Oxera

Economic analysis of the design, cost and performance of the UK Renewables Obligation and capital grants scheme

Report prepared for the National Audit Office

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Executive Summary

Oxera has analysed a range of questions surrounding renewables policy in order to highlight the main issues behind the policy and the nature of the analysis that can be used to support policy development.

Headline results from this report include the following.

– Cheaper technologies are able to earn substantial infra-marginal rents under the Renewables Obligation (RO). For example, a hypothetical landfill project commissioned in 2003/04 is estimated to earn a return of over 20%.

– The removal of landfill gas from the RO would have a negligible impact on the overall growth of renewables, while at the same time lowering support by about £2 billion over the life of the RO (£125m pa).

– Oxera estimates that 21% of the emissions avoided by replacing coal with biomass in co-fired coal plant is eroded by increases in the output of those plant.

– Suppliers responding to an Oxera survey for this study highlighted the shortfall in buy-out funding resulting from supplier failures as a factor that has an adverse impact on confidence in the Renewables Obligation Certificate (ROC) market.

– Transaction costs associated with the RO were estimated to be less than 1% of the income received by the renewables sector under the RO. This shows the RO to be administratively efficient.

– The announcement of a 15.4% target for 2015/16 is projected to increase compliance with the supplier obligation in 2010/11 from 79% to 95%, under Oxera's Central scenario assumptions. Implicit in these assumptions are favourable planning and investment conditions.

– The total support to renewables (ie, the subsidy) over the RO period is £15 billion–£24 billion (£930m–£1,510m pa),[1] with a central estimate of £21 billion (£1,290m pa). Of this, around £10 billion (£600m pa) is transfer payment, sometimes described as deadweight.

– Increasing capital grants for marginal technologies alongside a reduction in the buy-out price would yield net consumer benefits, for any given environmental outcome. Oxera estimates that, for every £1m increase in capital grants, consumer costs under the RO might fall by £2m. This conclusion is weakened if capital grants are poorly targeted.

– Removing plant with Non-Fossil Fuel Obligation (NFFO) contracts from the RO would reduce overall support by around £620m or around £3.20 per tonne of CO_2 saved. This is because it is more expensive to fund Non-Fossil Purchasing Agency (NFPA) liabilities through the RO than through the Fossil Fuel Levy (FFL). Removing all ex-NFFO contract plant from the RO would reduce the support further.

[1] The per-annum costs quoted in brackets are annuities equivalent in value to the present-value sums, calculated over a 24-year period (2003/04 to 2026/27) at a 3.5% interest rate.

– The results are sensitive to the assumptions made. Significant reductions in support costs are shown if higher electricity prices and lower unit costs are assumed.

– The analysis suggests that, given expectations of wholesale electricity prices at that time, the chosen RO buy-out price of 3p/kWh was set at broadly the right level, given the level of capital grants available.

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1 Introduction

1.1 Structure of the report

This report uses Oxera's renewables model and the results of an industry survey undertaken by Oxera to address a range of questions about renewables policy. As such, it highlights key policy issues and illustrates the type of analysis that can be used to support the policy development process.

Sections 2 to 8 set out Oxera's analysis of the following policy questions.

– What approaches can be used to calculate the cost of the renewables programme?
– What are the estimated costs of the renewables programme?
– Who bears the costs of the renewables programme?
– Was the buy-out price set at the optimal level?
– To what extent do cheaper technologies earn infra-marginal rents?
– Were the right technologies included in the Renewables Obligation (RO)?
– Did the fact that the profile of the RO target was inconsistent with the development of the planning regime have a significant effect?
– Does support for co-firing lead to perverse environmental outcomes?
– What is the impact of co-firing on incentives for other renewables?
– How liquid is the Renewables Obligation Certificate (ROC) market over different time horizons?
– How large are the transaction costs arising from the RO?
– What is the effect of charging renewables developers for network costs?
– How does certainty over long-term targets affect policy outcomes in the early years of the RO?
– What is the impact of capital grants?
– How do capital grants and the level of the buy-out price interact?
– How does the RO interact with the EU ETS and the CCL?
– Would the exclusion of Non-Fossil-Fuel Obligation (NFFO) plant have improved RO outcomes?

The appendices describe Oxera's renewables model, the Low, Central and High scenario modelling assumptions and the survey methodology.

1.2 Introduction to Oxera's renewables model

The following sections present results from the Oxera renewables model. This model has been developed by Oxera to answer a range of questions relating to the development of the renewables industry. It has previously been used by the DTI to provide the quantitative backbone to the 2003 Renewables Innovation Review. As with all models of this kind, the results are dependent on the underlying assumptions—in this case especially the expected rate of technical progress in the renewables industry, implying reduced unit costs, and the cost of electricity generated by more conventional means. The assumptions used in this report were those in use in Oxera in mid-2004.

The following conventions governing the representation of these results are used throughout the report.

– Investment is modelled over the period to 2026/27.

– Financial figures are quoted as lump-sum present values. Selected figures are also given as their equivalent annuity payments (constant annual flows over the same period).

– One measure of cost-effectiveness is in terms of 'cost per tonne of CO_2 avoided'. These figures can be compared with cost-effectiveness estimates presented in the Annexes to the DTI Energy White Paper.[2] Note that any policy that has two objectives (as the renewables programme does)—namely avoiding CO_2 emissions today and inducing innovation that will make it easier to avoid CO_2 emissions tomorrow—could perform badly on a measure of the present cost per tonne of carbon.

– The results are reported on the basis of a central case; however, given the inherent uncertainties, it is also important to consider the sensitivity of the results to changes in the key assumptions. Sensitivities are reported for the main calculations.

– The analysis proceeds by way of a series of questions, with answers derived through the change of one assumption, with all others being held constant. For example, the assumptions about the effectiveness of capital grants (see section 8.1) might not hold if the assumption about the coverage of the RO were changed at the same time.

– All the main results in this report include the impact of the government's announcement in December 2003 of a rise in the renewables target to 15.4% by 2015/16.

The analysis is built around a number of analytical concepts, enabling judgements to be made about the success of different approaches. These concepts are defined in the following box, which can be referred to as the various measures are introduced.

Box 1.1 Definitions

Internal rate of return (IRR): a measure of the profitability of an investment. It is defined as the rate of interest which, when used to discount the cash flows of an investment, reduces the net present value (NPV) of the investment to zero.

'Support': the total cost, to either the Exchequer or the consumer, of purchasing renewables rather than buying electricity at a price which reflects no government intervention. In the main analysis, this includes:

– capital grants;
– income from ROCs;
– network cross-subsidies;
– the benefit of Levy Exemption Certificates (LECs);
– the effect of the EU Emissions Trading Scheme (EU ETS) on electricity prices.

Resource cost premium: the total cost of renewable generation (including the cost of intermittency and network reinforcements), minus the wholesale price of electricity. It is a measure of the net costs to the economy of choosing renewable generation.

Transfer payment: this is a measure of the extent to which support has been provided unnecessarily—ie, it is defined as the total revenue to renewables generation, minus the total costs of generation.

[2] See DTI (2003), 'Our Energy Future—Creating a Low Carbon Economy', Annex 1: Long Term Low Carbon Options, February.

1.3 What approaches can be used to calculate the cost of the renewables programme?

Table 1.1 summarises measures for calculating the cost of renewables.

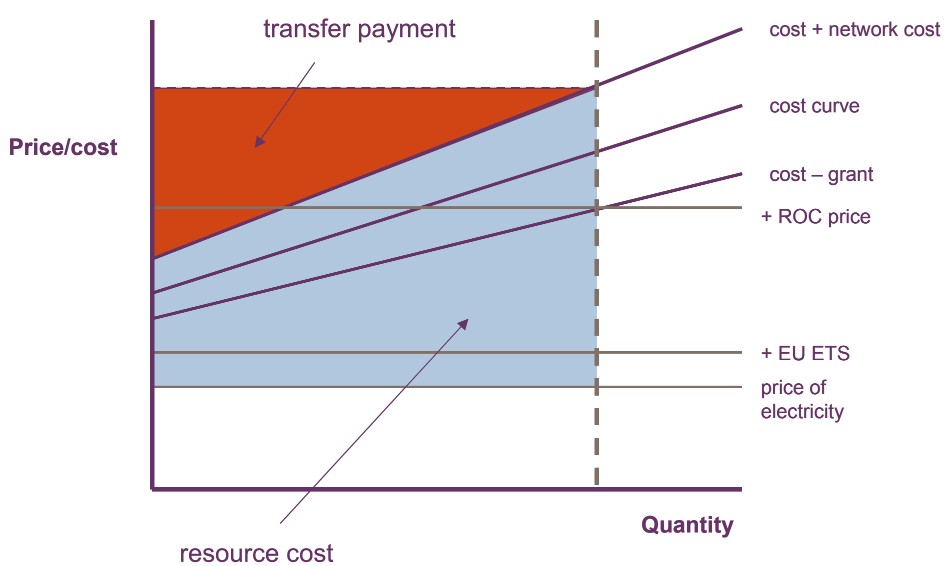
Table 1.1 Policy measures of the cost of renewables

Measure	Calculation	Usefulness
Total 'support'	£m = capital grants (£/MW * MW entry) + ROC price * eligible volume + cross-subsidised cost of network reinforcements	This shows the total public cost of the policy
Transfer payment	£m = total revenue to renewables generation – total costs of generation £/MWh = £m/MWh generated	This shows the efficiency of support
Cost to customers as percentage of bill	% of bill = (ROC price * eligible volume)/(price to customers * total supply)	This shows the impact on household, and industrial and commercial bills, which can be compared with the impact of other policies, and indicates the impact on the level of competitiveness of some sensitive sectors
Resource cost premium	£m = total costs of renewable generation (including the cost of intermittence and network reinforcements) – (wholesale price * renewable eligible volume) resource cost premium/tonne CO_2 = resource cost premium/emissions avoided	This is a measure of cost-effectiveness which can be compared with other costs of saving carbon and so shows whether the policy is worth pursuing. Also, when broken down by technology, it highlights which technologies are worth supporting
Total resource cost premium over time	Resource cost premium* discount factor, using social time preference rate	

Source: Oxera.

These measures are shown schematically in Figure 1.1. The total support cost is the sum of the transfer payment and the resource cost.

Figure 1.1 Schematic representation of policy measures of the cost of renewables



Source: Oxera.

1.4 What are the estimated costs of the renewables programme?

Renewable electricity generators have higher costs than conventional generators. Onshore wind, for example, has high capital costs because the turbines, towers and electrical infrastructure are expensive. It has very low operating costs, which helps to compensate for the cost of the initial investment. On the other side of the equation, the revenues available to renewables generators comprise the sale of power (adjusted for the impact of the EU ETS on wholesale electricity prices), the sale of ROCs and LECs, and any capital or operating grant entitlements. They also benefit from the deep reinforcement or extension of network infrastructure by the network operators to accommodate the generation capacity of the renewables generators (they are required to pay for shallow reinforcement). Some parts of the subsidy would be paid by individual parties. Taxpayers pay capital grants and arguably also pay for LECs, since Climate Change Levy (CCL) revenue is forgone, and taxpayers have to meet the Exchequer's needs through other taxes instead. The network subsidy and the EU ETS subsidy are paid by electricity consumers.

Table 1.2 shows selected cost measures for the renewables programme as a whole over the period 2003/04 to 2026/27, under the Low, Central and High scenarios. These scenarios are defined in Tables A2.4 and A2.10 in Appendix 2. They vary in the assumed wholesale electricity price and unit costs of new build. 'Low' refers to the lowest likely electricity price and highest unit costs, 'Central' to the best estimate of the electricity price and central unit costs, and 'High' to a highest likely electricity price and lowest unit costs.

The total discounted support provided under the programme over the whole of this period is estimated to be £15 billion–£24 billion (£930m–£1,510m pa),[3] of which 40–80% comes from the RO. This gives a support cost of £50–£140/tonne CO_2 avoided (which is high in relation to current valuations of carbon in the EU ETS of well under £10/tonne CO_2 avoided). Resource costs are estimated to be £5 billion–£12 billion, implying a transfer payment of £10 billion–£13 billion (£9.6 billion in the Central scenario) (£600m–£780m pa). In the Central scenario transfer payments represent almost half of the total support provided to the renewables sector. In summary, in the Central case, the support paid to the renewables sector over the life of the RO, from all the various sources of financial support, totals around £21 billion (£1,290m pa). If it were perfectly targeted, the same renewable generation might have been purchased for around £10 billion (£600m pa) less support.

Some, and possibly all, of the transfer payment might be returned to consumers through the process of competition between suppliers. The transfer payment is a payment from suppliers to generators, and appears as generators' supernormal profits. If suppliers are vertically integrated with generators, and the supply market is competitive, those supernormal profits earned in the generation activity may be transferred back to the supply business and competed away. Therefore, throughout this report, the estimates of these transfer payment figures represent the upper limit of what consumers will actually pay. If competition between suppliers and between generators is 100% effective, consumers will pay none of the transfer payment; if there is no competition, they will pay all of it.

[3] The per-annum costs quoted in brackets are annuities equivalent in value to the present-value sums, calculated over a 24-year period (2003/04 to 2026/27) at a 3.5% interest rate.

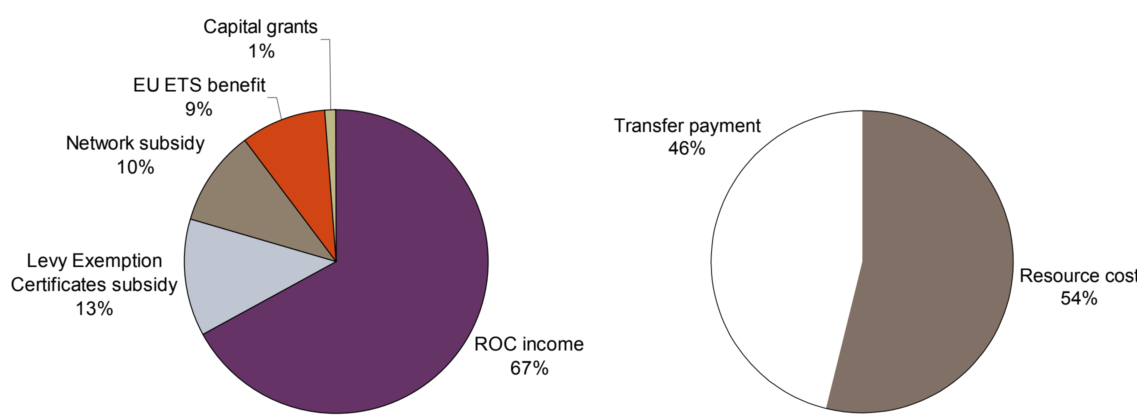
Table 1.2 Cost measures—Low, Central and High scenarios

Indicator	High	Central	Low
EU ETS benefit (£m)	3,293	1,919	1,361
Capital grants (£m)	163	220	48*
ROC income (£m)	5,929	13,918	18,792
Network subsidy (£m)	2,141	2,141	2,141
LEC subsidy (£m)	3,410	2,600	1,965
Total support (£m)	14,936	20,798	24,307
Resource cost (£m)	5,209	11,193	11,775
Transfer payment (£m)	9,726	9,606	12,532
CO_2 avoided (mt, discounted)	293	226	173
Value of CO_2 abated at £20/tCO_2 (£m)	5,858	4,519	3,469
Support/tonne CO_2 avoided (£)	51	92	141
Resource cost/tonne CO_2 avoided (£)	18	50	76

Note: * This low value of capital grants is due to a low volume of build.
Source: Oxera.

The sources of support for renewables are shown for the Central scenario in Figure 1.2.

Figure 1.2 The sources of support for renewables



Source: Oxera.

Table 1.3 gives the level of compliance with the RO in each year.

