Department of Trade & Industry

Impact of banding the Renewables Obligation – Costs of electricity production

April 2007

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Contents

Abbreviations and definitions

ACT	Advanced Conversion Technologies
Capacity factor	Expected actual energy production as a percentage of the theoretical maximum energy production
CHP	Combined Heat and Power
DEFRA	Department for Environment Food and Rural Affairs
DNC	Declared Net Capacity
DTI	Department of Trade and Industry
EU	European Union
GJ	Giga Joule
GW	GigaWatt
GWh	GigaWatt hour
kW	KiloWatt
LCPD	Large Combustion Plant Directive
MW	MegaWatt
MWh	MegaWatt hour
MWhe	MegaWatt hour electrical
MWht	MegaWatt hour thermal
Nominal costs	Expected costs at time incurred
NPV	Net Present Value
Ofgem	Office for Gas and Electricity Markets
PPA	Power Purchase Agreement
Progress ratio	Ratio to inflate/deflate costs with every doubling of installed capacity of a given technology
PV	Photovoltaic
Real costs	Costs at today's value of money
RO	Renewable Obligation
ROC	Renewable Obligation Certificate
RPI	Retail Price Index
SRC	Short Rotation Coppice

Abbreviations and definitions

TW	TeraWatt
TWh	TeraWatt hour

Executive Summary

Methodology

Ernst and Young were commissioned to estimate the levelised costs per MWh, for a number of renewable technologies. These have been calculated by considering the underlying project assumptions including the predicted capital, operating and fuel costs, other non-electricity income, the operational life of the assets and the cost of capital. A high, medium and low levelised cost was estimated to reflect the current range of project costs that developers are generally experiencing.

Levelised costs reflect the amount of electricity revenue per MWh, net of PPA discounts, which is needed throughout the life of the technology to make the respective technology commercially viable. For technologies utilising a variable natural resource an assumption has been made as to the relevant capacity factor for that resource.

Initial underlying assumptions have been compiled from previous reports commissioned by the DTI and other DTI specific information, as listed in Appendix C, as well as Ernst and Young proprietary data and used to produce initial cost per MWh data. This was subsequently validated in discussions with members of the renewable energy industry, as listed in Appendix B. The technologies which are expected to be the greatest contributors to renewable energy generation were consulted in greater detail.

Costs per MWh were also estimated for 2010, 2015 and 2020. These future costs were based on the costs in 2006 and then escalated or deflated based on major drivers such as the estimated future capacity. It should be noted that the expected capacities are based on the technologies receiving enough income to enable market entry and not the maximum capacity that is physically possible if technologies received infinite revenue support. Both the capacity and the estimated future costs per MWh were also validated through consultation with members of the renewable energy industry.

Capacity factors and key cost drivers

The table overleaf shows the relevant capacity factors assumed for each of the technologies along with the key value drivers for calculation of the levelised costs for the technologies. The capacity factor represents the percentage of the theoretical maximum capacity of a given technology producing electricity 24 hours a day every day of the year, approximately 8,760 hours a year. Applying the capacity factor to the theoretical maximum capacity of a given technology results in the expected electricity production after transmission and other losses.

The capacity factor is not 100% because of such influences as downtime due to maintenance, unavailability of resource and transmission and other losses. As can be seen in the table below the technologies that are dependent on natural resource such as wind, hydro, wave, tidal and solar have the lowest capacity factors.

Executive Summary

Capacity factors and key value drivers

Technology	Capacity factor	Levelised costs key driver
ONSHORE WIND - LARGE - HIGH WIND	31%	Capital Cost
ONSHORE WIND - SMALL - HIGH WIND	31%	Operating / Capital Cost
ONSHORE WIND - LARGE - LOW WIND	26%	Capital Cost
ONSHORE WIND - SMALL - LOW WIND	26%	Operating / Capital Cost
OFFSHORE WIND	35%	Capital / Operating Cost
CO-FIRING REGULAR	90%	Fuel costs
CO-FIRING - ENERGY CROP	90%	Fuel Cost
BIOMASS - REGULAR	80%	Fuel Cost
BIOMASS ENERGY CROP	80%	Fuel Cost
BIOMASS CHP	80%	Fuel Cost
LANDFILL GAS	61%	Capital Cost
LARGE SCALE HYDRO	36%	Capital Cost
SMALL SCALE HYDRO	40%	Operating / Capital Cost
SEWAGE GAS	80%	Capital Cost
SOLAR PV	16%	Capital Cost
WAVE	30%	Capital Cost
TIDAL	35%	Capital Cost
EFW CHP	83%	Heat Network Cost
AD CHP	83%	Capital / Operating Cost
GASIFICATION/PYROLYSIS	83%	Capital / Operating Cost

Levelised costs – medium costs

The table overleaf presents the medium levelised costs for each of the technologies from 2006 to 2020.

Levelised costs for the onshore and offshore wind technologies rise to 2010 to reflect a view that the current turbine supply constraints and the high price of steel will continue. After this, prices are expected to steadily fall as the supply chain stabilises.

Levelised costs for the technologies that utilise biomass, including co-firing, as a fuel source increase to 2010 to reflect the current supply shortages and the impact of extreme weather on the main supply regions. Thereafter the costs are expected to fall steadily to reflect the predicted stabilisation of the supply networks.

Sewage gas, landfill gas and hydro are relatively mature technologies and as such the levelised costs remain level in real terms over the period covered.

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Wave, tidal and solar PV are relatively immature technologies and as such improvements in the efficiency of the technology should bring the costs down over the period covered.

Levelised costs for AD CHP and gasification/pyrolysis technologies are expected to steadily increase in line with the recent increases in waste infrastructure costs and then flatten as the industry matures.

Medium levelised costs - £/MWh (real)

