1 suggests that, based on Oxera's base case assumptions, a reduction in the onshore banding level below 0.95 ROC/MWh might be expected to decrease total onshore wind deployment relative to expectations at the current banding level and prior to the introduction of CPS. A reduction in the onshore banding level to around 0.95 ROC/MWh would offset the increase in revenues associated with CPS.

Table 2.1 ROC equivalent of increased carbon prices

Discounted revenue increase (£/MW)	39,562
Discounted ROC revenue (£/MW)	864,257
ROC equivalent of revenue increase	**0.05**

Note: Figures are based on a discount rate of 10%, load factor of 28% and plant life of 24 years based on Mott MacDonald (2010).
Source: Oxera.

As set out above, the effects of CPS should arguably be evaluated alongside the other proposed reforms within DECC's Electricity Market Reform (EMR) package. Without further clarity over the full package of reforms, it would be inefficient to link revisions to the current banding levels to the additional revenues associated with CPS alone if other elements of the reform package may act to worsen project economics.

3 The impact of alternative banding scenarios on onshore wind deployment

This section provides an assessment of the impact of the change in electricity price expectations associated with CPS, as well as different banding scenarios, on onshore wind economics and total onshore wind deployment.

The analysis uses wholesale power and ROC prices using Oxera's GB power model and renewables market model, as well as analysis of the regional distribution of potential onshore wind projects submitted to Ofgem as part of its review of transmission charging within Project TransmiT.[15] A detailed description of the modelling approach and underlying data is provided in the Appendix.

3.1 The impact on onshore wind economics

The internal rates of return (IRR) of a number of representative onshore wind projects are analysed below. These are used to compare movements in the range of the IRRs of potential projects relative to hurdle rate benchmarks to assess the impact of a number of model sensitivities on total deployment.

The analysis is based on discounted cash flow models that use Oxera's GB power price and ROC price projections as inputs, as well as regional cost and load factor differences as summarised in the Appendix. Results of the analysis are presented from model sensitivities along two dimensions, as follows.

– **Electricity prices.** Onshore wind economics and total onshore wind deployment in 2020 are calculated using electricity price revenues derived from Oxera's base case with and without CPS.

– **Banding levels.** Additional sensitivities of project economics and deployment levels are presented in Oxera's central case, based on the following onshore banding levels: 1 ROC/MWh, 0.9 ROC/MWh and 0.75 ROC/MWh.

Table 3.1 shows the IRR of a representative UK onshore wind project along these two dimensions, relative to the reference case with electricity prices that include CPS and 1 ROC/MWh. The table highlights that an increase in power prices associated with CPS (equivalent to an increase in total revenues of 1.9% as set out above) could increase project returns by around 28 basis points.

The banding sensitivities reported in the table show that, relative to the reference case:

– a decrease in onshore banding from 1 ROC/MWh to 0.9 ROC/MWh would reduce onshore wind IRRs by around 71 basis points;
– a decrease in onshore banding from 1 ROC/MWh to 0.75 ROC/MWh would reduce onshore wind IRRs by around 178 basis points.

[15] See Oxera (2010), 'Principles and priorities for transmission charging reform', November.

Table 3.1 IRR sensitivity of a representative onshore wind farm (basis point difference relative to reference case)

	No CPS	With CPS
1 ROC	–28	reference
0.9 ROC		–71
0.75 ROC		–178

Note: Shaded cells show the model sensitivities explored.
Source: Oxera.

As a cross-check, similar analysis of alternative banding scenarios was also undertaken using DECC's June 2010 electricity price projections.[16] This led to similar results, in which onshore wind IRRs decreased by around 60 basis points following a reduction in banding from 1 ROC/MWh to 0.9 ROC/MWh.

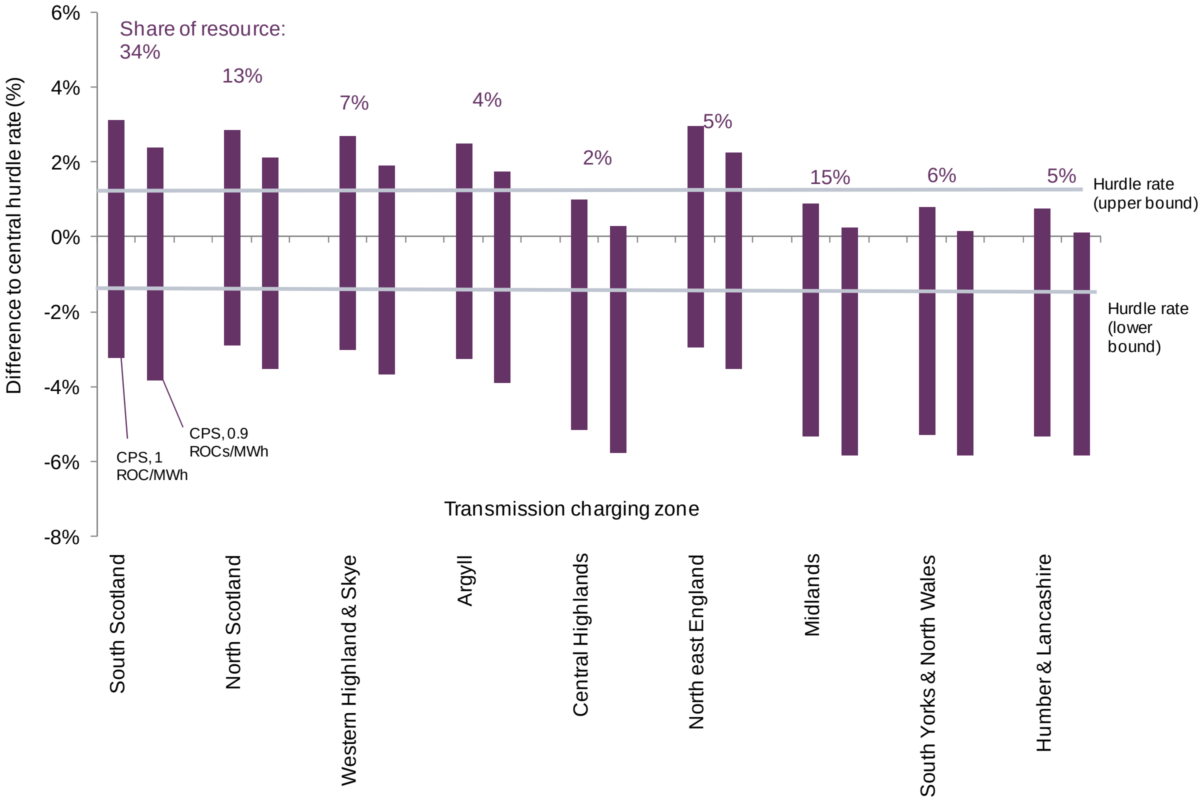
Figure 3.1 illustrates the impact on representative project IRRs in the nine most resource abundant transmission charging (TNUoS) regions as a result of reducing onshore banding from 1 ROC/MWh to 0.9 ROC/MWh within the CPS price sensitivity.

