Oxera

Reform of the Renewables Obligation

What is the likely impact of changes?

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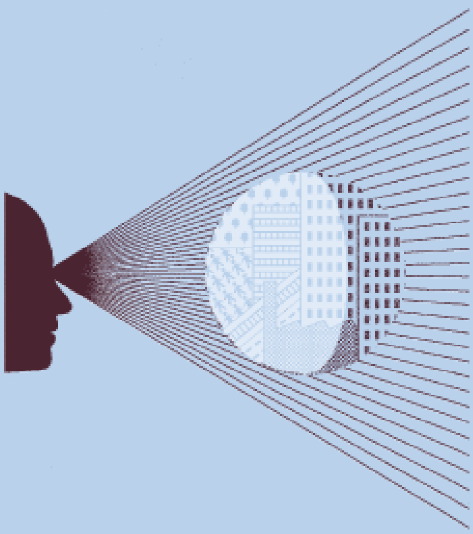

Executive summary

The UK has set targets to increase the proportion of electricity generation from renewable technologies as part of its long-term commitment to reduce fossil-fuel dependence and decrease climate-damaging carbon emissions. The Renewables Obligation (RO) is the primary mechanism for achieving these goals.

In addition to proposing an increase in the level of renewable generation, the 2006 Energy Review raised the question of whether the current mechanism could be improved. Features of the current RO perceived as undesirable include the following.

- The RO does not differentiate between levels of support given to higher- and lower-cost technologies. This could lead to technologies such as onshore wind dominating the renewables market in the short term, which might hinder the commercialisation of other technologies that have the potential to make a significant contribution to renewable generation in the long term.
- Some technologies that are more economic (ie, least costly), such as co-firing, may be given more support than they require, leading to an unnecessarily high cost of the scheme to customers relative to renewables deployed.
- Under the current RO mechanism, the Renewables Obligation Certificate (ROC) price may fall sharply if the volume of renewables in the market rises above the obligation size. The risk of this may be adversely affecting current build decisions.

The 2006 Energy Review set out measures that could be implemented to alleviate these problems. These included:

- changing the level of support in terms of ROCs/MWh granted to each technology (banding);
- raising the maximum size of the obligation to 20% of electricity under a headroom mechanism that increases the obligation size if volumes are high in order to prevent ROC price crashes;
- removing the link between the buyout price and RPI from 2015.

This study employs a modelling framework to provide an assessment of policy options for changing the RO. Using assumptions of supply curves for different renewable generation technologies provided by Ernst & Young,[1] the modelling shows how alternative RO mechanisms would be expected to affect renewable volumes and technology types.

An important element of a banded RO would be the ability of government to periodically review the banding levels assigned to each technology. In its consultation on the banding proposals, the government suggested that projects reaching a defined milestone before the introduction would benefit from grandfathering—ie, projects other than co-firing would have the number of ROCs/MWh protected. This has been included in the modelling approach.

The government has also proposed that reviews of banding levels for new projects might be likely to occur every three to five years. For this reason, analysis of the outcomes in terms of

[1] Ernst & Young (2007), 'Impact of Banding the Renewables Obligation: Costs of Electricity Production', forthcoming.

deployment of renewable generation has focused on the period up to 2015. Beyond that point the uncertainty in terms of technology costs, wholesale electricity and carbon prices, and other underlying assumptions would make it difficult to assess what appropriate banding levels for new projects will be.

An assessment is made of the lifetime costs and benefits of each policy scenario, assuming that the banding levels introduced in 2009 remain unchanged for the remainder of the RO, with the exception of regular co-firing in some scenarios. This assessment involves consideration of factors such as the resource cost, the carbon savings, and the social value of carbon saved. It also sets out distributional effects including the cost to the Exchequer, the cost to firms and the cost to the customer. It does not explicitly value any wider benefits that might arise from diversity in renewable generation; nor does it examine the extent to which promotion of diverse technologies might contribute to a reduction in future technology costs, and therefore to the cost of renewable generation in the long term, although an element of price reduction is implicit in the Ernst & Young data. The modelling does show the extent to which technology diversity can be encouraged, and overall renewable generation increased, through changing the RO, and the expected cost for this.

Table 1 provides a detailed breakdown of the quantified costs and benefits in each case, while the key features of the scenarios are described below.

– The Base Case modelled reflects the current RO with a small modification in the elimination of the cap on energy crop co-firing. The modelling shows that, overall renewable volumes stay below the target level, and onshore wind retains a high share of the overall renewable market.

The banding scenarios examined were modelled with the buyout price link to RPI removed from 2015/16 with the exception of Scenario 6, which retains the link.

– Scenario 1 is based around an extremely disaggregated banding scheme, where there are large differences between the levels of ROC support given to different technologies. Bands are set to reflect the central price estimate for each technology. Overall, renewables volumes increase sharply, as do the costs compared with the Base Case, despite the reduction in support granted to co-firing. There is greater diversity in technology choice, but the high levels of support given to the most expensive technologies also mean that the overall costs of the scheme are very sensitive to small changes in capital costs.

– In Scenario 2, the current support for high-cost technologies is maintained, but support for low-cost technologies is cut and the cap on co-firing removed. This results in more carbon savings than the Base Case, with a similar overall resource cost. However, it does not result in as much renewable generation or carbon savings as the other scenarios; it has limited diversity in technology penetration; and it does not encourage the emergence of technologies such as tidal stream, wave and solar PV.

– In Scenario 3, less support is given to the most expensive technologies, although there is still considerable differentiation between the highest and lowest bands. This scenario has the highest level of carbon savings, but also has the highest cost to consumers of all the scenarios without the buyout price link to RPI.

– In Scenario 4, the support granted to co-firing is cut further, as is the support given to the more expensive technologies (such as tidal stream, wave and solar PV). Offshore wind volumes are higher, although volumes of the higher-cost technologies are lower than in Scenario 3. The cost-effectiveness of carbon saved is an improvement over Scenario 3, although net volumes are decreased slightly.

– In Scenario 5 the bandings are rebalanced slightly from Scenario 4, resulting in similar levels of overall carbon savings and resource costs, but with greater diversity, and increased volumes of technologies such as tidal stream, wave and solar PV.

Scenario 6 retains the bandings from Scenario 5, but reintroduces the buyout price link to RPI in order to produce the largest growth in renewables while retaining a reduction in deadweight loss over the base case.

In conclusion, this study finds that banding can be used as an effective tool to change the renewables volumes and mix of technologies. If introduced, it could increase generation volumes to the point where headroom is necessary to avoid a collapse of the ROC price. At its most extreme, disaggregated banding could provide powerful incentives for some of the more expensive technologies, but with a high overall cost, which is very sensitive to changes in technology costs. A less disaggregated form of banding could strike a balance between technology promotion, diversity, and the cost to consumers.

Table 1 Comparison of key cost–benefit metrics between Base Case and scenarios

Cost–benefit analysis	Base Case	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
Deployment in 2015/16 (TWh)	39.3	44.6	39.6	46.2	44.7	43.9	46.7
Carbon saved (lifetime, MtC)	90.6	95.4	91.1	99.5	96.5	95.2	103.1
RO deadweight (lifetime costs, discounted, £m)	–9,100	–6,000	–8,200	–6,200	–4,900	–5,000	–5,700
Resource cost (£m, lifetime costs, discounted)	–14,600	–17,100	–13,600	–18,700	–17,500	–16,800	–19,400
Net banding position ROC/MWh in 2015/16	1	1.18	0.89	1.22	1.13	1.09	1.12
Distributional analysis							
Exchequer cost (lifetime costs, discounted, £m)	–1,900	–2,000	–1,900	–2,100	–2,000	–2,000	–2,200
Firm cost (lifetime costs, discounted, £m)	–13,800	–16,300	–12,800	–17,900	–16,700	–16,000	–18,500
Consumer cost (lifetime costs, discounted, £m)	–23,700	–23,200	–21,800	–24,900	–22,400	–21,800	–25,100

Note: Costs are rounded to the nearest £100m.
Source: Oxera analysis.

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1 Introduction

The Department of Trade and Industry's (DTI) Energy review identified several measures designed to support the development and deployment of renewable technologies.[2] Particular emphasis was placed on strengthening and modifying the Renewables Obligation (RO), with the current RO consultation proposing four main changes:

– extending obligation levels to 20% on the basis of a guaranteed headroom;
– containing the cost to consumers resulting from this increase by removing the inflation link to buyout prices;
– reducing the impact of an oversupply of Renewables Obligation Certificates (ROCs) through the use of the 'ski-slope' mechanism, whereby parties redeeming ROCs are required to pay into the buyout fund in the event of the obligation being exceeded;
– introducing a banding system in order to provide more support to emerging technologies and less to established technologies.

There are a number of practical issues relating to the introduction of banding to the regime including:

– how many bands should be set?
– at what level should bands be set?
– should the banding decision be net-neutral—ie, retaining the same level of overall support as the current mechanism?
– what impact does the loss of direct equivalence between generation and ROCs have on the requirement for headroom and ski-slope mechanisms?

Decisions made with respect to the above will impact on the effectiveness of the RO and the banding proposal, the risk for potential investors, and the overall efficiency of investment. This report, commissioned by the DTI, analyses the potential effect of different approaches to banding the RO using Oxera's Renewables Market Model, and utilising the renewable cost projections produced by Ernst & Young in a separately commissioned study into the economics of renewable technologies.[3]

The impact of each banding option is assessed relative to a Base Case scenario, with no changes to the existing policy. The changes as a result of introducing banding are illustrated through several key outcomes:

– the level of renewables build, both at an aggregate level and by technology type;
– the level of ROC prices; and
– the resource costs, carbon savings and costs to consumers, firms and the Exchequer.

The remainder of this report is structured as follows:

– section 2 describes the modelling methodology;
– section 3 reports the main input assumptions to the model;
– section 4 presents the Base Case results, against which the banding options are compared;
– section 5 analyses various banding options;
– section 6 summarises the analysis;
– Appendix 1 details the technology supply curves;

[2] Department of Trade and Industry (2006), 'The Energy Challenge: Energy Review', July.
[3] Ernst & Young (2007), 'Impact of Banding the Renewables Obligation: Costs of Electricity Production', forthcoming.

– Appendix 2 shows the detailed input assumptions;
– Appendix 3 shows detailed output results from the Base Case and scenarios, and the outputs from the sensitivities around the key input assumptions.

2 Modelling methodology

The analysis presented in this report is based on a simulation model of the renewables market. In this section, the framework of the model is outlined, together with an explanation of the welfare and cost calculations based on the underlying results.

2.1 Model framework

The basic approach taken in Oxera's Renewables Market Model is to simulate the likely pattern of renewables investment, based on key assumptions regarding the future revenue streams and costs of the various renewable generation technologies. Three main sources of revenue are represented within the model:

– wholesale electricity prices;
– Climate Change Levy Exemption Certificates (LECs); and
– Renewables Obligation Certificates (ROCs).

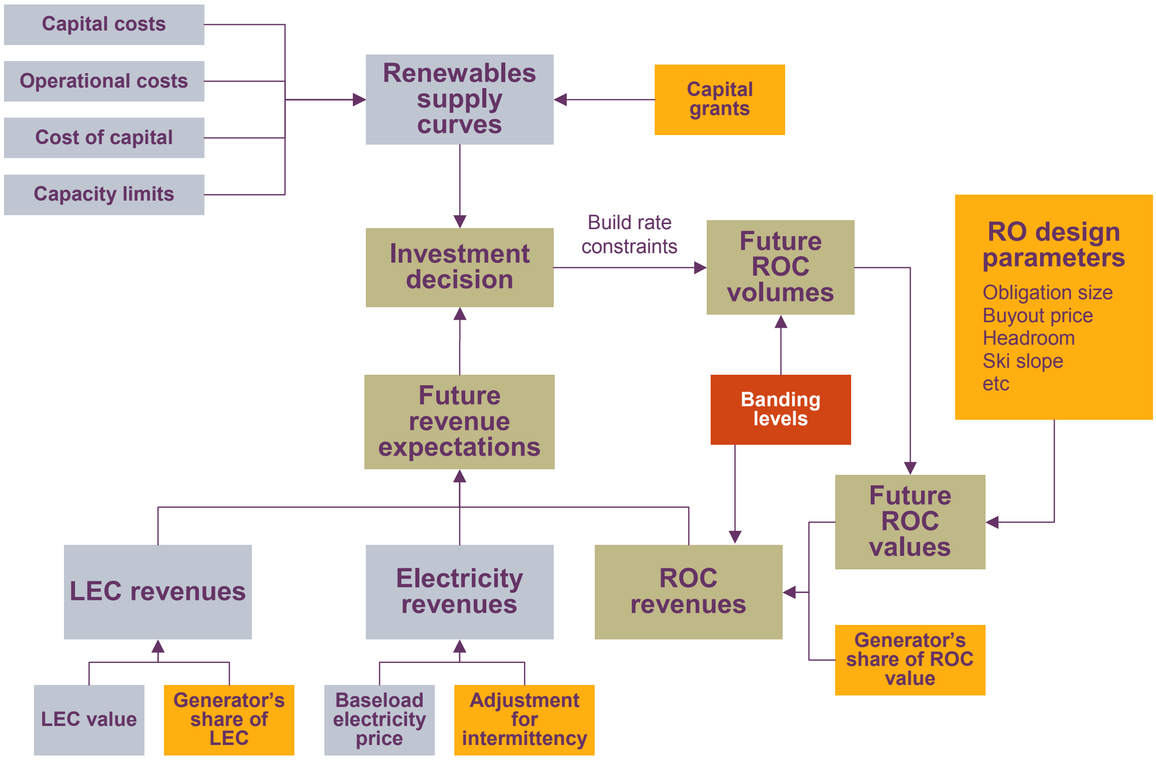
The first two of these revenue streams are treated as exogenous input assumptions to the model, while the value of ROC revenues is determined endogenously in the model. The other key set of assumptions feeding into the model is a set of supply curves, representing the levelised generation costs for various forms of renewable generation (details of how these cost curves have been formed are provided in section 3). In addition, support from known government grants was taken into account in the modelling framework. In the case of co-firing, the avoided costs of coal and carbon are used in place of electricity revenues.

A high-level overview of the model structure is shown in Figure 2.1. This diagram highlights a central circularity in understanding the drivers of investment in renewable generation. The investment decisions taken in any given year will be influenced by an investor's expectations of future ROC revenues. However, investment decisions will, in turn, affect the future revenue expectations through the impact of ROC volumes on the size of the buyout fund, and hence the market value of ROCs.

Oxera's model addresses this circularity between investment decisions and future revenue expectations by using a multi-phase simulation approach. The first phase of the simulation uses renewable generation supply curves and build rate constraints to determine an expected path of future ROC prices based on the costs of the marginal renewable technology. The second phase then uses these ROC price expectations to simulate a set of investment decisions consistent with the ROC price expectations. Finally, the outcomes of these investment decisions are used to update the future ROC price expectations.

The advantage of this approach is that it ensures that the investment decisions will take account of the impact of policy decisions on the future ROC market. For example, freezing the buyout price from 2015/16 may reduce the real value of ROCs. This would be reflected within the ROC price expectations and would therefore influence investment decisions prior to 2015/16.

Figure 2.1 Overview of modelling approach



Note: Blue boxes are input assumptions; orange boxes are model parameters; and brown boxes are model calculations.
Source: Oxera.

In each year, the expected ROC price is determined from an assessment of the renewable supply curve in that year against a ROC value function. The supply curve is defined in terms of the ROC price required to support a given volume of renewable generation and is therefore derived from an assessment of the revenue and cost streams in each year and the maximum availability of each technology. The supply curve will exhibit step changes between projects based on different technologies, while, within a given technology, it will be upward-sloping, representing variations in cost—for example, due to differences in project size, location or fuel cost.

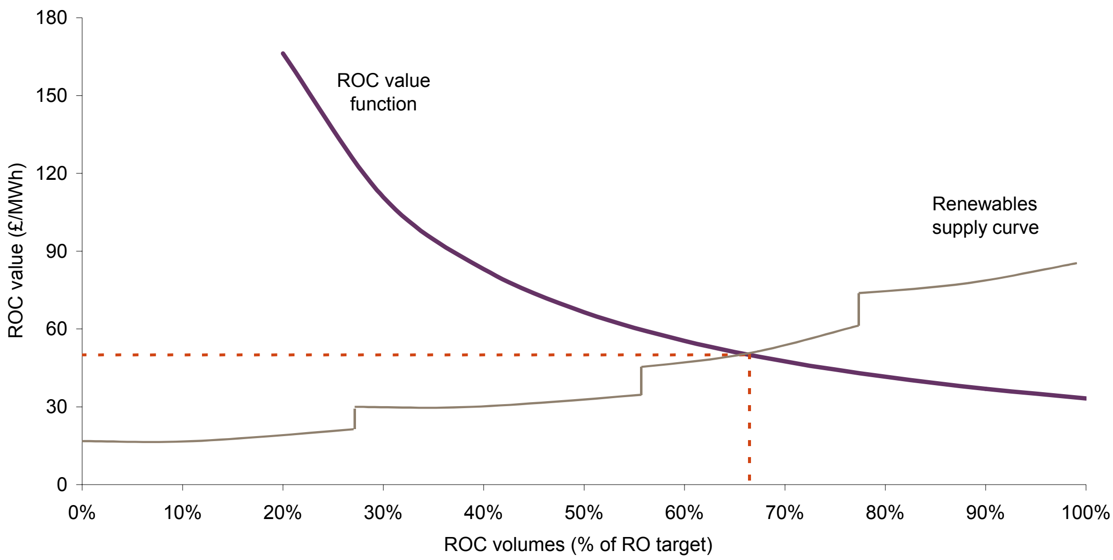
The ROC value function draws on the direct relationship between the level of support required by renewable generation technologies and the volume of generation that can be supported. The value of ROCs is defined in the equation below and implies that, as the total volume of ROCs in the market approaches the obligation size, their value will fall towards the buyout price.[4]

$$\text{ROC value} = \frac{\text{Buyout price} * \text{Overall obligation size}}{\text{Total volume of ROCs}}$$

Figure 2.2 illustrates the interaction between renewable generation costs and ROC values using a hypothetical supply curve for renewable generation projects. In this example, ROC volumes must stay below 66% of the obligation size in order for the RO to provide the £50/MWh support required by the marginal project.

[4] This equation holds only where total ROC volumes do not exceed the obligation size.

Figure 2.2 Intersection of supply curve and ROC value function



2.2 Welfare calculations

To investigate the welfare effects of the mechanism, several metrics were identified in conjunction with the DTI. The cost–benefit metrics used were:

– **the resource cost**—the cost of the renewables generation less the cost of the equivalent amount of conventional generation, assumed to come from a CCGT at a fixed cost of £37.4/MWh;

– **carbon savings**—assuming a counterfactual generation from a new build CCGT (without distribution/transmission losses) with an emission factor of 0.351tCO_2/MWh;

– **social value of carbon saved**—assuming a social cost of carbon of £86/tonne in 2007 and rising £1/year thereafter;

– **the net benefit**—the benefit of the social value of the carbon saved less the cost of the renewable generation;

– **the cost-effectiveness** of the mechanism in terms of resource cost (£/tC) saved.

– **the deadweight loss**—the cost to the consumer less the resource cost.[5]

In addition, the following distributional effects were calculated:

– **cost to the Exchequer**—calculated as the forgone revenues from the Climate Change Levy, plus the value of any capital grants given as incentives;

– **cost to firms**—the cost to both generators and suppliers without considering any pass-through of costs to consumers. This ignores any revenues from the buyout fund recycling, which are assumed to be internalised within firms

[5] This is a ‘deadweight’ loss from the point of view of consumers, although not necessarily for society as a whole since it represents a transfer rather than an absolute resource cost.

– **cost to the consumer**—equal to the obligation size multiplied by the minimum of the buyout price and the outturn ROC price.[6] This is the total cost of the subsidy to suppliers, which, it is assumed, is passed through to consumers.

Each metric has been calculated for snapshot years (2010/11 and 2020/21) and over the lifetime of the RO. Both discounted and non-discounted totals have been presented, with a declining long-term discount rate being applied, as per guidance in the HM Treasury Green Book (and shown in Table 2.1).

Table 2.1 Discount rate applied in present value welfare and CBA calculations

Years	Rate (%)
0–30	3.50
31–75	3.00
76–125	2.50

Note: CBA, cost–benefit analysis.
Source: HM Treasury (2003), 'The Green Book: Appraisal and Evaluation in Central Government', January.

[6] The ROC price may be below the buyout price in the presence of an operational ski-slope mechanism and where ROC volumes exceed the obligation size.

3 Model assumptions

As Figure 2.1 illustrated, the model has two main sets of input that influence the results:

– **cost and revenue assumptions**—the underlying components that determine the renewables supply curve over time; and

– **model parameters**—factors that define the regime (RO design parameters and banding levels), related policies (capital grants), and commercial interactions (shares of revenue and cost streams that the renewable generator/investor can expect to receive).

This section presents the main input assumptions and relevant model parameters, including High and Low sensitivities, where applicable.

3.1 Cost and revenue assumptions

3.1.1 Renewable generation costs

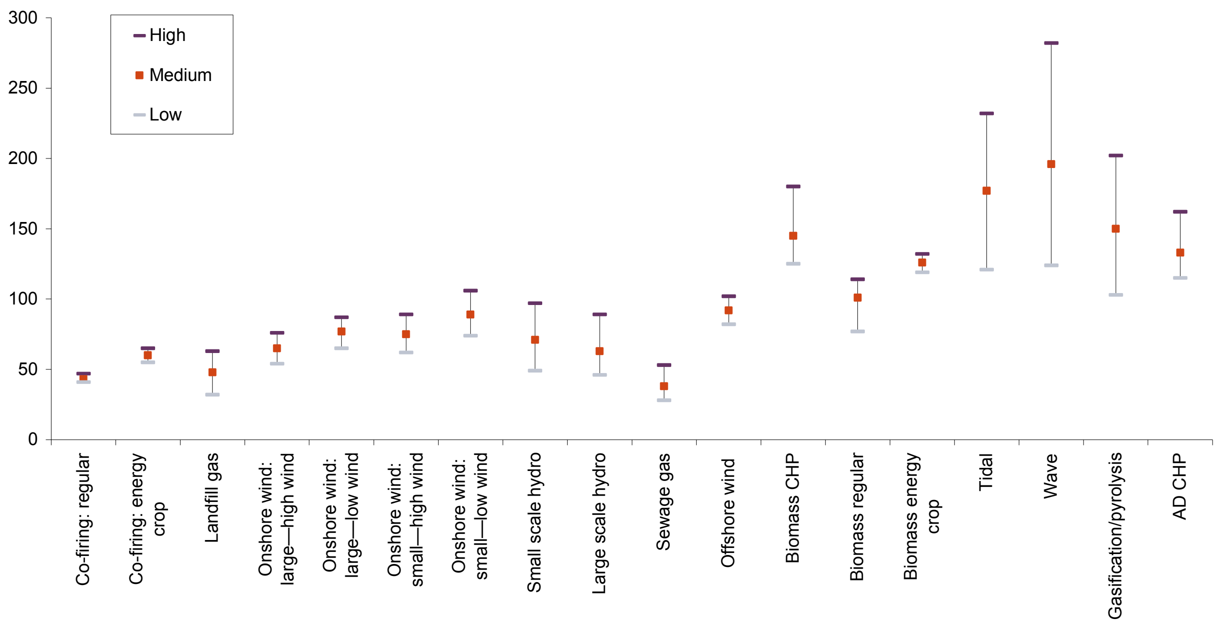
The Renewables Market Model uses as an input a set of annual renewable generation supply curves. For this study, these supply curves were derived from analysis conducted by Ernst & Young. For each of the eligible renewable technologies, Ernst & Young provided snapshot levelised generation costs in 2006, 2010, 2015 and 2020. Each snapshot included a High-, Central- and Low-cost segment, and an indication of the likely level of deployment for each technology, assuming that new entry occurs when economically viable. For example, Figure 3.1 shows the range of levelised costs for the included technologies in 2010.

The renewable supply curves for each technology were constructed with a minimum of three steps, corresponding to the High-, Central- and Low-cost estimates.[7] The renewable generation volume associated with each of these steps was estimated by allocating a proportion of the likely deployment volumes to each of the cost steps. These weightings were agreed in consultation with the DTI and Ernst & Young, and are intended to reflect a best estimate of the distribution of generation costs for each technology.

Additional steps were added to this supply curve by Oxera in order to represent further renewable generation volumes above the assumed deployment rates, but capped by Ernst & Young's estimates of the maximum feasible potential for each technology. Oxera has applied a cost that is 10% higher than the corresponding Ernst & Young High scenario cost estimate for these steps, reflecting the fact that these volumes will be more expensive for the market to access. Further discussion is provided in Appendix 1.

[7] In the case of offshore wind and large onshore wind projects, five supply curve steps were created by interpolating between the three existing price estimates.

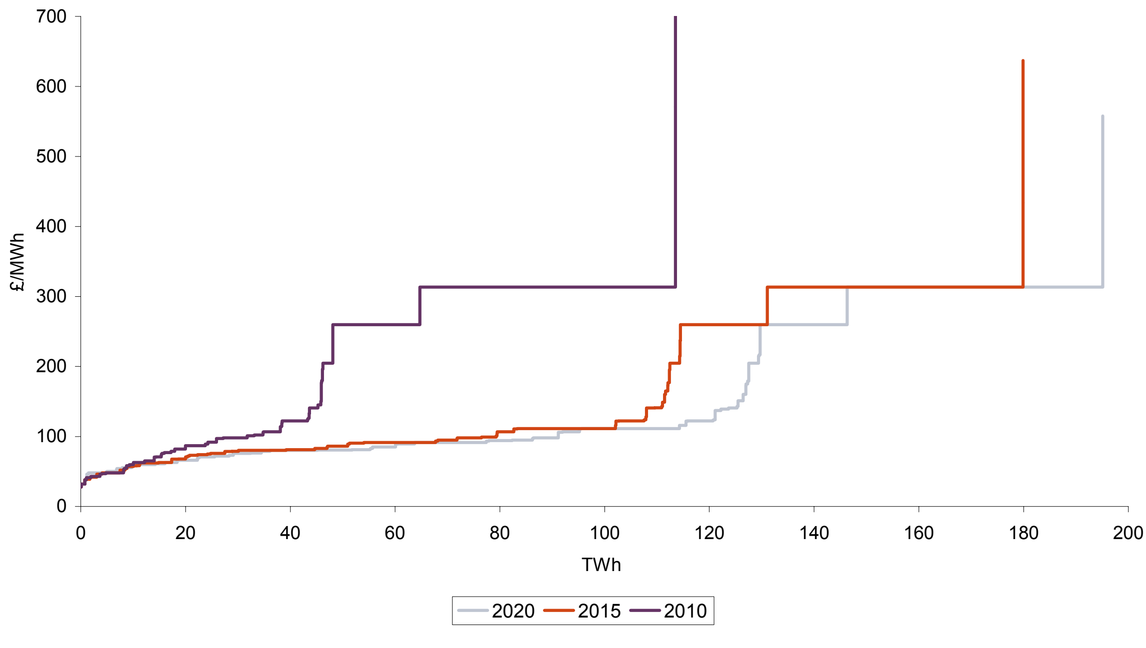
Figure 3.1 Levelised costs of renewable generation in 2010 (£/MWh)



Note: Co-firing capital costs were removed from the overall cost levels since it is assumed that the majority of upgrading required to produce additional co-firing has already been undertaken. AD CHP, anaerobic digester combined heat and power.
Source: Ernst & Young (2007), op. cit.

The resulting renewable supply curves for 2010, 2015 and 2020 are shown in Figure 3.2. As can be seen, the curves shift to the right over time, reflecting cost reductions associated with learning effects and increasing levels of potential deployment of technologies. All three supply curves illustrate potential volumes substantially in excess of their respective obligation levels (33.8TWh, 52.4TWh and 55.9TWh), although a high proportion of this available capacity is very expensive to produce.

Figure 3.2 Evolution of renewables supply curve

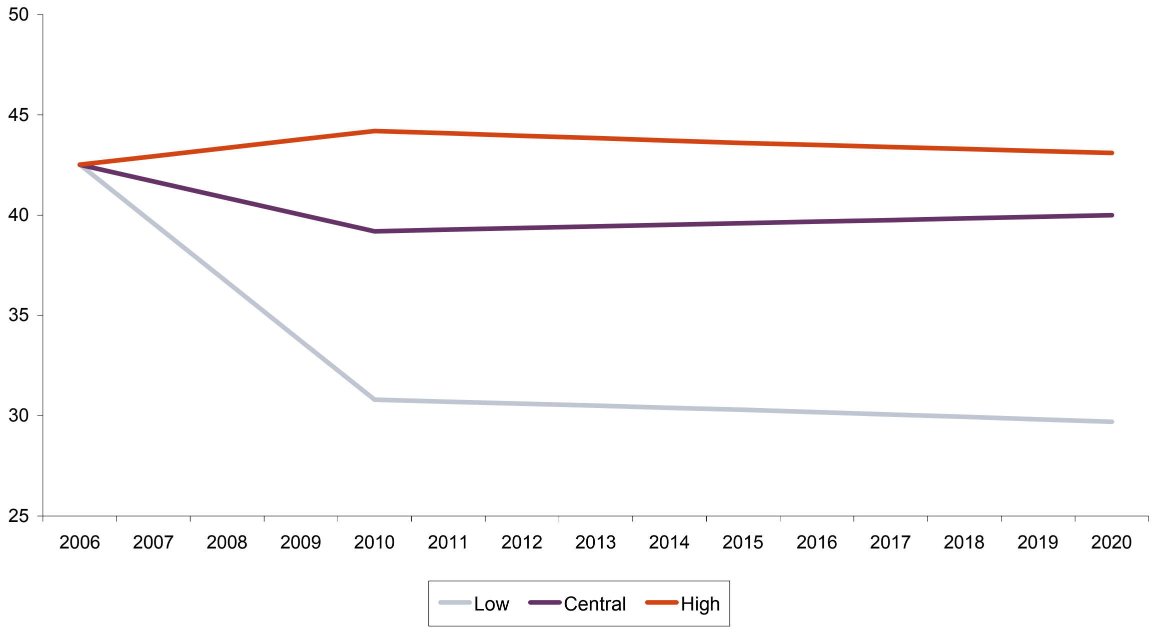


Source: Oxera calculations based on Ernst & Young data.

3.1.2 Revenue assumptions

In addition to ROC revenues, determined endogenously through the modelling, renewable generators have access to two other revenue streams through wholesale electricity sales and Climate Change Levy Exemptions Certificates (LECs). The latter are assumed to be fixed at £4.3/MWh in real terms, whereas the wholesale electricity revenues will depend on the prevailing wholesale electricity price in the year. Table A2.1 in Appendix 2 and Figure 3.3 present the High, Central and Low wholesale electricity price assumptions. While differences in outturn wholesale prices will respond to potential variations in fuel and carbon prices, the overall supply–demand balance, and underlying fuel mix across time, the scenarios reported below are based on underlying data provided by the DTI.

Figure 3.3 Wholesale electricity price assumptions (£/MWh)



Source: DTI and Oxera calculations. Prices are real 2006.

3.1.3 Carbon and coal prices

Whereas Oxera has not used specific scenarios for input fuel prices to derive the underlying wholesale electricity prices, explicit assumptions on carbon and coal prices are utilised in assessing the relative cost of co-firing with energy and non-energy crops (as discussed in section 2). Tables A2.2 and A2.3 in Appendix 2 present the coal and carbon price assumptions respectively. High, Central and Low coal prices are presented, but only the Central price assumption underlies the Low, Central and High electricity price sensitivities used in the modelling.

3.1.4 Build rates and planning

The volumes of each technology that can be feasibly built in a single year may be constrained by factors such as a relatively small number of firms qualified to build infrastructure, steel shortages, planning restraints, etc. Therefore, the following maximum build levels for some given technologies have been included in the modelling approach.

Table 3.1 Assumed build rate capacity

Technology	Maximum capacity (GW)	Assumed load factor (%)	Maximum output (TWh)
Onshore wind: large, high wind	0.3	31	0.81
Offshore wind	1.0	37	3.24
Onshore wind: large, low wind	0.4	26	0.91

Source: Oxera analysis.

3.2 Model parameters

In addition to the revenue and cost assumptions, there are further model parameters that affect the simulations. Of these, the majority either define the precise form of the RO regime (eg, changes in the level of the obligation, the assumed buyout price, etc) or adjust the revenue streams that generators expect (eg, through assumptions on the proportion of ROC or LEC revenues that a generator receives).

However, one core assumption that affects the fundamental operation of the model is the level of electricity sales, since this determines the obligation size, and therefore the ROC value function as described in section 2. For this purpose, High, Central and Low sales assumptions (consistent with the DTI electricity price assumptions) are shown in Table A2.4. These are taken from intermediate and ongoing energy projections available after the publication of the 2006 Energy review, with extrapolation between the 2010, 2015 and 2020 snapshots.

4 The Base Case

The Base Case simulates the expected renewables growth under the current RO regime (ie, in the absence of any policy change including the introduction of any banding mechanism) and, as such, is the benchmark against which the banding options are compared. The first year for which the model produces results is 2007/08. Data for 2002/03 to 2005/06 is taken from actual levels of renewable generation provided by the DTI, and data for 2006/07 is extrapolated from Ernst & Young estimates. For the purposes of this analysis, the current RO regime is defined to include the following components:

– the original list of RO-eligible technologies;
– each MWh generated earns one ROC (ie, no banding);
– the obligation size is assumed to increase to 15.4% by 2015/16;[8]
– energy crop co-firing is uncapped from 2007, as per the statutory consultation;
– existing caps on non-energy crop co-firing are maintained—implying a cap of 10% until 2010/11, 5% until 2015/16, and nothing thereafter;
– the buyout price linked to RPI.

In addition, the core scenario also uses the following assumption set for the variables described in section 3:

– central electricity wholesale prices;
– central coal prices;
– central electricity sales.

The Base Case results are presented below, and the sensitivity of these results to the key input assumptions is also discussed.

4.1 Results

The Base Case results are summarised in Figure 4.1 (and Table A3.1 in Appendix 3), and show that, given the assumptions, the Renewables Obligation, while encouraging growth in renewable generation, will not deliver levels of generation close to the 15.4% maximum obligation size. Whereas in the period 2007/08 to 2010/11 renewable generation is around 2% below the obligation size, this gap has grown to 4%, around 13.8TWh, by 2015/16, and there is very limited growth in volumes in subsequent years.

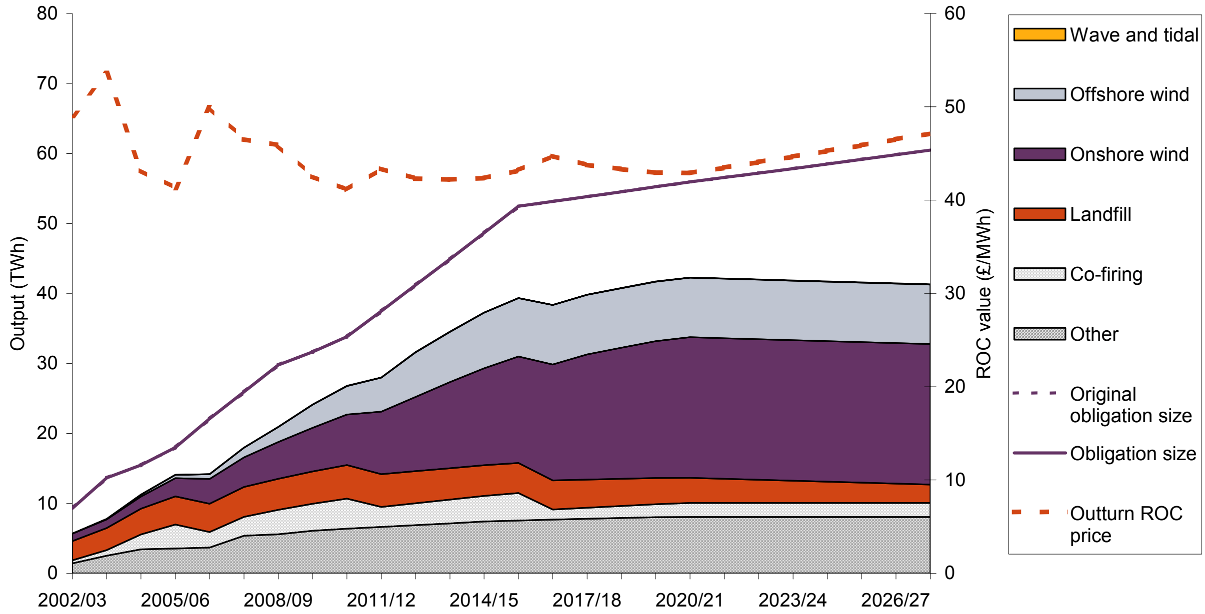
The step change in the reduction of volume growth post-2015/16 arises from a combination of two factors.

First, the obligation size is capped at 15.4% of total UK sales and, therefore, any increase in the absolute size of the obligation occurs solely via increases in UK electricity sales. This affects expectations of future ROC prices. Figure 4.1 shows how these expectations lead to a decrease in the rate of construction of both onshore wind and all other technologies. Importantly, from 2015/16, there is a cessation of offshore wind investment. The latter effect is a purely economic outcome due to anticipated revenue streams being insufficient to provide an appropriate return for the investment. In Figure 4.1 and subsequent figures and tables, ‘Other’ refers to all other renewable technologies not explicitly stated, including hydro, sewage gas, solar PV, gasification/pyrolysis, biomass, micro CHP, AD CHP, and EfW. A

[8] There is an equivalent cap of 6.3% for Northern Ireland starting in 2012/13.

comprehensive breakdown of volumes from all modelled technologies in the Base Case is provided in Appendix 3

Figure 4.1 Base Case Central volumes



Source: Oxera analysis.

Second, 2015/16 sees the removal of non-energy crop co-firing from the RO, thereby explaining the reduction in eligible volume from 3.9TWh to 1.4TWh between 2015/16 and 2016/17.

The economics for all technologies deteriorates post-2015/16. In fact, no new renewables build is observed in the period post-2020/21. This is a consequence of the finite length of the RO. Without the expectation of future ROC revenues post-2027/28, the value of future investments is reduced. The closer an investment is made to the end date of the scheme, the less time the investment will receive support from the RO to cover its capital costs. The predicted revenues from sales of electricity in the Central assumptions are not sufficient by themselves to bring forward new deployment. 2020/21 is recognised by the model as the last year in which new capacity of any technology can be constructed and run economically.

The lack of new investment is responsible for the upturn in the ROC value from 2020/21. However, because of the relatively flat slope of the renewable supply curve at the operational volumes (ie, around 40TWh), the increment is insufficient to adequately compensate for the shorter period of ROC eligibility, and so no additional investment is forthcoming. Build rate constraints do, however, play a part in this outcome. For example, in the period from 2010/11 to 2015/16, large onshore wind projects are bound by the build rate constraint. If it were feasible to expand maximum build rates, because of the technology's lower marginal cost, additional investment would be forthcoming. To quantify this effect, an extra sensitivity was modelled whereby the planning mechanism was assumed to be more streamlined, and the annual build limit removed. The results of this sensitivity are shown in Appendix 3 in Tables A3.7, A3.8, A3.14 and A3.15.

The cost and benefits and distributional impacts of the current regime are examined in Table 4.1. Currently the RO is forecast to save over 90MtC over the remaining lifetime of the projects, at a discounted resource cost of £14.6 billion. The discounted cost to the consumers is greater than £23 billion over the period, while the Exchequer incurs a cost of only £1.9 billion in forgone revenues from the Climate Change Levy.

Table 4.1 CBA and distributional impacts of the Base Case

	Period		
Cost–benefit analysis	**2010**	**2020**	**Lifetime**
Resource cost (£m)	–700	–700	–14,600
Carbon saved (MtC)	2.6	3.9	90.6
Deployment in 2015/16 (TWh)			39.3
Net banding position ROC/MWh in 2015/16			1
Value of carbon saved (£m)	200	200	5,600
NPV cost–benefit (£m)	–500	–500	–9,000
Cost-effectiveness (£/tC)			–161
RO deadweight	–400	–500	–9,100
Distributional analysis			
Exchequer cost (£m)	–100	–100	–1,900
Firm cost (£m)	–600	–700	–13,800
Consumer cost (£m)	–1,000	–1,200	–23,700

Notes: NPV, net present value. Resource cost assumes a conventional generation counterfactual cost of £37.4/MWh. Carbon savings are calculated using an emissions factor of 0.351tCO_2/MWh in counterfactual generation from a CCGT. Costs have been rounded to the nearest £100m.
Source: Oxera analysis.

4.2 Sensitivity analysis

The Base Case results are dependent on the underlying assumptions chosen. The extent to which alternative assumptions would improve or worsen the performance of the RO is investigated through a series of sensitivities on the core assumptions, namely:

– high and low demand and wholesale electricity prices;
– renewables cost assumptions;
– carbon costs.