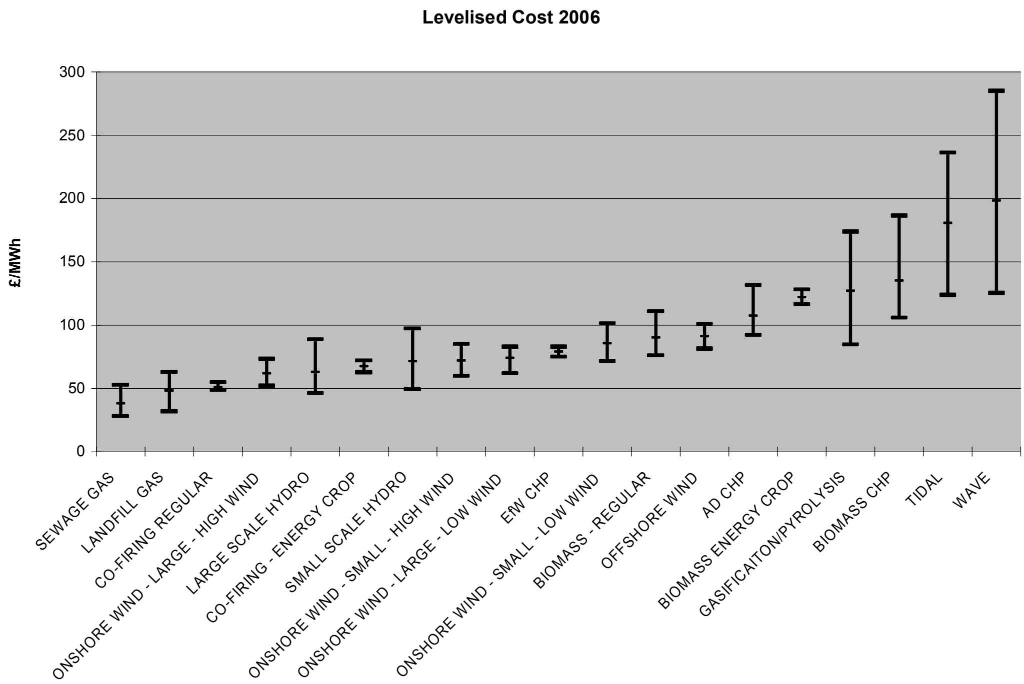
	2006	2010	2015	2020
ONSHORE WIND - LARGE - HIGH WIND	62	65	62	61
ONSHORE WIND - SMALL - HIGH WIND	72	75	72	70
ONSHORE WIND - LARGE - LOW WIND	74	77	74	72
ONSHORE WIND - SMALL - LOW WIND	86	89	86	83
OFFSHORE WIND	91	92	86	85
CO-FIRING REGULAR	51	53	52	49
CO-FIRING - ENERGY CROP	67	70	68	64
BIOMASS - REGULAR	90	101	99	95
BIOMASS ENERGY CROP	122	126	122	116
BIOMASS CHP	135	145	141	139
LANDFILL GAS	48	48	48	48
LARGE SCALE HYDRO	63	63	63	63
SMALL SCALE HYDRO	71	71	71	71
SEWAGE GAS	38	38	38	38
SOLAR PV	635	571	508	444
WAVE	199	196	165	151
TIDAL	181	177	149	137
EFW CHP	79	79	79	79
AD CHP	107	133	143	143
GASIFICATION/PYROLYSIS	127	150	160	160

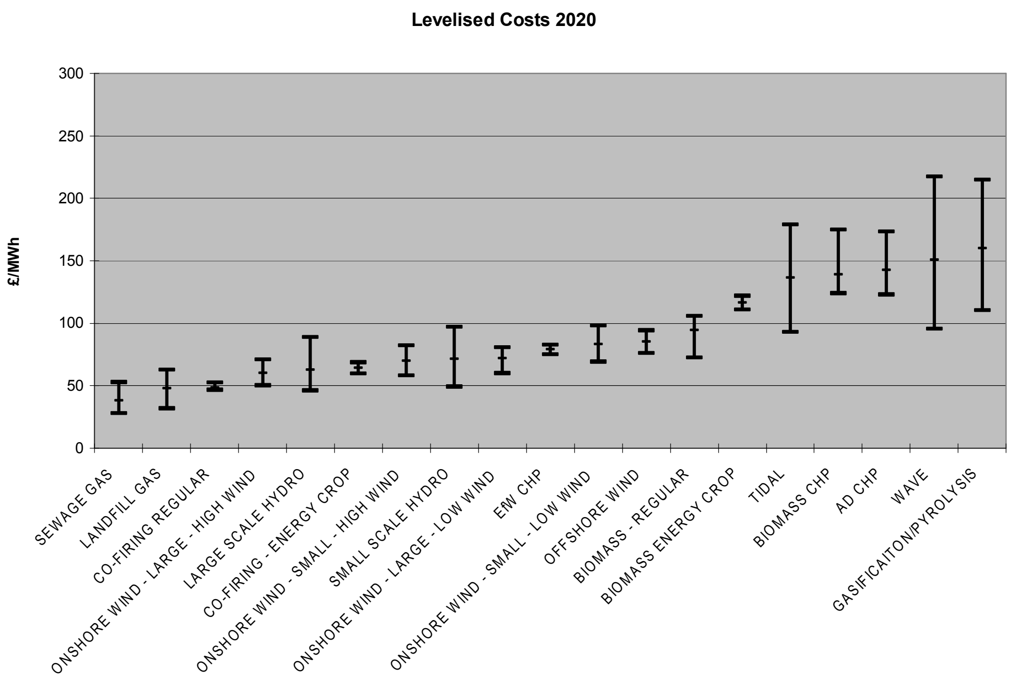
Range of levelised costs

The charts overleaf present the range of high, medium and low levelised costs in 2006 and 2020, solar PV has been omitted due to the costs being significantly higher. For mature technologies this represents the current range of the actual project costs that are being experienced by developers and for immature technologies without commercially operational

Executive Summary

projects it represents a view of what the actual project costs are anticipated to be, as well as the level of uncertainty over these costs.





The high costs reflect projects that are subject to such influences as being far from the grid, being situated in locations that require additional ground preparation costs, or in the case of the biomass technologies further from the cheaper sources of fuel. The majority of the projects are expected to be around the medium level as opposed to the extremes.

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The charts highlight that that emerging technologies generally have a higher range of values than that of the more mature technologies. The exception to this trend is hydro which has a large range due to the variety of costs applying to high head, reservoir with dam, or low head, run of river, projects.

Onshore Wind

Assumptions

In this report onshore wind has been separated into two main categories, large wind farms (greater than 10 MW installed capacity) and small (less than or equal to 10 MW installed).

It has been assumed that going forward under the current planning regime large wind farms will account for c.95% of the potential total onshore wind energy generation per annum, this has been corroborated with discussions with industry.

Both large and small categories have been separated into high wind speed and low wind speed sub-categories. Although wind resource varies in a continuous curve for the purposes of this report we have defined high wind sites as having an average capacity factor of 31% and low wind of 26%. This is based on our proprietary information and discussions with a selection of major wind farm owners and developers and gives a suitable approximation of typical projects.

Category	Capacity	High Capacity Factor	Low Capacity Factor	% of Potential
Large wind	>10 MW	31%	26%	c. 95%
Small wind	<10 MW	31%	26%	c. 5%

Capacity

The current amount of onshore wind generation of approximately 3 TWh has been based on the amount of onshore wind ROCs issued in the twelve months to September 2006 taken from the Ofgem ROC register as shown in Appendix A.

It has been assumed that the majority of currently commercially available sites rely on wind speeds of above 6.5 m/s. The low wind speed capacity was therefore assumed to be the resource above 6.5m/s. The divide between high and low wind speeds was taken as a wind speed of 7.5 m/s. As presented in the table below this resulted in 38% of the total generation capacity[1] arising from high wind sites whilst the remaining 62% was from the lower wind speed sites of between 6.5m/s and 7.5 m/s.

Onshore wind – Enviros figures on low wind resource in the UK for both the 6.5-7.5 m/s and > 7.5 m/s sites

	Wind Resource[1]	% of total
>= 6.5m/s & <7.5m/s	16.6 TWh	c.62%
>= 7.5m/s	10.6 TWh	c.38%
	27.2 TWh	100%

To support future cost reductions/increases future capacity was estimated. The forecasted data was taken from a collation of future market forecasts and verified by industry consultation.

