Title: Government response to the consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013-17 and the Renewables Obligation Order 2012.	**Impact Assessment (IA)**
IA No: DECC0075	**Date:** 25/07/2012
Lead department or agency: Department of Energy and Climate Change (DECC)	**Stage:** Final
Other departments or agencies: Ofgem	**Source of intervention:** Domestic
	Type of measure: Primary legislation
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Summary: Intervention and Options

RPC Opinion: N/A

Cost of Preferred (or more likely) Option				
Total Net Present Value	**Business Net Present Value**	**Net cost to business per year** (EANCB on 2009 prices)	**In scope of One-In, One-Out?**	**Measure qualifies as**
-£1,800m	N/A	N/A	No	N/A

What is the problem under consideration? Why is government intervention necessary?

Renewable energy technologies are more expensive than fossil fuel alternatives, this and other non-financial barriers make government intervention necessary to incentivise sufficient investment in renewable electricity generation for the UK to meet its EU 2020 renewable energy targets. The Renewables Obligation (RO) is currently the UK's principal mechanism to incentivise growth in large scale renewable electricity generation. Bands of support under the RO were introduced in 2009, which allowed the RO to offer varied support levels by technology, and reviews of those banding levels were set for every four years. Banding reviews are necessary to help ensure enough large scale renewable electricity generation is deployed to achieve the UK's 2020 targets, this deployment is achieved cost effectively and the scheme meets other objectives, including delivering value for money to electricity consumers.

What are the policy objectives and the intended effects?

RO bands for the period 1st April 2013 to 31st March 2017 are proposed at levels that should help ensure the RO supports sufficient growth in renewable energy deployment to meet the UK's 2020 renewable energy targets. These recommendations on RO bands should increase the efficiency of the RO, offer value for money to consumers and ensure that the scheme remains within the budgetary constraints as set through the Levy Control Framework (LCF). By incentivising deployment of renewable electricity the RO supports delivery of wider energy and climate change goals to 2050, including reductions in greenhouse gas emission and the increased diversification of energy supply.

What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)

In October 2011 the Government consulted on different options for setting the RO bands for new stations for the review period from 1st April 2013 to 31st March 2017. This Impact Assessment (IA) considers three options:

(i) Option 1: Do nothing – leave current policy unchanged over the review period (i.e. maintain the current RO bands from 2013 to 2017[1]).

(ii) Option 2: Consultation bands – adopt RO bands over the review period as set out in the Government Consultation published in October 2011.

(iii) Option 3: Response bands – adopt refined RO bands over the review period as set out in the Government Response to the Consultation published alongside this IA in July 2012.

Option 3 is the preferred option. It reflects new evidence gathered during the consultation and adjusts some bands accordingly, with the aim of providing sufficient support for cost-effective renewable technology deployment to achieve the 2020 targets, offering value for money to consumers and staying within the LCF budgetary constraints.

Will the policy be reviewed? This is the last scheduled review. DECC will continue to monitor costs and deployment in the usual way.

Does implementation go beyond minimum EU requirements?	N/A				
Are any of these organisations in scope? If Micros not exempted set out reason in Evidence Base.	**Micro** N/A	**< 20** N/A	**Small** N/A	**Medium** N/A	**Large** N/A
What is the CO_2 equivalent change in greenhouse gas emissions? (Million tonnes CO_2 equivalent)	**Traded:** -82	**Non-traded:**			

1 Unlike for other technologies, "do nothing" would see the offshore wind band reduce from 2 to 1.5 ROCs/MWh from 1 April 2014, in line with the offshore-wind-specific early banding review conducted in 2009.

I have read the Impact Assessment and I am satisfied that (a) it represents a fair and reasonable view of the expected costs, benefits and impact of the policy, and (b) that the benefits justify the costs.

Signed by the responsible Minister: Charles Hendry Date: 24.07.12

Summary: Analysis & Evidence   Policy Option 2 Consultation bands

Description: the package of bands proposed in the Consultation. Impacts presented relative to the Do Nothing Option 1 (current bands).

FULL ECONOMIC ASSESSMENT

Price Base	PV Base	Time Period	Net Benefit (Present Value (PV)) (£m)		
2011/12	2012/13	Years 27	Low:	High:	Best Estimate: -2,300

COSTS (£m)	Total Transition (Constant Price) Years		Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				
High				
Best Estimate			89	**4,400**

Description and scale of key monetised costs by 'main affected groups'

The monetised costs are increases in overall system generation costs and balancing costs, rounded to two significant figures. There is also a distributional cost to electricity consumers from higher RO support costs.

Other key non-monetised costs by 'main affected groups'

Wider macroeconomic costs of the small increase in retail electricity prices and, any small increase in intermittent generation that could adversely affect the security of supply.

BENEFITS (£m)	Total Transition (Constant Price) Years		Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low				
High				
Best Estimate			74	**2,100**

Description and scale of key monetised benefits by 'main affected groups'

The monetised benefits are the reduction in costs of EU Emissions Trading System Allowance (EUA) purchase to the UK power sector.

Other key non-monetised benefits by 'main affected groups'

Bringing forward wave and tidal stream technologies as options for decarbonising the power sector and meeting rising electricity demand; developing renewables industries (note developing one sector of the economy will lead to some displacement and crowding out in other sectors); reducing risk of missing the UK's 2020 renewables target and of incurring potentially unlimited infraction fines; increased security of supply due to reductions in fossil fuel imports. There are likely to be small net air quality benefits, as the air quality benefits of displacing fossil fuel electricity generation outweigh any negative air quality impacts of increasing bioenergy and waste renewable technologies.

Key assumptions/sensitivities/risks — **Discount rate (%)** 3.5%

- Current technology costs and learning rates
- Maximum build rates by technology
- Biomass availability and fuel prices
- Fossil fuel prices
- Hurdle rates

BUSINESS ASSESSMENT (Option 1)

Direct impact on business (Equivalent Annual) £m:			In scope of OIOO?	Measure qualifies as
Costs: N/A	**Benefits:** N/A	**Net:** N/A	No	N/A

Summary: Analysis & Evidence Policy Option 3 Response bands

Description: revised bands taking into account new evidence gathered during the Consultation. Impacts presented relative to the Do Nothing Option 1 (current bands).

FULL ECONOMIC ASSESSMENT

Price Base	PV Base	Time Period	Net Benefit (Present Value (PV)) (£m)		
2011/12	2012/13	Years 27	Low: -4,000	High: +2,900	Best Estimate: -1,800

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				5,600*
High				-3,500*
Best Estimate			67	3,700

Description and scale of key monetised costs by 'main affected groups'

The monetised costs are increases in overall system generation costs and balancing costs, rounded to two significant figures. There is also a distributional cost to electricity consumers from higher RO support costs.

Other key non-monetised costs by 'main affected groups'

Wider macroeconomic costs of the small increase in retail electricity prices and any small increase in intermittent generation that could adversely affect the security of supply.

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low				1,600*
High				-600*
Best Estimate			69	1,900**

Description and scale of key monetised benefits by 'main affected groups'

The monetised benefits are the reduction in costs of EUA purchase to the UK power sector. There are small net air quality benefits, as the air quality benefits of displacing fossil fuel electricity generation outweigh any negative air quality impacts of increasing bioenergy and waste renewable technologies.

Other key non-monetised benefits by 'main affected groups'

Bringing forward wave and tidal stream technologies as options for the decarbonising the power sector and meeting rising electricity demand; developing renewables industries (note developing one sector of the economy will lead to some displacement and crowding out in other sectors); reducing risk of missing UK's 2020 renewables target and of incurring potentially unlimited infraction fines; increased security of supply due to reductions in fossil fuel imports.

Key assumptions/sensitivities/risks **Discount rate (%)** 3.5%

Key assumptions, sensitivities and risks relate to: current technology costs and learning rates; Maximum build rates by technology; Biomass availability and fuel prices; Fossil fuel prices; and Hurdle rates.

BUSINESS ASSESSMENT (Option 2)

Direct impact on business (Equivalent Annual) £m:			In scope of OIOO?	Measure qualifies as
Costs: N/A	**Benefits:** N/A	**Net:** N/A	No	N/A

***The monetised costs and benefits associated with the low net benefit estimate relate to a high fossil fuel price scenario, where both costs and benefits increase compared with current bands. The monetised costs and benefits associated with the high net benefit estimate relate to a low fossil fuel price scenario, where both costs and benefits decrease compared with current bands. Details of these scenarios are presented in Section 5 and Annex D of this IA.

**The benefits in the central case (central fossil fuel prices) are higher than in the low case (high fossil fuel case) owing to the higher increase in renewable deployment (largely ECF and conversions) under proposed bands compared to current bands.

Evidence Base (for summary sheets)

The evidences base is set out as follows:

1. Strategic overview

1. The EU Renewable Energy Directive commits the UK to meeting 15% of its energy needs from renewable sources by 2020. To achieve this, renewable electricity supply from large scale generation will need to increase from around 26TWh in 2010 to around 108TWh (under the central renewables deployment scenario) by 2020, and further deployment of renewable electricity will need to come from smaller-scale generation (<5MW).

2. The Renewables Obligation (RO), introduced in 2002, is currently the Government's main financial policy mechanism for incentivising the deployment of large scale renewable electricity generation in the UK – small scale renewable electricity generation is incentivised through a separate Feed-in-Tariff scheme. Since the introduction of the RO in 2002, there has been a more than trebling in the UK's renewable generation, from 1.8% to 9.4% in 2011.[2] The RO has played an important part in securing reductions in carbon dioxide emissions, alongside other policy measures such as the Climate Change Act 2008.

3. From the RO's introduction in 2002 until 2008/09, all renewable energy technologies received the same band of support at 1 Renewable Obligation Certificate (ROC) per MWh of renewable electricity generated. Different RO bands of support for eligible technologies were set for new stations in the four years from 2009/10 to 2012/13, which sought to remove overcompensation of lower cost technologies and provide incentive for more expensive technologies that had significant deployment potential.

4. The Government Consultation published in October 2011[3] consulted on the levels of banded support for renewable electricity generation for the period 1st April 2013 to 31st March 2017 (except for offshore wind[4] where the RO bands were only considered for 2014/15 to 2016/17), and a number of other matters relating to the draft Renewables Obligation (Amendment) Order 2012 - including grandfathering, the co-firing cap, the bioliquids cap and definitional changes to some bands.

5. The RO will close to new renewables stations from 1st April 2017, whilst maintaining support for existing stations in the scheme out to their respective end dates (of which the latest would be expected in 2037), as part of the Electricity Market Reform. Support for large-scale renewable electricity will be available from around 2014 onwards through the new Feed-in Tariff with Contract-for-Difference scheme (FiT with CfD).

6. The objectives of this banding review are to:
   i. Set cost effective support levels for renewable technologies from 2013/14 to 2016/17;
   ii. Set levels which would keep the UK on track to meet the 2020 target, including interim targets for the two-year periods 2013-2014 and 2015-2016,and our longer term decarbonisation targets;
   iii. Fully take into account all six statutory factors for banding decisions, summarised below:
      (a) the costs (including capital costs) associated with each renewable electricity technology;

2 RO-eligible electricity generation as a proportion of UK electricity sales

3 http://www.decc.gov.uk/en/content/cms/consultations/cons_ro_review/cons_ro_review.aspx

4 An early review of the band for offshore wind was held in 2009, which led to it increasing from 1.5 to 2 ROCs/MWh for new stations up to and including 2013/14, after which it was due, in the absence of other action, to fall back to 1.5 ROCs/MWh.

(b) the income associated with generating electricity from each renewable electricity technology;
(c) the supplies from renewable sources exempted from the climate change Levy (CCL) in relation to generating electricity from each renewable electricity technology;
(d) the desirability of promoting the industries associated with renewables;
(e) impacts on the market for ROCs and on consumers; and
(f) contributions towards achieving European targets, including the interim and final 2020 renewables target.

7. The Coalition Government has made clear its commitment to maintaining a banded RO alongside other support mechanisms that will be introduced through Electricity Market Reform (i.e. FiT with CfD), with the aim of securing a significant increase in investment in renewable electricity generation.

8. In the light of new evidence generated through the Consultation process, this IA sets out the costs and benefits of final decisions on appropriate RO banding support levels for the period 1st April 2013 to 31st March 2017 for all eligible technologies. It should be noted that the assumed bands for large scale solar PV, standard co-firing and co-firing with energy crops will be subject to further consultation.

9. There are a number of related policy issues that are not covered in this IA and are subject to separate consultations, including: proposals to implement a dedicated biomass cap; to bring in further sustainability requirements for biomass; to bring in a new set of monitoring and reporting requirements for the co-firing and conversions bands; to take away support for new sub-5MW solar PV, AD, hydro and onshore installations in Great Britain; to remove the uplift for co-firing with energy crops; and to re-assess the solar PV band in the light of new evidence. These issues are discussed in Annex E.

2. Policy Objective / Rationale for intervention

10. The overarching objective of the RO is to facilitate the delivery of the UK's renewable energy targets, as set under the EU Renewable Directive. Government needs to ensure support is available to large-scale renewable electricity technologies, as current renewables costs are higher than their conventional alternatives, and as such they would not be undertaken at the levels required or in the timescales needed in the absence of support. Current bands under the RO do not put the UK on track to meet the renewables targets, therefore further cost effective deployment of large scale renewable electricity is required.

11. In addition to this, there are a number of market failures and other barriers which would lead to too little investment in renewable technologies without government intervention. These include: the negative externalities relating to greenhouse gas (CHG) emissions (i.e. the damage costs of GHG emissions are not factored into investor decision making, although this is being partially addressed by the EU Emissions Trading System, supported by the Carbon Price Floor); positive externalities relating to investment in innovative and emerging technologies; the homogenous nature of electricity as a product (from a consumers' perspective electricity is electricity[5] and is difficult for renewable generators to compete on anything other than price); imperfect information; and, limited access to capital.

[5] Although suppliers may label their electricity and tariffs according to its emissions.

12. RO bands for the period 1st April 2013 to 31st March 2017 are proposed at levels that should help ensure the RO supports sufficient growth in renewable energy deployment to meet the UK's 2020 renewable energy targets. These recommendations on RO bands should increase the efficiency of the RO, offer value for money to consumers and ensure that the scheme remains within the budgetary constraints as set through the Levy Control Framework (LCF). By incentivising deployment of renewable electricity the RO supports delivery of wider energy and climate change goals to 2050, including reductions in greenhouse gas emission and the increased diversification of energy supply.

3. Analytical approach

13. This IA sets out the impact on deployment of renewable technologies, and costs and benefits of changes to RO bands, against the counterfactual of continuing with current banding levels. This IA also estimates quantitatively and/or qualitatively as far as possible a number of other impacts, including:

    i) Carbon impacts;

    ii) Security of supply impacts;

    iii) Air quality and other environmental and social impacts; and

    iv) Ensuring compatibility with/ minimising risk of not being on a cost-effective pathway to 80% decarbonisation of the economy by 2050.

14. The analytical approach to assessing the impact of the options considered in this IA is broadly unchanged from the analysis for the RO banding review consultation. Changes to the evidence base are detailed in section 3 A) and Annex A. The analysis is based on a combination of electricity despatch modelling by Pöyry consultants and in-house renewables investment decision modelling described in sections 3 B) to E).

A) Updated evidence base

15. To inform the IA that accompanied the Consultation published in October 2011, evidence was gathered by Arup, supported by their subcontractors Ernst & Young, on the deployment potential and generation costs of renewable electricity technologies currently or potentially eligible for RO support.[6] Other sources of evidence used included project pipeline data[7] and research commissioned for the CCC's Renewable Energy Review.[8]

16. During the consultation, responses were sought on the evidence collected for all technologies. In particular the National Non-Food Crops Centre collected data from advanced conversion technologies (ACT) developers and recommended ranges for the costs and deployment to be used in this analysis, while the international energy consultants AEA carried out a similar process for renewable combined heat and power (CHP) costs and deployment. DECC worked with coal generators considering biomass conversion/enhanced co-firing to understand costs, technical characteristics and deployment potential.

17. Revised estimates of capital costs, operating costs and certain other parameters for all technologies

[6] Arup (2011) available alongside the consultation document at:
http://www.decc.gov.uk/en/content/cms/consultations/cons_ro_review/cons_ro_review.aspx
[7] From the Office for Renewable Energy Deployment, DECC
[8] Mott MacDonald (2011), Costs of Low Carbon Generation Technologies, available at
hmccc.s3.amazonaws.com/Renewables%20Review/MML%20final%20report%20for%20CCC%209%20may%202011.pdf

were in the form of a range, generally reflecting the 10th and 90th percentiles of sample data for the pipeline of potential projects (or existing projects where pipeline data was not available). Projections of future costs were determined by learning rates (reflecting learning and economies of scale, market dynamics, etc). Cost data used in modelling the options for this IA are summarised in the annex to the government response. In Annex A of this IA is an explanation of revisions to DECC's cost data since publication of the Consultation IA in November 2011, based on consultation responses and third party information.

18. Since publication of the Consultation IA, all overarching assumptions have been revisited to reflect the latest evidence. These include:
    i. New DECC Fossil Fuel prices[9], which affect the estimates of wholesale electricity prices, and the costs of fossil fuel generation.[10]
    ii. New renewable fuel supply constraints and prices for biomass and waste technologies.[11]
    iii. New DECC electricity demand projections[12]
    iv. New DECC carbon prices for electricity modelling[13]
    v. Heat revenues, i.e. avoided cost of heat – revised following change to fossil fuel prices and carbon prices
    vi. Value of Levy Exemption Certificates (LECs) – post 2023/24 the amount of LECs supplied by renewable generators is estimated to exceed the demand for LECs from firms which pay the full rate of Climate Change Levy (CCL). The price of a LEC will therefore fall to the price paid by firms under a Climate Change Agreement (CCA), i.e. 10% of the full value.[14]
    vii. The conclusions of the government's Bioenergy Strategy[15]

19. Whilst all assumptions have been scrutinised, they are still subject to uncertainty. For example, the range of renewable capital costs which have been submitted as part of the consultation has been used as a proxy for the full range of overall project costs. However, these may over or under-estimate the variation in costs across projects for any particular technology. How costs vary over time is uncertain and to a large extent will depend on global deployment and the rate at which economies of scale can be achieved, technological developments and supply chain market dynamics. Future wholesale electricity prices are uncertain as they depend on many factors including fossil fuel prices and the impact of the changing regulatory framework, inter alia.

B) Interactions with Electricity Market Reform

20. Full implementation of the Electricity Market Reform (EMR) has been assumed by Pöyry consultants in modelling the impact of RO banding options on the electricity market. This is consistent with the approach taken for the government Consultation and entails the introduction of:

[9] http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/ff_prices/ff_prices.aspx
[10] Assumptions on investor expectations of wholesale electricity prices can influence the ROC banding needed significantly, i.e. if lower wholesale electricity prices are assumed, a higher ROC band is needed for the investment to break even. For the central scenario, it is assumed that investors base their decisions on the modelled wholesale electricity prices from Pöyry, but that they have just five years of foresight, after which they assume electricity prices are constant in real terms at the level of the fifth year. In reality, different investors will have different views of future wholesale electricity prices.
[11] Based on AEA (2011), evidence provided in consultation and DECC calculations
[12] http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/en_emis_projs/en_emis_projs.aspx#2011-projections
[13] http://www.decc.gov.uk/en/content/cms/emissions/valuation/valuation.aspx#
[14] Demand for LECs is derived from two sources: firms which pay the full rate of CCL and firms under CCAs, who only pay 10% of the full cost of the CCL. Once demand for LECs from firms who pay the full rate of the CCL is satiated, the price falls to the avoided cost of the discounted CCL under CCAs.
[15] http://www.decc.gov.uk/en/content/cms/meeting_energy/bioenergy/strategy/strategy.aspx

i. An Emissions Performance Standard (EPS);
ii. A capacity mechanism;[16]
iii. Carbon Price Floor; and
iv. A system of feed-in tariffs with contract for difference[17] (FiT with CfD) to support low carbon technologies including renewables.

21. After the introduction of the new FiT with CfD (the first contracts are expected in 2014), new renewables developers will have the choice between support under the RO and support under the FiT with CfD, until the closure of the RO to new stations from 1st April 2017. Investment decisions are likely to be aided by financial investment decision (FID) enabling strategies should these be implemented as part of the EMR package. In view of this, it has been assumed for the purpose of this analysis that:

    i. All new renewables stations eligible for the RO and commissioning in 2013/14, 2014/15 and 2015/16 will be supported under the RO (except where they are eligible for small-scale FiTs).
    ii. All new renewables stations eligible for the RO and commissioning in 2016/17 will be supported under the new FiT with CfD scheme, rather than the RO.

22. These are simplifying assumptions and it is not clear at this stage whether individual investors will choose the RO or the FiT with CfD. The switchover point is a modelling simplification. In reality, there is likely to be an overlap period, with some new renewables stations choosing the FiT with CfD in earlier years, and some choosing the RO in 2016/17, if they judge the risk of missing the RO end-date to be insignificant (or if their construction overruns from an intended accreditation date in earlier years).

C) General modelling approach

23. To analyse the options set out in this IA, DECC commissioned Pöyry to run their Eureca electricity market despatch model and ROCket renewable electricity model. In addition, DECC undertook in-house analysis to act as a cross check and test additional sensitivities.

24. ROCket determines the renewables investment and hence deployment for a given set of RO bands. The range of overall generation costs (i.e. levelised costs) for most technologies is driven by considering the range of capital costs only, keeping all other assumptions on their central values. The range of ROCs required for ACT and Energy from Waste (EfW) plants is driven by both the range of capital costs and gate fees (negative fuel costs), as there is particular uncertainty about the gate fee for these plants. Given the way in which projects in the EfW market compete with each other for waste contracts, the ROCs required for EfW CHP plants have been assessed relative to the economics of power only plants with the same assumption on gate fees.