In addition, the impact of removing the RPI link to the buyout price after 2015/16 is also investigated. Results for all of these are reported below. One aspect that does not change is the impact of the finite term of the RO; in all scenarios, this structural aspect of the regime fails to provide sufficient support to incentivise new investment post-2020/21. The detailed results of this analysis can be found in Appendix 3.

4.2.1 High and Low scenarios

The High and Low scenarios are designed to simulate conditions that are likely to be more conducive (the 'High' case) and less conducive (the 'Low' case) to renewable generation through appropriate changes to three of the main market drivers of renewable investment: the wholesale electricity price, the level of UK consumption, and the coal price.

Wholesale electricity prices represent one of the two main revenue streams for a renewable generator, and therefore variations in the level of this revenue stream would be expected to affect the attractiveness of new investment. The other main revenue stream is ROC revenues (LEC revenues are relatively small compared with these other two elements), and variations in the level of demand, through their impact on the absolute size of the obligation, can be expected to influence future ROC price expectations. Finally, variations in coal prices affect the cost-effectiveness of co-firing, with higher coal prices making co-firing more cost-effective, all other things being equal.

Consequently, the 'High' sensitivity is based on the high electricity, demand and coal assumptions, with the 'Low' sensitivity using the low assumptions for each of those variables. Table 4.2 shows the comparison with the Base Case of the levels of renewable generation under each scenario.

The broad results are as would be anticipated: the overall level of renewable growth is higher under the 'High' sensitivity and lower under the 'Low' sensitivity. However, the reduction in renewable growth in the Low scenario (4.9TWh in 2015/16) is more significant than the increment to generation in the High scenario (1.7TWh in 2015/16). This partially reflects the asymmetry in the variation from the Central case of the high and low assumptions—for example, the electricity wholesale price is around £9/MWh lower on average under the Low scenario, whereas it is only around £4/MWh higher in the High scenario.

Table 4.2 Comparison of levels of renewables generation for the Base Case, Low and High scenarios

	Total renewable generation (TWh)			% electricity sales		
Year	High	Base	Low	High	Base	Low
2007/08	18.5	18.0	18.0	5.5	5.4	5.4
2008/09	21.8	20.9	20.9	6.6	6.3	6.3
2009/10	25.0	24.1	23.7	7.6	7.3	7.2
2010/11	27.7	26.8	25.8	8.4	8.1	7.8
2011/12	28.9	28.0	26.4	8.7	8.4	8.0
2012/13	32.6	31.6	29.2	9.7	9.4	8.7
2013/14	35.5	34.5	31.3	10.5	10.2	9.3
2014/15	38.2	37.3	33.0	11.2	10.9	9.7
2015/16	41.0	39.3	34.4	11.9	11.4	10.0
2016/17	40.0	38.4	32.7	11.4	11.0	9.4
2017/18	41.6	39.8	33.7	11.7	11.2	9.5
2018/19	42.7	40.8	34.4	11.9	11.3	9.6
2019/20	43.7	41.7	35.0	12.0	11.5	9.7
2020/21	44.6	42.3	35.4	12.1	11.5	9.7
2021/22	44.4	42.1	35.3	11.9	11.3	9.6
2022/23	44.3	42.0	35.1	11.7	11.1	9.4
2023/24	44.2	41.9	35.0	11.5	11.0	9.3
2024/25	44.0	41.7	34.9	11.4	10.8	9.1
2025/26	43.9	41.6	34.7	11.2	10.7	9.0
2026/27	43.7	41.4	34.6	11.1	10.5	8.9
2027/28	43.6	41.3	34.4	10.9	10.4	8.7

Source: Oxera analysis.

As Tables A3.2 and A3.3 in Appendix 3 show, the change in renewable volumes is reflected in levels of onshore and offshore wind generation. In terms of the generic ROC price determination described in Figure 2.2, the High and Low scenarios shift the renewable supply curve down or up respectively, with the consequent implications for the overall level of generation. Output of the low-cost renewable options, such as landfill gas and co-firing, is largely unaffected by these shifts since the changes do not affect their position in the supply curve.

In the Low scenario, the lower price assumptions increase the level of support required to fund these projects, with the implication that the level of renewable generation must be further from the obligation size to produce sufficiently high ROC prices. Consequently, the rate of growth in both onshore and offshore capacity is lower, with no new offshore build post-2013/14, and continued, but slower, onshore build up to 2020/21.

4.2.2 Renewable cost sensitivities

One of the main uncertainties with regard to renewable technologies is the underlying cost, since this determines the extent to which additional support is required and hence the level of ROC prices necessary in the market. A High and Low cost sensitivity has been investigated, with renewable costs increased and decreased by 10% respectively, for each year of modelling.

As Table 4.3 shows, an increase in the assumed renewable costs reduces renewable generation (by 4.9TWh in 2015/16, and by 6.2TWh by the end of the RO) relative to the Central Base Case. The rationale for this is the same as that for the ‘Low’ scenario described in section 4.2.1. Essentially, the level of support required by any renewable technology for a given electricity revenue stream is now higher (ie, the renewable supply curve shifts upwards in Figure 2.2), and hence, at the margin, a lower volume of generation must emerge in equilibrium.

A reduction in costs by 10% has a relatively symmetric effect to that of the increase in costs—output is 4.5TWh higher in 2015/16 and 6.4TWh higher in the final year of the RO. Significantly, although the level of generation is higher, the marginal technology cost is still higher than the buyout price, and hence total volumes of generation are still below the obligation size.

4.2.3 Removal of RPI from the buyout price after 2015/16

A final sensitivity on the underlying RO mechanism is also presented in Table 4.3. This involves freezing the value of the buyout price from 2015/16. While reducing the cost to consumers of the RO itself, this adjustment has the effect of lowering the expected value of ROCs (through reducing the real value of the buyout fund) and hence reducing the attractiveness of new investment. In general, the freezing of the buyout price reduces renewable generation by around 1% of total generation—for example, in 2015/16, the level of renewable generation is 10.4% compared with 11.4% under the Base Case.

Table 4.3 Comparison of levels of renewables generation for the Base Case Central under different sensitivities

	Total renewable generation (TWh)			% electricity sales		
Year	Costs +10%	Costs–10%	RPI out	Costs +10%	Costs–10%	RPI out
2007/08	17.1	18.5	18.0	5.1	5.5	5.4
2008/09	19.7	21.8	20.9	5.9	6.6	6.3
2009/10	22.3	25.1	23.7	6.7	7.6	7.1
2010/11	24.4	27.8	25.8	7.4	8.4	7.8
2011/12	25.1	29.4	26.5	7.5	8.8	7.9
2012/13	27.8	34.2	29.2	8.3	10.2	8.7
2013/14	30.1	37.5	31.5	8.9	11.0	9.3
2014/15	32.3	40.9	33.8	9.4	11.9	9.9
2015/16	34.4	43.8	35.9	9.9	12.7	10.4
2016/17	32.7	43.2	34.6	9.3	12.3	9.9
2017/18	33.7	45.1	35.6	9.5	12.7	10.0
2018/19	34.6	46.5	36.5	9.6	12.9	10.2
2019/20	35.5	47.7	37.2	9.7	13.1	10.2
2020/21	36.0	48.7	37.8	9.8	13.2	10.2
2021/22	35.9	48.5	37.6	9.6	13.0	10.1
2022/23	35.8	48.4	37.5	9.5	12.8	9.9
2023/24	35.6	48.3	37.4	9.3	12.7	9.8
2024/25	35.5	48.1	37.2	9.2	12.5	9.7
2025/26	35.3	48.0	37.1	9.1	12.3	9.5
2026/27	35.2	47.8	36.9	8.9	12.1	9.4
2027/28	35.1	47.7	36.8	8.8	12.0	9.2

Source: Oxera analysis.

5 Review of banding options

To assess the impact of banding on the effectiveness of the RO, it is necessary to make some assumptions regarding the definition of a band. In particular:

– **the coverage of the band**—to what extent are different technologies assigned their own band or grouped together;

– **the ROC value within that band**—are bands set to ensure that the average, or most expensive, project is expected to be viable, and in what year?

With the exception of co-firing, the scenarios presented in this report assume that the same level of banding is applied from April 1st 2009 across the remainder of the obligation.

This section presents the results of several scenarios of possible band definitions. Two further differences from the Base Case are also incorporated into these scenarios.

– **The removal of the cap on non-energy crop co-firing**. Since alternative co-firing options are differentiated according to bands, no additional mechanism to restrict non-energy crop co-firing was required.

– **The inclusion of an explicit headroom mechanism**. The headroom is activated when a threshold volume of eligible generation is met and ensures that the effective obligation size expressed as numbers of ROCs is at least 6% higher than generated volumes from 2009/10.[9]

For Scenarios 1–5, a further change of removing the link to RPI from the buyout price from 2015/16 was modelled. The RPI link was retained for Scenario 6.

Oxera tested a range of scenarios that differed in the disaggregation of the bands and the ROC value attributable to each MWh of output. A summary of these scenarios, reflecting a wide range of banding options, is presented in Table 5.1.

In brief, the scenarios are as follows:

– Scenario 1 bands each technology separately;
– Scenario 2 bands down economic technologies and maintains support for more costly technologies;
– Scenario 3 groups together the higher-cost technologies;
– Scenario 4 further increases the aggregation of bands;
– Scenario 5 rebalances the bands for greater support to emerging technologies;
– Scenario 6 applies the RPI link to the buyout price under Scenario 5 bands.

[9] This prevents the potentially destabilising effect of a ROC price collapse that may otherwise be anticipated and that could therefore reduce incentives to invest.

Table 5.1 Banding assumptions for each scenario (ROC/MWh)

Technology	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenarios 5 and 6
Sewage gas	0	0.25	0.25	0.25	0.25
Landfill Gas	0.25	0.25	0.25	0.25	0.25
Co-firing (regular)	0.4	0.25/0.2/0.3	0.4	0.25/0.2/0.1	0.25/0.2/0.2
Hydro	0.8	1	1	1	1
Onshore wind	1	1	1	1	1
Offshore wind	1.5	1	1.6	1.6	1.5
Co-firing (energy crop)	0.9	1	1	1	1
Energy from waste (EfW)/CHP	1.1	1	1	1	1
Biomass (regular)	1.8	1	1.6	1.6	1.5
Waste ACTs	3	1	2.8	1.6	2
Biomass (energy crop/CHP)	2.5	1	2.8	1.6	2
Tidal stream	3.9	1	2.8	1.6	2
Wave	4.5	1	2.8	1.6	2
Solar PV	15.2	1	2.8	1.6	2

Source: DTI.

The main results of the scenarios are described below. The evolution of the banding levels through the model process was designed to identify groupings of bands that would encourage overall investment and reduce deadweight in the RO, while containing costs to consumers. Within the technologies there may be appropriate groupings that would be suitable for this purpose.

In general, the forecast volumes of renewable generation in the banded scenarios are greater than that predicted in the Base Case, and the contribution from less economically viable technologies is increased. However, the mechanism through which this is achieved (ie, introducing more ROCs into the market) has the risk of activating the headroom mechanism, thereby increasing the cost to consumers. Consequently, as well as comparing costs and cost-effectiveness, the analysis also focused on the impact of the alternative banding options on renewable generation and costs to consumers—this led to further examination and revision of the headroom mechanism.

Comparison between the scenarios shows some disparity in overall levels of generation produced as well as in the technology mix. The effects of banded support vary between technologies, and some scenarios harness this more effectively than others. In Figure 5.1 and subsequent figures and tables, ‘Other’ refers to all other renewable technologies not explicitly stated, including hydro, sewage gas, solar PV, gasification/pyrolysis, biomass, micro CHP, AD CHP, and EfW. A comprehensive breakdown of volumes from all modelled technologies in each scenario is provided in Appendix 3.

5.1 Scenario 1: Maximum disaggregation of bands

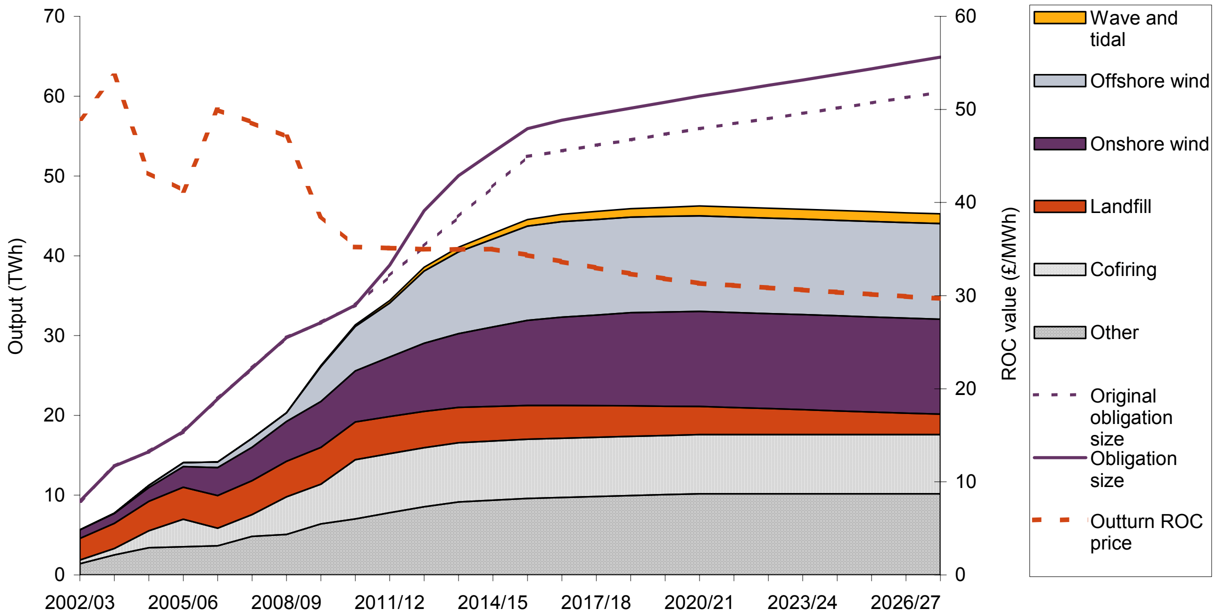
The initial scenario tested the ‘purest’ form of banding—ie, assuming a separate band for each technology, set so as to make the central step of each individual technology supply curve economic. As shown in Table 5.1, this requires a large range of effective bands, running from 0.25—15.2 ROC/MWh, although the majority of bands are in the lower end of this bracket, with only Solar PV requiring the very significant support levels at the top end.

The generation output and ROC volumes observed under this scenario are shown in Figures 5.1 and 5.2. Volumes of renewable generation are higher than under the Base Case.

The effect of the banding in terms of the incentives that it provides to more costly technologies can be seen in this scenario. In particular, the higher ROC band attributed to offshore wind accelerates the development of that technology—total volumes increase by 2020/21 to 15.3TWh compared with 8.5TWh in the Base Case. Moreover, additional volumes continue to enter the market until 2019/20—four years later than in the Base Case. Similar changes to incentives are seen by the more costly technologies—for example, wave and tidal stream projects contribute 1.9TWh by 2020/21.

Furthermore, an important feature of the banding scenarios compared with the Base Case is the relaxation of the caps on co-firing. The low fixed costs required by co-firing mean that the level of support provided by the current RO is greatly above that which is required to make co-firing economic. However, with the introduction of banding, the effective support received by co-firing from the RO is significantly reduced, thus increasing the allocative efficiency of the RO. The effects of this, as illustrated in Table A3.19 of Appendix 3, are higher volumes of co-firing in the longer term.

Figure 5.1 Renewables volume in Scenario 1



Source: Oxera analysis.

While emerging technologies benefit from the increased support, onshore wind, which retains its current level of 1 ROC/MWh, does not benefit to such an extent. In fact, levels of generation from onshore wind fall by approximately one-third by 2020 in Scenario 1 compared with the Base Case, although the overall volumes are still almost four times higher in 2020 than in 2007. Similarly, generation from landfill gas is also down slightly. The principal reason for this result is that, despite onshore wind receiving the same levels of support, the increased total amount of ROCs in the market (above the equivalent output levels) depresses the expected ROC prices and revenues, and hence disincentivises onshore wind developments compared with the Base Case. There is therefore a degree of transference between technologies as a result of banding. Table 5.2 illustrates the differences in Scenario 1 versus the Base Case for selected years.

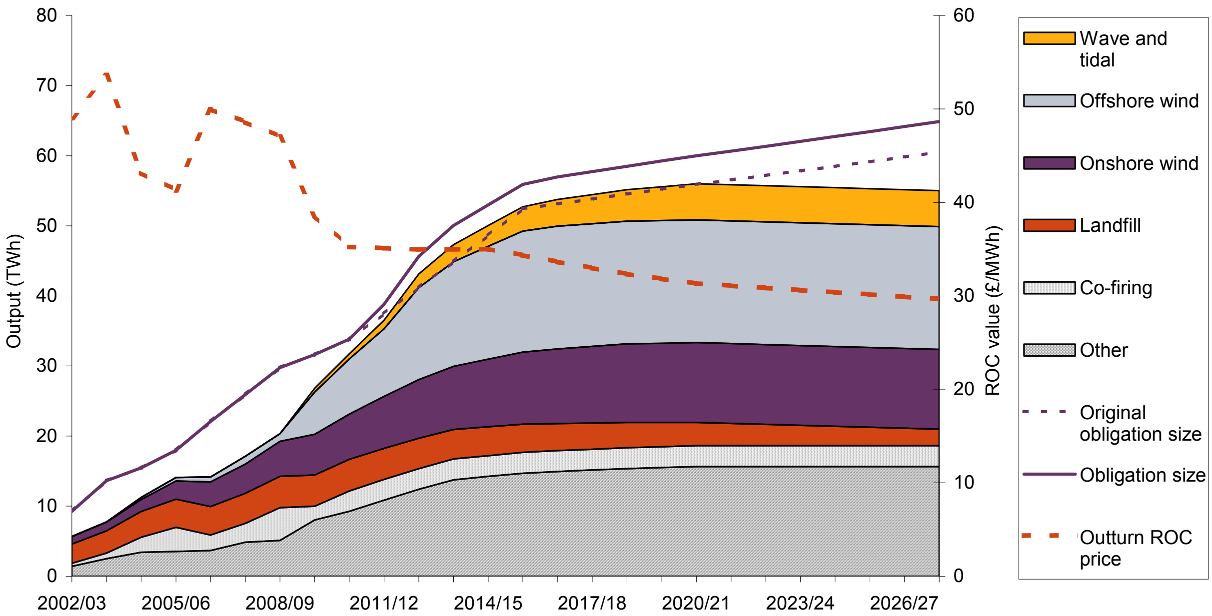
Table 5.2 Increase in generation levels in Scenario 1 over Base Case (TWh)

Year	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Wave and tidal	Total renewable generation
2007/08	–0.5	0.0	0.0	0.0	–0.3	0.0	–0.8
2012/13	1.7	4.3	–0.1	–2.1	2.7	0.4	6.9
2015/16	2.1	3.5	–0.1	-4.5	3.5	0.8	5.2

Source: Oxera analysis.

The disjoint between renewable volumes and ROC volumes is illustrated in Figure 5.2. In 2015/16 the number of ROCs in the market per MWh of renewable generation has increased to 1.18.

Figure 5.2 ROC volumes in Scenario 1



Source: Oxera analysis.

5.1.1 CBA and distributional impacts

Table 5.3 shows the cost–benefit analysis and distributional effects of the banding regime of Scenario 1. Underlying the main differences between Scenario 1 and the Base Case is the greater amount of renewable generation that occurs under the banded scenario. This extra generation is also from more expensive sources (due to the impact of the banding regime) and hence the overall resource cost increases significantly more than the social value of carbon savings. This has the effect of increasing the net cost of the scheme, with discounted lifetime net costs now of £11.1 billion, compared with £9 billion in the Base Case

Significantly, the cost-effectiveness has declined, with the cost per tonne of carbon saved rising from £161/t to £179/t over the lifetime of the RO as a result of the changes bringing forward investment in more expensive technologies.

In terms of the distributional cost, the Exchequer bears a small increment from the forgone revenues from the CCL, and costs to consumers rise to over £23 billion. However, the cost to firms increases by over 50% to over £16 billion.[10] Revenues and payments from the buyout fund recycling are regarded as internalised among firms and not added to the costs.

Table 5.3 CBA and distributional effects of Scenario 1

	Period		
Cost–benefit analysis	**2010**	**2020**	**Lifetime**
Resource cost (£m)	–800	–800	–17,100
Carbon saved (MtC)	3.0	4.3	95.4
Deployment in 2015/16 (TWh)			44.6
Net banding position ROC/MWh in 2015/16			1.18
Value of carbon saved (£m)	200	300	6,000
NPV cost–benefit (£m)	–600	–500	–11,100
Cost-effectiveness (£/tC)			–179
RO deadweight	–200	–300	–6,000
Distributional analysis			
Exchequer cost (£m)	–100	–100	–2,000
Firm cost (£m)	–800	–800	–16,300
Consumer cost (£m)	–1,000	–1,100	–23,200

Note: Resource cost assumes a conventional generation counterfactual cost of £37.4/MWh. Carbon savings are calculated using an emissions factor of 0.351tCO_2/MWh in counterfactual generation from a CCGT. Costs have been rounded to the nearest £100m.
Source: Oxera analysis.

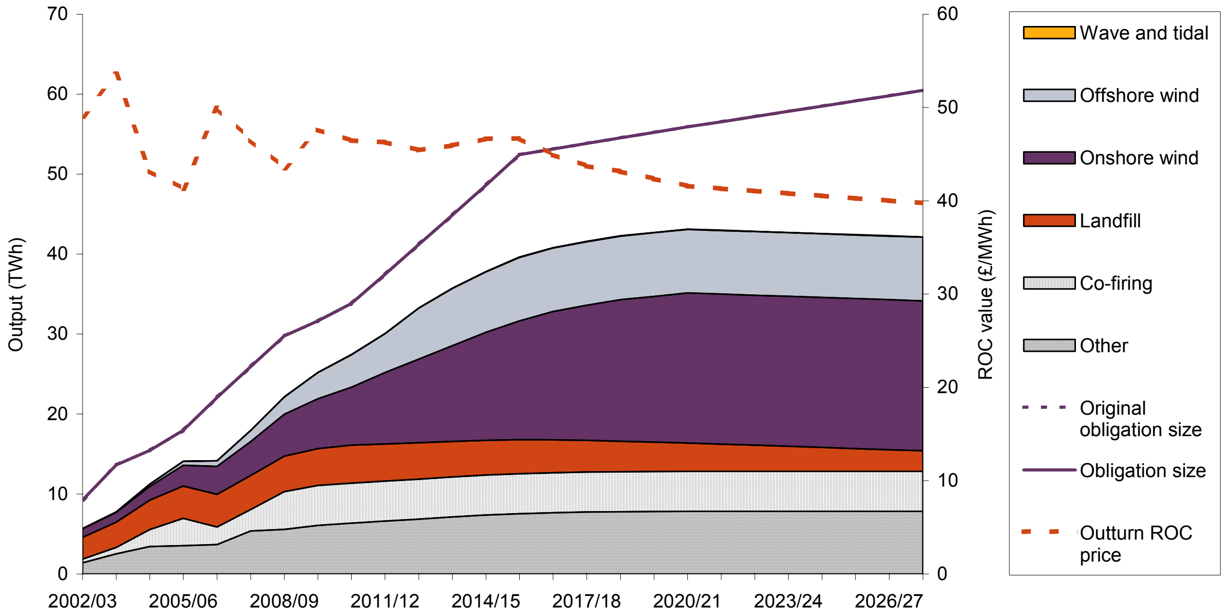
5.2 Scenario 2: Banding down for low-cost technologies

Scenario 2 describes a regime of just two bands: 0.25 ROC/MWh for economic technologies, and 1 ROC/MWh for all other technologies. This scenario attempts to remove inefficiency from the RO by taking away support from economically viable technologies where it is not required, but does not provide support for emerging technologies.

Figure 5.3 shows the volume levels expected under the banding regime of Scenario 2. As expected, the reduced levels of support lead to volumes not much greater than the Base Case, the increase coming only from the increased future ROC price driven by the removal of ROCs from economic technologies. Landfill and co-firing levels drop the most significantly, while the absence of support for emerging technologies means that no other new build comes forward to meet the gap.

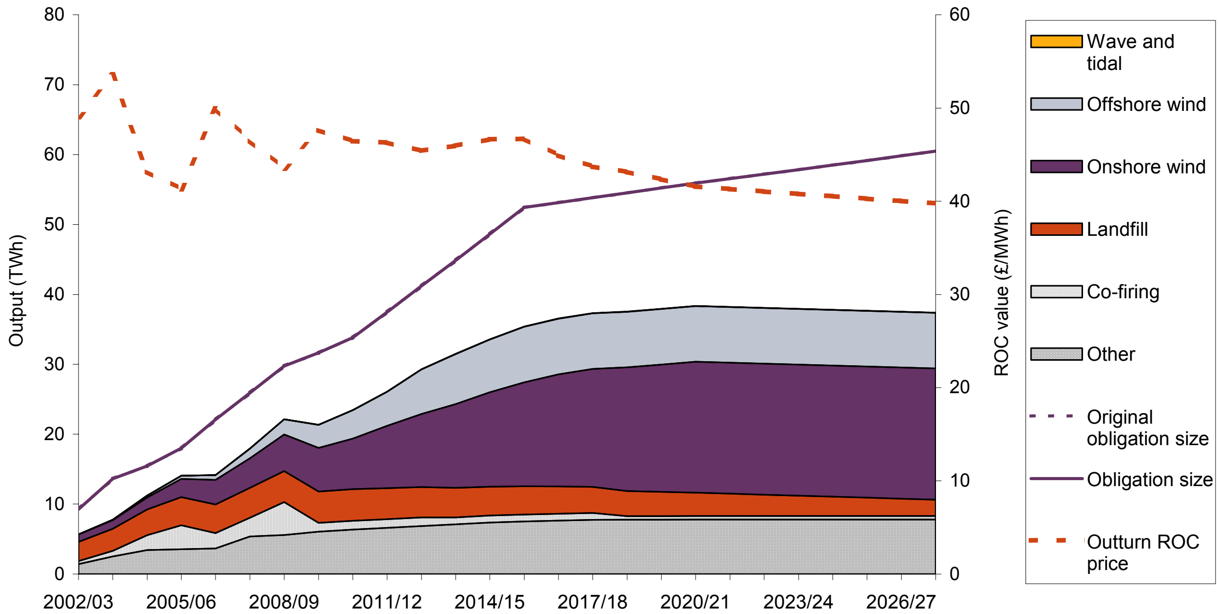
[10] Costs to firms include costs to suppliers and generators; costs to consumers imply that all supplier costs are passed on.

Figure 5.3 Volume levels in Scenario 2, Central



Source: Oxera analysis.

Figure 5.4 ROC volumes under Scenario 2, Central



Source: Oxera analysis.

5.2.1 Cost–benefit analysis and distributional impact

Table 5.4 shows the costs and benefits calculations from Scenario 2. The most notable result is the cost-effectiveness £/tC measure. Scenario 2 delivers 91.1MtC compared with the Base Case of less than 90.6MtC, but at a lower resource cost. The cost-effectiveness is therefore higher in Scenario 2, indicating that removing support for more economic technologies delivers some efficiency savings.

Table 5.4 CBA and distributional impact of Scenario 2

	Period		
Cost–benefit analysis	**2010**	**2020**	**Lifetime**
Resource cost (£m)	–700	–600	–13,600
Carbon saved (MtC)	2.	4.	91.1
Deployment in 2015/16 (TWh)			39.6
Net banding position ROC/MWh in 2015/16			0.89
Value of carbon saved (£m)	200	300	5,700
NPV cost–benefit (£m)	–500	–300	–7,900
Cost-effectiveness (£/tC)			–149
RO deadweight	–400	–400	–8,200
Distributional analysis			
Exchequer cost (£m)	–100	–100	–1,900
Firm cost (£m)	–600	–600	–12,800
Consumer cost (£m)	–1,000	–1,100	–21,800

Note: Resource cost assumes a conventional generation counterfactual cost of £37.4/MWh. Carbon savings are calculated using an emissions factor of 0.351tCO_2/MWh in counterfactual generation from a CCGT. Costs have been rounded to the nearest £100m.
Source: Oxera analysis.

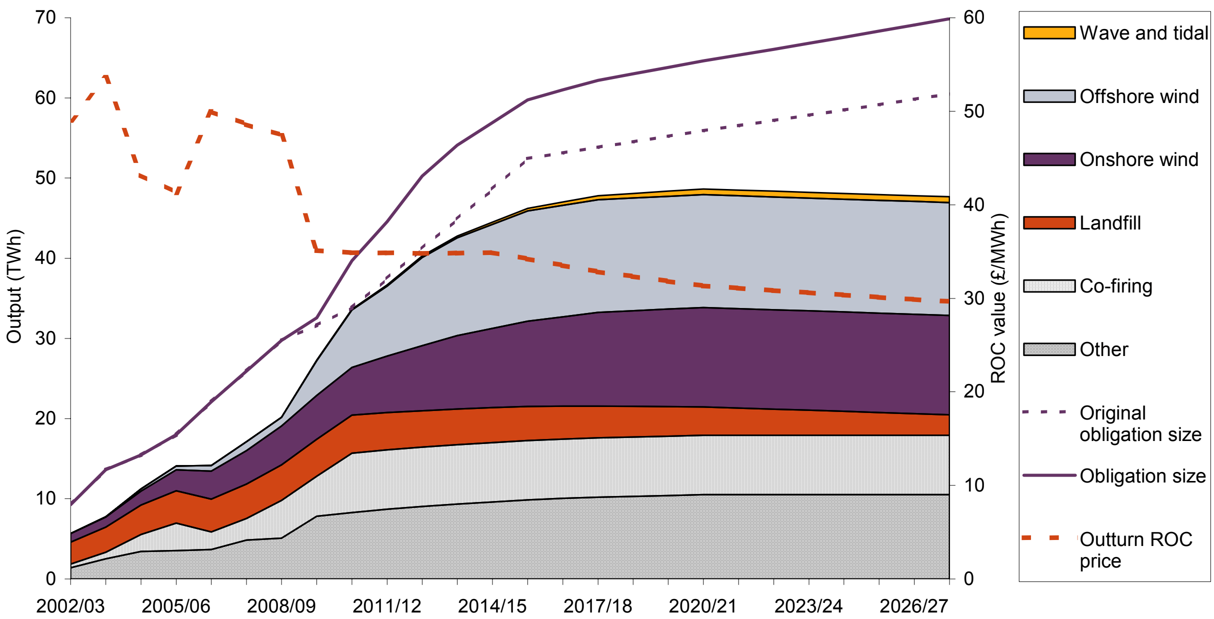
5.3 Scenario 3: Grouping the technologies

In Scenario 3, the support given to emerging technologies has been simplified and the technologies grouped into five bands, with the least economic options placed in a band of 2.8 ROC/MWh. This has the advantage of mitigating the very high number of ROCs in the market allocated to less economic technologies, while retaining the support given to biomass and offshore wind.

Scenario 3 delivers a large amount of new generation, particularly from offshore wind, co-firing and other sources. Although a small amount of tidal build is predicted, the level of support granted is not sufficient to replicate the large growth in more costly technologies that the very disaggregated banding mechanism of Scenario 1 delivered.

Scenario 3 also sees the headroom mechanism activated since the level of output is greater than the obligation by around 2009/10.

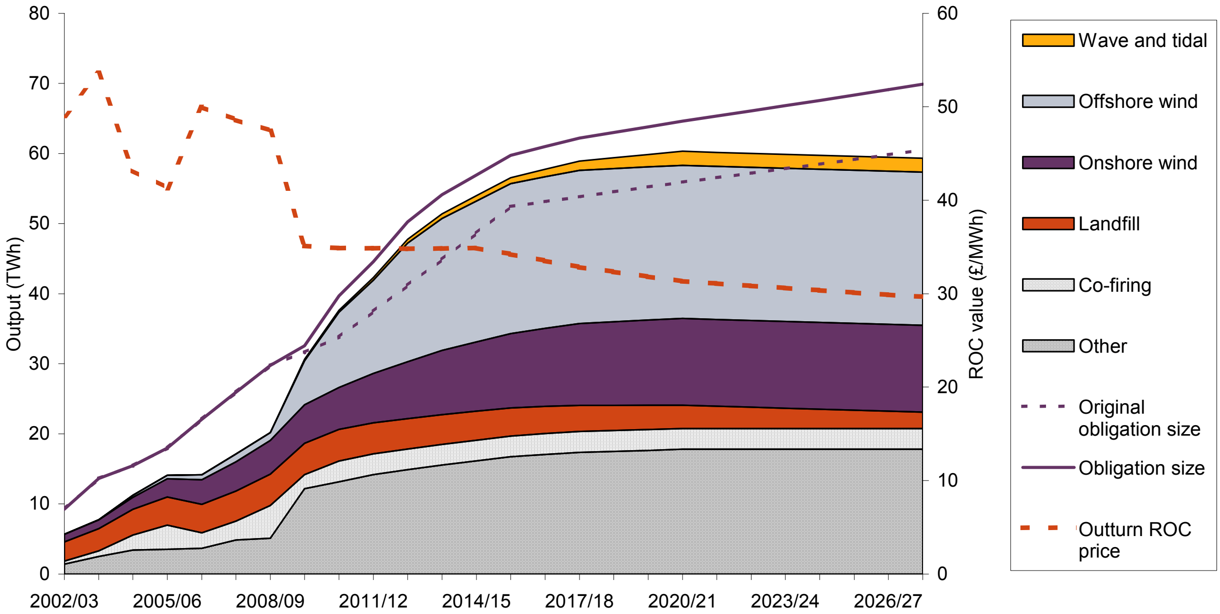
Figure 5.5 Renewables volume in Scenario 3



Source: Oxera analysis.

Overall ROC volumes in Scenario 3 are greater than the MWh totals of generation, indicating that the banding-up effect on more costly technologies is having a greater impact than the banding-down on co-firing, landfill and sewage gas.

Figure 5.6 ROC volumes in Scenario 3



Source: Oxera analysis.

5.3.1 Cost–benefit analysis and distributional effects

Scenario 3 is successful at bringing onstream significant levels of new renewable generation compared with the Base Case, although at a higher cost in both overall cost–benefit terms and £/tC efficiency terms. This scenario leads to the greatest divergence from the unbanded ratio of 1 ROC per MWh at 1.22 ROC/MWh.

Table 5.5 CBA and distributional effects of Scenario 3

	Period		
Cost–benefit analysis	**2010**	**2020**	**Lifetime**
Resource cost (£m)	–1,000	–900	–18,700
Carbon saved (MtC)	3.2	4.5	99.5
Deployment in 2015/16 (TWh)			46.2
Net banding position ROC/MWh in 2015/16			1.22
Value of carbon saved (£m)	300	300	6,300
NPV cost–benefit (£m)	–700	–600	–12,400
Cost-effectiveness (£/tC)			–188
RO deadweight	–200	–300	–6,200
Distributional analysis			
Exchequer cost (£m)	–100	–100	–2,100
Firm cost (£m)	–1,000	–900	–17,900
Consumer cost (£m)	–1,200	–1,200	–24,900

Note: Resource cost assumes a conventional generation counterfactual cost of £37.4/MWh. Carbon savings are calculated using an emissions factor of 0.351tCO_2/MWh in counterfactual generation from a CCGT. Costs have been rounded to the nearest £100m.
Source: Oxera analysis.

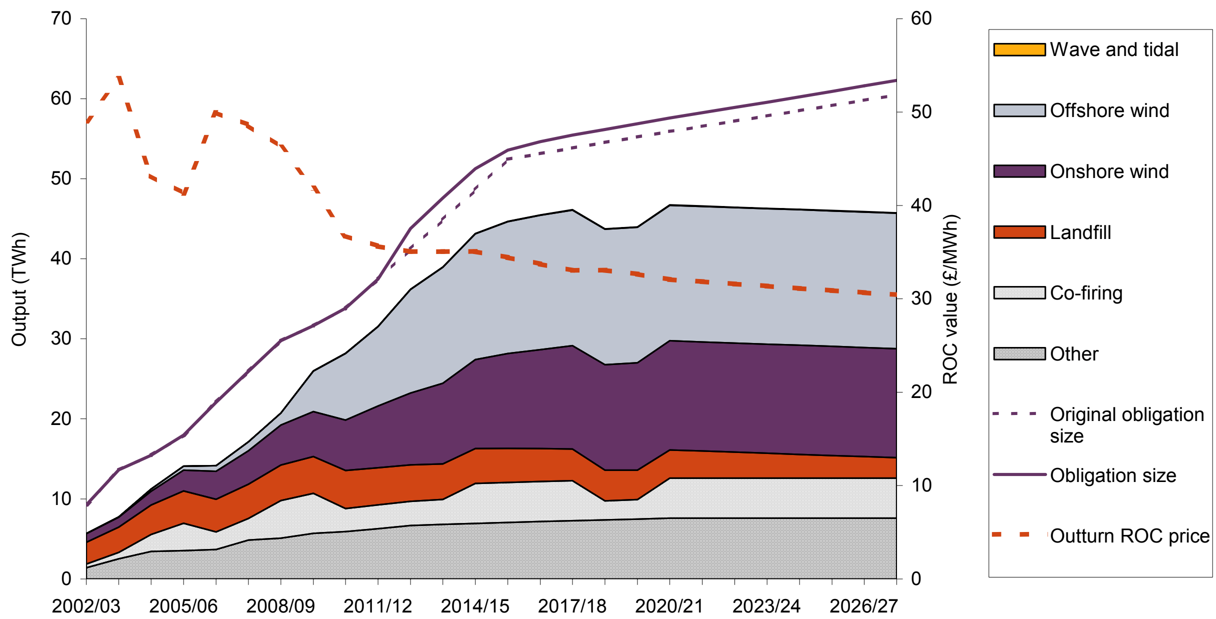
5.4 Scenario 4: Limited set of bands

Three separate bands are introduced in Scenario 4 and each technology is assigned a banding level. The bands have been selected such that the lowest-cost generation technologies—co-firing, landfill and sewage gas—are banded down to 0.25 ROC/MWh, while the emerging, higher-cost technologies receive 1.6 ROC/MWh. All onshore wind and small and large hydro remain at 1 ROC/MWh. This structure means that the very high-cost technologies such as solar PV are granted the same number of ROCs as lower-cost emerging technologies such as offshore wind.

The case for a reduction in support for co-firing built into this scenario is presented in Appendix 3 (Tables A3.24–A3.26). A sensitivity is examined whereby co-firing is banded at 0.4 ROC/MWh, which over-rewards co-firing since it seeks to cover capital costs that are typically written down over only a five-year period. This results in a short-term transference into co-firing at the expense of new offshore wind volume. Comparison of these two cases also indicates that, by 2015/16, co-firing volumes are the same with both banding levels, suggesting that 0.4 ROC/MWh may be unnecessary for co-firing to reach its maximum output.

Scenario 4 banding levels are not sufficiently high to bring onstream wave or tidal without capital grants, but do increase volumes of offshore wind. The overall net effect is an increase in RO volumes, but with growth partially constrained in the period 2010–15.

Figure 5.7 Renewables volume in Scenario 4



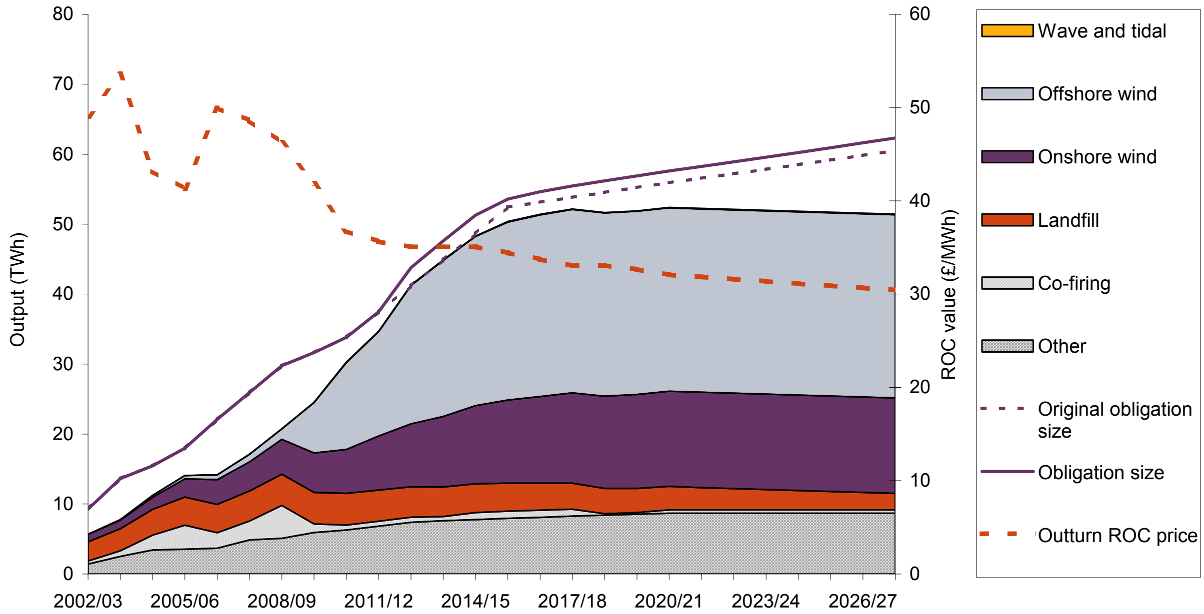
Source: Oxera analysis.