It was assumed that the proportion of high wind sites is likely to change over time due to delays caused by the building and commissioning of the Beauly-Denny transmission line running from the highlands of Scotland an area which contains mainly high wind sites. This analysis assumes that this will cause a delay to 1000 MW[2] of high wind projects and that the capacity will not come on line prior to 2010. The table below reflects the assumptions on the high and low wind build rates, reflecting the installation of the Beauly-Denny capacity between 2011 and 2020.

[1] Source: ENVIROS, September 2005, The costs of supplying renewable energy

[2] Source: BWEA, April 2006, Onshore Wind: Powering Ahead, analysis of the onshore wind industry to 2010

Onshore Wind

Onshore wind – build rate, MWs installed per annum

MW per annum	2006	2007 - 2010	2011 - 2015	2016 - 2020
High wind	n/a	61	346	226
Low wind	n/a	394	394	394
Total	n/a	455	740	620

The table below presents the predicted total electricity generation per annum for the high wind and low wind sites, separated into large and small sites, calculated by taking the installed capacities in the table above and applying the capacity factors of 31% and 26% to high and low wind sites respectively.

Onshore wind - total electricity generation per annum

TWh	2006	2007 - 2010	2011 - 2015	2016 - 2020
Large - High wind	1.1	1.7	6.2	9.1
Large - Low wind	1.7	5.1	9.4	13.7
Small - High wind	0.1	0.1	0.3	0.5
Small - Low wind	0.1	0.3	0.5	0.7
Total	3.0	7.2	16.4	24.0
% High wind	38%	25%	39%	40%

Onshore Wind – Large (> 10MW)

Capital Costs

The table below presents the range of and medium current capital costs and how they are expected to change over time in £'000 per MW installed, in real terms.

Onshore wind - large - capital costs (real)

£'000/MW	2006	2010	2015	2020
High	1,233	1,329	1,284	1,253
Medium	1,089	1,173	1,133	1,106
Low	880	948	916	894

We have assumed that the capital costs per MW installed of high and low wind sites are the same. The current capital costs reflect the circa 25% increase in the capital costs over the past 12 to 24 months, and are based on actual project information for a number of recent developments. The range of costs reflects the general spread of costs seen in recent projects. The variation is caused by the changing costs of each component.

Costs are assumed to change over the period covered due to the impact of the technology maturing over time and external market drivers.

The breakdown of the capital costs are presented in the table below, and are based on a sample of actual project information.

Onshore wind – large - capital cost breakdown

Capital cost breakdown	
Planning	3%
Infrastructure - grid	14%
Infrastructure - other	17%
Plant	66%

Onshore Wind

Planning costs, in real terms, are predicted to increase over time as UK installed capacity increases. This is due to developers developing sites with greater planning issues. The grid costs are the predicted connection costs to the local network. The infrastructure costs, including grid and civil engineering, have been assumed to remain flat in real terms.

Plant costs, including turbines, towers and blades, are expected to increase in real terms over the next four or five years due to the continued supply shortages for turbines and the continued increases in steel prices. It has been assumed that the supply/demand balance will have stabilised by 2010 and that plant costs will therefore start to reduce as new production facilities come on line, creating a softening of the supply/demand balance, combined with potential economies of scale and the development of new cheaper turbines. It has been assumed that capital costs would not fall below the current levels in real terms as major turbine manufactures are unlikely to want to go back to encountering the profitability issues that they have faced in recent times especially now that consolidation has occurred in the sector. In addition we are assuming that no major market withdraws from the renewable energy sector.

Operating & Maintenance costs

With the exception of the transmission costs, we have assumed that the operating and maintenance costs per MW installed of both high and low wind sites are the same. For large high wind sites an additional £10,000 per MW installed per annum has been included on the 'High' estimates to reflect the increased average transmission costs for sites connected to the transmission network in the North of Scotland.

Onshore wind – large high wind - operating costs (real)

£'000/MW/yr	2006	2010	2015	2020
High	54	51	48	45
Medium	41	39	36	34
Low	38	36	34	32

Onshore wind – large low wind - operating costs (real)

£'000/MW/yr	2006	2010	2015	2020
High	44	41	39	37
Medium	41	39	36	34
Low	38	36	34	32

The tables above present the range and the average of the total operating and maintenance costs for large onshore wind farms in £'000's per MW installed per annum (real). The significant items of operating and maintenance costs are turbine operating and maintenance, use of systems charges, insurance, rates and rent.

Operating costs increase as projects end their fixed price warranty periods the operating costs increase. Several consultees provided data from recent projects and transactions with third parties to support this.

Insurance costs and rates, in real terms, are expected to increase over time in line with increases over the past few years. All other operating and maintenance costs, in real terms, are expected to decrease over time as UK installed capacity increases due to learning effects. Overall insurance

Onshore Wind

costs and rates are a smaller proportion of the total operating and maintenance costs, approximately 40%, than the other operating and maintenance costs and therefore overall the operating and maintenance costs reduce over time.

Cost of Capital and operating life

Onshore wind is a mature technology and as such a 10% pre-tax real cost of capital has been used in the analysis. The operating life of an onshore wind farm is assumed to be 20 years.

Levelised Costs

The above assumptions result in the levelised costs for large onshore wind, high and low wind, as presented in the tables below.

Onshore wind – large - high wind (31% capacity factor), levelised costs

£/MWh	2006	2010	2015	2020
High	73	76	73	71
Medium	62	65	62	61
Low	52	54	52	50

Onshore wind –large - low wind (26% capacity factor), levelised costs

£/MWh	2006	2010	2015	2020
High	83	87	83	81
Medium	74	77	74	72
Low	62	65	62	60

High levelised costs reflect an estimate of the highest prices that are currently being achieved by projects, with the assumed wind speed. As can be seen by the absolute level of these costs it is less likely that a low wind site would be developed at the high cost range.

Low levelised costs reflect the lowest prices that are currently being achieved by projects. Feedback from consultees suggested that there were unlikely to be many sites built at these low cost levels going forwards.

Onshore Wind

Onshore wind - Small

Capital Costs

For the purposes of calculating the levelised costs we have assumed that the capital costs per MW installed of high and low wind sites are the same.

Onshore wind – small - capital costs (real)

£'000/MW	2006	2010	2015	2020
High	1,418	1,522	1,475	1,440
Medium	1,252	1,344	1,303	1,271
Low	1,012	1,086	1,053	1,027

The table above presents the range and the average of the current capital costs and how they are expected to change over time in £'000 per MW installed (real). The capital cost per MW installed is higher for small wind farms than for large wind farms as there are some costs that are generally fixed and incurred on a per site basis.

Small wind farms are also generally developed by smaller entities that have lower buying power than the developers of large wind farms. The current difficulties of developing small wind sites have meant that there has been relatively few small wind projects built recently. Some small projects may use second hand turbines and avoid the higher costs per MW, however the total costs per MWh may not be any lower due to having a lower remaining operating life, likely to incur greater maintenance costs and due to being an older generation of technology and likely to be less efficient at generating electricity.

Capital costs are assumed to change over time due to the same factors as large wind farms ie, the impact of the technology maturing over time and external market drivers. The breakdown of the capital costs is shown in the table below.

Onshore wind – small - capital cost breakdown

Capital cost breakdown	
Planning	14%
Infrastructure – grid	15%
Infrastructure – other	12%
Plant	59%

This demonstrates that on average the planning costs for small wind farms are proportionally more expensive than for large wind farms, which reflects the element of fixed costs in the planning process.