25. Eureca is used to estimate non-renewable investment decisions, short-run despatch decisions for all technologies and how total supply meets demand overall and the resulting wholesale prices. The modelling approach involves iteration between the two models, with wholesale electricity prices from the Eureca model driving investor decisions in the ROCket model, which then influences electricity prices. Because of the relatively high level of uncertainty on the future deployment of biomass conversion and enhanced co-firing (ECF), a more detailed analysis was also used to look at the possible impact of different banding levels on the deployment of these two technologies and hence costs.

[16] Assumed to be implemented if capacity margins are expected drop below 10%.
[17] For full details, see the Energy Bill (2012), available at: http://www.decc.gov.uk/en/content/cms/legislation/energybill2012/energybill2012.aspx

26. Alongside Pöyry modelling, DECC developed an in-house discounted cashflow model to determine the range of ROCs required for each technology for each year until 2016/17 – this analysis is presented at Annex F. The in-house analysis was used to cross check the results from the Pöyry modelling, explore further sensitivities and help choose the banding options for Pöyry to model according to the objectives set out in section 3. D) below.

D) Approach used for selecting the banding options for each technology

27. DECC's in-house analysis determined a range of ROCs required by each technology. From this range bands were chosen (for each technology in each year of the banding review period) to model in ROCket/Eureca and, ultimately, to set the bands for the options in this IA. To ensure the schemes objectives are met, as set out in section 1, the following principles were followed when selecting the bands for each technology:

    i. To reduce costs to consumers the bands incentivised more of the relatively cheaper technologies and less of the relatively expensive technologies.
    ii. Proposed bands are never above the top of the ranges of ROCs required to ensure that costs to the economy and consumers are not higher than necessary.
    iii. Technologies with significant large-scale deployment potential were incentivised so that the expected trajectory remains on track to meet large-scale electricity's contribution to interim and 2020 renewables targets, while ensuring a range of technologies are incentivised.
    iv. Technologies which have strategic long-term value for 2020 and beyond, and/or where is it particularly desirable to promote the industries associated with the technologies, were allocated more support than a strict minimising cost approach up to 2020 (this applies to offshore wind, ACTs, wave and tidal technologies).
    v. Bands were selected to ensure coal to biomass conversions and enhanced co-firing are incentivised at a level consistent with helping security of electricity supply, more detail on the modelling approach for these technologies is given in Annex C.
    vi. To limit costs to consumers, bands were selected to ensure expected RO spend was less than the total RO budget for the four years of the Levy Control Framework (LCF) and that expected overspends in individual years did not exceed the 20% allowed flexibility on the overall LCF budget.

E) Modelling approaches for biomass conversions and Enhanced Co-Firing (ECF)

28. The responses to the Banding Review consultation indicated there was more potential for biomass conversions and ECF during the banding review period, than indicated by Arup's analysis on technical potential for the RO consultation. Given this uncertainty and the large potential impact of this technology on RO spending and renewable electricity deployment, potential uptake was analysed in detail. In common with the approach taken for all technologies, DECC undertook Pöyry modelling and in-house modelling of conversions and ECF investment decisions. In addition to this, a "bottom-up" view based on a combination of modelling, together with technical and market intelligence, was generated to underpin the central results set out in section 5. below. Full details for these technologies are presented in Annex C.

4. Description of options considered

29. This section explores the options considered as part of the Government Response to the consultation on the RO banding review. There are a number of related policy issues that are not covered in this IA and are subject to separate consultations (see Annex E).

Option 1 – Do nothing (Current bands)

30. This option retains the bands which are currently offered through the RO, as shown in the second column of Table 1 below. It also retains the cap on co-firing at 12.5% of all ROCs that suppliers can submit in a given year.

Option 2 – Consultation bands

31. This option reflects the bandings as proposed in the Consultation. In particular, it removes the cap on co-firing; introduced two new bands of ECF and conversion; increases support for wave and tidal stream to 5 ROCs/MWh (subject to a 30MW project cap); cuts support for hydro and EfW to 0.5 ROCs/MWh; reduces support for onshore wind to 0.9 ROCs/MWh; and reduces support for everything at the 2 ROCs level, including offshore wind, to 1.9 in 2015/16 and 1.8 in 2016/17.

Option 3 – Response bands

32. Following assessment of new evidence received through the Consultation and updated analysis, the following changes to the Consultation bands have been announced in the Government Response:

- **Standard co-firing (SCF), enhanced co-firing (ECF) and conversion:**

  I. To redefine SCF, ECF and conversion as burning a percentage of biomass fuel in a boiler /unit as opposed to the percentage of biomass fuel burnt in the whole (former) fossil fuel power station, with bands increasing gradually as a greater percentage of biomass is burned in each unit as follows:

     - SCF (Up to 50% biomass) at 0.3 ROCs/MWh in 2013/14 and 2014/15 rising to 0.5ROCs/MWh for the rest of the period – this proposal will be the subject of a further consultation
     - Mid-range co-firing (50% to up to 85% biomass) at 0.6 ROCs/MWh
     - High-range co-firing (85% to up to 100% biomass) at 0.7 ROCs/MWh in 2013/14, rising to 0.9 ROCs/MWh from 2014/15
     - Conversion (100% biomass) at 1.0 ROC/MWh

  II. Proposed new monitoring and reporting requirements for biomass conversions and ECF will be the subject of a new consultation. See section 9 of the government response.

  III. Bioliquids will not be an eligible fuel for the mid-range co-firing and high-range co-firing bands.

  IV. There will be no additional support for mid-range co-firing with energy crops, high-range co-firing with energy crops or conversion with energy crops bands.

  V. There will be additional support for mid-range co-firing with CHP, high-range co-firing with CHP and conversion with CHP bands.[18] Extra support for CHP may incentivise heat

[18] These extra bands are not expected to result in significant extra deployment, as neither the evidence available for the consultation or the

offtake on these technologies where there is a heat demand, allowing greater efficiency and carbon savings.

- **Solar PV.** Evidence by PB Power[19] collected for the FiTs Consultation demonstrated that estimates of the cost of solar PV had fallen dramatically. In response to this evidence, the Government will consult on proposals for reduced ROC support for solar PV generating stations which accredit or add additional capacity on or after 1 April 2013;
- **Energy from Waste CHP:** EfW CHP will be supported at a higher level (1 ROC/MWh) than that proposed in the consultation. New cost evidence was used and an investment decision was assessed against a counterfactual of building a power-only plant, which is a more appropriate basis than no investment at all. This new analysis indicated more support was required.
- **Advanced Conversion Technologies[20]:** analysis of data from the ACT call for evidence indicated that the costs of most 'standard' (steam cycle) plants had been underestimated for the consultation, with a range of ROCs required from 0 to 7.7[21]. The new evidence suggests that the ROCs required to incentivise all of the technical potential for both 'standard' and 'advanced' (gas engine) is above 2 ROCs/MWh, although much of it can be brought on at 2 ROCs. In order to encourage the development of a reasonable level of both standard and advanced ACT, the Government response has announced that all new accreditations and additional capacity added in 2013/14 and 2014/15 will receive 2 ROCs/MWh, reducing to 1.9 ROCs/MWh in 2015/16 and 1.8 ROCs/MWh in 2016/17.
- **Hydro:** in order to incentivise more deployment of this cost-effective technology, support has been increased from the consultation proposal of 0.5 ROCs/MWh to 0.7 ROCs/MWh for new accreditations and additional capacity added in the banding review period (1 April 2013 to 31 March 2017). Following consultation responses, and further discussions with developers, the generic cost and potential assumptions for hydro above 5MW were revised, and individual pipeline project data analysed - these individual results are commercially confidential.
- **Landfill gas:** an additional 0.1 ROCs/MWh will be available to incentivise waste heat to power units as evidence was provided of the additional efficiency gain and hence additional generation of adding 'waste heat to power' units onto landfill gas installations. Whilst no costs were provided to suggest landfill recovery required support from open sites, consultation responses indicated that there was new landfill gas potential from closed sites no longer accepting waste, and that there were additional costs associated with closed sites, which are expected to require 0.2 ROCs/MWh to proceed. Given the cost-effectiveness of landfill gas recovery, support is now proposed at 0.2 ROCs/MWh for landfill gas generation from closed sites.

33. Table 1 below shows the banding level for each technology under all three options considered in this IA. Options relating to scheme design decisions other than banding levels (i.e. grandfathering, technology definitions and caps), and their impacts, are described separately in the government response and Annex E to this IA.

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evidence gathered through the consultation indicated any potential for these technologies with CHP.

[19] http://www.decc.gov.uk/en/content/cms/meeting_energy/Renewable_ener/feedin_tariff/feedin_tariff.aspx

[20] In Table 1 these are labelled as standard and advanced gasification and pyrolysis.

[21] 2014/15 ROC range.

Table 1: Technology banding option packages considered for new build from 2013-17, bandings in ROCs/MWh of renewable electricity supplied

Technology	Option 1: Current bands/do nothing	Option 2: Consultation bands	Option 3: Response bands
Wave	5 in Scotland, 2 in rest of UK	5 up to a 30MW project cap. 2 above the cap	
Tidal stream	3 in Scotland, 2 in rest of UK	5 up to a 30MW project cap. 2 above the cap	
Solar PV	2.0	2.0 in 2013/14 and 2014/15, 1.9 in 2015/16 and 1.8 in 2016/17	Proposals subject to further consultation
Onshore wind	1.0	0.9 except small-scale in N.I.[22]	
Offshore wind	2 to 2013/14; 1.5 2014/15 onwards[23]	2.0 in 2013/14 and 2014/15; 1.9 in 2015/16 and 1.8 in 2016/17	
Hydro	1.0	0.5	0.7 except small-scale in N.I.
Standard co-firing of biomass	0.5	0.5 (defined as less than 15% co-firing of whole station)	0.3 in 2013/14 and 2014/15; 0.5 in 2015/16 and 2016/17 (defined as 0-49% co-firing in a unit) – proposals subject to further consultation
Enhanced co-firing of biomass	Eligible for co-firing of biomass, 0.5	1.0 (ECF defined as biomass 15% or more of whole station)	0.6 (50-84% cofiring) 0.7 (85-99% cofiring), rising to 0.9 in 2014/15 (percentages of units)
Biomass conversion	Eligible for dedicated biomass, 1.5	1.0 (conversion defined as biomass 100% of whole station)	1.0 (conversion defined as biomass 100% of a unit)
Biomass conversion with CHP	Eligible for dedicated biomass with CHP, 2	Conversion defined as biomass 100% of whole station	1.5 or 1 plus RHI in 2013/14 and 2014/15; 1 plus RHI from 2015/16 (biomass 100% of a unit)
Biomass conversion using energy crops	Eligible for dedicated energy crops, 2	Conversion defined as biomass 100% of whole station	1 (biomass 100% of a unit) – no separate band to biomass conversion
Biomass conversion using energy crops with CHP	Eligible for dedicated energy crops with CHP, 2	Conversion defined as biomass 100% of whole station	1.5 or 1 plus RHI in 2013/14 and 2014/15; 1 plus RHI from 2015/16 (biomass 100% of a unit)
Dedicated biomass	1.5	1.5 in 2013/14, 2014/15 and 2015/16; 1.4 in 2016/17	
Dedicated biomass with CHP	2.0	2.0 or 1.5 plus RHI in 2013/14 and 2014/15; 1.5 plus RHI in 2015/16; and 1.4 plus RHI in 2016/17	

[22] Higher rates of support are available for such installations in Northern Ireland, which does not currently operate a small-scale FIT scheme. The Government will shortly consult on proposals to exclude from the RO new solar PV, AD, hydro and onshore wind installations at or below 5 MW that are currently eligible for support under either the RO or FITs scheme.

[23] Unlike for other technologies, "do nothing" would see the offshore wind band reduce from 2 to 1.5 ROCs/MWh from 1 April 2014, in line with the offshore-wind-specific banding review conducted in 2009

Technology	Option 1: Current bands/do nothing	Option 2: Consultation bands	Option 3: Response bands
Dedicated energy crops	2.0	2.0 in 2013/14 and 2014/15; 1.9 in 2015/16 and 1.8 in 2016/17	
Dedicated energy crops with CHP	2.0	2.0 in 2013/14 and 2014/15; 1.9 in 2015/16 and 1.8 in 2016/17	
Co-firing of biomass with CHP	1.0	1 (defined as less than 15% co-firing of whole station)	0.5 ROC uplift in addition to prevailing ROC support available to SCF until 31 March 2015
Co-firing of energy crops	1.0		Proposals subject to further consultation
Enhanced co-firing of biomass with CHP	Eligible for co-firing of biomass with CHP, 1	Defined as less than 15% co-firing of whole station	1.1 or 0.6 plus RHI in 2013/14 and 2014/15; 0.6 plus RHI from 2015/16 (50-84% co-firing in a unit); 1.2 or 0.7 plus RHI in 2013/14; 1.4 or 0.9 plus RHI in 2014/15; 0.9 plus RHI from 2015/16 (85-99% co-firing in a unit)
Co-firing of energy crops with CHP	1.5		Proposals subject to further consultation
Energy from waste with CHP	1.0	0.5	1.0
Standard gasification, standard pyrolysis	1.0	0.5	2.0 in 2013/14 and 2014/15; 1.9 in 2015/16 and 1.8 in 2016/17
Advanced gasification, advanced pyrolysis	2.0	2.0 in 2013/14 and 2014/15; 1.9 in 2015/16 and 1.8 in 2016/17	
Landfill gas	0.25	0	0 for open landfill sites, 0.2 for closed sites. 0.1 for new Waste Heat to Power at open and closed sites.
Sewage gas	0.5		
AD	2.0	2.0 in 2013/14 and 2014/15; 1.9 in 2015/16 and 1.8 in 2016/17	2.0 in 2013/14 and 2014/15; 1.9 in 2015/16 and 1.8 in 2016/17 except small-scale in Northern Ireland
Geopressure	1.0		
Geothermal	2.0	2.0 in 2013/14 and 2014/15; 1.9 in 2015/16 and 1.8 in 2016/17	
Tidal impoundment – barrage or lagoon	2.0	2.0 in 2013/14 and 2014/15; 1.9 in 2015/16 and 1.8 in 2016/17	

5. Impacts of options considered

34. This section sets out the impact of Option 2 and Option 3 of the Government response to the consultation on the RO banding review in terms of:

    A) Renewable electricity deployment and the generation mix
    B) Total power sector generation costs (excluding carbon allowance purchases)
    C) Carbon allowance purchase costs
    D) System balancing costs
    E) Air quality impacts
    F) Net monetised impacts (B + C + D + E)
    G) Non-monetised impacts
    H) Distributional impacts

A) Renewable electricity deployment and the generation mix

35. Annex B gives full details of the capacity and generation mix under current bands, as well as the new build supported by the RO under Options 2 and 3 considered over the banding review period from 2013/14 to 2016/17.[24] Table 2 and 3 below summarise this information for the main technologies.

Table 2: Modelled new build capacity under different options, MW

		New build under the RO during the 2013-17 Banding Review period, supported under the RO***		
Modelled Capacity (MW)	**Total deployment by 2012/13**	**Option 1 Current bands**	**Option 2 Consultation bands**	**Option 3 Response bands**
Biomass conversion and enhanced co-firing	1,200	1,500	3,200	3,200
Onshore wind (>5MW)*	7,000	2,800	2,600	2,600
Offshore wind	3,600**	0	530	530
Dedicated biomass >50MW	50	78	78	78
Dedicated biomass <50MW	340	170	170	170
Tidal stream	2	0	23	23
Wave	1	0	0	0
Other****	3,400	980	960	710
Total 'large-scale'****	**16,000**	**5,500**	**7,600**	**7,300**

Source: modelling by Pöyry consultants; DECC bottom-up conversions/ECF assessment; results rounded to two significant figures.
* Onshore wind (>5MW) includes onshore wind <5MW in Northern Ireland.
**For offshore wind this is total deployment by 2013/14 as the band is already set for 2013/14.
*** For offshore wind this only includes capacity built in 2014/15 and 2015/16.
****Note 'large-scale' renewables are defined as all UK renewable electricity except for <5MW AD, PV, hydro and wind supported by FiTs in Great Britain. Other includes large scale >5 MW PV. Bands for large scale PV will be subject to further consultation in the near future. Large scale PV costs and deployment are indicative at this stage

[24] This includes renewables new build commissioning from 2013/14 to 2015/16. In 2016/17, new build is assumed to be supported by CfDs.

Table 3: Modelled generation from new build capacity under different options, GWh per year

Modelled annual generation (GWh per year)	Annual generation from capacity built by 31/3/2012	Annual generation in 2016/17 from new build supported under the RO during the Banding Review period (2013/14 - 2016/17):***		
		Option 1 Current bands	Option 2 Consultation bands	Option 3 Response bands
Biomass conversion and enhanced co-firing	6,800	8,300	18,400	18,400
Onshore wind (>5MW)*	17,000	6,800	6,400	6,400
Offshore wind	11,000**	0	1,600	1,600
Dedicated biomass >50MW	400	610	610	610
Dedicated biomass <50MW	2,600	1,400	1,400	1,400
Tidal stream	8	0	80	80
Wave	3	0	0	0
Other****	17,000	4,100	3,900	3,900
Total 'large-scale'** **	**55,000**	**21,000**	**32,000**	**32,000**

Source: modelling by Pöyry consultants; DECC bottom-up conversions/ECF assessment; results rounded to two significant figures

* Onshore wind (>5MW) includes onshore wind <5MW in Northern Ireland.

** For offshore wind this is generation from capacity built by 2013/14 as the band is already set for 2013/14.

*** For offshore wind this only includes generation from capacity build in 2014/15 and 2015/16.

****Note 'large-scale' renewables are defined as all UK renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain. Other includes large scale PV. Bands for large scale PV will be subject to further consultation in the near future. Large scale PV costs and deployment are indicative at this stage.

36. As discussed in section 3. B), the simplifying assumption has been made that new stations with the choice between the RO and FiT with CfD will choose the RO up until 31st March 2016, and the FiT with CfD thereafter. This implies that the RO bandings will influence build over the first three years of the banding review period, which is presented in the tables above (though in reality it may be that some new build still occurs under the RO in 2016/17 and some build modelled as being under the RO before that is actually supported by the FiT with CfD).

37. Total modelled large-scale renewable electricity generation, towards the renewable target in 2016/17 is around 68TWh under Option 1 and around 79TWh[25] under Options 2 and 3, net of decommissioning but excluding new build from CfDs. Total generation in 2016/17 for each of the options is not the sum of existing generation and new build generation in Table 3, as decommissioning of some renewable plants has not been accounted for in this table and generation from standard co-firing is estimated to be slightly higher in 2012/13 than in 2016/17.

38. These tables are based on the results of modelling by Pöyry consultants coupled with DECC bottom up analysis for ECF and conversions; as with any modelling the outputs are based on input assumptions and therefore subject to uncertainty. Note ECF includes both the mid-range and high-range co-firing bands.

39. **Option 2 (Consultation bands):** increases renewables capacity by around 2.1GW and renewables generation by around 11TWh by 2016/17 compared to Option 1, to reach around 79TWh/y large-scale renewable electricity in total (net of decommissioning, and excluding new build under CfDs). This section outlines how each technology contributes towards total modelled capacity and generation.

[25] Generation is around 79.5TWh in the modelling for options 2 and 3, the difference between generation under option 1 and options 2 and 3 when rounded is closer to 11TWh that 12TWh. The difference in generation between options 2 and 3 is negligible, only around 40GWh.

40. Option 2 reduces support for biomass conversion (from 1.5 to 1 ROCs/MWh), but at the same time increases support for enhanced co-firing (ECF) compared to current bands. DECC's bottom-up assessment assumes one or two plants shift from full conversion to ECF. In total, 1.7GW of ECF capacity delivering around 10 additional TWh/y of generation is brought on under Option 2.

41. Support for onshore wind is reduced from 1 to 0.9 ROCs/MWh. New build onshore wind over the banding review period under the RO falls from 2.8GW to 2.6GW [26], compared to current bands. Generation from new build falls from 6.8TWh/y to 6.4TWh/y compared to current bands.

42. The band for offshore wind is increased compared to the bands that would be in place in the absence of this banding review, remaining at 2 ROCs in 2014/15 and reducing to 1.9 in 2015/16 and 1.8 in 2016/17, as opposed to 1.5 in those years (which was the previously-announced position, following the offshore-wind-specific banding review in 2009). New build offshore wind capacity in 2014/15 and 2015/16[27] increases, relative to a band of 1.5 ROCs, by around 530MW, delivering around 1.6TWh/y of additional generation.[28]

43. The band for dedicated biomass remains at 1.5 ROCs/MWh in line with current bands for the first three years of the banding review period, reducing to 1.4 in 2016/17. Modelled capacity for plant size less than 50MW is 170MW and for plant size above 50MW is around 78MW by 2015/16. New build dedicated biomass capacity remains the same as under current bands, with almost 250MW of capacity deployed by 2016/17. However, market assessment indicates that there could be scope for more deployment potential by 2016/17. This it is likely to be restricted by a combination of project economics, feedstock constraints and a cap on dedicated biomass within the RO, for which there will be a new consultation.

44. Support for tidal stream is increased from 2 ROCs/MWh to 5 ROCs/MWh (3 to 5 in the case of Scotland) which, in combination with assumed 25% grants[29], brings on around 23MW of modelled capacity by 2015/16. DECC believe this to be a conservative estimate; more might come forward if the costs or required returns are lower than assumed, but it is expected that tidal stream deployment will remain relatively modest under the RO, in the tens rather than multiple hundreds of MWs by 1st April 2017.