Table 1.3 Contribution to the RO target in each year (% of supply)

	Obligation	Low	Central	High
2003/04	4.3	2.4	2.4	2.4
2004/05	4.9	3.4	3.9	4.0
2005/06	5.5	3.7	4.7	4.7
2006/07	6.7	4.0	5.2	5.2
2007/08	7.9	4.4	6.0	6.5
2008/09	9.1	5.6	7.4	7.9
2009/10	9.7	7.0	8.8	9.4
2010/11	10.4	7.5	9.9	10.4
2011/12	11.4	8.7	11.4	11.8
2012/13	12.4	9.8	12.6	12.8
2013/14	13.4	10.2	13.6	13.9
2014/15	14.4	10.4	14.6	14.9
2015/16	15.4	10.6	14.8	15.9

Source: Oxera.

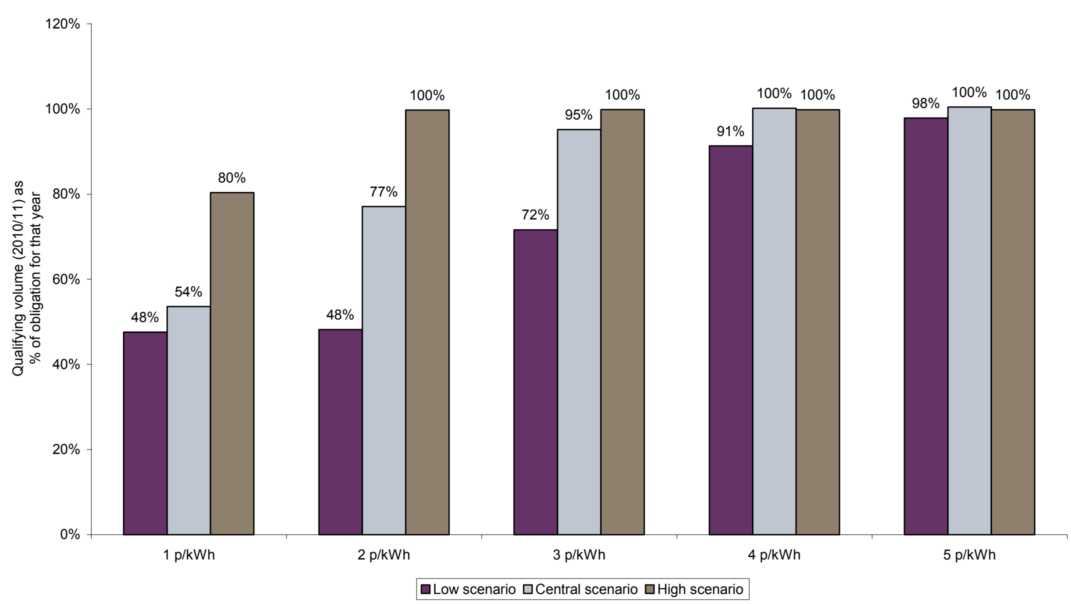
2 Over-incentivisation

2.1 Was the buy-out price set at the optimal level?

Oxera has examined what effect setting the buy-out price at different levels would have on the likelihood of meeting the 2010 renewables target and on the average cost per tonne of CO_2 avoided over the period up to 2026/27. The analysis assumes that the level of capital grant available for each technology in each year (in £/kW) is fixed. The interaction between the buy-out price and the level of capital grants is addressed separately in section 8.2.

Figure 2.1 shows that the higher the buy-out price, the greater the incentive for renewables build and hence the greater the likelihood of meeting the 2010 target. Under the Central scenario assumptions, a buy-out price of 3p/kWh leads to renewable output in 2010/11 equivalent to 95% of the obligation on suppliers. (This includes the impact of the government's announcement of a rise in the target to 15.4% by 2015/16; performance under the original parameters of the scheme is discussed in section 7.1.) The results are sensitive to assumptions such as maximum build rate and the pace of cost reductions, particularly with the newer and more expensive technologies, such as offshore wind and biomass, but less so for the more established technologies. The rate of offshore wind build is critical: the Central scenario predicts completion of 1.3 GW of capacity by 2006, and 5 GW by 2010. All these assumptions are consistent with the DTI's view of potential build rates and cost reductions, which are based on market evidence in the form of planning and licence applications, and on trends in unit costs, for both renewable and other technologies.

Figure 2.1 Impact of the buy-out price on performance against supplier obligation in 2010/11

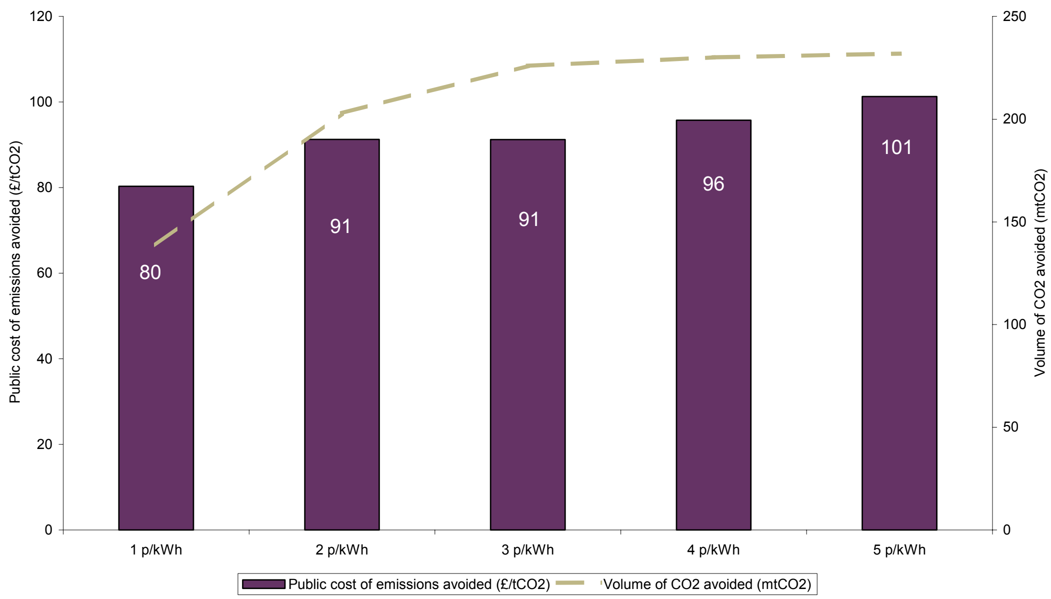


Source: Oxera.

One way of using Figure 2.1 is to make a judgement about the appropriate level of the buy-out price, given the government's renewables target. A buy-out price of 3p/kWh delivers 95% compliance or more in the Central and High scenarios. However, there is a degree of uncertainty surrounding these numbers—notably concerning the underlying assumptions about reductions in costs—and 2p/kWh would prove sufficient if lower costs were assumed.

Figure 2.1 shows that a higher buy-out price provides stronger incentives for renewables growth. Figure 2.2, below, shows that greater growth in renewables is accompanied by higher support costs per tonne of CO_2 avoided, although these stabilise above a buy-out of 2p/kWh.

Figure 2.2 Payments for emissions avoided (£/tCO_2) under the Central scenario



Note: The support figures here exclude capital grants.
Source: Oxera.

2.2 To what extent do cheaper technologies earn infra-marginal rents?

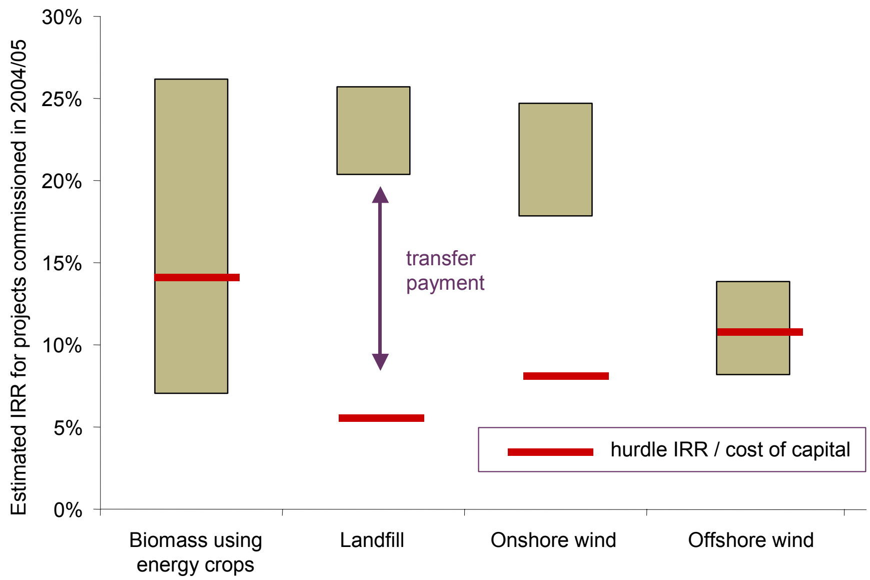
This section compares returns earned by developers by technology and over time. Oxera has estimated the range of internal rates of return (IRRs) earned by new plant in each year and for each technology.

The IRR is a measure of the profitability of an investment. It is defined as the rate of interest which, when used to discount the money flows of an investment, reduces the NPV of the investment to zero. In practice, this means that the sum of the initial investment—a cost—and the subsequent (discounted) profit flows is zero. The implication being that if the discounted rate is the target rate of return (cost of capital) then it would be possible to return the desired rate of profit and repay the initial investment. Only under special circumstances do IRRs equal the rates of return derived from accounting figures.[4] Indeed, IRRs have the merit of avoiding many of the distortions inherent in accounting rates of return.

[4] See, for example, Edwards, J., Kay, J. and Mayer, C. (1987), *The Economic Analysis of Accounting Profitability*, Oxford: Clarendon Press.

Figure 2.3 shows IRRs for projects commissioned in 2004/05, under the cost assumptions defined in Table A2.4 in Appendix 2.

Figure 2.3 Estimated range of IRR for projects commissioned in 2004/05, by technology, Central scenario



Note: The large range in IRRs shown for energy crops is due to the wide range of generation costs assumed: £46–£70/MWh. The cost of landfill generation in 2004/05 is assumed to be the same as the price of the successful landfill bids in the last NFFO round.
Source: Oxera.

One way to interpret the results is to compare the estimated IRRs with the hurdle rates of return obtained in the work summarised in the DTI Renewables Innovation Review.[5] Where an IRR in excess of the hurdle rate is obtained, the project may be seen as generating a transfer payment—a return in excess of that needed to get it off the ground. For plant built in 2004, the DTI Renewables Innovation Review used the following representative hurdle rates, derived from discussions with developers and bankers:

Energy crops with bespoke plant	14%
Marine	14%
Offshore wind	11%
Onshore wind	8%
Landfill	6%

The Oxera results suggest that offshore wind, energy crops and marine generation have rates of return that are inadequate or barely adequate to attract finance. All the other technologies generate transfer payments to a greater or lesser degree, creating the potential for returns above those needed to recompense the investment, given the relevant degree of risk (as represented by the hurdle rate of return). The most conspicuous case is landfill gas generation, which accounted for half of the ROCs issued by Ofgem in the first year of the RO, and which earns a return of over 20%, while the appropriate hurdle rate is nearer to 6%.

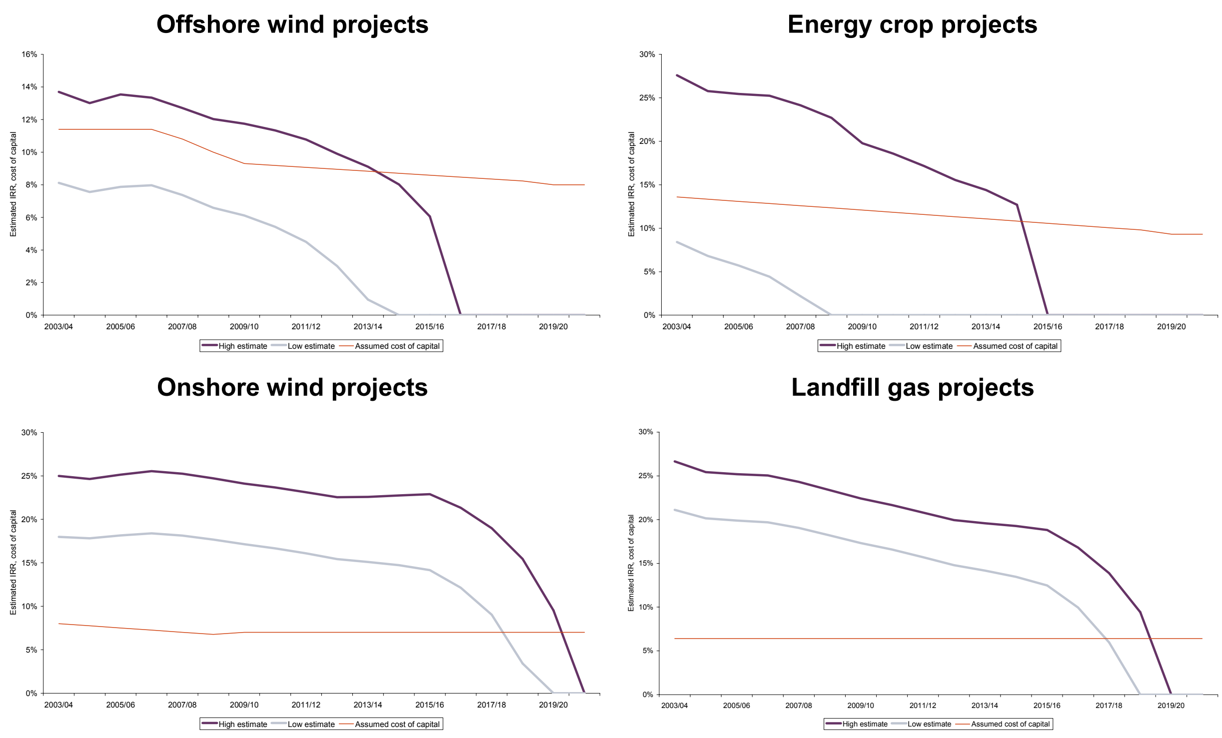
[5] DTI (2004), 'Conclusions of the Renewables Innovation Review', February, available at http://www.dti.gov.uk/energy /renewables/policy/renewables_innovation_review.shtml

One way of interpreting these results is as an indication of the costs of the choice of a technology-neutral RO. The figures suggest that, at the chosen buy-out price of 3p/kWh, the economics of offshore wind developments is marginal—this is exactly as it should be since the buy-out price has to incentivise investment in the most expensive developments needed to meet the overall target. If the buy-out price could be varied by technology (which it could not be within the parameters of the current scheme design), the following buy-out prices (in p/kWh) would seem broadly sufficient to recompense the required investment. These figures are estimated by subtracting revenue per unit of electricity from the unit cost of generation for each technology, to leave a shortfall to be met by the sale of ROCs. If onshore wind were required to pay the full cost of its need for network reinforcement and extension, it would require a buy-out of 2p/kWh rather than the 1.5p/kWh shown below.

Energy crops with bespoke plant	3–4p/kWh
Marine	4p/kWh
Offshore wind	3p/kWh
Onshore wind	1.5p/kWh

Figure 2.4 shows the evolution of IRRs through time for two expensive technologies (offshore wind and energy crops) and two cheap technologies (onshore wind and landfill gas), along with the expected cost of capital used for each technology. Two cost assumptions have been used—high and low—covering a range of assumptions about the initial level and the subsequent possible evolution of capital and operating costs.

Figure 2.4 Change in IRR through time



Source: Oxera.

Figure 2.4 suggests that there will be some tendency for the cost of capital required for the most risky technologies to decline over time. This is a reflection of an assumed reduction in risk as the market becomes more comfortable with investments of this kind. In all cases, the estimated IRR tends to fall through time: build costs fall over time and ROC prices also decline from their highest levels during the early years of the RO. Under the high electricity price scenario, new offshore wind and energy crop plant would cease to be built from 2013/14 or so, whereas onshore wind and landfill would cease to be built from around

2018/19. Under the low electricity price scenario, there would be no offshore wind or energy crop build, and onshore wind and landfill plant construction would cease a year or so earlier. It might be thought that declining build costs would lead to an increase in rates of return over time, but the merit of the RO is that, as generation costs fall, and with a static target, the ROC price falls below the buy-out price. Thus, the scheme manages to extract these gains for the consumer.