Operating & Maintenance costs

For the purposes of calculating the levelised costs we have assumed that the operating and maintenance costs per MW installed of high and low wind sites are the same.

Onshore wind – small - operating costs (real)

£'000/MW/yr	2006	2010	2015	2020
High	64	63	62	60
Medium	48	47	46	45
Low	44	43	42	41

The table above presents the range and an average of the total operating and maintenance costs for small onshore wind farms in £'000 per MW installed, per annum (real). The significant items of operating and maintenance costs are turbine operating and maintenance, use of systems charges, insurance, rates and rent.

Operating and maintenance costs for small wind farms are higher per MW installed per annum than for the large wind farms due to the owners having lower buying power than the owners of large wind farms. The operating and maintenance costs for small wind farms are expected to change over time and driven by the same factors as those for the large wind farms.

Levelised Costs

The above assumptions result in the levelised costs for small onshore wind, high and low wind, as presented below in the tables below.

Onshore wind –small - high wind (31% capacity factor), levelised costs

£/MWh	2006	2010	2015	2020
High	85	89	86	84
Medium	72	75	73	71
Low	60	63	61	60

Onshore wind – small - low wind (26% capacity factor), levelised costs

£/MWh	2006	2010	2015	2020
High	101	106	103	101
Medium	86	90	87	85
Low	71	75	73	71

The range of levelised costs reflects the current range of costs of developing, building and operating small wind farms.

Micro wind

Micro wind generation could provide 6% of the UK's electricity needs by 2050[3], and is currently a fast developing market. Micro wind installations are easily retro-fitted or applied to new builds but currently require planning permission. Proposed changes to planning rules however may force planners to accept micro-renewables in most areas except on listed buildings or within conservation areas. Although the UK has an excellent wind resource, micro wind performance is highly dependant on the suitability of the site.

Due to microgeneration technologies being essentially for domestic use, the cost of these technologies is better measured in terms of payback and savings achieved rather than on a levelised cost basis. Micro wind turbines range in size from 0.6kW to 15kW and are produced by a number of different manufacturers. These systems vary in cost from £1,250/kW to £4,000/kW dependent on the type of turbine, site location and technology used, with grants available for installation under the Low Carbon Buildings programme for up to 30% of the capital cost. It has not been possible to calculate a levelised cost due to the variances of the capacity factors applicable for micro wind turbines.

[3] EST, November 2005, Potential for Microgeneration Study and Analysis

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Most currently available micro wind turbines have an advertised working life of 20-25 years, although the long term reliability of technology is not yet proven, with simple payback periods ranging between 7 to 20 years. ROCs are available for micro wind turbines however these have often not been submitted due to the administration this would involve. Currently ROC income is often not the key driver on which micro generation purchase decisions are made, the site owners' desire to help the environment is often more important than an economic benefit.

Offshore Wind

Assumptions

Capacity

The 2006 generation capacity is based on the offshore wind ROCs issued for the twelve months to September 2006, as taken from Ofgem's ROC register as presented in Appendix A. This is currently produced from offshore windfarms at; Scroby Sands, North Hoyle, Kentish Flats and Barrow.

It is recognised that the future cost per MWh for offshore wind will be influenced by the capacity installed. The following estimate was therefore made as to what capacity could be installed by 2020. This estimate assumes that the projects are generally seen as economic under any new Renewable Obligation ("RO") structure.

The predicted total electricity generation capacity is based on a projection of the pipeline of Round One, Round Two and a few other planned UK projects. The forecasted timing of these projects has been taken from recent press announcements and discussions with developers. We have taken into consideration that not all the offshore wind farms will be developed and that not all these wind farms will be developed to the maximum potential installed capacity. The impact of these assumptions on the total electricity produced per annum is presented in the table below.

Offshore wind - total electricity generation per annum

TWh	2006	2010	2015	2020
Total	0.6	8.3	18.2	22.0

Although it is recognised that there is a range of capacity factors applicable for offshore wind farms it has been assumed, for the purposes of estimating the TWh figure, that the average capacity factor is and will be 35%. This assumption is based on actual project data and the consultee's general feedback for future projects.

Capital Costs

The following table presents the range and average of current capital costs and how they are expected to change over time in £'000's per MW installed basis (real). These costs are based on actual project data from projects and recent tender responses both in the UK and in other European countries.

Offshore wind - capital costs (real)

£'000/MW	2006	2010	2015	2020
High	1,713	1,794	1,658	1,658
Medium	1,542	1,614	1,493	1,492
Low	1,371	1,435	1,327	1,326

The table below presents the breakdown of the capital costs, which is based on actual project data.

Offshore wind – capital cost breakdown

Capital cost breakdown	
Planning	2%
Infrastructure – grid	n/a
Infrastructure - other	46%
Plant	52%

Offshore Wind

Planning costs, in real terms, are expected to decrease over time as UK installed capacity increases. This is expected to occur as the offshore developers gain experience and as the planning authorities get more used to processing planning applications.

It has been assumed that the offshore projects are transmission connected, and that as such they will pay an annual amount instead of paying upfront for the capital costs of the grid. This is a simplifying assumption as it is recognised that some Round One projects will be connected to the distribution system.

Infrastructure costs have been assumed to reduce in real terms until 2015. The primary reason for this was the view that the costs of the civils will reduce as the developers and contractors gain experience. Thereafter these costs are expected to increase as these wind farms will be located further offshore, and in deeper water. It has been assumed that the total capital costs are similar for Round 1 and Round 2 projects.

Plant costs, including turbines, towers and blades, are expected to increase in real terms over the next four or five years due to the global supply/demand imbalance in the supply of turbines and continuing high prices for steel. Thereafter it has been assumed that the supply/demand balance will have stabilised enabling the plant costs to reduce due to a learning effect as the number of turbines manufactured increases.

Operating & Maintenance costs

Offshore wind - operating costs (real)

£'000/MW/yr	2006	2010	2015	2020
High	88	81	77	76
Medium	81	74	70	69
Low	73	67	63	63

The table above presents the range and average of the total operating and maintenance costs for large offshore wind farms, in £'000 per MW installed per annum (real). These include transmission use of systems charges of between £22,000 and £28,000 per MW installed per annum. These charges were derived using National Grid's existing onshore charging methodology, and are the highest and lowest estimates for double circuit 60km cable connections in the three strategic areas. In practice, as a result of the proposed offshore Security and Quality of Supply Standard (SQSS) a Determining Design Variation Discount of £13,500 per MW installed per annum could be applied to these charges. This potential reduction has not been included in the above operating costs because at the time the modelling was undertaken no decision had been taken on the recommendations of the Offshore Transmission Experts Group (OTEG) SQSS sub-group. The Government's decision to broadly accept the majority of the recommendations of the sub-group was published on 2 April 2007. Those recommendations include a single circuit design, under which circumstances the discount would be applied.

To consider how the operating and maintenance costs may change over time the costs have been separated into plant, insurance and all other operating and maintenance costs. The plant operating and maintenance costs are expected to decrease, in real terms, over time as the UK installed capacity increases due to learning effects. The insurance costs are expected to decrease to 2015, in real terms, as the market matures and the risks are better understood and then flatten off. The other operating and maintenance costs are expected to remain flat over the period to 2020.