45. Support for wave is increased from 2 ROCs/MWh to 5 ROCs/MWh becoming equal to the banding support in Scotland, where wave is already eligible for 5. Modelling results show support at 5 ROCs/MWh with a 25% capital grant is not sufficient, given current cost assumptions, to bring on any wave deployment between 2013/14 and 2015/16. However, the bottom of the range of ROCs required is only 5.3 ROCs/MWh in 2015/16, so with a little more cost reduction, or a lower required return, there may be some wave deployment in that year. The modelling indicates that 5 ROCs/MWh would be sufficient to incentivise some wave deployment in 2016/17, but this is assumed to be supported by the FiT with CfD.

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[26] According to Pöyry modelling. DECC's in-house modelling suggests a fall of 250MW. The cost-benefit analysis below uses the Pöyry results.

[27] The offshore wind band for 2013/14 is already committed and so not considered in this analysis.

[28] As explained in section 2B, a simplifying assumption used in the modelling is that all new build generation in 2016/17 chooses the new FiTs with CfD.

[29] Wave and tidal schemes may be eligible for a grant of up to 25% under the Marine Energy Array Demonstrator (MEAD) scheme. In modelling the banding options for these technologies we have assumed projects receive the full grant, to avoid overcompensation under the RO. This does not pre-judge the levels that may be available under MEAD or other support mechanisms.

46. Option 2 reduces the bands for standard ACT from 1.0 to 0.5, EfW CHP from 1.0 to 0.5 and large-scale hydro (<5MW) from 1.0 to 0.5. This reduces standard ACT deployment by 36MW, or over 80% (resulting from the use of new cost data from stakeholders provided in the call for evidence). DECC assessed the ROCs required for EfW CHP in-house, on the basis of the relativity between the economics of EfW power only and EfW CHP and looked at individual project data for pipeline hydro plants. This indicates that the reduction in EfW CHP and large-scale hydro bands to 0.5 would reduce deployment by around 220MW (100%) and 16MW (around 70%) respectively.[30]

47. **Option 3 (Response bands):** increases renewables capacity by around 1.8GW compared to current bands (0.3GW less than under Option 2) and renewables generation by around 11TWh by 2016/17, the same as Option 2, to reach around 79TWh/y large-scale renewable electricity in total (net of decommissioning, excluding new build under CfDs).

48. Modelled deployment for Option 3 is the same as for Option 2, except with regard to ECF, standard ACT, landfill gas and SCF. DECC's bottom-up assessment for ECF shows 1.5GW of new build in 2013/14 under Option 2 is delayed to 2014/15 under Option 3 (when the band rises for 85-99% from 0.7 to 0.9 ROCs/MWh). Standard ACT new build in Option 3 (with ROCs/MWh of 2 in 2013/14 and 2014/15, 1.9 in 2015/16 and 1.8 in 2016/17) reaches around 43MW in the Pöyry modelling from 2013/14 to 2015/16, compared to around 7MW under Consultation bands (0.5 ROCs). Landfill gas from closed sites is increased to 0.2 ROCs/MWh and from waste to heat power to 0.1 ROCs/MWh, which brings on around 12MW of new capacity, compared to around 11MW with no support in option 2 (Consultation bands). Under the bands set out in Option 3, generation from SCF is expected to reduce in the first two years of the banding review period compared to Option 2, but contribute the same amount of renewable generation towards the renewables targets in 2015/16 and 2016/17 as in Option 2. The SCF banding support will be subject to a further consultation, as will assumed support levels for large scale solar PV.

49. DECC assessed the ROCs required for EfW CHP in-house on the basis of the relativity between the economics of EfW power only and EfW CHP; and looked at individual project data for pipeline hydro plants. This in-house analysis indicates that 1.0 ROC/MWh would bring on around 40%, but not all of the EfW CHP potential. For large-scale hydro, the in-house analysis indicated that 0.7 ROCs/MWh would bring on almost all of the available potential.

50. Table 4 below shows non-renewable generation over time for Option 3, and the change relative to Option 1. In the first few years, the main difference relates to a reduction in coal generation, with the gap first filled by CCGT generation, whilst converting coal plant are offline, and then biomass (and a little coal again in the case of ECF) once they are online again. CCGT falls below current bands from 2016/17 onwards as more renewables generation comes online and displaces it. The future generation mix is very uncertain, especially post-2020, and these results should be treated as purely illustrative further into the future.

[30] Note that the deployment estimates in Tables 2 and 3 and the cost-benefit analysis results are based on the Pöyry modelling, which used a counterfactual of no investment at all (as opposed to power-only investment) for EfW CHP and which used generic hydro plant data. They do not fully reflect the bottom up estimates generated by DECC through its ROCs required analysis set out in Annex F.

Table 4: Great Britain non-renewable generation in TWh under Option 3 Response bands, and change relative to Option 1 Current Bands

	2013/14		2014/15		2015/16		2016/17			2020/21		2025/26		2030/31	
	TWh	•	TWh	•	TWh	•	TWh	•		TWh	•	TWh	•	TWh	•
CCGT	73	6	66	10	57	3	86	-2		81	-6	43	-11	34	1
CCS Coal and Gas	0	0	1	0	2	0	2	0		9	0	9	0	18	0
Non-renewable CHP	25	0	25	1	25	0	27	0		30	0	31	-2	31	-1
Coal	112	-1	117	-10	110	-12	68	-10		37	-5	4	2	0	0
OCGT	1	0	1	0	1	0	1	0		1	0	0	0	0	0
Nuclear	66	0	61	0	61	0	61	0		44	0	97	0	114	0
Oil	0	0	0	0	0	0	0	0		0	0	0	0	0	0
Total non-renewable generation in GB	277	5	271	1	256	-9	245	-12		203	-11	184	-11	198	1

Source: modelling by Pöyry consultants and DECC calculations to nearest TWh

B) Total power sector generation costs (excluding carbon allowance purchases)

51. Total generation costs (defined as capital costs, finance costs[31], operating costs and fuel costs) increase under Options 2 and 3, compared to Option 1. Options 2 and 3 bring on more enhanced co-firing, offshore wind and tidal stream, whilst reducing deployment of onshore wind. Both options increase deployment of large scale electricity overall, putting the UK on track to meet large-scale renewable electricity's share of the renewable energy targets. The significant net increase in renewables build increases renewable generation costs, whilst the reduction in coal and later gas generation reduces non-renewables generation costs. The renewable technologies generation costs are higher than those of coal and gas, and so total generation costs increase as a result of the changes in bands.

52. The slightly lower increase in discounted total generation costs under Option 3 compared to Option 2 is primarily due to the delay in bringing on additional ECF from 2013/14 to 2014/15 (under consultation bands ECF gets 1.0 ROC/MWh from 2013/14 onwards whilst under the response bands 85-99% ECF gets 0.7 ROCs/MWh in 2013/14 and 0.9 in 2014/15 onwards). This also reflects lower costs associated with SCF under Option 3, where low range co-firing (defined as 0-49% biomass co-firing in a unit) receives banded support of 0.3 ROCs/MWh in 2013/14 and 2014/15 rising to 0.5ROCs/MWh for the rest of the period, compared with banded support of 0.5 ROCs/MWh over the entire review period for less than 15% co-firing of a whole station under Option 2.

Table 5: Total power sector generation costs to 2040 under different banding options (discounted 2011/12 prices; £bn)

£billion	Option 1 Current bands (absolute)	Option 2 Consultation bands – relative to current bands	Option 3 Response bands – relative to current bands
Renewable	260	+11.9	+10.9
Non-Renewable	310	-7.7	-7.3
Total	**570**	**+4.3**	**+3.6**

Source: modelling by Pöyry consultants and DECC calculations

C) Carbon allowance purchase costs

53. The reduction in coal and gas generation under Option 2 leads to a reduction in total grid CO_2 emissions by around 92Mt to 2040, compared to current bands. Option 3 (Response bands) leads to a reduction of around 82Mt to 2040, compared to current bands.

54. The UK power sector is part of the EU Emissions Trading System (EU-ETS). This means that any reductions in UK power sector greenhouse gas emissions will be offset by increases (or foregone reductions) elsewhere in the EU-ETS. However, there is a benefit to the UK from such emissions reductions in terms of avoided carbon allowance (known as EUAs) purchase costs. The emissions reductions (offset by increase elsewhere) under Options 2 and 3 are valued at the DECC central traded carbon appraisal values[32] and amount to around £2.1bn and £1.9bn, respectively, of EUA purchase cost savings, compared to current bands.

[31] Finance costs are taken into account by annuitising capital costs at the assumed hurdle rates over a 15-year period.
[32] Which can be found on DECC's website here: http://www.decc.gov.uk/en/content/cms/about/ec_social_res/iag_guidance/iag_guidance.aspx

Table 6: EUA purchase costs to 2040 under different options, discounted 2011/12 prices (£bn)

£billion	Option 1 Current bands - absolute	Option 2 Consultation bands – change relative to current bands	Option 3 Response bands – change relative to current bands
Total	37	-2.1	-1.9

Source: modelling by Pöyry consultants and DECC calculations

D) System balancing costs

55. System balancing costs tend to rise with increased amounts of intermittent generation on the system. Under Options 2 and 3 system balancing costs are estimated to rise by around £0.1bn, compared to under current bands.

Table 7: System balancing costs to 2040 different options, discounted 2011/12 prices (£bn)

£billion	Option 1 Current bands - absolute	Option 2 Consultation bands – change relative to current bands	Option 3 Response bands – change relative to current bands
Total	24	+0.1	+0.1

Source: modelling by Pöyry consultants and DECC calculations

E) Air quality impacts

56. DEFRA has modelled the impact on air quality of Option 3 (Response bands) against the impact of Option 1 (Current bands), under three fossil fuel price scenarios. For this assessment, annual renewables and non-renewable generation to 2039/40 under each scenario was converted into air quality emissions and combined with impact factors[33] from the UK Integrated Assessment Model. The impacts on air quality have been assessed and quantified using the agreed methodology of the Inter-Departmental Group on the Costs and Benefits of Air Quality[34].

57. DEFRA's analysis found that in all three fossil fuel price scenarios, Option 3 (Response bands) reduce the impact of air pollution on human health compared to current bands, and that the impact is greatest (i.e. the benefit for human health is highest) in the central fossil fuel price scenario. Under this scenario, the central monetised estimate from improved air quality is a present value of £66m.

Table 8: Air quality impacts, discounted 2011/12 prices (£m)

	Air quality cost sensitivities (+ve implies a benefit)		
Scenario	**Low**	**Central**	**High**
Low fossil fuel price	£7	£9	£10
Central fossil fuel price	£53	£66	£75
High fossil fuel price	£39	£48	£54

58. The benefits presented in Table 8 do not increase, as one would expect, in line with the fossil fuel price scenarios. *Relative* fossil fuel prices change in each scenario, affecting the mix of coal and gas generation which renewable technologies would displace. For example, if the fossil fuel price scenario resulted in relatively less coal than gas generation, uptake of renewables, on average,

[33] Impact factors represent the relationship between emissions and a number of environmental metrics reflecting impacts on human health and ecosystem damage.
[34] More information on this methodology can be found here http://www.defra.gov.uk/environment/quality/air/air-quality/economic/

would lead to relatively lower reductions in air quality emissions, and therefore the air quality benefits would also be lower.

59. In addition, the benefits presented above only include the impact on human health, not the impact on ecosystems or the natural environment. Poor air quality can have a negative impact on ecosystems. At present there is not sufficient evidence to monetise these impacts.

F) Net monetised impacts (B + C + D + E) and sensitivity analysis

60. The monetised generation cost, carbon credit purchase cost, balancing cost and air quality impacts (all discounted at the social discount rate[35]), are summed below to give the net present value of the change in policy at -£2.3bn for Option 2 consultation bands and -£1.8bn for Option 3. The NPVs are driven primarily by the increases in total generation costs caused by bringing on more renewables generation in place of cheaper conversion generation.

Table 9: Social monetised impacts of banding changes, £bn discounted in 2011/12 prices

Option •	**Option 2**		**Option 3**	
Impact on •	**Benefits (+)**	**Costs (-)**	**Benefits (+)**	**Costs (-)**
Total power sector generation costs [reduction = social benefit (+); increase = social cost (-)]		-4.3		-3.6
Carbon credit purchase costs [reduction = social benefit (+); increase = social cost (-)]	+2.1		+1.9	
Balancing costs [reduction = social benefit (+); increase = social cost (-)]		-0.1		-0.1
NPV excluding air quality impacts	**-2.3**		**-1.8**	
Air quality impacts	Not calculated		+0.06	
NPV including air quality impacts	Not calculated		**-1.75**	

-Source: modelling by Pöyry consultants and DECC calculations

61. Sensitivity analysis has been undertaken for Option 3, including;
    - Fossil fuel price sensitivities[36]
    - Assuming new build in 2016/17 is all supported by the RO rather than by CfDs
    - Biomass conversions and enhanced co-firing

62. Full details are provided in Annex D, Table 10 and 11 below summarise the results of the sensitivity analysis scenarios on NPV, capacity and generation mix for Option 3. Annex D presents alternative approaches to sensitivity analysis and looks at other potential scenarios for biomass conversion, as well as the capacity and generation impacts should all new installations come on under the RO rather than FiTs with CfD in 2016/17.

[35] Assumed to be 3.5%
[36] High and low fossil fuel price projections can be found on DECC's website here: http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/ff_prices/ff_prices.aspx

Table 10: Sensitivity Analysis of social monetised impacts of banding changes (£bn discounted in 2011/12 prices)

Option 3 (relative to Option 1)	NPV excluding air quality impacts
Central Scenario	-1.8
High fossil fuel price scenario	-4.0
Low fossil fuel price scenario	2.9

Table 11: Net new capacity and modelled generation under the RO during the 2013-17 Banding Review Period[37]

Scenario	Capacity (MW)	Generation (MWh/year)
Central Scenario	7,300	32,000
High fossil fuel price scenario	8,500	38,000
Low fossil fuel price scenario	2,000	8,800
All capacity under RO (not FiT with CfDs) to 2016/17	9,300	39,000

G) Non-monetised impacts

63. It should be noted that the monetised costs and benefits above do not include several potentially significant impacts. There are a number of positive non-monetised impacts such as; lower future costs of decarbonisation, reduced risk of missing the 2020 renewables target and related fines, and greater foreign direct investment (FDI) in turbine manufacturing. In addition, negative non-monetised impacts include the macroeconomic costs of higher electricity bills and increased risk of intermittent generation.

64. This section describes these non monetised impacts in more detail, in the following order:
    - Security of supply impacts
    - Impacts on other industries competing for biomass resource
    - Wider environmental and social impacts
    - Risk of missing 2020 renewables target
    - Macroeconomic impacts
    - Lifecycle greenhouse gas emissions

Security of supply impacts

65. Options 2 and 3 reduce reliance on imported fossil fuels relative to the do nothing option, but at the same time by increasing the amount of intermittent generation, these options may increase the small probabilities of brown-outs or even black-outs. However, it is assumed here that these small amounts of extra intermittent generation will be accommodated on the grid with an increase in other kinds of balancing services – back-up generation, interconnection, storage and/or demand-side response. System balancing costs are included in the monetised costs and discussed in section 5. D).

[37] Further detail is provided in Annex B and D

Impacts on other industries competing for biomass resource

66. Continuing support for biomass-related electricity technologies could impact on other sectors that use the same fuel sources, such as the wood products industry (e.g. for furniture and construction material) and the pulp and paper industry. A report commissioned for the Bioenergy Strategy used lifecycle analysis to quantify the carbon balances associated with different forest management approaches and uses of forest wood[38], and therefore enabled us to compare the carbon impacts of using wood and energy crops in energy versus other uses. The scenarios analysed included: using harvested wood for bioenergy (heat or electricity); choosing alternative uses (such as construction products); or leaving the forest unharvested or unmanaged. The analysis indicated that, in the context of wider decarbonisation of the economy, wood products can be an important store of carbon. Therefore, to achieve optimal GHG scenarios woody biomass should be used for the production of both material products and for bioenergy uses, with re-use and recycling wherever possible. Given the important role of wood products as a store of carbon, we have considered the potential competition for resources between the wood products industry and woody biomass for energy use in further detail.

67. The bioresource supply scenarios used as a constraint in the modelling of the RO Banding Review scenarios were derived from the scenarios developed for the Bioenergy Strategy, and which were based on AEA Technology analysis[39]. The Bioenergy Strategy Analytical Annex includes a full explanation of AEA assumptions, and how the bioresource supply scenarios were derived for the low risk bioenergy pathway analysis[40]. Although isolating the potential impact of the RO on the wood products industry is extremely difficult given the potential impact of other policies and market drivers on the demand of the relevant feedstocks, in order to reflect the finite nature of the feedstocks for biomass and their competing uses, AEA considered the extent of competing uses, e.g. use of agricultural land for food and feed or wood for timber, pulp, paper, and panel board, etc, and whether or not this competition was price dependent. Only those resources where competition was considered to be price dependent (i.e. potentially available to the bioenergy sector at higher prices) or where no significant competition existed, were viewed as potentially available to the bioenergy sector. For example, it was assumed that half the unconstrained potential estimated from UK sawmill residue would be available to the energy sector due to competition from the wood panelling industry. However, it is recognised that the wood products industry and the energy sector could compete for the same fuel source, and the impact of this competition on prices and availability of resource is difficult to forecast, given the uncertainty around future demand from non-energy sectors and the impact of increasing demand for bioresources from the energy sector. For further information on the current market for wood in the UK see Appendix 1 in the Bioenergy Strategy Analytical Annex.

68. In addition, two modifications were made to the Bioenergy Strategy bioresource supply scenarios (derived from AEA modelling) in the work which underpins this IA: first, to take account of the impact of sustainability standards in the RO[41]; and secondly, to include the updated estimates on the potential supply of residual waste, based on consultation responses and analysis used for the Defra Waste Review 2011. The review looked at scenarios of total potential waste resource available consistent with Government ambition, rather than a realistic forecast of what feedstock may be available. These modifications lead to lower supply scenarios in total than those assumed in the

[38] Forest Research and North Energy Associates, Carbon impacts of using biomass in bioenergy and other sectors: Forests, 2012

[39] AEA: 2010 UK and global bioenergy resource. http://www.decc.gov.uk/en/content/cms/meeting_energy/bioenergy/strategy/strategy.aspx

[40] Section 1, Bioenergy Strategy: analytical annex, 2012
http://www.decc.gov.uk/en/content/cms/meeting_energy/bioenergy/strategy/strategy.aspx

[41] AEA estimates apply RED sustainability standards to biofuels, and assume all biomass is produced from existing forest or abandoned agricultural land, but do not include specific sustainability standards for solid biomass given that the RED does not mandate for this. Sustainability standards applied are consistent with a 60% threshold compared to the EU average (712 kgCO2/MWh) which is the current reporting standard under the RO.

Bioenergy Strategy analysis.

69. Based on the latest Forest Commissions estimates, approximately 10.3 Million green tonnes (Mgt) of UK virgin wood was delivered in 2011, of this total wood panelling consumed approximately 30% (1.4 Mgt of virgin wood and 1.8 of sawmill products). The energy sector accounted for approximately 15% of this total in 2011, an increase from 5% in 2007[42]. For further information on the current market for wood in the UK, including analysis on prices, see the Government Bioenergy Strategy and supporting documents.

70. The current forecast for woody biomass use from the heat[43] and power sector in 2016/17 is approximately 17 million oven dried tonnes (Modt), of this 15 Modt is from the power sector based on the latest RO Banding Review proposals and associated projections. This demand could be met by a number of different feedstocks (both within the UK and imported), such as wood, agricultural residues and (UK) waste wood. Smaller scale power generators are more likely use domestic feedstocks: of the total 15 Modt forecast in 2016/17, approximately 3 Modt is expected to be used by smaller scale generators. Assuming 50% of woody biomass feedstocks for heat come from the domestic markets (as larger generators likely to source from international markets) total forecast demand of domestic fuels for heat could be in the region of 1 Modt in 2016. Therefore, in total the forecast domestic bioresource use from the power and heat sector is approximately 5 Modt (including 10% of large scale power generation). Table 12 below summarises the total forecast woody biomass use from heat and power sector in 2016/17.

Table 12: Breakdown of total forecast woody biomass use from heat and power in 2016/17 (Modt)

	2016/17
Large scale biomass	12
Small scale biomass	3
CHP	1
Heat	2
Total	17

Note: Figures may not sum due to rounding.

71. The supply scenarios used to constrain the RO modelling assume between 17 and 28 Modt of total available woody biomass in 2016/17, of this 9 - 11 Modt are from UK sources, and between 8 and 17 Modt are from imports. The large majority of the feedstock demand for electricity generation is expected to come from >50MW generators which will source their supplies through imports (90%) due to the need for volume certainty and long term contracts (7-15 years). It should be remembered that the supply assumptions used for the RO modelling are entered as a constraint, not a forecast of what bioresource we consider to be actually available in the future. Table 13 below summarises the 2016/17 woody biomass supply constraint used for RO analysis.

Table 13: Woody biomass supply constraint used for RO analysis (Modt in 2016/17)

	2016/17
UK woody biomass	9 - 11
Imported woody biomass	8 - 17
Total	17 - 28

Note: Figures may not sum due to rounding.

72. At an aggregate level (i.e. sum of feedstocks), the forecast bioresource use implied by the deployment under the new RO Bands does not breach the central bioresource supply constraint, this

[42] Forestry Statistics 2011 http://www.forestry.gov.uk/pdf/trprod12.pdf/$FILE/trprod12.pdf

[43] Forecast woody biomass use for the heat sector in 2016 is based on illustrative DECC analysis for the RHI, and is subject to change.

is shown in Table 14 below. To note, these supply figures do not include domestic or imported bioliquid supply.