The largest impact on the model from introducing banding is the increase in investment in offshore wind farms. This is a direct result from the banding level on offshore wind, increasing all revenues associated with the sale of ROCs by 60%. The increase in investment in offshore wind is so large that, in both 2009/10 and 2012/13, the build rate constraint is binding and, in addition, the capacity constraint binds in 2010/11. While the levels of investment in onshore wind are approximately 25% lower than in the Base Case, where the build rate constraint binds for six consecutive years from 2010/11, there is still significant investment in onshore generation, with the build rate constraint binding in both 2011/12 and 2012/13. The kinks in the co-firing volumes are partially a result of banding level changes over time.

An analysis of the volume chart alone is insufficient to explain the dynamics of the RO under a banding scenario. For a more detailed analysis, the ROC volume chart has been included below (Figure 5.8). This chart depicts the number of ROCs granted to each technology from generating renewable electricity at the levels shown in the figure above. Figure 5.8 clearly depicts the effects of the introduction of banding, with technologies that have been banded up receiving more than one ROC per MWh generated, and technologies that have been banded down, receiving a fraction of a ROC per MWh.

The figure also explains the reason for the divergence between the original Renewables Obligation and the actual level. In Figure 5.7 the investment in renewables appears to be insufficiently large to activate the headroom mechanism. In Figure 5.8, however, the number of ROCs granted to offshore wind is so large that the number of ROCs in the market exceeds the original obligation size as early as 2012/13, activating the headroom mechanism. By 2015/16, the number of ROCs has reached 53.9m, coming from some 47.2TWh of renewables generation.

Figure 5.8 Scenario 4 central ROC volumes



Source: Oxera analysis.

5.4.1 Cost–benefit analysis and distributional impacts

Under Scenario 4, more renewable generation is forecast from all sources including developing technology, and therefore there is a greater cost to firms to provide it compared with the Base Case, and, to a lesser extent, with the Exchequer and consumers. Table 5.6 shows the complete breakdown of cost–benefit analysis and distributional effects.

Table 5.6 CBA and distributional impact in Scenario 4

		Period	
Cost–benefit analysis	**2010**	**2020**	**Lifetime**
Resource cost (£m)	–800	–800	–17,500
Carbon saved (MtC)	2.	4.	96.5
Deployment in 2015/16 (TWh)			44.7
Net banding position ROC/MWh in 2015/16			1.13
Value of carbon saved (£m)	200	300	6,100
NPV cost–benefit (£m)	–600	–500	–11,400
Cost-effectiveness (£/tC)			–181
RO deadweight	–200	–300	–4,900
Distributional analysis			
Exchequer cost (£m)	–100	–100	–2,000
Firm cost (£m)	–800	–800	–16,700
Consumer cost (£m)	–1,000	–1,100	–22,400

Note: Resource cost assumes a conventional generation counterfactual cost of £37.4/MWh Carbon savings are calculated using an emissions factor of 0.351tCO_2/MWh in counterfactual generation from a CCGT. Costs have been rounded to the nearest £100m.
Source: Oxera analysis.

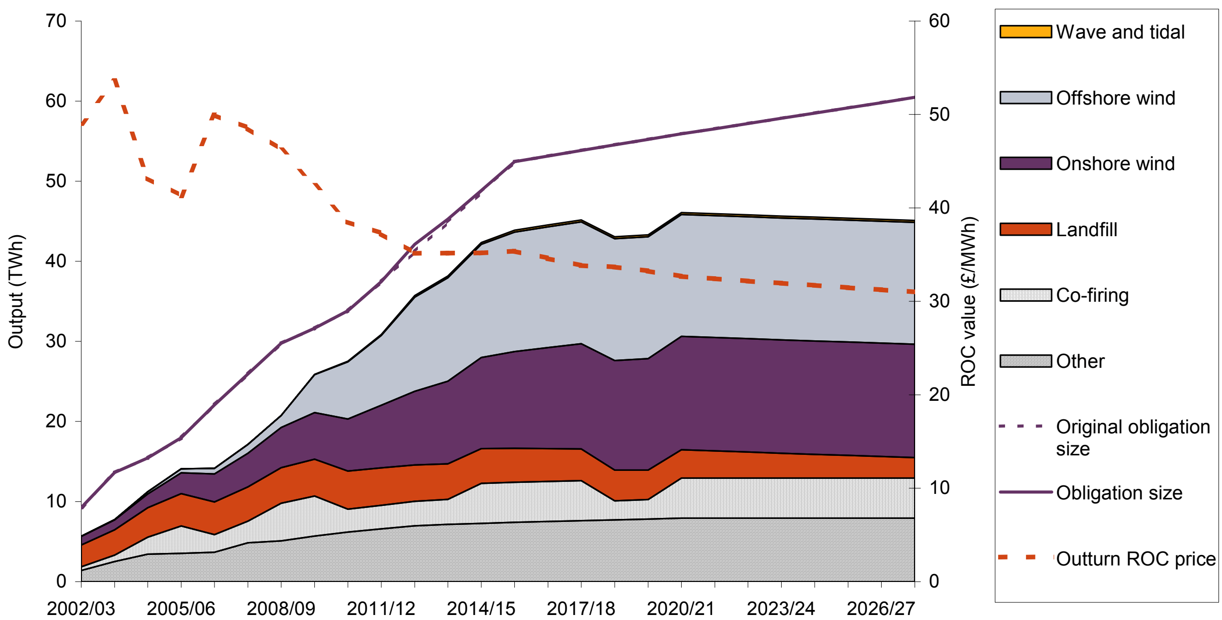
5.5 Scenario 5: Rebalanced set of bands

Scenario 5 separates offshore wind and regular biomass from the emerging technologies band by creating a separate band for these two technologies with a ROC multiple of 1.5. The emerging technologies ROC multiple increases to 2 from the outset of banding. All other technologies remain as in Scenario 4. The results from Scenario 5 are presented below.

The changes in the bands in Scenario 5 have a small but significant effect on the RO. First, investment in offshore wind is lower than in Scenario 4, which is as expected with a lower band multiple on the ROCs received. Investment in emerging technologies increases as the expected value of projects increases, with a higher ROC multiple on electricity produced. Interestingly, onshore investment is higher in Scenario 5, even though there is no change in the band on onshore wind. This effect is driven by the economics in the market under Scenario 5. Decreasing the band on offshore wind truncates the renewables supply curve as fewer ROCs are granted to offshore generation. This has the effect of shifting the interception between the supply curve and the ROC value to the left, decreasing the number of ROCs in the market and increasing their value. With a higher value for ROCs, marginal onshore projects that may have been uneconomic under Scenario 4, increase in their expected value and receive a greater amount of investment as a result. The volumes of offshore wind in this scenario were restricted in 2009/10 by the annual build rate constraints of 3.24TWh assumed in the modelling. Were these constraints not binding—for example, if planning constraints were relaxed—then the overall volumes of renewable generation may be greater.

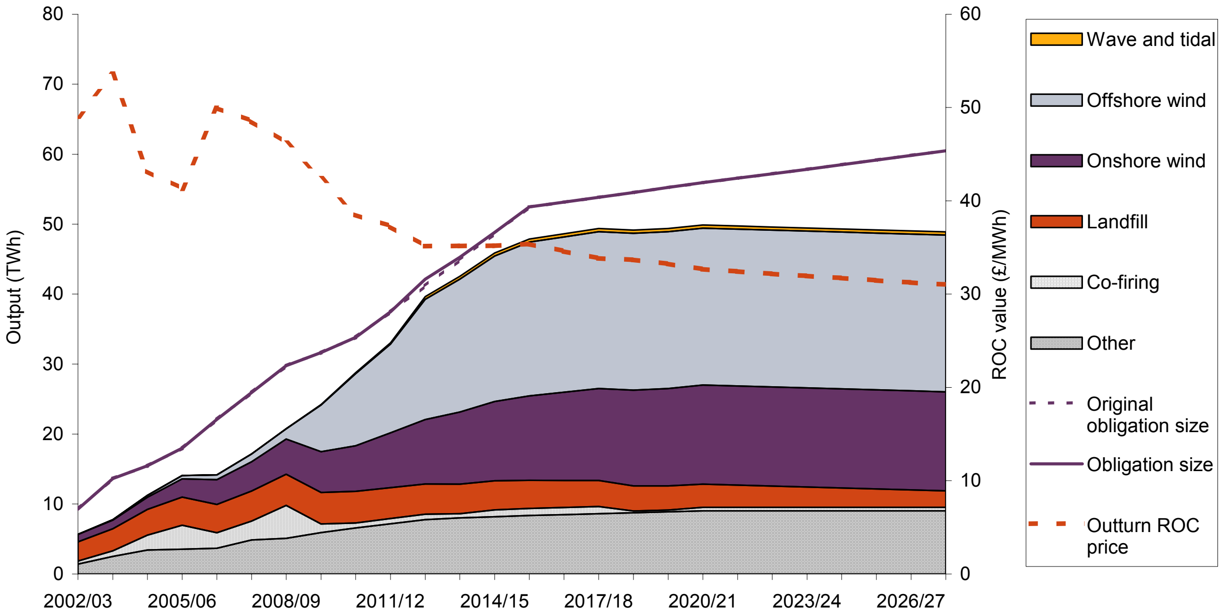
The significance of there being fewer ROCs in the market under Scenario 5 is that the cost to consumers is lower than in Scenario 4 as a result of the diminished impact of the headroom This is of particular importance since Scenario 5 sees a greater volume of renewable generation coming onstream over the duration of the RO, while also being cheaper than Scenario 4.

Figure 5.9 Scenario 5 central renewables volume



Source: Oxera analysis.

Figure 5.10 Scenario 5 central renewables ROC volume chart



Source: Oxera analysis.

5.5.1 Cost-benefit analysis and distributional impacts

Scenario 5 delivers a higher level of carbon savings than the Base Case, but at a correspondingly higher cost to all parties. The increased generation from higher-cost technologies leads to lower-cost effectiveness, which is observed with a cost of £176/MtC in discounted terms over the lifetime of the projects.

Table 5.7 CBA and distributional impact in Scenario 5

	Period		
Cost–benefit analysis	**2010**	**2020**	**Lifetime**
Resource cost (£m)	–800	–800	–16,800
Carbon saved (MtC)	2.	4.	95.2
Deployment in 2015/16 (TWh)			43.9
Net banding position ROC/MWh in 2015/16			1.09
Value of carbon saved (£m)	200	300	6,000
NPV cost–benefit (£m)	–600	–500	–10,800
Cost-effectiveness (£/tC)			–176
RO deadweight	–200	–300	–5,000
Distributional analysis			
Exchequer cost (£m)	–100	–100	–2,000
Firm cost (£m)	–800	–800	–16,000
Consumer cost (£m)	–1,000	–1,100	–21,800

Note: Resource cost assumes a conventional generation counterfactual cost of £37.4/MWh. Carbon savings are calculated using an emissions factor of 0.351tCO_2/MWh in counterfactual generation from a CCGT. Costs have been rounded to the nearest £100m.
Source: Oxera analysis.

5.5.2 Sensitivities around Scenario 5

Appendix 3 presents some of the additional sensitivities modelled around Scenario 5, which broadly illustrate the effects that the different drivers have on build volumes. Total volumes vary from 37.2TWh in 2015/16 under low electricity prices to 57TWh under high-price and low-cost conditions. The charts in the appendix illustrate under the high-price and low-cost sensitivities the diversion of the obligation from its original size, and these drivers are also strong enough to smooth the kinks in co-firing volumes caused by the banding changes.

Table 5.8 Renewables volumes in 2015/16 in Scenario 5 under various sensitivities (TWh)

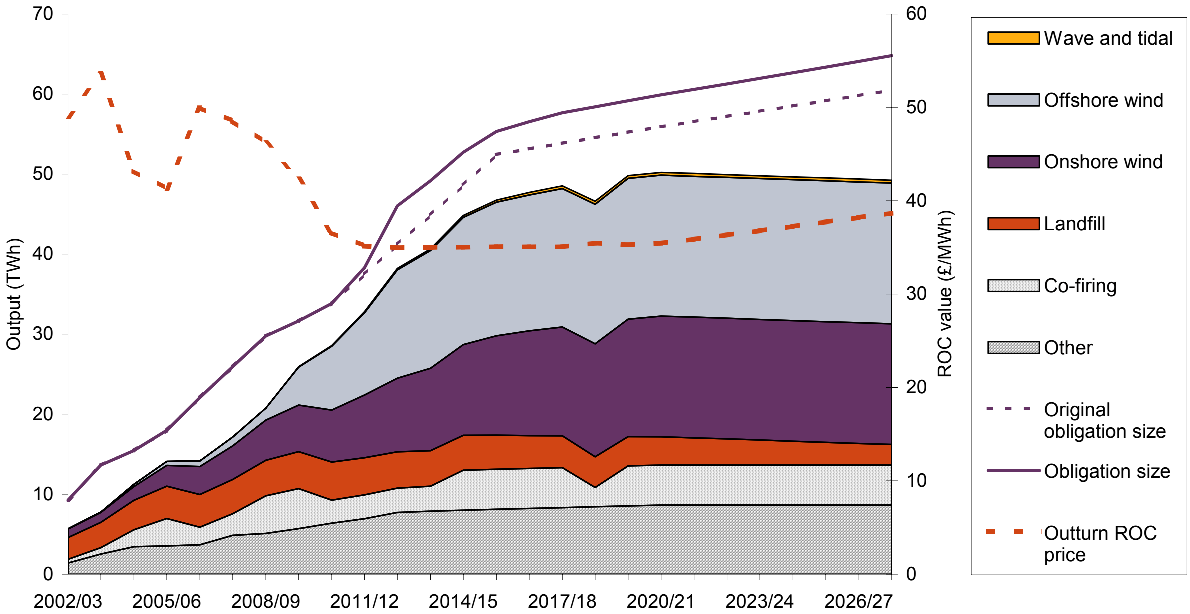
Sensitivity	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
Central	7.4	5.0	4.2	12.2	14.9	43.9	12.7
Costs – 10%	9.3	5.0	4.2	13.7	17.9	50.2	14.4
Costs + 10%	6.8	3.3	4.0	10.6	12.6	37.3	10.8
Including planning	7.5	5.0	4.7	12.3	15.3	44.8	12.9
High prices	8.4	5.0	4.2	12.7	15.3	45.7	13.2
High prices, costs –10%	9.9	7.4	4.7	14.7	20.3	57.0	16.4
High prices, including planning	8.0	7.4	4.7	13.1	15.7	48.9	14.1
Low prices	6.9	3.3	4.0	10.1	13.0	37.2	10.8

Source: Oxera analysis.

5.6 Scenario 6: Retaining the buyout price link to the RPI

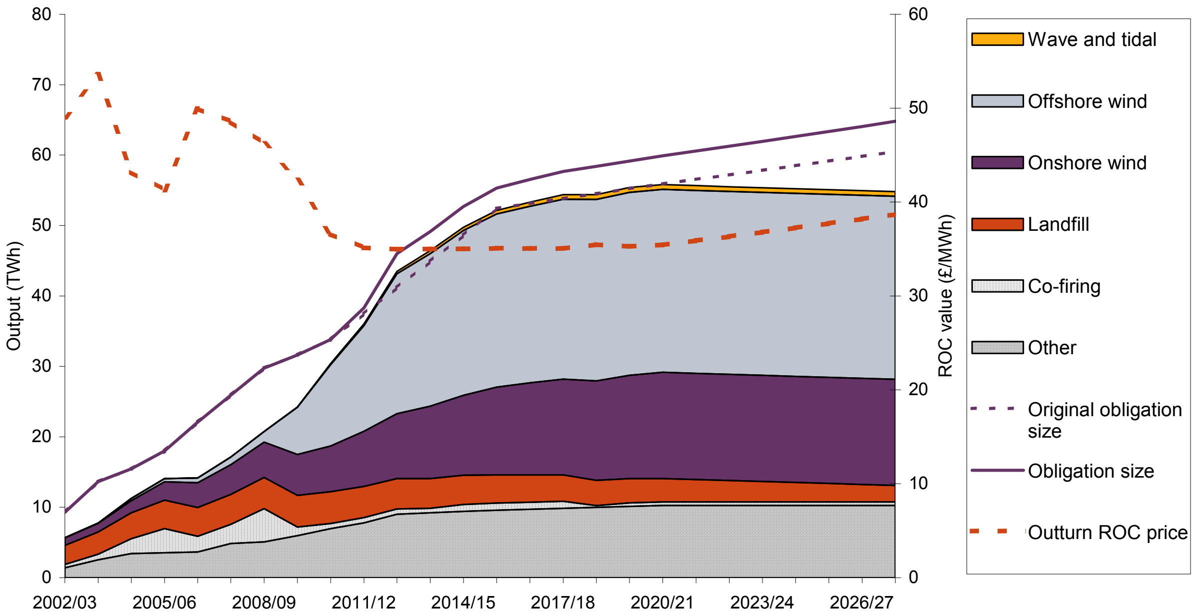
Of all the scenarios where banding-up occurs, Scenario 5 has the lowest consumer costs, and drives significant increases in deployment and brings forward a more diverse generation mix. As such, Scenario 6 was run maintaining the Scenario 5 banding levels and inherent benefits, but retaining the link of the buyout price to RPI. Unfreezing the buyout price makes ROC redemption more favourable than buying out as time passes, leading to greater deployment of renewable generation.

Figure 5.11 Scenario 6 central renewables volume



Source: Oxera.

Figure 5.12 Scenario 6 central renewables ROC volume



Source: Oxera.

The distributional impacts of this refinement are shown in Table 5.9. Linking the buyout price to RPI has the expected effect of increasing the deployment of renewable generation, which in turn increases the resource cost slightly. However, in comparison with the Base Case, the deadweight loss remains considerably lower. These effects are broadly the same as those observed in the Base Case sensitivities, with RPI-in runs for all scenarios compared with the equivalent delinked sensitivity.

Table 5.9 CBA and distributional impact in Scenario 6

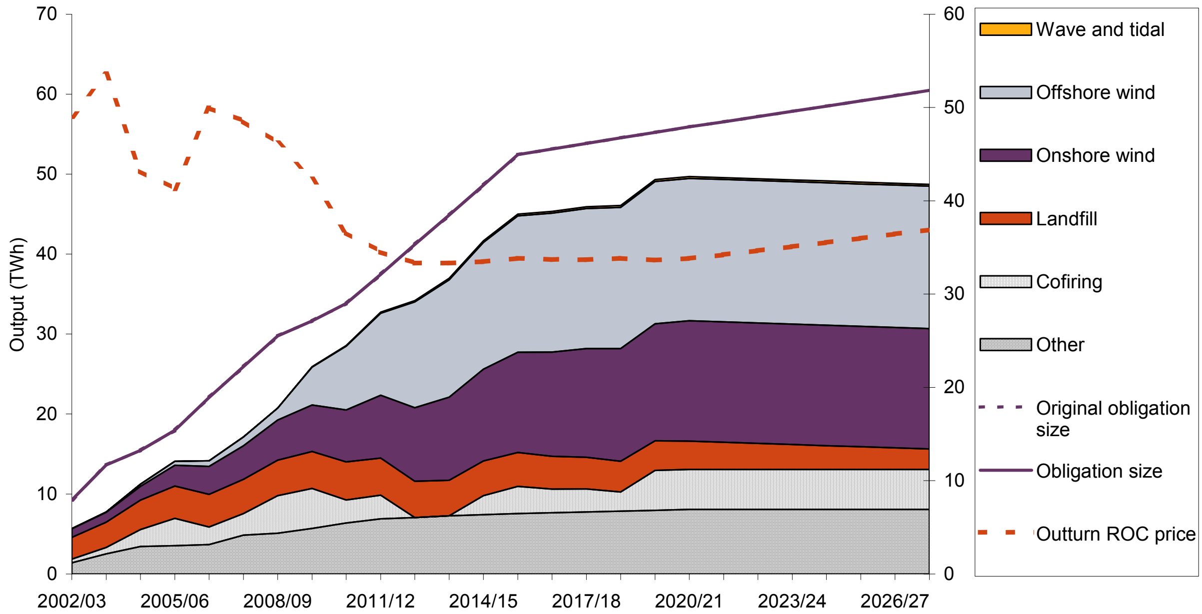
	Period		
Cost–benefit analysis	**2010**	**2020**	**Lifetime**
Resource cost (£m)	–800	–900	–19,400
Carbon saved (MtC)	2.7	4.7	103.1
Deployment in 2015/16 (TWh)			46.7
Net banding position ROC/MWh in 2015/16			1.12
Value of carbon saved (£m)	200	300	6,500
NPV cost–benefit (£m)	–600	–600	–12,900
Cost-effectiveness (£/tC)			–188
RO deadweight	–200	–300	–5,700
Distributional analysis			
Exchequer cost (£m)	–100	–100	–2,200
Firm cost (£m)	–800	–900	–18,500
Consumer cost (£m)	–1,000	–1,300	–25,100

Note: Resource cost assumes a conventional generation counterfactual cost of £37.4/MWh. Carbon savings are calculated using an emissions factor of 0.351tCO_2/MWh in counterfactual generation from a CCGT. Costs have been rounded to the nearest £100m.
Source: Oxera analysis.

5.6.1 Impact of headroom

The proposals made in the Energy Review report included introducing a headroom mechanism from 2015/16. However, it was observed in the early runs that banding-up technologies such as offshore wind resulted in an increased ROC issue in the period 2010–15, and potential over-compliance in this period that might have led to a crash in the ROC market. It was therefore decided to model the introduction of the headroom mechanism from 2009 when banding is assumed to come into effect. This was adopted as the standard condition for further runs. Without the headroom in place in 2009/10–15, the model assumes that potential investors would anticipate the ROC price crash and defer their build decision. The increase in the size of the obligation from its original level leads to increased renewable generation, but also increased cost to consumers. Figure 5.13 shows the volumes expected without a headroom mechanism from 2009/10 and comparison between this and Figure 5.12 illustrates the effects of this, most notably an the absence of co-firing from 2012/13 to 2013/14. The activation of the headroom mechanism from 2011/12 observed in Figure 5.12 allows both co-firing and new build for other technologies to continue, resulting in a greater overall deployment by the target date of 2015/16.

Figure 5.13 Scenario 6 without a headroom mechanism in 2009/10



Source: Oxera.

5.7 Comparison of banding options

The volume of renewable generation in all banding scenarios is greater than in the Base Case. Of the scenarios without the buyout price link to RPI, banding Scenario 3 delivers the largest volumes of new generation, mainly due to the flattening of the supply curve that results from the extra support given to more expensive technologies. Despite giving no direct support through banding to any technology, Scenario 2 delivers more renewable generation than the Base Case by reducing the ROC volumes in the market allocated to co-firing, and simultaneously removing the regulatory cap and thereby bringing extra co-firing onstream. Scenario 5 has the lowest consumer costs of all scenarios where banding up-occurs while delivering increased renewables deployment over the base case and closest 1 ROC:1MWh ratio. Scenario 6 retains the banding levels and positive characteristics of Scenario 5 but has the RPI link to the buyout price retained, delivering high levels of generation. Table 5.10 compares the key cost–benefit and distributional metrics across the Base Case and banded scenarios.

Table 5.10 Comparison of key results

Cost–benefit analysis	Base Case	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
Deployment in 2015/16 (TWh)	39.3	44.6	39.6	46.2	44.7	43.9	46.7
Carbon saved (lifetime, MtC)	90.6	95.4	91.1	99.5	96.5	95.2	103.1
RO deadweight (lifetime costs, discounted, £m)	–9,100	–6,000	–8,200	–6,200	–4,900	–5,000	–5,700
Resource cost (£m, lifetime costs, discounted)	–14,600	–17,100	–13,600	–18,700	–17,500	–16,800	–19,400
Net banding position ROC/MWh in 2015/16	1	1.18	0.89	1.22	1.13	1.09	1.12
Distributional analysis							
Exchequer cost (lifetime costs, discounted, £m)	–1,900	–2,000	–1,900	–2,100	–2,000	–2,000	–2,200
Firm cost (lifetime costs, discounted, £m)	–13,800	–16,300	–12,800	–17,900	–16,700	–16,000	–18,500
Consumer cost (lifetime costs, discounted, £m)	–23,700	–23,200	–21,800	–24,900	–22,400	–21,800	–25,100

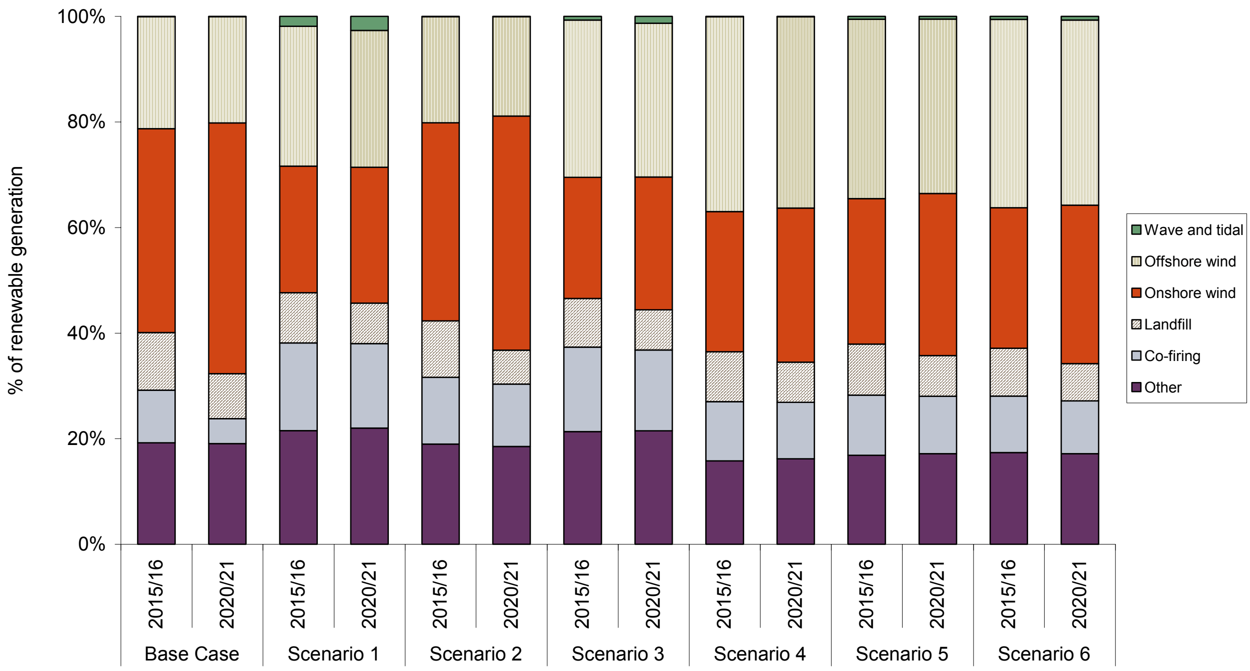
Source: Oxera analysis.

In terms of cost-effectiveness, Scenario 2 delivers the most efficient benefits, since it generates a greater amount of RO-eligible electricity than the Base Case at a cost per tonne of carbon that is lower than all the other scenarios. The main factor behind this is the introduction of more co-firing in this scenario and the removal of the excess support given to more economic technologies. The other scenarios are less effective in this regard since the marginal cost of reducing 1 tonne of carbon through, for example, building an extra unit off offshore wind is significantly greater than the average MWh cost in the Base Case.

The consumer costs are largely a function of the ROC volumes and buyout price, and therefore are most affected when the volumes activate the headroom mechanism. Scenarios 1 and 3, with the largest degree of disaggregation in banding and highest ROC volumes, are consequently more expensive to the consumer, although in all scenarios without the RPI link except Scenario 3, the cost to the consumer is lower than in the Base Case. Scenario 2 does not trigger the headroom mechanism, and the consumer costs are therefore the same as in the Base Case. Scenario 5 delivers a balance of new generation and a substantial reduction in consumer costs with moderate increases in resource costs and a slight decrease in cost-effectiveness. Scenario 6 delivers the greatest extra deployment of renewable generation, with the same cost-effectiveness as Scenario 3 and a significant reduction in deadweight loss compared with the Base Case

As expected, the cost-levelling effect that banding produces has an effect on the mix of technologies employed. Scenario 1 produces the most diverse mix, and the only significant quantities of wave and tidal generation. Scenario 2 is roughly equal to the Base Case, with the exception of the greatly increased proportion of co-firing observed in 2020/21. Figure 5.14 shows a comparison of the technology mix in 2015/16 and 2020/21 across scenarios.

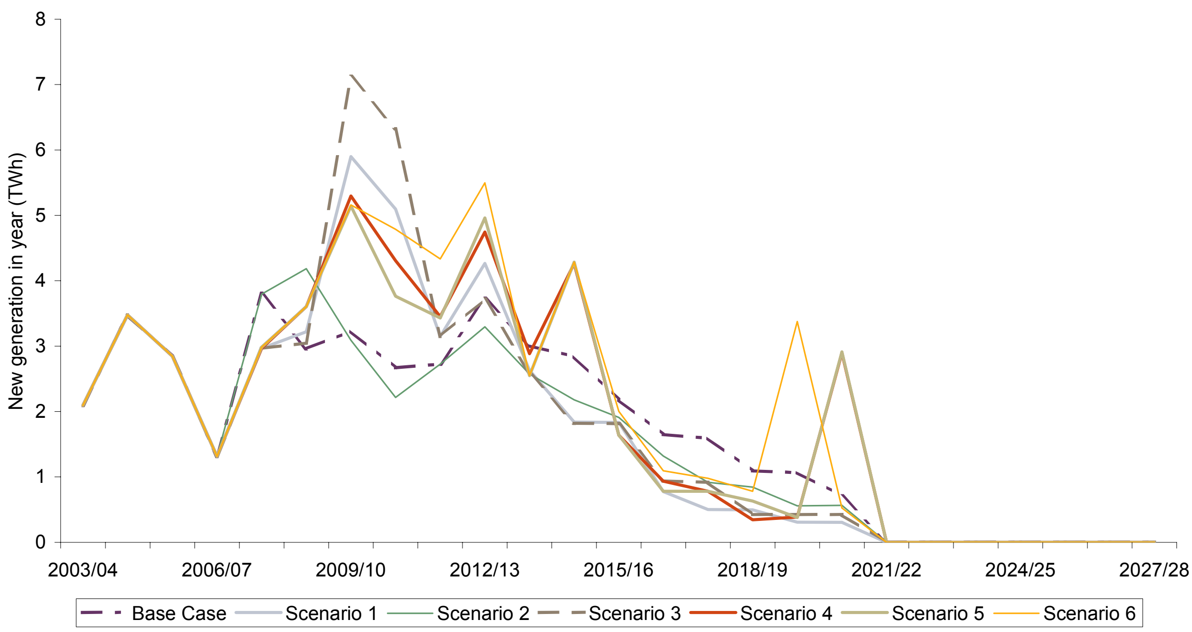
Figure 5.14 Comparison of generation mix in technologies across banding scenarios



Source: Oxera analysis.

Examination of the timing of when new infrastructure comes on-stream shows that, although there are differentials in the middle period of around 2008–15, all scenarios show a pattern of investment that broadly decreases in the years after 2015 and stops completely in 2021/22. This is a reflection of the smaller time frame available after this point to recoup the necessary investment through ROC revenues. The different banding regimes do not have a sufficiently strong effect to significantly lengthen the period during which new build is economically feasible.

Figure 5.15 Year-on-year levels of new generation



Source: Oxera analysis.

6 Conclusions

While the current RO regime (allowing for the change in the treatment of energy crop co-firing) continues to support growth in renewable generation, the modelling of the mechanism highlights several important points.

- Under a range of sensitivities, the volume of generation will be in the order of 10–11% by 2015/16, compared with an obligation size of 15.4%.
- Only if costs are significantly lower (a cost reduction of 10% is assumed in the modelling) do renewable volumes increase materially, to 12.7% by 2015/16, compared with 11.4% in the Base Case. This arises because the ROC price determination depends on the costs of the marginal technology—the higher this cost, the higher the ROC price required to support it, and therefore the further from the obligation target the market must be to produce a sufficiently high value of buyout fund recycling.
- The majority of new renewable generation arises from new onshore and offshore wind projects—by 2015/16 these account for around 60% of total renewable generation volumes.
- The finite lifetime of the RO regime has a significant impact on investment decisions since it limits the period over which later investments can expect to receive revenues from ROCs. As a consequence, the modelling predicts that, under the Base Case assumptions, no new investment will be forthcoming through the RO scheme after 2020/21. Furthermore, for higher-cost projects such as offshore wind, the effect is evident earlier—offshore wind investment ceases after 2015/16 in the Base Case.
- The mechanism generates deadweight loss because the ROC price is set by the marginal technology. The discounted deadweight loss over the lifetime of the RO is calculated as £9.1 billion in the Base Case.

The proposed introduction of banding is intended to improve the efficiency of the RO scheme through reducing the deadweight loss arising from over-subsidising low-cost technologies; increase the overall volume of renewable generation; and increase the diversity of renewable generation technologies in the market.

Since the banding options lead to increased volumes of ROCs in the market, they have been modelled in conjunction with the introduction of a headroom mechanism to reduce the adverse investment implications of uncertainty over ROC price volatility. In all scenarios where ROC-ing up (ie, awarding more than 1 ROC per MWh) occurs the headroom mechanism is triggered, and this increases the overall cost to consumers (since it raises the absolute size of the obligation). This can be offset in part through efficiency gains.

The cut-off dates for investment are the same in the Base Case and all banded scenarios, suggesting that the time frame for ROC revenue collection is a more dominant factor in investment decisions than the effects of banding.

6.1.1 Effects of banding regimes

Considerations of the most appropriate level of banding to achieve the stated goals of the RO involve several factors, not all of which are adequately captured in straightforward cost–benefit terms. It may be the case that the introduction of new renewable volumes has significant second-order effects, such as economies of scale and R&D incentives, which may contribute benefits in the future that are not captured within the modelling framework.

Compared with the Base Case, all the banding options delivered additional renewable generation. Total lifetime renewable generation under the Base Case was 946TWh, whereas under the different banding options, total generation was in the range 1,020–1,119TWh. Scenario 1, where the banding was differentiated by individual technologies, was the banding regime that delivered the greatest volumes of renewables. However, the costs for this in terms of deadweight loss are high, and it appears that some modifications to this scenario may increase efficiency.

The reverse case is explored in Scenario 2, where there is no banding-up of less economic technology, and the cost per tonne of carbon saved falls to £149. This illustrates the relative efficiency of co-firing as a means of achieving carbon savings. Supporting co-firing does not encourage significant capital investment and subsequent continued benefit beyond the RO lifetime when compared with high fixed cost and low variable cost technologies such as wind. However, the overall carbon savings produced by Scenario 2 are not significantly greater than the Base Case; this option may therefore not be particularly effective in meeting the UK's targets for renewable generation.

Grouping some technologies in Scenario 3 reduces the levels of support to very expensive technology and, as a result, tightens the ROC market sufficiently to return the greatest levels of renewable volumes of the scenarios without the RPI link; however, the costs to the consumer of doing so are correspondingly high.

All scenarios show substantial increases in co-firing. This arises because, under the banding arrangements, the constraint on non-energy co-firing volumes within the current RO is removed and co-firing is a low-cost renewable option. The support levels for co-firing in Scenarios 1 and 3 take account of neither the avoided costs for use of coal-fired generation that drive co-firing nor of the shorter periods used to recoup investment generally applied to the modest investments required for co-firing. Scenario 4 therefore cuts support for co-firing and delivers a reduction in the lifetime deadweight loss. More generally, banding does reduce the lifetime deadweight loss of the RO regime—the discounted figure is between £5.7 billion and £8.4 billion—implying more effective targeting of support.

Scenario 5 rebalances the banding levels slightly, and succeeds in delivering approximately the same overall levels of carbon savings at similar resource costs. However, the generation mix in Scenario 5 is more diverse than in Scenario 4, and brings greater volumes of new technology onstream, which may have unforeseen benefits in increasing development and cutting the costs of these technologies. In addition, Scenario 5 has the second lowest deadweight loss as a result of the lower volumes of ROCs in the market than Scenario 1 and a higher proportion of cost pass-through than Scenario 2.

Scenario 6 takes the balance of benefits from Scenario 5 and then significantly boosts the overall levels of new build, with the higher buyout prices driving this increase in demand. This results in the highest amount of new generation and subsequently the greatest amount of carbon savings at over 103MtC over the project's lifetime.

Overall, the cost-effectiveness of the RO declines because the introduction of more high-cost technologies leads to a higher cost per tonne of carbon saved compared with the Base Case. The Base Case has £161/tC saved, whereas the cost is in the range of £176–£188/tC saved in all scenarios where additional ROCs are provided to high-cost technologies. However, it should be noted that £/MtC is only one possible measure of cost-effectiveness. Other benefits that may accrue from deference of fossil-fuel generation, such as reduced liability to shocks in gas prices, for example, might be captured in a different approach to assessing effectiveness.

In all banded scenarios, there has been a redistribution of the costs away from consumers and on to firms and the Exchequer. Except for Scenarios 3 and 6, the lifetime costs to the consumer have decreased compared with the Base Case, despite increasing renewable generation.

The ROC banding required to make different technologies viable varies significantly. For example, under the Ernst & Young cost assumptions, wave and tidal projects need a band of 3.9 to 4.5 (without any grant support), whereas offshore wind requires a band of 1.5. Thus, only in scenarios where the high-cost emerging technologies are separated from the lower-cost technologies are substantive volumes of these emerging technologies observed.

In all banding options where there is ROC-ing up, however, the change in the mix of generation relative to the Base Case results in lower volumes of onshore wind in the market. This arises because there is no change in the ROC band for onshore wind, so other banding changes improve the relative cost position of alternative technologies compared with onshore wind. Onshore wind still experiences strong growth over time, with volumes increasing almost fourfold from 4.2TWh in 2007 to 15.1TWh in 2020.

In conclusion, this study finds that banding can be used as an effective tool to change the renewables volumes and mix of technologies. If introduced, it could increase generation volumes to the point where headroom is necessary to avoid a collapse of the ROC price. At its most extreme, disaggregated banding could provide powerful incentives for some of the more expensive technologies, but with a high overall cost, which is very sensitive to changes in technology costs. A less disaggregated form of banding such as that prescribed by Scenario 5 or 6 could strike a balance between technology promotion, diversity, and the cost-effectiveness of carbon reductions.

Appendix 1 Aspects of technology supply curves

For each technology Ernst & Young have predicted a high, central and low cost and a total predicted capacity for 2006, 2010, 2015 and 2020. For most technologies, to separate the single predicted capacity value between the three cost estimates, a 0.25, 0.5, 0.25 weighting has been used for the low, central and high costs, respectively.

However, for the following technologies, the Ernst & Young data has been separated to include two more cost levels, one between the Low and Central case and the second between the Central and High case:

– onshore wind, large, high wind;
– onshore wind, large, low wind;
– onshore wind, small;
– offshore wind.

The costs assigned to these additional levels are a linear interpolation of the Ernst & Young data. The capacity weighting assigned to the cost levels is 0.2 for each case, meaning that there is an equal split of the predicted capacity between the five cost levels.

In addition, an assumption has been made that the high cost level of each technology is not actually the highest cost possible in the model. One further cost level for each technology at a 10% premium in each year has been included. This addition captures the effect of year-by-year constraints on additional build beyond the predicted capacity levels, but still allows such investment to occur if it is financially viable at the higher cost and within the build rate constraint.

Table A1.1 Predicted capacity values for each technology (TWh)

	2006	2010	2015	2020
Co-firing regular	2.6	7.9	7.4	6.0
Co-firing - energy crop	0.1	0.9	1.3	2.0
Landfill gas	4.1	4.8	4.3	3.6
Onshore wind, large, high wind	1.1	1.7	6.2	9.1
Onshore wind, large, low wind	1.7	5.1	9.4	13.7
Onshore wind, small, high wind	0.1	0.1	0.3	0.5
Onshore wind, small, low wind	0.1	0.3	0.5	0.7
Small-scale hydro	0.1	0.3	0.6	0.8
Large-scale hydro	1.9	2.0	2.1	2.3
Sewage gas	0.3	0.4	0.4	0.5
Offshore wind	0.6	8.3	18.2	22.0
Biomass CHP	0	0.8	1.9	2.1
Biomass, Regular	0.9	1.9	4.0	5.0
Biomass energy crop	0.1	0.2	0.7	1.8
Tidal	0	0.1	0.5	1.4
Wave	0	0.1	0.5	1.2
Gasification/pyrolysis	0	0.1	0.3	0.7
AD CHP	0	0.1	0.2	0.3
EfW/CHP	0	0.7	1.2	1.6
Solar PV	0	0	0	0

Source: Ernst & Young (2007), op. cit.