The figure shows two bars for each region, which represent the distribution of potential project IRRs, based on estimates of the variation in project costs and load factors, relative to hurdle rate estimates from Oxera's recent assessment for the Committee on Climate Change.[17] A second bar is shown for each region to highlight the shift in the distribution of returns under the 0.9 ROC/MWh banding scenario. This shows that significantly fewer potential projects are above hurdle rate, and therefore less likely to be developed, as the banding level is reduced.

Figure 3.1 also highlights the distribution of potential accessible onshore wind resource across transmission charging zones, alongside the range of potential project returns. The figure highlights that Scottish transmission charging zones account for 60% of the total resource, compared to the 91% of the total resource contained within the nine most resource-abundant charging zones.

[16] DECC (2010), 'Updated Energy Projections', June.
[17] Oxera (2011), 'Discount rates for low-carbon renewable generation technologies', April.

Figure 3.1 Impact of reduced banding levels on onshore wind economics



Note: IRRs are presented relative to hurdle rates (pre-tax, real) based on Oxera (2011), op. cit. The nine most resource abundant regions are shown, accounting for 91% of the total resource.
Source: Oxera.

Project economics vary *between* regions due to differences in wind speed, which drives expected load factors, as well as transmission charge differentials and other cost differences. Load factors and cost variations will also lead to a distribution of projects *within* regions.

Table 3.2 summarises the regional differences in costs and load factors for representative plant in each of the nine most significant charging zones with respect to wind resource that are used in the analysis, as identified in the Appendix.

Table 3.2 Regional variations in load factors and costs (pre-tax, real)

TNUoS generation zone	TNUoS (£/kW)	CAPEX index	Fixed O&M index	Load factor (%)
Western Highland & Skye	22.8	1.0	1.3	26–36
North Scotland	20.1	1.0	1.1	24–34
Central Highlands	17.6	1.0	1.3	22–32
Argyll	13.3	1.0	1.3	24–34
South Scotland	12.5	0.9	1.1	22–32
North east England	8.8	1.0	1.0	22–32
Humber & Lancashire	5.4	1.1	0.9	19–29
South Yorks & North Wales	3.6	1.1	1.0	19–29
Midlands	1.6	1.0	0.9	18–28

Note: The CAPEX and fixed O&M indices represent the ratio of regional costs to a national base case. Regional variations are based on cost estimates of prospective projects. Cost variations are applied to the base case in Mott MacDonald (2010), ‘UK Electricity Generation Costs Update’, June. Cost indices for West Highlands are

assumed to equal those in Argyll. Zonal load factors are based on Oxera analysis and data on historical load factors of plant.
Source: Mott MacDonald, ScottishPower and Oxera analysis.[18]

The analysis of the range of returns within regions, as highlighted in Figure 3.1, shows that, while some projects may perform better than others, under a reduced banding level for onshore wind a significant number of potential projects are likely to be uneconomic or marginal, even within the most resource-abundant areas of Great Britain. The dataset used to create these ranges is described in more detail in the Appendix.

3.2 Impact on deployment levels

The impact of the model sensitivities described above on the deployment of onshore wind is presented in Table 3.3. This is calculated by comparing the relative share of projects within each region above hurdle rate, as illustrated in Figure 3.1, within each of the model sensitivities. The figures represent changes in the amount of total resource above hurdle rate relative to the reference case, with electricity prices that include the effect of CPS, and onshore banding of 1 ROC/MWh.

Table 3.3 Relative deployment of onshore wind

	No CPS	With CPS
1 ROC	–4%	reference
0.9 ROC		–10%
0.75 ROC		–25%

Source: Oxera.

The results in Table 3.3 highlight the following:

– the introduction of CPS increases the discounted value of expected future revenue by approximately 1.9%, which, based on the current banding levels, could increase expected onshore wind deployment by around 4% of the total resource potential;

– reducing onshore banding to 0.9 ROC/MWh from 1 ROC/MWh in a scenario with CPS could decrease onshore wind deployment by around 10% of the total resource potential;

– reducing onshore banding to 0.75 ROC/MWh from 1 ROC/MWh could decrease onshore wind deployment by around 25% of the total resource potential.

Similar analysis was also undertaken using DECC's June 2010 projections. This led to similar results, in which deployment fell by around 8% of the total resource potential following a reduction in banding from 1 ROC/MWh to 0.9 ROC/MWh.