Offshore Wind

Cost of Capital and operating life

Offshore wind is less mature than onshore wind and as such a 12% pre-tax real cost of capital has been used in the analysis. This rate is based on our proprietary information and from our consultation with offshore wind farm developers. The operating life of an offshore wind farm has been assumed to be 20 years.

Levelised Costs

The above assumptions result in the levelised costs for offshore wind as presented in the table below. The range of levelised costs reflects the range in the costs of offshore wind farms from the most expensive to the cheapest per MWh. The medium cost per MWh is seen as the average project given the current cost base.

Offshore wind - levelised costs (real)

£/MWh	2006	2010	2015	2020
High	101	102	95	94
Medium	91	92	86	85
Low	81	82	76	76

Progress ratios

The following progress ratios have been assumed to reflect how the respective capital and operating costs increase/decrease with every doubling of total installed UK generating capacity.

Offshore wind - capital cost progress ratios

	% of costs	2010	2015	2020
Planning	2%	92%	90%	90%
Infrastructure	46%	92%	95%	110%
Plant	52%	108%	92%	92%

Offshore wind - operating cost progress ratios

	% of costs	2010	2015	2020
Plant maintenance	32%	95%	90%	90%
Insurance	16%	95%	90%	100%
Other including grid	51%	100%	100%	100%

Co-firing

Assumptions

Capacity

The total capacity is based on the assumption that the proposed amendment to the current Renewables Obligation legislation that removes the caps on the co-firing proportion of each supplier's obligation and on the maximum proportion of regular biomass that can be co-fired are implemented.

The generating capacity for 2006 is based on the actual co-firing ROCs issued for the twelve months to September 2006, taken from Ofgem's ROC register and shown in Appendix A.

The estimated amount of co-firing for future years is based on discussions with a number of owners of co-firing generation plants in the UK and the IPA's Economics of Co-Firing report, which indicated that the owners of co-firing capacity intend to spend additional capital to increase the potential amount of co-firing that is achievable. The co-firing capacity drops in the period from 2016 to 2020 due to a number of coal fired stations opting out of LCPD and therefore no longer being operational after 2015.

It should be noted that the decision whether to co-fire is based on the generation costs of co-firing versus the generation costs using just coal.

It is anticipated that the proportion of energy crops will increase over time as generators look to use locally sourced energy crops. The total annual generation capacity for regular biomass, non-energy crop material, and energy crop, biomass specifically grown for generating energy, is shown below.

Co-firing - total annual generating capacity

TWh	2006	2010	2015	2020
Total	2.7	8.7	8.7	7.9
% Regular	95%	90%	85%	75%
Regular	2.6	7.9	7.4	6.0
Energy crops	0.1	0.9	1.3	2.0

Capital costs for regular and energy crops

Capital costs for co-firing on existing and refurbished coal fired power stations have been based on the DTI's 'Economic analysis of biomass' and discussions with co-firing generators who provided capital costs for existing and planned capital expenditure. Based on discussions with co-firing generators the investment decision is based on a relatively short time frame to account for the regulatory uncertainties, and as such a 5 year period has been used with a 10% cost of capital resulting in a capital cost of circa £10/MWh. It should be noted that the capital cost would fall to around £5/MWh if the investment decision was based on a 15 year period, as might be the case with greater regulatory certainty, this would result in the co-firing levelised costs falling by £5/MWh.

Fuel, transport and operating costs

The fuel price conversion from £/GJ to £/MWh is based on multiplying by 3.6 then dividing by the generation efficiency, the efficiency for co-firing is assumed to be 35%. For example a fuel price of £3.70/GJ is converted to £38.06/MWh (3.70 x 3.6 ÷ 0.35 = 38.06).

Co-firing

Regular Biomass

The main imported regular biomass fuels consist of palm kernel and olive residues (in the form of pellets and cake). Information from consultees informed us that the current prices for palm kernels are between £5.20/GJ and £5.90/GJ whilst for olive residues, prices are in the region of £4.40/GJ to £5.20/GJ, depending on its form. These prices should be seen in the context that over the last 12 months the markets have seen a low of £3.85/GJ.

The current high level of prices are a consequence of supply shortages due to extreme weather conditions including droughts and floods in the Indo-Malay area, from which most of the biomass is sourced, and countries such as Belgium, Holland and Sweden buying large volumes of biomass at high prices. The import price of £4.50/GJ has been used since consultees generally took the view that it is around this price level that will enable imports to be considered for the UK. Above this price, generators will attempt to buy more expensive domestically sourced material, depending on availability. The prices of the regular biomass fuels used in this analysis are shown in the table below.

Regular biomass fuel costs – delivered

Fuel Type	Mix of fuels	Price £/GJ	Price £/MWh
Wood arisings	14%	2.90[4]	29.83
Straw	29%	2.40[4]	24.69
Imports	57%	4.50[4]	46.29
Figure used, blended		**3.70**	**38.06**

Co-firing generators burn a greater proportion of imports than UK sourced regular biomass fuels to benefit from the increased market liquidity. Thus for co-firing it has been assumed, as shown in the previous table, that over half of the fuel used will be from imports. The availability of wood arisings is limited in comparison to the other regular biomass fuels and therefore a lower proportion of wood arisings has been assumed.

Demand for biomass and hence prices continue to rise in the UK so we have assumed that the prices rise to 2010. From this point it is anticipated that due to greater levels of stability in the domestic market and more established supply structures, prices are assumed to fall.

Operating costs have been assumed to average £3/MWh, however in reality these vary depending on the fuel source used, the table below presents the combined fuel, transport and operating costs for co-firing with regular biomass in £/MWhe.

Co-firing – regular fuel, transport and operating costs (real)

£/MWhe	2006	2010	2015	2020
High	45	47	46	43
Medium	41	43	42	39
Low	39	41	39	37

The medium costs are based on the expected blended mix of fuels, it has been assumed that the range either side of the average is weighted towards the higher end, since the increased demand on the fuel is anticipated to put upward pressure on prices

[4] Source: DTI, 2006, Economic Analysis of Biomass Energy

Co-firing

Energy Crops

Energy crop fuel costs are based on DTI's 'Economic Analysis of Biomass Energy' report and discussions with energy crop fuel importers and users. Consultees thought that the costs from the DTI's report where seen to be on the low side, due to the high cost of preparing the range of fuels being considered. The DTI's fuel costs are based on a baled or billet/chip form of miscanthus and SRC respectively. The majority of energy crops are now being processed into compacted forms (pellets and cubes), by the fuel suppliers, for which prices were quoted and the average prices for Miscanthus and SRC costs are shown in the table below and are assumed to be used in equal quantities thus the 2006 figure used for the cost of Energy Crop is £5.40 GJ.

Energy crop biomass fuel costs – delivered.

Fuel Type	Price £/GJ	Price £/MWh
Miscanthus	4.95	50.91
SRC	5.85	60.17
Figure Used	**5.40**	**55.54**

Forward fuel costs have been assumed to rise to 2010 to reflect current supply capacity and the move to other more expensive energy crops. The industry view saw the current trend of high biomass prices continuing for the next 5 years based largely on supply constraints. Energy crop prices in particular were forecast to rise based on extremely restricted supplies in the short run to 2010, with large quantities only available from 2012. Some consultees thought that twice as much fuel could be grown now without interfering with food supplies.