2.3 Were the right technologies included in the RO?

This sub-section examines the strength of the case for including landfill gas and co-firing in the RO.

2.3.1 Landfill gas

In the last Non-Fossil Fuel Order, contract prices for currently commissioned landfill gas sites were in the region of 3p/kWh. Hence, with a wholesale price of electricity of 2p/kWh and a CCL exemption of 0.4p/kWh, landfill only required a price premium of about 0.6p/kWh—far less than the support it is receiving under the RO. (Future landfill projects may be more expensive because they are less suitable sites, but environmental regulation[6] requires them to be built anyway.) Furthermore, because much of the resource for landfill gas is already utilised (see Table A2.1), there is limited potential for stimulating further new entry.

Oxera tested what would have happened had landfill gas been made ineligible for ROCs so that the RO target was reduced in line with the amount of capacity removed from the RO.

Making landfill ineligible would have a small impact on the overall growth in renewables, for the following reasons.

– The level of build of landfill gas plant would be largely unaffected by removal from the RO, both because the technology is close to commercial viability without additional support and because build can be mandated in any case through environmental legislation.

– The removal of landfill generation with corresponding reductions in the level of the RO would increase ROC prices, since the same buy-out fund would be distributed among fewer ROC holders. This would lead to a marginal increase in build rates of other renewable technologies, although the effect is not significant.

Table 2.1 below shows the financial impact of making landfill ineligible. The total support paid by consumers would fall by about £2 billion (£125m pa), as consumers no longer fund the infra-marginal (economic) rents (shown in the table as 'transfers') previously received by landfill developers through the RO. However, this would lead to a small fall in the total support cost, from £92 to £90/tonne CO_2 saved.

[6] The Landfill (England and Wales) Regulations 2002.

Table 2.1 Impact of landfill eligibility on overall policy outcomes

	Landfill eligible	Landfill ineligible	Change
High scenario			
Total support			
£m	14,936	12,718	–2,218
£/tCO_2	51.0	45.4	–5.6
Transfer			
£m	9,726	8,309	–1,417
Central scenario			
Total support			
£m	20,798	18,838	–1,960
£/tCO_2	92.1	89.8	–2.2
Transfer			
£m	9,606	9,434	–171
Low scenario			
Total support			
£m	24,307	22,475	–1,832
£/tCO_2	140.1	138.4	–1.7
Transfer			
£m	12,532	12,211	–321

Source: Oxera.

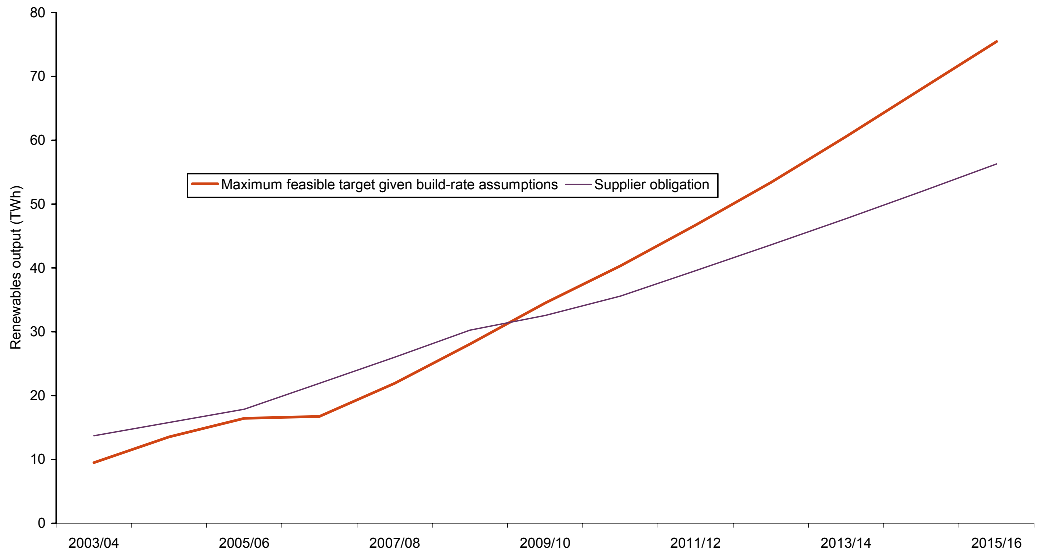
One caveat to these results is that, where landfill sites were funded through NFFO contracts, inclusion within the RO enables the Fossil Fuel Levy (FFL) to be kept at zero, with offsetting benefits for consumers. The issue of excluding NFFO plant is examined in more detail in section 8.4.

2.4 What was the effect of the profile of the RO target being inconsistent with the planning regime?

In the model, the maximum build rate for each technology acts as a proxy for planning restrictions. This assumption is based on an examination of historical rates of build, the numbers of applications submitted, and knowledge of the number of large players in the market and their plans. Recent changes in planning policy could have the effect of broadly permitting the level of activity assumed (ie, without the changes, the level of activity would be constrained to be lower than assumed in this report). Oxera has investigated the impact of re-profiling the RO to ensure consistency with the maximum build-rate assumptions.

Figure 2.5 identifies the maximum level of renewable generation in each year that is consistent with assumed maximum build rates. In all years up to and including 2008/09, the renewables sector is unable, under the central assumptions, to grow fast enough for suppliers to meet all of their obligations through the purchase of ROCs.

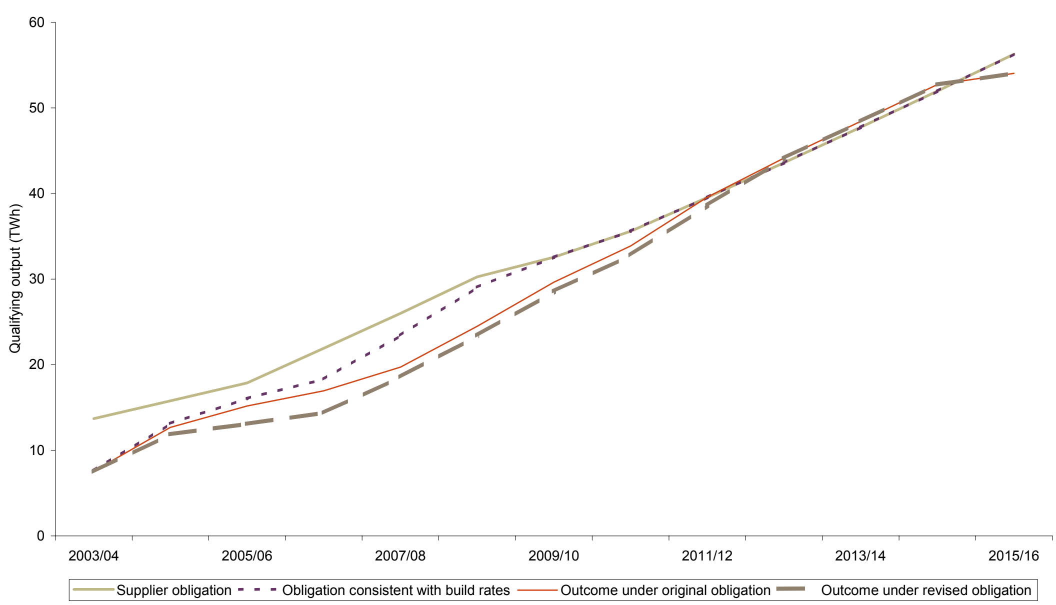
Figure 2.5 Restrictions on build rate mean supplier obligation cannot be met in early years under the Central scenario



Source: Oxera.

Figure 2.6 shows the effect on the growth in renewables output of reducing the level of the RO in the early years to match the maximum possible level of output. Under the revised RO, renewables output would be slightly lower, as the level of buy-out fund and consequently the value of ROCs fall. This leads to lower levels of offshore wind capacity. Onshore wind capacity remains constrained by the maximum build rate rather than the commercial return.

Figure 2.6 An obligation consistent with build rates would reduce entry incentives



Source: Oxera.

Reducing the RO target in the early years would lower the total support paid by consumers and taxpayers by around £0.6 billion (£35m pa). Resource costs would fall by around £0.9

billion, but transfers would rise (by £0.3 billion). This shows that, had the profile of the RO been consistent with a realistic assessment of the maximum rate of new build, the RO might have been slightly more efficient and the costs to consumers might have been slightly lower.

Table 2.2 Impact of obligation consistent with planning controls on policy outcomes

	Outcome under		Change
	Original obligation	Revised obligation	
Support			
£m	20,798	20,242	–556
£/tCO_2	92.1	90.8	–1.2
Transfers			
£m	9,606	9,938	333
Resource cost premium			
£m	11,193	10,304	–889
£/tCO_2	49.5	46.2	–3.3

Source: Oxera.

3 Perverse incentives

3.1 Does support for co-firing lead to perverse environmental outcomes?

One concern about co-firing is that, by providing an additional source of revenue for coal plant, it might have the perverse effect of raising the share of coal plant in the fuel mix and keeping coal plant open, with adverse environmental effects.

Oxera has examined this issue through its wholesale electricity market model, using the assumptions set out in Appendix 4. Based on conversations with generators, and knowledge that all coal-fired plant have applied for authority to burn biomass but so far few have actually done so, it has been assumed that all coal plant would co-fire with 3% of input fuel (as measured by calorific value) being biomass. A 3% input would require very limited modification to existing plant and is consistent with the current limits to the eligibility of co-firing plant for ROCs. It would generate around 3TWh pa of electricity, in line with the maximum anticipated annual output from co-firing in the co-firing study for the DTI by ILEX.[7] Details of the assumptions used for fuel prices and calorific values are given in Appendix 4. A constant ROC price of £40/MWh and a constant proportion of co-firing of 3% were assumed for this modelling exercise.

Co-firing was found to allow coal plant to operate profitably at lower electricity prices due to the additional ROC income available from generation. Table 3.1 shows the results of running Oxera's wholesale model with these adjustments for co-firing. If the output of coal plant is kept constant, co-firing reduces coal-burn by 3% (ie, the assumed percentage biomass content), with corresponding reductions in CO_2 emissions from the generation sector as a whole (taking account of the net impact on CO_2 of burning biomass). However, coal plant are found to increase their share of total generation output, partly offsetting the emissions savings from co-firing by keeping coal-burn higher than it would otherwise be. This perverse effect erodes 11–40% (an average of 21%) of the emissions savings benefit of co-firing, with the impact varying between years. This variation between years arises from changes in fuel prices, the phasing of the EU ETS, and the start of the Large Combustion Plants Directive in 2008, all of which affect the operation of coal-fired plant. The coal-fired plant benefit significantly from greater profitability while co-firing. Over the period 2004/05–10/11, assuming full exposure to market revenues and costs, their profits are increased by about £870m (c. £4m/GW pa).

[7] ILEX Energy Consulting (2003), 'An Assessment of the Changes to Renewables Obligation Rules Relating to Co-Firing', August.

Table 3.1 Impact of co-firing on carbon emissions

	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11
Without co-firing							
Output of coal plant (TWh)	98	101	105	107	101	101	101
Coal-burn (mt)	37.5	38.6	40.2	40.8	38.8	38.6	38.7
CO_2 emissions (mt)	153.1	153.9	158.2	159.0	160.2	160.3	160.9
With co-firing, keeping output of coal plant constant							
Coal-burn (mt)	36	37	39	40	38	37	38
CO_2 emissions (mt)	150.5	151.2	155.5	156.2	157.5	157.7	158.3
Reduction in emissions compared with scenario without co-firing (mt)	2.6	2.6	2.8	2.8	2.7	2.7	2.7
With co-firing, taking account of changes in despatch							
Output of coal plant (TWh)	100	103	106	108	102	102	103
Coal-burn (mt)	37.3	38.1	39.4	40.0	38.0	38.0	38.1
CO_2 emissions (mt)	151.5	151.9	155.9	156.5	157.8	158.2	158.9
Reduction in emissions compared with scenario without co-firing (mt)	1.5	2.0	2.4	2.5	2.4	2.1	2.1
Carbon benefit (%) lost through increase in coal output	40	26	14	12	11	21	23

Note: CO_2 emissions are from the whole generation sector, not just coal plant.
Source: Oxera.

These results suggest that the improved economic competitiveness of coal-fired plant when co-fired with biomass does offset, to some extent, the environmental benefits of co-firing, and that around 20% of the benefits are offset. Oxera has looked at only one scenario of input fuel prices, carbon price and ROC price. There might be circumstances in which the effect could be greater or less—for example, if the combined fuel and carbon permit costs of coal and gas plant were very close and the ROC price were high, co-firing might lead to greater levels of induced coal-burn.

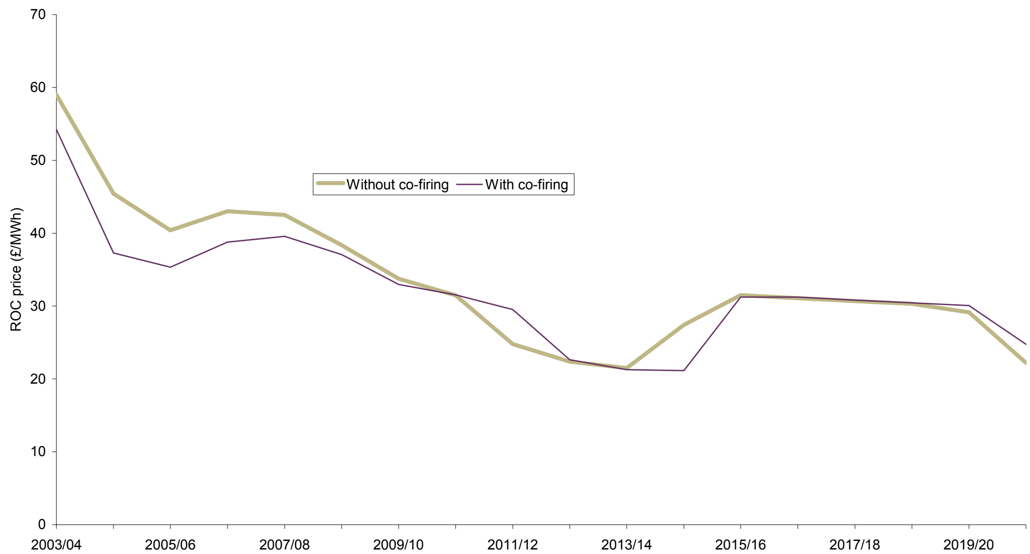
Co-firing might also have additional impacts that have not been modelled (eg, reduced thermal efficiency of coal plant, or increased maintenance costs).

3.2 What is the impact of co-firing on incentives for other renewables?

Oxera has run the model without any contribution from co-firing to assess the effect on ROC prices and build rates for other renewable technologies.

Figure 3.1 shows that co-firing reduces ROC prices in the early years—a direct result of the increase in the supply of generation eligible for ROCs. In later years, as the contribution of co-firing falls, ROC prices are almost identical.