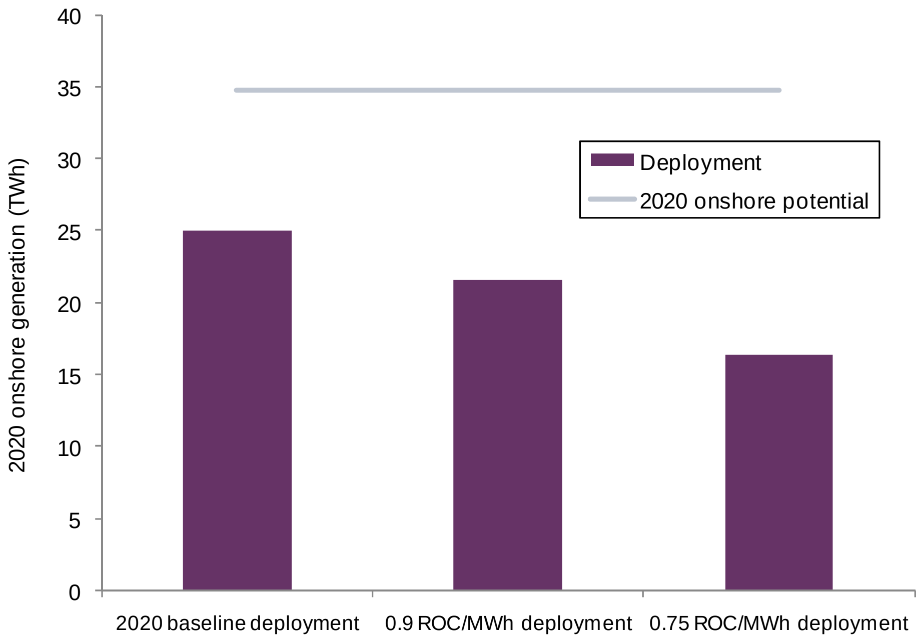
On the assumption that the impact of changes in banding levels and/or power price projections (impacted through the CPS) affects the deployment of potential projects from 2013 onwards, Figure 3.2 shows the scale of the potential effects on 2020 onshore wind output. This shows that onshore wind output could be around 3.5TWh lower by 2020 in the 0.9 ROC/MWh scenario, and 8.6TWh lower in the 0.75 ROC/TWh scenario relative to the reference case with 1 ROC/MWh.

Figure 3.3 extends this analysis, and highlights that, of the 3.5TWh of onshore wind potential made uneconomic from a decrease in onshore banding from 1 ROC/MWh to 0.9 ROC/MWh, around 68% of the potential projects affected are within transmission charging zones located

[18] References in this report to ScottishPower also encompass ScottishPower Renewables.

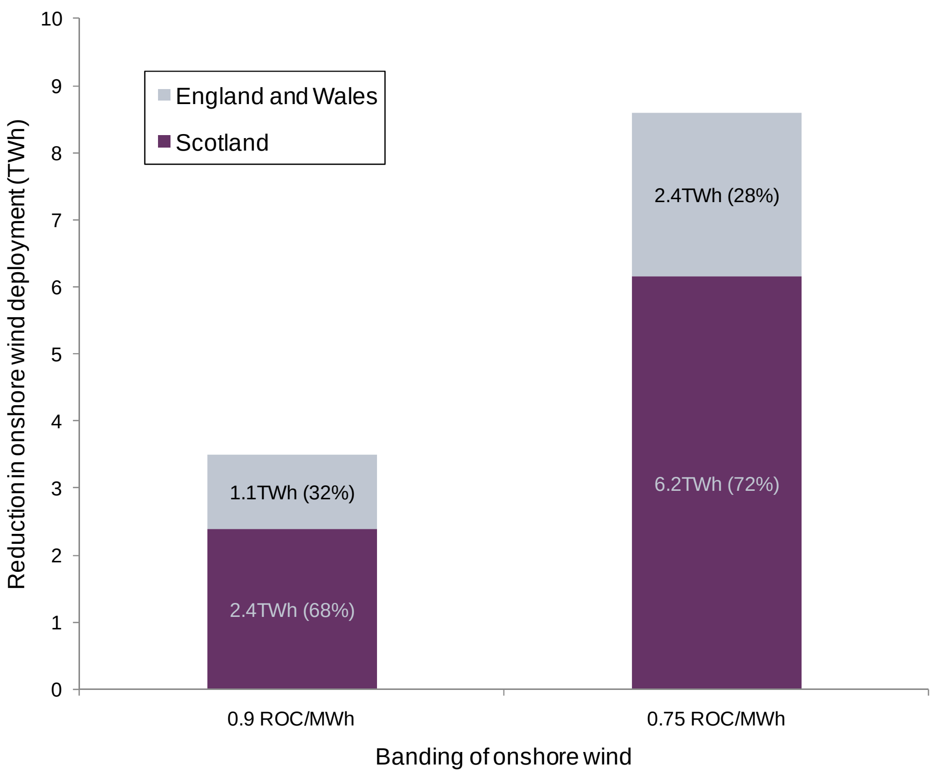
in Scotland. Of the 8.6TWh of onshore wind potential made uneconomic from a decrease on onshore banding from 1 ROC/MWh to 0.75 ROC/MWh, around 72% of the potential projects affected are in Scotland.

Figure 3.2 Impact of alternative banding scenarios on onshore wind deployment



Source: Oxera.

Figure 3.3 Location of reduced onshore wind deployment



Source: Oxera.

4 The impact of alternative banding scenarios on the total costs of meeting the renewables targets

This section provides an assessment of the costs associated with changes in onshore wind deployment in the scenarios developed in section 3. It outlines the difference in annual support costs between scenarios, based on the assumption that it is likely that any reduction in onshore wind would be provided by offshore wind if the UK is to meet its 2020 renewables target and low-carbon budgets. It also provides an indication of the likely difference in associated transmission network costs associated with a shift in the generation mix towards increased offshore wind.

The results present annual cost differences in 2020. The effective level of support under large-scale renewable feed-in-tariffs that may ultimately replace support under the RO from 2017 is assumed to be similar to that within the revised banding levels in the analysis.