Appendix 2 Input assumptions

Input assumptions have been provided by the DTI for 2006, 2010, 2015 and 2020. A linear interpolation was used to derive figures for the intervening years.

Table A2.1 Wholesale electricity price assumptions (£/MWh)

	Low	Central	High
2007/08	39.6	41.7	42.9
2008/09	36.7	40.9	43.4
2009/10	33.7	40.0	43.8
2010/11	30.8	39.2	44.2
2011/12	30.7	39.3	44.1
2012/13	30.6	39.4	44.0
2013/14	30.5	39.4	43.8
2014/15	30.4	39.5	43.7
2015/16	30.3	39.6	43.6
2016/17	30.2	39.7	43.5
2017/18	30.1	39.8	43.4
2018/19	29.9	39.8	43.3
2019/20	29.8	39.9	43.2
2020/21	29.7	40.0	43.1
2021/22	29.7	40.0	43.1
2022/23	29.7	40.0	43.1
2023/24	29.7	40.0	43.1
2024/25	29.7	40.0	43.1
2025/26	29.7	40.0	43.1
2026/27	29.7	40.0	43.1
2027/28	29.7	40.0	43.1

Note: DTI assumptions from intermediate energy projections, some of which have been updated in the final figures for the forthcoming Energy White Paper.
Source: DTI and Oxera calculations.

Table A2.2 Coal price assumptions (£/t, ARA price)[1]

	Low	Central	High
2007/08	33.3	33.3	35.6
2008/09	31.6	31.6	36.4
2009/10	29.9	30.0	37.1
2010/11	28.3	30.0	37.8
2011/12	26.6	30.2	38.5
2012/13	25.0	30.4	39.2
2013/14	23.3	30.6	40.0
2014/15	21.7	30.8	40.7
2015/16	20.0	31.0	41.4
2016/17	20.0	31.2	42.1
2017/18	20.0	31.4	42.8
2018/19	20.0	31.6	43.6
2019/20	20.0	31.8	44.3
2020/21	20.0	32.0	45.0
2021/22	20.3	32.2	45.2
2022/23	20.6	32.5	45.5
2023/24	20.9	32.7	45.7
2024/25	21.1	32.9	45.9
2025/26	21.4	33.1	46.1
2026/27	21.7	33.4	46.4
2027/28	22.0	33.6	46.6

Note: ARA, Amsterdam, Rotterdam, Antwerp. [1] A £7.5/t transport cost is added to this wholesale price to obtain an assumed delivery price at the station gate.
Source: DTI and Oxera calculations.

Table A2.3 Carbon price assumptions (€/tCO_2)

	Central
2007/08	12
2008/09	18
2009/10	20
2010/11	20
2011/12	21
2012/13	22
2013/14	23
2014/15	24
2015/16	25
2016/17	25
2017/18	25
2018/19	25
2019/20	25
2020/21	25
2021/22	25
2022/23	25
2023/24	25
2024/25	25
2025/26	25
2026/27	25
2027/28	25

Source: DTI and Oxera calculations.

Table A2.4 UK electricity sales (TWh)

	Low	Central	High
2007/08	332.9	333.3	333.1
2008/09	331.4	332.3	331.8
2009/10	329.9	331.2	330.5
2010/11	328.4	330.1	329.1
2011/12	331.6	333.2	332.2
2012/13	334.9	336.2	335.3
2013/14	338.1	339.3	338.4
2014/15	341.4	342.3	341.4
2015/16	344.6	345.4	344.5
2016/17	348.7	350.0	349.5
2017/18	352.7	354.6	354.5
2018/19	356.8	359.2	359.5
2019/20	360.9	363.8	364.6
2020/21	364.9	368.4	369.6
2021/22	369.0	372.5	373.7
2022/23	373.2	376.7	377.9
2023/24	377.4	381.0	382.2
2024/25	381.7	385.3	386.5
2025/26	386.0	389.6	390.9
2026/27	390.3	394.0	395.3
2027/28	394.7	398.4	399.7

Note: DTI assumptions from intermediate energy projections, some of which have been updated in the final figures for the forthcoming Energy White Paper.
Source: DTI and Oxera calculations.

Appendix 3 Summary results of sensitivities

Many sensitivities were tested in the modelling that underpins this appendix. For clarity, the table headings state the sensitivities used in each result set:

– Base, scenario 1, etc indicates the banding scenario used;
– Central, High, Low indicates the electricity and coal price inputs used;
– RPI in indicates that the buyout price is linked to RPI;
– costs – 10% or + 10% used capital costs that are 10% lower or higher than the Central forecast;
– inc planning refers to the assumption that build rate constraints on wind farms do not apply due to streamlining of planning regulations;
– headroom % from year states the headroom assumption used.

A3.1 Base Case sensitivities

Table A3.1 Renewables generation by type for the Base Case Central scenario (TWh)

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.4	2.7	4.3	4.2	1.4	18.0	5.4
2008/09	5.6	3.5	4.5	5.2	2.2	20.9	6.3
2009/10	6.1	3.9	4.6	6.2	3.3	24.1	7.3
2010/11	6.4	4.3	4.8	7.2	4.1	26.8	8.1
2011/12	6.7	2.9	4.7	8.9	4.9	28.0	8.4
2012/13	6.9	3.1	4.6	10.6	6.4	31.6	9.4
2013/14	7.2	3.4	4.5	12.3	7.2	34.5	10.2
2014/15	7.4	3.7	4.4	13.8	8.0	37.3	10.9
2015/16	7.6	3.9	4.3	15.2	8.4	39.3	11.4
2016/17	7.7	1.4	4.2	16.6	8.5	38.4	11.0
2017/18	7.8	1.6	4.0	17.9	8.5	39.8	11.2
2018/19	7.9	1.7	3.9	18.7	8.5	40.8	11.3
2019/20	8.0	1.9	3.7	19.6	8.5	41.7	11.5
2020/21	8.1	2.0	3.6	20.1	8.5	42.3	11.5
2021/22	8.1	2.0	3.5	20.1	8.5	42.1	11.3
2022/23	8.1	2.0	3.3	20.1	8.5	42.0	11.1
2023/24	8.1	2.0	3.2	20.1	8.5	41.9	11.0
2024/25	8.1	2.0	3.0	20.1	8.5	41.7	10.8
2025/26	8.1	2.0	2.9	20.1	8.5	41.6	10.7
2026/27	8.1	2.0	2.8	20.1	8.5	41.4	10.5
2027/28	8.1	2.0	2.6	20.1	8.5	41.3	10.4

Source: Oxera analysis.

Table A3.2 Changes in renewable generation relative to the Base Case in the High scenario (TWh)

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation
2007/08	0.1	0	0	0	0.4	0.5
2008/09	0.1	0	0	0	0.7	0.9
2009/10	0.1	0	0	0	0.7	0.9
2010/11	0.1	0	0	0.1	0.7	0.9
2011/12	0.1	–0.1	0	0.1	0.7	0.9
2012/13	0.2	0	0	0.1	0.7	1
2013/14	0.1	0	0	0.1	0.7	1
2014/15	0.2	–0.1	0	0.1	0.7	0.9
2015/16	0.2	0	0	0.3	1.1	1.7
2016/17	0.2	0	0	0.2	1.1	1.6
2017/18	0.3	0	0	0.3	1.3	1.8
2018/19	0.3	0	0	0.4	1.3	1.9
2019/20	0.3	0	0	0.4	1.3	2
2020/21	0.3	0	0	0.7	1.3	2.3
2021/22	0.3	0	0	0.7	1.3	2.3
2022/23	0.3	0	0	0.7	1.3	2.3
2023/24	0.3	0	0	0.7	1.3	2.3
2024/25	0.3	0	0	0.7	1.3	2.3
2025/26	0.3	0	0	0.7	1.3	2.3
2026/27	0.3	0	0	0.7	1.3	2.3
2027/28	0.3	0	0	0.7	1.3	2.3

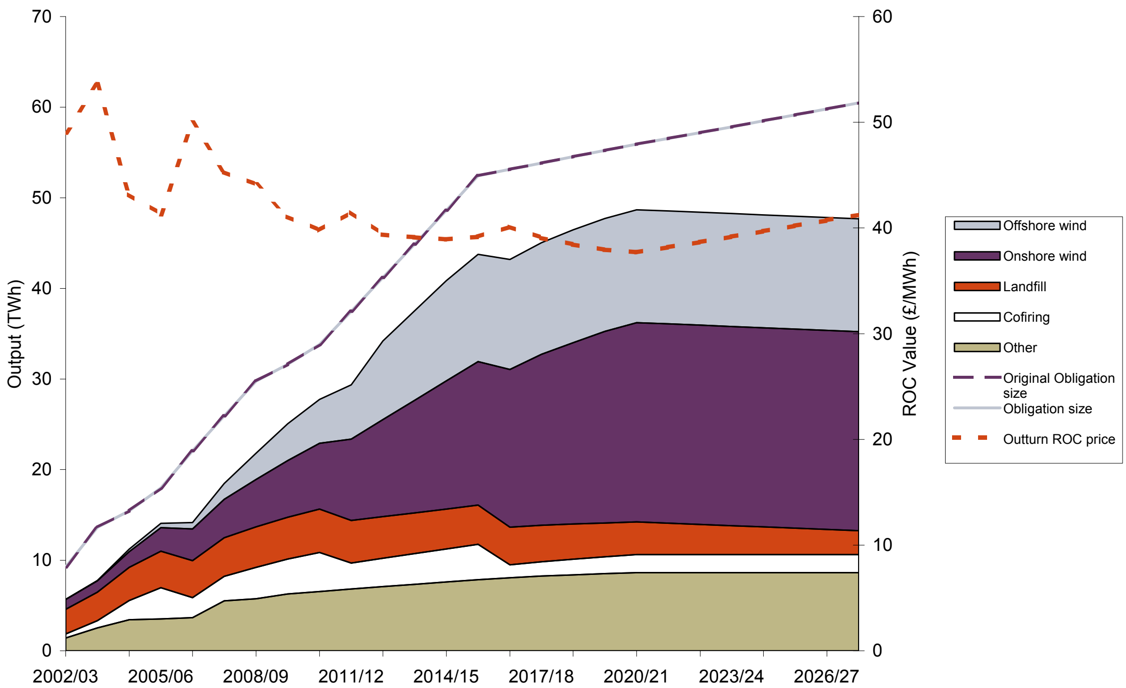
Source: Oxera analysis.

Table A3.3 Changes in renewable generation relative to the Base Case in the Low scenario (TWh)

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation
2007/08	0	0	0	0	0	0
2008/09	0	0	0	0	0	0
2009/10	0	0	0	0	–0.4	–0.4
2010/11	0	0	0	–0.1	–0.8	–1
2011/12	–0.1	–0.1	0	–0.3	–1.2	–1.6
2012/13	0	0	0	–0.5	–2	–2.4
2013/14	0	0	0	–0.9	–2.4	–3.2
2014/15	–0.1	–0.1	0	–1	–3.2	–4.3
2015/16	–0.1	0	0	–1.3	–3.6	–4.9
2016/17	–0.1	0	0	–1.9	–3.7	–5.7
2017/18	–0.1	0	0	–2.4	–3.7	–6.1
2018/19	–0.1	0	0	–2.5	–3.7	–6.4
2019/20	–0.2	0	0	–2.9	–3.7	–6.7
2020/21	–0.2	0	0	–3	–3.7	–6.9
2021/22	–0.2	0	0	–3	–3.7	–6.8
2022/23	–0.2	0	0	–3	–3.7	–6.9
2023/24	–0.2	0	0	–3	–3.7	–6.9
2024/25	–0.2	0	0	–3	–3.7	–6.8
2025/26	–0.2	0	0	–3	–3.7	–6.9
2026/27	–0.2	0	0	–3	–3.7	–6.8
2027/28	–0.2	0	0	–3	–3.7	–6.9

Source: Oxera analysis.

Figure A3.1 Base: Central, RPI in, costs – 10%, no planning results



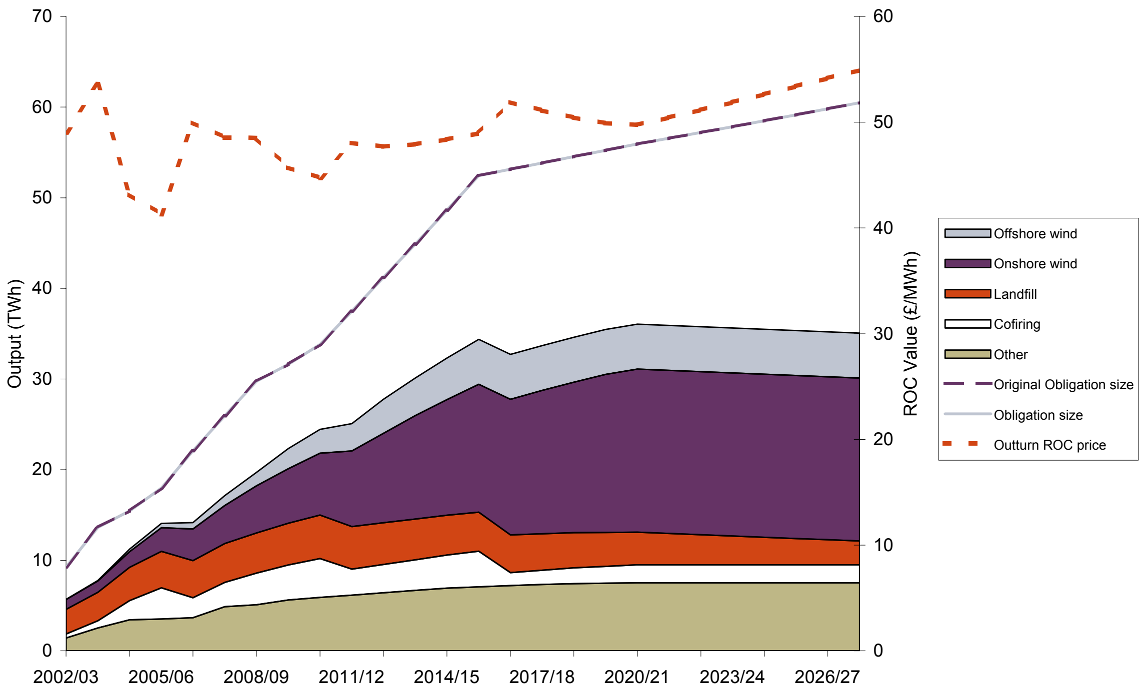
Source: Oxera analysis.

Table A3.4 Base: Central, RPI in, costs – 10%, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.5	2.7	4.3	4.2	1.8	18.5	5.5
2008/09	5.7	3.5	4.5	5.2	2.9	21.8	6.6
2009/10	6.3	3.9	4.6	6.2	4.1	25.1	7.6
2010/11	6.6	4.3	4.8	7.3	4.8	27.8	8.4
2011/12	6.8	2.9	4.7	9.0	6.0	29.4	8.8
2012/13	7.1	3.1	4.6	10.7	8.7	34.2	10.2
2013/14	7.3	3.4	4.5	12.4	9.9	37.5	11.0
2014/15	7.6	3.7	4.4	14.2	11.1	40.9	11.9
2015/16	7.9	3.9	4.3	15.8	11.9	43.8	12.7
2016/17	8.1	1.4	4.2	17.4	12.2	43.2	12.3
2017/18	8.3	1.6	4.0	18.9	12.3	45.1	12.7
2018/19	8.4	1.7	3.9	20.0	12.5	46.5	12.9
2019/20	8.5	1.9	3.7	21.2	12.5	47.7	13.1
2020/21	8.6	2.0	3.6	22.0	12.5	48.7	13.2
2021/22	8.6	2.0	3.5	22.0	12.5	48.5	13.0
2022/23	8.6	2.0	3.3	22.0	12.5	48.4	12.8
2023/24	8.6	2.0	3.2	22.0	12.5	48.3	12.7
2024/25	8.6	2.0	3.0	22.0	12.5	48.1	12.5
2025/26	8.6	2.0	2.9	22.0	12.5	48.0	12.3
2026/27	8.6	2.0	2.8	22.0	12.5	47.8	12.1
2027/28	8.6	2.0	2.6	22.0	12.5	47.7	12.0

Source: Oxera analysis.

Figure A3.2 Base: Central, RPI in, costs + 10%, no planning results



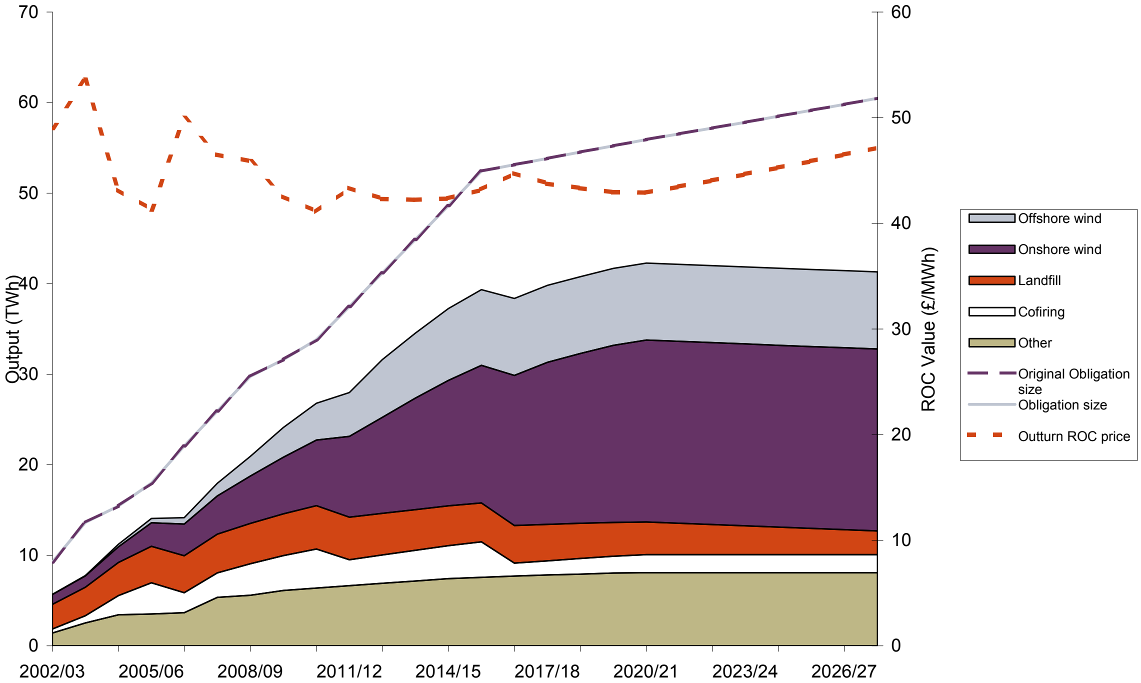
Source: Oxera analysis.

Table A3.5 Base: central, RPI in, costs + 10%, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	4.9	2.7	4.3	4.2	1.1	17.1	5.1
2008/09	5.1	3.5	4.5	5.2	1.5	19.7	5.9
2009/10	5.6	3.9	4.6	6.0	2.2	22.3	6.7
2010/11	5.9	4.3	4.8	6.8	2.6	24.4	7.4
2011/12	6.2	2.9	4.7	8.3	3.0	25.1	7.5
2012/13	6.4	3.1	4.6	9.9	3.8	27.8	8.3
2013/14	6.7	3.4	4.5	11.4	4.2	30.1	8.9
2014/15	6.9	3.7	4.4	12.8	4.6	32.3	9.4
2015/16	7.1	3.9	4.3	14.1	5.0	34.4	9.9
2016/17	7.2	1.4	4.2	15.0	5.0	32.7	9.3
2017/18	7.3	1.6	4.0	15.8	5.0	33.7	9.5
2018/19	7.4	1.7	3.9	16.6	5.0	34.6	9.6
2019/20	7.5	1.9	3.7	17.5	5.0	35.5	9.7
2020/21	7.5	2.0	3.6	18.0	5.0	36.0	9.8
2021/22	7.5	2.0	3.5	18.0	5.0	35.9	9.6
2022/23	7.5	2.0	3.3	18.0	5.0	35.8	9.5
2023/24	7.5	2.0	3.2	18.0	5.0	35.6	9.3
2024/25	7.5	2.0	3.0	18.0	5.0	35.5	9.2
2025/26	7.5	2.0	2.9	18.0	5.0	35.3	9.1
2026/27	7.5	2.0	2.8	18.0	5.0	35.2	8.9
2027/28	7.5	2.0	2.6	18.0	5.0	35.1	8.8

Source: Oxera analysis.

Figure A3.3 Base: Central, RPI in, no planning results



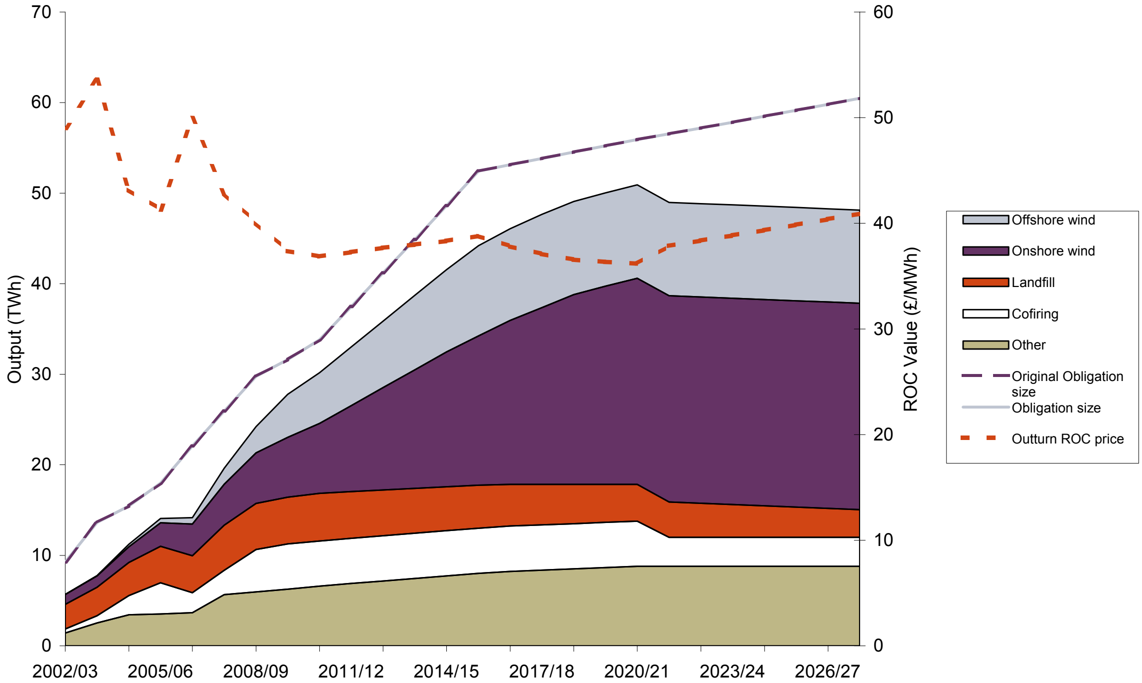
Source: Oxera analysis.

Table A3.6 Base: Central, RPI in, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.4	2.7	4.3	4.2	1.4	18.0	5.4
2008/09	5.6	3.5	4.5	5.2	2.2	20.9	6.3
2009/10	6.1	3.9	4.6	6.2	3.3	24.1	7.3
2010/11	6.4	4.3	4.8	7.2	4.1	26.8	8.1
2011/12	6.7	2.9	4.7	8.9	4.9	28.0	8.4
2012/13	6.9	3.1	4.6	10.6	6.4	31.6	9.4
2013/14	7.2	3.4	4.5	12.3	7.2	34.5	10.2
2014/15	7.4	3.7	4.4	13.8	8.0	37.3	10.9
2015/16	7.6	3.9	4.3	15.2	8.4	39.3	11.4
2016/17	7.7	1.4	4.2	16.6	8.5	38.4	11.0
2017/18	7.8	1.6	4.0	17.9	8.5	39.8	11.2
2018/19	7.9	1.7	3.9	18.7	8.5	40.8	11.3
2019/20	8.0	1.9	3.7	19.6	8.5	41.7	11.5
2020/21	8.1	2.0	3.6	20.1	8.5	42.3	11.5
2021/22	8.1	2.0	3.5	20.1	8.5	42.1	11.3
2022/23	8.1	2.0	3.3	20.1	8.5	42.0	11.1
2023/24	8.1	2.0	3.2	20.1	8.5	41.9	11.0
2024/25	8.1	2.0	3.0	20.1	8.5	41.7	10.8
2025/26	8.1	2.0	2.9	20.1	8.5	41.6	10.7
2026/27	8.1	2.0	2.8	20.1	8.5	41.4	10.5
2027/28	8.1	2.0	2.6	20.1	8.5	41.3	10.4

Source: Oxera analysis.

Figure A3.4 Base: High, RPI in, costs – 10%, inc planning results



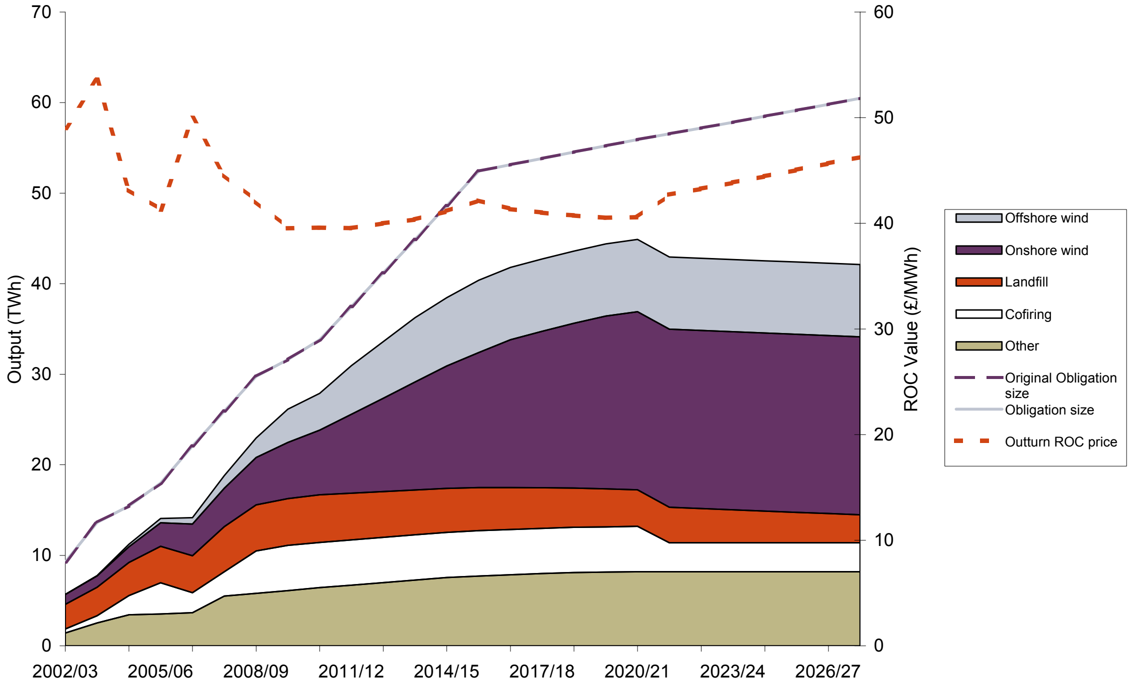
Source: Oxera analysis.

Table A3.7 Base: High, RPI in, costs – 10%, inc planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.6	2.7	5.0	4.5	1.8	19.6	5.9
2008/09	5.9	4.7	5.1	5.6	2.9	24.2	7.3
2009/10	6.3	5.0	5.2	6.6	4.8	27.8	8.4
2010/11	6.6	5.0	5.3	7.7	5.6	30.2	9.1
2011/12	6.9	5.0	5.2	9.5	6.5	33.0	9.9
2012/13	7.2	5.0	5.1	11.3	7.4	35.9	10.7
2013/14	7.4	5.0	5.0	13.1	8.2	38.7	11.4
2014/15	7.7	5.0	4.9	14.9	9.1	41.6	12.1
2015/16	8.0	5.0	4.8	16.5	10.0	44.2	12.8
2016/17	8.2	5.0	4.6	18.1	10.1	46.1	13.2
2017/18	8.4	5.0	4.5	19.5	10.3	47.7	13.4
2018/19	8.5	5.0	4.3	20.9	10.3	49.1	13.7
2019/20	8.6	5.0	4.2	21.9	10.3	50.0	13.7
2020/21	8.8	5.0	4.1	22.8	10.3	50.9	13.8
2021/22	8.8	3.2	3.9	22.8	10.3	49.0	13.1
2022/23	8.8	3.2	3.8	22.8	10.3	48.8	12.9
2023/24	8.8	3.2	3.6	22.8	10.3	48.7	12.8
2024/25	8.8	3.2	3.5	22.8	10.3	48.6	12.6
2025/26	8.8	3.2	3.4	22.8	10.3	48.4	12.4
2026/27	8.8	3.2	3.2	22.8	10.3	48.3	12.2
2027/28	8.8	3.2	3.1	22.8	10.3	48.1	12.1

Source: Oxera analysis.

Figure A3.5 Base: High, RPI in, inc planning results



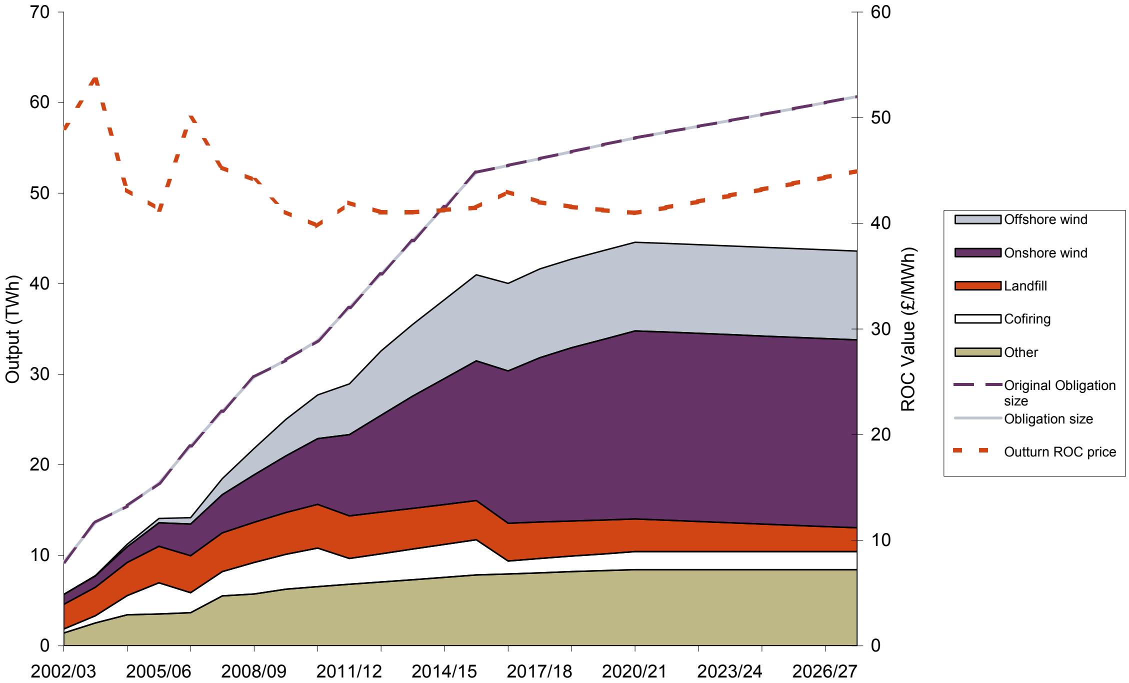
Source: Oxera analysis.

Table A3.8 Base: High, RPI in, inc planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.5	2.7	5.0	4.2	1.4	18.8	5.6
2008/09	5.8	4.7	5.1	5.2	2.2	23.0	6.9
2009/10	6.1	5.0	5.2	6.2	3.7	26.1	7.9
2010/11	6.4	5.0	5.3	7.1	4.1	27.9	8.4
2011/12	6.7	5.0	5.2	8.7	5.4	30.9	9.3
2012/13	7.0	5.0	5.1	10.3	6.2	33.6	10.0
2013/14	7.3	5.0	5.0	11.9	7.1	36.2	10.7
2014/15	7.5	5.0	4.9	13.5	7.6	38.5	11.2
2015/16	7.7	5.0	4.8	14.9	8.0	40.4	11.7
2016/17	7.8	5.0	4.6	16.4	8.0	41.8	11.9
2017/18	8.0	5.0	4.5	17.3	8.0	42.7	12.0
2018/19	8.1	5.0	4.3	18.2	8.0	43.6	12.1
2019/20	8.1	5.0	4.2	19.1	8.0	44.4	12.2
2020/21	8.2	5.0	4.1	19.7	8.0	44.9	12.2
2021/22	8.2	3.2	3.9	19.7	8.0	43.0	11.5
2022/23	8.2	3.2	3.8	19.7	8.0	42.8	11.4
2023/24	8.2	3.2	3.6	19.7	8.0	42.7	11.2
2024/25	8.2	3.2	3.5	19.7	8.0	42.5	11.0
2025/26	8.2	3.2	3.4	19.7	8.0	42.4	10.9
2026/27	8.2	3.2	3.2	19.7	8.0	42.3	10.7
2027/28	8.2	3.2	3.1	19.7	8.0	42.1	10.6

Source: Oxera analysis.

Figure A3.6 Base: High, RPI in, no planning results



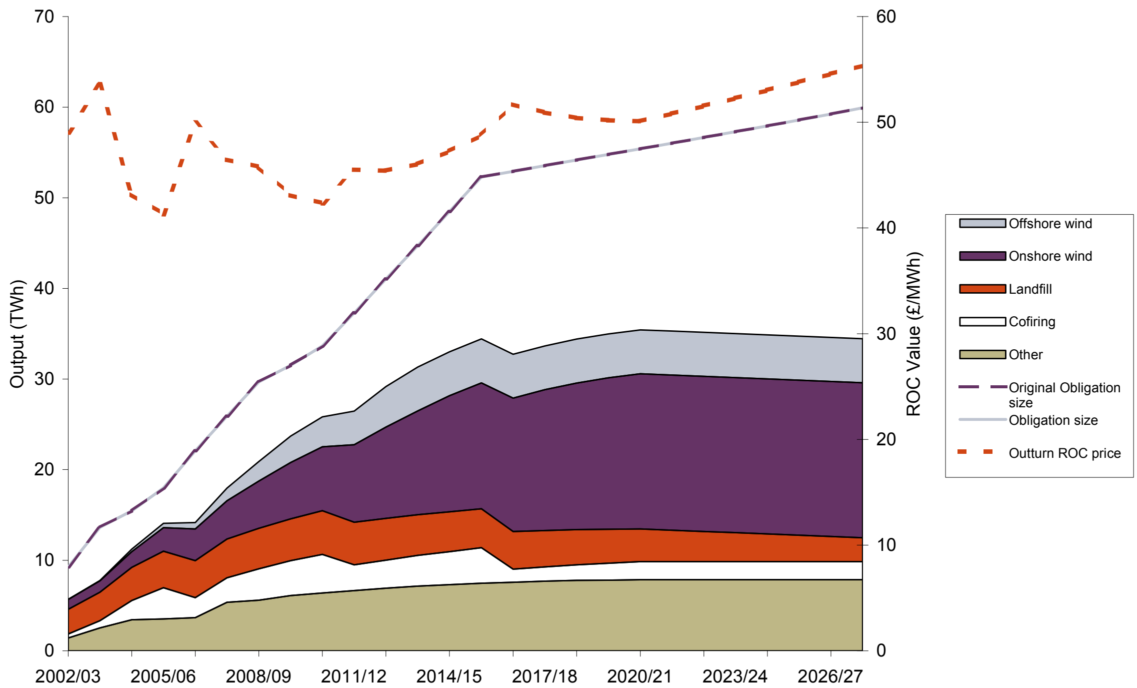
Source: Oxera analysis.

Table A3.9 Base: High, RPI in, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.5	2.7	4.3	4.2	1.8	18.5	5.5
2008/09	5.7	3.5	4.5	5.2	2.9	21.8	6.6
2009/10	6.2	3.9	4.6	6.2	4.0	25.0	7.6
2010/11	6.5	4.3	4.8	7.3	4.8	27.7	8.4
2011/12	6.8	2.8	4.7	9.0	5.6	28.9	8.7
2012/13	7.1	3.1	4.6	10.7	7.1	32.6	9.7
2013/14	7.3	3.4	4.5	12.4	7.9	35.5	10.5
2014/15	7.6	3.6	4.4	13.9	8.7	38.2	11.2
2015/16	7.8	3.9	4.3	15.5	9.5	41.0	11.9
2016/17	7.9	1.4	4.2	16.8	9.6	40.0	11.4
2017/18	8.1	1.6	4.0	18.2	9.8	41.6	11.7
2018/19	8.2	1.7	3.9	19.1	9.8	42.7	11.9
2019/20	8.3	1.9	3.7	20.0	9.8	43.7	12.0
2020/21	8.4	2.0	3.6	20.8	9.8	44.6	12.1
2021/22	8.4	2.0	3.5	20.8	9.8	44.4	11.9
2022/23	8.4	2.0	3.3	20.8	9.8	44.3	11.7
2023/24	8.4	2.0	3.2	20.8	9.8	44.2	11.5
2024/25	8.4	2.0	3.0	20.8	9.8	44.0	11.4
2025/26	8.4	2.0	2.9	20.8	9.8	43.9	11.2
2026/27	8.4	2.0	2.8	20.8	9.8	43.7	11.1
2027/28	8.4	2.0	2.6	20.8	9.8	43.6	10.9

Source: Oxera analysis.

Figure A3.7 Base: Low, RPI in, no planning results



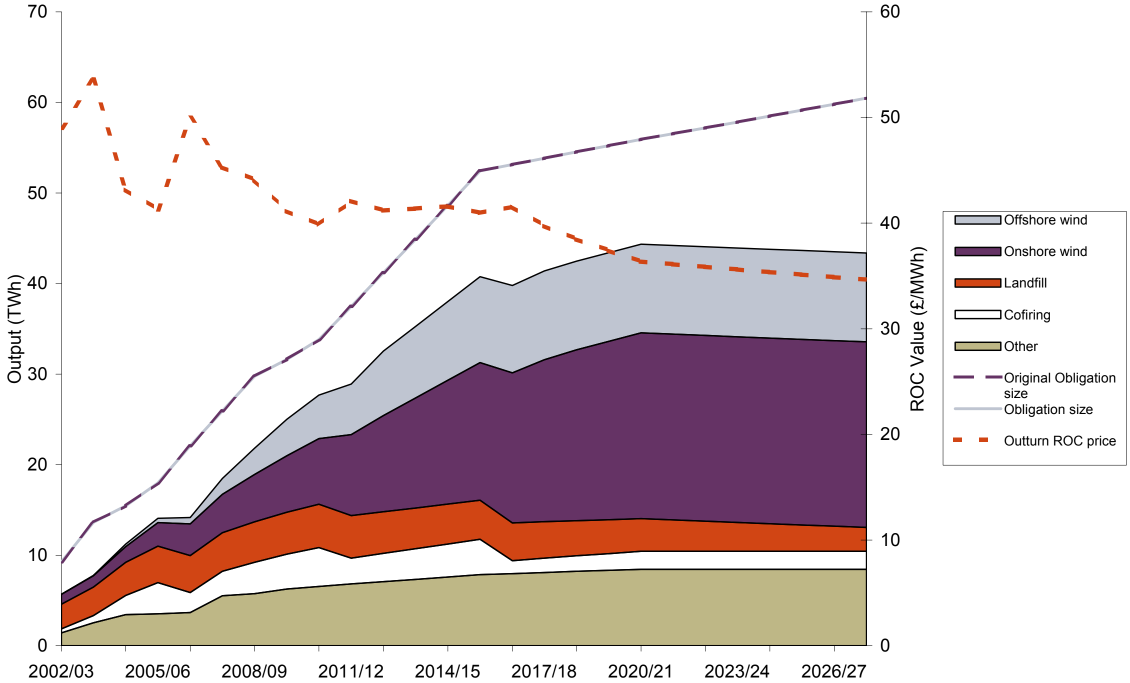
Source: Oxera analysis.