SRC and miscanthus are understood to represent the majority of energy crops planted in the current marketplace but future expansion will probably occur with annual crops, with higher quoted prices of £5.00/GJ to £6.00/GJ, which have the advantage of being much more compatible with agricultural practices and are finding considerable favour with farmers/growers.

After 2010 it has been assumed that prices will fall steadily to reflect the impact of research and development, the maturing of the industry and stabilisation of supply networks.

Operating costs of energy crops are assumed to be £2/MWh. The table below presents the energy crop combined fuel, transport and operating costs in £/MWhe.

Co-firing – energy crop - fuel, transport and operating costs (real)

£/MWhe	2006	2010	2015	2020
High	62	65	63	59
Medium	57	60	58	54
Low	53	55	54	50

Levelised Costs

Total generation costs for co-firing with regular biomass range between £49/MWh and £55/MWh and with energy crop ranging from £63/MWh to £72/MWh. The average levelised costs are based on the total cost of the underlying fuel and the likely uptake of the fuel in co-firing (for example there is limited availability of wood arising and the preference for longer term contracts weights the average towards imported regular fuels).

Co-firing

For energy crops the range either side of the average is weighted towards the higher end, since the increased demand on the fuel is anticipated to put upward pressure on prices. Energy crops are evenly weighted towards the high and the low to reflect an even use of miscanthus and SRC.

The tables below show the total levelised costs, including capital expenditure, for co-firing with regular biomass crops and co-firing with energy crops. It should be noted that the levelised costs be reduced by c.£5/MWh if greater regulatory certainty enabled the investment decisions to be made over a longer period.

Co-firing – regular - levelised costs (real)

£/MWh	2006	2010	2015	2020
High	55	57	56	53
Medium	51	53	52	49
Low	49	51	49	47

Co-firing - energy crops - levelised costs (real)

£/MWh	2006	2010	2015	2020
High	72	75	73	69
Medium	67	70	68	64
Low	63	65	64	60

Biomass

Assumptions

Capacity

The 2006 total biomass capacity figures are based on the Ofgem ROC register for the 12 months ending September 2006 as shown in Appendix A.

Thereafter future estimates have been produced to evaluate how this might change the cost per MWh. These estimates are based on our proprietary information and discussions with the biomass industry. By 2010 it is assumed that an extra 150MW installed capacity will be implemented, with a further 350MW in both the periods 2011 to 2015 and 2016 to 2020. With sufficient support a limited number of consultees believed that the predicted capacity for energy crops could double, however this has not been reflected in the capacities due to the low level of uptake for energy crops to date. The amount of energy crops used is currently low however the demand and proportion of energy crops is assumed to increase over time due to supply restrictions of the regular biomass fuel.

The table below presents the total predicted biomass capacity and breakdown between regular fuels and energy crop fuels.

Biomass – regular and energy crops, predicted capacity

	2006	2010	2015	2020
Predicted Capacity Total Biomass (TWh pa)	1.0	2.1	4.7	7.3
Regular	95%	90%	85%	75%
Energy Crops	5%	10%	15%	25%
Predicted Capacity – Regular(TWh pa)	0.9	1.9	4.0	5.5
Predicted Capacity – Energy Crops (TWh pa)	0.1	0.2	0.7	1.8

Capital Costs

Capital costs for both regular and energy crop biomass for 2006 were based on the DTI's working paper 'Economic Analysis of Biomass Energy' consulted on by industry at the DTI Seminar, 15th December 2006. Other capital cost figures were collated from a range of sources including the Carbon Trust 'Biomass Sector Review' 2005, EY industry knowledge and project data provided by industry. These sources showed a significant range from £1.1 million per MW to £2.2 million per MW, however this reflected a vast difference in plant sizes, from 12.5MW to 350MW. The larger plants have a lower cost per MW due to the economies of scale.

The plant costs have recently increased by a significant amount due to demand for generation assets from both China and Eastern European countries. The majority of costs were between £1.7 m per MW and £1.9 m per MW. As power plants dedicated to using only biomass tend to be smaller than those for fossil fuel plants (approximately 20-50MW) a cost of £1.8 m per MW was used.

The following table presents the assumed capital costs for biomass plants and how they may change over time.

Biomass

Biomass – regular and energy crop, capital costs (real)

£'000/MW	2006	2010	2015	2020
Base	1,800	1,798	1,767	1,750

Biomass – regular and energy crop, large, capital cost breakdown

Capital cost breakdown	
Planning	4%
Infrastructure - grid	8%
Infrastructure - other	28%
Plant	60%

The table above presents the breakdown of the biomass capital costs based on actual project data. The 'planning' and 'infrastructure' capital costs were assumed to remain constant over time, whilst the plant costs were assumed to reduce over time due to learning effects.

Our figures assumed that the plant complied with the EU Waste Incineration Directive emission requirements, which enables it to burn contaminated waste wood. An energy crop plant may have marginally cheaper capital costs as it does not need to be waste incineration compliant, however, as a less proven technology the same capital costs have been assumed for both regular and energy crop plants.

Operating and Maintenance Costs

Operating and maintenance costs were based on the DTI's Working Paper 'Economic Analysis of Biomass Energy', proprietary information and our discussions with industry. Fixed operating expenses were agreed at 3% of capital expenditure with an additional variable cost of £1.1/MWhe. Due to a learning effect, operating costs in real terms are expected to decrease over time as the UK installed capacity increases. The operating and maintenance costs are presented in the table below.

Biomass – regular and energy crop, operating and maintenance costs (real)

£'000/MW/yr	2006	2010	2015	2020
Base	62	61	58	56

Fuel

Regular Biomass

In addition to the regular fuel types used for co-firing, regular biomass plants can also use waste wood. There is currently only a negligible amount of imports being used in dedicated biomass plants, as they tend to be built around cheaper locally sourced domestic fuel. For this reason the percentages of imports used in 2006 is less than for Co-firing, and for 2006 an average fuel price has been assumed Thereafter, as the biomass generating capacity increases it is assumed that a greater proportion of imported fuel will be used due to the restricted availability of domestic fuels. This reliance on imported fuel is also seen in the currently proposed larger biomass projects. The table below presents the prices and mix of regular biomass fuels used.

Biomass

Regular Biomass Fuel Costs – delivered.

Fuel Type	Price £/GJ	Mix of fuels 2010+
Wood arisings	2.90[5]	14%
Wood waste	1.80[5]	14%
Straw	2.40[5]	14%
Imports	4.50[5]	57%
Figure Used	**£2.90/GJ, 2006**	**£3.60/GJ, 2010+**

Demand for biomass and hence prices continue to rise in the UK, so we have assumed prices rising to 2010. From this point, with greater stability in the market and more established supply structures, prices are assumed to fall. The conversion from £/GJ to £/MWh is based on multiplying by 3.6 and dividing by an efficiency factor of 28%, the £/MWh fuel costs are shown in the table below.