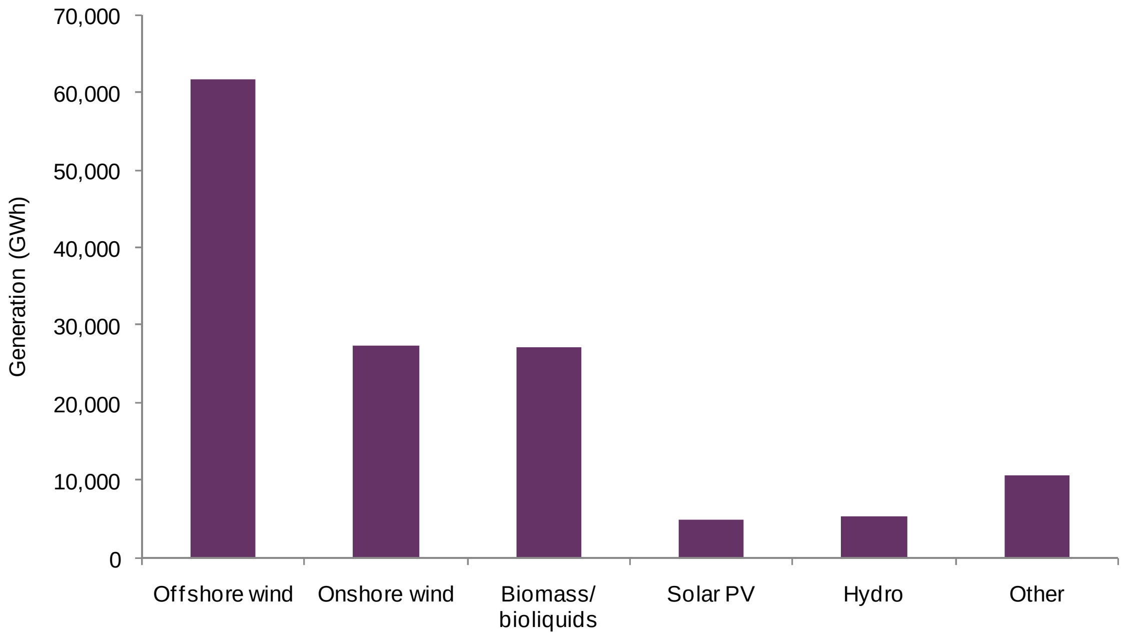
4.1 RO support costs

Annual support costs under the RO are currently fixed in advance for each year, and equal to the obligation size (measured in ROCs) multiplied by the buyout price. Since renewables deployment is expected to grow over the course of the next decade, however, the RO's headroom mechanism implies that total support costs will depend on the expected volume of deployment of the different renewable technologies, and their ROC banding.[19] Similarly, under a system of Feed-in-Tariffs (FITs) as proposed within DECC's EMR package, total costs might be expected to depend on the support levels within those contracts and the number of contracts per technology as dictated by policy.

The ARUP report commissioned by DECC suggests that, based on resource potential, the three renewable technologies with the most abundant resource in 2020 (in terms of generation potential as opposed to capacity) are onshore wind, offshore wind and biomass. This is highlighted in Figure 4.1.

[19] The obligation size in any year is either set at a value determined within the Renewables Obligation Order (ROO), or determined by DECC and equal to the expected number of ROCs to be produced in that year, plus headroom.

Figure 4.1 Renewable capacity and generation potential in 2020



Source: ARUP.

The Committee on Climate Change's recent Renewable Energy Review assumed that no new investment in biomass would take place in the power sector beyond 2020, given sustainability concerns and the demands for biomass from other sectors (such as industrial heat and aviation).[20] Given these potential limits, and any potential policy response that may limit investment in biomass, the analysis below focuses on the substitution of onshore wind by offshore wind, induced by reduced banding levels for onshore wind. The greater use of offshore wind in place of onshore wind might be expected to have two effects on total support costs:

– to lower the support costs associated with reduced onshore deployment, and to lower levels of support to those onshore projects that still get built; and
– to increase the support costs associated with increased offshore deployment.

Figure 4.2 provides an assessment of the change in support costs that could result from the reduction in onshore wind deployment estimated in section 3 above. The figure highlights that:

– the reduction in support to onshore wind implies that the costs of the support that does get built could fall by around £170m per annum if banding levels were reduced to 0.9 ROC/MWh, and £373m per annum if banding levels were reduced to 0.75 ROC/MWh, taking into account both the reduced unit support and the reduced deployment;

– if these reduced onshore wind volumes were to be replaced by additional offshore wind, the costs of the support would increase by around £258m per annum if banding levels were reduced to 0.9 ROC/MWh, and £640m per annum if banding levels were reduced to 0.75 ROC/MWh, as a result of higher support being provided to offshore wind;[21] and

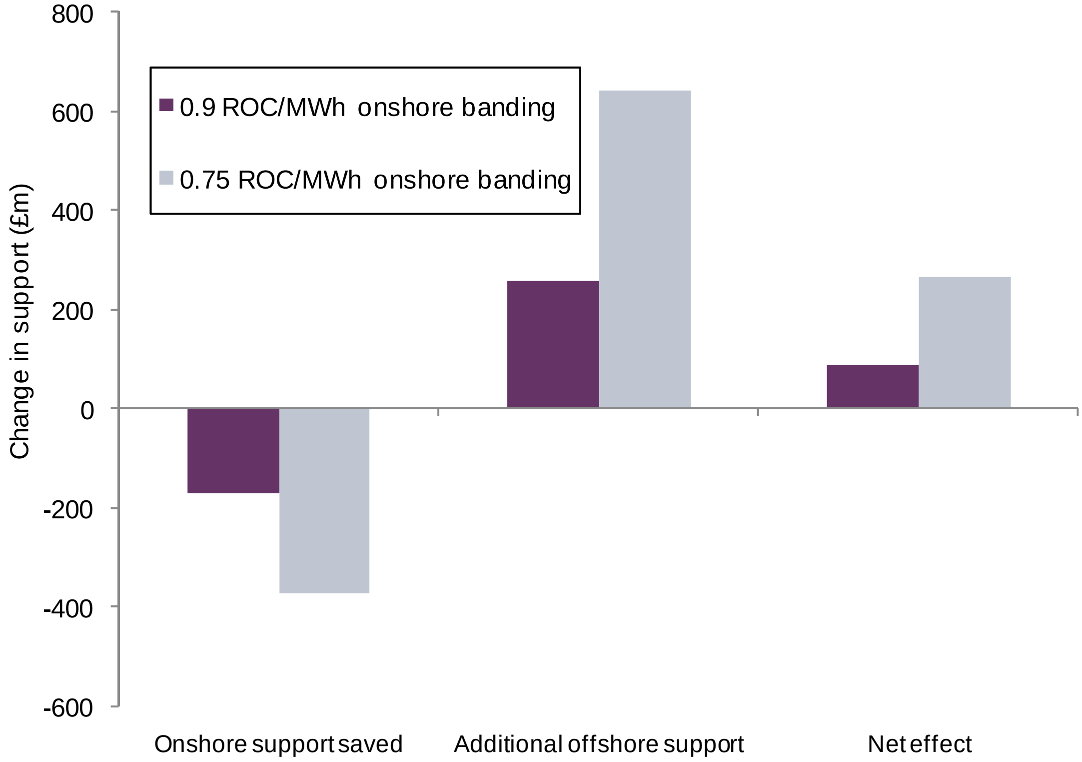
[20] The Committee on Climate Change's preliminary conclusion was that without Carbon Capture and Storage (CCS), biomass would probably be of more value when used outside the power sector. See Committee on Climate Change (2011), 'The Renewable Energy Review', May, p. 93.
[21] The banding level of offshore wind is assumed to remain at 2 ROC/MWh.