Table 14: Comparing power sector forecast bioresource use and supply constraint used for RO analysis (Modt 2013/14 to 2016/17)

Modt	2013/14	2014/15	2015/16	2016/17
Forecast bioresource use (existing bands)	17	19	22	25
Forecast bioresource use (new bands)	14	18	25	29
Supply constraint (central)	38	38	38	40
Supply constraint (high)	48	51	54	60

73. The analysis above suggests that UK resources should be sufficient to meet both energy and wood products demand for woody biomass. However, it recognises that the future demand for wood from other sectors and future supply is extremely difficult to predict and that for the upper end of the potential domestic supplies to materialise prices will have to rise. Although analysis of historic evidence suggests that movements in domestic prices appear to be correlated to international prices of wood, rather than domestic demand for co-firing generation[44], it is recognised that the full impact of the RO (and other renewable policies) on the demand and prices for these feedstocks is very difficult to estimateat this stage. DECC will work closely with the wood products industry and biomass electricity generators to ensure robust monitoring measures are in place for biomass feedstocks to provide early warning of supply risks from the electricity sector.

74. For further analysis of the potential impacts of UK bioenergy policies on other sectors of the economy see the Government's Bioenergy Strategy and supporting documents.

Wider environmental and social impacts

i. Land use

75. The forecast bioresource use in the power sector implied by the expected biomass deployment under Option 3 revised proposals has been assessed for its potential impact on land use. Energy to land conversion factors, developed by the Forestry Commission for the Bioenergy Strategy 2012, have been used to convert from projected estimates of energy demand by feedstock to hectares of land required, adjusted for potential improvements in productivity.

76. It is estimated that between 54-60k hectares of land were utilised in 2011, around 60%[45] of which used for arable crops (OSR[46]) to produce bioliquids and the remainder for woody energy crops such as miscanthus and short rotation coppice (SRC). By 2030 total land use is expected to rise to between 91-113k hectares with around 80% of this used to grow woody energy crops. Table 15 illustrates the potential land use requirement under Option 3 revised proposals.

[44] http://www.decc.gov.uk/en/content/cms/meeting_energy/bioenergy/strategy/strategy.aspx

[45] This estimate assumes all of the bioliquid used for electricity generation in 2011 are derived from arable crops, which is considered to be an upper estimate of the impact on land use. The latest figures from OfGEM biomass sustainability report (http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=318&refer=Sustainability/Environment/RenewablObl/FuelledStations) indicate that fuels derived from arable crops which are not wastes or residues made up less than 1% (by mass) of bioliquid feedstocks used between April 2010 and April 2011.

[46] Used Cooking Oil is another potential feedstock suggesting that these estimates may be overestimates. However, analysis for the Bio-Energy Strategy suggests this feedstock would be most cost effectively used as a transport fuel.

Table 15: Total land use impact of Renewables Obligation, kha

Summary	2011/12	2015/16	2020/21	2025/26	2030/31
Energy Crops (low)	21	24	109	88	73
Energy Crops (high)	23	26	129	113	91
Arable Crops (low)	33	31	67	49	18
Arable Crops (high)	37	37	79	61	22
Total (low)	54	55	176	137	91
Total (high)	60	63	208	174	113

77. The split between domestic and imported feedstocks is highly uncertain and will depend upon prices, the development of supply chains within the UK and overcoming barriers around establishment. Our best assessment at this stage, based upon supply modelling, is that domestic UK feedstocks could represent around 20% of total energy crops in early years (c5k hectares), and around 10% by 2020 and beyond (c12k hectares). For context, in 2011 plantings of woody energy crops were around 11k hectares in England.

78. The marginal impacts on land use of Option 3 compared to Option 1 is set out below. This shows that the proposed amendments will not lead to a change in the potential use of arable crops for bioliquids, but that more land is likely to be used to grow woody energy crops for biomass combustion (in later years).

Table 16: Marginal land use impact of proposed amendments to Renewables Obligation, kha

Summary	2011/12	2015/16	2020/21	2025/26	2030/31
Energy Crops (low)	0	-5	69	58	54
Energy Crops (high)	0	-6	82	73	67
Arable Crops (low)	0	0	0	0	0
Arable Crops (high)	0	0	0	0	0
Total (low)	0	-5	69	58	54
Total (high)	0	-6	82	73	67

ii. Food security

79. The Bioenergy Strategy 2012 set out the principles by which Government should act to ensure the sustainability of bioenergy feedstocks, as well as a level of ambition consistent with those principles. The estimates in this analysis are consistent with the principles set out in the Strategy and the overall level of ambition it set taking account of food security needs.

80. To date, land used to grow woody energy crops in the UK has tended to be lower-quality, marginal or idle land which is generally unsuitable for food production. However, we should continue to monitor patterns of agricultural land use carefully, to identify changes that happen as a result of, for example, changing commodity prices, and determine whether there is a shift in the way in which different types of land are being used for food or energy production.

iii. Wider Environment (biodiversity, water demand)

81. Demand for bioenergy can present risks for biodiversity and ecosystems through loss of semi-natural and natural habitats (such as forest clearance), intensification of agricultural production and the potential introduction of non-native invasive species. There is, therefore, a potential tension with the Government’s commitment to halt and reverse biodiversity loss and ecosystem degradation both domestically and internationally, particularly the issue of potentially increasing water stress.

82. On the other hand, a number of reports show that perennial energy crops, such as short rotation coppice and miscanthus if cultivated in the right place and in the right way, can be better for biodiversity and water quality than arable crops such as wheat and maize. There will also be benefits if energy demand leads to unmanaged forests being brought back into sensitive management. The precise impacts depend on the previous nature of the land, the nature and location of the new crops and their management, for example by avoiding large swathes of monoculture.

83. Risks can be reduced and benefits increased by: taking steps to create additional feedstock supply in appropriate ways, thus reducing the pressure for agricultural expansion into natural habitats; applying standards and safeguards effectively to exclude biomass from unsustainable sources; monitoring impacts and undertaking periodic reviews of policies and measures to ensure bioenergy expansion proceeds at a sustainable pace.

84. For further information on potential wider environmental impacts from bioenergy feedstock cultivation see DECC Carbon Plan analytical annex[47], and the NNFCC report on energy crop potential which discusses biodiversity issues[48].

Risk of missing 2020 renewables target

85. Options 2 and 3 reduce the risk of missing the 2020 renewables energy target by incentivising offshore wind deployment in the UK, that wouldn't be incentivised under current bands. Analysis of expected subsequent cost reductions and technical potential suggests that offshore wind deployment forms part of a cost-effective mix for reaching the 2020 target. Continuing deployment of offshore wind also enables a strategic option for post-2020 power decarbonisation and sector expansion.

86. The impacts relating to enabling an option for future UK marine deployment are not monetised. Options 2 and 3 reduce the risks of not being able to achieve decarbonisation and expansion of the power sector required to 2030 and 2050 to meet the carbon budgets. It does this by creating two more low-carbon technology options, wave and tidal stream, for the generation mix. Their potential is uncertain, but they could eventually reach around 27GW in 2050.[49] Marine technologies' outputs are expected to be more predictable than that of wind generation, which is expected to imply lower balancing costs - this potential impact on balancing costs has not been monetised.

87. Marine technologies in the long term may also prove relatively expensive overall and not a cost-effective part of the future low-carbon mix. Future relative technology costs are very uncertain. No attempt is made here to monetise their option value. Whether future marine deployment turned out to have a net benefit would depend on many uncertain factors, including the speed of cost reductions in wave and tidal stream technologies, the availability and cost of alternative low-carbon technologies and the system balancing costs relating to the intermittency of wave and tidal stream compared to wind.

Macroeconomic impacts

88. Other important impacts which are not monetised include the wider macroeconomic impacts of changes in retail electricity prices. Slightly higher electricity bills (than would otherwise have been in place – i.e. lower rises in bills) mean higher costs to industry and less real income for consumers. However, the increases in bills from these proposals (set out in section H below) are expected to be

[47] Page 184. http://www.decc.gov.uk/assets/decc/11/tackling-climate-change/carbon-plan/3749-carbon-plan-annex-b-dec-2011.pdf
[48] http://www.decc.gov.uk/assets/decc/11/meeting-energy-demand/bio-energy/5138-domestic-energy-crops-potential-and-constraints-r.pdf
[49] According to Ernst & Young (2010), *Costs of and financial support for wave, tidal stream and tidal range technologies*. Their total wave and tidal stream deployment range in 2050 is 9-43GW.

relatively small when compared to the absolute bill impact of the RO under Option 1.

89. Options 2 and 3 also imply an increased likelihood of attracting FDI, for example in offshore wind turbine manufacturing, which is expected to be associated with positive spillover effects. Growth in industries related to renewable electricity as a result of these proposals could also affect propensity to imports and exports. That growth will be balanced by displacement of resources (capital and labour) from other sectors. Overall, the GDP impacts of incentivising renewable electricity deployment are unclear.

Lifecycle greenhouse gas emissions

90. The analysis of carbon emissions above looked at the CO2 emissions from the UK power sector associated with the burning of fossil fuels and valued these at the central DECC EU-ETS traded sector appraisal carbon prices. An assessment has also been made of the full lifecycle greenhouse gas emissions associated with all the UK power sector generation, including not only the emissions from burning fossil, biomass and waste fuels, but also the emissions associated with fuel transportation, construction of power stations and in the case of waste technologies, avoided greenhouse gas emissions from waste going to landfill.

91. Table 17 below shows the full lifecycle emissions associated with the projected UK power sector generation under Option 1 (current bands) and the preferred Option 3 (Response bands). Overall the estimated difference in full lifecycle emissions due to changing bands to the preferred Option 3 comes to a reduction of 87Mt compared to Option 1.

Table 17: Full lifecycle greenhouse gas emissions impacts

	Option 1 Current bands - absolute	**Option 3 Response bands – change relative to current bands**
Mt CO_2 equivalent	2,313	-93

92. Note that it has not been possible to estimate the time profile of these emissions savings in the same way as for the CO2 savings from avoided burning of fossil fuels above, and therefore the full lifecycle impact has not been monetised. The estimated full lifecycle greenhouse gas emissions impact at 93Mt is higher than the estimated CO2 savings from avoided burning of fossil fuels at 82Mt.

H) Distributional impacts

93. Changing RO bands can change levels of renewables deployment, and hence the levels of RO costs falling on consumers; wholesale prices (impacting on retail prices) can be reduced on average when more wind is on the system; and system balancing costs increase with more intermittent generation.

RO support costs

94. The changes in bands in the different options have a number of impacts on electricity consumers. Table 18 below shows how Options 2 and 3 reduce the level of RO support costs in the first few years, owing to the reduction in rents by reducing bands, and incentivising the more cost-effective renewable technologies. However, these options bring on more renewable generation in the last two years of the banding review period and in subsequent years, raising RO support costs in these years. The PV of lifetime increases to RO support costs is £2.3bn in Option 2 and £1.5bn in Option 3.

Table 18: RO support costs to 2039/40 (2011/12 prices, £m)

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Current bands	1,400	1,900	2,900	3,100	3,200	3,300
Impact of Option 2 Consultation Bands	-	-	-160	-64	110	230
Impact of Option 3 Revised Proposals	-	-	-390	-320	67	180

Source: modelling by Pöyry consultants and DECC calculations; Estimates rounded to two significant figures

Wholesale price impacts

95. By bringing on slightly more wind generation, on average over the modelling lifetime to 2039/40, Option 3 revised proposals reduces wholesale prices relative to the current bands. The net present value to consumers of these lower wholesale prices is a benefit of around £260m in PV terms.[50] Option 2 Consultation Bands is assumed to deliver the same wholesale prices as Option 3, and hence the same benefit relative to current bands.

Net impact on consumers (including balancing costs)

96. The net impact on consumers relative to current bands, comes to an increase in costs to consumers of around £2.2bn in NPV terms under Option 2, and around £1.3bn under Option 3. These net impacts include wholesale cost of electricity savings and balancing costs.

Table 19: Lifetime impact on consumers of banding options compared to maintaining current bands (2011/12 prices, £m) - negative indicates a net cost and positive indicates a net benefit

	Option 2 relative to Option 1	Option 3 relative to Option 1
Total impact on consumers	-2,200	-1,300

Source: modelling by Pöyry consultants and DECC calculations; estimates rounded to two significant figures

Bill impacts

97. Costs to consumers increase by around £2.2bn in NPV terms under Option 2 and around £1.3bn under Option 3 relative to Option 1. Under both options there is a small reduction in average annual bills in the first few years, then as more renewable generation comes through in later years, the RO support costs and balancing costs push up bills, generally more than the (generally later) reduction in wholesale prices pushes bills down. The average annual bill impact from 2012 to 2030 of the change in bands on households, medium-sized non-domestic users and energy-intensive users is set out in Table 20 below. Under the preferred Option 3, electricity bills are increased by a modest average over the period of 0.1-0.2% compared to current bands.

Table 20: Impact of changing RO bands to Option 3 (Response bands), on average annual electricity bills 2012-2030 (£2010 prices)

	Average household	Medium-sized non-domestic user	Large energy-intensive user
Average annual electricity bill impact	£0.7 (0.1%)	£3,000 (0.2%)	£20,000 (0.2%)

Notes: Medium sized non domestic user impact is rounded to the nearest £1,000. Based on the mid-point of Eurostat "medium industrial user" consumption band. Large energy intensive user impact is rounded to the nearest £10,000. Based on a user consuming 100,000mwh pa. The estimate is before energy efficiency savings.

98. In terms of absolute contribution to household bills, revised bands under Option 3 are projected to lead to a total impact from the RO of around £53 to the average household's annual electricity bill by

[50] This reduction in wholesale prices occurs mainly post-2020. In the Pöyry modelling there is an increase in wholesale prices under Revised Proposals relative to Current Bands up to 2015/16, which is due to coal plant coming offline for 12 months to adapt ready for enhanced co-firing and conversions. It is likely that conversions and ECF will not require plant to be offline for so long and that a lot of the work may take place over period when coal plant do not tend to generate so much. i.e. the summer months. Given these uncertainties, DECC have excluded this increase in wholesale prices from the analysis.

2016/17, based on estimated average household annual electricity bills and household electricity demand *before* the impact of energy efficiency policies. Table 21 below shows the contribution to household bills of current bands and Option 3 based on estimated household electricity demand before and after the impact of energy efficiency policies. Energy efficiency policies are expected to lead to significant reductions in household electricity demand, whilst business and public sector demand are projected to rise, shifting some of the RO cost burden from household to business and the public sector.[51]

Table 21: Absolute contribution to average household electricity bills of RO support costs under current bands and the preferred option (£2011/12 prices)

Basis:		2013/14	2014/15	2015/16	2016/17
Household electricity demand before policies	**Current bands**	44	47	49	50
	Option 3 Response bands	38	42	50	53
Household electricity demand after policies	**Current bands**	36	37	37	37
	Option 3 Response bands	31	33	38	39

Source: modelling by Pöyry consultants and DECC calculations; Estimates rounded to nearest £1.

Producer surplus

99. In reducing the bands where analysis suggests that this would have a zero or low impact on deployment, Option 2 consultation bands and Option 3 revised proposals are likely to reduce producer surplus by an estimated £1.2bn over the modelling lifetime to 2039/40. This producer surplus, also known as rents, is defined simply as the sum of positive cashflow NPVs (discounting at the hurdle rates) for renewables plant.

6. Wider impacts

Equality

100. This policy has no significant bearing on protected characteristics, including age, disability, gender reassignment, pregnancy and maternity, race, religion or belief, sex and sexual orientation.

Environmental Issues

101. The greenhouse gas emissions impacts and non-greenhouse gas air quality impacts are covered in section 5G. The proposed banding options lead to carbon savings within the UK power sector, but these will be offset by increases in emissions elsewhere within the capped EU-ETS traded emissions sector. There will therefore be no net impact on greenhouse gas emissions.

102. The RO provides the Government's support scheme for renewables electricity generation. It incentivises investment in renewables projects which help to move the UK away from fossil fuel dependency towards a low carbon economy with consequential carbon savings from displaced fossil fuel generation.

103. Individual projects supported under the RO that are deemed to have the potential to cause significant adverse impacts are required to undertake an Environmental Impact Assessment

[51] Unlike the overall analysis of consumer costs, table 21 does not take into account the (relatively small) indirect effects of the RO on household electricity bills through reducing wholesale prices and increasing balancing costs.

(Directive 85/337/EEC) as part of the planning process.

104. Any future deployment of renewable and low carbon energy infrastructure will be subject to all relevant environmental legislation and controls, and aims to contribute to government policy objectives that enhance the natural environment .

Rural proofing

105. A large proportion of renewable energy is produced in rural areas and affects businesses involved in the growth (of biomass) and generation of renewable energy and rural communities living in the vicinity of new developments. Increasing the proportion of energy from renewable sources will mean more renewable energy developments in rural areas.

106. Whilst there has been no separate or explicit assessment of the needs of rural areas, the RO banding review proposals are set within this wider policy context and the Government's overall reforms of the planning system. Separate planning legislation exists to ensure that the environmental and social impacts of renewable energy developments, and the views of those living near to installations, are fully taken into account.

107. Development of RO policy has been subject to extensive consultation. This has included business interests within the renewables sector and consumer interests. It has also included relevant rural business groups but has not specifically sought to engage rural community groups in particular. Nevertheless, consultation responses that have been taken into account in formulating final decisions on the RO Banding Review were received from community/rural groups including: Campaign to Protect Rural England; Scottish Natural Heritage; Cambrian Mountains Society; Country Land & Business Association; Royal Society for the Protection of Birds, Friends of the Earth; and numerous local rural campaign groups.

Sustainable Development

108. The RO is aimed at increasing the deployment of renewable electricity generation in order to move the UK away from fossil fuel dependency towards a low carbon economy in preparation for a future when supplies of gas and oil will become tighter and more expensive. From 1 April 2011, under the Renewables Obligation, electricity generators over 50kW are required to report annually on their performance against sustainability criteria for biomass feedstocks they use. This criteria includes a minimum 60% (285.12 kgCO2eq/MWh) Greenhouse Gas lifecycle emission saving for electricity generation using solid biomass or biogas relative to fossil fuel, and general restrictions on the use of materials sourced from land with high biodiversity or carbon stock value such as primary forest, protected areas, wetland and peatland. The sustainability criteria apply to the use of imported as well as domestic biomass and biogas for electricity generation but do not apply to waste or biomass wholly derived from waste. Generators are required to report annually to Ofgem on their performance against these criteria, which will help inform future Government policy on sustainable use of biomass for electricity generation.

109. Following a two year transition period, the intention is from April 2013, generators of 1MWe capacity and above will be required to meet the sustainability criteria in order to receive support under RO.

110. The Government will consult shortly on a new trajectory of biomass fuel sustainability requirements to 2020.

Competition

111. The RO is a market-based instrument that operates in a competitive market for electricity. It is open to all participants in renewable generation. The way in which the RO recycles money from the buy-out fund should act as a positive incentive to competition between suppliers, and reduce barriers to entry for renewable electricity generators.

Small Firms

112. The major impact of the RO on the large majority of small business is likely to come from increased costs of electricity which, while affecting all electricity consumers, are likely to represent a larger proportion of income for smaller companies, as they are less likely to have their own generation compared to – particularly - larger industrial users with heavy electricity requirements.

113. The majority of smaller businesses involved in renewables generation are likely to seek support under FiTs, as the simplicity and income-certainty of FiTs makes them better suited to small business needs. Small businesses involved in licensed electricity supply should not experience any additional burdens from the proposals.

114. The Government will consult shortly on support for new small-scale solar PV, AD, hydro and wind generation under the RO in Great Britain.

7. Summary and preferred option with description of implementation plan

115. The preferred option is Option 3 (Response bands). It delivers 32TWh/y of additional generation from new build over the 2013-17 banding review period towards the 2020 renewables target, compared to 21TWh/y under Option 1 (current bands). Under central assumptions, this achieves the 'large-scale'[52] renewable electricity deployment required to meet the UK's interim and 2020 renewable energy targets under the EU Renewable Energy Directive.

116. Option 3 also increases the efficiency of the RO, delivering a lower average cost per MWh of renewables for the electricity consumers who bear the cost of the RO. It does this by focussing on the more cost-effective technologies and reducing excess profits to renewables developers. The latter is achieved through reducing support in technologies such as hydro above 5MW (sub-5 MW hydro is supported by FiTs) and biomass conversion, but without reducing renewables deployment.

117. The Government's expectation is that renewables support will reduce as the costs of renewable technologies fall. The proposed RO banding for offshore wind, which represents one of the more expensive technologies required to meet the 2020 renewables target, is reduced from 2.0 in 2013/14 and 2014/15 to 1.9 ROCs/MWh in 2015/16 and to 1.8 ROCs/MWh in 2016/17 as offshore wind costs are projected to fall. The banding for all other technologies beginning at 2 ROCs/MWh are proposed to fall likewise (with the exception of wave and tidal stream). Complementary policies will help bring down renewable generation costs, such as innovation support programmes, support for the development of new large-scale coastal manufacturing facilities and a joint HMG-business taskforce.

118. Table 922 below summarises the costs and benefits of Option 2 (Consultation bands) and Option 3 (Response bands) compared to Option 1 (Current bands).