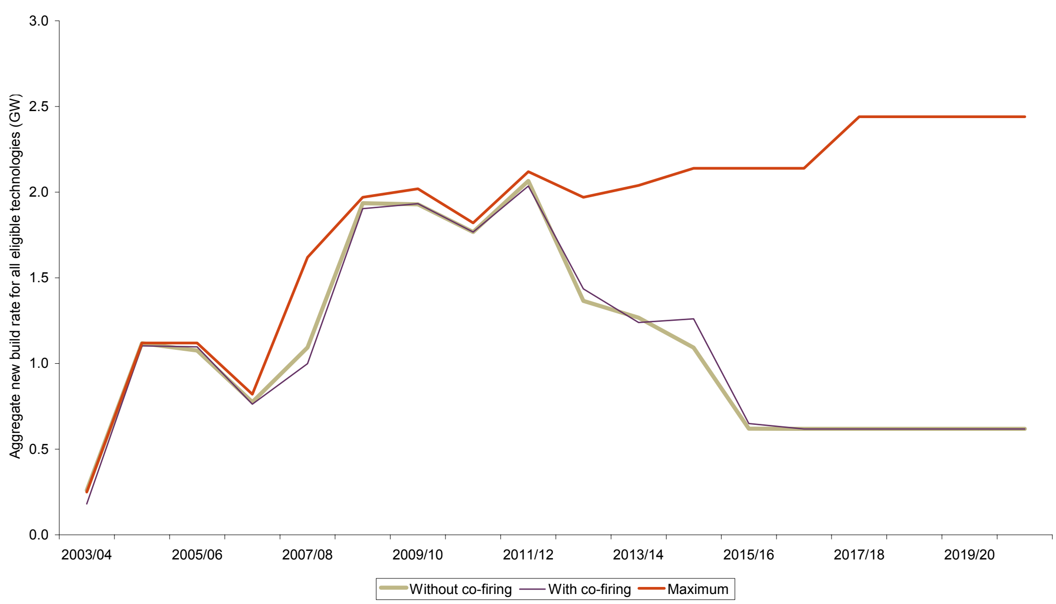
Figure 3.1 Impact of co-firing on ROC prices



Source: Oxera.

Figure 3.2 examines more closely the impact of co-firing on the build rate of other renewable technologies. The effect is negligible. For other technologies, build rates are restricted (at least in the early years) by maximum build-rate assumptions rather than project returns, and hence are unaffected by the fall in ROC prices resulting from co-firing.

Figure 3.2 Impact of co-firing on build rate for other renewable technologies



Source: Oxera.

The main effect of co-firing is to increase revenues available for fossil-fuel generators while reducing the transfer payments received by other renewable developers.

In summary, two conditions must hold for co-firing to improve environmental outcomes:

- build rates of other renewables in the early years of the RO must be primarily constrained by factors such as planning rather than project economics; and
- the perverse fuel-switching effect of co-firing must not be strong enough to erode completely the environmental benefits of replacing coal with biomass in existing power stations.

Both conditions appear to be satisfied.

4 Market liquidity

4.1 How liquid is the ROC market over different time horizons?

Oxera has drawn on responses to its survey of suppliers and developers to answer this question, first examining how ROCs are traded, and then looking at liquidity and pricing of contracts over different time horizons. The survey collected responses from around 30% of generators and 75% of suppliers by market share.

Survey respondents differ in how they trade ROCs. However, the overall picture is that bilateral negotiation is the most common method of trading, with smaller volumes traded over the counter.[8]

Table 4.1 Number of respondents using different methods of trading ROCs

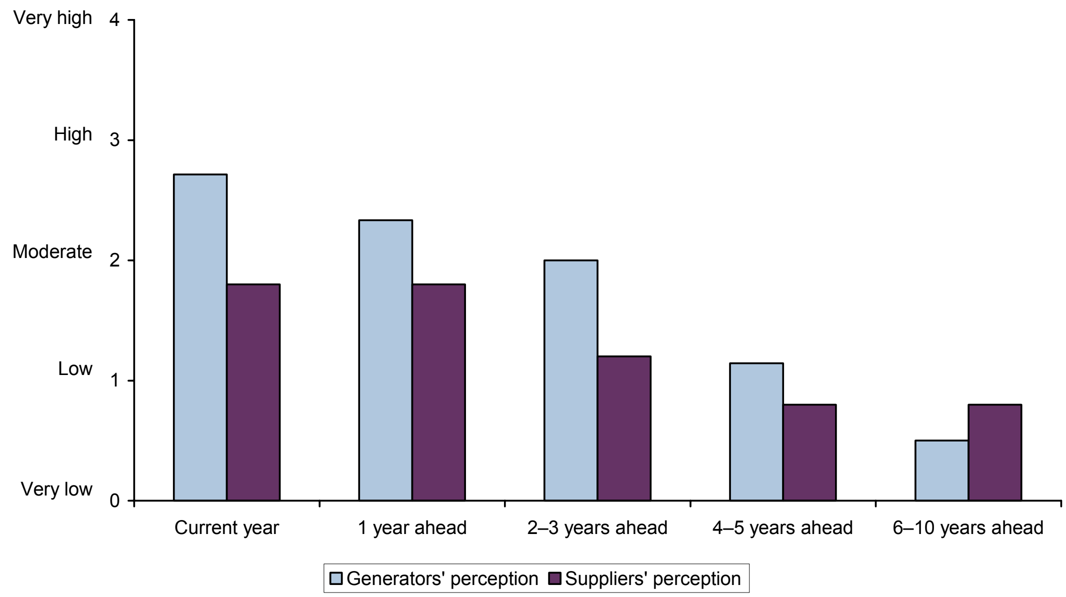
	Generators	Suppliers
Bilateral negotiations	6	3
Over-the-counter market[1]	1	3
NFPA/NFPA Scotland (NFPAS) auction	0	2
NFFO contracts	1	0
Other	2	0

Notes: [1] Over-the-counter refers to face-to-face transactions (rather than screen-based trading), and includes transactions via brokers.
Source: Oxera survey.

Figure 4.1 shows the perception of market liquidity among the generators and suppliers that responded to the survey. As expected, the market is perceived to be less liquid further into the future. Although the sample size is too small to draw definite conclusions, suppliers that responded to the survey tended to have a more pessimistic view of market liquidity than generators. Suppliers perceived, on average, the availability of contracts 2–3 years ahead to be ‘low’, whereas the average score given by generators only fell to this level once contracts 4–5 years ahead were being considered. Nevertheless, the survey as a whole suggests a mismatch between the current market conditions and the life of renewable generating plant.

[8] For the purposes of this survey, Oxera has interpreted ‘over the counter’ trading as referring to the trading of standardised contracts outside of an exchange.

Figure 4.1 Perceptions of market liquidity



Source: Oxera survey.

Respondents mentioned a range of factors that affect market liquidity.

– Two suppliers drew attention to the adverse impact on market confidence, trading volumes and prices of the shortfall in buy-out funds resulting from supplier failures such as TXU (UK) Ltd, Maverick Energy Ltd and Atlantic Energy.

– One generator listed the following factors which it regarded as responsible for low liquidity and substantial price discounts for generators:

  – the revocation risk on generators (the risk that the accreditation of the certificates will be retrospectively withdrawn because eligibility rules were broken);
  – the lack of incentive on suppliers to contract for ROCs rather than pay the buy-out price;
  – generators' inability to redeem ROCs;
  – uncertainty caused by political and credit risk (a counterparty going into liquidation), leading to short-term trading and discounts for longer-term deals.

  Overall, the generator argued that these factors reduced ROC prices below the full value of a redeemed ROC and inhibited long-term contracting, thereby damaging confidence in renewables investment.

– One supplier mentioned the ability of large Scottish suppliers to arbitrage between the RO and Scottish Renewables Obligation (SRO) at the expense of other market participants.

These concerns have been reviewed by the DTI and Ofgem as part of their responsibilities for ensuring the orderly development of the market.

5 Transaction costs

5.1 How large are the transaction costs arising from the RO?

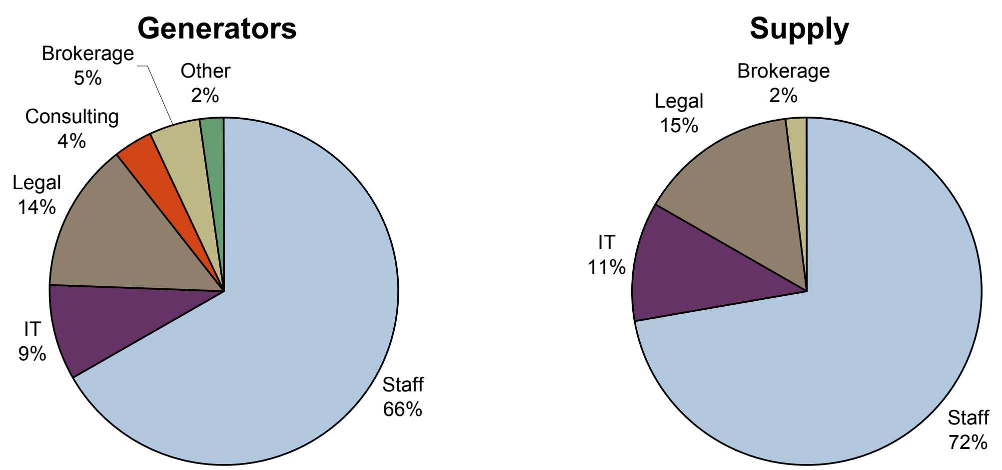
Oxera estimated the transaction costs associated with the RO, drawing on information provided by survey respondents. Transaction costs are defined as the costs of conducting an economic exchange between two parties.

The surveys requested information on staff employed in administrative and trading activities arising from the RO, along with one-off and ongoing costs in five areas of potential cost: IT, legal, consulting, brokerage, and other. Oxera has computed the NPV of transaction costs implied by survey returns using the following assumptions:

– the cost of each full-time employee was assumed to be £28,000 per year, broadly equivalent to the average national salary of £25,170,[9] uplifted to account for employer National Insurance Contributions;
– an NPV value for ongoing costs has been calculated over a lifetime of 24 years (matching the 24-year period from 2003/04 to 2026/27 covered in Oxera's modelling), using a discount rate of 3.5% as recommended in the Treasury's Green Book.[10]

The breakdown of costs between categories is shown in Figure 5.1 for generators and suppliers. In both cases, staff costs account for 70% of total transaction costs.

Figure 5.1 Breakdown of transaction costs between cost categories (%)



Source: Oxera survey.

Table 5.1 below demonstrates that the transaction costs associated with the RO tend to be ongoing rather than one-off implementation costs.

[9] National Statistics (2003), 'Labour Market New Earnings Survey 2003'.
[10] HM Treasury (2003), 'The Green Book: Appraisal and Evaluation in Central Government', January.

Table 5.1 Breakdown between one-off and ongoing costs (%)

	Generators	Suppliers
One-off	4	8
Ongoing	96	92

Source: Oxera survey.

To produce a present-value estimate of industry-wide transaction costs, the cost estimates for survey respondents need to be scaled up. Oxera has produced illustrative figures only using the following scaling methodology:

– the total cost figure for suppliers that responded to the survey has been scaled up in line with their share of domestic electricity customers;
– the total cost figure for generators that responded to the survey has been scaled up in line with their share of renewable electricity production.

Table 5.2 shows the industry-wide estimate that results from these calculations. In total, transaction costs are estimated to be £54m, representing less than 1% of income received under the RO in the Central scenario. These costs are small and show the ROC system to be administratively efficient.

Table 5.2 Estimate of industry-wide transaction costs

	Value
Transaction costs (£m)	
Generators	31
Suppliers	23
Total	**54**
Comparison against size of market	
Total discounted ROC income in the Central scenario (£m)	12,704
Transaction costs as percentage of ROC income (%)	0.4

Note: The higher cost figure for generators as opposed to suppliers may reflect the different approach to scaling up survey returns to provide an industry-wide estimate.
Source: Oxera survey.

6 Grid investment

6.1 What is the effect of charging renewables developers for network costs?

Table A2.7 in Appendix 2 summarises the cost assumptions used by Oxera for system back-up and network reinforcement costs. To some extent, intermittent renewables, such as wind, may be contributing towards system back-up costs through the imbalance payments assumed in Tables A2.3 and A2.4. However, the Central scenario assumes that renewables developers make no contribution to network reinforcement costs; consequently, where these costs are covered, they form a support to renewables.

To assess the potential impact of cost-reflective charging for network reinforcement, Oxera has run the model with network costs treated as an additional capital cost for developers.[11] The £/kW network cost assumptions are shown in Table 6.1, calculated by dividing reinforcement costs for each technology by the increase in installed capacity in the Central scenario. By using a fixed £/kW cost assumption, Oxera has allowed network costs to fall if developers respond to cost-reflective charging by reducing the volume of build for affected technologies.

Table 6.1 Network cost assumptions for Great Britain under the Central scenario

	Onshore wind	Offshore wind	Marine	Energy crops
Network reinforcement up to 2026/27 (£m, annuitised, cumulative, discounted)	1,615	378	83	64
Increase in installed capacity up to 2026/27 (MW)	12,400	8,020	1,140	1,028
Additional capital cost for new build (£/kW)	130	47	73	63

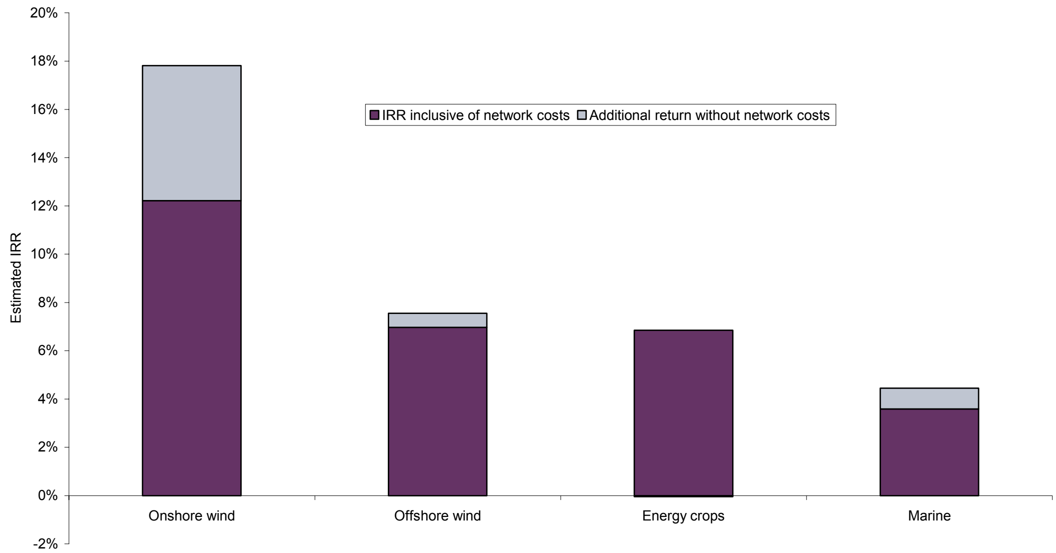
Source: Oxera.

The third row in Table 6.1 shows the (discounted) costs per kW of new renewables capacity (eg, £130/kW in the case of onshore wind). The significance of the figures can be seen from a comparison with plant capital costs (ie, approximately £700/kW in the case of onshore wind).

Figure 6.1 shows the impact of including network costs on the IRR estimates of projects built and commissioned in 2004/05, before taking account of any consequent effects on levels of development, ROC prices and technology learning rates. As can be seen, the IRRs would be reduced if developers were required to cover these costs in full. Onshore wind and marine generation are the most adversely affected, whereas the impact is more marginal for offshore wind and energy crop projects. The data used in Figure 6.1 is taken from the bottom end of the ranges shown in Figure 2.3. Figure 6.2 shows the effect on compliance with the RO target in 2010/11.