Table A3.10 Base: Low, RPI in, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.4	2.7	4.3	4.2	1.4	18.0	5.4
2008/09	5.6	3.5	4.5	5.2	2.2	20.9	6.3
2009/10	6.1	3.9	4.6	6.2	2.9	23.7	7.2
2010/11	6.4	4.3	4.8	7.1	3.3	25.8	7.8
2011/12	6.6	2.8	4.7	8.6	3.7	26.4	8.0
2012/13	6.9	3.1	4.6	10.1	4.4	29.2	8.7
2013/14	7.2	3.4	4.5	11.4	4.8	31.3	9.3
2014/15	7.3	3.6	4.4	12.8	4.8	33.0	9.7
2015/16	7.5	3.9	4.3	13.9	4.8	34.4	10.0
2016/17	7.6	1.4	4.2	14.7	4.8	32.7	9.4
2017/18	7.7	1.6	4.0	15.5	4.8	33.7	9.5
2018/19	7.8	1.7	3.9	16.2	4.8	34.4	9.6
2019/20	7.8	1.9	3.7	16.7	4.8	35.0	9.7
2020/21	7.9	2.0	3.6	17.1	4.8	35.4	9.7
2021/22	7.9	2.0	3.5	17.1	4.8	35.3	9.6
2022/23	7.9	2.0	3.3	17.1	4.8	35.1	9.4
2023/24	7.9	2.0	3.2	17.1	4.8	35.0	9.3
2024/25	7.9	2.0	3.0	17.1	4.8	34.9	9.1
2025/26	7.9	2.0	2.9	17.1	4.8	34.7	9.0
2026/27	7.9	2.0	2.8	17.1	4.8	34.6	8.9
2027/28	7.9	2.0	2.6	17.1	4.8	34.4	8.7

Source: Oxera analysis.

Figure A3.8 Base: Central, RPI out, costs – 10%, no planning results



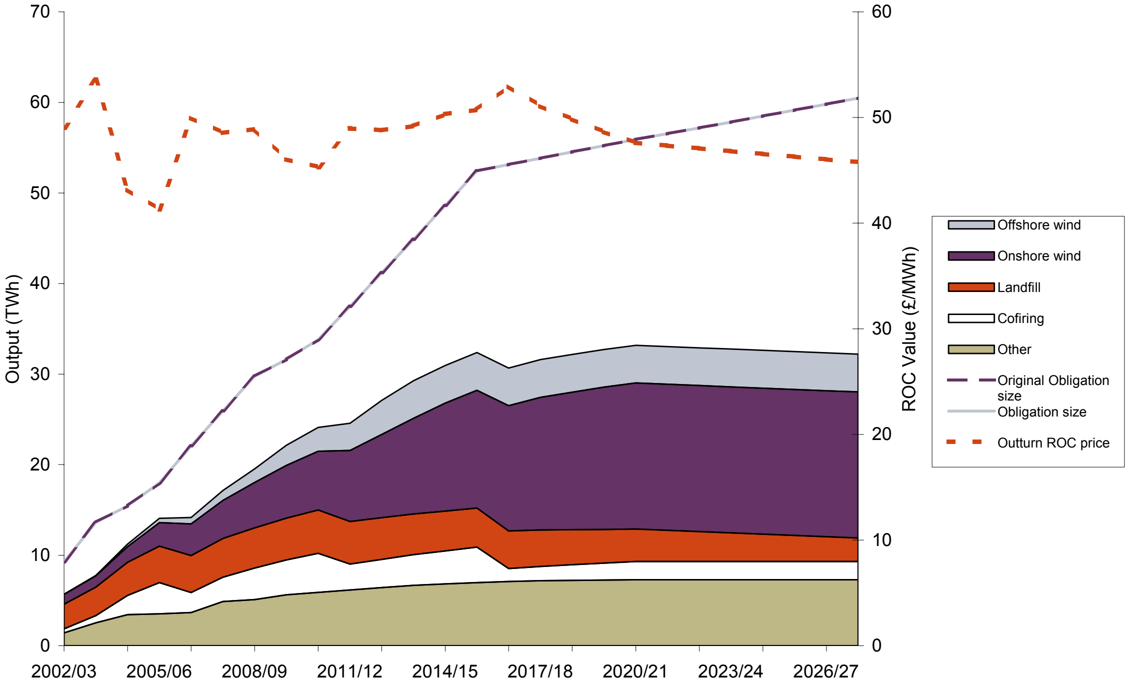
Source: Oxera analysis.

Table A3.11 Base: Central, RPI out, costs – 10%, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.5	2.7	4.3	4.2	1.8	18.5	5.5
2008/09	5.7	3.5	4.5	5.2	2.9	21.8	6.6
2009/10	6.3	3.9	4.6	6.2	4.0	25.0	7.5
2010/11	6.5	4.3	4.8	7.2	4.8	27.7	8.4
2011/12	6.8	2.9	4.7	8.9	5.6	28.9	8.7
2012/13	7.1	3.1	4.6	10.6	7.1	32.5	9.7
2013/14	7.3	3.4	4.5	12.1	7.9	35.3	10.4
2014/15	7.6	3.7	4.4	13.7	8.7	38.0	11.1
2015/16	7.8	3.9	4.3	15.2	9.5	40.8	11.8
2016/17	8.0	1.4	4.2	16.6	9.6	39.8	11.4
2017/18	8.1	1.6	4.0	17.9	9.8	41.4	11.7
2018/19	8.2	1.7	3.9	18.9	9.8	42.5	11.8
2019/20	8.3	1.9	3.7	19.7	9.8	43.4	11.9
2020/21	8.4	2.0	3.6	20.5	9.8	44.3	12.0
2021/22	8.4	2.0	3.5	20.5	9.8	44.2	11.9
2022/23	8.4	2.0	3.3	20.5	9.8	44.1	11.7
2023/24	8.4	2.0	3.2	20.5	9.8	43.9	11.5
2024/25	8.4	2.0	3.0	20.5	9.8	43.8	11.4
2025/26	8.4	2.0	2.9	20.5	9.8	43.6	11.2
2026/27	8.4	2.0	2.8	20.5	9.8	43.5	11.0
2027/28	8.4	2.0	2.6	20.5	9.8	43.4	10.9

Source: Oxera analysis.

Figure A3.9 Base: Central RPI out, costs + 10%, no planning results



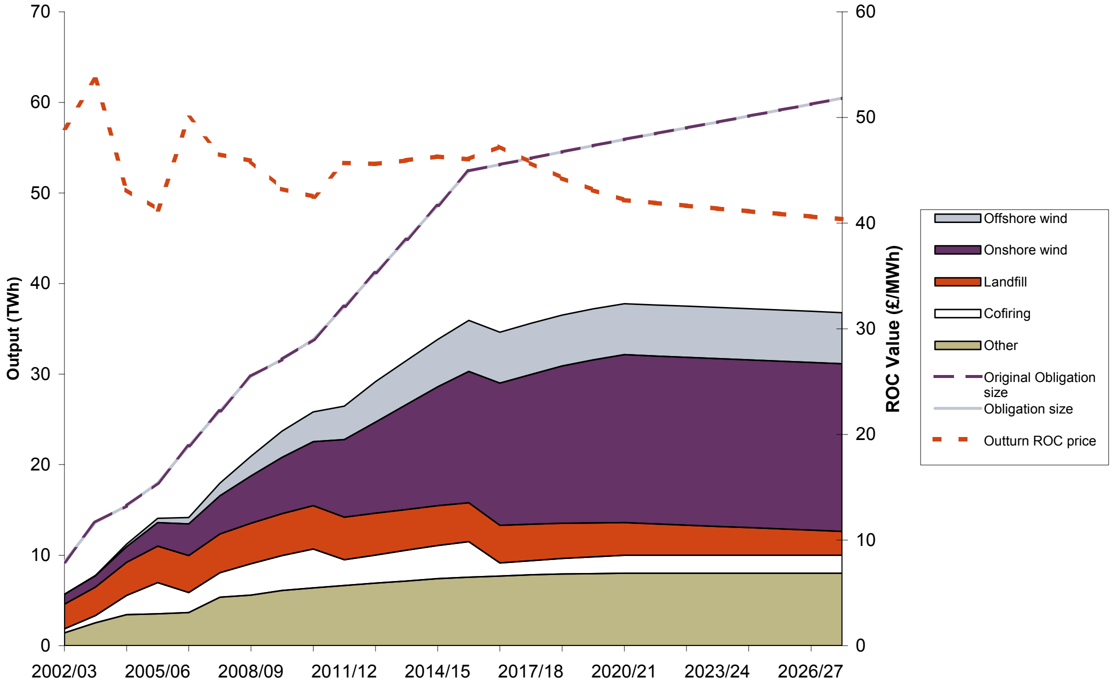
Source: Oxera analysis.

Table A3.12 Base: Central, RPI out, costs + 10%, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	4.9	2.7	4.3	4.2	1.1	17.1	5.1
2008/09	5.1	3.5	4.5	5.0	1.5	19.5	5.9
2009/10	5.6	3.9	4.6	5.8	2.2	22.2	6.7
2010/11	5.9	4.3	4.8	6.5	2.6	24.1	7.3
2011/12	6.2	2.9	4.7	7.8	3.0	24.6	7.4
2012/13	6.4	3.1	4.6	9.2	3.8	27.1	8.1
2013/14	6.7	3.4	4.5	10.6	4.2	29.3	8.6
2014/15	6.8	3.7	4.4	11.9	4.2	31.0	9.0
2015/16	7.0	3.9	4.3	13.0	4.2	32.4	9.4
2016/17	7.1	1.4	4.2	13.8	4.2	30.7	8.8
2017/18	7.2	1.6	4.0	14.6	4.2	31.6	8.9
2018/19	7.2	1.7	3.9	15.2	4.2	32.2	8.9
2019/20	7.2	1.9	3.7	15.7	4.2	32.7	9.0
2020/21	7.3	2.0	3.6	16.1	4.2	33.2	9.0
2021/22	7.3	2.0	3.5	16.1	4.2	33.0	8.9
2022/23	7.3	2.0	3.3	16.1	4.2	32.9	8.7
2023/24	7.3	2.0	3.2	16.1	4.2	32.8	8.6
2024/25	7.3	2.0	3.0	16.1	4.2	32.6	8.5
2025/26	7.3	2.0	2.9	16.1	4.2	32.5	8.3
2026/27	7.3	2.0	2.8	16.1	4.2	32.3	8.2
2027/28	7.3	2.0	2.6	16.1	4.2	32.2	8.1

Source: Oxera analysis.

Figure A3.10 Base: Central, no planning results



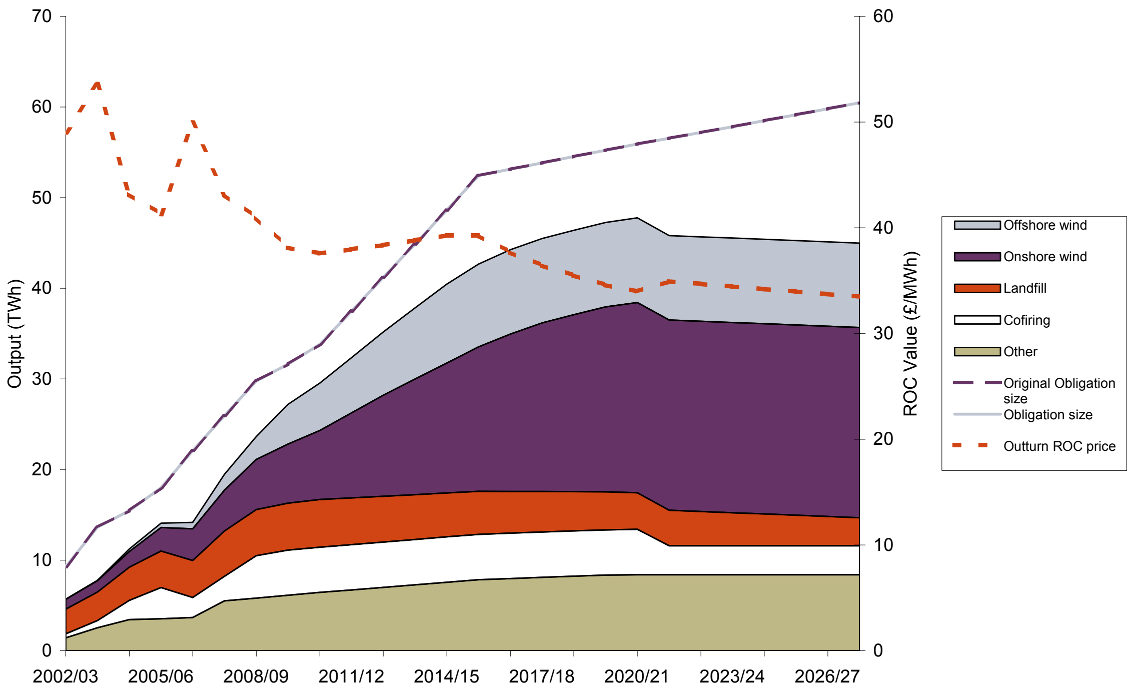
Source: Oxera analysis.

Table A3.13 Base: Central, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.4	2.7	4.3	4.2	1.4	18.0	5.4
2008/09	5.6	3.5	4.5	5.2	2.2	20.9	6.3
2009/10	6.1	3.9	4.6	6.2	2.9	23.7	7.1
2010/11	6.4	4.3	4.8	7.1	3.3	25.8	7.8
2011/12	6.6	2.9	4.7	8.6	3.7	26.5	7.9
2012/13	6.9	3.1	4.6	10.1	4.4	29.2	8.7
2013/14	7.2	3.4	4.5	11.6	4.8	31.5	9.3
2014/15	7.4	3.7	4.4	13.1	5.2	33.8	9.9
2015/16	7.6	3.9	4.3	14.5	5.6	35.9	10.4
2016/17	7.7	1.4	4.2	15.7	5.6	34.6	9.9
2017/18	7.8	1.6	4.0	16.5	5.6	35.6	10.0
2018/19	7.9	1.7	3.9	17.4	5.6	36.5	10.2
2019/20	8.0	1.9	3.7	18.0	5.6	37.2	10.2
2020/21	8.0	2.0	3.6	18.5	5.6	37.8	10.2
2021/22	8.0	2.0	3.5	18.5	5.6	37.6	10.1
2022/23	8.0	2.0	3.3	18.5	5.6	37.5	9.9
2023/24	8.0	2.0	3.2	18.5	5.6	37.4	9.8
2024/25	8.0	2.0	3.0	18.5	5.6	37.2	9.7
2025/26	8.0	2.0	2.9	18.5	5.6	37.1	9.5
2026/27	8.0	2.0	2.8	18.5	5.6	36.9	9.4
2027/28	8.0	2.0	2.6	18.5	5.6	36.8	9.2

Source: Oxera analysis.

Figure A3.11 Base: High, RPI out, costs – 10%, inc planning results



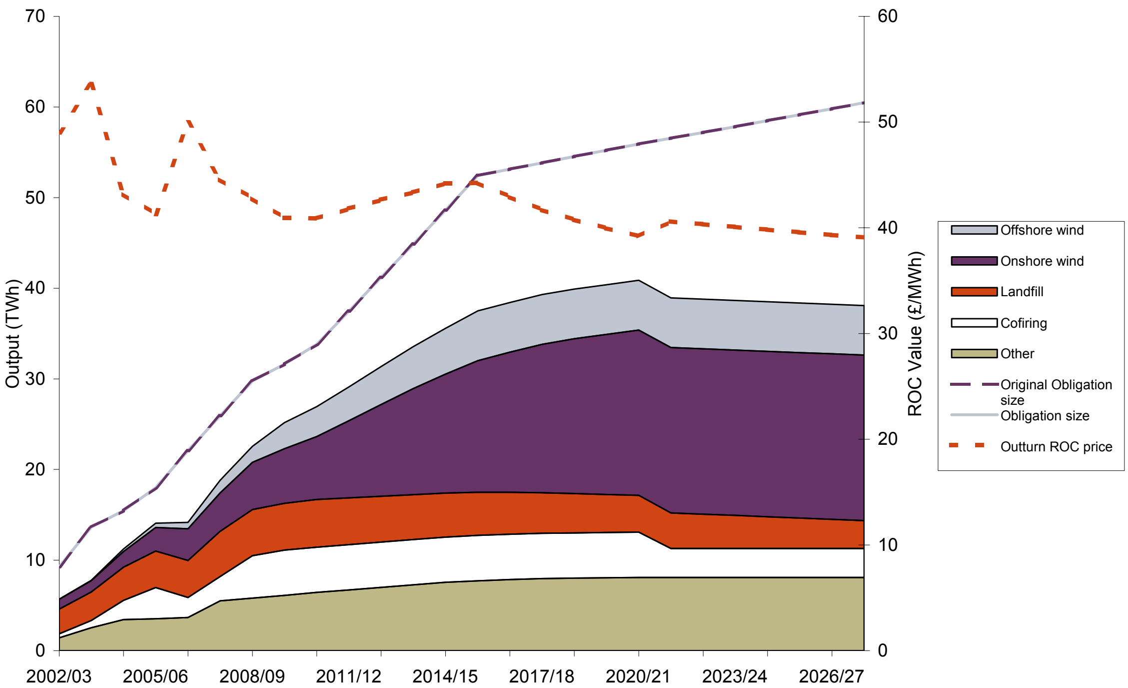
Source: Oxera analysis.

Table A3.14 Base: High, RPI out, costs – 10%, inc planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.5	2.7	5.0	4.5	1.8	19.5	5.8
2008/09	5.8	4.7	5.1	5.5	2.5	23.6	7.1
2009/10	6.1	5.0	5.2	6.5	4.4	27.2	8.2
2010/11	6.4	5.0	5.3	7.6	5.2	29.5	8.9
2011/12	6.7	5.0	5.2	9.4	6.1	32.3	9.7
2012/13	7.0	5.0	5.1	11.1	7.0	35.2	10.4
2013/14	7.3	5.0	5.0	12.7	7.8	37.8	11.1
2014/15	7.5	5.0	4.9	14.3	8.7	40.5	11.8
2015/16	7.8	5.0	4.8	15.9	9.2	42.7	12.3
2016/17	8.0	5.0	4.6	17.4	9.3	44.3	12.6
2017/18	8.1	5.0	4.5	18.6	9.3	45.5	12.8
2018/19	8.2	5.0	4.3	19.5	9.3	46.4	12.9
2019/20	8.3	5.0	4.2	20.4	9.3	47.3	13.0
2020/21	8.4	5.0	4.1	21.0	9.3	47.8	13.0
2021/22	8.4	3.2	3.9	21.0	9.3	45.8	12.3
2022/23	8.4	3.2	3.8	21.0	9.3	45.7	12.1
2023/24	8.4	3.2	3.6	21.0	9.3	45.5	11.9
2024/25	8.4	3.2	3.5	21.0	9.3	45.4	11.8
2025/26	8.4	3.2	3.4	21.0	9.3	45.3	11.6
2026/27	8.4	3.2	3.2	21.0	9.3	45.1	11.4
2027/28	8.4	3.2	3.1	21.0	9.3	45.0	11.3

Source: Oxera analysis.

Figure A3.12 Base: High, inc planning results



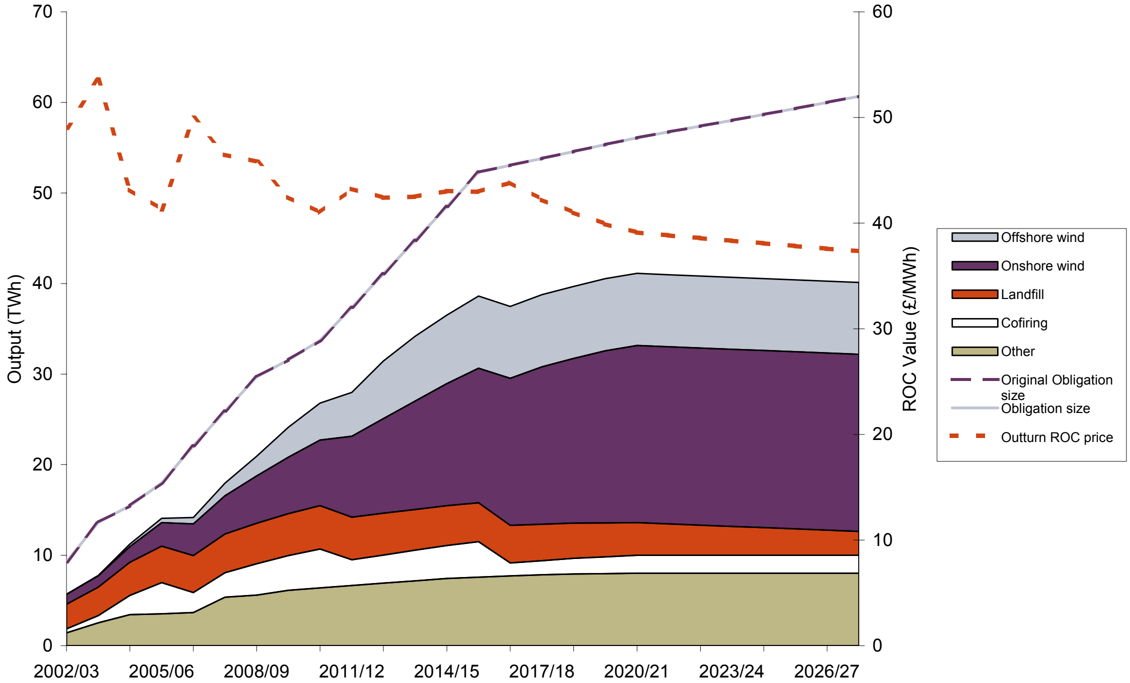
Source: Oxera analysis.

Table A3.15 Base: High, inc planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.5	2.7	5.0	4.2	1.4	18.8	5.6
2008/09	5.8	4.7	5.1	5.2	1.8	22.6	6.8
2009/10	6.1	5.0	5.2	6.0	2.9	25.2	7.6
2010/11	6.4	5.0	5.3	6.9	3.3	26.9	8.1
2011/12	6.7	5.0	5.2	8.5	3.7	29.1	8.7
2012/13	7.0	5.0	5.1	10.1	4.2	31.3	9.3
2013/14	7.3	5.0	5.0	11.7	4.6	33.6	9.9
2014/15	7.5	5.0	4.9	13.1	5.1	35.6	10.4
2015/16	7.7	5.0	4.8	14.5	5.5	37.5	10.8
2016/17	7.8	5.0	4.6	15.5	5.5	38.4	11.0
2017/18	8.0	5.0	4.5	16.4	5.5	39.3	11.1
2018/19	8.0	5.0	4.3	17.1	5.5	39.9	11.1
2019/20	8.0	5.0	4.2	17.7	5.5	40.4	11.1
2020/21	8.1	5.0	4.1	18.3	5.5	40.9	11.1
2021/22	8.1	3.2	3.9	18.3	5.5	38.9	10.4
2022/23	8.1	3.2	3.8	18.3	5.5	38.8	10.3
2023/24	8.1	3.2	3.6	18.3	5.5	38.7	10.1
2024/25	8.1	3.2	3.5	18.3	5.5	38.5	10.0
2025/26	8.1	3.2	3.4	18.3	5.5	38.4	9.8
2026/27	8.1	3.2	3.2	18.3	5.5	38.2	9.7
2027/28	8.1	3.2	3.1	18.3	5.5	38.1	9.6

Source: Oxera analysis.

Figure A3.13 Base: High, no planning results



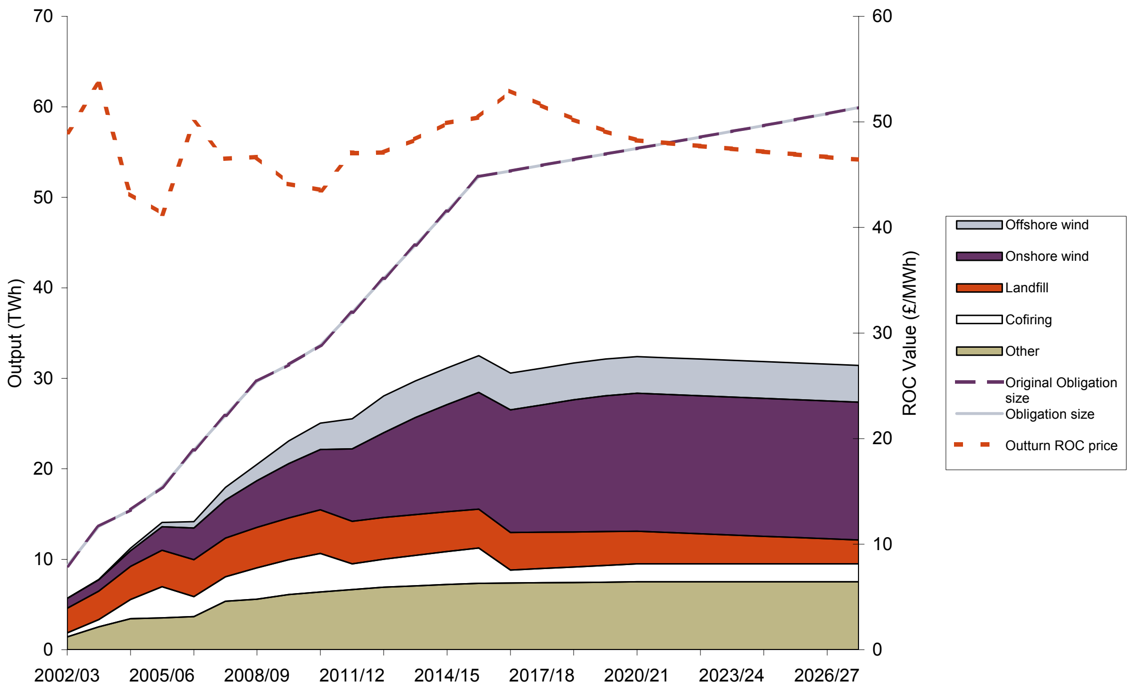
Source: Oxera analysis.

Table A3.16 Base: High, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.4	2.7	4.3	4.2	1.4	18.0	5.4
2008/09	5.6	3.5	4.5	5.2	2.2	20.9	6.3
2009/10	6.1	3.9	4.6	6.2	3.3	24.1	7.3
2010/11	6.4	4.3	4.8	7.2	4.1	26.8	8.1
2011/12	6.7	2.8	4.7	8.9	4.9	28.0	8.4
2012/13	6.9	3.1	4.6	10.5	6.4	31.4	9.4
2013/14	7.2	3.4	4.5	12.0	7.2	34.2	10.1
2014/15	7.4	3.6	4.4	13.5	7.6	36.5	10.7
2015/16	7.6	3.9	4.3	14.9	8.0	38.6	11.2
2016/17	7.7	1.4	4.2	16.2	8.0	37.5	10.7
2017/18	7.8	1.6	4.0	17.4	8.0	38.8	10.9
2018/19	7.9	1.7	3.9	18.2	8.0	39.7	11.0
2019/20	8.0	1.9	3.7	19.0	8.0	40.5	11.1
2020/21	8.0	2.0	3.6	19.6	8.0	41.1	11.1
2021/22	8.0	2.0	3.5	19.6	8.0	41.0	11.0
2022/23	8.0	2.0	3.3	19.6	8.0	40.8	10.8
2023/24	8.0	2.0	3.2	19.6	8.0	40.7	10.6
2024/25	8.0	2.0	3.0	19.6	8.0	40.6	10.5
2025/26	8.0	2.0	2.9	19.6	8.0	40.4	10.3
2026/27	8.0	2.0	2.8	19.6	8.0	40.3	10.2
2027/28	8.0	2.0	2.6	19.6	8.0	40.1	10.0

Source: Oxera analysis.

Figure A3.14 Base: Low, no planning results



Source: Oxera analysis.

Table A3.17 Base: Low, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.4	2.7	4.3	4.2	1.4	17.9	5.4
2008/09	5.6	3.5	4.5	5.2	1.8	20.5	6.2
2009/10	6.1	3.9	4.6	6.0	2.5	23.1	7.0
2010/11	6.4	4.3	4.8	6.7	2.9	25.0	7.6
2011/12	6.6	2.8	4.7	8.0	3.3	25.5	7.7
2012/13	6.9	3.1	4.6	9.4	4.1	28.0	8.4
2013/14	7.1	3.4	4.5	10.7	4.1	29.7	8.8
2014/15	7.2	3.6	4.4	11.8	4.1	31.1	9.1
2015/16	7.3	3.9	4.3	12.9	4.1	32.5	9.4
2016/17	7.4	1.4	4.2	13.5	4.1	30.6	8.8
2017/18	7.4	1.6	4.0	14.1	4.1	31.1	8.8
2018/19	7.4	1.7	3.9	14.6	4.1	31.7	8.9
2019/20	7.5	1.9	3.7	15.0	4.1	32.1	8.9
2020/21	7.5	2.0	3.6	15.2	4.1	32.4	8.9
2021/22	7.5	2.0	3.5	15.2	4.1	32.3	8.7
2022/23	7.5	2.0	3.3	15.2	4.1	32.1	8.6
2023/24	7.5	2.0	3.2	15.2	4.1	32.0	8.5
2024/25	7.5	2.0	3.0	15.2	4.1	31.8	8.3
2025/26	7.5	2.0	2.9	15.2	4.1	31.7	8.2
2026/27	7.5	2.0	2.8	15.2	4.1	31.6	8.1
2027/28	7.5	2.0	2.6	15.2	4.1	31.4	8.0

Source: Oxera analysis.

A3.2 Detailed renewable generation results

Table A3.18 Renewable generation by type in the Base scenario

Output by technology	Co-firing: existing capacity	Co-firing: new capacity	Landfill	Onshore wind: large, high wind	Onshore wind: small	Small hydro	Large hydro	Sewage gas	Offshore wind	Solar PV	Tidal	Wave	Gas/ pyro	Biomass CHP	Biomass regular	Biomass energy crops	Micro CHP	AD CHP	Onshore wind: large low wind	EfW CHP	Biomass CHP (non-banded)	Biomass (non-banded)
2007/08	2.7	0.0	4.3	1.3	0.3	0.1	2.4	0.9	1.4	0.0	0.0	0.0	0.0	0.0	1.2	0.0	0.0	0.0	2.7	0.2	0.0	0.6
2008/09	3.5	0.0	4.5	1.4	0.3	0.2	2.4	0.9	2.2	0.0	0.0	0.0	0.0	0.0	1.2	0.0	0.0	0.0	3.5	0.4	0.0	0.6
2009/10	3.9	0.0	4.6	1.6	0.3	0.2	2.4	0.9	3.3	0.0	0.0	0.0	0.0	0.0	1.4	0.0	0.0	0.0	4.4	0.5	0.0	0.6
2010/11	4.3	0.0	4.8	1.7	0.3	0.2	2.4	0.9	4.1	0.0	0.0	0.0	0.0	0.0	1.5	0.0	0.0	0.0	5.2	0.7	0.0	0.6
2011/12	2.9	0.0	4.7	2.5	0.4	0.3	2.4	0.9	4.9	0.0	0.0	0.0	0.0	0.0	1.6	0.0	0.0	0.0	6.0	0.8	0.0	0.6
2012/13	3.1	0.0	4.6	3.3	0.4	0.3	2.4	0.9	6.4	0.0	0.0	0.0	0.0	0.0	1.7	0.0	0.0	0.0	6.9	0.9	0.0	0.6
2013/14	3.4	0.0	4.5	4.1	0.5	0.4	2.4	0.9	7.2	0.0	0.0	0.0	0.0	0.0	1.8	0.0	0.0	0.0	7.7	1.0	0.0	0.6
2014/15	3.7	0.0	4.4	5.0	0.5	0.4	2.4	0.9	8.0	0.0	0.0	0.0	0.0	0.0	1.9	0.0	0.0	0.0	8.4	1.1	0.0	0.6
2015/16	3.9	0.0	4.3	5.8	0.5	0.5	2.4	0.9	8.4	0.0	0.0	0.0	0.0	0.0	2.0	0.0	0.0	0.0	8.9	1.1	0.0	0.6
2016/17	1.4	0.0	4.2	6.6	0.6	0.5	2.4	0.9	8.5	0.0	0.0	0.0	0.0	0.0	2.1	0.0	0.0	0.0	9.4	1.1	0.0	0.6
2017/18	1.6	0.0	4.0	7.4	0.6	0.5	2.4	1.0	8.5	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	0.0	9.9	1.1	0.0	0.6
2018/19	1.7	0.0	3.9	7.8	0.7	0.5	2.5	1.0	8.5	0.0	0.0	0.0	0.0	0.0	2.3	0.0	0.0	0.0	10.3	1.1	0.0	0.6
2019/20	1.9	0.0	3.7	8.3	0.7	0.5	2.5	1.0	8.5	0.0	0.0	0.0	0.0	0.0	2.3	0.0	0.0	0.0	10.6	1.1	0.0	0.6
2020/21	2.0	0.0	3.6	8.6	0.7	0.5	2.5	1.0	8.5	0.0	0.0	0.0	0.0	0.0	2.3	0.0	0.0	0.0	10.8	1.1	0.0	0.6
2021/22	2.0	0.0	3.5	8.6	0.7	0.5	2.5	1.0	8.5	0.0	0.0	0.0	0.0	0.0	2.3	0.0	0.0	0.0	10.8	1.1	0.0	0.6
2022/23	2.0	0.0	3.3	8.6	0.7	0.5	2.5	1.0	8.5	0.0	0.0	0.0	0.0	0.0	2.3	0.0	0.0	0.0	10.8	1.1	0.0	0.6
2023/24	2.0	0.0	3.2	8.6	0.7	0.5	2.5	1.0	8.5	0.0	0.0	0.0	0.0	0.0	2.3	0.0	0.0	0.0	10.8	1.1	0.0	0.6
2024/25	2.0	0.0	3.0	8.6	0.7	0.5	2.5	1.0	8.5	0.0	0.0	0.0	0.0	0.0	2.3	0.0	0.0	0.0	10.8	1.1	0.0	0.6
2025/26	2.0	0.0	2.9	8.6	0.7	0.5	2.5	1.0	8.5	0.0	0.0	0.0	0.0	0.0	2.3	0.0	0.0	0.0	10.8	1.1	0.0	0.6
2026/27	2.0	0.0	2.8	8.6	0.7	0.5	2.5	1.0	8.5	0.0	0.0	0.0	0.0	0.0	2.3	0.0	0.0	0.0	10.8	1.1	0.0	0.6
2027/28	2.0	0.0	2.6	8.6	0.7	0.5	2.5	1.0	8.5	0.0	0.0	0.0	0.0	0.0	2.3	0.0	0.0	0.0	10.8	1.1	0.0	0.6

Source: Oxera analysis.

Table A3.19 Renewables generation by type for Scenario 1 Central (TWh)

Output by technology	Co-firing: existing capacity	Co-firing: new capacity	Landfill	Onshore wind: large, high wind	Onshore wind: small	Small hydro	Large hydro	Sewage gas	Offshore wind	Solar PV	Tidal	Wave	Gas/ pyro	Biomass CHP	Biomass regular	Biomass energy crops	Micro CHP	AD CHP	Onshore wind: large low wind	EfW CHP	Biomass CHP (non-banded)	Biomass (non-banded)
2007/08	2.7	0.0	4.3	1.3	0.2	0.1	2.4	0.9	1.1	0.0	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0	2.6	0.2	0.0	0.2
2008/09	4.7	0.0	4.5	1.4	0.3	0.2	2.4	0.9	1.1	0.0	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0	3.3	0.4	0.0	0.2
2009/10	5.0	0.0	4.6	1.5	0.3	0.2	2.4	0.9	4.3	0.0	0.1	0.1	0.1	0.5	1.4	0.2	0.0	0.1	4.0	0.5	0.0	0.2
2010/11	5.0	2.4	4.7	1.6	0.3	0.2	2.4	0.9	5.6	0.0	0.1	0.1	0.1	0.6	1.6	0.2	0.0	0.1	4.5	0.7	0.0	0.2
2011/12	7.4	0.0	4.6	2.2	0.3	0.3	2.4	0.9	6.8	0.0	0.2	0.2	0.1	0.8	1.9	0.3	0.0	0.1	5.0	0.8	0.0	0.2
2012/13	7.4	0.0	4.5	2.7	0.3	0.3	2.4	0.9	9.0	0.0	0.2	0.2	0.1	0.9	2.3	0.4	0.0	0.1	5.5	0.9	0.0	0.2
2013/14	7.4	0.0	4.4	3.1	0.4	0.3	2.4	0.9	10.2	0.0	0.3	0.3	0.1	1.1	2.6	0.5	0.0	0.1	5.8	0.9	0.0	0.2
2014/15	7.4	0.0	4.3	3.4	0.4	0.3	2.4	0.9	11.0	0.0	0.4	0.4	0.2	1.2	2.7	0.5	0.0	0.1	6.2	0.9	0.0	0.2
2015/16	7.4	0.0	4.2	3.8	0.4	0.3	2.4	0.9	11.8	0.0	0.4	0.4	0.2	1.2	2.8	0.5	0.0	0.1	6.5	0.9	0.0	0.2
2016/17	7.4	0.0	4.1	4.0	0.4	0.3	2.4	0.9	12.0	0.0	0.5	0.5	0.2	1.2	2.9	0.5	0.0	0.1	6.7	0.9	0.0	0.2
2017/18	7.4	0.0	4.0	4.1	0.4	0.4	2.4	0.9	12.0	0.0	0.5	0.5	0.2	1.2	2.9	0.5	0.0	0.1	6.9	0.9	0.0	0.2
2018/19	7.4	0.0	3.8	4.2	0.4	0.4	2.5	0.9	12.0	0.0	0.6	0.5	0.2	1.2	3.0	0.5	0.0	0.1	7.0	0.9	0.0	0.2
2019/20	7.4	0.0	3.7	4.4	0.4	0.4	2.5	0.9	12.0	0.0	0.6	0.6	0.2	1.2	3.1	0.5	0.0	0.1	7.0	0.9	0.0	0.2
2020/21	7.4	0.0	3.5	4.5	0.4	0.4	2.5	1.0	12.0	0.0	0.6	0.6	0.2	1.2	3.2	0.5	0.0	0.1	7.0	0.9	0.0	0.2
2021/22	7.4	0.0	3.4	4.5	0.4	0.4	2.5	1.0	12.0	0.0	0.6	0.6	0.2	1.2	3.2	0.5	0.0	0.1	7.0	0.9	0.0	0.2
2022/23	7.4	0.0	3.3	4.5	0.4	0.4	2.5	1.0	12.0	0.0	0.6	0.6	0.2	1.2	3.2	0.5	0.0	0.1	7.0	0.9	0.0	0.2
2023/24	7.4	0.0	3.1	4.5	0.4	0.4	2.5	1.0	12.0	0.0	0.6	0.6	0.2	1.2	3.2	0.5	0.0	0.1	7.0	0.9	0.0	0.2
2024/25	7.4	0.0	3.0	4.5	0.4	0.4	2.5	1.0	12.0	0.0	0.6	0.6	0.2	1.2	3.2	0.5	0.0	0.1	7.0	0.9	0.0	0.2
2025/26	7.4	0.0	2.8	4.5	0.4	0.4	2.5	1.0	12.0	0.0	0.6	0.6	0.2	1.2	3.2	0.5	0.0	0.1	7.0	0.9	0.0	0.2
2026/27	7.4	0.0	2.7	4.5	0.4	0.4	2.5	1.0	12.0	0.0	0.6	0.6	0.2	1.2	3.2	0.5	0.0	0.1	7.0	0.9	0.0	0.2
2027/28	7.4	0.0	2.6	4.5	0.4	0.4	2.5	1.0	12.0	0.0	0.6	0.6	0.2	1.2	3.2	0.5	0.0	0.1	7.0	0.9	0.0	0.2

Source: Oxera analysis.