Table 22: Social monetised impacts of banding changes, £bn discounted in 2011/12 prices

Option •	**Option 2**		**Option 3**	
Impact on •	**Benefits (+)**	**Costs (-)**	**Benefits (+)**	**Costs (-)**
Total power sector generation costs [reduction = social benefit (+); increase = social cost (-)]		-4.3		-3.6
Carbon credit purchase costs [reduction = social benefit (+); increase = social cost (-)]	+2.1		+1.9	
Balancing costs [reduction = social benefit (+); increase = social cost (-)]		-0.1		-0.1
NPV excluding air quality impacts	**-2.3**		**-1.8**	
Air quality impacts	Not calculated		+0.06	
NPV including air quality impacts	Not calculated		**-1.75**	

Source: modelling by Pöyry consultants and DECC calculations

[52] 'Large-scale' renewable electricity is defined as all UK renewable electricity except that in Great Britain from stations with an installed capacity below 5MW in AD, solar PV, wind and hydro technologies, i.e. except that electricity which is eligible for support under the small-scale FITs scheme.

119. The preferred Option 3 is more affordable to consumers compared to Option 1 (Current bands) and Option 2 (Consultation bands), allowing the RO to stay within its Levy Control Framework budget over the four years of 2011/12 to 2014/15. Under central assumptions Option 3 is expected to deliver the large-scale renewable electricity share of the overall renewable energy interim targets, on the way to the 2020 renewable energy target.

Implementation

120. The RO is administered and enforced by Ofgem, who report annually on their administration of the RO and conduct regular audits in relation to compliance with the RO.

121. DECC is responsible for monitoring the impact of the RO on the development of renewable energy and collects detailed information on growth in renewable energy generation and projects under development.

Annex A - Details of key assumptions

A) Updates to key assumptions since Consultation Impact Assessment

122. As in the Consultation document, Arup research provided estimates of current costs of renewable electricity technologies through access to proprietary information, use of external reports, and consultation with renewable developers. Arup also made projections of future generation costs, based on their assumed learning rates (cost reductions with increased deployment reflecting technological learning, economies of scale etc.), global deployment projections from the IEA Blue Map scenarios and future prices of key cost drivers such as labour and industrial commodities.

123. Arup also gathered information on maximum deployment potential, in the form of annual new build rates for each technology. Low, medium and high estimates of these annual build rates were developed to reflect varying levels of non-financial barriers to deployment, such as planning, supply chain and grid constraints. The Arup estimates of generation costs and deployment potential were used to create annual stepped supply curves for each technology.[53] The high version of the annual maximum build rates was used for these, reflecting the high level of ambition the Government has to tackle non-financial barriers to renewables deployment, as detailed in the Renewables Roadmap.[54] Development of the supply chain, grid extensions and planning success will be just as important as providing the right financial incentives in achieving the 2020 renewables target.

124. Some cost, deployment and technical data has been revised since the analysis for the consultation impact assessment, in line with consultation responses and some technical updates. The primary changes that have been made are:

a. Load factors for **onshore wind >5MW** have been reduced across all regions following the inclusion of the latest year's data into the long run average**.** Maximum technical potential increased slightly and region split revised in light of revised project pipeline data.
b. Central and high cost estimates for **onshore <5MW** have been revised upwards in light of new evidence from consultation and analysis for the Feed-in-Tariff scheme.
c. Operating costs have been revised downwards by 15% for **offshore wind R2** following consultation evidence**.** At consultation, it was assumed 100% of the revenues accrue to the project, consultation evidence suggested some farms would secure PPAs, and therefore receive a discount on the revenues, the new assumption is that projects can only secure 95% of the full value of revenues on average across all projects. In addition, maximum build rates have been revised downwards in light of new pipeline data.
d. The capital cost range for **Dedicated biomass (both sizes)** was widened and the maximum build rate assumptions have been change based on consultation evidence and project pipeline data, respectively.
e. The fuel cost assumption for **Dedicated biomass >50MW** was revised downwards as it is now assumed they can source a higher proportion of woodchip.
f. The data for **Dedicated biomass CHP** has been substantially revised following the CHP call for evidence, a revised view of the technical potential based on the deployment pipeline, and heat revenues have been adjusted to take account of revised fossil fuel and carbon price

[53] As Arup's medium cost estimates represent the median, the supply curves take into account cost skewedness. If the median equals the mid-point of the low to high range, then the distribution is fairly even, while a median above (below) the mid-point implies costs are more skewed towards the higher (lower) end. Therefore, our supply curve, which assumes five cost tranches (low, low/medium/, medium, medium/high, high), each with 20% of the available potential, assumes more deployment potential at lower costs, if costs are skewed towards the low side, while it assumes more deployment potential at higher costs, if costs are skewed towards the high side.

[54] DECC (2011), UK Renewable Energy Roadmap, available at www.decc.gov.uk/assets/decc/11/meeting-energy-demand/renewable-energy/2167-uk-renewable-energy-roadmap.pdf

assumptions and reduced by 20% to better reflect the discount which CHP generators received on their heat output.

g. The cost, deployment and technical data for **Advanced Conversion Technology** plants was substantially revised following the call for evidence, which was compiled by NNFCC. The gate fee assumption was revised downwards to reflect both the greater fuel refining required and the increased competition for waste from the rest of the EU.

h. Capital costs and operating costs for **Biomass conversion and enhanced co-firing** plants were unchanged from the consultation, but biomass prices were adjusted downwards slightly in line with Dedicated biomass >50MW.

Table A 1: Assumed Feedstock Prices for Solid Biomass and Waste Plant

£/MWh(e) fuel input basis (NVC)	Lowest	Low	Central	High	Highest
Dedicated biomass <50MW, CoCHP	7	9	12	15	18
Dedicated biomass >50MW, biomass CHP	19	21	23	24	26
Standard co-firing, conversions, ECF	25	26	28	31	33
UK energy crops	13	19	25	27	29
ACT (assumed gate fee)	-8	-6	-5	-3	-1
EfW (assumed gate fee)	-26	-25	-23	-21	-19

Source: Internal analysis based on AEA (2011) and WRAP gate fee report (2011)

Table A 2: Assumed feedstock prices for bioliquid plant

	Current	**2020**			**2030**		
£/MWh input		**Low**	**Central**	**High**	**Low**	**Central**	**Very High**
Biodiesel	75	48	69	73	48	69	73
Bioethanol	58	50	54	58	43	47	83

Source: AEA (2011)

Table A 3: Assumed hurdle rates at different financial close dates[55], with hurdle rates from 2010-16 assuming support under the RO and from 2017 onwards assuming support under the new FIT with CfD

	2010-16	2017-18	2020-25	2026-30
Onshore wind	9.6%	8.6%	8.6%	8.6%
Offshore wind	11.6%	10.5%	10.5%	8.6%
Offshore wind R3	13.2%	12.3%	12.3%	10.9%
Geothermal	22.7%	21.2%	21.2%	15.3%
PV	7.5%	7.0%	7.0%	7.0%
Biomass	12.7%	11.9%	11.9%	10.9%
Bioliquid	12.7%	11.8%	11.8%	10.6%
EfW	11.9%	11.1%	11.1%	11.1%
AD	13.2%	13.2%	12.3%	11.1%
ACT	12.7%	11.8%	11.8%	10.6%
Landfill gas	9.6%	9.6%	8.6%	8.6%
Sewage gas	9.6%	8.6%	8.6%	8.6%
Hydro	7.5%	7.0%	7.0%	7.0%
Wave	8.0%	8.0%	12.8%	12.3%
Tidal stream	13.2%	12.3%	12.3%	11.1%
Tidal barrage	7.5%	7.0%	7.0%	7.0%

Source: DECC assumptions, based on Arup (2011), Oxera (2011) and Redpoint (2010)

125. The heat produced by CHP stations has a value which influences their project economics. This value may be through sale of the heat in the form of steam to a nearby buyer, or if the heat is used on-site, through avoiding the costs of generating the heat by other means. The latter costs are also relevant to the buyer, as if they were not buying the heat, they would have to generate it by other means (or find an alternative seller).

126. Heat revenues have been calculated using the avoided cost of heat generation approach. This is based on gas boiler costs of £30/kW capex and £0.2/kW/y opex from AEA/Nera (2009)[56], DECC gas fuel price assumptions and DECC carbon price assumptions (where the installation would be large enough to be in the EU-ETS).

127. The values of heat revenues per MWh of electricity, will depend on the heat to power ratios of the CHP stations, as provided by Arup. The results vary significantly, as shown in the table below. Heat revenues are included in levelised costs with a negative sign.

[55] For CHP, a 1% increase in the hurdle rates in assumed to reflect the increased difficulties in finding and retaining a heat customer for the life of the generation asset.
[56] AEA/Nera (2009) *UK Supply Curve for Renewable Heat,* available at www.rhincentive.co.uk/library/regulation/0907Heat_Supply_Curve.pdf

Table A 4: Heat revenues

Technology	Levelised heat revenue, £/MWh of electrical output (£2010/11 prices)
Energy from waste with CHP	£18
Geothermal with CHP	£86
Dedicated bioliquids with CHP	£13
ACT with CHP	£23
Dedicated biomass with CHP	£50
Anaerobic Digestion CHP	£21

Marine revenues

128. It is possible that early wave and tidal stream arrays may be in receipt of grant funding, subject to state aids approval. DECC has recently announced a £20m marine funding programme. For the purposes of modelling, the following simplifying assumptions were made:

- Grants are made to demonstration projects in addition to ROC bandings, subject to not exceeding state aid limits on maximum percentage of total investment costs.
- Grants were limited to bringing on half of the available tidal stream and wave potential in individual years.

Small-scale electricity in feed-in tariff technologies (AD, solar PV, hydro and wind)

129. In the modelling, new installations with less than 5MW of installed capacity in these technologies are assumed to be supported under feed-in tariffs (FiTs) rather than the RO. This is a simplification: whilst microgeneration (<50kW) is only supported by FiTs, installations between 50kW and 5MW have the choice between RO and FiT support. FiTs have generally given more generous support than the RO up to now, reflecting higher generation costs at lower capacities. However, some installations with the choice are likely to continue to accredit under the RO, for example if financial institutions are more familiar with the RO mechanism.

Fossil fuel prices

130. The analysis uses the latest available finalised DECC fossil fuel price projections published in October 2011[57].

Co-firing, enhanced co-firing and biomass conversions

131. In the Pöyry modelling, the decision to enhance co-fire or convert a station fully is modelled on a unit-by-unit basis. If a unit is economic to convert under the bandings in the scenario, then it does so fully for as long as it is economic to do so. Standard co-firing is assumed to be 20% co-firing of a coal plant, where it is economic under the bandings in the scenario being modelled.

132. The choice between burning coal and burning biomass for each coal/co-firing plant is made in the model according to which alternative gives the highest NPV of cashflows (discounting at the hurdle rate).

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[57] Available at: http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/en_emis_projs/en_emis_projs.aspx

Wholesale price income

133. As set out in the Evidence Base, it was assumed that plants receive the wholesale prices endogenously modelled by Pöyry consultants, and investment decisions are made with five-year foresight (from the point of the main financial investment decision – assumed to be just before construction begins) of rising wholesale prices (which rise due to the carbon price floor and rising gas prices). Thereafter wholesale prices are assumed by investors to be flat at the level of the fifth year. This market failure – information failure in a lack of certainty for investors about rising wholesale prices – means that ROC levels have to be set higher than in a world of perfect information about future wholesale prices, to achieve the same level of deployment.

134. The table below sets out the wholesale prices under Option 3 with central, low and high fossil fuel prices. The underlying fossil fuel prices have been updated since those used in the consultation.

Table A 5:Wholesale prices under Option 3 (£2011/12)

	GB wholesale electricity price		
	Central fossil fuel prices	**Low fossil fuel prices**	**High fossil fuel prices**
2011/12	60	57	61
2012/13	63	48	68
2013/14	68	42	72
2014/15	73	43	75
2015/16	73	44	76
2016/17	75	45	80
2017/18	73	46	82
2018/19	70	46	85
2019/20	71	49	86
2020/21	72	50	88
2021/22	74	52	91
2022/23	74	53	93
2023/24	75	55	93
2024/25	76	57	97
2025/26	76	59	94
2026/27	73	61	91
2027/28	77	62	95
2028/29	74	61	89
2029/30	74	59	83
2030/31	75	57	76

Source: Pöyry

Annex B - Renewables capacity and generation mix details

Table B 1: Renewables capacity mix under different banding options, MW

All large-scale* (non-FiTs) capacity	Total deployment by 2012/13	New build under the RO during the 2013-17 Banding Review period, MW*** Option 1 Current bands	Option 2 Consultation bands	Option 3 Response bands
Enhanced co-firing and conversions	1,200	1,500	3,200	3,200
Onshore wind	7,000	2,800	2,600	2,600
Offshore wind	3,600**	0	530	530
Dedicated biomass >50MW	50	78	78	78
Dedicated biomass <50MW	340	170	170	170
Biomass CHP	33	80	80	80
PV	50	470	470	*Reconsulting*
Energy from waste power only	290	120	140	140
Energy from waste CHP	28	220	220	220
ACT standard and CHP	7	43	7	43
ACT advanced	2	0	0	0
Sewage gas	210	11	11	11
AD	37	2	2	2
Hydro	1,700	8	8	8
Tidal stream	2	0	23	23
Wave	1	0	0	0
Bioliquids	51	0	0	0
Co-firing with CHP	0	0	0	0
Geothermal	10	10	8	8
Landfill gas	1,100	13	11	12
TOTAL	19,823	5,500	7,600	7,300

Source: modelling by Pöyry consultants; DECC bottom-up conversions/ECF assessment; Results rounded to two significant figures

*Note 'large-scale' renewables are defined as all UK renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain. Bands for large scale solar PV will be subject to further consultation. Large scale PV costs and deployment are indicative at this stage.
** Includes capacity built in 2013/14, as the band is already set for 2013/14.
*** For offshore wind this only includes new build in 2014/15 and 2015/16

Table B 2: Renewables generation mix under different banding options (GWh)

Modelled large-scale*annual generation (GWh per year)	Generation from capacity built by 31/3/2012	Generation from net new build under the RO during the 2013-17 Banding Review period:***		
		Option 1 current bands	Option 2 Consultation bands	Option 3 Response bands
Enhanced co-firing and conversions	6,800	8,300	18,400	18,400
Onshore wind	17,100	6,800	6,400	6,400
Offshore wind	11,000**	0	1,600	1,600
Dedicated biomass >50MW	400	610	610	610
Dedicated biomass <50MW	2,600	1,400	1,400	1,400
Biomass CHP	220	530	530	530
PV	48	440	440	*Re-consulting*
Energy from waste power only	1,700	890	1,000	1,000
Energy from waste CHP	200	1,700	1,700	1,700
ACT standard and CHP	40	260	39	260
ACT advanced	9	0	0	0
Sewage gas	630	52	52	52
AD	170	10	10	10
Hydro	4,900	28	28	28
Tidal stream	8	0	80	80
Wave	3	0	0	0
Bioliquids	150	0	0	0
Co-firing with CHP	0	0	0	0
Geothermal	0	80	64	64
Landfill gas	5,900	93	75	85
Standard co-firing	3,200	N/A	N/A	N/A
TOTAL	55,000	21,000	32,000	32,000

Source: modelling by Pöyry consultants; DECC bottom-up conversions/ECF assessment; Results rounded to two significant figures

*Note 'large-scale' renewables are defined as all UK renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain. Bands for large scale solar PV will be subject to further consultation. Large scale PV costs and deployment are indicative at this stage.

** This includes generation from capacity built by 2013/14, as the offshore wind band for 2013/14 has already been set.

*** For offshore wind this includes only generation from new build in 2014/15 and 2015/16

Table B 3: Renewables capacity mix under high fossil fuel prices, MW

All large-scale* (non-FiTs) capacity	Total deployment by 2012/13		New build under the RO during the 2013-17 Banding Review period, MW:*** Option 1 Current bands		Option 3 Response bands	
	High FF	Difference from central FF	High FF	Difference from central FF	High FF	Difference from central FF
Biomass conversion and enhanced co-firing	1,200	*0*	2,400	*970*	3,700	*510*
Onshore wind (>5MW)	7,100	*48*	3,200	*400*	2,800	*220*
Offshore wind	3,600**	*0*	200	*200*	740	*200*
Dedicated biomass >50MW	50	*0*	140	*61*	160	*78*
Dedicated biomass <50MW	340	*3*	230	*55*	230	*55*
Biomass CHP	33	*0*	80	*0*	80	*0*
PV	53	*0*	470	*0*	280	*96*
Energy from waste power only	290	*1*	140	*17*	140	*0*
Energy from waste CHP	28	*0*	260	*40*	260	*40*
ACT standard and CHP	7	*0*	43	*0*	46	*4*
ACT advanced	2	*0*	0	*0*	0	*0*
Sewage gas	210	*1*	11	*0*	11	*0*
AD	37	*0*	2	*0*	2	*0*
Hydro	1,700	*6*	20	*12*	8	*0*
Tidal stream	2	*0*	0	*0*	23	*0*
Wave	1	*0*	0	*0*	0	*0*
Bioliquids	51	*0*	0	*0*	0	*0*
Co-firing with CHP	0	*0*	0	*0*	0	*0*
Geothermal	0	*0*	10	*0*	10	*2*
Landfill gas	1,100	*1*	12	*-1*	12	*0*
TOTAL	**16,000**	***61***	**7,300**	***1,800***	**8,500**	***1,200***

Source: modelling by Pöyry consultants; DECC bottom-up conversions/ECF assessment; Results rounded to two significant figures

*Note 'large-scale' renewables are defined as all UK renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain. Bands for large scale solar PV will be subject to further consultation. Large scale PV costs and deployment are indicative at this stage.

** Includes capacity built in 2013/14, as the band is already set for 2013/14.

*** For offshore wind this only includes new build in 2014/15 and 2015/16

Table B 4: Renewables generation mix under high fossil fuel prices (GWh)

Modelled annual generation (GWh per year) from large-scale* renewable capacity	Generation from capacity built by 31/3/2012	Generation from net new build under the RO during the 2013-17 Banding Review period:***			
		Option 1 Current bands		Option 3 Response bands	
	High FF	High FF	Difference from central FF	High FF	Difference from central FF
Enhanced co-firing and conversions	6,800	14,000	*5,500*	21,000	*2,900*
Onshore wind	17,000	7,800	*990*	6,800	*480*
Offshore wind	11,000**	620	*620*	2,300	*620*
Dedicated biomass >50MW	400	1,100	*480*	1,200	*610*
Dedicated biomass <50MW	2,700	1,800	*430*	1,800	*430*
Biomass CHP	220	530	*0*	530	*0*
PV	48	440	*0*	260	*91*
Energy from waste power only	1,700	1,000	*120*	1,000	*0*
Energy from waste CHP	200	2,000	*300*	2,000	*300*
ACT standard and CHP	40	260	*0*	280	*22*
ACT advanced	9	0	*0*	0	*0*
Sewage gas	640	52	*0*	52	*0*
AD	170	10	*0*	10	*0*
Hydro	4,900	66	*38*	28	*0*
Tidal stream	8	0	*0*	80	*0*
Wave	3	0	*0*	0	*0*
Bioliquids	150	0	*0*	0	*0*
Co-firing with CHP	0	0	*0*	0	*0*
Geothermal	0	80	*0*	80	*16*
Landfill gas	5,900	93	*0*	93	*9*
Standard co-firing	4,000	N/A	N/A	N/A	N/A
TOTAL	**56,000**	**30,000**	***8,500***	**38,000**	***5,500***

Source: modelling by Pöyry consultants; DECC bottom-up conversions/ECF assessment; Results rounded to two significant figures

*Note 'large-scale' renewables are defined as all UK renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain. Bands for large scale solar PV will be subject to further consultation. Large scale PV costs and deployment are indicative at this stage.

** This includes generation from capacity built by 2013/14, as the offshore wind band for 2013/14 has already been set.

*** For offshore wind this includes only generation from new build in 2014/15 and 2015/16

Table B 5: Renewables capacity mix under low fossil fuel prices, MW

All large-scale* (non-FiTs) capacity	Total deployment by 2012/13		New build under the RO during the 2013-17 Banding Review period, MW:*** Option 1 Current bands		Option 3 Response bands	
	low FF	Difference from central FF	Low FF	Difference from central FF	low FF	Difference from central FF
Biomass conversion and enhanced co-firing	750	*-450*	1,200	*-220*	770	*-2,400*
Onshore wind (>5MW)	6,800	*-220*	1,000	*-1,800*	880	*-1,700*
Offshore wind	3,600**	*0*	0	*0*	0	*-530*
Dedicated biomass >50MW	50	*0*	0	*-78*	0	*-78*
Dedicated biomass <50MW	300	*-36*	2	*-170*	2	*-170*
Biomass CHP	33	*0*	80	*0*	80	*0*
PV	40	*-13*	320	*-150*	10	*-170*
Energy from waste power only	280	*-9*	20	*-110*	20	*-120*
Energy from waste CHP	21	*-7*	180	*-40*	180	*-40*
ACT standard and CHP	1	*-6*	7	*-36*	7	*-36*
ACT advanced	2	*0*	0	*0*	0	*0*
Sewage gas	200	*-5*	2	*-9*	2	*-9*
AD	37	*0*	2	*0*	2	*0*
Hydro	1,700	*0*	8	*0*	1	*-6*
Tidal stream	2	*0*	0	*0*	15	*-8*
Wave	1	*0*	0	*0*	0	*0*
Bioliquids	51	*0*	0	*0*	0	*0*
Co-firing with CHP	0	*0*	0	*0*	0	*0*
Geothermal	0	*0*	8	*-2*	8	*0*
Landfill gas	1,100	*-2*	12	*-1*	12	*0*
TOTAL	**15,000**	*-740*	**2,900**	*-2,600*	**2,000**	***-5,300***

Source: modelling by Pöyry consultants; DECC bottom-up conversions/ECF assessment; Results rounded to two significant figures

*Note 'large-scale' renewables are defined as all UK renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain. Bands for large scale solar PV will be subject to further consultation. Large scale PV costs and deployment are indicative at this stage.