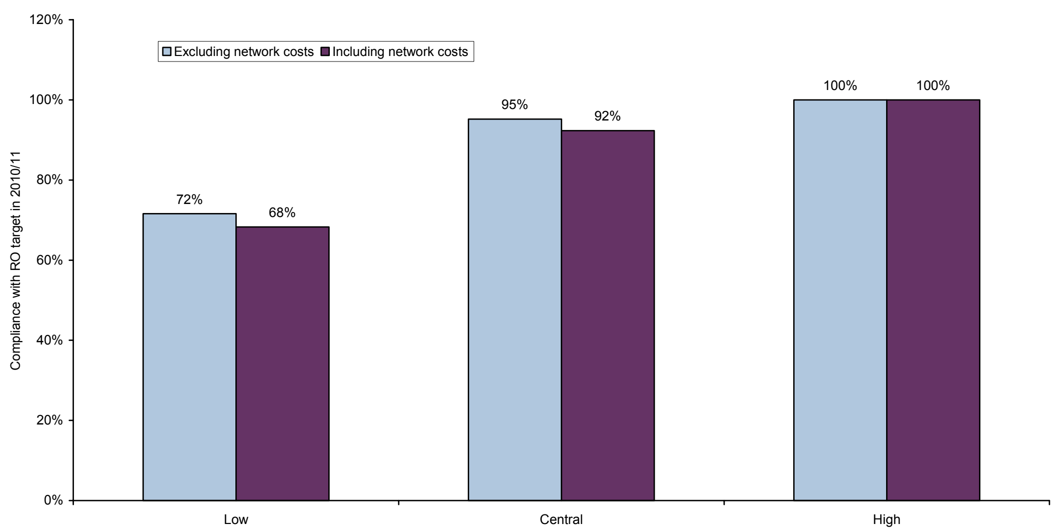
[11] Depending on the structure of charges, some elements of network costs could be an ongoing cost for developers (eg, use-of-system charges), rather than an upfront capital cost (eg, connection charges).

Figure 6.1 Impact of network costs on IRR estimates for projects built and commissioned in 2004/05



Note: These figures do not take account of the potential effect of cost-reflective charging on levels of development, ROC prices and technology learning rates.
Source: Oxera.

Figure 6.2 Impact of network costs on compliance with RO target in 2010/11



Source: Oxera.

Estimates have been made of the impact of network charging on the scale and distribution of renewable development. As would be expected, network charging reduces renewables build in the early years. As shown in Table 6.2, cost-reflective charging also leads to a reduction in network costs. This is because charging encourages developers to take account of network costs in their decisions about new build, and thereby to optimise the scale and pattern of their investments in relation to all costs. The total reduction in support is £240m (£15m pa).

Table 6.2 Impact of cost-reflective network charges on policy outcomes

	Without cost-reflective network charges	With cost-reflective network charges	Reduction
Network cost (£m)	2,141	2,141	0
Total support (£m)	20,798	20,560	238
£/tCO_2	92	93	–1

Source: Oxera.

7 Long-term incentivisation

7.1 How does certainty over long-term targets affect policy outcomes in the early years of the RO?

To address this question, Oxera has run the model with the following targets:

– the original RO targets, remaining constant at 10.4% of electricity supplies after 2010;
– the current RO, remaining constant at 15.4% after 2015/16;
– a hypothetical obligation increasing linearly from 2015/16 to reach 20% by 2020/21, consistent with the government's ambition to double the share of electricity supplied from renewables to 20% by 2020.

Table 7.1 shows the proportion of the RO target in 2010 that is met by each technology.

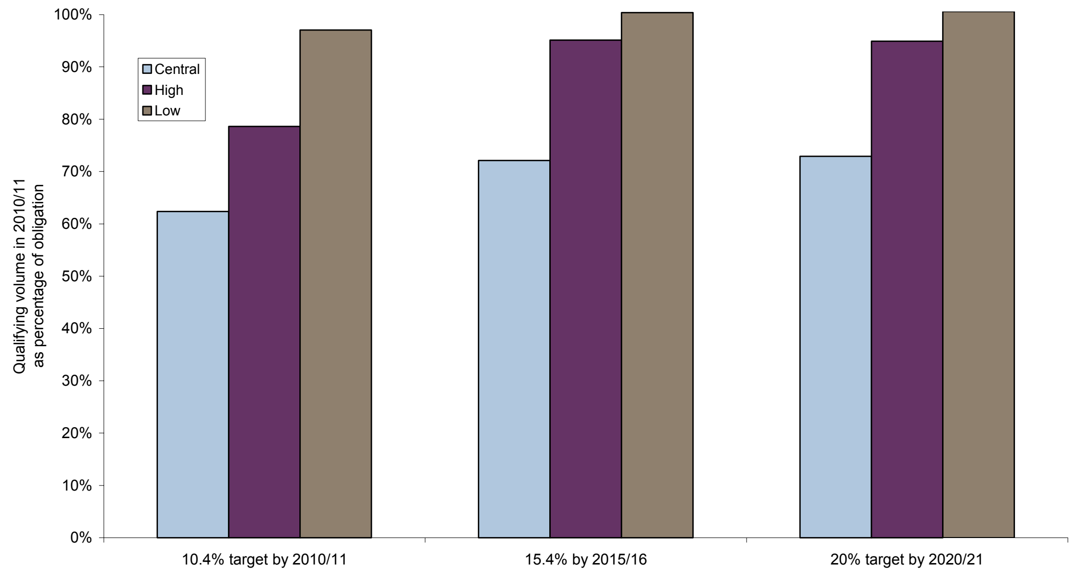
Table 7.1 Contributions to the RO target in 2010 (%)

Scenario	Onshore wind	Offshore wind	Energy crops	Marine	Co-firing	Landfill	Small hydro	Sewage sludge	Solar PV
Low	28.2	22.3	3.3	0.5	2.2	10.2	3.5	1.8	0.0
Central	28.1	41.3	7.0	0.8	2.2	10.2	3.5	1.8	0.0
High	28.2	46.2	7.0	1.2	2.2	10.2	3.5	1.8	0.0

Source: Oxera.

Figure 7.1 shows the effect of greater policy certainty on performance against the RO in 2010/11. While announcing a 15.4% target for 2015/16 increases renewables output from 79% to 95% of the RO in 2010/11, the incremental impact of announcing a firm commitment to a 20% target for 2020/21 would appear to be negligible. The policy conclusion seems to be that the increase in the target to 15.4% was a positive move. The fact that, in these simulations, a target for 2020/21 appears to have a negligible effect should not be taken to imply that some further commitment beyond 2015/16 would not be helpful. In particular, a rolling increase in the target might provide a useful way of reducing the uncertainties surrounding potential returns.

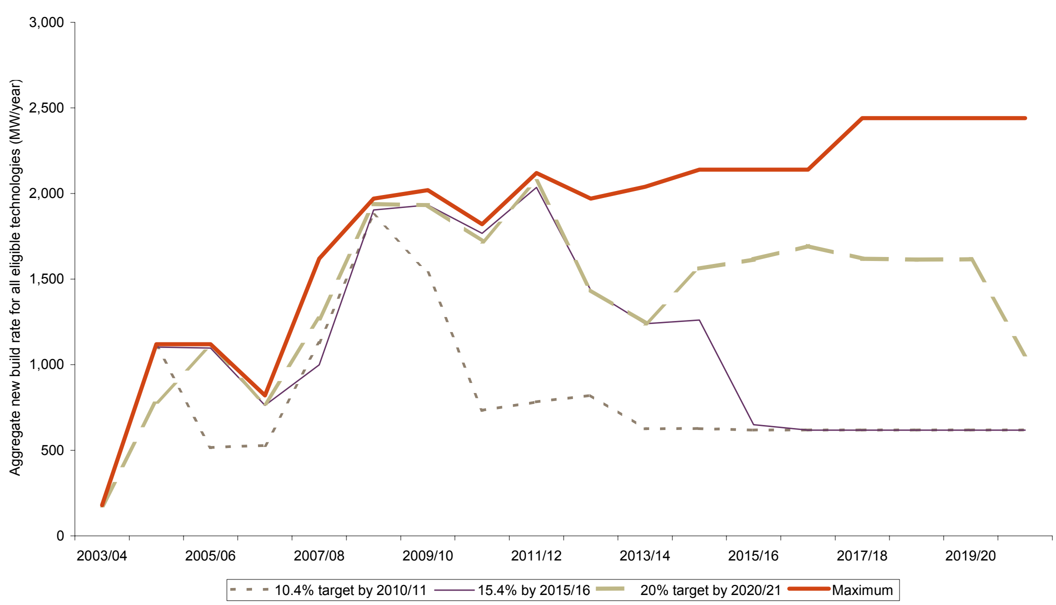
Figure 7.1 Impact of policy certainty on performance against obligation in 2010/11



Source: Oxera.

More detail on annual build rates is given in Figure 7.2, which shows that the build rate tends to be higher in the early years, and to be sustained for longer, the more certainty developers have about long-term targets.

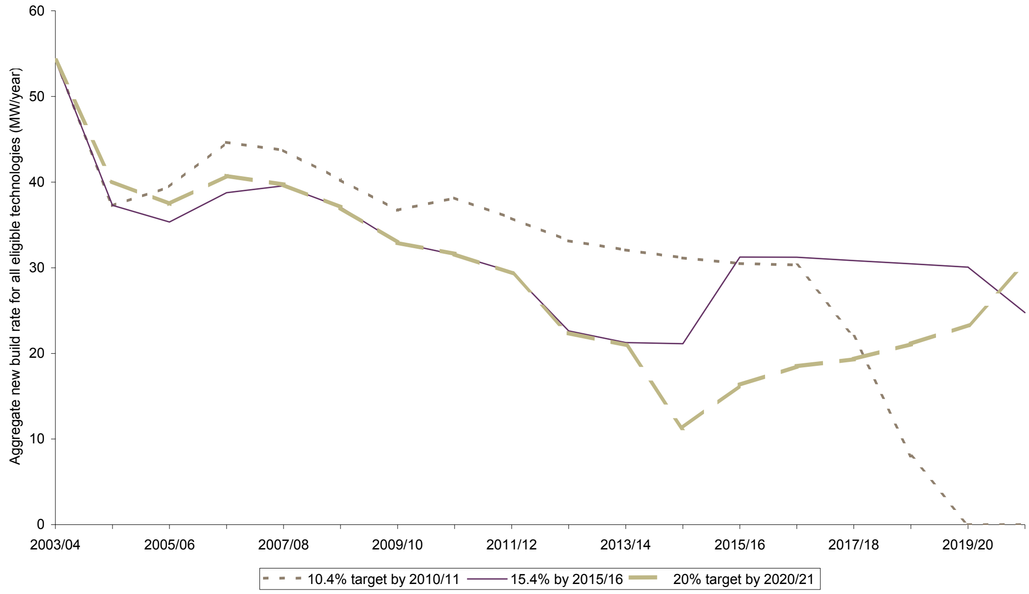
Figure 7.2 Effect of policy certainty on build rates



Source: Oxera.

A corollary of higher build rates arising from greater policy certainty is that ROC prices will tend to be lower. In later years, a higher target helps to maintain ROC prices at higher levels due to the continuing year-on-year increases in the demand for ROCs. There is an intervening period of years when a low target is achievable, but the model suggests that ROC prices will be held at around the buy-out price, implying a stable strategy between developers of not building. These effects are shown in Figure 7.3.

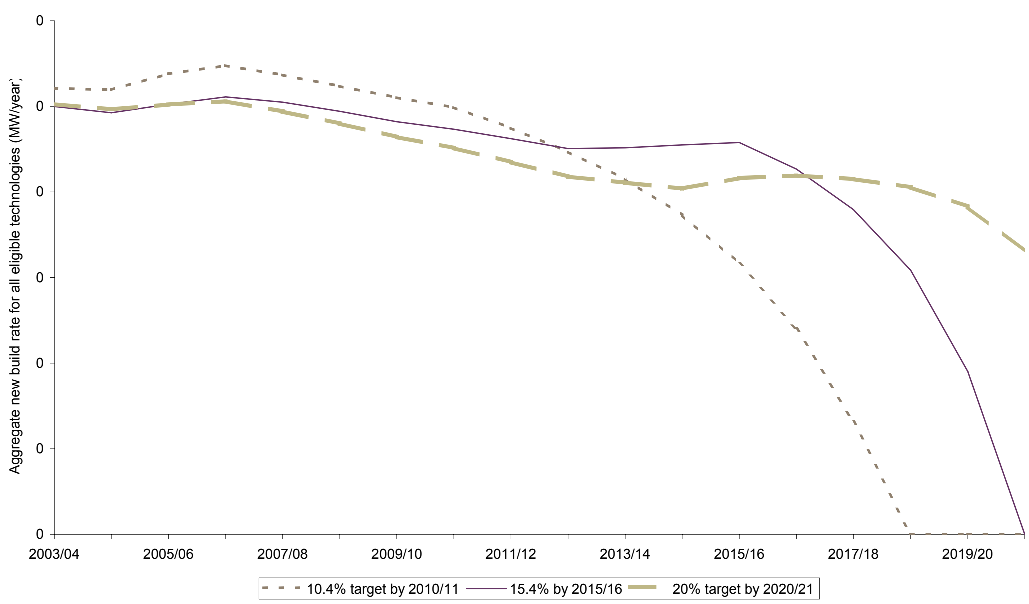
Figure 7.3 Impact of policy certainty on ROC price



Source: Oxera.

Figure 7.4 shows the overall impact on the IRR of onshore wind projects in various years. For projects built and commissioned towards the beginning of the period, returns are slightly higher without firm long-term policy commitments. This is because higher ROC prices in early years more than offset lower revenues in the latter part of project lifetimes. However, for projects built and commissioned further into the future, returns are greater if the government has committed to a higher target. Similar patterns in IRRs were observed for other technologies.

Figure 7.4 Impact on IRR through time for onshore wind (high estimate of IRR range)



Source: Oxera.

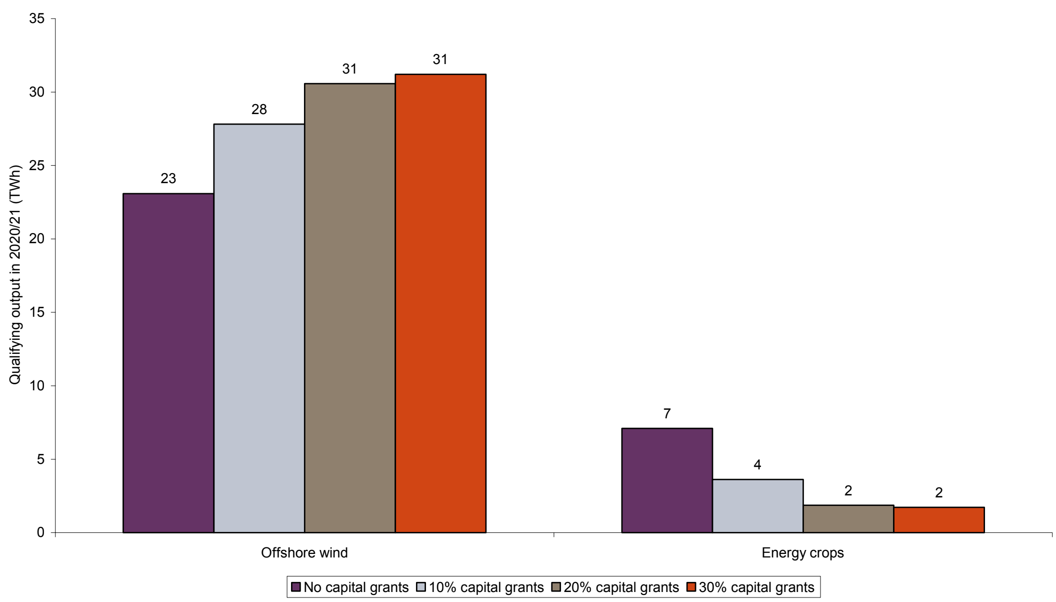
8 Renewable energy programme

8.1 What is the impact of capital grants?

As set out in Table A2.8 in Appendix 2, the Central scenario assumes that varying levels of capital grants are available for offshore wind, energy crops and marine generation, with capital grant programmes ending in different years for each technology. To discern more easily the impact of capital grants, Oxera has run the model without any capital grants at all, and has then allowed varying levels of capital grant for one technology only (offshore wind). In these runs, the buy-out price has been kept constant at £30/MWh; interactions between capital grants and the buy-out price are considered separately in section 8.2.