– the net effect could be to increase renewables support costs by around £89m per annum if banding levels were reduced to 0.9 ROC/MWh, and £267m per annum if banding levels were reduced to 0.75 ROC/MWh.

Similar analysis of alternative banding scenarios was also undertaken using DECC's June 2010 electricity price projections. This led to similar results, in which the net effect was to increase support costs by £55m per annum following a reduction in banding from 1 ROC/MWh to 0.9 ROC/MWh.

The reduction in total support to onshore wind from reduced banding levels has been estimated on the basis that it would affect projects accredited from 2013, with plant that is built and accredited before then receiving grandfathered support levels.

Figure 4.2 Impact of reduced onshore wind banding on annual support in 2020 (£m per annum)



Note: Prices are in 2009 values, and the buyout price equal to £37.19/ROC.
Source: Oxera.

4.2 Transmission costs

Changes in the relative shares of onshore and offshore wind also have implications for transmission investment. The costs of offshore transmission investment are borne by offshore project developers directly through charges payable to Offshore Transmission Owners (OFTOs). The impact of changes in onshore banding levels on offshore transmission costs are therefore reflected in the support cost differences set out above.

Changes in the relative shares of onshore and offshore wind deployment can, however, affect the extent of onshore grid reinforcement required. Differences in these costs are borne by all network users, and are examined below. To illustrate these effects, estimates of indicative incremental onshore transmission costs associated with onshore and offshore wind are set out in Table 4.1, based on analysis from two sources, as summarised in Box 4.1.

Table 4.1 Average cost of onshore transmission capacity per GW (£ billion)

Study	Onshore wind	Offshore wind
ENSG, 2009	0.23–0.27	0.14–0.24
Sinclair Knight Merz (SKM), 2008	0.12–0.13	

Note: Offshore wind figures relate to onshore reinforcement.
Source: ENSG (2009), 'Our electricity transmission network: a vision for 2020'. SKM (2008), 'Growth scenarios for UK renewables generation and implications for future developments and operation of electricity networks'.

For the purpose of analysing substitution between onshore and offshore wind, this report uses the figures derived from the ENSG report, which allow a comparison between the onshore costs related to onshore and offshore wind deployment. As highlighted in Table 4.1, this gives a range of the onshore costs borne by all network users of between £0.2 billion/GW and £0.3 billion/GW for onshore wind, and a range of between £0.1 billion/GW and £0.2 billion/GW for offshore wind. The implied difference in costs would be lower if onshore wind costs were based on those reported in the SKM report.

Given that offshore wind typically operates at a higher load factor than onshore wind, around 0.8 GW of offshore wind capacity is required to replace the output associated with 1 GW of onshore wind.[22] This, combined with the cost differences identified above, suggests that the savings in onshore transmission costs associated with the replacement of output of 1GW of onshore wind with offshore wind could be around £0.04 billion/GW to £0.16 billion/GW.

Box 4.1 Studies into the impact of wind penetration on transmission costs

– **ENSG—'Our electricity transmission network: a vision for 2020' (2009)**
The ENSG report focuses solely on onshore transmission infrastructure, and provides model results of the investment needed in the period to 2020 under three generation scenarios. The report does not clearly differentiate between transmission costs required for onshore wind and those onshore reinforcement costs that are allocated to offshore, although the overall transmission costs are broken down by area (and by project within each area). In the estimates presented in Table 4.1, an approximation of this split has been made such that all investment in Scottish transmission is related to onshore, and transmission investment in Eastern England and Wales is related to offshore wind generation.

– **SKM—'Growth scenarios for UK renewables generation and implications for future developments and operation of electricity networks' (2008)**
SKM's report was commissioned by BERR in order to understand the issues and costs related to increased renewables penetration on the grid by 2020. As part of this assessment, power flows across a number of system boundaries were assessed to understand the level of reinforcement, and the use of AC or DC transmission according to the distance of offshore wind farms from the network was analysed. While connection costs related to offshore wind generation and onshore wind generation are split out in the figures, costs related to distribution and transmission are not considered separately. In relation to transmission reinforcement, a fixed cost of £0.8 billion for 'other reinforcement' appears to have been used in all scenarios, and for the estimates presented in Table 4.1, has been allocated equally to offshore and onshore wind.

[22] Based on load factors of onshore and offshore wind of 28% and 35% respectively.

Based on the transmission cost ranges identified above, Table 4.2 highlights the cost differences associated with the onshore/offshore wind substitution implied by the ROC banding sensitivities set out in section 3. The table also shows these costs on an annual basis, based on an annuitised value using a (real) discount rate of 6%.

Table 4.2 Transmission cost implications of alternative ROC banding sensitivities

Study	0.9 ROC banding	0.75 ROC banding
Additional offshore (TWh)	3.5	8.6
Additional offshore (GW)	1.4	3.5
Transmission unit cost difference (£ billion/GW)	0.04–0.16	0.04–0.16
Total cost difference (£ billion)	0.05–0.22	0.13–0.55
Annualised cost saving (£m per annum)	5–19	11–48

Note: Annualised costs are based on a real discount rate of 6% and 20-year asset life. Offshore wind load factor is assumed to be 35%.
Source: ENDG, SKM, Crown Estate, and Oxera analysis.

The equivalent analysis using DECC's 2010 electricity price projections leads to a saving in net onshore transmission costs of around £3m–£15m per annum following a reduction in banding from 1 ROC/MWh to 0.9 ROC/MWh.

The range in transmission unit costs is representative of considerable uncertainty surrounding the incremental cost of substituting offshore wind for onshore wind, where individual projects may have no incremental costs, but significant volumes of either will require transmission grid strengthening and/or expansion of offshore transmission. The investments will involve large-scale projects and, as such, the cost profile of increasing either will be necessarily lumpy.

4.3 Overall impact

The combined impact of the increase in support costs and reduction in transmission costs associated with a decrease in onshore banding to 0.9 ROC/MWh and 0.75 ROC/MWh are shown in Table 4.3 and Figure 4.3.