Biomass – regular, fuel costs (real)

£/MWh	2006	2010	2015	2020
High	58	61	59	55
Medium	37	49	47	44
Low	23	24	24	22

Energy Crop Biomass

The extensive assumptions regarding energy crop biomass fuel prices are outlined in the section on co-firing and based on miscanthus and short rotation coppice fuels with an average price of £5.40/GJ. The conversion from £/GJ to £/MWh is based on multiplying by 3.6 and dividing by an efficiency factor of 28%, the £/MWh fuel prices are shown in the table below.

Biomass – energy crop, fuel costs (real)

£/MWh	2006	2010	2015	2020
High	75	79	77	71
Medium	69	73	71	66
Low	64	67	65	60

Cost of Capital and operating life

Dedicated biomass is an emerging technology without proven supply chains and long term contracts, and as such a 15% pre-tax real cost of capital has been used in the analysis to reflect the increased risk reward within the projects. An operating life of 15 years and a capacity factor of 80% were also assumed.

A few consultees commented that the energy crop sector may see a marginally higher cost of capital than that of regular biomass, largely because of the greater instability in the supply chain (with an inability to gain long term supply contracts) and that past energy crop projects have

[5] Source: DTI,2006, Economic Analysis of Biomass Energy

Biomass

failed. However, for the purposes of this report and ease of comparison, it was agreed that using a consistent cost of capital would be more appropriate.

Levelised Costs

The key driver for the Biomass levelised costs is the fuel price.

Biomass – regular, levelised costs (real)

£/MWh	2006	2010	2015	2020
High	111	114	111	106
Medium	90	101	99	95
Low	76	77	75	73

Biomass – energy crop, levelised costs (real)

£/MWh	2006	2010	2015	2020
High	128	132	128	122
Medium	122	126	122	116
Low	116	119	116	111

Biomass - CHP

Assumptions

Balance of steam and electricity

The economics of a biomass CHP plant is effected by the balance between the heat and electrical output, which can vary considerably, our analysis is based on a plant configured for 30 MWht and 8 MWe as was used in the DTI consultation.

Capacity

Biomass CHP - total annual generating capacity

TWh	2006	2010	2015	2020
Total	-	0.8	1.9	2.1

The 2006 figure is taken as zero as Ofgem do not separate the power generated from biomass into CHP and non-CHP. The table above presents the estimated total annual generating capacity for Biomass CHP based on the assumption of additional installed capacity of 30 MW per annum, and a capacity factor of 80%[6].

Fuel costs

The £/GJ assumptions for fuel costs are as per on the costs assumed on Co-firing, however the conversion to £/MWhe are different due to the biomass CHP plants having a different efficiency to co-firing plants. The CHP plant configuration that was assumed and consulted on have lower electrical efficiency at 16% and higher heat efficiency, in comparison to co-firing plants, to achieve the optimum overall performance. The table below presents the fuel costs per MWhe.

Biomass CHP - fuel costs (real)

£/MWhe	2006	2010	2015	2020
High	120	120	120	120
Medium	88	88	88	88
Low	77	77	77	77

Steam revenue

Steam revenue assumptions have been based on cost savings of not using a 30MWth oil plant and instead using a 30MWth and 8MWe biomass CHP plant. Current steam revenue of an average £13.6/MWhth has been used which equates to £51/MWhe. There were comments that the 30MWth and 8MWe plant was too biased towards steam, in the current economic environment, as there is no support for steam from green sources. Whilst these comments reflect current commercial practice it was felt that the plant size should be the same as the one that the DTI consulted on.

The following table presents the current steam revenue assumptions and the expectation of how this will change over time.

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[6] Source: DTI, 2007, Economic Analysis of Biomass Energy

Biomass - CHP

Biomass CHP - Steam revenue (real)

£/MWhe	2006	2010	2015	2020
High	60	65	66	68
Medium	51	41	42	44
Low	43	23	23	22

The element of the steam revenue which relates to fuel costs changes over time in line with the forecasted change of the heavy fuel oil prices. This is presented in the table below. The capital and operating cost elements of the steam revenue are assumed to be stable over time in real terms since oil plant technology is mature.

Biomass CHP - heavy fuel oil (real)[7]

p/therm	2006	2010	2015	2020
High	55	60	61	63
Medium	46	36	37	39
Low	38	18	18	17

Capital Costs

Capital costs are based on our propriety information, real project data provided by industry consultees and the DTI's 'Economic analysis of Biomass' report.

In the event that a less efficient CHP project was built to produce relatively more electricity than the modelled plant the capital cost per MWe would reduce.

Biomass CHP - capital costs (real)

£'000/MWe	2006	2010	2015	2020
High	4,600	4,573	4,509	4,501
Medium	3,550	3,529	3,480	3,474
Low	2,500	2,485	2,451	2,446

The table above presents the assumptions for the current capital costs, per £'000 MWe installed, and how they are expected to change over time. The breakdown of the capital costs is presented in the table below based on project data.

Biomass CHP, capital cost breakdown

Capital cost breakdown	
Planning	4%
Infrastructure – grid	8%
Infrastructure – other	27%
Plant	48%

Planning costs are expected to remain level in real terms over the period covered. The infrastructure costs are a fully mature part of the capital costs and as such these costs are not expected to decrease or increase in real terms over the period covered. The plant costs are not fully mature and as such these costs are expected to decrease slightly in real terms over time as the technology and manufacturing processes improve.

[7] Source: DTI, 2007, Economic Analysis of Biomass Energy

Biomass - CHP

Operating costs

The table below presents the assumptions for the current operating costs, per £'000 MWe installed per annum, and how they are expected to change over time. The operating costs are also based on the same sources of information as the capital costs. The operating processes are not fully mature and so these are expected to reduce over time in real terms as additional experience is gained.

Biomass CHP - operating costs (real)

£'000/MWe/yr	2006	2010	2015	2020
High	100	98	92	91
Medium	83	81	77	76
Low	75	73	69	68

Levelised Costs

The above assumptions result in levelised costs presented in the table below:

Biomass CHP - levelised costs (real)

£/MWhe	2006	2010	2015	2020
High	186	180	177	175
Medium	135	145	141	139
Low	106	125	124	124

Micro Biomass CHP

Assumptions

Micro CHP is based on biomass CHP plants that have an installed capacity of 50KW and below. At this domestic scale, in contrast with micro wind, there are no micro biomass CHP plants that are commercially available. The issue is that the non biomass micro CHP plants, that are commercial available, are based on combustion technology requiring a gas fuel and it is not currently commercially viable to obtain biogas for domestic use. Since the micro biomass CHP technology appears to currently be commercially unviable it has not been possible to obtain the assumptions necessary to calculate levelised costs.

Landfill Gas

Assumptions

Capacity

The current installed generation capacity figure of 4.1TWh has been based on the total ROCs issued in the period 1 October 2005 to 31 September 2006 as published by Ofgem (see Appendix A). A capacity factor of 61% has been assumed, this being the current industry average for all landfill gas installations from the first compliance period of the Renewables Obligation (1 April 2002 to 31 March 2003) to date.