** Includes capacity built in 2013/14, as the band is already set for 2013/14.

*** For offshore wind this only includes new build in 2014/15 and 2015/16

Table B 6: Renewables generation mix under low fossil fuel prices (GWh)

Modelled annual generation (GWh per year) from large-scale* renewable capacity	Generation from capacity built by 31/3/2012	Generation from net new build under the RO during the 2013-17 Banding Review period:***			
		Option 1 Current bands		Option Response bands	
	Low FF	Low FF	Difference from central FF	Low FF	Difference from central FF
Enhanced co-firing and conversions	4,300	7,000	*-1,300*	4,400	*-14,000*
Onshore wind	17,000	2,600	*-4,200*	2,200	*-4,200*
Offshore wind	11,000**	0	*0*	0	*-1,600*
Dedicated biomass >50MW	400	0	*-610*	0	*-610*
Dedicated biomass <50MW	2,400	16	*-1,400*	16	*-1,400*
Biomass CHP	220	530	*0*	530	*0*
PV	36	300	*-140*	8	*-160*
Energy from waste power only	1,700	110	*-780*	110	*-900*
Energy from waste CHP	140	1,400	*-300*	1,400	*-300*
ACT standard and CHP	6	39	*-220*	39	*-220*
ACT advanced	9	0	*0*	0	*0*
Sewage gas	610	12	*-41*	12	*-41*
AD	170	10	*0*	10	*0*
Hydro	4,900	28	*0*	4	*-24*
Tidal stream	8	0	*0*	51	*-28*
Wave	3	0	*0*	0	*0*
Bioliquids	150	0	*0*	0	*0*
Co-firing with CHP	0	0	*0*	0	*0*
Geothermal	0	64	*-16*	64	*0*
Landfill gas	5,900	54	*-39*	37	*-47*
Standard co-firing	450	N/A	N/A	N/A	N/A
TOTAL	**48,000**	**12,000**	***-9,000***	**8,800**	***-24,000***

Source: modelling by Pöyry consultants; DECC bottom-up conversions/ECF assessment; Results rounded to two significant figures

*Note 'large-scale' renewables are defined as all UK renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain. Bands for large scale solar PV will be subject to further consultation. Large scale PV costs and deployment are indicative at this stage.

** This includes generation from capacity built by 2013/14, as the offshore wind band for 2013/14 has already been set.

*** For offshore wind this includes only generation from new build in 2014/15 and 2015/16

Annex C - Modelling approaches for biomass conversions and Enhanced Co-Firing

135. In the lead consultation option, standard co-firing was defined as burning 0-14% biomass fuel in a whole (former) fossil fuel power station, with enhanced co-firing defined as burning 15-99% biomass fuel. In light of evidence submitted as part of the consultation and additional technical advice, it became clear that total ECF/conversion costs reflected their percentage of biomass fuel input to the boiler/unit they were burnt in, more than the percentage they represent of the whole station's biomass fuel input. The basis of the definitions has therefore been switched to a per unit basis in the Government response. Whilst the capital costs follow a roughly linear profile from 20% of a unit upwards (roughly constant capex per kW of biomass with increasing percentages of biomass), the proportionate reductions of efficiency and capacity on a generation asset increase the closer the unit gets to burning 100% biomass and fuel costs per MWh can increase too. Furthermore, there is a policy objective to encourage higher proportions of biomass burn to increase decarbonisation and to achieve a higher degree of 'lock-in' for (former) fossil fuel plant to biomass. The revised proposals therefore increase the bands in a step-wise fashion as a greater percentage of biomass is burned in the unit (by creating a mid-range co-firing band for co-firing between 50-84% in a unit, and a high-range co-firing band for co-firing between 85-99% in a unit).[58]

136. There is an affordability constraint in the form of the Levy Control Framework (LCF). Whilst conversions and enhanced co-firing represent some of the most cost-effective renewable technologies, they also represent the majority of expected new RO spend from 2013-17. Analysis suggests control of ECF and/or conversions costs is necessary to stay within the LCF. The band for high-range co-firing is therefore set at a lower level (0.7 ROCs/MWh) in 2013/14 to remain within the LCF for that year, before increasing to 0.9 ROCs/MWh in 2014/15 for the rest of the period to further incentivise deployment. The band for low range co-firing is proposed at a lower level (0.3 ROCs/MWh) in 2013/14 and 2014/15 before increasing to 0.5ROCs/MWh for the rest of the period – this proposal will be the subject of a new consultation.

137. New biomass conversions are not expected to pose the same degree of budgetary risk as ECF under the LCF, and the policy objective is to incentivise higher percentages of biomass burn. Conversions provide both higher levels of renewable output and more certain renewable output towards renewable targets than ECF. However, conversions, like ECF, still represent a significant risk on the one hand to renewables targets if deployment is too low; and on the other to affordability for consumers if deployment is too high. It is proposed that both will therefore be subject to the new monitoring and reporting requirements, on which a separate consultation will be published shortly.

138. In line with the evidence provided in consultation, each approach examines the conversion of individual generation units, rather than the plant as a whole. This is consistent with the revised proposed definitions for enhanced co-firing and conversions set out in the Government Response to consultation. Enhanced co-firing is defined as burning 50% or more biomass in a boiler. The proportion of biomass burned in each unit may vary according the relative prices of biomass and coal throughout the year. Owing to the difficulty of forecasting short-term movements in relative prices throughout the year, this has not been modelled. Instead, relative biomass-coal prices were assumed to vary annually. The analysis assumes a constant amount of biomass will be burned *per generation*

[58] In general when ECF is referred to in the results below, it covers mid-range and high-range co-firing. The analysis found that only high-range co-firing is expected to occur at the proposed rates.

unit, in every year, irrespective of the other uncertainties set out earlier.

139. Owing to the relatively small number of potential conversions/ECF and the commercial confidentiality of the data provided, results are not presented in this IA for individual plants but they have been aggregated. In addition, given that it is difficult to recreate the economics of the investment decision faced by coal generators accurately for every individual case, the results have been aggregated to average out non-systematic errors.

140. As was the case for other technologies, assumptions were supplied to Pöyry and inputted into DECC's in-house renewables investment model on the costs, technical characteristics and deployment potential of biomass conversions and ECF plants. Three plants were modelled individually, based on data collected for, and during, the consultation. Other potential projects used average values for costs and technical characteristics. Evidence collected as part of the consultation was used to produce deployment potential scenarios.

A) Pöyry modelling

141. With respect to biomass conversions and ECF, Pöyry were instructed to investigate the impact of current bands and revised proposals under two scenarios:

- central assumptions with a biomass fuel availability constraint; and
- high biomass conversions/ECF deployment potential with no biomass fuel constraint.

Relaxing the biomass fuel supply constraint was chosen as a sensitivity because availability of sustainable biomass is a key uncertainty which will directly affect how much biomass generation is possible.

B) DECC In-house modelling

142. Each potential candidate for conversion or ECF was modelled separately. First, it was important to determine how economic the plant was in continuing to burn coal, and for how long. Owing to changes in fossil fuel, carbon and electricity prices over time, some plants cease to be economic before others e.g. for having a lower efficiency. When determining the minimum level of RO support to incentivise a conversion/ECF, the profitability must be identical to that when the plant burns coal. When discounting cashflows, a higher discount rate (11.6%) is used in the biomass case, than the coal case (7.5%), reflecting the risk of switching to a new fuel and the impacts that could have on the existing boilers, and the relative immaturity of the biomass fuel supply chain.

143. The in-house model then estimates which plants will decide to convert/ECF based on a comparison of the estimated ROCs required and the ROC support under the scenario being modelled. The methodology is similar to that used for the Pöyry ROCket modelling, but there is no biomass constraint modelled in any of the scenarios.

C) Bottom-up scenarios

144. It is important to recognise that although the evidence has been assessed in detail, substantial uncertainties remain with the modelling assumptions which have been made in relation to these two technologies of enhanced co-firing and conversions. For example, a 10% rise in the price of biomass is estimated to result in investors requiring an additional 0.25 ROCs per MWh. The sensitivity analysis presented in Annex D attempts to illustrate some of this uncertainty, but outcomes outside these ranges are still possible.

145. The results for ECF and conversions. from the modelling analysis did not reflect the market intelligence and judgement of likely deployment by DECC. It was therefore decided to construct bottom-up deployment scenarios, informed by the modelling evidence above, by consultation evidence and by market intelligence. These scenarios set out estimated deployment at different ROC banding levels. Additional factors which have been considered were:

- Geographical factors which may influence price and therefore likelihood of an investment going ahead
- Time required to develop the feedstock supply chain, and competition for resource with other biomass generators
- Ownership of other plants - if a company owns multiple plants it is likely to decide on a priority order rather than multiple simultaneous conversions

146. A number of scenarios were provided to Pöyry and ‘forced-on’ in the modelling results presented in this IA. All other technologies have been modelled by Pöyry using their ROCket and Eureca models, following the process set out in section 3.

Annex D – Sensitivity Analysis

A) Biomass conversions and enhanced co-firing

147. As set out in Annex C, the uptake of biomass conversions and ECF plants were explored using three different modelling approaches: Pöyry modelling, in-house analysis and bottom-up.

148. All three approaches used “central” and “high” estimates of biomass conversions/ECF potential. The impact of these scenarios on uptake in response to the banding options was explored using the different modelling approaches. The ‘central’ potential contained generation units which were more likely to convert/ECF based on consultation evidence indicating well-developed plans. The ‘high’ potential also contained units which were more speculative, but nevertheless showed potential to convert/ECF in the future.

149. Table D1 sets out the capacity and generation in 2016/17, under the three different modelling methodologies set out in Annex C. For each methodology, a number of scenarios are presented, which vary the potential, fossil fuel prices and banding scenario.

150. Pöyry modelling (consultation bands and revised proposals):
- Central potential – uptake estimated under the central set of assumptions, set out in Annex A.
- No fuel constraint and high potential – This sensitivity removes the biomass fuel supply constraint and uses the high estimate of biomass conversions and ECF potential

151. In-house model (consultation bands and revised proposals):
- Central uptake potential – under low, central and high fossil fuel price assumptions
- High deployment potential – under central fossil fuel price assumptions

152. Bottom-up (consultation bands, current bands and revised proposals):
- Current bands and revised proposals used the central estimate of potential, under low, central and high fossil fuel prices
- Consultation bands used the central estimate of potential, under central fossil fuel prices.

Table D 1: Biomass conversion/ECF results

Model approach	Banding scenario	Potential assumption	Fossil fuel price assumption	Generation in 2016/17 TWh
Pöyry modelling	Current bands	Central	Central	5.8
	Consultation bands	Central		16
		High, plus no fuel constraint		15
	0.9 ROCs/MWh for conversion and ECF	Central		11
In-house model	Consultation bands	Central	Central	5.1
			Low	5.1
			High	12
		High	Central	10
	Response bands	Central	Central	5.1
			Low	0.0
			High	5.1
		High	Central	5.1
Bottom-up assessment	Current bands	Central	Low	7.0
			Central	8.3
			High	14
	Response bands		Low	4.4
			Central	18
			High	21
	Consultation proposals		Central	18

Source: Pöyry modelling, DECC modelling and DECC calculations, rounded to two significant figures.

153. DECC examined the results of the Pöyry and in-house modelling, which showed ECF and conversions deployment ranging from 0-16 TWh/y by 2016/17, depending on banding levels and other assumptions, alongside industry intelligence and expert judgement, and believe it is likely on a central view that deployment would be higher than the modelling indicates. This DECC view is the 'bottom-up assessment' set out above which was 'forced on' in the main Pöyry modelling results above. However, there is very considerable uncertainty surrounding the level of ECF and conversions deployment, given the variability of relative coal to biomass fuel prices, and uncertainty about the levels of available biomass amongst other factors, as illustrated by the range of estimates in the table above.

B) Fossil fuel price sensitivities

High fossil fuel prices

154. This section outlines renewable deployment, monetised costs and benefits and distributional impacts under a high fossil fuel price scenario

Renewable deployment

155. Tables D2 and D3 summarise the capacity and generation mix in a world of high fossil fuel prices[59] for current bands and the new-build supported by the RO under new banding levels over the 2013-17 banding review period. Generally, owing to renewable technologies becoming more cost-competitive under high fossil fuel prices, more renewable capacity is built over the Banding Review period in both current bands and new bands when compared to central fossil fuel price scenarios.

Table D 2: Modelled new build capacity under different options, MW

Modelled Capacity (MW)	**Total deployment by 2012/13**		**New build under the RO during the 2013-17 Banding Review period:******			
Scenario	**Option 1 Current bands**		**Option 1 Current bands**		**Option 3 Response bands**	
Fossil fuel price	**High**	**N/A**	**High**	**N/A**	**High**	**N/A**
		Difference from central FF		**Difference from central FF**		**Difference from central FF**
Biomass conversion and ECF	1,200	*0*	2,400	*970*	3,700	*510*
Onshore wind (>5MW)*	7,100	*48*	3,200	*400*	2,800	*220*
Offshore wind	3,600***	*0*	200	*200*	740	*200*
Dedicated biomass >50MW	50	*0*	140	*61*	160	*78*
Dedicated biomass <50MW	340	*3*	230	*55*	230	*55*
Tidal stream	3	*0*	0	*0*	23	*0*
Wave	1	*0*	0	*0*	0	*0*
Other**	3,400	*10*	1,100	*68*	850	*140*
Total 'large-scale'**	**16,000**	***61***	**7,300**	***1,800***	**8,500**	***1,200***

* Onshore wind (>5MW) includes onshore wind <5MW in Northern Ireland.
**Note 'large-scale' are renewables defined as all renewable electricity except for <5MW AD, PV, hydro and wind supported by FiTs in Great Britain.
*** Includes new build in 2013/14
**** For offshore wind includes only new build in 2014/15 and 2015/16

156. Under high fossil fuel prices, new proposed bands brings on around 1.3GW of ECF and conversion capacity that does not come on under current bands (as there is no separate band for enhanced co-firing and the standard co-firing rate is not enough to bring on any enhanced capacity), delivering an additional 7 TWh/y of generation towards the 2020 renewables target.

157. Under high fossil fuel prices, new proposals lead to generation from onshore wind new build of around 6.8TWh, a reduction of 1 TWh from current bands. This compares with a reduction of 0.5TWh under central fossil fuel prices.

158. Under high fossil fuel prices total large-scale renewables new build increases by 1.2GW under new proposed bands compared to central fossil fuel prices. This equates to an increase in generation towards the 2020 renewables target of 8TWh.

[59] High fossil fuel price assumptions (as central and low) are the latest DECC projections, published October 2011.

Table D 3: Modelled generation from new build capacity under different options, GWh per year[60]

Modelled Generation (GWh)	Total deployment by 2012/13		New build under the RO during the 2013-17 Banding Review period:****			
Scenario	**Option 1 Current bands**		**Option 1 Current bands**		**Option 3 Response bands**	
Fossil fuel price	**High**	**N/A**	**High**	**N/A**	**High**	**N/A**
		Difference from central FF		**Difference from central FF**		**Difference from central FF**
Biomass conversion and ECF	6,800	*0*	14,000	*5,500*	21,000	*2,900*
Onshore wind (>5MW)*	17,000	*120*	7,800	*990*	6,800	*480*
Offshore wind	11,000***	*0*	620	*620*	2,300	*620*
Dedicated biomass >50MW	400	*0*	1,100	*480*	1,200	*610*
Dedicated biomass <50MW	2,700	*24*	1,800	*430*	1,800	*430*
Tidal stream	8	*0*	0	*0*	80	-
Wave	3	*0*	0	*0*	0	-
Other**	14,000	*840*	4,500	*460*	4,300	*440*
Total 'large-scale'**	**52,000**	***980***	**30,000**	***8,500***	**38,000**	***5,500***

* Onshore wind (>5MW) includes onshore wind <5MW in Northern Ireland.
**Note 'large-scale' are renewables defined as all renewable electricity except for <5MW AD, PV, hydro and wind supported by FiTs in Great Britain.
*** This includes generation from capacity built by 2013/14, as the offshore wind band for 2013/14 has already been set.
**** For offshore wind this includes only generation from new build in 2014/15 and 2015/16.

Monetised costs and benefits

159. Under new proposals, renewable generation costs are £7.9bn higher while non-renewable generation costs are £2.4bn lower than under current bands. This compares to £10.9bn higher renewable generation costs and £7.3bn lower non-renewable generation costs than under current bands in the scenario with central fossil fuel prices. The increase in renewable generation compared to current bands is lower under the high fossil fuel price scenario, than in the central scenario, driven mainly by the difference in the impact on ECF and biomass conversions – this result comes from our bottom up modelling of ECF and conversions and the economics of different plant under fossil fuel scenarios (see table D1). Under high fossil fuel prices the level of ECF/ conversion reaches the technical constraint on total conversions – which restricts the total increase in deployment under this scenario. This leads to a lower increase in renewable generation costs (from proposed bands compared to current bands) in the high fossil fuel case than the central case. The reduction in non-renewable generation costs are significantly lower in the high fossil fuel scenario than in the central scenario – leading to a higher overall increase in costs of £5.5bn in the high fossil fuel price scenario.

160. Under high FF prices, new proposed bands produces 56Mt fewer CO_2 emissions and hence £1.6bn lower carbon credit purchase costs than under current bands. This compares to 82Mt less CO_2 emissions and £1.9bn lower carbon credit purchase costs under new bands than under current bands in a world with central fossil fuel prices. This smaller impact on CO_2 in the high fossil fuel case is as a result of the lower increase in renewable generation than under the central case.

161. Balancing costs are slightly higher under high fossil fuel price assumptions compared to current bands. This is a smaller impact than in the central fossil fuel price scenario, where proposed bands

[60] Note that the generation figures include 12 months of generation from the new build during 2015/16, which is assumed to start generating halfway through 2015/16. The sum of the generation from capacity built by 1/4/13 and the generation built under the RO banding review period is therefore greater than total renewable generation in 2015/16, but lower than total renewable generation in 2016/17. In this latter year, it is assumed there is new build of renewables under the FiT with CfD.

lead to £100m increase in balancing cost compared to current bands.

162. The table below summarises the monetised impacts. Note, the signing below (unlike in the tables above) is positive for a benefits and negative for a cost. Table D4 shows that the total impact of new bands under high fossil fuel prices is a £5.5bn increase in costs and a £1.6bn increase in benefits, as compared to current bandings in a high fossil fuel price scenario. Option 3 in a high fossil fuel price world imposes a larger net present cost of £4bn due to more renewables being deployed.

Table D 4: Monetised costs and benefits to 2039/40 summary, NPV (£bn 2011/12 prices)

	Option 3 (High FF) relative to Option 1 (High FF)
Generation costs	-£5.5bn
EUA purchase	+£1.6bn
Balancing costs	-£0.05bn
Total impact	**-£4.0bn**

Estimates rounded to two significant figures

Distributional impacts

163. Under high fossil fuel prices, Option 3 refined proposals reduce the cost of the RO. The lifetime (to the end of the RO in 2037) reduction in RO costs from Option 3 refined proposals comes to a PV of £370m (£2011/12 prices), relative to current bands under high fossil fuel prices. This compares to an increase in RO costs under central fossil fuel prices of £1.5bn. RO costs overall are higher in a high fossil fuel price world due to more renewable generation coming on and hence more ROCs being issued; renewables generation goes up due to high fossil fuel prices more under current bands than under Option 3 refined proposals as set out above.

Table D 5: RO support costs under high fossil fuel prices (£m 2011/12 prices, undiscounted)

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Current bands (high FF)	1,400	1,900	2,900	3,300	3,700	3,900
Impact of Option 3 Response bands (high FF)	-	-	-420	-450	-140	0

164. Under high fossil fuel prices, Option 3 refined proposals reduces wholesale prices relative to the current bands. The net present value to consumers of these lower wholesale prices is a benefit of around £430m in NPV terms. This compares to around a benefit of £260m in NPV terms under central fossil fuel prices.

165. Under high fossil fuel prices, the net impact on consumers relative to current bands, covering RO support costs, wholesale price impacts and balancing costs, comes to comes to a net benefit of around £91m in NPV terms for Option 3 refined proposals. This compares to a £1.4bn net cost under central fossil fuel prices.

Low fossil fuel prices

166. This section outlines renewable deployment, monetised costs and benefits and distributional impacts under a low fossil fuel price scenario

Renewable deployment

167. Tables D6 and D7 summarise the capacity and generation mix in a world of low fossil fuel prices[61] for current bands and the new-build supported by the RO under new proposed bands over the 2013-17 banding review period. Generally, due to renewable technologies becoming less cost-competitive under low fossil fuel prices, significantly less renewable capacity is being built over the period in either current bands or Option 3 refined proposals when compared to central fossil fuel price scenarios.