Table A3.20 Renewable generation by type in Scenario 3 (TWh)

Output by Technology	Co-firing existing capacity	Co-firing new capacity	Landfill	Onshore wind: large, high wind	Onshore wind: small	Small hydro	Large hydro	Sewage gas	Offshore wind	Solar PV	Tidal	Wave	Gas/ pyro	Biomass CHP	Biomass regular	Biomass energy crops	Micro CHP	AD CHP	Onshore wind: large, low wind	EfW CHP	Biomass CHP (non-banded)	Biomass (non-banded)
2007/08	2.7	0.0	4.3	1.3	0.2	0.1	2.4	0.9	1.1	0.0	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0	2.6	0.2	0.0	0.2
2008/09	4.7	0.0	4.5	1.4	0.3	0.2	2.4	0.9	1.1	0.0	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0	3.1	0.4	0.0	0.2
2009/10	5.0	0.0	4.6	1.6	0.3	0.2	2.4	0.9	4.3	0.0	0.0	0.0	0.1	0.5	1.4	1.8	0.0	0.1	3.6	0.4	0.0	0.2
2010/11	5.0	2.4	4.7	1.7	0.3	0.2	2.4	0.9	7.1	0.0	0.0	0.0	0.1	0.6	1.6	1.8	0.0	0.1	4.0	0.4	0.0	0.2
2011/12	7.4	0.0	4.6	2.4	0.3	0.3	2.4	0.9	8.7	0.0	0.1	0.1	0.1	0.8	1.7	1.9	0.0	0.1	4.3	0.4	0.0	0.2
2012/13	7.4	0.0	4.5	3.1	0.3	0.3	2.4	0.9	11.0	0.0	0.1	0.1	0.1	0.8	1.8	2.0	0.0	0.1	4.7	0.4	0.0	0.2
2013/14	7.4	0.0	4.4	3.9	0.3	0.3	2.4	0.9	12.2	0.0	0.1	0.1	0.1	0.9	1.9	2.1	0.0	0.1	5.0	0.4	0.0	0.2
2014/15	7.4	0.0	4.3	4.4	0.3	0.4	2.4	0.9	13.0	0.0	0.1	0.1	0.1	0.9	2.1	2.2	0.0	0.1	5.2	0.4	0.0	0.2
2015/16	7.4	0.0	4.2	4.9	0.3	0.4	2.4	0.9	13.8	0.0	0.2	0.2	0.1	1.0	2.2	2.3	0.0	0.1	5.3	0.4	0.0	0.2
2016/17	7.4	0.0	4.1	5.3	0.4	0.4	2.4	0.9	13.9	0.0	0.2	0.2	0.1	1.0	2.2	2.3	0.0	0.1	5.5	0.4	0.0	0.2
2017/18	7.4	0.0	4.0	5.6	0.4	0.4	2.4	0.9	14.1	0.0	0.2	0.2	0.1	1.0	2.3	2.4	0.0	0.1	5.7	0.4	0.0	0.2
2018/19	7.4	0.0	3.8	5.9	0.4	0.4	2.5	0.9	14.1	0.0	0.3	0.3	0.1	1.0	2.4	2.4	0.0	0.1	5.7	0.4	0.0	0.2
2019/20	7.4	0.0	3.7	6.1	0.4	0.4	2.5	0.9	14.1	0.0	0.3	0.3	0.1	1.0	2.5	2.4	0.0	0.1	5.7	0.4	0.0	0.2
2020/21	7.4	0.0	3.5	6.3	0.4	0.4	2.5	1.0	14.1	0.0	0.4	0.3	0.1	1.0	2.5	2.4	0.0	0.1	5.7	0.4	0.0	0.2
2021/22	7.4	0.0	3.4	6.3	0.4	0.4	2.5	1.0	14.1	0.0	0.4	0.3	0.1	1.0	2.5	2.4	0.0	0.1	5.7	0.4	0.0	0.2
2022/23	7.4	0.0	3.3	6.3	0.4	0.4	2.5	1.0	14.1	0.0	0.4	0.3	0.1	1.0	2.5	2.4	0.0	0.1	5.7	0.4	0.0	0.2
2023/24	7.4	0.0	3.1	6.3	0.4	0.4	2.5	1.0	14.1	0.0	0.4	0.3	0.1	1.0	2.5	2.4	0.0	0.1	5.7	0.4	0.0	0.2
2024/25	7.4	0.0	3.0	6.3	0.4	0.4	2.5	1.0	14.1	0.0	0.4	0.3	0.1	1.0	2.5	2.4	0.0	0.1	5.7	0.4	0.0	0.2
2025/26	7.4	0.0	2.8	6.3	0.4	0.4	2.5	1.0	14.1	0.0	0.4	0.3	0.1	1.0	2.5	2.4	0.0	0.1	5.7	0.4	0.0	0.2
2026/27	7.4	0.0	2.7	6.3	0.4	0.4	2.5	1.0	14.1	0.0	0.4	0.3	0.1	1.0	2.5	2.4	0.0	0.1	5.7	0.4	0.0	0.2
2027/28	7.4	0.0	2.6	6.3	0.4	0.4	2.5	1.0	14.1	0.0	0.4	0.3	0.1	1.0	2.5	2.4	0.0	0.1	5.7	0.4	0.0	0.2

Source: Oxera analysis.

Table A3.21 Renewable generation by type in Scenario 4 (TWh)

Output by technology	Co-firing: existing capacity	Co-firing: new capacity	Landfill	Onshore wind: large, high wind	Onshore wind: small	Small hydro	Large hydro	Sewage gas	Offshore wind	Solar PV	Tidal	Wave	Gas/ pyro	Biomass CHP	Biomass regular	Biomass energy crops	Micro CHP	AD CHP	Onshore wind: large, low wind	EfW CHP	Biomass CHP (non-banded)	Biomass (non-banded)
2007/08	2.7	0.0	4.3	1.3	0.2	0.1	2.4	0.9	1.1	0.0	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0	2.6	0.2	0.0	0.2
2008/09	4.7	0.0	4.5	1.4	0.3	0.2	2.4	0.9	1.5	0.0	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0	3.3	0.4	0.0	0.2
2009/10	5.0	0.0	4.6	1.6	0.3	0.2	2.4	0.9	5.0	0.0	0.0	0.0	0.0	0.0	1.4	0.0	0.0	0.0	3.8	0.5	0.0	0.2
2010/11	2.9	0.0	4.7	1.7	0.3	0.2	2.4	0.9	8.3	0.0	0.0	0.0	0.0	0.0	1.6	0.0	0.0	0.0	4.3	0.5	0.0	0.2
2011/12	3.0	0.0	4.6	2.6	0.3	0.3	2.4	0.9	9.9	0.0	0.0	0.0	0.0	0.0	1.9	0.0	0.0	0.0	4.8	0.5	0.0	0.2
2012/13	3.0	0.0	4.5	3.5	0.3	0.3	2.4	0.9	12.9	0.0	0.0	0.0	0.0	0.0	2.3	0.0	0.0	0.0	5.2	0.5	0.0	0.2
2013/14	3.1	0.0	4.4	4.2	0.4	0.4	2.4	0.9	14.5	0.0	0.0	0.0	0.0	0.0	2.4	0.0	0.0	0.0	5.5	0.5	0.0	0.2
2014/15	5.0	0.0	4.3	4.9	0.4	0.4	2.4	0.9	15.7	0.0	0.0	0.0	0.0	0.0	2.5	0.0	0.0	0.0	5.8	0.5	0.0	0.2
2015/16	5.0	0.0	4.2	5.5	0.4	0.4	2.4	0.9	16.5	0.0	0.0	0.0	0.0	0.0	2.6	0.0	0.0	0.0	6.0	0.5	0.0	0.2
2016/17	5.0	0.0	4.1	5.8	0.4	0.4	2.4	0.9	16.8	0.0	0.0	0.0	0.0	0.0	2.7	0.0	0.0	0.0	6.2	0.5	0.0	0.2
2017/18	5.0	0.0	4.0	6.2	0.4	0.4	2.4	0.9	16.9	0.0	0.0	0.0	0.0	0.0	2.7	0.0	0.0	0.0	6.4	0.5	0.0	0.2
2018/19	2.4	0.0	3.8	6.4	0.4	0.4	2.5	0.9	16.9	0.0	0.0	0.0	0.0	0.0	2.8	0.0	0.0	0.0	6.4	0.5	0.0	0.2
2019/20	2.4	0.0	3.7	6.6	0.4	0.4	2.5	0.9	16.9	0.0	0.0	0.0	0.0	0.0	2.9	0.0	0.0	0.0	6.4	0.5	0.0	0.2
2020/21	5.0	0.0	3.5	6.9	0.4	0.4	2.5	1.0	16.9	0.0	0.0	0.0	0.0	0.0	3.0	0.0	0.0	0.0	6.4	0.5	0.0	0.2
2021/22	5.0	0.0	3.4	6.9	0.4	0.4	2.5	1.0	16.9	0.0	0.0	0.0	0.0	0.0	3.0	0.0	0.0	0.0	6.4	0.5	0.0	0.2
2022/23	5.0	0.0	3.3	6.9	0.4	0.4	2.5	1.0	16.9	0.0	0.0	0.0	0.0	0.0	3.0	0.0	0.0	0.0	6.4	0.5	0.0	0.2
2023/24	5.0	0.0	3.1	6.9	0.4	0.4	2.5	1.0	16.9	0.0	0.0	0.0	0.0	0.0	3.0	0.0	0.0	0.0	6.4	0.5	0.0	0.2
2024/25	5.0	0.0	3.0	6.9	0.4	0.4	2.5	1.0	16.9	0.0	0.0	0.0	0.0	0.0	3.0	0.0	0.0	0.0	6.4	0.5	0.0	0.2
2025/26	5.0	0.0	2.8	6.9	0.4	0.4	2.5	1.0	16.9	0.0	0.0	0.0	0.0	0.0	3.0	0.0	0.0	0.0	6.4	0.5	0.0	0.2
2026/27	5.0	0.0	2.7	6.9	0.4	0.4	2.5	1.0	16.9	0.0	0.0	0.0	0.0	0.0	3.0	0.0	0.0	0.0	6.4	0.5	0.0	0.2
2027/28	5.0	0.0	2.6	6.9	0.4	0.4	2.5	1.0	16.9	0.0	0.0	0.0	0.0	0.0	3.0	0.0	0.0	0.0	6.4	0.5	0.0	0.2

Source: Oxera analysis.

Table A3.22 Renewable generation by type for Scenario 5 Central (TWh)

Output by technology	Co-firing: existing capacity	Co-firing: new capacity	Landfill	Onshore wind: large, high wind	Onshore wind: small	Small hydro	Large hydro	Sewage gas	Offshore wind	Solar PV	Tidal	Wave	Gas/ pyro	Biomass CHP	Biomass regular	Biomass energy crops	Micro CHP	AD CHP	Onshore wind: large, low wind	EfW CHP	Biomass CHP (non-banded)	Biomass (non-banded)
2007/08	2.7	0.0	4.3	1.3	0.2	0.1	2.4	0.9	1.1	0.0	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0	2.6	0.2	0.0	0.2
2008/09	4.7	0.0	4.5	1.4	0.3	0.2	2.4	0.9	1.5	0.0	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0	3.3	0.4	0.0	0.2
2009/10	5.0	0.0	4.6	1.6	0.3	0.2	2.4	0.9	4.7	0.0	0.0	0.0	0.0	0.0	1.4	0.0	0.0	0.0	4.0	0.5	0.0	0.2
2010/11	2.9	0.0	4.7	1.7	0.3	0.2	2.4	0.9	7.1	0.0	0.0	0.0	0.0	0.0	1.6	0.1	0.0	0.0	4.5	0.7	0.0	0.2
2011/12	3.0	0.0	4.6	2.5	0.3	0.3	2.4	0.9	8.7	0.0	0.1	0.0	0.0	0.0	1.9	0.1	0.0	0.0	5.0	0.7	0.0	0.2
2012/13	3.0	0.0	4.5	3.3	0.3	0.3	2.4	0.9	11.8	0.0	0.1	0.1	0.0	0.0	2.3	0.1	0.0	0.0	5.5	0.7	0.0	0.2
2013/14	3.1	0.0	4.4	4.0	0.4	0.4	2.4	0.9	12.9	0.0	0.1	0.1	0.1	0.0	2.4	0.1	0.0	0.0	5.8	0.7	0.0	0.2
2014/15	5.0	0.0	4.3	4.8	0.4	0.4	2.4	0.9	14.1	0.0	0.1	0.1	0.1	0.0	2.5	0.1	0.0	0.0	6.2	0.7	0.0	0.2
2015/16	5.0	0.0	4.2	5.4	0.4	0.4	2.4	0.9	14.9	0.0	0.1	0.1	0.1	0.0	2.6	0.1	0.0	0.0	6.3	0.7	0.0	0.2
2016/17	5.0	0.0	4.1	5.8	0.4	0.4	2.4	0.9	15.1	0.0	0.1	0.1	0.1	0.0	2.7	0.1	0.0	0.0	6.5	0.7	0.0	0.2
2017/18	5.0	0.0	4.0	6.1	0.4	0.4	2.4	0.9	15.2	0.0	0.1	0.1	0.1	0.0	2.7	0.1	0.0	0.0	6.7	0.7	0.0	0.2
2018/19	2.4	0.0	3.8	6.5	0.4	0.4	2.5	0.9	15.2	0.0	0.1	0.1	0.1	0.0	2.8	0.1	0.0	0.0	6.9	0.7	0.0	0.2
2019/20	2.4	0.0	3.7	6.7	0.4	0.4	2.5	0.9	15.2	0.0	0.1	0.1	0.1	0.0	2.9	0.1	0.0	0.0	6.9	0.7	0.0	0.2
2020/21	5.0	0.0	3.5	6.9	0.5	0.4	2.5	1.0	15.2	0.0	0.1	0.1	0.1	0.0	3.0	0.1	0.0	0.0	6.9	0.7	0.0	0.2
2021/22	5.0	0.0	3.4	6.9	0.5	0.4	2.5	1.0	15.2	0.0	0.1	0.1	0.1	0.0	3.0	0.1	0.0	0.0	6.9	0.7	0.0	0.2
2022/23	5.0	0.0	3.3	6.9	0.5	0.4	2.5	1.0	15.2	0.0	0.1	0.1	0.1	0.0	3.0	0.1	0.0	0.0	6.9	0.7	0.0	0.2
2023/24	5.0	0.0	3.1	6.9	0.5	0.4	2.5	1.0	15.2	0.0	0.1	0.1	0.1	0.0	3.0	0.1	0.0	0.0	6.9	0.7	0.0	0.2
2024/25	5.0	0.0	3.0	6.9	0.5	0.4	2.5	1.0	15.2	0.0	0.1	0.1	0.1	0.0	3.0	0.1	0.0	0.0	6.9	0.7	0.0	0.2
2025/26	5.0	0.0	2.8	6.9	0.5	0.4	2.5	1.0	15.2	0.0	0.1	0.1	0.1	0.0	3.0	0.1	0.0	0.0	6.9	0.7	0.0	0.2
2026/27	5.0	0.0	2.7	6.9	0.5	0.4	2.5	1.0	15.2	0.0	0.1	0.1	0.1	0.0	3.0	0.1	0.0	0.0	6.9	0.7	0.0	0.2
2027/28	5.0	0.0	2.6	6.9	0.5	0.4	2.5	1.0	15.2	0.0	0.1	0.1	0.1	0.0	3.0	0.1	0.0	0.0	6.9	0.7	0.0	0.2

Source: Oxera analysis.

Table A3.23 Renewable generation by type for Scenario 2 Central (TWh)

Output by technology	Co-firing: existing capacity	Co-firing: new capacity	Landfill	Onshore wind: large, high wind	Onshore wind: small	Small hydro	Large hydro	Sewage gas	Offshore wind	Solar PV	Tidal	Wave	Gas/pyro	Biomass CHP	Biomass regular	Biomass energy crops	Micro CHP	AD CHP	Onshore wind: large, low wind	EfW CHP	Biomass CHP (non-banded)	Biomass (non-banded)
2007/08	2.7	0.0	4.3	1.3	0.3	0.1	2.4	0.9	1.4	0.0	0.0	0.0	0.0	0.0	1.2	0.0	0.0	0.0	2.7	0.2	0.0	0.6
2008/09	4.7	0.0	4.5	1.4	0.3	0.2	2.4	0.9	2.2	0.0	0.0	0.0	0.0	0.0	1.2	0.0	0.0	0.0	3.5	0.4	0.0	0.6
2009/10	5.0	0.0	4.6	1.6	0.3	0.2	2.4	0.9	3.3	0.0	0.0	0.0	0.0	0.0	1.4	0.0	0.0	0.0	4.4	0.5	0.0	0.6
2010/11	5.0	0.0	4.7	1.7	0.3	0.2	2.4	0.9	4.1	0.0	0.0	0.0	0.0	0.0	1.5	0.0	0.0	0.0	5.2	0.7	0.0	0.6
2011/12	5.0	0.0	4.6	2.5	0.4	0.3	2.4	0.9	4.9	0.0	0.0	0.0	0.0	0.0	1.6	0.0	0.0	0.0	6.0	0.8	0.0	0.6
2012/13	5.0	0.0	4.5	3.3	0.4	0.3	2.4	0.9	6.4	0.0	0.0	0.0	0.0	0.0	1.7	0.0	0.0	0.0	6.7	0.9	0.0	0.6
2013/14	5.0	0.0	4.4	4.1	0.5	0.4	2.4	0.9	7.2	0.0	0.0	0.0	0.0	0.0	1.8	0.0	0.0	0.0	7.4	1.0	0.0	0.6
2014/15	5.0	0.0	4.3	5.0	0.5	0.4	2.4	0.9	7.6	0.0	0.0	0.0	0.0	0.0	1.9	0.0	0.0	0.0	8.1	1.1	0.0	0.6
2015/16	5.0	0.0	4.2	5.8	0.5	0.5	2.4	0.9	8.0	0.0	0.0	0.0	0.0	0.0	2.0	0.0	0.0	0.0	8.6	1.1	0.0	0.6
2016/17	5.0	0.0	4.1	6.6	0.6	0.5	2.4	0.9	8.0	0.0	0.0	0.0	0.0	0.0	2.1	0.0	0.0	0.0	8.9	1.1	0.0	0.6
2017/18	5.0	0.0	4.0	7.1	0.6	0.5	2.4	0.9	8.0	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	0.0	9.2	1.1	0.0	0.6
2018/19	5.0	0.0	3.8	7.5	0.6	0.5	2.5	0.9	8.0	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	0.0	9.6	1.1	0.0	0.6
2019/20	5.0	0.0	3.7	7.9	0.6	0.5	2.5	0.9	8.0	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	0.0	9.8	1.1	0.0	0.6
2020/21	5.0	0.0	3.5	8.2	0.6	0.5	2.5	1.0	8.0	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	0.0	9.9	1.1	0.0	0.6
2021/22	5.0	0.0	3.4	8.2	0.6	0.5	2.5	1.0	8.0	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	0.0	9.9	1.1	0.0	0.6
2022/23	5.0	0.0	3.3	8.2	0.6	0.5	2.5	1.0	8.0	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	0.0	9.9	1.1	0.0	0.6
2023/24	5.0	0.0	3.1	8.2	0.6	0.5	2.5	1.0	8.0	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	0.0	9.9	1.1	0.0	0.6
2024/25	5.0	0.0	3.0	8.2	0.6	0.5	2.5	1.0	8.0	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	0.0	9.9	1.1	0.0	0.6
2025/26	5.0	0.0	2.8	8.2	0.6	0.5	2.5	1.0	8.0	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	0.0	9.9	1.1	0.0	0.6
2026/27	5.0	0.0	2.7	8.2	0.6	0.5	2.5	1.0	8.0	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	0.0	9.9	1.1	0.0	0.6
2027/28	5.0	0.0	2.6	8.2	0.6	0.5	2.5	1.0	8.0	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	0.0	9.9	1.1	0.0	0.6

Source: Oxera analysis.

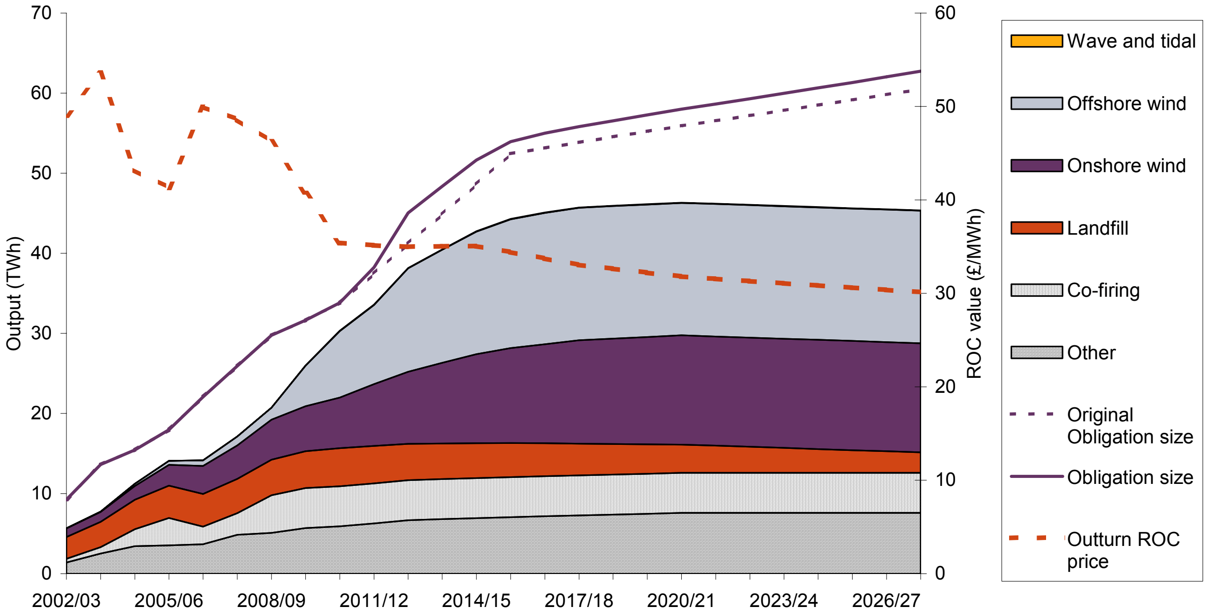
Table A3.24 Renewable generation by type for Scenario 6 Central (TWh)

Output by technology	Co-firing: existing capacity	Co-firing: new capacity	Landfill	Onshore wind: large, high wind	Onshore wind: small	Small hydro	Large hydro	Sewage gas	Offshore wind	Solar PV	Tidal	Wave	Gas/pyro	Biomass CHP	Biomass regular	Biomass energy crops	Micro CHP	AD CHP	Onshore wind: large, low wind	EfW CHP	Biomass CHP (non-banded)	Biomass (non-banded)
2007/08	2.7	0.0	4.3	1.3	0.2	0.1	2.4	0.9	1.1	0.0	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0	2.7	0.2	0.0	0.2
2008/09	4.7	0.0	4.5	1.4	0.3	0.2	2.4	0.9	1.5	0.0	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0	3.3	0.4	0.0	0.2
2009/10	5.0	0.0	4.6	1.6	0.3	0.2	2.4	0.9	4.7	0.0	0.0	0.0	0.0	0.0	1.4	0.0	0.0	0.0	4.0	0.5	0.0	0.2
2010/11	2.9	0.0	4.7	1.7	0.3	0.2	2.4	0.9	8.0	0.0	0.0	0.0	0.0	0.2	1.6	0.1	0.0	0.0	4.5	0.7	0.0	0.2
2011/12	3.0	0.0	4.6	2.5	0.3	0.3	2.4	0.9	10.3	0.0	0.1	0.1	0.0	0.3	1.9	0.1	0.0	0.0	5.0	0.8	0.0	0.2
2012/13	3.0	0.0	4.5	3.3	0.3	0.3	2.4	0.9	13.5	0.0	0.1	0.1	0.0	0.3	2.3	0.3	0.0	0.0	5.5	0.9	0.0	0.2
2013/14	3.1	0.0	4.4	4.0	0.4	0.4	2.4	0.9	14.7	0.0	0.1	0.1	0.1	0.3	2.4	0.3	0.0	0.0	5.9	0.9	0.0	0.2
2014/15	5.0	0.0	4.3	4.8	0.4	0.4	2.4	0.9	15.9	0.0	0.1	0.1	0.1	0.3	2.5	0.3	0.0	0.0	6.2	0.9	0.0	0.2
2015/16	5.0	0.0	4.2	5.5	0.4	0.4	2.4	0.9	16.7	0.0	0.2	0.1	0.1	0.3	2.6	0.3	0.0	0.0	6.5	0.9	0.0	0.2
2016/17	5.0	0.0	4.1	6.0	0.4	0.4	2.4	0.9	17.0	0.0	0.2	0.1	0.1	0.3	2.7	0.3	0.0	0.0	6.7	0.9	0.0	0.2
2017/18	5.0	0.0	4.0	6.3	0.4	0.4	2.4	0.9	17.3	0.0	0.2	0.1	0.1	0.3	2.7	0.3	0.0	0.0	6.9	0.9	0.0	0.2
2018/19	2.4	0.0	3.8	6.6	0.4	0.4	2.5	0.9	17.4	0.0	0.2	0.1	0.1	0.3	2.8	0.3	0.0	0.0	7.1	0.9	0.0	0.2
2019/20	5.0	0.0	3.7	7.0	0.4	0.4	2.5	0.9	17.6	0.0	0.2	0.1	0.1	0.3	2.9	0.3	0.0	0.0	7.2	0.9	0.0	0.2
2020/21	5.0	0.0	3.5	7.2	0.5	0.4	2.5	1.0	17.6	0.0	0.2	0.1	0.1	0.3	3.0	0.3	0.0	0.0	7.4	0.9	0.0	0.2
2021/22	5.0	0.0	3.4	7.2	0.5	0.4	2.5	1.0	17.6	0.0	0.2	0.1	0.1	0.3	3.0	0.3	0.0	0.0	7.4	0.9	0.0	0.2
2022/23	5.0	0.0	3.3	7.2	0.5	0.4	2.5	1.0	17.6	0.0	0.2	0.1	0.1	0.3	3.0	0.3	0.0	0.0	7.4	0.9	0.0	0.2
2023/24	5.0	0.0	3.1	7.2	0.5	0.4	2.5	1.0	17.6	0.0	0.2	0.1	0.1	0.3	3.0	0.3	0.0	0.0	7.4	0.9	0.0	0.2
2024/25	5.0	0.0	3.0	7.2	0.5	0.4	2.5	1.0	17.6	0.0	0.2	0.1	0.1	0.3	3.0	0.3	0.0	0.0	7.4	0.9	0.0	0.2
2025/26	5.0	0.0	2.8	7.2	0.5	0.4	2.5	1.0	17.6	0.0	0.2	0.1	0.1	0.3	3.0	0.3	0.0	0.0	7.4	0.9	0.0	0.2
2026/27	5.0	0.0	2.7	7.2	0.5	0.4	2.5	1.0	17.6	0.0	0.2	0.1	0.1	0.3	3.0	0.3	0.0	0.0	7.4	0.9	0.0	0.2
2027/28	5.0	0.0	2.6	7.2	0.5	0.4	2.5	1.0	17.6	0.0	0.2	0.1	0.1	0.3	3.0	0.3	0.0	0.0	7.4	0.9	0.0	0.2

Source: Oxera analysis.

A3.3 Scenario 4 with 0.4 co-firing band

Figure A3.15 Scenario 4: 0.4 co-firing band, Central: RPI out, headroom 6% from 2009



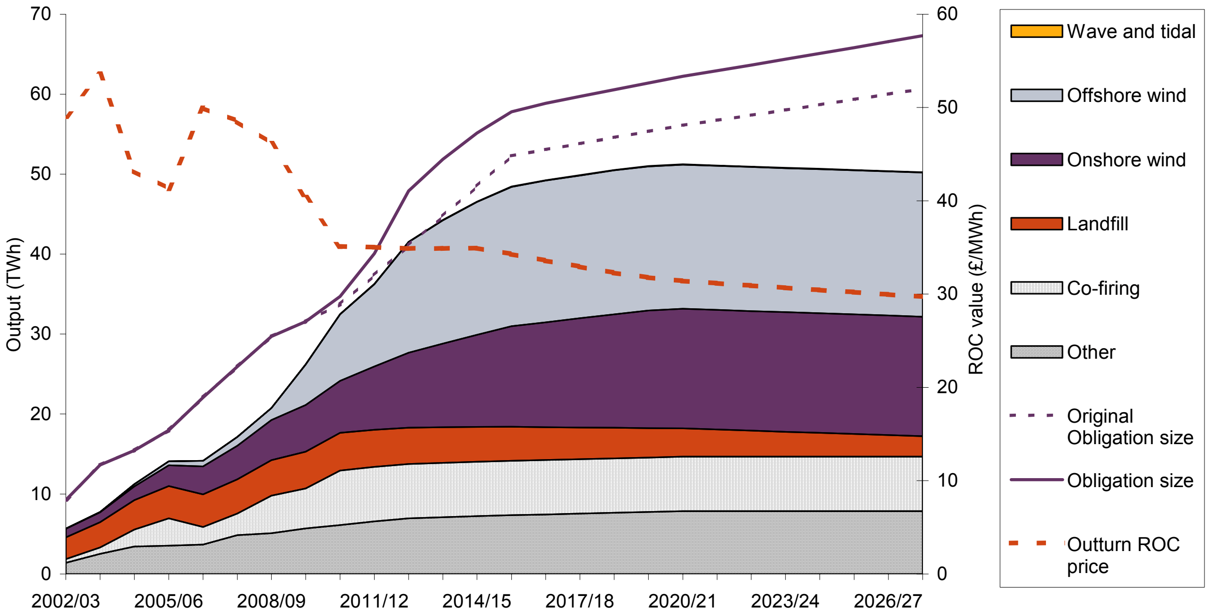
Source: Oxera analysis.

Table A3.25 Scenario 4: 0.4 co-firing band, Central, RPI out, headroom 6% from 2009 results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Wave and tidal	Total renewable generation	As a % of total sales
2002/03	1.4	0.4	2.7	1.09	0.0	0.0	5.7	1.8
2003/04	2.5	0.8	3.2	1.2	0.0	0.0	7.8	2.4
2004/05	3.4	2.1	3.7	1.7	0.3	0.0	11.2	3.5
2005/06	3.5	3.4	4.0	2.6	0.5	0.0	14.1	4.3
2006/07	3.7	2.2	4.1	3.5	0.7	0.0	14.2	4.2
2007/08	4.9	2.7	4.3	4.2	1.1	0.0	17.1	5.1
2008/09	5.1	4.7	4.5	5.0	1.5	0.0	20.7	6.2
2009/10	5.7	5.0	4.6	5.6	5.0	0.0	26.0	7.8
2010/11	5.9	5.0	4.7	6.3	8.3	0.0	30.3	9.2
2011/12	6.3	5.0	4.6	7.7	9.9	0.0	33.6	10.1
2012/13	6.7	5.0	4.5	9.0	12.9	0.0	38.2	11.3
2013/14	6.8	5.0	4.4	10.1	14.1	0.0	40.5	11.9
2014/15	6.9	5.0	4.3	11.1	15.3	0.0	42.8	12.5
2015/16	7.1	5.0	4.2	11.9	16.1	0.0	44.3	12.8
2016/17	7.2	5.0	4.1	12.4	16.4	0.0	45.1	12.9
2017/18	7.3	5.0	4.0	12.9	16.5	0.0	45.7	12.9
2018/19	7.4	5.0	3.8	13.2	16.5	0.0	45.9	12.8
2019/20	7.5	5.0	3.7	13.4	16.5	0.0	46.1	12.7
2020/21	7.6	5.0	3.5	13.6	16.5	0.0	46.3	12.6
2021/22	7.6	5.0	3.4	13.6	16.5	0.0	46.2	12.4
2022/23	7.6	5.0	3.3	13.6	16.5	0.0	46.1	12.2
2023/24	7.6	5.0	3.1	13.6	16.5	0.0	45.9	12.0
2024/25	7.6	5.0	3.0	13.6	16.5	0.0	45.8	11.9
2025/26	7.6	5.0	2.8	13.6	16.5	0.0	45.6	11.7
2026/27	7.6	5.0	2.7	13.6	16.5	0.0	45.5	11.5
2027/28	7.6	5.0	2.6	13.6	16.5	0.0	45.4	11.4

Source: Oxera analysis.

Figure A3.16 Scenario 4: 0.4 co-firing band, High, RPI out, headroom 6% from 2009



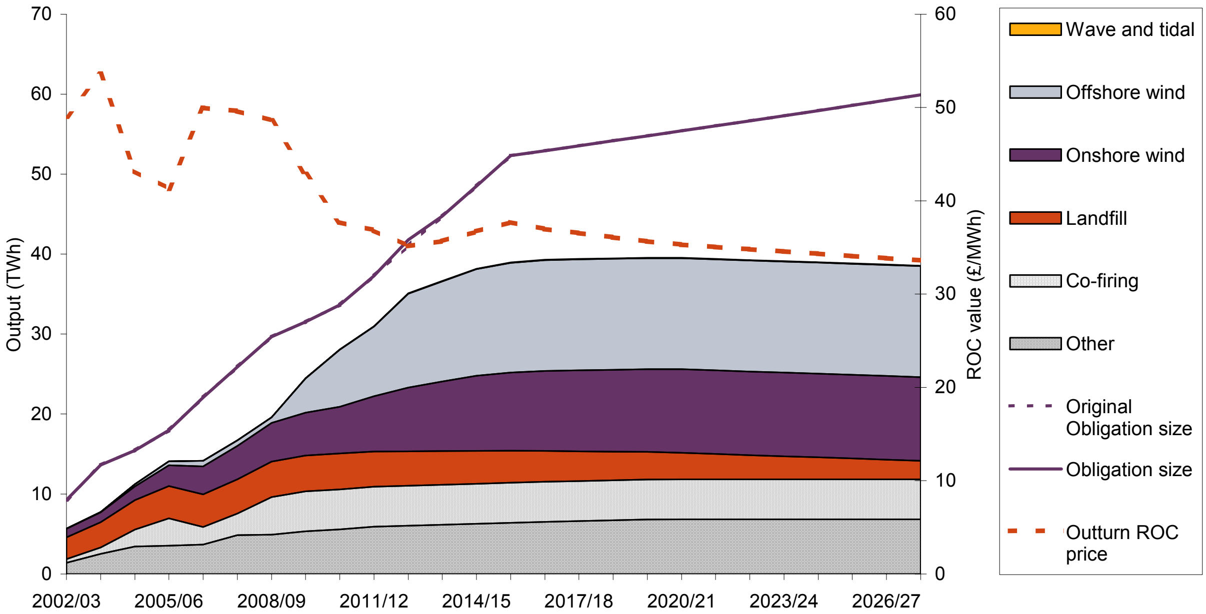
Source: Oxera analysis.

Table A3.26 Scenario 4 with 0.4 co-firing band High, headroom 6% from 2009 results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Wave and tidal	Total renewable generation	As % of total sales
2002/03	1.4	0.4	2.7	1.09	0.0	0.0	5.7	1.8
2003/04	2.5	0.8	3.2	1.2	0.0	0.0	7.8	2.4
2004/05	3.4	2.1	3.7	1.7	0.3	0.0	11.2	3.5
2005/06	3.5	3.4	4.0	2.6	0.5	0.0	14.1	4.3
2006/07	3.7	2.2	4.1	3.5	0.7	0.0	14.2	4.2
2007/08	4.9	2.7	4.3	4.2	1.1	0.0	17.1	5.1
2008/09	5.1	4.7	4.5	5.0	1.5	0.0	20.8	6.3
2009/10	5.7	5.0	4.6	5.8	5.0	0.0	26.2	7.9
2010/11	6.1	6.8	4.7	6.5	8.3	0.0	32.5	9.9
2011/12	6.6	6.8	4.6	7.9	10.3	0.0	36.3	10.9
2012/13	6.9	6.8	4.5	9.4	13.8	0.0	41.5	12.4
2013/14	7.1	6.8	4.4	10.5	15.4	0.0	44.3	13.1
2014/15	7.2	6.8	4.3	11.5	16.6	0.0	46.6	13.6
2015/16	7.3	6.8	4.2	12.6	17.4	0.0	48.4	14.0
2016/17	7.4	6.8	4.1	13.1	17.7	0.0	49.2	14.1
2017/18	7.5	6.8	4.0	13.7	17.9	0.0	49.9	14.1
2018/19	7.6	6.8	3.8	14.2	18.0	0.0	50.5	14.0
2019/20	7.8	6.8	3.7	14.7	18.0	0.0	51.0	14.0
2020/21	7.9	6.8	3.5	15.0	18.0	0.0	51.2	13.8
2021/22	7.9	6.8	3.4	15.0	18.0	0.0	51.1	13.7
2022/23	7.9	6.8	3.3	15.0	18.0	0.0	50.9	13.5
2023/24	7.9	6.8	3.1	15.0	18.0	0.0	50.8	13.3
2024/25	7.9	6.8	3.0	15.0	18.0	0.0	50.7	13.1
2025/26	7.9	6.8	2.8	15.0	18.0	0.0	50.5	12.9
2026/27	7.9	6.8	2.7	15.0	18.0	0.0	50.4	12.7
2027/28	7.9	6.8	2.6	15.0	18.0	0.0	50.2	12.6

Source: Oxera analysis.

Figure A3.17 Scenario 4: 0.4 co-firing band, Low, headroom 6% from 2009



Source: Oxera analysis.

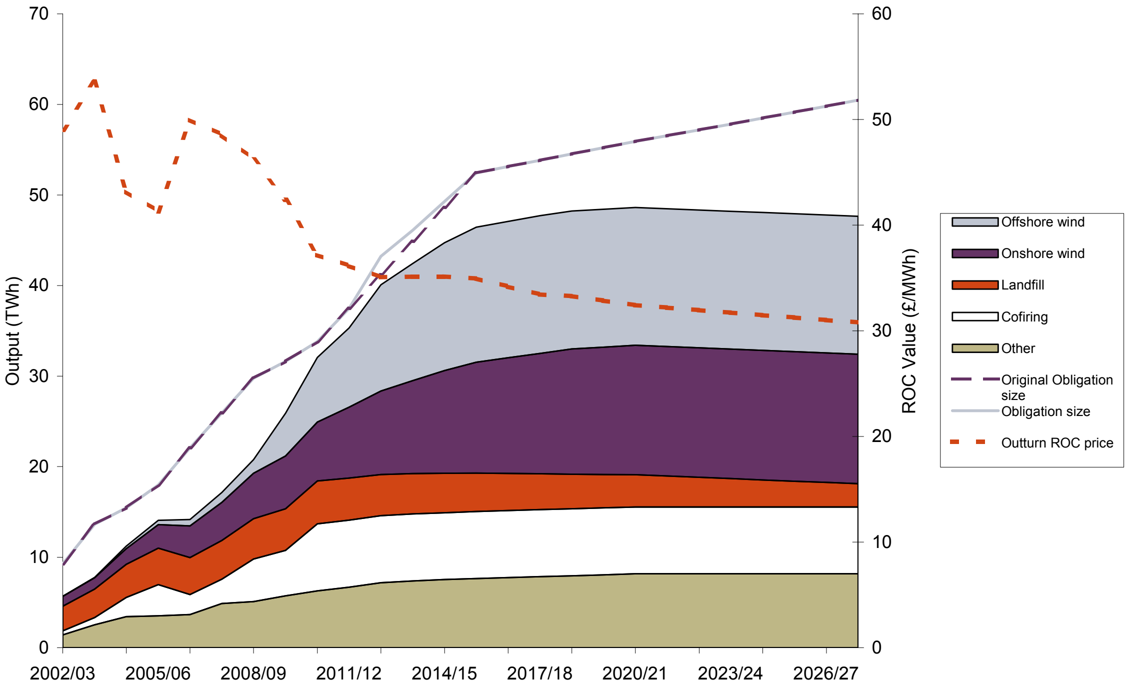
Table A3.27 Scenario 4: 0.4 co-firing band, Low, RPI out, headroom 6% from 2009

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Wave and tidal	Total renewable generation	As a % of total sales
2002/03	1.4	0.4	2.7	1.09	0.0	0.0	5.7	1.8
2003/04	2.5	0.8	3.2	1.2	0.0	0.0	7.8	2.4
2004/05	3.4	2.1	3.7	1.7	0.3	0.0	11.2	3.5
2005/06	3.5	3.4	4.0	2.6	0.5	0.0	14.1	4.3
2006/07	3.7	2.2	4.1	3.5	0.7	0.0	14.2	4.2
2007/08	4.9	2.7	4.3	4.2	0.7	0.0	16.7	5.0
2008/09	4.9	4.7	4.5	4.8	0.7	0.0	19.6	5.9
2009/10	5.3	5.0	4.5	5.4	4.3	0.0	24.5	7.4
2010/11	5.6	5.0	4.5	5.8	7.1	0.0	28.1	8.5
2011/12	5.9	5.0	4.4	6.9	8.7	0.0	31.0	9.3
2012/13	6.0	5.0	4.3	8.0	11.8	0.0	35.1	10.5
2013/14	6.2	5.0	4.2	8.7	12.5	0.0	36.6	10.8
2014/15	6.3	5.0	4.1	9.4	13.3	0.0	38.2	11.2
2015/16	6.4	5.0	4.0	9.8	13.7	0.0	39.0	11.3
2016/17	6.5	5.0	3.9	10.0	13.9	0.0	39.3	11.3
2017/18	6.6	5.0	3.7	10.1	13.9	0.0	39.4	11.2
2018/19	6.7	5.0	3.6	10.2	13.9	0.0	39.5	11.0
2019/20	6.8	5.0	3.4	10.3	13.9	0.0	39.5	10.9
2020/21	6.8	5.0	3.3	10.5	13.9	0.0	39.5	10.8
2021/22	6.8	5.0	3.2	10.5	13.9	0.0	39.4	10.7
2022/23	6.8	5.0	3.0	10.5	13.9	0.0	39.3	10.5
2023/24	6.8	5.0	2.9	10.5	13.9	0.0	39.1	10.4
2024/25	6.8	5.0	2.7	10.5	13.9	0.0	39.0	10.2
2025/26	6.8	5.0	2.6	10.5	13.9	0.0	38.8	10.1
2026/27	6.8	5.0	2.5	10.5	13.9	0.0	38.7	9.9
2027/28	6.8	5.0	2.3	10.5	13.9	0.0	38.6	9.8

Source: Oxera analysis.