Figure 8.1 shows the impact on output from offshore wind and energy crops in 2020/21 of offering grants to offshore wind developers only, for varying proportions of their capital cost throughout the period being modelled (2003/04 to 2026/27). Although results for 2020/21 are reported, similar patterns are evident in other years. Offshore wind output increases, while there is a smaller offsetting reduction in energy crop generation through the impact of increased supply of ROCs on the ROC price. Although not shown in the chart, there is also a very small reduction in marine development. The growth of all other technologies (onshore wind, landfill, small hydro, and sewage sludge) is unaffected, reflecting the fact that the key constraint on these technologies is build-rate restrictions rather than project economics.

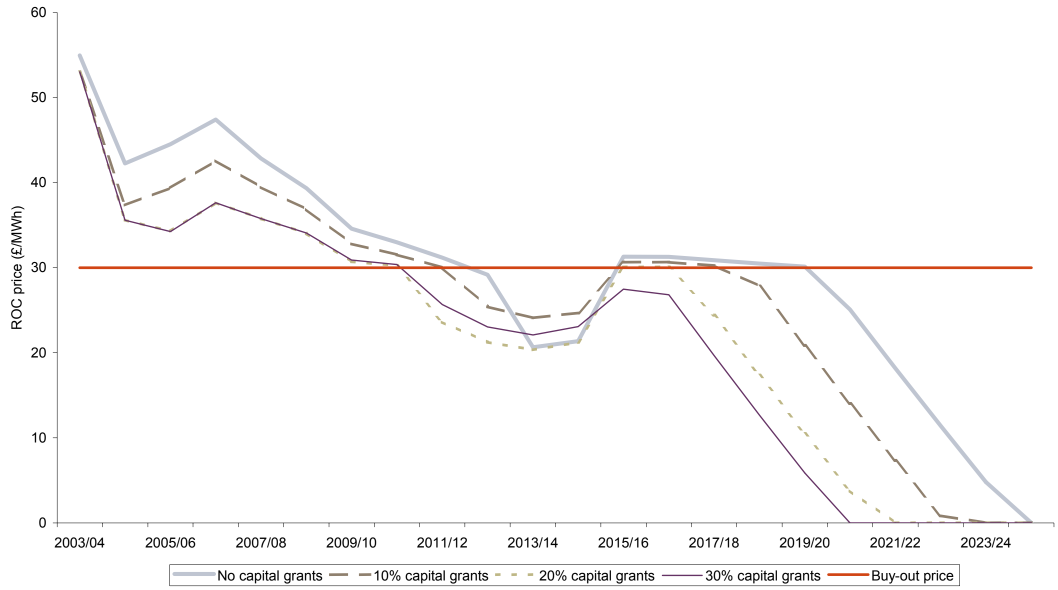
Figure 8.1 Impact of capital grants for offshore wind on qualifying output from offshore wind and energy crops in 2020/21



Source: Oxera.

Overall, there is a net increase in renewables development which tends to reduce the ROC price, as shown in Figure 8.2.

Figure 8.2 Impact of capital grants for offshore wind on ROC price



Source: Oxera.

Table 8.1 shows the effect of offshore wind capital grants on overall policy outcomes.

Table 8.1 Policy outcomes with varying levels of capital grant for offshore wind

	Capital grants			
	None	**10%**	**20%**	**30%**
CO_2 saving (mt, discounted)	222	227	233	234
Total support	20,687	19,939	18,789	18,831
EU ETS benefit (£m)	1,882	1,931	1,983	1,990
Capital grants (£m)	0	466	1,068	1,620
ROC income (£m)	14,117	12,785	10,910	10,385
Network cross-subsidy (£m)	2,141	2,141	2,141	2,141
LEC income (£m)	2,547	2,616	2,687	2,696
Support/tonne CO_2 saved (£)	93	88	81	81

Source: Oxera.

Table 8.1 shows that:

- by increasing the level of renewables development, capital grants give rise to greater CO_2 savings;
- under Oxera's modelling assumptions, the provision of capital grants leads to a greater reduction in ROC income because the obligation is met earlier, and Oxera assumes throughout this report that the ROC price falls rapidly below the buy-out price when these circumstances arise (see Figure 8.2). This reduces the total support provided to the renewables industry and hence the support/tonne CO_2 saved. However, this result might not hold under alternative assumptions about the behaviour of ROC prices when renewables generation matches or exceeds the obligation. For example, an alternative assumption might be that strategic decisions by generators will limit the supply of new projects such that the ROC prices stabilise at the level required to fund the marginal renewables technology.

8.2 How do capital grants and the level of the buy-out price interact?

Capital grants allow the same level of development to be achieved with a lower buy-out price, reducing deadweight. Oxera varied the buy-out price for different levels of capital grant in order to identify combinations of capital grant and buy-out price that achieve the same discounted renewable output as obtained in a revised version of the Central scenario.[12] The results are shown in Table 8.2.

Table 8.2 Scenarios yielding the same discounted renewable output as revised Central scenario

Scenario	Years in which offshore wind grants are available	Level of offshore grants (% of capital cost)[1]	Total capital grants (£m)[2]	Level of buy-out price (£/MWh)[3]
Revised base[4]	2003/04–2008/09	10 (falling to 4 in 2008/09)	466	30
Equivalent scenario 1	2003/04–2010/11	20	1,068	25.40
Equivalent scenario 2	2003/04–2010/11	30	1,620	21.90

Note: [1] Oxera adjusted offshore grants only, as grants for energy crops and marine generation were already assumed to be at the state-aid maximum of 40% of capital cost. [2] Total for offshore wind, energy crops and marine generation. [3] These are not round figures, as the buy-out price was adjusted until the discounted electricity output matched that in the revised Central scenario. [4] For this analysis, Oxera used a slightly different baseline scenario to the Central scenario used in the rest of this report. This baseline scenario involves £188m of grants, compared with £118m in the main Central scenario.
Source: Oxera.

Table 8.3 supports the argument that capital grants combined with a lower buy-out price allow the same level of development to be achieved at lower overall cost to the public. The provision of an additional £1.1 billion in capital grants allows support through the RO to fall by £2.4 billion (£150m pa), leading to an overall reduction in consumer support. **In other words, for every £1m increase in capital grants, the cost to consumers of the RO falls by around £2m**. (Unlike the results in section 8.1, this reduction in support is not dependent on the assumed behaviour of ROC prices once the RO is met; rather, it is a direct result of reducing the buy-out price.) This consumer benefit is achieved by reducing transfer payments to infra-marginal technologies.

This is a strong conclusion and two implicit assumptions need to be recognised: first, the capital grant is itself well targeted, with limited payments to projects which would have gone ahead in any case; and, second, the availability of capital grants does nothing to inflate the overall level of costs (or remove the pressures on the industry to reduce costs).

[12] For this section, Oxera updated its capital grant assumptions following information received from the DTI.

Table 8.3 Comparison of policy outcomes for combinations of capital grant and buy-out price delivering equivalent renewable output

	Revised base	Equivalent scenario 1	Equivalent scenario 2
Total support (£m)	19,939	18,789	18,831
EU ETS benefit (£m)	1,930	1,983	1,989
Capital grants (£m)	466	1,068	1,620
ROC income (£m)	12,785	10,910	10,385
Network subsidy (£m)	2,141	2,141	2,141
LEC subsidy (£m)	2,616	2,687	2,696
Support/tonne CO_2 saved (£)	88	81	81

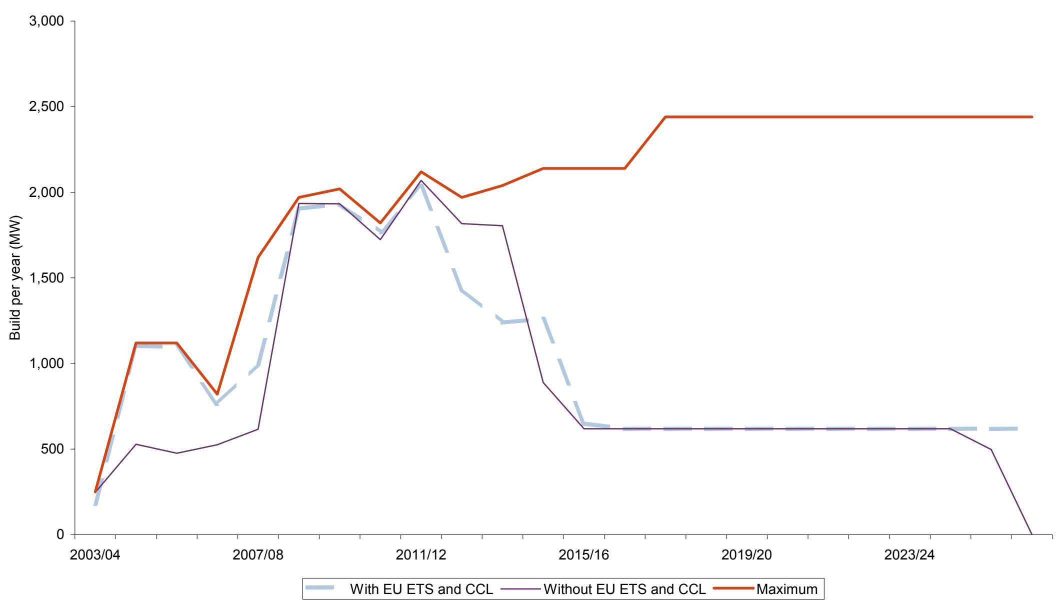
Source: Oxera.

8.3 How does the RO interact with the EU ETS and the CCL?

The renewables model has been run without the electricity price benefits attributed to the EU ETS and the CCL exemption.

Figures 8.3 and 8.4 show that the removal of the financial benefits accruing to renewable generators from the EU ETS and CCL exemption leads to a reduction in renewables build. It results in a reduction in the level of achievement of the RO target in 2010/11 to 82% from 95%, and in 2015/16 to 91% from 96%.

Figure 8.3 Impact of EU ETS and CCL exemption on annual build rates



Source: Oxera.

Figure 8.4 Impact of EU ETS and CCL exemption on cumulative build

Source: Oxera.

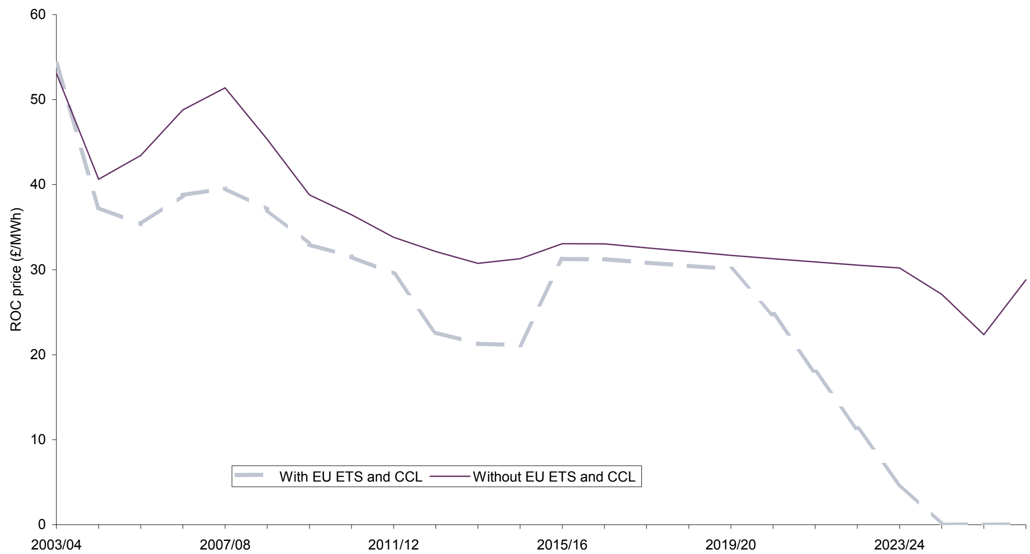
Table 8.4 Cumulative new build above baseline capacity (MW)

	With EU ETS and CCL	Without EU ETS and CCL	Difference
2004/05	1,284	775	509
2005/06	2,381	1,251	1,129
2006/07	3,144	1,777	1,366
2007/08	4,142	2,393	1,749
2008/09	6,046	4,328	1,718
2009/10	7,979	6,261	1,718
2010/11	9,747	7,984	1,763
2015/16	16,367	15,183	1,184
2020/21	19,456	18,276	1,179
2025/26	22,544	21,248	1,296

Source: Oxera.

The reduced supply of renewable generation leads to increased ROC prices, as shown in Figure 8.5 below, because buy-out funds are distributed among fewer ROC holders. For those projects that are built, this will partly offset the lost financial benefit associated with the EU ETS and the CCL exemption. This illustrates how the recycling of buy-out funds creates a partly self-correcting mechanism for dealing with external shocks to the renewables sector. Figure 8.6 compares the revenue available to a renewables generator in 2010/11. The chart reinforces the finding that, while the overall unit revenue available to a renewables generator falls, a rise in the ROC price partly offsets the lost value of the EU ETS and CCL exemption.

Figure 8.5 Impact of EU ETS and CCL exemption on ROC prices



Source: Oxera.

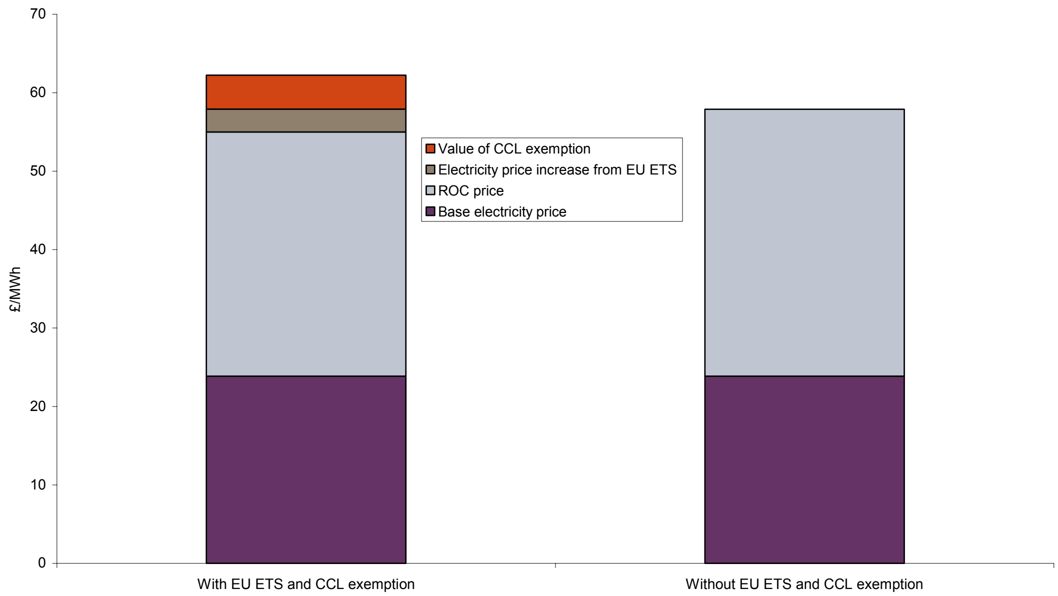
Table 8.5 overleaf shows the overall effect on policy outcomes. The reduction in EU ETS and CCL benefits is partly offset by an increase in ROC income since the ROC price falls less quickly below the buy-out price in later years of the RO (see Figure 8.6). The overall level of support is barely altered in the Central scenario, but is over £3 billion (£190m pa) less in the other scenarios.