Table D 6: Modelled new build capacity under different options, MW

Modelled Capacity (MW)	**Total deployment by 2012/13**		**New build under the RO during the 2013-17 Banding Review period:******			
Scenario	**Option 1 Current bands**		**Option 1 Current bands**		**Option 3 Response bands**	
Fossil fuel price	**Low**	**N/A**	**Low**	**N/A**	**Low**	**N/A**
		Difference from central FF		**Difference from central FF**		**Difference from central FF**
Biomass conversion and ECF	750	*-450*	1,200	*-220*	770	*-2,400*
Onshore wind (>5MW)*	6,800	*-220*	1,000	*-1,800*	880	*-1,700*
Offshore wind	3,600***	*0*	0	*0*	0	*-530*
Dedicated biomass >50MW	50	*0*	0	*-78*	0	*-78*
Dedicated biomass <50MW	300	*-36*	2	*-170*	2	*-170*
Tidal stream	3	*0*	0	*0*	15	*-8*
Wave	1	*0*	0	*0*	0	*0*
Other**	3,400	*-42*	640	*-350*	320	*-390*
Total 'large-scale'**	**15,000**	***-740***	**2,900**	***-2,600***	**2,000**	***-5,300***

Source: Pöyry modelling and DECC calculations; all figures rounded to two significant figures.
* Onshore wind (>5MW) includes onshore wind <5MW in Northern Ireland.
**Note 'large-scale' are renewables defined as all renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain.
*** Includes new build in 2013/14
**** For offshore wind includes only new build in 2014/15 and 2015/16

168. Total capacity of all technologies in 2015/16 is 5.3GW lower under low fossil fuel prices than under central fossil fuel prices for Option 3 refined proposals and generation is 24TWh/y lower by 2016/17.

169. For Option 3 refined proposals, under central fossil fuel price assumptions there are 3.2GW of ECF and conversion capacity deployed delivering 18TWh/y by 2016/17, compared to 2.4GW under low fossil fuel prices delivering 14TWh/y. Under central fossil fuel prices, offshore wind new build also increases under Option 3 by 530MW compared to current bands, while under low fossil fuel prices no additional offshore is coming on under Option 3 compared to current bands.

170. Under low fossil fuel prices, there is around 160MW less onshore wind deployed during the banding review period at the proposed 0.9 ROCs under Option 3, compared to the current band of 1 ROC and 0.4TWh/y less of generation by 2016/17. Around 1.7GW less onshore wind is built under Option 3 with low as opposed to central fossil fuel prices giving 4.2TWh/y less generation by 2016/17.

[61] High fossil fuel price assumptions (as central and low) are the latest DECC projections, first published May 2009.

Table D 7: Modelled generation from new build capacity under different options, GWh per year[62]

Modelled Generation (GWh)	Total deployment by 2012/13		New build under the RO during the 2013-17 Banding Review period:****			
Scenario	**Option 1 Current bands**		**Option 1 Current bands**		**Option 3 Response bands**	
Fossil fuel price	**Low**	**N/A**	**Low**	**N/A**	**Low**	**N/A**
		Difference from central FF		**Difference from central FF**		**Difference from central FF**
Biomass conversion and ECF	4,300	*-2,600*	7,000	*-1,300*	4,400	*-14,000*
Onshore wind (>5MW)*	17,000	*-510*	2,600	*-4,200*	2,200	*-4,200*
Offshore wind	11,000***	*0*	0	*0*	0	*-1,600*
Dedicated biomass >50MW	400	*0*	0	*-610*	0	*-610*
Dedicated biomass <50MW	2,400	*-280*	16	*-1,400*	16	*-1,400*
Tidal stream	8	*0*	0	*0*	51	*-28*
Wave	3	*0*	0	*0*	0	*0*
Other**	14,000	*-3,000*	2,500	*-1,500*	2,200	*-1,700*
Total 'large-scale'**	**48,000**	***-6,300***	**12,000**	***-9,000***	**8,800**	***-24,000***

Source: Pöyry modelling and DECC calculations; all figures are rounded to two significant figures.
* Onshore wind (>5MW) includes onshore wind <5MW in Northern Ireland.
**Note 'large-scale' are renewables defined as all renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain.
*** This includes generation from capacity built by 2013/14, as the offshore wind band for 2013/14 has already been set.
**** For offshore wind this includes only generation from new build in 2014/15 and 2015/16.

171. The net impact of Option 3 refined proposals in a low fossil fuel price world is to reduce renewables new build by around 0.9GW compared to current bands and to reduce renewables generation towards the 2020 renewables target by around 3.4TWh/y.

172. In comparison, under central fossil fuel prices, renewable new build increases by 1.8GW compared to current bands under Option 3 refined proposals and renewables generation towards the 2020 renewables target increases by 11TWh/y. So under low fossil fuel prices, the contribution of new build under the new bands is greatly reduced, with deployment higher under current bands.

Monetised costs and benefits

173. Under the preferred Option 3 refined proposals in a low fossil fuel prices world, renewable generation costs are £4.0bn lower than under current bands while non-renewable generation costs are £640m higher. This compares to £11bn higher renewable generation costs and £7.5bn lower non-renewable generation costs than under current bands in the scenario with central fossil fuel prices.

174. Option 3 refined proposals is associated with a relatively small increase of 24Mt in CO_2 emissions in the power sector to 2040 and hence £600m higher EUA (carbon credit) purchase costs than under current bands. (offset by higher emissions elsewhere within the EU-ETS). This compares to 82Mt less CO_2 emissions and £1.9bn lower carbon credit purchase costs under Option 3 than under current bands in a world with central fossil fuel prices.

[62] Note that the generation figures include 12 months of generation from the new build during 2015/16, which is assumed to start generating halfway through 2015/16. The sum of the generation from capacity built by 1/4/13 and the generation built under the RO banding review period is therefore greater than total renewable generation in 2015/16, but lower than total renewable generation in 2016/17. In this latter year, it is assumed there is new build of renewables under the FIT with CfD.

175. Balancing costs are £85m lower in Option 3 than under current bands with low fossil fuel price assumptions due to there being less onshore wind in the system. This compares to £94m higher balancing costs than under current bands with central fossil fuel prices.

176. The table below summarises the monetised impacts. Note, the signing below is positive for a benefits and negative for a cost. It shows that the total impact of Option 3 refined proposals under low fossil fuel prices is a £3.4bn reduction in costs and a £0.6bn reduction in benefits, as compared to current bandings in a low fossil fuel price scenario. This compares to a £1.6bn increase in costs under central fossil fuel prices.

Table D 8: Monetised costs and benefits to 2039/40 summary, NPV (2011/12 prices)

	Option 3 (Low FF) relative to option 1 (Low FF)
Generation costs	+£3.4bn
EUA purchase	-£0.6bn
Balancing costs	+£0.1bn
Total impact	**+£2.9bn**

Source: Pöyry modelling and DECC calculations; all figuresare rounded to two significant figures

Distributional impacts

177. Under low fossil fuel prices, Option 3 refined proposals reduces the cost of the RO. The lifetime (to the end of the RO in 2037) reduction in RO costs from Option 3 comes to an NPV of £3.7bn (£2011/12 prices), relative to current bands under low fossil fuel prices. This compares to an increase in RO costs under central fossil fuel prices of £1.5bn. RO costs are lower in a low instead of central fossil fuel price world due to less renewable generation coming on and hence less ROCs being issued.

Table D 9: RO support costs under low fossil fuel prices (£m 2011/12 prices, undiscounted)

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Current bands	1,400	1,900	2,600	2,700	2,700	2,700
Impact of Option 3 Revised Proposals	-	-	-200	-360	-340	-340

Source: Pöyry modelling and DECC calculations; all figures are rounded to two significant figures.

178. Under low fossil fuel prices, Option 3 refined proposals increases wholesale prices relative to the current bands. The net present value to consumers of these higher wholesale prices is a cost of around £1.8bn in NPV terms. This compares to a benefit to consumers of around £260m in NPV terms under central fossil fuel prices.

179. Under high fossil fuel prices, the net impact on consumers relative to current bands, covering RO support costs, wholesale price impacts and balancing costs, comes to comes to a net benefit of around £1.8m in NPV terms for Option 3 refined proposals. This compares to a £1.4bn net cost under central fossil fuel prices.

C) Assuming new build in 2016/17 is all supported by the RO rather than by CfDs

180. Under the Electricity Market Reform (EMR), the RO is due to close to new capacity from 1st April 2017. Between the introduction of the new support mechanism under the EMR (known as the CfD) and 31st March 2017, new large-scale renewable capacity in eligible technologies will have a choice between support under the RO and support under the CfD. Under the central assumptions set out above, all the capacity built up to and including 2015/16 is assumed to choose the RO, and capacity

in 2016/17 is assumed to choose the CfD, due to the greater revenue stability it offers alongside avoiding the risk of missing the RO cut-off date in the event of construction delay. This sensitivity looks at new capacity in 2016/17 choosing the RO, with all other assumptions as for the preferred Option 3 refined proposals.

181. Tables D10 and D11 below shows that new build under the RO increases by around 2GW under this sensitivity, compared to under central assumptions, delivering around 7TWh more generation under the RO.

Table D 10: Modelled new build capacity under the RO with new build switching from the RO to CfD support from 2016/17 or from 2017/18, for Option 3 (Response bands)

Modelled Capacity (MW)	Total deployment by 2012/13	New build under the RO during the 2013-17 Banding Review period****	
		RO supports new build 2013/14 to 2015/16	RO supports new build 2013/14 to 2016/17
Biomass conversion and enhanced co-firing	1,200	3,200	3,900
Onshore wind (>5MW)*	7,000	2,600	3,200
Offshore wind	3,600***	530	960
Dedicated biomass >50MW	50	78	78
Dedicated biomass <50MW	340	170	230
Tidal stream	2	23	31
Wave	1	0	0
Other**	3,400	710	930
Total 'large-scale'**	**16,000**	**7,300**	**9,300**

Source: Pöyry modelling and DECC calculations; all figures are rounded to two significant figures

* Onshore wind (>5MW) includes onshore wind <5MW in Northern Ireland.

**Note 'large-scale' are renewables defined as all renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain.

*** Includes new build in 2013/14; **** For offshore wind includes only new build in 2014/15 and 2015/16

Table D 11: Modelled generation from new build capacity under the RO with new build switching from the RO to CfD support from 2016/17 or from 2017/18

Modelled annual generation (GWh per year)	Generation from capacity built by 31/3/2012	Generation from net new build under the RO during the 2013-17 Banding Review period:****	
		RO supports new build 2013/14 to 2015/16	RO supports new build 2013/14 to 2016/17
Biomass conversion and enhanced co-firing	6,800	18,400	22,000
Onshore wind (>5MW)*	17,000	6,400	7,800
Offshore wind	11,000***	1,600	3,000
Dedicated biomass >50MW	400	610	610
Dedicated biomass <50MW	26,00	1,400	1,800
Tidal stream	8	80	110
Wave	3	0	0
Other**	17,000	3,900	4,600
Total 'large-scale'**	**55,000**	**32,000**	**39,000**

Source: Pöyry modelling and DECC calculations; all figures are rounded to two significant figures

* Onshore wind (>5MW) includes onshore wind <5MW in Northern Ireland.

**Note 'large-scale' are renewables defined as all renewable electricity except for <5MW AD, PV, hydro and wind in Great Britain.

*** This includes generation from capacity built by 2013/14, as the offshore wind band for 2013/14 has already been set.

**** For offshore wind this includes only generation from new build in 2014/15 and 2015/16.

182. The extra renewable generation brought on in this sensitivity increases RO costs in 2016/17 by £220m and in 2017/18 by £430m (discounted £2011/12 prices).

Annex E – Other banding review decisions (i.e. excluding banding)

A) Grandfathering

183. Grandfathering is a firm policy intention to fix the RO banding level for generating capacity for the whole 20 years of its support under the RO (subject to the 2037 end date of the RO). In July 2010, the Government declared its intention to change the grandfathering policy for biomass generation, and stated its intention to grandfather support for biomass and AD and EFW, but not to grandfather support for bioliquids in the RO. The impact assessment published in July 2010 estimated the impact of grandfathering for plant that generated prior to April 2013.[63]

184. The banding review consultation sets out the approach to grandfathering ROC levels for plant accrediting post April 2013. The policy intention post 2013 is to maintain the current position for dedicated biomass, AD and energy from waste from CHP - to grandfather new accreditations from 1st April 2013 to 31st March 2017 at the support levels prevailing at the time of accreditation - and to make the following changes:

1) Creation of two new bands: for biomass conversion; and for mid-range co-firing bands as from 1 April 2013 and the high-range co-firing band as from 1 April 2014, which will be grandfathered at their new rates.

2) Grandfather bioliquids for dedicated plants and conversions at the rates prevailing at the time of their accreditation, but introduce a cap on bioliquids equivalent to around 2 TWh/y.

3) Grandfather the 'energy crops uplift' for dedicated biomass with energy crops and the 'CHP uplift' at the levels prevailing at the time of accreditation. This means maintaining the differential between grandfathering dedicated energy crops and dedicated biomass with CHP at the full banding level prevailing at the time of accreditation. For dedicated biomass with CHP, this level is proposed to be 2 ROCs/MWh to 2014/15, and for dedicated energy crops 2 ROCs/MWh to 2014/15, 1.9 ROCs in 2015/16 and 1.8 ROCs in 2016/17.[64] The Government has decided to consult on removing the energy crop uplift for standard co-firing and so grandfathering policy will not apply to the uplift for those stations.

185. The revised proposals in the Government Response maintain these grandfathering policies in terms of grandfathering at the rate prevailing at the time of accreditation, but with the following exceptions. Grandfathering policy will not apply to bioliquids when they are used for co-firing. Furthermore, grandfathering policy will not apply to the energy crop uplift for co-firing, as there will be a consultation on removing the energy crop uplift for those stations. However, there will be a consultation on proposals for the energy crop uplift to continue for a limited period of time for standard co-firers that currently use energy crops.

186. A further exception to these grandfathering decisions is low-range co-firing. Low-range co-firing requires minimal additional capital expenditure to coal generation, especially compared with the capital expenditure for other renewable technologies. Co-firing generators can switch between coal and biomass (up to around 10%) fuel sources in response to changing relative fuel prices and are

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[63] See : http://www.decc.gov.uk/assets/decc/consultations/rhi/256-impact-assessment.pdf.

[64] Note that it is proposed to close combined heat and power bands to new accreditations from 1st 2015 (i.e. remove the uplift), and to provide support to CHP technologies thereafter through a combination of RO support and RHI support.

more likely to do so than ECF and full conversions. Future relative coal and biomass prices are extremely uncertain, and hence it is not thought appropriate to set the level of ROC support for the full period of up to 20 years.

187. In analysis of costs and benefits above, biomass technologies have been modelled as being grandfathered in both the counterfactual, and under proposed new bands. The impact on costs and benefits are therefore those associated with the new banding levels. Biomass conversion and enhanced co-firing have been modelled in the counterfactual as being captured by the current dedicated biomass and co-firing bands. The new bands for conversion and enhanced co-firing are assumed to be grandfathered. The costs of this change are included in the overall cost of the lead scenario.

Grandfathering Bioliquids

188. Bespoke analysis of the Restats database and the Ofgem sustainability report for 2009/2010[65] indicates that in 2010, generation using bioliquids is estimated at 125GWh of electricity generation. This is in a mix of dedicated biomass and co-firing, and it is expected that, under current proposals, and with levels of support grandfathered for dedicated bioliquids, these levels of generation would continue. It is further expected that in the absence of grandfathering few new dedicated bioliquid projects could secure finance, and therefore grandfathering is assumed to increase the level of generation from bioliquids.

189. Under the revised bioliquid cost assumptions and the proposed ROC levels, the modelling does not assume additional deployment of electricity from bioliquids, and it can therefore be assumed that impact of grandfathering ROCs for dedicated bioliquids will be small. Nonetheless it is anticipated that the increased certainty offered by the policy could have the impact of bringing forward the small amount of low cost bioliquid deployment identified. The total supported generation from bioliquids would, however, be capped at the equivalent of around 2TWh/y.

Grandfathering the Energy crops uplift

190. Government's current policy is to not grandfather where the support level covers primarily a fuel cost. Grandfathering the energy crop uplift therefore represents a departure from current policy. The reasons for doing so are:

- the need to increase the total biomass resource available for energy use to 2020 and beyond. Energy crops are one of the few sources of biomass that the UK can grow and expand production;
- to minimise the impacts of bio-electricity on other biomass (wood) using industries;
- to achieve the security of supply benefits of having a diversity of indigenous biomass sources and supply chains; and
- to create new opportunities for UK farmers.

191. In 2010, energy crops were used to generate 60GWh of electricity. Uptake of the uplift since 2009 has been slow. This is in part due to the fact that perennial energy crops take a minimum of three years to establish and grow, but will crop for up to 10 years. There has also been a reluctance on the part of growers and energy suppliers to engage in long term contracts without financial surety.

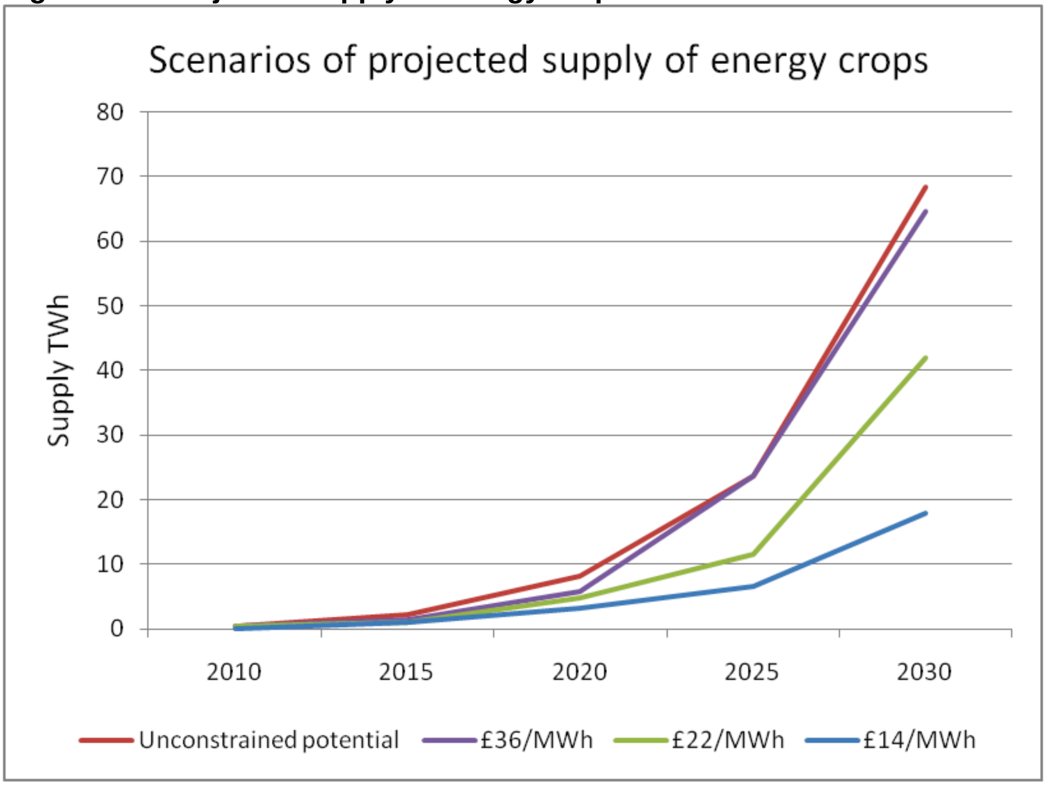
192. Analysis by AEA of future potential global biomass resource indicated that, assuming the use of

[65] OfGem (2011), Annual Sustainability Report 2010-11, available at www.ofgem.gov.uk/Sustainability/Environment/RenewablObl/FuelledStations/Documents1/Annual%20Sustainability%20Report%202010-11.pdf

marginal land and increasing yields and that global food demands are met first, the growth of energy crops in the UK could provide primary energy equivalent to an additional 5TWh in 2020 and up to 50 TWh in 2030 (see Figure 2 below). Grandfathering would therefore protect existing UK investment and set the framework for an increase in the use of energy crops over the medium to longer term.

193. As noted above, the Government intends to re-consult on the band for co-firing with energy crops.

Figure D 1: Projected supply of energy crops in different scenarios.



Note: The unconstrained potential is the same at all price points. The scenarios showing supply at different prices assume no market or other constraints are overcome. The AEA study showed that supply will vary according to how the market is able to overcome these barriers.

B) Definitional changes to energy crops bands

194. The energy crop uplift was introduced in 2009 to encourage the planting within the UK of perennial crops such as Miscanthus and short rotation coppice species such as willow and poplar so as to increase the available biomass resource which does not directly impact on food prices or divert food to energy use. The Government Response sets out the decision to redefine those energy crops which will be eligible for the uplift since concerns have been raised by some non-governmental organisations (NGOs) that the existing definition could allow a wider variety of crops than originally intended, including food crops, to benefit. Continuing with the current definition could therefore lead to unintended consequences. The Government proposes to close this loophole so as to prevent crops from being subsidised which are (a) not perennial or (b) which are food crops and which (c) do not require additional support in order develop the supply chain. This can be done by one of two ways:

i. Restrict the definition to perennial energy crops only through exclusion
ii. Restrict the definition to named energy crops through a positive list

195. Restricting the definition to “perennial energy crops only” risks inclusion of perennial food crops such as palm oil, unless it is defined such a manner so as to exclude any crop which could also be

used as a food crop. Ensuring a legally water-tight exclusion of such crops from the definition will be difficult. Restricting the definition to named energy crops risks excluding valuable crops unless the list is reviewed regularly or made less species specific. However, it is easier to legally define. On balance, the latter is easier to understand and enforce and less open to legal challenge on interpretation.

196. Currently there are no energy crops which do not meet the proposed revised definition claiming ROCs. Changes to the definition of energy crops are therefore not expected to result in economic loss to energy crop producers or energy suppliers.

C) Definitional changes to gasification and pyrolysis bands

197. The Government considered whether to introduce the proposed standard 'steam cycle' and advanced 'gas engine' definitions from the consultation. Analysis by the NNFCC, based on energy balance information provided, showed that on average steam cycle processes are less efficient than gas engine processes even taking into account the parasitic load required (although the Government recognises the issues in measuring efficiency fairly across different processes).