The table shows that the overall impact of decreasing onshore banding to 0.9 ROC/MWh could lead to a net increase in annual costs of around £70m–£84m per annum by 2020, and the impact of decreasing onshore banding to 0.75 ROC/MWh could lead to a net increase in annual costs of around £219m–£256m per annum.

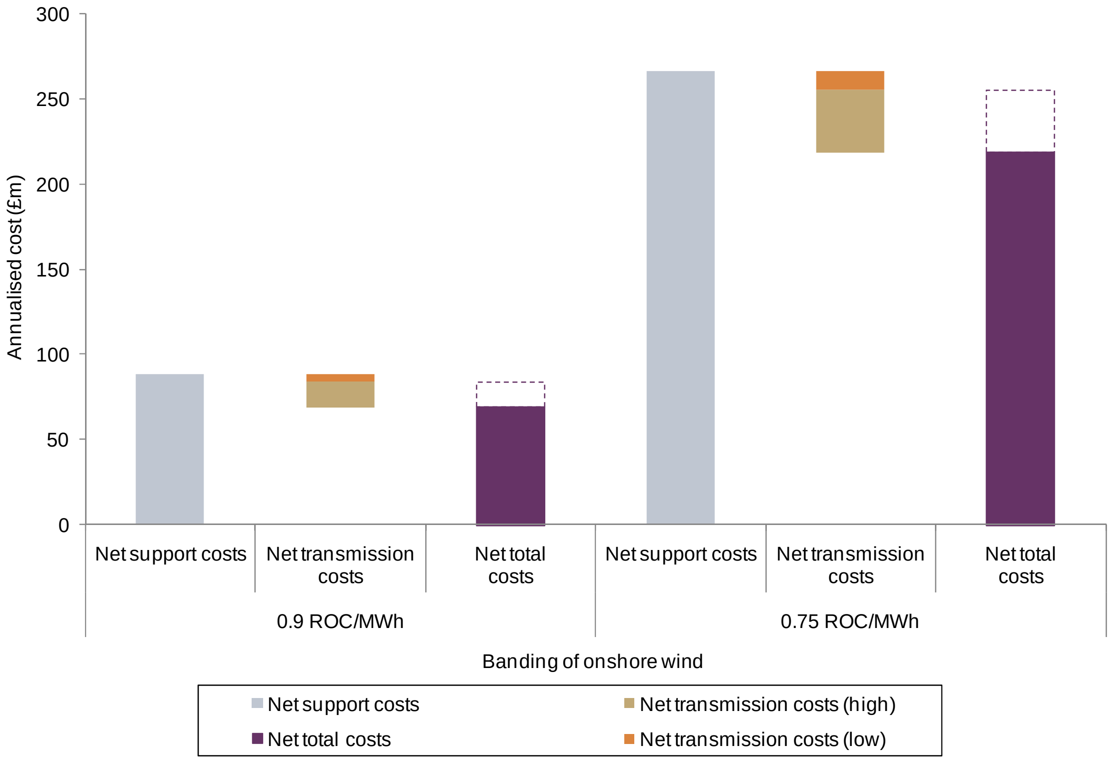
Table 4.3 Overall net effect of banding scenarios

Net costs (£m)	0.9 ROC banding	0.75 ROC banding
Increase in support costs	89	267
Change in transmission costs	–5 to –19	–11 to –48
Total increase in costs	**70–84**	**219–256**

Source: Oxera.

Similar analysis using DECC's June 2010 electricity projections leads to an overall increase in support and transmission costs of £40m–£51m per annum following a reduction in banding from 1 ROC/MWh to 0.9 ROC/MWh.

Figure 4.3 Net effect of banding scenarios (£m per annum)



Source: Oxera analysis.

5 Conclusions

The analysis in this report has provided an assessment of the possible effect on onshore wind economics from the introduction of Carbon Price Support (CPS), and the impact on project economics, deployment levels, and additional costs associated with alternative banding scenarios for onshore wind. The key conclusions of the analysis are that:

– the introduction of CPS is likely to increase onshore wind revenues by less than 2%, and improve returns to onshore wind projects by around 30 basis points;

– the increase in revenues associated with CPS is equivalent to a change in onshore ROC banding of around 0.05 ROC/MWh, and therefore banding levels below 0.95 ROC/MWh might be expected to reduce overall levels of onshore wind deployment relative to that expected before the introduction of CPS;

– other elements of the EMR package, such as the proposed capacity mechanism, could adversely affect onshore wind economics, although it is difficult to estimate the effects without further details on how a new mechanism might work;

– a reduction in onshore banding to 0.9 ROC/MWh could reduce project returns by around 71 basis points and make an additional 10% of potential projects uneconomic, equivalent to around 3.5TWh by 2020 (68% of the projects affected are expected to be located in Scotland);

– a reduction in onshore banding to 0.75 ROC/MWh could reduce project returns by around 180 basis points and make an additional 25% of potential projects uneconomic, equivalent to around 8.6TWh by 2020 (72% of the projects affected are expected to be located in Scotland);

– if a reduction in onshore wind deployment associated with such banding changes were to be replaced by offshore wind (the UK's most abundant renewable resource), there would be likely to be an associated increase in support costs alongside a relatively small decrease in required onshore transmission costs;

– a reduction in onshore banding from 1 ROC/MWh to 0.9 ROC/MWh could increase net support costs by around £89m per annum, while reducing net onshore transmission costs by around £5m–£19m per annum, leading to an overall increase of around £70m–£84m per annum;

– a reduction in onshore banding from 1 ROC/MWh to 0.75 ROC/MWh could increase net support costs by around £267m per annum, while reducing net onshore transmission costs of around £11m–£48m per annum, leading to an overall increase of around £219m–£256m per annum.

The results above suggest that, given the distribution of project economics derived in the analysis, the additional revenues associated with the introduction of CPS are unlikely to warrant a reduction in onshore banding. Any reduction in onshore wind banding is likely to reduce onshore wind deployment, and replacing this reduced onshore wind output with increased offshore wind deployment would lead to a significant increase in costs.