Table 8.5 Effect of EU ETS and CCL exemption on policy outcomes

	With EU ETS and CCL exemption	Without EU ETS and CCL exemption	Change
Central scenario			
CO_2 avoided (mt, discounted)	226	209	–16
Support payments (£m)			
EU ETS benefit	1,919	0	–1,919
LEC subsidy	2,600	0	–2,600
Capital grants	220	111	–109
ROC income	13,918	18,489	4,571
Network subsidy	2,141	2,141	0
Total support (£m)	20,798	20,741	–57
Support/tonne CO_2 avoided (£)	92.1	99.0	7.0
Resource cost premium (£m)	11,193	9,087	–2,105
Resource cost premium/tonne of CO_2 avoided (£)	49.5	43.4	–6.2
Transfer payment (£m)	9,606	11,654	2,048
Low scenario			
CO_2 avoided (mt, discounted)	173	148	–25
Total support (£m)	24,307	20,973	–3,335
Support/tonne CO_2 avoided (£)	140.1	141.7	1.6
Resource cost premium (£m)	11,775	8,584	–3,191
Transfer payment (£m)	12,532	12,388	–144
High scenario			
CO_2 avoided (mt, discounted)	293	254	–38
Total support (£m)	14,936	11,836	–3,100
Support/tonne CO_2 avoided (£)	51.0	46.5	–4.5
Resource cost premium (£m)	5,209	7,102	1,893
Transfer payment (£m)	9,726	4,734	–4,992

Source: Oxera.

Figure 8.6 Change in revenue elements in 2010/11 for renewables generators



Source: Oxera.

The EU ETS could have another effect on the renewables market through its impact on electricity demand. If the rise in electricity prices expected to result from the EU ETS were to lead to reduced power consumption, the size of the obligation on suppliers would fall because it is defined as a percentage of electricity sales. In turn, this could reduce the size of the buy-out fund, decreasing ROC prices and deterring renewables build at the margin. The size of this effect is likely to be small because electricity consumption is generally perceived to be price-inelastic.

8.4 Would the exclusion of NFFO plant have improved RO outcomes?

Plant built under the later rounds of the NFFO programme continue to receive their contractual revenue entitlements from the Non-Fossil Purchasing Agency (NFPA). The output of such plant (both the power and the ROCs) is sold by the NFPA to suppliers at an auction. The revenue raised in this way has allowed the FFL, originally used to fund the cost of NFFO contracts, to be set at zero.

There could be an element of deadweight in subsidising NFFO plant through the RO, given that these plant could perhaps have been funded more cheaply through the FFL. Oxera has explored this issue by running the model with output from NFFO plant that are ineligible for ROCs. The level of the RO on suppliers was reduced correspondingly.

The modelling adjustments made by Oxera removed around two-thirds of the estimated eligible output of NFFO plant.[13] Table 8.6 shows the output removed from the RO as a proportion of baseline generation for the three technologies where adjustments were made.

[13] The remainder was difficult to match to the technology categories in Oxera's model, or would have caused modelling difficulties given Oxera's baseline capacity assumptions.

Table 8.6 Proportion of baseline output of each technology removed from the RO

	Small hydro	Landfill gas	Onshore wind
2003/04	96	74	21
2004/05	96	74	21
2005/06	96	74	21
2006/07	93	70	21
2007/08	93	64	13
2008/09	93	67	13
2009/10	93	69	13
2010/11	83	72	9
2011/12	5	71	7
2012/13	5	74	7
2013/14	1	34	2
2014/15	0	0	2
Thereafter	0	0	0

Source: Oxera.

The removal of NFFO output, with corresponding adjustments to the target, increases ROC prices in the early years as the buy-out fund is distributed among fewer ROC holders. Estimates of the effect on NFPA funds are shown in Table 8.7 below. In the Central scenario, the NFPA's revenues from selling ROCs are estimated to exceed its NFFO contract liabilities, implying that the FFL can be maintained at zero throughout the period. The NFPA records a surplus of £560m. Without this ROC income, however, the NFPA would have to recover an estimated £222m through the FFL.

Table 8.7 summarises the overall effect on policy outcomes. Excluding NFFO-contracted plant and adjusting the target lead to an overall reduction in support because the decrease in ROC income from lowering the level of the RO more than offsets increased consumer payments through the FFL. (Given that Oxera has not removed the entire output of NFFO plant from the RO, net consumer benefits are likely to be higher than suggested by the table.)

Table 8.7 Impact on support cost/tonne CO_2 avoided

	Base	NFFO output ineligible	Change
Central scenario			
CO_2 saved (mt, discounted)	225.9	227.2	1.3
Total support (£m)	20,798	20,182	–616
EU ETS benefit	1,919	1,875	–44
Capital grants	220	230	10
ROC income	13,918	13,192	–726
Network subsidy	2,141	2,141	0
LEC subsidy	2,600	2,526	–74
FFL	0	217	217
Support/tonne CO_2 saved (£)	92.1	88.8	–3.2
Low scenario			
CO_2 saved (mt, discounted)	173.5	174.5	1.0
Total support (£m)	24,307	23,825	–482
Support/tonne CO_2 saved (£)	140.1	136.6	–3.6
High scenario			
CO_2 saved (mt, discounted)	292.9	293.6	0.7
Total support (£m)	14,936	14,209	–726
Support/tonne CO_2 saved (£)	51.0	48.4	–2.6

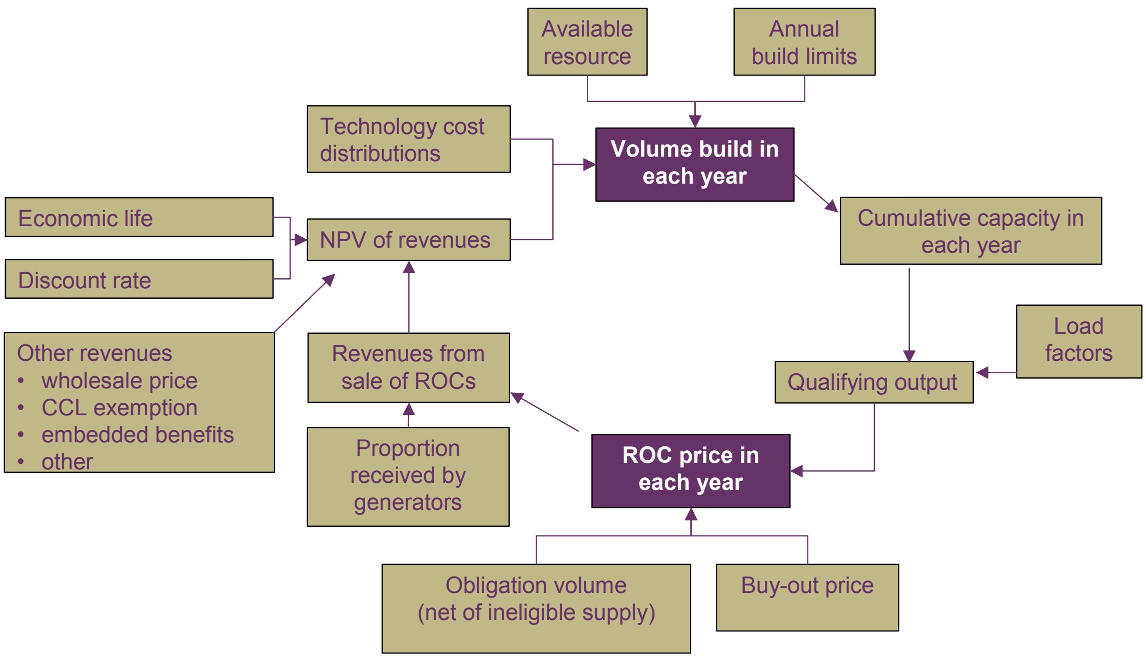
Source: Oxera.

When an NFFO-contracted plant completes the term of its contract with the NFPA, it goes ex-contract and receives ROCs directly. When these plant were built, there was no expectation of any financial support post-contract. Their eligibility for ROCs creates no additional renewable generation, so excluding all ex-contract NFFO plant from the RO could be a means of reducing the size of the support.

Appendix 1 Description of model

Oxera has constructed a detailed model of the renewables sector, enabling scenario analysis to be undertaken of the potential development of the sector up to 2020. The workings of the model, which is under continuous development, are illustrated in Figure A1.1.

Figure A1.1 Oxera's Renewables Model



Source: Oxera.

For a given scenario, the model undertakes an iterative procedure to compute annual levels of new build and annual prices for ROCs that are mutually consistent. In other words, it identifies the market equilibrium in which new-build levels would give rise to the calculated level of ROC prices, and developers would voluntarily choose that level of new build in response to computed ROC prices.

In modelling developer decisions, the model compares, for each technology, the discounted revenues available to a developer over the project lifetime with a distribution for the project's costs. The revenue calculation takes account of the government-backed support available (eg, the RO, capital grants, and the CCL exemption) in addition to revenues from the sale of electricity in the wholesale market and embedded benefits. Costs are assumed to fall though time as technological learning takes place.[14] Annual new build is restricted by resource limits and by maximum build rates, which are intended to reflect constraints that could arise from manufacturing capacity, planning or legal restrictions, or availability of finance for new technologies.

[14] Some of the runs in this report use learning curves explicitly linking costs to cumulative build, as computed by the model. However, later model runs use fixed-cost assumptions (which nonetheless fell through time) to avoid perverse modelling effects.

Appendix 2 Base modelling assumptions

The following tables set out the base modelling assumptions used by Oxera in this work for the NAO.

Table A2.1 Accessible resource, initial capacity and build rates

	Accessible resource (MW)			Initial capacity (MW)	Maximum build rate		
	Northern Ireland	Scotland	England & Wales		2003/04	2009/10	2019/20
Onshore wind	2,000	12,000	3,000	410	300	600	600
Offshore wind	2,000	6,000	17,000	1	100	1,250	1,000
Energy crops	1,000	3,000	10,000	110	0	50	270
Waste	150	250	600	310	0	0	0
Marine	500	2,500	3,000	3	0	50	500
Landfill	20	60	600	530	50	50	50
Co-firing	50	100	1,050	215	0	0	0

Note: the initial capacity figures were chosen so that, when added to the build figures in 2003/04 and multiplied by the load factor, the electricity generated was equal to the amount reported by Ofgem in the ROC register for that technology.

Source: Oxera.

Table A2.2 Load factors—eligibility for the RO

Resources	Load factor	Proportion eligible for RO (%)	
		2004	2010
Onshore wind	0.30	100	100
Offshore wind	0.35	100	100
Energy crops	0.85	100	100
Waste	0.34	0	0
Marine	0.30	100	100
Landfill	0.63	100	100
Co-firing	0.43	100	100

Source: Oxera.

Table A2.3 Existing plant costs

	Fixed costs (£/kW)	O&M (£/kW/yr)	Fuel cost (£/MWh)	Balancing cost (£/MWh)
Onshore wind	1,000	15	0	2
Offshore wind	1,100	35	0	2
Energy crops	1,350	41	3.5	0
Waste	50	15	0	0
Marine	1,500	60	0	2
Landfill	1,464	44.4	0	0
Co-firing	5	0.15	16	0

Note: O&M, operations and maintenance.
Source: Oxera.

Table A2.4 New plant costs, 2004

	Fixed costs (£/kW)	O&M (£/kW/yr)	Fuel cost (£/MWh)	Balancing cost (£/MWh)	Cost of capital (%)
High scenario					
Onshore wind	505–656	12–14.8	0	2	7.8
Offshore wind	845–1,089	28–34	0	2	11.4
Energy crops	810–972	24–28	11–22	0	13.3
Waste	450–540	14–16	0	0	6.4
Marine	893–1,072	36–43	0	2	13.4
Landfill	1,098–1,318	33–40	0	0	6.4
Co-firing	90–108	9–11	0	0	6.4
Central scenario					
Onshore wind	594–772	14–17	0	2	7.8
Offshore wind	1,056–1,373	35–42	0	2	11.4
Energy crops	1,350–1,620	41–49	18–36	0	13.3
Waste	500–600	15–18	0	0	6.4
Marine	1,489–1,787	60–71	0	2	13.4
Landfill	1,220–1,464	37–44	0	0	6.4
Co-firing	100–120	10–12	0	0	6.4
Low scenario					
Onshore wind	683–888	17–21	0	2	7.8
Offshore wind	1,320–1,716	42–50	0	2	11.4
Energy crops	1,890–2,268	57–68	25–50	0	13.3
Waste	550–660	17–20	0	0	6.4
Marine	2,085–2,502	83–100	0	2	13.4
Landfill	1,342–1,610	41–49	0	0	6.4
Co-firing	110–132	11–13.2	0	0	6.4

Source: Oxera.

Table A2.5 Average capital costs of projects built in each year under the Central scenario (£/kW)

	Onshore wind	Offshore wind	Energy crops	Waste	Marine	Landfill	Co-firing
2003/04	591	1,100	1,350	500	1,500	1,220	100
2004/05	578	1,096	1,350	500	1,489	1,220	100
2005/06	568	1,045	1,350	500	1,462	1,220	100
2006/07	560	935	1,350	500	1,435	1,220	100
2007/08	553	935	1,350	500	1,408	1,220	100
2008/09	546	923	1,350	500	1,381	1,220	100
2009/10	540	898	1,350	500	1,354	1,220	100
2010/11	535	879	1,350	500	1,195	1,220	100
2011/12	530	860	1,350	500	1,060	1,220	100
2012/13	525	847	1,350	500	1,060	1,220	100
2013/14	520	836	1,350	500	1,060	1,220	100
2014/15	516	826	1,350	500	1,060	1,220	100
2015/16	512	818	1,350	500	1,060	1,220	100
2016/17	508	810	1,350	500	1,060	1,220	100
2017/18	505	802	1,350	500	1,060	1,220	100
2018/19	501	794	1,350	500	1,060	1,220	100
2019/20	500	787	1,350	500	1,060	1,220	100
2020/21	500	787	1,350	500	1,060	1,220	100
2021/22	499	787	1,350	500	1,060	1,220	100
2022/23	499	787	1,350	500	1,060	1,220	100
2023/24	498	787	1,350	500	1,060	1,220	100
2026/27	498	787	1,350	500	1,060	1,220	100
2025/25	497	787	1,350	500	1,060	1,220	100
2026/27	591	787	1,350	500	1,060	1,220	100

Source: Oxera.

The costs in Tables A2.5 and A2.6 are based on initial cost estimates for 2004, taken from a variety of sources used for the DTI Renewables Innovation Review and referenced therein. These initial costs are rolled forward using ‘learning curves’. These reduce the unit cost by a factor of the rate of growth of installed capacity. There is strong empirical evidence that historical changes in unit costs for products have been linked to growth of installed capacity, and have been an exponential function of output to date. Whether this function will apply to future cost changes in renewables generation technologies is open to speculation, but it is a reasonable assumption to make.

Operating unit costs and balance of plant capital costs were assumed to be a function of UK-installed generation capacity, and turbine and process plant capital costs were assumed to be a function of world-installed generation capacity. This is intended to reflect national and global markets for technologies and skills associated with the plant itself (global), its installation (national), and its operation (national). The distinction is rather crude, however.

The factors relating unit costs to installed capacity are known as ‘progress ratios’ and set the percentage change in unit cost for each doubling of installed capacity. Studies of progress ratios in other sectors find typical values between 80% and 90% for technologies undergoing moderate and very rapid technical change. The figures here lie within this range for those technologies where further technical development is anticipated, but the purpose of using learning curves here is not so much to predict the future cost of renewable energy generation, but to incorporate mechanics that endogenises the unit cost of new build in the model, so that unit cost becomes a function of how much of each technology is built. Progress ratios of 90% were used for onshore wind throughout the time period, for offshore wind from 2007/08, and for energy crops from 2007/08 until 2018/19. A progress ratio of 85% was used for energy crops, and a ratio of 100% was used for landfill and co-firing (implying no cost improvement in these technologies).

At the same time, the costs in Tables A2.5 and A2.6 reflect a gradual movement up the supply curve as the best and cheapest sites are developed, leaving more expensive sites to be developed later. This counteracts the trend in unit cost reduction caused by 'learning'.