198. Based on project information, it is also clear that several plants currently using steam cycle generation can reach high efficiencies and be considered innovative, as well as deliver a wider range of low carbon energy outputs beyond power generation. The Government therefore believes that, based on both cost data and policy aims, there is not a strong rationale for continuing with the proposed differentiation of standard and advanced under the RO.

D) Bioliquids cap

199. The Government Response sets out the decision to support the use of bioliquids in dedicated biomass, CHP, co-firing and conversion, subject to an overall cap on bioliquids in the RO. This was to limit the risk that that grandfathered support for bioliquids could lead to a high proportion of bioliquids electricity generation, which would draw in bioliquid sources from other priority sectors – and could cause a 'lock in' of feedstock. The proposals to limit both the level of support and the level of deployment of bioliquids greatly reduce the risks associated with grandfathering existing and planned generation.

200. Although the proposal did not differentiate support for bioliquids from other biomass sources, consultation responses exposed a risk that a wider range of bioliquid feedstocks could be used in co-firing than originally anticipated if the support level increased above 0.5ROCs. A high deployment of bioliquids in co-firing may negatively affect those who rely on contracts with vertically integrated companies to secure sales of bioliquid ROCs. We therefore intend to limit support for bioliquids in co-firing to 0.5ROCs, regardless of the proportion of bioliquid used.

201. In relation to the Renewables Obligation, a cap of 4% of the total number of ROCs is likely to prevent obligated suppliers from receiving support for bioliquid electricity generation that exceeds 2TWh of bioliquid electricity generation within a year. It is important to note that setting a cap alone does not guarantee transport biofuels will not be diverted into electricity production, but lowers the risk of market pull from other sectors.

202. Analysis by AEA[66] and E4Tech[67] shows that there is likely to be a constrained supply of sustainable biofuel to 2020. Table E 1 shows illustrative ranges for electricity generation from sustainable feedstocks in 2020 (based on DECC analysis, using E4Tech and NNFCC data):

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[66] AEA (2011), *UK and Global Bioenergy Resource – Final Report,* available at www.decc.gov.uk/assets/decc/What%20we%20do/UK%20energy%20supply/Energy%20mix/Renewable%20energy/policy/1464-aea-2010-uk-and-global-bioenergy-report.pdf

[67] E4Tech (2010), *Biomass prices in the heat and electricity sectors in the UK,* available at

Table E 1: Electricity generation from sustainable feedstocks in 2020

Bioliquid	Electricity generated in 2020 (TWh)
Transport fuel	0 – 0.032
Non-transport fuel	2.0 – 2.5

203. The theoretical deployment potential for bioliquids, estimated by NNFCC[68], is much higher than that forecast above. These are given in Table E 2, which shows the technical deployment rates with no constraints applied to take into account the support level or availability/ price of feedstock:

Table E 2: Theoretical potential for bioliquids in 2020

Scenario	Electricity generation (TWh)
Low	4.7
Medium	7.7
High	12.9

204. A cap of around 2TWh in 2020 therefore corresponds to the lower estimate of non-transport bioliquids in 2020. This corresponds with the OfGem sustainability reports[69] which shows that the primary bioliquid feedstocks used under the RO for electricity generation were of a type not suitable for transport use and were used primarily in co-firing and dedicated bioliquid generation. The intention is not for the cap to limit the current use or projects about to come on stream, and it is expected that, assuming no further growth, the current level of deployment would still be apparent in 2020.

205. Consultation responses highlight the risks that a cap may have on certain suppliers to secure finance and sell ROCs at their full value. We consider that an exemption from the cap for CHP accredited stations under 1MW and micro generators will increase investor confidence in these sectors, but is unlikely to lead to a high level of bioliquid use in the RO.

E) The co-firing cap

206. Currently the RO includes a cap for biomass co-firing of 12.5%. This means that licensed suppliers are restricted to producing only 12.5% of their overall obligation from co-firing of regular biomass ROCs. It is proposed to remove the co-firing cap from 2013/14 onwards to allow more generation from this cost-effective renewable technology.

207. Historically, the total ROCs presented by suppliers did not reach the 12.5% cap, due to a combination of (a) either lack of attractiveness due to high biomass prices in comparison to coal; and/or (b) the cap itself sending a restricting signal to the market and so limiting uptake. For 2011/12 the total Renewables Obligation is set at around 38m ROCs, implying a maximum of 4.7m ROCs would be available for co-firing.

208. The modelling finds that at central assumptions the cap does not restrict standard co-firing generation, as much of the potential standard co-firing generation is not economic relative to burning

www.rhincentive.co.uk/library/regulation/100201Biomass_prices.pdf

[68] Evaluation of Bioliquid Feedstocks & Heat, Elec. & CHP Technologies, NNFCC 11-016, www.nnfcc.co.uk/tools/evaluation-of-bioliquid-feedstocks-and-heat-electricity-and-chp-technologies-nnfcc-11-016

[69] Sustainability Report on biomass fuelled generating stations for 2009/10 obligation period, OfGem, http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=248&refer=Sustainability/Environment/RenewablObl/FuelledStations
Sustainability Report on biomass fuelled generating stations for 2009/10 obligation period, OfGem
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=318&refer=Sustainability/Environment/RenewablObl/FuelledStations

coal. While there is no evidence to date, the cap could constrain co-firing in the future. Removing the co-firing cap would remove this uncertainty. Given its cost-effectiveness, this could reduce the overall cost of the RO in comparison to more expensive technologies.

209. While removing the co-firing cap might be beneficial for the overall cost of the RO, there is a risk of under-predicting the amount of co-firing when setting the obligation level each year due to added uncertainty. Under-predicting the amount of co-firing might result in significantly reduced ROC prices, which in turn results in reduced investor confidence.

Annex F – In-house ROCs required analysis

Table F 1: ROCs required for investment for each technology in each year based on DECC in-house analysis and rationales for proposed bands

		Country	Cost tranche	2013/14	2014/15	2015/16	2016/17	Rationale for bands
Wind	**Onshore >5MW**	E&W	Low	0.5	0.4	0.4	0.5	No changes are proposed to the consultation proposals Incentivises the more cost-effective onshore deployment.
			Low-medium	0.7	0.7	0.7	0.7	
			Medium	1.0	0.9	1.0	1.0	
			Medium-high	1.3	1.2	1.2	1.3	
			High	1.5	1.5	1.5	1.5	
	Onshore >5MW	Scotland	Low	0.2	0.2	0.2	0.2	
			Low-medium	0.5	0.4	0.4	0.5	
			Medium	0.7	0.6	0.7	0.7	
			Medium-high	0.9	0.9	0.9	0.9	
			High	1.2	1.1	1.1	1.2	
	Offshore Round 2	UK	Low	2.0	1.8	1.4	1.5	No changes are proposed to the consultation proposals. Analysis shows that if offshore wind is to make a cost-effective contribution to the 2020 target it is necessary to encourage some deployment over the banding review period.
			Low-medium	2.3	2.0	1.7	1.7	
			Medium	2.5	2.3	1.9	1.9	
			Medium-high	2.8	2.6	2.1	2.1	
			High	3.1	2.8	2.4	2.4	
	Offshore Round 3	UK	Low	2.6	2.5	2.5	2.5	
			Low-medium	2.9	2.8	2.8	2.8	
			Medium	3.2	3.1	3.1	3.1	
			Medium-high	3.6	3.6	3.5	3.5	
			High	4.0	4.0	3.9	3.9	
Biomass	**Biomass conversion and Enhanced Co-firing**	UK		0.3	1.1	0.8		1.0 is judged enough to bring on biomass conversions which are cost-effective and provide more certainty towards renewables target than enhanced co-firing. ECF is set lower due to lower hurdle rates and RO budgetary risks.
			Range from modelling many individual plants/boilers					
			Modelling judged likely to underestimate deployment.					
				1.2	1.2	1.2		
	Dedicated biomass <50MW	UK	Low	1.1	1.1	1.1	1.2	Our aim is to bring forward only the most cost and carbon-effective plants which can contribute in the short to medium term to GHG reduction and to avoid lock-in of biomass to uses which are sub-optimal in the long term. We therefore propose keeping ROC
			Low-medium	1.4	1.4	1.4	1.4	
			Medium	1.7	1.6	1.7	1.7	
			Medium-high	2.1	2.0	2.1	2.1	
			High	2.5	2.4	2.4	2.5	
	Dedicated biomass >50MW	UK	Low	1.5	1.5	1.4	1.5	
			Low-medium	1.6	1.6	1.6	1.6	
			Medium	1.7	1.7	1.7	1.7	

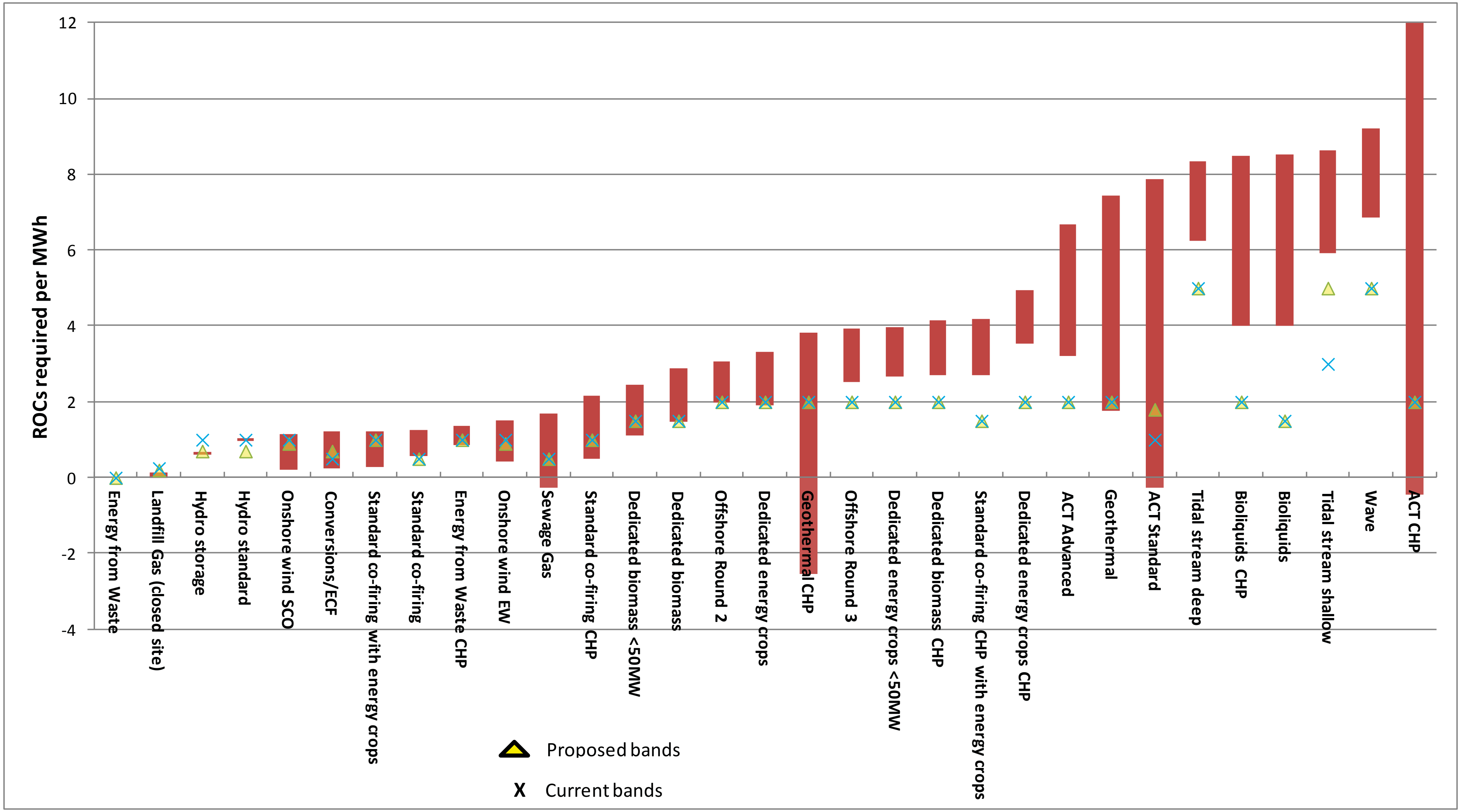
	Country	Cost tranche	2013/14	2014/15	2015/16	2016/17	Rationale for bands
		Medium-high	2.3	2.3	2.2	2.3	support at 1.5 ROC, degressing to 1.4 ROC from 1 April 2016, subject to a cap around the equivalent of 800-1000MW (subject to consultation).
		High	2.9	2.9	2.8	2.9	
Dedicated biomass <50MW with Energy Crops	UK	Low	2.7	2.6	2.7	2.7	
		Low-medium	3.0	2.9	2.9	3.0	
		Medium	3.2	3.2	3.2	3.3	
		Medium-high	3.6	3.6	3.6	3.6	
		High	4.0	3.9	4.0	4.0	
Dedicated biomass >50MW with Energy Crops	UK	Low	2.0	1.9	1.9	1.9	
		Low-medium	2.1	2.0	2.0	2.1	
		Medium	2.2	2.2	2.1	2.2	
		Medium-high	2.8	2.7	2.7	2.7	
		High	3.3	3.3	3.3	3.3	
Biomass CHP	UK	Low	2.8	2.7	2.7	2.7	Unchanged from consultation proposal i.e. removal of 1/2 ROC uplift from 2015/16.
		Low-medium	3.1	3.1	3.0	3.1	
		Medium	3.5	3.4	3.4	3.4	
		Medium-high	3.8	3.8	3.7	3.8	
		High	4.2	4.1	4.1	4.1	
Biomass CHP with Energy Crops	UK	Low	3.6	3.5	3.5	3.5	
		Low-medium	3.9	3.9	3.8	3.9	
		Medium	4.3	4.2	4.2	4.2	
		Medium-high	4.6	4.6	4.5	4.6	
		High	5.0	4.9	4.9	4.9	
Bioliquids	UK	Low	4.0	4.1	4.1	4.1	Setting support in line with solid biomass (except when co-fired) to limit the risk of drawing bioliquids away from other sectors
		Low-medium	5.9	5.8	5.8	5.7	
		Medium	6.7	6.7	6.6	6.6	
		Medium-high	7.6	7.6	7.6	7.5	
		High	8.6	8.5	8.5	8.5	
Bioliquids CHP	UK	Low	4.0	4.0	4.0	4.0	
		Low-medium	5.8	5.8	5.8	5.8	
		Medium	6.7	6.7	6.7	6.7	
		Medium-high	7.6	7.6	7.6	7.6	
		High	8.5	8.5	8.5	8.5	
Standard co-firing	UK	Low	0.6	0.6	0.5	0.5	Leaving at 0.3 and not increasing so as to provide sufficient difference with enhanced co-firing and conversion to that those preferred technologies (more renewable output) are incentivised.
		Low-medium	0.7	0.7	0.7	0.6	
		Medium	0.9	0.9	0.8	0.8	
		Medium-high	1.1	1.1	1.0	1.0	
		High	1.3	1.3	1.2	1.2	
Standard co-firing with Energy Crops	UK	Low	0.3	0.2	0.4	0.4	Re-consulting on removing this band due to lack of evidence of significant cost differential for energy crops and potential long-term budget risks.
		Low-medium	0.6	0.5	0.6	0.6	
		Medium	0.9	0.8	0.8	0.8	
		Medium-high	1.0	1.0	1.0	1.0	
		High	1.2	1.2	1.2	1.2	

		Country	Cost tranche	2013/14	2014/15	2015/16	2016/17	Rationale for bands
	CoCHP	UK	Low	0.5	0.5	0.5	0.6	No supply curve assumed, as only one or two potential plants. 1.0 ROC is sufficient to bring on a new CoCHP plant if biomass costs below central estimate. Also anything higher not so cost-effective. Providing the uplift to ECF to create a difference from standard co-firing with CHP.
			Low-medium	0.9	0.9	0.9	1.0	
			Medium	1.3	1.3	1.3	1.4	
			Medium-high	1.8	1.7	1.7	1.8	
			High	2.2	2.2	2.2	2.3	
	CoCHP with Energy Crops	UK	Low	2.8	2.7	2.9	3.0	Re-consulting on this band.
			Low-medium	3.2	3.1	3.3	3.4	
			Medium	3.6	3.6	3.6	3.7	
			Medium-high	3.9	3.9	3.9	4.0	
			High	4.2	4.2	4.3	4.4	
Waste	**Energy from waste power only**	UK	Low	0.0	0.0	0.0	0.0	No support offered as before. Modelling suggests none required.
			Low-medium	0.0	0.0	0.0	0.0	
			Medium	0.0	0.0	0.0	0.0	
			Medium-high	0.0	0.0	0.0	0.0	
			High	0.0	0.0	0.0	0.0	
	Energy from waste CHP	UK	Low	0.9	0.9	0.9	0.9	Based on the differential in overall NPVs between a power-only plant and a CHP plant - the CHP plant has to have a better NPV to go ahead.
			Low-medium	1.0	1.0	1.0	1.0	
			Medium	1.1	1.1	1.1	1.1	
			Medium-high	1.3	1.3	1.3	1.2	
			High	1.4	1.4	1.4	1.4	
	ACT Standard	UK	Low	0.0	0.0	0.0	0.0	Setting support in line with offshore wind, as not cost-effective to support more expensive technologies for the renewables target
			Low-medium	1.7	1.6	1.6	1.6	
			Medium	3.6	3.5	3.5	3.5	
			Medium-high	5.8	5.6	5.6	5.6	
			High	7.9	7.7	7.7	7.7	
	ACT Advanced	UK	Low	3.2	3.1	3.1	3.2	Setting support in line with offshore wind, as not cost-effective to support more expensive technologies for the renewables target
			Low-medium	4.3	4.2	4.2	4.2	
			Medium	5.4	5.2	5.3	5.3	
			Medium-high	6.1	5.9	5.9	5.9	
			High	6.7	6.6	6.6	6.6	
	ACT CHP	UK	Low	0.0	0.0	0.0	0.0	Setting support in line with offshore wind, as not cost-effective to support more expensive technologies for the renewables target
			Low-medium	2.6	2.5	2.5	2.5	
			Medium	5.6	5.4	5.4	5.4	
			Medium-high	8.9	8.7	8.7	8.7	
			High	12.2	12.0	12.0	11.9	
	Sewage gas	UK	Low	0.0	0.0	0.0	0.0	Setting support to bring on the most cost-effective deployment.
			Low-medium	0.1	0.1	0.1	0.2	
			Medium	0.5	0.4	0.5	0.5	

		Country	Cost tranche	2013/14	2014/15	2015/16	2016/17	Rationale for bands
			Medium-high	1.1	1.0	1.1	1.1	
			High	1.7	1.7	1.7	1.7	
	Landfill gas	UK	Low	0.0	0.0	0.0	0.0	Setting support to bring on all the cost-effective deployment.
			Low-medium	0.0	0.0	0.0	0.0	
			Medium	0.0	0.0	0.0	0.0	
			Medium-high	0.0	0.0	0.0	0.0	
			High	0.2	0.2	0.2	0.2	
Geothermal	**Geothermal**	UK	Low	1.8	1.6	1.4	1.3	Setting support in line with offshore wind, as not cost-effective to support more expensive technologies for the renewables target
			Low-medium	3.3	3.0	2.7	2.6	
			Medium	4.8	4.4	4.1	3.8	
			Medium-high	6.1	5.7	5.3	5.0	
			High	7.5	7.0	6.5	6.1	
	Geothermal CHP	UK	Low	0.0	0.0	0.0	0.0	Setting support in line with offshore wind, as not cost-effective to support more expensive technologies for the renewables target
			Low-medium	0.0	0.0	0.0	0.0	
			Medium	0.9	0.5	0.1	0.0	
			Medium-high	2.4	1.9	1.4	1.0	
			High	3.8	3.2	2.7	2.3	
Hydro	**Hydro >5MW (Standard)**	UK						ROC banding set on the basis of individual project data provided at consultation to bring on all cost-effective deployment whilst avoiding over-compensation
			Medium	1.0	1.0	1.1	1.2	
	Hydro >5MW (storage)	UK						
			Medium	0.6	0.6	0.7	0.9	
Marine	**Tidal stream shallow**	UK	Low	6.0	4.7	3.4	2.5	5 ROCs/MWh with a 20% grant enough to bring on a proportion of the supply curves, assuming investors are prepared to fund early projects as a 'loss leader' with a low return of around 8%. Actual grants will be set at lower levels if necessary to avoid any potential overcompensation.
			Low-medium	6.9	5.4	3.9	3.0	
			Medium	7.8	6.2	4.5	3.5	
			Medium-high	8.2	6.5	4.8	3.7	
			High	8.7	6.9	5.0	3.9	
	Tidal stream deep	UK	Low	6.3	5.4	4.5	3.7	
			Low-medium	6.8	5.8	5.0	4.1	
			Medium	7.3	6.3	5.4	4.4	
			Medium-high	7.9	6.8	5.8	4.8	
			High	8.4	7.3	6.2	5.1	
	Wave	UK	Low	6.9	5.9	5.3	4.8	5 ROCs/MWh with a 20% grant might just be enough to bring on a proportion of the supply curves (though not quite on this evidence), assuming investors are prepared to fund early projects as a 'loss leader' with a low return
			Low-medium	7.5	6.4	5.8	5.2	
			Medium	8.0	7.0	6.3	5.7	
			Medium-high	8.7	7.5	6.8	6.2	
			High	9.3	8.1	7.4	6.6	

	Country	Cost tranche	2013/14	2014/15	2015/16	2016/17	Rationale for bands
							of around 8%. Actual grants will be set at lower levels if necessary to avoid any potential overcompensation.

Figure F 1 – ROCs required for new installations in 2013/14[70]



70 ROCs required will vary by year owing to changes in costs and revenues over time

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