The effects of other potential reforms put forward in DECC's EMR package have not been considered. The proposed capacity mechanism could have the effect of lowering wholesale electricity prices received by onshore wind without providing a corresponding increase in revenues through capacity payments. Thus, it would be inefficient to link revisions to the current banding levels to the additional revenues associated with CPS alone if other elements of the reform package may subsequently act to worsen onshore wind economics.

A1 Underlying data and modelling approach

This appendix sets out the data used, and approach taken, regarding onshore wind resource. The modelling methodology used in calculating the assumed regional differences in load factor and cost is presented, followed by a summary of the underlying power and ROC prices that result from the analysis.

A1.1 Onshore resource data and conclusions

The geographic distribution of practical, available onshore wind resource can be assessed by estimating the total accessible resource (ie, based on the distribution of mean wind speeds and excluding land where wind turbines could not be physically located or would face environmental restrictions), and making adjustments for assumptions on wind farm grouping, build-rate constraints and network limitations.

Accessible resources might be expected to be relatively constant over time, since these exclude more dynamic aspects such as supply chain constraints and network limitations. Table A1.1 presents a high-level split of onshore wind resource potential between Scotland, England and Wales, and Northern Ireland, before accounting for network constraints, based on a comprehensive estimation of resource potential undertaken for the government in 2000.

While the estimated level of the total accessible resource is likely to have changed over time, with increased understanding of the implications for deployment potential of topology, wind turbulence and wind speed, the broad split of resource across regions from previous studies should still be expected to hold. Table A1.1 highlights that around 78% of the accessible onshore wind resource in Great Britain (GB) is in Scotland.

Table A1.1 UK onshore wind accessible resource

	England and Wales	Scotland	Northern Ireland	UK
Capacity (MW)	20,291	68,824	20,564	109,679

Source: ETSU (2000), 'New and Renewable Energy: Prospects in the UK for the 21st Century: Supporting Analysis'.

A snapshot of the current practical resource, which considers network capability and high-level project economics, can be gained from looking at the distribution of current projects and those in planning, consented or under construction, although this may underestimate the potential resource that can be exploited through further grid reinforcement. Table A1.2 considers existing projects and potential projects in Great Britain, and highlights that around two-thirds of the current onshore wind projects (including those consented and in planning) are in Scotland.

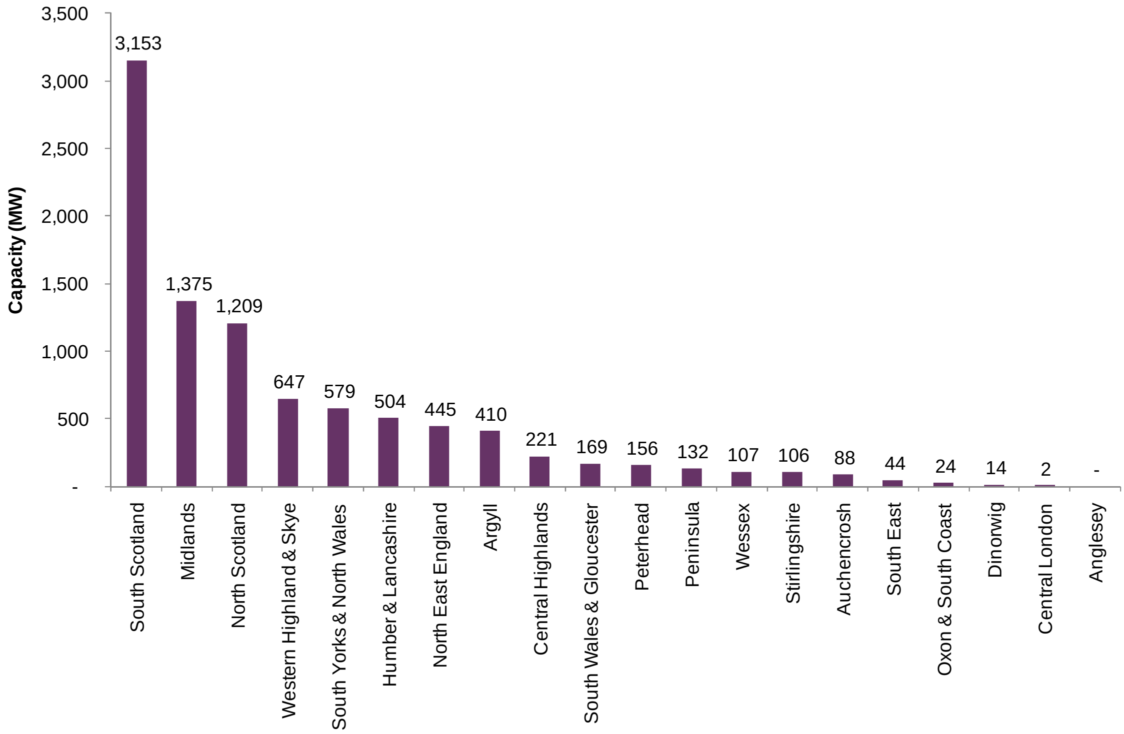
Table A1.2 High-level distribution of GB onshore wind prospects (MW)

	Operational	Under construction	Consented	In planning	Total
England and Wales	1,726 (43%)	130 (12%)	1,490 (45%)	1,775 (35%)	**5,120 (38%)**
Scotland	2,314 (57%)	928 (88%)	1,833 (55%)	3,229 (65%)	**8,304 (62%)**
GB	4,041 (100%)	1,058 (100%)	3,323 (100%)	5,004 (100%)	**13,425 (100%)**

Source: RenewableUK and Oxera analysis.

Figure A1.2 summarises the geographic distribution of the GB onshore wind development portfolio by TNUoS charging zone.

Figure A1.2 Distribution of the current GB onshore wind prospects by TNUoS zone



Note: Prospects include the projects under construction, consented and in planning reported in Table A.1.2.
Source: RenewableUK and Oxera analysis.

Figure A1.2 highlights that South Scotland has the largest volume of onshore wind capacity currently in planning, consented or under construction, and represents around 34% of the portfolio of current wind projects that are in construction or being considered across Great Britain. The nine charging zones that contain the most resource in terms of capacity under consideration (ranging from South Scotland to Central Highlands in Figure A.1.2) represent 91% of the total portfolio.