A3.4 Scenario 5 sensitivities

Figure A3.18 Scenario 5: Central, RPI out, headroom 2009 – 6%, no planning results



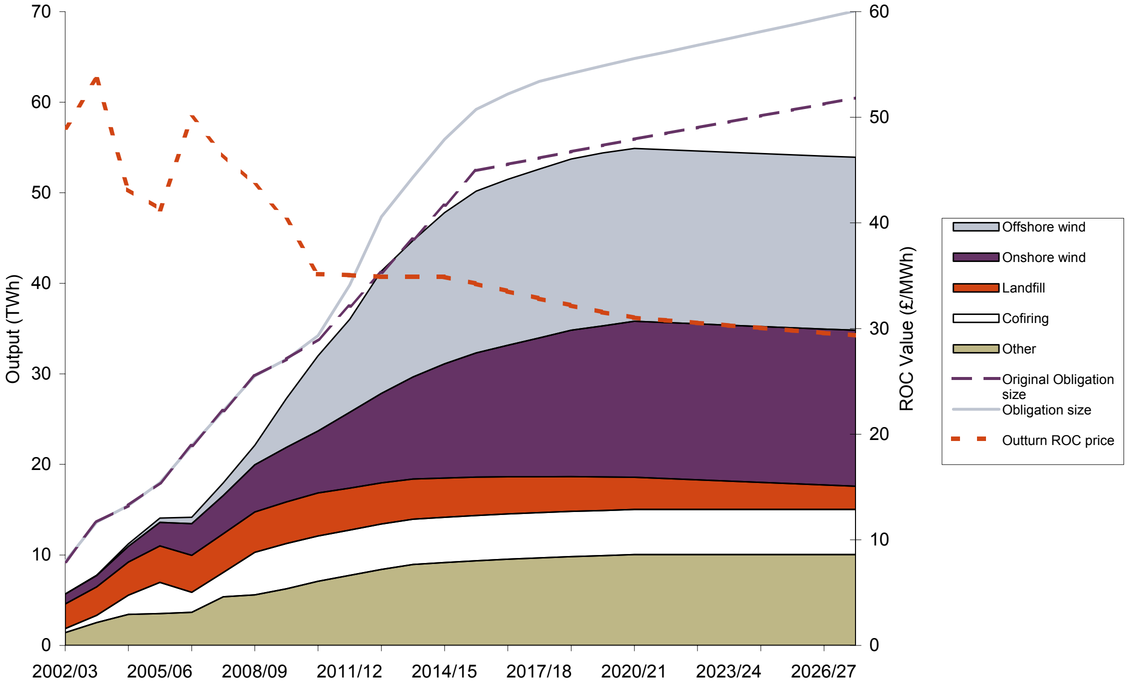
Source: Oxera analysis.

Table A3.28 Scenario 5: Central, RPI out, headroom 2009 – 6%, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	4.9	2.7	4.3	4.2	1.1	17.1	5.1
2008/09	5.1	4.7	4.5	5.0	1.5	20.8	6.2
2009/10	5.7	5.0	4.6	5.8	4.7	25.9	7.8
2010/11	6.3	7.4	4.7	6.5	7.1	32.1	9.7
2011/12	6.7	7.4	4.6	7.8	8.7	35.3	10.6
2012/13	7.2	7.4	4.5	9.2	11.8	40.1	11.9
2013/14	7.4	7.4	4.4	10.3	12.9	42.4	12.4
2014/15	7.5	7.4	4.3	11.3	14.1	44.7	13.0
2015/16	7.6	7.4	4.2	12.2	14.9	46.4	13.4
2016/17	7.7	7.4	4.1	12.8	15.1	47.1	13.4
2017/18	7.8	7.4	4.0	13.3	15.2	47.7	13.4
2018/19	7.9	7.4	3.8	13.8	15.2	48.2	13.4
2019/20	8.0	7.4	3.7	14.1	15.2	48.4	13.2
2020/21	8.2	7.4	3.5	14.3	15.2	48.6	13.1
2021/22	8.2	7.4	3.4	14.3	15.2	48.5	13.0
2022/23	8.2	7.4	3.3	14.3	15.2	48.3	12.8
2023/24	8.2	7.4	3.1	14.3	15.2	48.2	12.6
2024/25	8.2	7.4	3.0	14.3	15.2	48.1	12.4
2025/26	8.2	7.4	2.8	14.3	15.2	47.9	12.2
2026/27	8.2	7.4	2.7	14.3	15.2	47.8	12.1
2027/28	8.2	7.4	2.6	14.3	15.2	47.6	11.9

Source: Oxera analysis.

Figure A3.19 Scenario 5: Central, RPI out, headroom 2009 – 6%, costs – 10%, no planning results



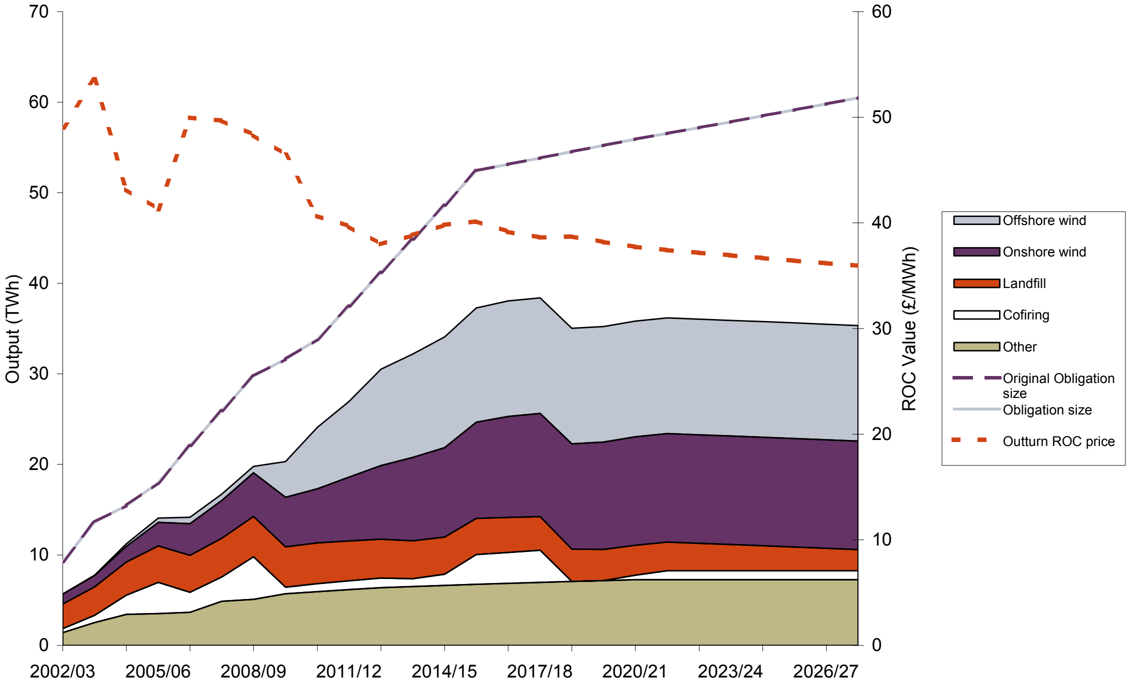
Source: Oxera analysis.

Table A3.29 Scenario 5: Central, RPI out, headroom 2009 – 6%, costs – 10%, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.4	2.7	4.3	4.2	1.4	18.0	5.4
2008/09	5.6	4.7	4.5	5.2	2.2	22.1	6.7
2009/10	6.3	5.0	4.6	6.0	5.4	27.3	8.2
2010/11	7.1	5.0	4.7	6.9	8.3	32.0	9.7
2011/12	7.7	5.0	4.6	8.4	10.3	36.0	10.8
2012/13	8.4	5.0	4.5	9.9	13.5	41.4	12.2
2013/14	8.9	5.0	4.4	11.3	15.1	44.8	13.1
2014/15	9.2	5.0	4.3	12.6	16.7	47.8	13.9
2015/16	9.3	5.0	4.2	13.7	17.9	50.2	14.4
2016/17	9.5	5.0	4.1	14.5	18.3	51.5	14.6
2017/18	9.7	5.0	4.0	15.3	18.6	52.6	14.7
2018/19	9.8	5.0	3.8	16.2	18.9	53.7	14.8
2019/20	9.9	5.0	3.7	16.7	19.1	54.4	14.8
2020/21	10.0	5.0	3.5	17.2	19.1	54.9	14.8
2021/22	10.0	5.0	3.4	17.2	19.1	54.8	14.6
2022/23	10.0	5.0	3.3	17.2	19.1	54.6	14.4
2023/24	10.0	5.0	3.1	17.2	19.1	54.5	14.2
2024/25	10.0	5.0	3.0	17.2	19.1	54.3	14.0
2025/26	10.0	5.0	2.8	17.2	19.1	54.2	13.8
2026/27	10.0	5.0	2.7	17.2	19.1	54.1	13.6
2027/28	10.0	5.0	2.6	17.2	19.1	53.9	13.4

Source: Oxera analysis.

Figure A3.20 Scenario 5: Central, RPI out, headroom 2009 – 6%, costs + 10%, no planning results



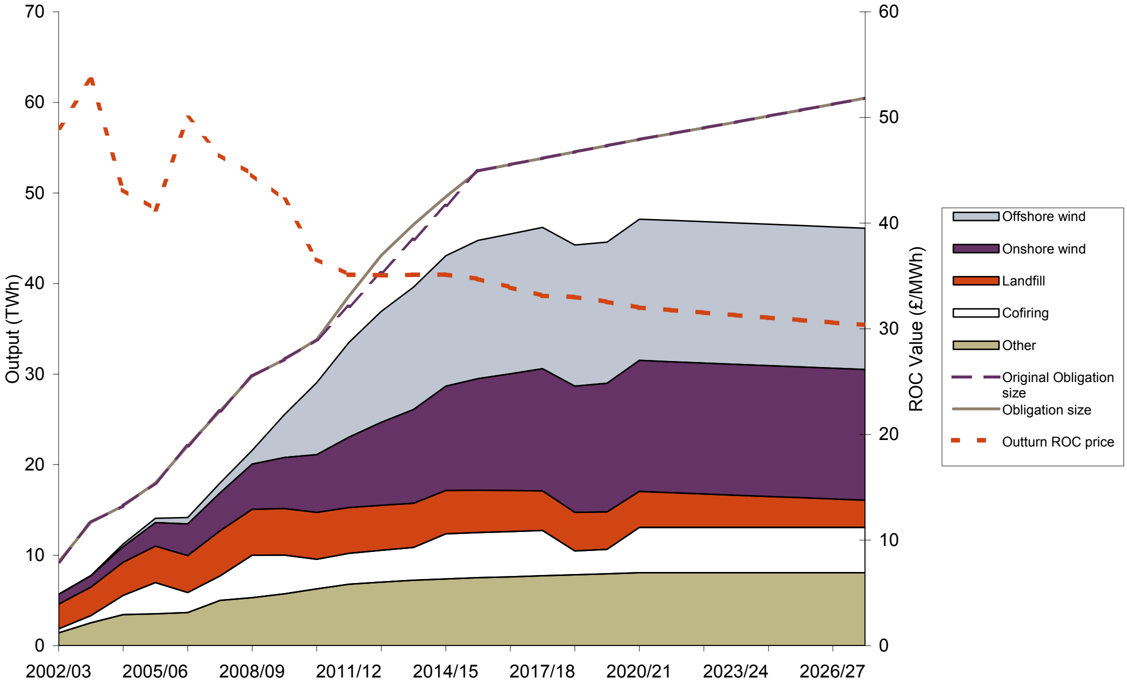
Source: Oxera analysis.

Table A3.30 Scenario 5: Central, RPI out, headroom 2009 – 6%, costs + 10%, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	4.9	2.7	4.3	4.2	0.7	16.7	5.0
2008/09	5.1	4.7	4.5	4.8	0.7	19.8	5.9
2009/10	5.7	0.7	4.5	5.5	3.9	20.3	6.1
2010/11	5.9	0.9	4.5	6.0	6.8	24.1	7.3
2011/12	6.2	1.0	4.4	7.0	8.4	27.0	8.1
2012/13	6.4	1.1	4.3	8.1	10.6	30.5	9.0
2013/14	6.5	0.9	4.2	9.2	11.4	32.2	9.5
2014/15	6.6	1.2	4.1	9.9	12.2	34.1	9.9
2015/16	6.8	3.3	4.0	10.6	12.6	37.3	10.8
2016/17	6.9	3.4	3.9	11.2	12.8	38.1	10.8
2017/18	7.0	3.6	3.7	11.4	12.8	38.4	10.8
2018/19	7.1	0.0	3.6	11.6	12.8	35.0	9.7
2019/20	7.2	0.0	3.4	11.9	12.8	35.2	9.7
2020/21	7.3	0.5	3.3	12.0	12.8	35.8	9.7
2021/22	7.3	1.0	3.2	12.0	12.8	36.2	9.7
2022/23	7.3	1.0	3.0	12.0	12.8	36.0	9.5
2023/24	7.3	1.0	2.9	12.0	12.8	35.9	9.4
2024/25	7.3	1.0	2.7	12.0	12.8	35.8	9.3
2025/26	7.3	1.0	2.6	12.0	12.8	35.6	9.1
2026/27	7.3	1.0	2.5	12.0	12.8	35.5	9.0
2027/28	7.3	1.0	2.3	12.0	12.8	35.3	8.8

Source: Oxera analysis.

Figure A3.21 Scenario 5: Central, RPI out, headroom 2009 – 6%, inc planning results



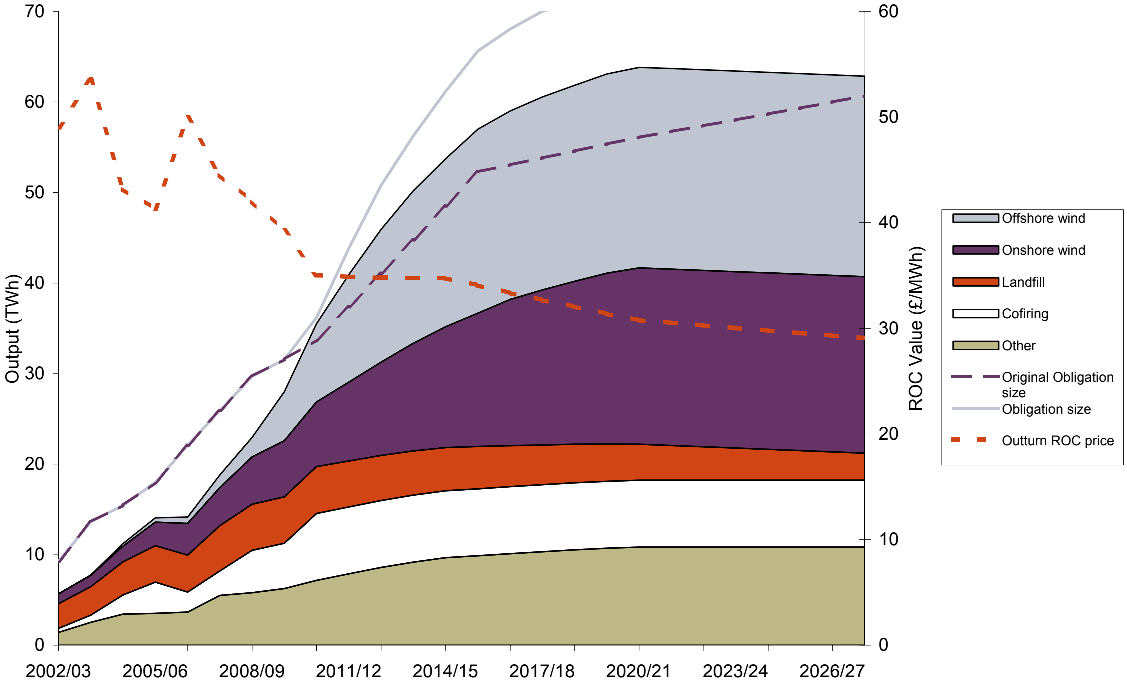
Source: Oxera analysis.

Table A3.31 Scenario 5: Central, RPI out, headroom 2009 – 6%, inc planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.0	2.7	5.0	4.2	1.1	18.0	5.4
2008/09	5.3	4.7	5.1	5.0	1.5	21.6	6.5
2009/10	5.7	4.3	5.1	5.6	4.7	25.5	7.7
2010/11	6.3	3.3	5.2	6.4	8.0	29.1	8.8
2011/12	6.8	3.4	5.1	7.8	10.5	33.5	10.0
2012/13	7.0	3.5	5.0	9.2	12.2	36.9	10.9
2013/14	7.2	3.6	4.9	10.4	13.5	39.6	11.6
2014/15	7.4	5.0	4.8	11.5	14.4	43.1	12.5
2015/16	7.5	5.0	4.7	12.3	15.3	44.8	12.9
2016/17	7.6	5.0	4.5	12.9	15.4	45.5	12.9
2017/18	7.7	5.0	4.4	13.5	15.6	46.2	13.0
2018/19	7.8	2.6	4.2	13.9	15.6	44.3	12.3
2019/20	7.9	2.7	4.1	14.2	15.6	44.6	12.2
2020/21	8.1	5.0	4.0	14.5	15.6	47.1	12.7
2021/22	8.1	5.0	3.8	14.5	15.6	47.0	12.6
2022/23	8.1	5.0	3.7	14.5	15.6	46.8	12.4
2023/24	8.1	5.0	3.5	14.5	15.6	46.7	12.2
2024/25	8.1	5.0	3.4	14.5	15.6	46.5	12.0
2025/26	8.1	5.0	3.3	14.5	15.6	46.4	11.9
2026/27	8.1	5.0	3.1	14.5	15.6	46.3	11.7
2027/28	8.1	5.0	3.0	14.5	15.6	46.1	11.5

Source: Oxera analysis.

Figure A3.22 Scenario 5: High, RPI out, headroom 2009 – 6%, cost – 10%, inc planning results



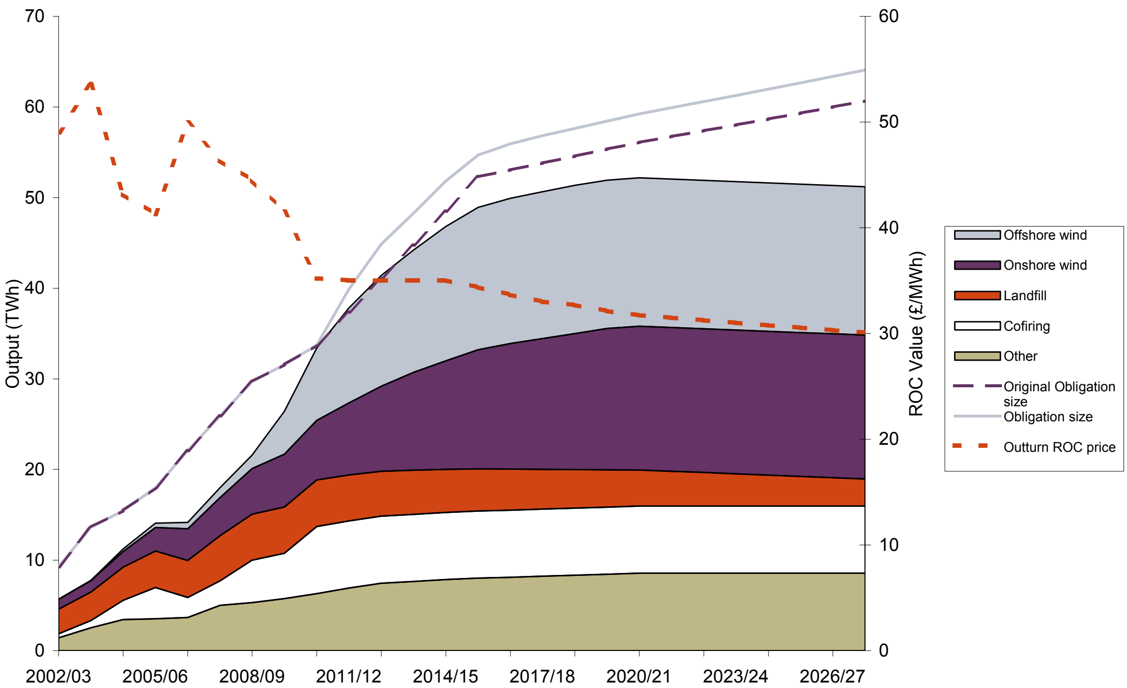
Source: Oxera analysis.

Table A3.32 Scenario 5: High, headroom 2009 – 6%, cost – 10% inc planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.5	2.7	5.0	4.2	1.4	18.8	5.6
2008/09	5.8	4.7	5.1	5.2	2.2	23.0	6.9
2009/10	6.3	5.0	5.1	6.2	5.4	28.0	8.5
2010/11	7.2	7.4	5.2	7.1	8.6	35.5	10.8
2011/12	7.9	7.4	5.1	8.7	11.9	40.9	12.3
2012/13	8.6	7.4	5.0	10.3	14.7	45.9	13.6
2013/14	9.2	7.4	4.9	11.9	16.8	50.2	14.8
2014/15	9.7	7.4	4.8	13.3	18.6	53.7	15.7
2015/16	9.9	7.4	4.7	14.7	20.3	57.0	16.4
2016/17	10.1	7.4	4.5	16.2	20.8	59.0	16.8
2017/18	10.3	7.4	4.4	17.1	21.3	60.5	16.9
2018/19	10.5	7.4	4.2	18.0	21.7	61.8	17.0
2019/20	10.7	7.4	4.1	18.9	22.0	63.1	17.1
2020/21	10.8	7.4	4.0	19.5	22.2	63.8	17.1
2021/22	10.8	7.4	3.8	19.5	22.2	63.7	16.9
2022/23	10.8	7.4	3.7	19.5	22.2	63.5	16.6
2023/24	10.8	7.4	3.5	19.5	22.2	63.4	16.4
2024/25	10.8	7.4	3.4	19.5	22.2	63.3	16.2
2025/26	10.8	7.4	3.3	19.5	22.2	63.1	16.0
2026/27	10.8	7.4	3.1	19.5	22.2	63.0	15.8
2027/28	10.8	7.4	3.0	19.5	22.2	62.8	15.6

Source: Oxera analysis.

Figure A3.23 Scenario 5: High, headroom 2009 – 6%, inc planning results



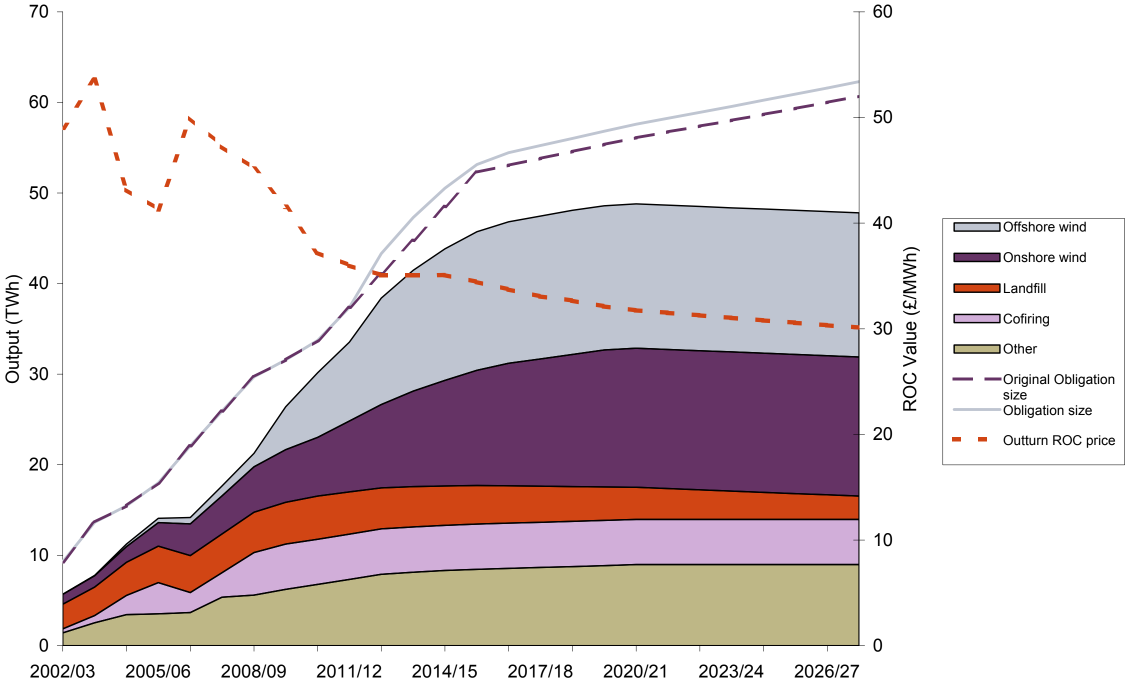
Source: Oxera analysis.

Table A3.33 Scenario 5: High, headroom 2009 – 6%, inc planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.0	2.7	5.0	4.2	1.1	18.0	5.4
2008/09	5.3	4.7	5.1	5.0	1.5	21.6	6.5
2009/10	5.7	5.0	5.1	5.8	4.7	26.4	8.0
2010/11	6.3	7.4	5.2	6.6	8.0	33.4	10.1
2011/12	6.9	7.4	5.1	8.0	10.5	37.8	11.4
2012/13	7.4	7.4	5.0	9.4	12.2	41.4	12.3
2013/14	7.6	7.4	4.9	10.8	13.5	44.2	13.0
2014/15	7.8	7.4	4.8	12.0	14.8	46.8	13.6
2015/16	8.0	7.4	4.7	13.1	15.7	48.9	14.1
2016/17	8.1	7.4	4.5	13.9	16.0	49.9	14.2
2017/18	8.2	7.4	4.4	14.4	16.2	50.7	14.2
2018/19	8.3	7.4	4.2	15.0	16.4	51.4	14.2
2019/20	8.4	7.4	4.1	15.6	16.4	51.9	14.2
2020/21	8.6	7.4	4.0	15.9	16.4	52.2	14.0
2021/22	8.6	7.4	3.8	15.9	16.4	52.0	13.9
2022/23	8.6	7.4	3.7	15.9	16.4	51.9	13.7
2023/24	8.6	7.4	3.5	15.9	16.4	51.8	13.5
2024/25	8.6	7.4	3.4	15.9	16.4	51.6	13.3
2025/26	8.6	7.4	3.3	15.9	16.4	51.5	13.1
2026/27	8.6	7.4	3.1	15.9	16.4	51.3	12.9
2027/28	8.6	7.4	3.0	15.9	16.4	51.2	12.7

Source: Oxera analysis.

Figure A3.24 Scenario 5: High, headroom 2009 – 6%, no planning results



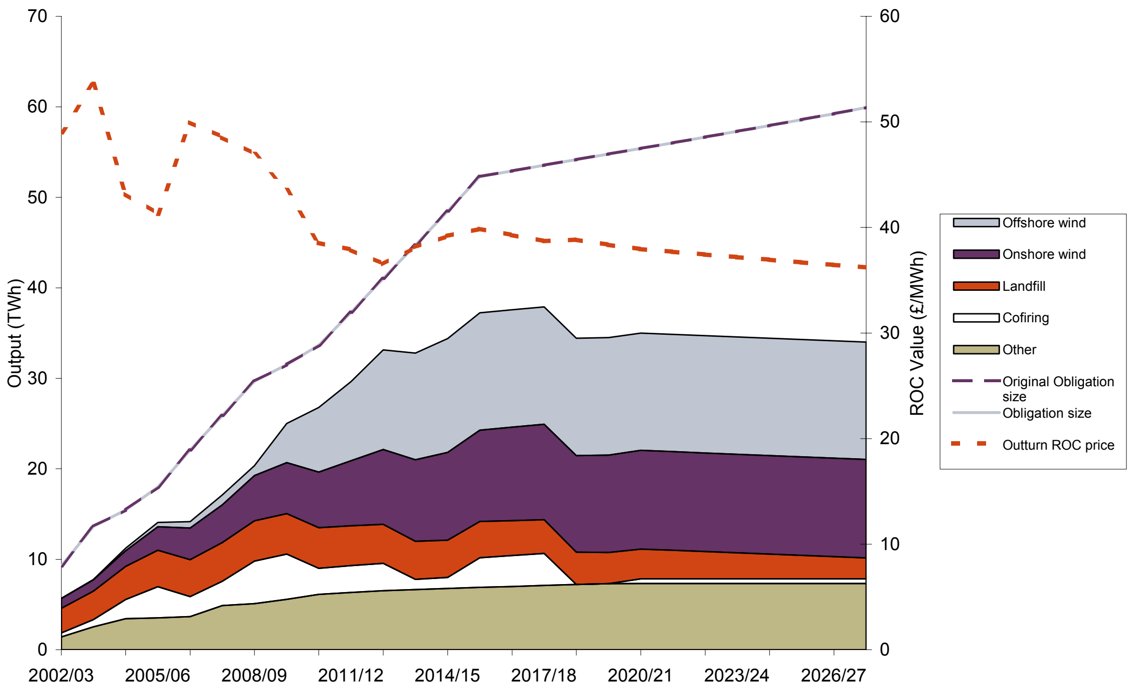
Source: Oxera analysis.

Table A3.34 Scenario 5: High, headroom 2009 – 6%, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.4	2.7	4.3	4.2	1.1	17.6	5.3
2008/09	5.6	4.7	4.5	5.0	1.5	21.2	6.4
2009/10	6.2	5.0	4.6	5.8	4.7	26.4	8.0
2010/11	6.8	5.0	4.7	6.5	7.1	30.2	9.1
2011/12	7.3	5.0	4.6	7.8	8.7	33.5	10.1
2012/13	7.9	5.0	4.5	9.2	11.8	38.4	11.4
2013/14	8.1	5.0	4.4	10.6	13.3	41.5	12.2
2014/15	8.3	5.0	4.3	11.7	14.5	43.8	12.8
2015/16	8.4	5.0	4.2	12.7	15.3	45.7	13.2
2016/17	8.5	5.0	4.1	13.5	15.6	46.8	13.3
2017/18	8.6	5.0	4.0	14.1	15.8	47.4	13.3
2018/19	8.7	5.0	3.8	14.6	15.9	48.1	13.3
2019/20	8.8	5.0	3.7	15.1	15.9	48.6	13.3
2020/21	9.0	5.0	3.5	15.4	15.9	48.8	13.1
2021/22	9.0	5.0	3.4	15.4	15.9	48.7	12.9
2022/23	9.0	5.0	3.3	15.4	15.9	48.5	12.8
2023/24	9.0	5.0	3.1	15.4	15.9	48.4	12.6
2024/25	9.0	5.0	3.0	15.4	15.9	48.2	12.4
2025/26	9.0	5.0	2.8	15.4	15.9	48.1	12.2
2026/27	9.0	5.0	2.7	15.4	15.9	48.0	12.1
2027/28	9.0	5.0	2.6	15.4	15.9	47.8	11.9

Source: Oxera analysis.

Figure A3.25 Scenario 5: Low, headroom 2009 – 6%, no planning results



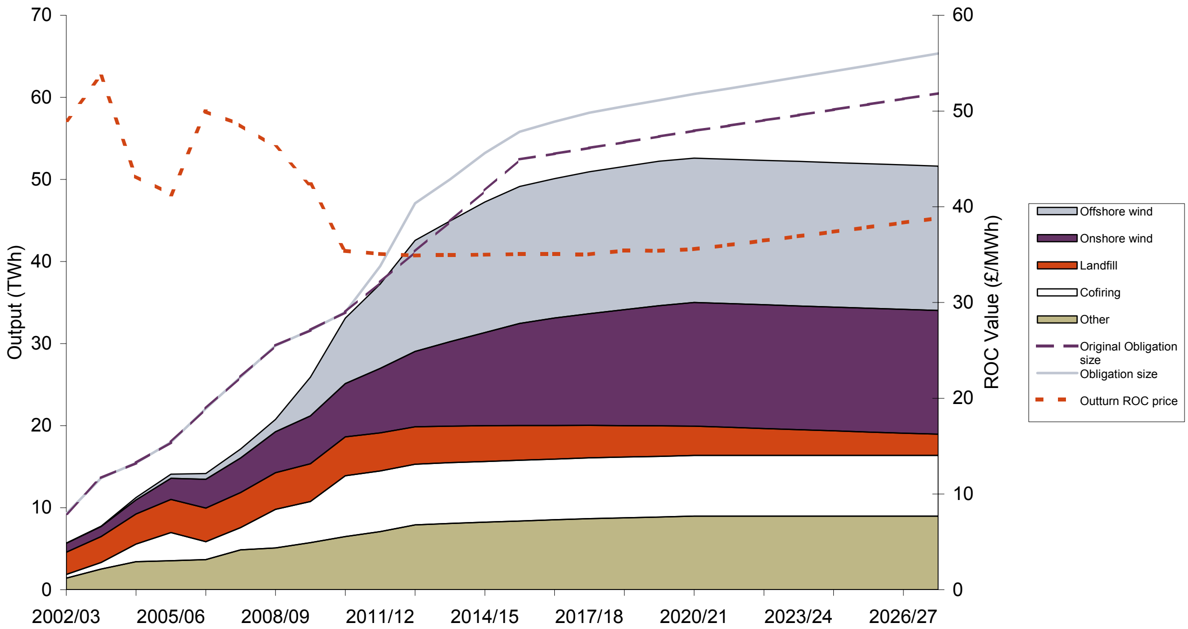
Source: Oxera analysis.

Table A3.35 Scenario 5: Low, headroom 2009 – 6%, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	4.9	2.7	4.3	4.2	1.1	17.1	5.1
2008/09	5.1	4.7	4.5	5.0	1.1	20.3	6.1
2009/10	5.6	5.0	4.5	5.6	4.3	25.0	7.6
2010/11	6.1	2.9	4.5	6.1	7.1	26.8	8.1
2011/12	6.3	3.0	4.4	7.2	8.7	29.6	8.9
2012/13	6.5	3.0	4.3	8.3	11.0	33.1	9.9
2013/14	6.6	1.1	4.2	9.0	11.8	32.8	9.7
2014/15	6.8	1.2	4.1	9.7	12.6	34.4	10.0
2015/16	6.9	3.3	4.0	10.1	13.0	37.2	10.8
2016/17	7.0	3.4	3.9	10.3	13.0	37.6	10.7
2017/18	7.1	3.6	3.7	10.6	13.0	37.9	10.7
2018/19	7.2	0.0	3.6	10.7	13.0	34.4	9.6
2019/20	7.3	0.0	3.4	10.8	13.0	34.5	9.5
2020/21	7.3	0.5	3.3	10.9	13.0	35.0	9.6
2021/22	7.3	0.5	3.2	10.9	13.0	34.9	9.4
2022/23	7.3	0.5	3.0	10.9	13.0	34.7	9.3
2023/24	7.3	0.5	2.9	10.9	13.0	34.6	9.1
2024/25	7.3	0.5	2.7	10.9	13.0	34.4	9.0
2025/26	7.3	0.5	2.6	10.9	13.0	34.3	8.9
2026/27	7.3	0.5	2.5	10.9	13.0	34.2	8.7
2027/28	7.3	0.5	2.3	10.9	13.0	34.0	8.6

Source: Oxera analysis.

Figure A3.26 Scenario 6: Central, headroom 2009 – 6%, no planning results



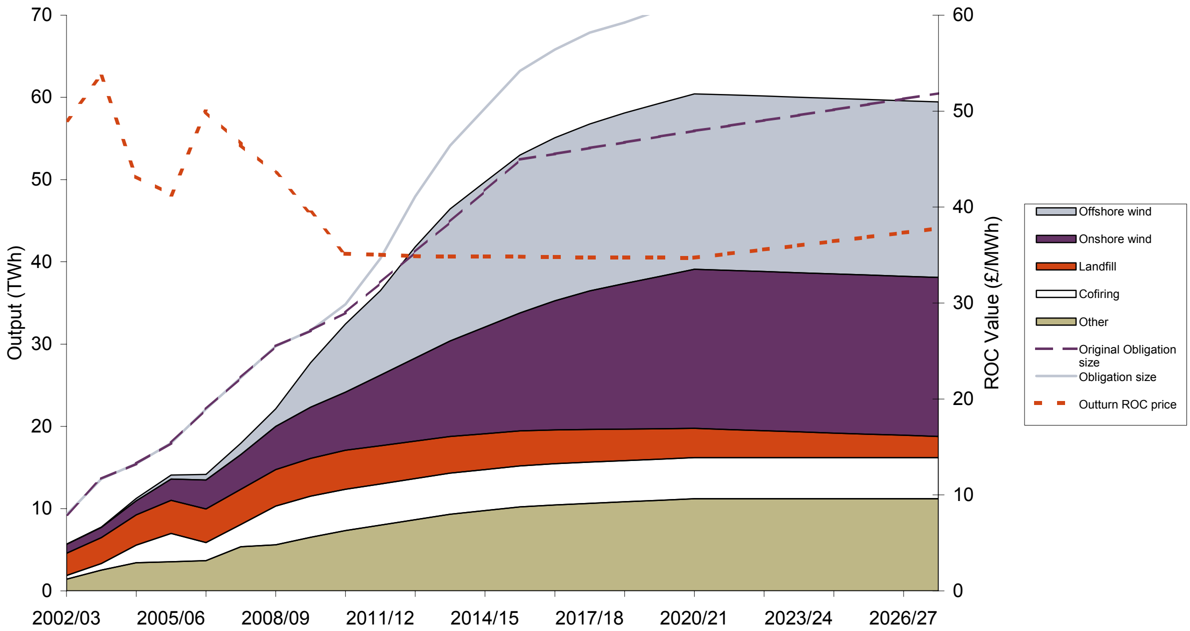
Source: Oxera analysis.

Table A3.36 Scenario 6: Central, headroom 2009 – 6%, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	4.9	2.7	4.3	4.2	1.1	17.1	5.1
2008/09	5.1	4.7	4.5	5.0	1.5	20.8	6.2
2009/10	5.8	5.0	4.6	5.8	4.7	25.9	7.8
2010/11	6.5	7.4	4.7	6.5	8.0	33.1	10.0
2011/12	7.1	7.4	4.6	7.8	10.3	37.3	11.1
2012/13	7.9	7.4	4.5	9.2	13.5	42.6	12.6
2013/14	8.1	7.4	4.4	10.3	14.7	44.9	13.2
2014/15	8.2	7.4	4.3	11.4	15.9	47.2	13.7
2015/16	8.4	7.4	4.2	12.4	16.7	49.1	14.2
2016/17	8.5	7.4	4.1	13.1	17.0	50.1	14.2
2017/18	8.7	7.4	4.0	13.6	17.3	50.9	14.3
2018/19	8.8	7.4	3.8	14.1	17.4	51.6	14.3
2019/20	8.9	7.4	3.7	14.7	17.6	52.2	14.3
2020/21	9.0	7.4	3.5	15.1	17.6	52.6	14.2
2021/22	9.0	7.4	3.4	15.1	17.6	52.5	14.0
2022/23	9.0	7.4	3.3	15.1	17.6	52.3	13.8
2023/24	9.0	7.4	3.1	15.1	17.6	52.2	13.6
2024/25	9.0	7.4	3.0	15.1	17.6	52.0	13.4
2025/26	9.0	7.4	2.8	15.1	17.6	51.9	13.2
2026/27	9.0	7.4	2.7	15.1	17.6	51.8	13.0
2027/28	9.0	7.4	2.6	15.1	17.6	51.6	12.9

Source: Oxera.