Table A2.6 Average O&M costs of projects built in each year under the Central scenario (£/kW)

	Onshore wind	Offshore wind	Energy crops	Waste	Marine	Landfill	Co-firing
2003/04	15.0	35.0	40.5	15.0	60.0	37.0	10.0
2004/05	15.0	35.0	40.5	15.0	60.0	37.0	10.0
2005/06	13.7	35.0	40.5	15.0	30.5	37.0	10.0
2006/07	13.0	35.0	40.5	15.0	27.5	37.0	10.0
2007/08	12.6	35.0	40.5	15.0	25.9	37.0	10.0
2008/09	12.3	33.9	40.5	15.0	24.8	37.0	10.0
2009/10	12.1	33.1	40.5	15.0	24.0	37.0	10.0
2010/11	11.9	32.5	39.8	15.0	23.3	37.0	10.0
2011/12	11.7	32.0	39.2	15.0	22.8	37.0	10.0
2012/13	11.6	31.5	38.7	15.0	22.3	37.0	10.0
2013/14	11.5	31.2	38.2	15.0	21.9	37.0	10.0
2014/15	11.3	30.8	37.9	15.0	21.6	37.0	10.0
2015/16	11.2	30.5	37.5	15.0	21.3	37.0	10.0
2016/17	11.2	30.3	37.2	15.0	21.0	37.0	10.0
2017/18	11.1	30.0	36.9	15.0	20.8	37.0	10.0
2018/19	11.0	29.8	36.6	15.0	20.5	37.0	10.0
2019/20	10.9	29.6	36.4	15.0	20.3	37.0	10.0
2020/21	10.9	29.4	36.4	15.0	20.1	36.9	10.0
2021/22	10.8	29.2	36.4	15.0	19.9	36.8	10.0
2022/23	10.7	29.0	36.4	15.0	19.8	36.7	10.0
2023/24	10.7	28.9	36.4	15.0	19.6	36.6	10.0
2026/27	10.6	28.7	36.4	15.0	19.5	36.5	10.0
2025/25	10.6	28.6	36.4	15.0	19.3	36.4	10.0
2026/27	10.5	28.4	36.4	15.0	19.2	36.3	10.0

Source: Oxera.

Table A2.7 System back-up capital costs and transmission and distribution reinforcement and additional system operating costs (£m)

	System back-up costs			Network reinforcement costs			
	Onshore wind	Offshore wind	Marine	Onshore wind	Offshore wind	Marine	Energy crops
2003/04				–	–	–	–
2004/05				–	–	–	–
2005/06				–	–	–	–
2006/07				30	–	–	1
2007/08				59	–	–	1
2008/09				89	4	–	2
2009/10	14	11	0	97	7	–	3
2010/11	14	11	0	97	7	–	3
2011/12	14	11	0	97	7	–	3
2012/13	14	11	0	112	7	–	3
2013/14	14	11	0	112	24	4	3
2014/15	14	11	0	126	34	7	5
2015/16	14	11	0	143	34	11	7
2016/17	14	11	0	143	49	12	7
2017/18	14	11	0	150	49	12	7
2018/19	14	11	0	150	49	12	7
2019/20	14	11	0	150	49	12	7
2020/21	14	11	0	150	49	12	7
2021/22	14	11	0	150	49	12	7
2022/23	14	11	0	150	49	12	7
2023/24	14	11	0	150	49	12	7
2026/27	14	11	0	150	49	12	7

Note: These figures are equivalent to £1.2 billion CAPEX in transmission reinforcement by 2010; £0.4 billion expenditure in distribution by 2010; and, in the period 2010–20, £1.1 billion CAPEX in transmission and £0.33 billion in distribution. The system back-up costs represent the capital costs of open-cycle gas-fired plant, as predicted in ILEX Energy Consulting (2002), 'Quantifying the System Costs of Additional Renewables in 2020', October.
Source: Oxera.

Table A2.8 Capital grant assumptions in the Central scenario

	Offshore wind			Energy crops			Marine		
	%[1]	£/kW	£m[2]	%[1]	£/kW	£m[2]	%[1]	£/kW	£m[2]
2003/04	10	110	3	15	203	–	0	0	–
2004/05	10	106	64	15	203	0	50	745	3
2005/06	10	105	62	15	203	0	50	731	7
2006/07	0	0	0	15	203	0	50	717	7
2007/08	0	0	0	15	203	10	50	704	7
2008/09	0	0	0	15	203	10	50	690	7
2009/10	0	0	0	10	135	7	50	608	7
2010/11	0	0	0	10	129	13	50	527	35
2011/12	0	0	0	10	123	20	50	459	26
2012/13	0	0	0	10	118	27	0	0	0
2013/14	0	0	0	10	114	36	0	0	0
2014/15	0	0	0	10	111	36	0	0	0
Thereafter	0	0	0	0	0	0	0	0	0
Discounted total			**129**			**159**			**99**

Notes: [1] Defined as a percentage of the lower-bound capital cost in that year. [2] £m figures will depend on the amount of build for each technology and hence represent a model output. However, Central scenario outcomes are included in the table as illustrative figures for the total cost of providing capital grants on these assumptions. Source: Oxera.

Table A2.9 Electricity supplied and generated

	Total electricity generated (TWh)	Losses (%)	Losses (TWh)	Auto-generation (TWh)	Total electricity supplied (TWh)	Demand growth
2003/04	386.5	8.5	32.85	35	318.6	
2004/05	392.1	8.5	33.33	37	321.8	1.5
2005/06	397.8	8.5	33.81	39	325.0	1.4
2006/07	403.4	8.5	34.29	42	327.1	1.4
2007/08	409.1	8.5	34.77	45	329.3	1.4
2008/09	414.7	8.5	35.25	47	332.5	1.4
2009/10	420.4	8.5	35.73	49	335.6	1.4
2010/11	425.4	8.5	36.16	47	342.3	1.2
2011/12	430.5	8.5	36.59	47	346.9	1.2
2012/13	435.6	8.5	37.03	47	351.6	1.2
2013/14	440.7	8.5	37.46	47	356.2	1.2
2014/15	445.8	8.5	37.89	47	360.9	1.2
2015/16	450.9	8.5	38.32	47	365.5	1.1
2016/17	455.9	8.5	38.76	47	370.2	1.1
2017/18	461.0	8.5	39.19	47	374.8	1.1
2018/19	466.1	8.5	39.62	47	379.5	1.1
2019/20	471.2	8.5	40.05	47	384.1	1.1
2020/21	476.3	8.5	40.48	47	388.8	1.1
2021/22	481.4	8.5	40.92	47	393.4	1.1
2022/23	486.4	8.5	41.35	47	398.1	1.1
2023/24	491.5	8.5	41.78	47	402.8	1.0
2026/27	496.6	8.5	42.21	47	407.4	1.0
2025/26	501.8	8.5	42.65	48	411.1	1.0
2026/27	506.9	8.5	43.09	49	414.9	1.0

Sources: DTI (2003), *Digest of UK Energy Statistics*, and Oxera calculations.

Table A2.10 Electricity prices, £/MWh

	Wholesale electricity price	Embedded benefits[2]	Impact of EU ETS included in wholesale price	LECs[1]
High scenario				
2003/04	20.0	2.5	0.00	4.3
2004/05	25.1	2.5	0.95	4.3
2005/06	28.2	2.5	3.81	4.3
2006/07	29.0	2.5	3.81	4.3
2007/08	28.8	2.5	3.81	4.3
2008/09	29.9	2.5	3.81	4.3
2009/10	30.0	2.5	3.81	4.3
2010/11 and thereafter	30.5	2.5	3.81	4.3
Central scenario				
2003/04	20.0	2.5	0.00	4.3
2004/05	25.1	2.5	0.73	4.3
2005/06	25.6	2.5	2.93	4.3
2006/07	26.9	2.5	2.93	4.3
2007/08	26.0	2.5	2.93	4.3
2008/09	26.3	2.5	2.93	4.3
2009/10	26.3	2.5	2.93	4.3
2010/11 and thereafter	26.8	2.5	2.93	4.3
Low scenario				
2003/04	20.0	2.5	0.00	4.3
2004/05	25.1	2.5	0.51	4.3
2005/06	23.0	2.5	2.05	4.3
2006/07	23.3	2.5	2.05	4.3
2007/08	21.0	2.5	2.05	4.3
2008/09	21.8	2.5	2.05	4.3
2009/10	21.8	2.5	2.05	4.3
2010/11 and thereafter	22.3	2.5	2.05	4.3

Note: [1] It is assumed that the generator receives only 90% of the value of the LECs. [2] Embedded benefits are defined as the avoided costs of national grid charges and transmission losses.
Source: Oxera.

Table A2.11 NFFO, estimate of maximum annual GWh generated

NFFO	Year	Biomass	Hydro	Landfill gas	Waste	Other	Sewage gas	Wind
1	1990	–	10	124	332	189	65	5
2	1991	–	–	166	235	93	106	138
3	1995	–	225	87	611	576	305	28
4	1997	–	7	1,055	249	97	25	4
5	1998	–	2	853	–	–	–	10
SRO 1	1994	73	25	–	28	–	–	66
SRO 2	1997	–	5	–	112	–	–	82
SRO 3	1999	–	–	–	77	–	–	28
NI 1	1994		2.3					12.7
NI 2	1996	0.3						2.6

Source: Oxera.

Table A2.12 NFFO, estimate of average contract prices (£/MWh)

NFFO	Biomass	Hydro	Landfill gas	Waste	Other	Sewage gas	Wind
1	60	67.5	58	60	54	60	100
2	60	60	57	66	59	59	110
3	43.5	44	37	38	50	50	43
4	34.6	44	32	30	50	34.6	38
5	55	27.1	27.1	27.1	50	27.1	27.1
SRO 1	43.5	44	37	38	50	50	43
SRO 2	34.6	44	32	30	50	34.6	38
SRO 3	55	27.1	27.1	27.1	50	27.1	27.1
NI 1	43.5	44	37	38	50	50	43
NI 2	34.6	44	32	30	50	34.6	38

Source: Oxera.

Table A2.13 Suppliers' obligation

	Percentage of electricity supplied to be sourced from renewables
2003/04	4.3
2004/05	4.9
2005/06	5.5
2006/07	6.7
2007/08	7.9
2008/09	9.1
2009/10	9.7
2010/11	10.4
2011/12	11.4
2012/13	12.4
2013/14	13.4
2014/15	14.4
2015/16	15.4
2016/17	15.4
2017/18	15.4
2018/19	15.4
2019/20	15.4
2020/21	15.4
2021/22	15.4
2022/23	15.4
2023/24	15.4
2026/27	15.4
2025/26	15.4
2026/27	15.4

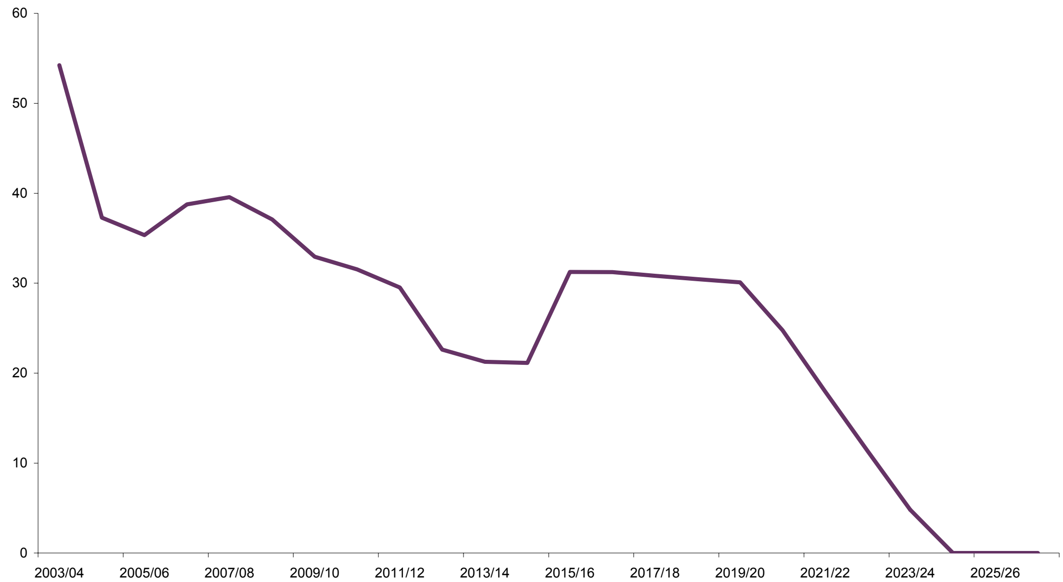
Source: Oxera.

Table A2.14 Other assumptions

Item	Assumed value
Proportion of ROC value received by generator	90%
Proportion of LEC value received by generator	90%
Plant lifetime	20 years
Depreciation	Straight-line
Tax payable	30% on post-tax operating profit
Enhanced capital allowances or accelerated depreciation	None
Rate of inflation used to estimate real cost of capital from nominal cost of capital	2.5%

Source: Oxera.

Figure A2.1 Expected ROC price (£/MWh) under the Central scenario



Source: Oxera.

Appendix 3 Survey methodology

Oxera carried out a survey of companies participating in the ROC market to gather information on:

– transaction costs associated with the RO (including staff, IT systems and legal, consulting and brokerage costs);
– trading activity and the liquidity of the ROC market over different time horizons;
– other views and comments on the ROC market.

Separate versions of the survey were prepared for generators and suppliers.

The survey was sent to the six large energy supply companies and to 12 renewable generating companies of varying size and technology. Oxera received responses from three suppliers (representing over 40% of domestic electricity customers) and from seven generators.

In line with assurances provided to respondents, Oxera has treated survey returns as confidential and has presented survey results in this report such that they cannot be traced to any individual respondent.

Appendix 4 Assumptions for co-firing analysis

Oxera examined co-firing using its wholesale electricity market model. We used the scenario of input fuel prices shown in Table A4.1, and assumed an EU ETS allowance price of €7/tonne CO_2.

Table A4.1 Fuel price assumptions used in wholesale market model[1]

	Coal (£/tonne)[2]	Gas (p/therm)[3]
2004/05	34.3	24.0
2005/06	30.2	24.3
2006/07	26.2	23.5
2007/08	22.6	23.0
2008/09	22.5	22.5
2009/10	22.4	22.0
2010/11	22.3	22.0

Note: [1] In the model, coal transportation costs vary for each coal plant, and gas prices vary according to a seasonal profile. [2] Coal prices are real ARA prices. [3] Gas prices are real prices at the National Balancing Point.
Source: Oxera.

The impact of co-firing was incorporated into the model by adjusting the short-run marginal cost (SRMC) of coal plant, as shown by the illustrative calculations in Table A4.2, as well as by changing the level of CO_2 and SO_2 emissions for each MWh generated from coal plant (assuming that biomass is treated as zero-emitting). Oxera made the simplifying assumption that all coal plant burn the same proportion of biomass. The table shows that co-firing allows coal plant to operate profitably at lower electricity prices due to the additional ROC income.

Table A4.2 Illustrative calculations of the impact of co-firing on the SRMC of coal plant

	Value	Comments
Assumptions		
Coal price (£/MWh)	4.94	
Biomass price (£/MWh)	12.06	
Proportion by calorific value of biomass burnt (%)	3	This level of co-firing was judged to be broadly consistent with the amount of biomass material available, and thus that it would not require significant investment by coal plant. A sensitivity test revealed the same pattern of results when a higher biomass proportion was used in the modelling
ROC price (£/MWh)	40	
Coal plant efficiency (%)	35	
SRMC without co-firing (£/MWh)		
Fuel cost	14.13	Calculated as the coal price divided by plant efficiency
SRMC with co-firing (£/MWh)		
Coal fuel cost	13.70	Coal fuel cost/MWh is lower under the co-firing scenario due to replacement of some coal with biomass
Biomass fuel cost	1.03	Calculated as biomass price divided by plant efficiency, multiplied by the percentage of biomass content
Total fuel cost	14.74	Fuel costs are slightly higher with co-firing because biomass is more expensive than coal
ROC income	1.20	Calculated as the ROC price multiplied by the percentage of biomass content
Net fuel cost	13.54	Fuel cost net of ROC income is lower under the co-firing scenario because ROC income more than offsets the additional cost of biomass relative to coal

Note: The assumed coal price varied between years.
Source: Oxera.

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