A1.2 The impact of regional variations in onshore wind load factors and costs

Project economics vary *between* regions due to differences in wind speed, which drive expected load factors, as well as TNUoS charge differentials and other cost differences. Load factors and cost variations will also lead to a distribution of projects *within* regions.

Table A1.3 combines the regional differences in costs and load factors for representative plant in each of the nine most significant charging zones with respect to wind resource, as identified in Figure A1.2, which presents an assessment of the returns to developments across transmission charging zones under the existing differentiated charging regime.

Table A1.3 Regional variations in load factors and costs (pre-tax, real)

TNUoS generation zone	TNUoS (£/kW)	CAPEX index	Fixed O&M index	Load factor (%)
Western Highland & Skye	22.8	1.0	1.3	26–36
North Scotland	20.1	1.0	1.1	24–34
Central Highlands	17.6	1.0	1.3	22–32
Argyll	13.3	1.0	1.3	24–34
South Scotland	12.5	0.9	1.1	22–32
North east England	8.8	1.0	1.0	22–32
Humber & Lancashire	5.4	1.1	0.9	19–29
South Yorks & North Wales	3.6	1.1	1.0	19–29
Midlands	1.6	1.0	0.9	18–28

Note: The CAPEX and fixed O&M indices represent the ratio of regional costs to a national base case. Regional variations are based on cost estimates of prospective projects. Cost variations are applied to the base case in Mott MacDonald (2010), op. cit. Cost indices for West Highlands are assumed to equal those in Argyll. Zonal load factors are based on Oxera analysis and data on historical load factors of plant.
Source: Mott MacDonald, ScottishPower, and Oxera analysis.

The impact of these variations in project load factors and local costs gives rise to a distribution of project IRRs both between and within regions, which are represented by the IRR ranges in the analysis.

An analysis of the range of returns *within* regions shows that, while some projects may perform better than others, a significant number of potential projects are likely to be uneconomic or marginal, even in the most resource-abundant areas of Great Britain. The dataset used to create these ranges is described in Box A1.1.

Box A1.1 Cost and load factor assumptions

The base-case onshore wind plant cost assumptions have been obtained from Mott MacDonald (2010), op. cit. These have been adjusted for estimated regional differences across TNUoS zones using project cost information obtained from ScottishPower's portfolio of prospective projects averaged across regions. The average level of fixed costs across regions has also been adjusted upwards in line with recent market experience, leading to the following increase in costs for prospective projects:

– changes to the structure of rates, which have increased the costs faced by Scottish developments by up to a factor of two, and those in England and Wales by a factor of four;
– increases in rent to reflect increasing market expectations;
– increases in community benefit contributions;
– recent experience of higher operating and maintenance contract costs as the turbine warranty periods for early projects have expired.

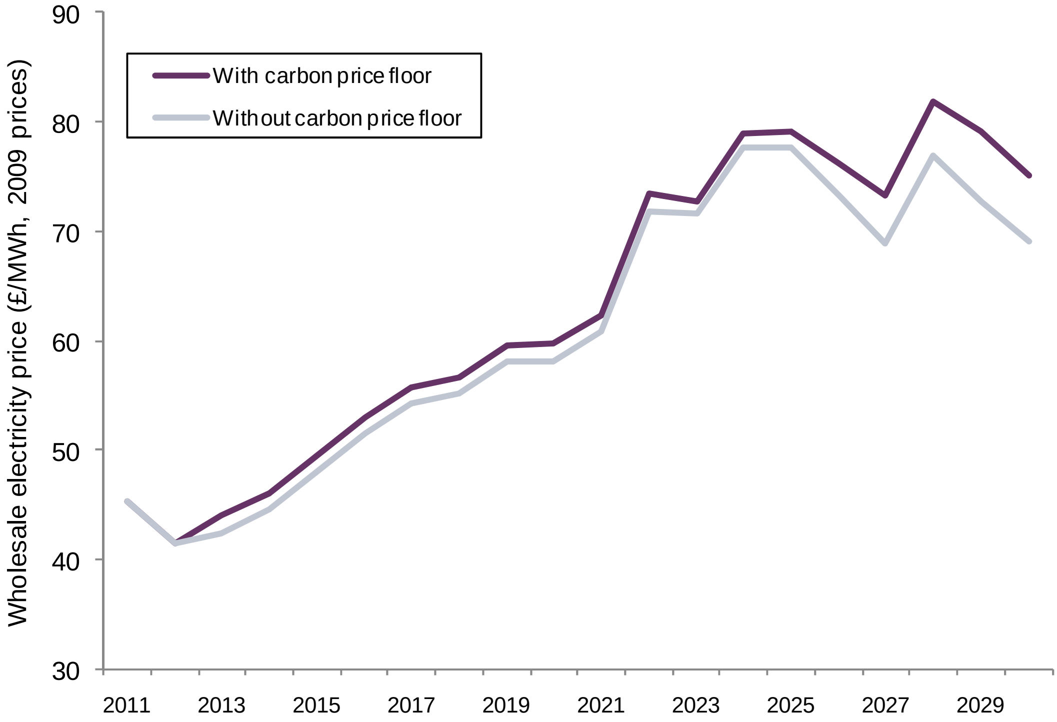
The central load factor in each zone has been estimated from consideration of the relative load factors from actual plant. The average load factor across zones is equal to the Mott MacDonald capacity factor adjusted for plant availability (27%).

High and low load-factor ranges have been estimated based on one standard deviation of actual plant variations. A five-percentage point standard deviation of load factors has been used based on an estimate of the standard deviation of load factors of all GB plant, which lies in the range 4–8%, depending on the size of the plant considered.

A1.3 Underlying power and ROC prices

Figure A1.3 illustrates the underlying power prices used in the analysis.

Figure A1.3 Time-weighted power prices with and without a carbon price floor



Source: Oxera analysis.

Outturn ROC prices show a gradual decrease from current levels to a fixed price of £37.7 per ROC from 2016/17 onwards. ROC price levels at five-year intervals are summarised in Table A1.4.

Table A1.4 Outturn ROC price with and without CPS

ROC price	2010/11	2015/16	2020/21	2025/26	2030/31
Outturn price (£/ROC)	45.5	37.9	37.7	37.7	37.7

Note: ROC prices are the same under both scenarios as significant differences in renewable volumes do not occur until after prices are set by the headroom mechanism.
Source: Oxera analysis.

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