Figure A3.27 Scenario 6: Central, headroom 2009 – 6%, costs – 10%, no planning results



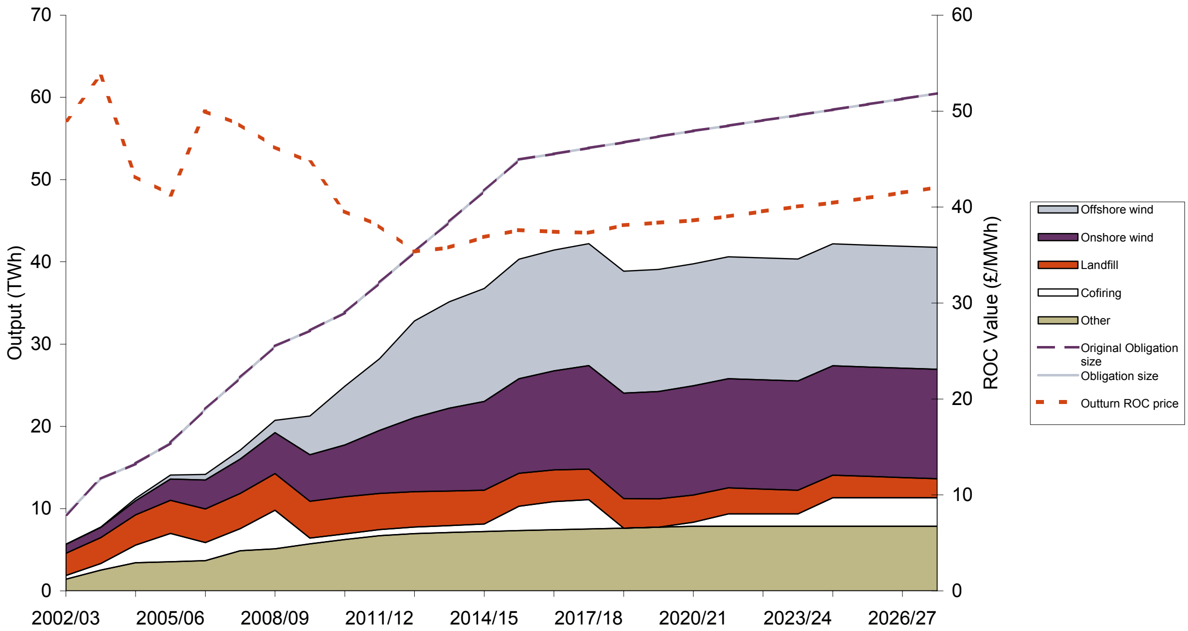
Source: Oxera.

Table A3.37 Scenario 6: Central, headroom 2009 – 6%, costs –10%, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.4	2.7	4.3	4.2	1.4	18.0	5.4
2008/09	5.6	4.7	4.5	5.2	2.2	22.1	6.7
2009/10	6.5	5.0	4.6	6.2	5.4	27.7	8.4
2010/11	7.3	5.0	4.7	7.1	8.3	32.4	9.8
2011/12	8.0	5.0	4.6	8.6	10.3	36.5	10.9
2012/13	8.7	5.0	4.5	10.1	13.5	41.8	12.4
2013/14	9.3	5.0	4.4	11.6	16.0	46.4	13.6
2014/15	9.8	5.0	4.3	13.0	17.6	49.7	14.4
2015/16	10.2	5.0	4.2	14.3	19.2	53.0	15.2
2016/17	10.4	5.0	4.1	15.7	19.8	55.1	15.6
2017/18	10.6	5.0	4.0	16.9	20.3	56.8	15.9
2018/19	10.8	5.0	3.8	17.7	20.7	58.1	16.0
2019/20	11.0	5.0	3.7	18.5	21.0	59.3	16.1
2020/21	11.2	5.0	3.5	19.3	21.3	60.4	16.2
2021/22	11.2	5.0	3.4	19.3	21.3	60.3	16.0
2022/23	11.2	5.0	3.3	19.3	21.3	60.2	15.8
2023/24	11.2	5.0	3.1	19.3	21.3	60.0	15.6
2024/25	11.2	5.0	3.0	19.3	21.3	59.9	15.4
2025/26	11.2	5.0	2.8	19.3	21.3	59.7	15.1
2026/27	11.2	5.0	2.7	19.3	21.3	59.6	14.9
2027/28	11.2	5.0	2.6	19.3	21.3	59.5	14.7

Source: Oxera.

Figure A3.28 Scenario 6: Central, headroom 2009 – 6%, costs + 10%, no planning results



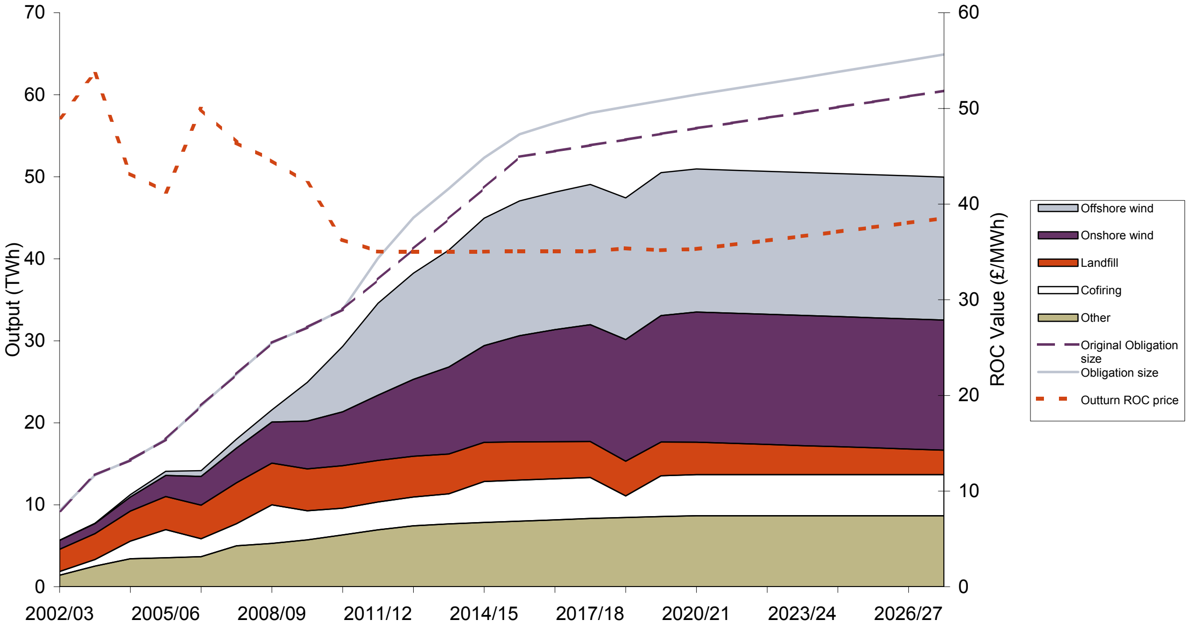
Source: Oxera.

Table A3.38 Scenario 6: Central, headroom 2009 – 6%, costs + 10%, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	4.9	2.7	4.3	4.2	1.1	17.1	5.1
2008/09	5.1	4.7	4.5	5.0	1.5	20.7	6.2
2009/10	5.7	0.7	4.5	5.6	4.7	21.3	6.4
2010/11	6.2	0.7	4.5	6.3	7.1	24.9	7.5
2011/12	6.7	0.7	4.4	7.7	8.7	28.2	8.4
2012/13	7.0	0.8	4.3	9.0	11.8	32.8	9.7
2013/14	7.1	0.9	4.2	10.1	12.9	35.2	10.3
2014/15	7.2	0.9	4.1	10.8	13.7	36.8	10.7
2015/16	7.3	3.0	4.0	11.5	14.5	40.3	11.6
2016/17	7.4	3.4	3.9	12.0	14.7	41.4	11.8
2017/18	7.5	3.6	3.7	12.6	14.8	42.2	11.9
2018/19	7.6	0.0	3.6	12.8	14.8	38.9	10.8
2019/20	7.7	0.0	3.4	13.1	14.8	39.1	10.7
2020/21	7.8	0.5	3.3	13.3	14.8	39.8	10.7
2021/22	7.8	1.5	3.2	13.3	14.8	40.6	10.9
2022/23	7.8	1.5	3.0	13.3	14.8	40.5	10.7
2023/24	7.8	1.5	2.9	13.3	14.8	40.3	10.5
2024/25	7.8	3.5	2.7	13.3	14.8	42.2	10.9
2025/26	7.8	3.5	2.6	13.3	14.8	42.0	10.7
2026/27	7.8	3.5	2.5	13.3	14.8	41.9	10.6
2027/28	7.8	3.5	2.3	13.3	14.8	41.8	10.4

Source: Oxera.

Figure A3.29 Scenario 6: Central, headroom 2009 – 6%, inc planning results



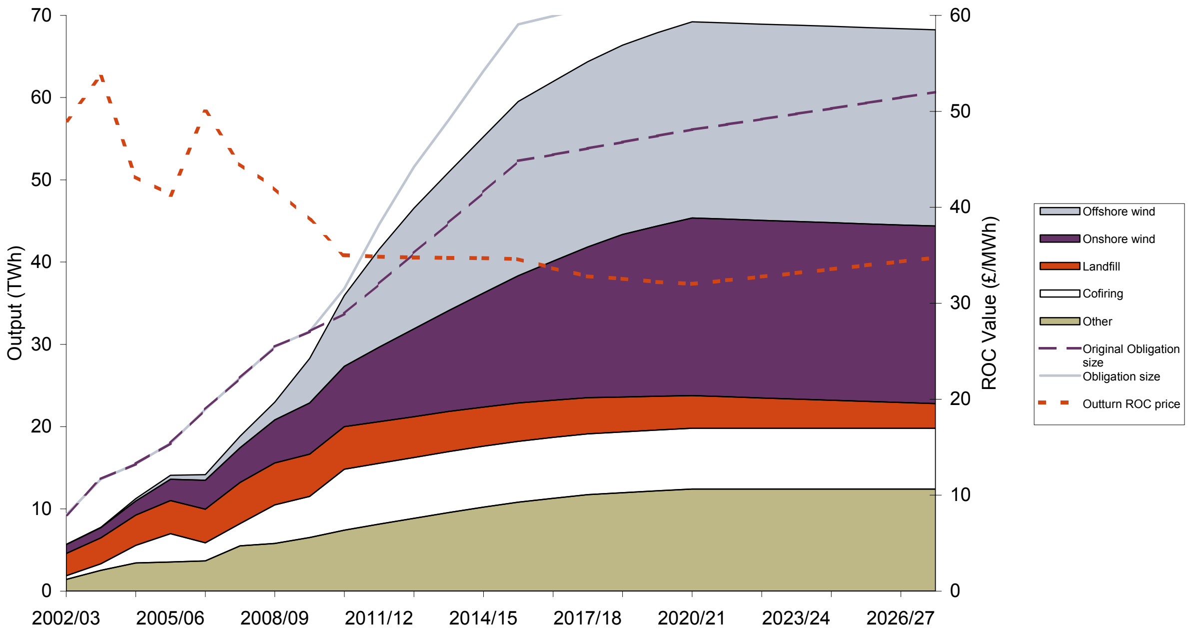
Source: Oxera

Table A3.39 Scenario 6: Central, headroom 2009 – 6%, inc planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.0	2.7	5.0	4.2	1.1	18.0	5.4
2008/09	5.3	4.7	5.1	5.0	1.5	21.6	6.5
2009/10	5.7	3.5	5.1	5.8	4.7	24.9	7.5
2010/11	6.3	3.3	5.2	6.6	8.0	29.3	8.8
2011/12	6.9	3.4	5.1	8.0	11.2	34.6	10.3
2012/13	7.4	3.5	5.0	9.4	12.9	38.2	11.3
2013/14	7.7	3.6	4.9	10.6	14.3	41.1	12.0
2014/15	7.8	5.0	4.8	11.8	15.6	45.0	13.1
2015/16	8.0	5.0	4.7	13.0	16.4	47.1	13.5
2016/17	8.2	5.0	4.5	13.7	16.8	48.1	13.7
2017/18	8.3	5.0	4.4	14.2	17.1	49.1	13.7
2018/19	8.4	2.6	4.2	14.8	17.3	47.4	13.1
2019/20	8.6	5.0	4.1	15.4	17.4	50.5	13.8
2020/21	8.7	5.0	4.0	15.9	17.4	50.9	13.7
2021/22	8.7	5.0	3.8	15.9	17.4	50.8	13.5
2022/23	8.7	5.0	3.7	15.9	17.4	50.7	13.3
2023/24	8.7	5.0	3.5	15.9	17.4	50.5	13.2
2024/25	8.7	5.0	3.4	15.9	17.4	50.4	13.0
2025/26	8.7	5.0	3.3	15.9	17.4	50.2	12.8
2026/27	8.7	5.0	3.1	15.9	17.4	50.1	12.6
2027/28	8.7	5.0	3.0	15.9	17.4	50.0	12.4

Source: Oxera.

Figure A3.30 Scenario 6: High, headroom 2009 – 6%, cost – 10%, inc planning results



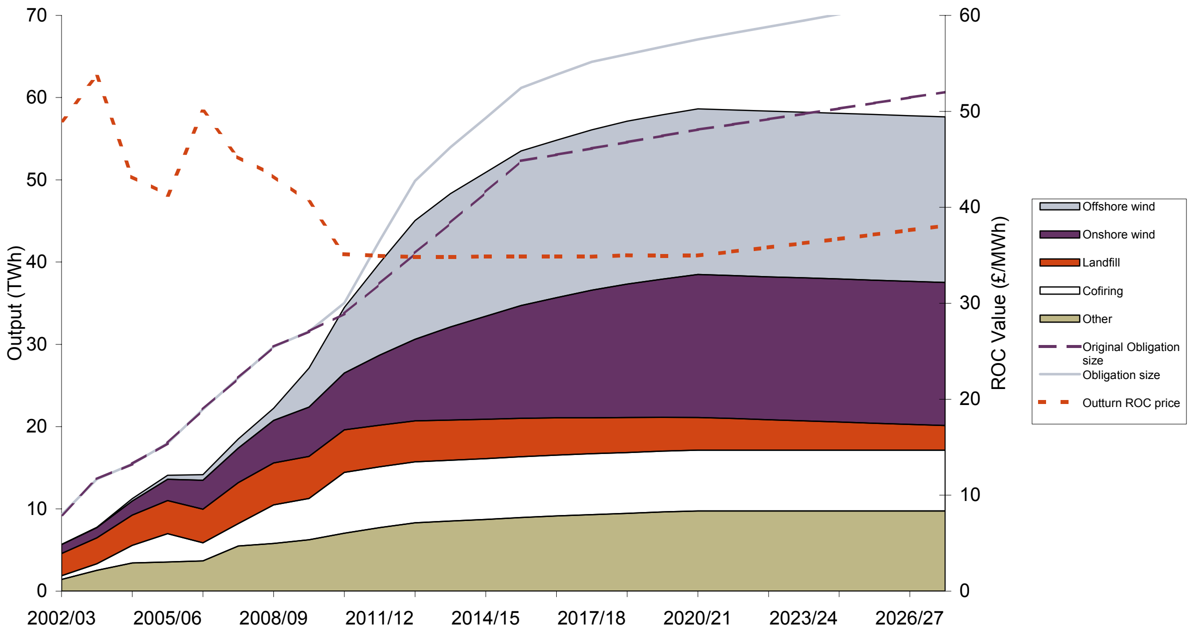
Source: Oxera.

Table A3.40 Scenario 6: High, headroom 2009 – 6%, cost – 10%, inc planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.5	2.7	5.0	4.2	1.4	18.8	5.6
2008/09	5.8	4.7	5.1	5.2	2.2	23.0	6.9
2009/10	6.5	5.0	5.1	6.2	5.4	28.3	8.5
2010/11	7.4	7.4	5.2	7.3	8.6	36.0	10.9
2011/12	8.1	7.4	5.1	9.1	11.9	41.6	12.5
2012/13	8.8	7.4	5.0	10.7	14.7	46.5	13.8
2013/14	9.6	7.4	4.9	12.3	16.8	50.9	15.0
2014/15	10.2	7.4	4.8	13.9	19.0	55.3	16.1
2015/16	10.8	7.4	4.7	15.5	21.2	59.5	17.2
2016/17	11.3	7.4	4.5	16.9	21.9	62.0	17.6
2017/18	11.7	7.4	4.4	18.3	22.5	64.4	18.0
2018/19	12.0	7.4	4.2	19.7	23.0	66.4	18.3
2019/20	12.2	7.4	4.1	20.7	23.5	67.9	18.4%
2020/21	12.4	7.4	4.0	21.6	23.9	69.2	18.5%
2021/22	12.4	7.4	3.8	21.6	23.9	69.1	18.3%
2022/23	12.4	7.4	3.7	21.6	23.9	68.9	18.0%
2023/24	12.4	7.4	3.5	21.6	23.9	68.8	17.8%
2024/25	12.4	7.4	3.4	21.6	23.9	68.7	17.6%
2025/26	12.4	7.4	3.3	21.6	23.9	68.5	17.3%
2026/27	12.4	7.4	3.1	21.6	23.9	68.4	17.1%
2027/28	12.4	7.4	3.0	21.6	23.9	68.2	16.9%

Source: Oxera.

Figure A3.31 Scenario 6: High, headroom 2009 – 6%, inc planning results



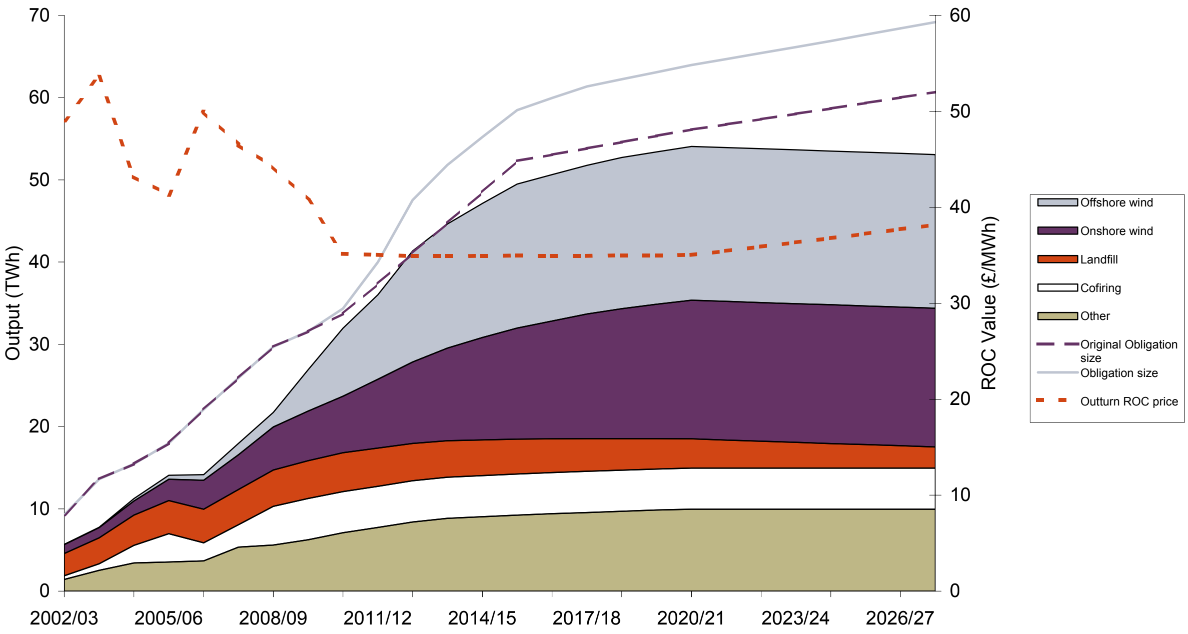
Source: Oxera.

Table A3.41 Scenario 6: High, headroom 2009 – 6%, inc planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.5	2.7	5.0	4.2	1.1	18.5	5.5
2008/09	5.8	4.7	5.1	5.2	1.5	22.2	6.7
2009/10	6.3	5.0	5.1	6.0	4.7	27.1	8.2
2010/11	7.0	7.4	5.2	6.9	8.0	34.5	10.5
2011/12	7.7	7.4	5.1	8.5	11.2	39.9	12.0
2012/13	8.3	7.4	5.0	9.9	14.4	45.0	13.4
2013/14	8.5	7.4	4.9	11.3	16.2	48.3	14.2
2014/15	8.7	7.4	4.8	12.5	17.5	50.9	14.8
2015/16	8.9	7.4	4.7	13.7	18.8	53.5	15.4
2016/17	9.1	7.4	4.5	14.6	19.1	54.8	15.6
2017/18	9.3	7.4	4.4	15.5	19.5	56.1	15.7
2018/19	9.5	7.4	4.2	16.2	19.8	57.1	15.7
2019/20	9.6	7.4	4.1	16.8	20.0	57.9	15.7
2020/21	9.7	7.4	4.0	17.4	20.1	58.6	15.7
2021/22	9.7	7.4	3.8	17.4	20.1	58.5	15.5
2022/23	9.7	7.4	3.7	17.4	20.1	58.4	15.3
2023/24	9.7	7.4	3.5	17.4	20.1	58.2	15.1
2024/25	9.7	7.4	3.4	17.4	20.1	58.1	14.9
2025/26	9.7	7.4	3.3	17.4	20.1	57.9	14.7
2026/27	9.7	7.4	3.1	17.4	20.1	57.8	14.5
2027/28	9.7	7.4	3.0	17.4	20.1	57.7	14.3

Source: Oxera.

Figure A3.32 Scenario 6: High, headroom 2009 – 6%, no planning results



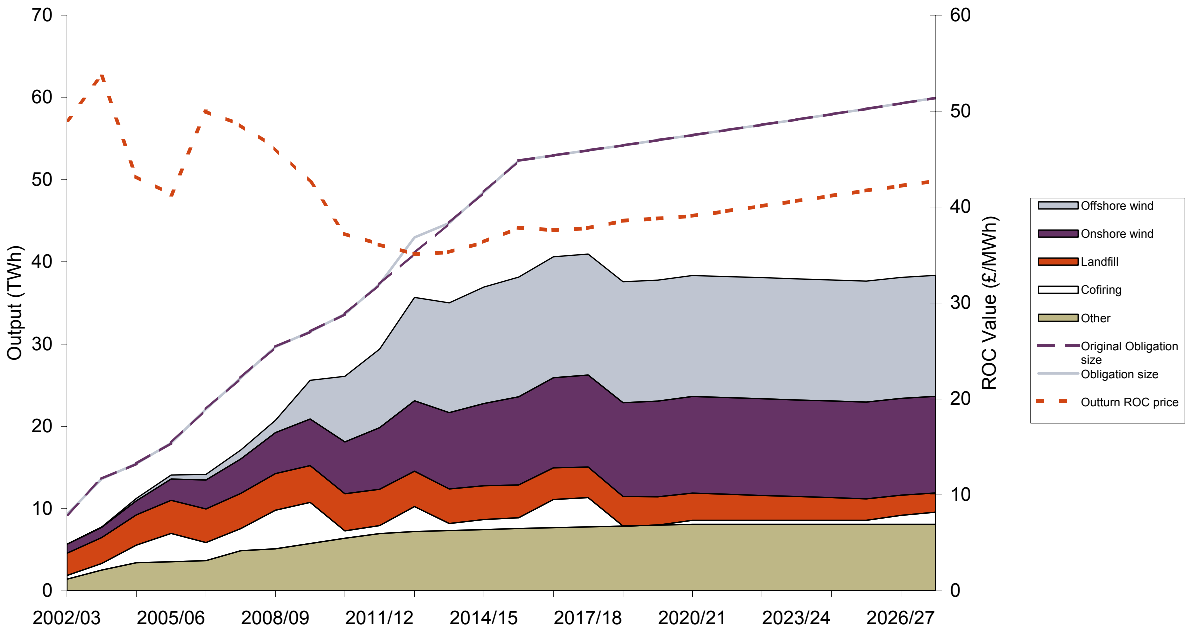
Source: Oxera.

Table A3.42 Scenario 6: High, headroom 2009 – 6%, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	5.4	2.7	4.3	4.2	1.4	18.0	5.4
2008/09	5.6	4.7	4.5	5.2	1.8	21.7	6.5
2009/10	6.3	5.0	4.6	6.0	5.0	26.9	8.1
2010/11	7.1	5.0	4.7	6.9	8.3	32.0	9.7
2011/12	7.7	5.0	4.6	8.4	10.3	36.0	10.8
2012/13	8.4	5.0	4.5	9.9	13.5	41.4	12.3
2013/14	8.8	5.0	4.4	11.3	15.1	44.6	13.1
2014/15	9.0	5.0	4.3	12.4	16.3	47.1	13.7
2015/16	9.2	5.0	4.2	13.5	17.5	49.5	14.3
2016/17	9.4	5.0	4.1	14.3	17.8	50.6	14.4
2017/18	9.6	5.0	4.0	15.1	18.1	51.8	14.5
2018/19	9.7	5.0	3.8	15.8	18.4	52.7	14.5
2019/20	9.9	5.0	3.7	16.3	18.5	53.4	14.5
2020/21	10.0	5.0	3.5	16.9	18.7	54.1	14.5
2021/22	10.0	5.0	3.4	16.9	18.7	53.9	14.3
2022/23	10.0	5.0	3.3	16.9	18.7	53.8	14.1
2023/24	10.0	5.0	3.1	16.9	18.7	53.6	13.9
2024/25	10.0	5.0	3.0	16.9	18.7	53.5	13.7
2025/26	10.0	5.0	2.8	16.9	18.7	53.4	13.5
2026/27	10.0	5.0	2.7	16.9	18.7	53.2	13.3
2027/28	10.0	5.0	2.6	16.9	18.7	53.1	13.1

Source: Oxera.

Figure A3.33 Scenario 6: Low, headroom 2009 – 6%, no planning results



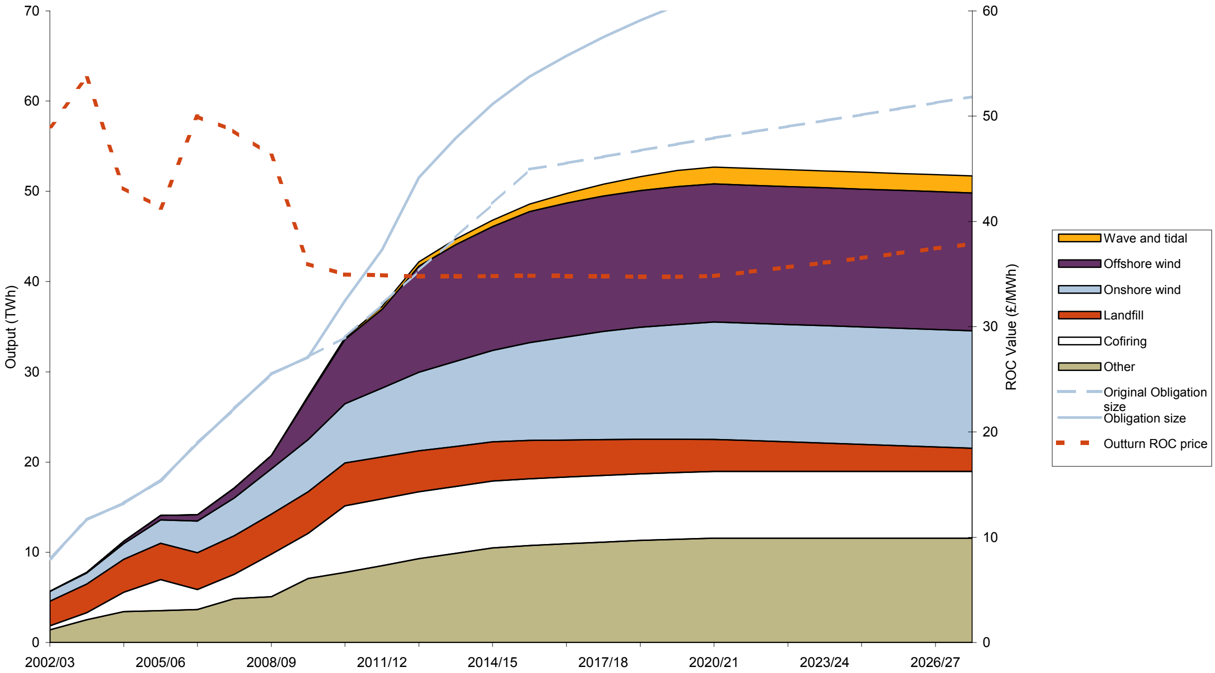
Source: Oxera.

Table A3.43 Scenario 6: Low, headroom 2009 – 6%, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Total renewable generation	As a % of total sales
2007/08	4.9	2.7	4.3	4.2	1.1	17.1	5.1
2008/09	5.1	4.7	4.5	5.0	1.5	20.7	6.3
2009/10	5.8	5.0	4.5	5.6	4.7	25.6	7.7
2010/11	6.4	0.9	4.5	6.3	8.0	26.1	7.9
2011/12	7.0	1.0	4.4	7.5	9.6	29.4	8.8
2012/13	7.2	3.0	4.3	8.5	12.6	35.7	10.6
2013/14	7.3	0.9	4.2	9.3	13.4	35.0	10.3
2014/15	7.5	1.2	4.1	10.0	14.2	36.9	10.8
2015/16	7.6	1.3	4.0	10.7	14.6	38.1	11.0
2016/17	7.7	3.4	3.9	10.9	14.7	40.6	11.6
2017/18	7.8	3.6	3.7	11.2	14.7	40.9	11.6
2018/19	7.9	0.0	3.6	11.4	14.7	37.6	10.5
2019/20	8.0	0.0	3.4	11.6	14.7	37.8	10.4
2020/21	8.1	0.5	3.3	11.8	14.7	38.4	10.5
2021/22	8.1	0.5	3.2	11.8	14.7	38.2	10.3
2022/23	8.1	0.5	3.0	11.8	14.7	38.1	10.1
2023/24	8.1	0.5	2.9	11.8	14.7	37.9	10.0
2024/25	8.1	0.5	2.7	11.8	14.7	37.8	9.8
2025/26	8.1	0.5	2.6	11.8	14.7	37.7	9.7
2026/27	8.1	1.1	2.5	11.8	14.7	38.1	9.7
2027/28	8.1	1.5	2.3	11.8	14.7	38.4	9.7

Source: Oxera.

Figure A3.34 Scenario 1: Central, RPI in, headroom 2009 – 6%, no planning results



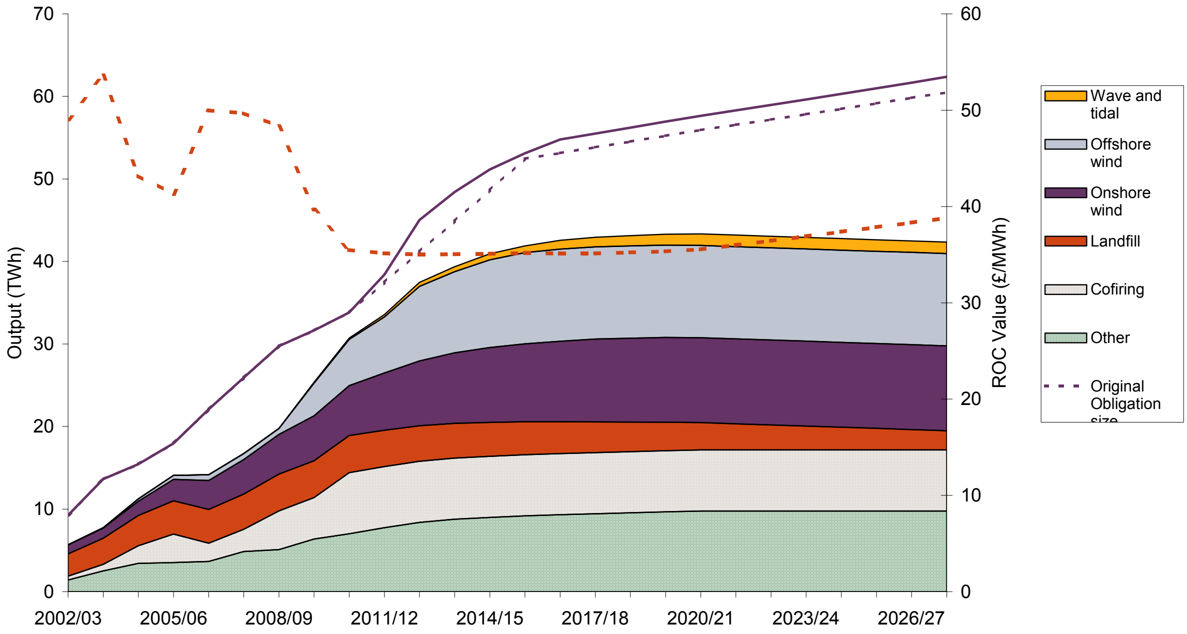
Source: Oxera.

Table A3.44 Scenario 1: Central, RPI in, headroom 2009 – 6%, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Wave and tidal	Total renewable generation	As % of total sales
2007/08	4.9	2.7	4.3	4.2	1.1	0.0	17.1	5.1
2008/09	5.1	4.7	4.5	5.0	1.5	0.0	20.7	6.2
2009/10	7.1	5.0	4.6	5.8	4.7	0.1	27.3	8.2
2010/11	7.8	7.4	4.7	6.6	7.1	0.2	33.8	10.2
2011/12	8.5	7.4	4.6	7.6	8.7	0.3	37.2	11.1
2012/13	9.3	7.4	4.5	8.7	11.8	0.5	42.2	12.4
2013/14	9.9	7.4	4.4	9.4	12.9	0.6	44.7	13.0
2014/15	10.5	7.4	4.3	10.1	13.7	0.7	46.8	13.5
2015/16	10.7	7.4	4.2	10.8	14.5	0.8	48.6	13.8
2016/17	10.9	7.4	4.1	11.4	14.8	1.1	49.8	13.9
2017/18	11.1	7.4	4.0	12.0	15.0	1.3	50.8	14.0
2018/19	11.3	7.4	3.8	12.4	15.1	1.6	51.6	13.9
2019/20	11.4	7.4	3.7	12.7	15.3	1.8	52.3	13.9
2020/21	11.6	7.4	3.5	13.0	15.3	1.9	52.7	13.8
2021/22	11.6	7.4	3.4	13.0	15.3	1.9	52.5	13.6
2022/23	11.6	7.4	3.3	13.0	15.3	1.9	52.4	13.4
2023/24	11.6	7.4	3.1	13.0	15.3	1.9	52.3	13.2
2024/25	11.6	7.4	3.0	13.0	15.3	1.9	52.1	13.0
2025/26	11.6	7.4	2.8	13.0	15.3	1.9	52.0	12.9
2026/27	11.6	7.4	2.7	13.0	15.3	1.9	51.8	12.7
2027/28	11.6	7.4	2.6	13.0	15.3	1.9	51.7	12.5

Source: Oxera.

Figure A3.35 Scenario 1: Central, RPI in, Headroom 2009 – 6%, costs + 10%, no planning results



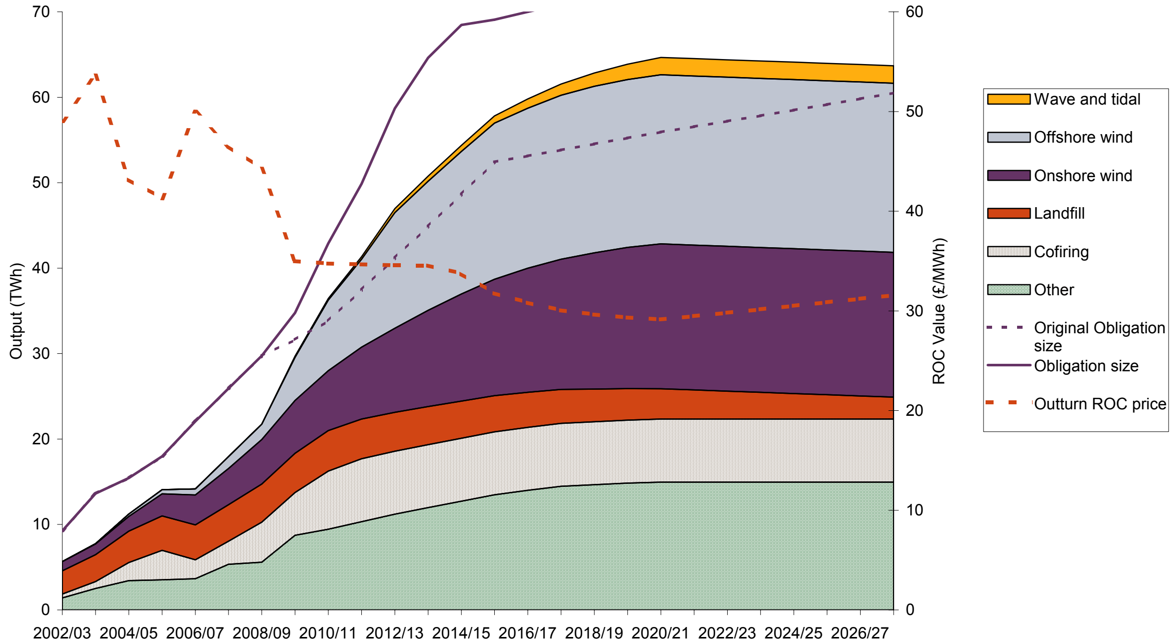
Source: Oxera.

Table A3.45 Scenario 1: Central, RPI in, headroom 2009 – 6%, costs + 10%, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Wave and tidal	Total renewable generation	As % of total sales
2007/08	2.7	4.3	4.2	0.7	0.0	0.0	11.9	5.0
2008/09	4.7	4.5	4.8	0.7	0.0	0.0	14.7	5.9
2009/10	2.0	4.5	5.5	5.6	0.6	0.0	18.0	7.6
2010/11	2.9	4.5	6.1	8.1	0.7	0.0	22.2	9.3
2011/12	3.0	4.4	6.9	9.9	1.2	0.0	25.3	10.0
2012/13	3.0	4.3	7.8	13.3	2.0	0.0	30.3	11.0
2013/14	3.0	4.2	8.4	14.5	2.5	0.0	32.5	11.4
2014/15	3.0	4.1	8.9	15.7	3.0	0.0	34.5	11.7
2015/16	3.0	4.0	9.2	16.3	3.5	0.0	35.9	11.9
2016/17	3.0	3.8	9.5	16.5	4.5	0.0	37.2	11.9
2017/18	3.0	3.7	9.7	16.5	4.8	0.0	37.7	11.8
2018/19	3.0	3.5	9.8	16.5	5.1	0.0	38.0	11.7
2019/20	3.0	3.4	9.9	16.5	5.5	0.0	38.3	11.5
2020/21	3.0	3.3	9.9	16.5	5.8	0.0	38.5	11.4
2021/22	3.0	3.1	9.9	16.5	5.8	0.0	38.3	11.2
2022/23	3.0	3.0	9.9	16.5	5.8	0.0	38.2	11.1
2023/24	3.0	2.8	9.9	16.5	5.8	0.0	38.1	10.9
2024/25	3.0	2.7	9.9	16.5	5.8	0.0	37.9	10.7
2025/26	3.0	2.6	9.9	16.5	5.8	0.0	37.8	10.6
2026/27	3.0	2.4	9.9	16.5	5.8	0.0	37.6	10.4
2027/28	3.0	2.3	9.9	16.5	5.8	0.0	37.5	10.3

Source: Oxera.

Figure A3.36 Scenario 1: Central, RPI in, headroom 2009 – 6%, costs – 10%, no planning results



Source: Oxera.

Table A3.46 Scenario 1: Central, RPI in, headroom 2009 – 6%, costs – 10%, no planning results

	Other	Co-firing	Landfill	Onshore wind	Offshore wind	Wave and tidal	Total renewable generation	As % of total sales
2007/08	2.7	4.3	4.2	1.4	0.0	0.0	12.6	5.4
2008/09	4.7	4.5	5.2	1.8	0.0	0.0	16.2	6.5
2009/10	2.0	4.5	6.2	6.7	0.6	0.0	19.9	8.9
2010/11	2.7	4.5	7.1	11.6	0.7	0.0	26.5	11.0
2011/12	2.9	4.4	8.3	14.6	1.2	0.0	31.5	12.3
2012/13	2.9	4.3	9.6	19.5	2.0	0.0	38.4	13.8
2013/14	2.9	4.2	10.9	21.9	2.5	0.0	42.5	14.8
2014/15	2.9	4.1	12.1	24.3	3.0	0.0	46.4	15.7
2015/16	2.9	4.0	13.1	26.7	3.5	0.0	50.2	16.5
2016/17	2.9	3.9	13.9	27.4	4.5	0.0	52.6	16.8
2017/18	2.9	3.7	14.6	28.1	5.5	0.0	54.8	17.0
2018/19	2.9	3.6	15.2	28.5	6.5	0.0	56.8	17.1
2019/20	2.9	3.5	15.8	28.7	7.5	0.0	58.4	17.1
2020/21	2.9	3.3	16.1	29.0	8.5	0.0	59.9	17.0
2021/22	2.9	3.2	16.1	29.0	8.5	0.0	59.7	16.8
2022/23	2.9	3.0	16.1	29.0	8.5	0.0	59.6	16.5
2023/24	2.9	2.9	16.1	29.0	8.5	0.0	59.4	16.3
2024/25	2.9	2.8	16.1	29.0	8.5	0.0	59.3	16.1
2025/26	2.9	2.6	16.1	29.0	8.5	0.0	59.2	15.9
2026/27	2.9	2.5	16.1	29.0	8.5	0.0	59.0	15.7
2027/28	2.9	2.3	16.1	29.0	8.5	0.0	58.9	15.5

Source: Oxera.

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