A build rate of 50MW per annum has been assumed from a current installed base of 781MW. In light of the growing maturity of the industry and regulatory changes to the landfill sector, it is anticipated that the maximum projected capacity will be limited to 891MW with this being reached in 2010. Subsequently, due to the decommissioning of existing capacity exceeding the volume of new capacity, the total net installed capacity will reduce to a level of 800MW in 2015 and 675MW in 2020. These figures are shown in the table below.

Landfill gas - projected installed capacity

TWh	2006	2010	2015	2020
Total	4.1	4.8	4.3	3.6

Capital Costs

Capital costs for landfill gas generation range from £0.65m/MW to £1.4m/MW with a medium cost of £1.0m/MW. The main drivers behind the range of costs were the site specific factors and various economies of scale for different sites and projects. Lower costs are generally seen for extensions of existing sites whereas building new installations generally results in higher costs. In exceptional circumstances the capital costs may reach up to £1.75m/MW due to high grid connection cost although any sites requiring any higher capital investment than this are uneconomic.

Due to the maturity of this particular technology, it was assumed that there would be no future capital reductions achieved either as a result of economies of scale or other market drivers and hence the capital costs in real terms are unchanged over the time period studied. The table below demonstrates the assumed capital costs per MW.

Landfill gas - capital costs (real)

£000's/MW	2006	2010	2015	2020
High	1,400	1,400	1,400	1,400
Medium	1,000	1,000	1,000	1,000
Low	650	650	650	650

For the purposes of the consultation, these costs were then analysed to produce a breakdown regarding the planning, infrastructure and plant costs associated with this technology and are shown in the table below for an average project.

Landfill gas - capital cost breakdown

Capital cost breakdown	
Planning	5%
Infrastructure – grid	30%
Infrastructure – other	10%
Plant	55%

Landfill Gas

The level of planning, infrastructure and grid costs are dependent on whether the installation is on a new or existing site, with lower costs generally associated with existing sites, however some existing sites need a new grid connection if the existing connection is unable to handle the greater generation of the site. It has been commented by some consultees that future new installations of landfill gas generation are now dependent on the grid connection cost.

Operating & Maintenance costs

Recent regulatory changes, notably the costs involved in meeting the Environment Agency's emissions monitoring requirements and the use of system changes have increased the operating and maintenance costs in the sector. The operation and maintenance costs for landfill gas generation range between £75,000/MW per annum and £130,000/MW. The variance between the high and low figures is predominantly created by the effect of the different size of installations with larger installations being able to take advantage of economies of scale. Future installations are likely to be smaller, because the best sites have already been exploited, and so the medium figure of £110,000/MW per annum has been used.

Landfill gas - operating and maintenance costs (real)

£000's/MW/yr	2006	2010	2015	2020
High	130	130	130	130
Medium	110	110	110	110
Low	75	75	75	75

Cost of Capital and operating life

The operating life of the assets is limited to the life of the gas reserves and has been taken to be 12 years. No resale value has been assumed for the assets due to plant being seen as being plant specific as costs of transferring assets are increasing and the size of future installations decreasing.

Landfill gas generation is a mature technology and as such a 10% pre-tax real cost of capital has been used in the analysis.

Levelised costs

As a result of the above assumptions, a levelised cost for a high, medium and low variance was calculated for landfill generation in £/MWh and are presented below.

Landfill gas - levelised costs (real)

£/MWh	2006	2010	2015	2020
High	63	63	63	63
Medium	48	48	48	48
Low	32	32	32	32

The high levelised costs above are generally for new smaller sites requiring a grid connection at a high cost with the low levelised costs generally seen in instances where a larger existing installation is developed. The medium is closer to the high value due to the majority of sites now being developed being of a smaller size and not benefiting from economies of scale.

Hydro

Hydro - Assumptions

Hydro generation has been split into two main categories:

1. Small scale hydro (including micro-hydro) projects less than 1.25MW, which are mainly low head ‘run of river’ projects; and
2. Mid scale hydro, projects larger than 1.25MW but smaller than 20MW, which are mainly high head ‘reservoir with dam’ projects

Large scale Hydro generation greater than 20 MW is outside the scope of this of this assignment since it is not anticipated that any further projects of this size will be developed in the UK.

Small hydro (including micro-hydro) - < 1.25MW

Capacity

The current installed generation capacity figure of 0.1TWh has been based on the total ROCs issued in the period 1 October 2005 to 31 September 2006 as published by Ofgem (see Appendix A). The capacity factor of 40% has been assumed to reflect the potential further sites which can be developed in the UK.

Although there is a large theoretical resource of small scale and micro-hydro projects, project economics dictate that there will be a further 16MW of installed capacity per annum coming online in the period to 2020. These figures are shown in the table below.

Small scale hydro - projected installed capacity

TWh	2006	2010	2015	2020
Total	0.1	0.3	0.6	0.8

Capital Costs

Capital costs for small scale hydro generation schemes vary considerably dependent upon site specific conditions and type of generation technology used. Capital costs were assumed to be in the range from £1.2m/MW in the low case to £2.2m/MW at the high level, with a medium cost of £1.65m/MW.

Higher capital costs are generally seen where there is a need for more expensive technology, eg, in low flow areas and sites which require further construction of buildings, access and infrastructure in addition to the grid connection costs. General cost increases in recent times are due to increasing turbine prices and more problematic projects being developed resulting in the increase of the average capital cost for small hydro schemes.

Due to the maturity of this technology, it was assumed that there would be no further capital reductions achieved either as a result of economies of scale or other market drivers and hence the capital costs in real terms are unchanged over the time period studied.

Capital costs for micro-hydro schemes are generally higher than for the small scale hydro projects, with capital costs as high as £2.8m/MW in some cases. The grid connection cost for micro-hydro projects increases dramatically for projects greater than 200kW (an increase from approx £10,000 to £50,000) and so for site sizes smaller than 200kW there is a marginal benefit to the project economics.

Hydro

The table below shows the assumed capital costs per MW for small scale hydro projects.

Small scale hydro - capital costs (real)

£000's/MW	2006	2010	2015	2020
High	2,200	2,200	2,200	2,200
Medium	1,650	1,650	1,650	1,650
Low	1,200	1,200	1,200	1,200

For the purposes of the consultation, these costs were then analysed to produce a breakdown regarding the planning, infrastructure and plant costs associated with this technology. These are shown in the table below for small scale hydro.

Small scale hydro - capital cost breakdown

Capital cost breakdown	
Planning	10%
Infrastructure – grid	10%
Infrastructure – other	20%
Plant	60%

Operating and Maintenance costs

Operating and maintenance costs were assumed to be in the range £20,000/MW per annum to £60,000/MW per annum with a medium figure of £40,000/MW per annum. The range of costs is again dependent on the size of the project and the associated economies of scale that the larger projects encounter, along with the lower operating and maintenance costs generally associated with high head projects. The lowest operating and maintenance costs were viewed as being £20,000/MW, reflecting the current market reality of employing an operator and the annual maintenance of the plant. The table below shows the range of figures.

Small scale hydro - operating and maintenance costs (real)

£000's/MW	2006	2010	2015	2020
High	60	60	60	60
Medium	40	40	40	40
Low	20	20	20	20

Cost of Capital and operating life

The operating life of hydro assets differs between the buildings and associated infrastructure and the plant and machinery. The plant and machinery and grid infrastructure have an operating life in the region of 25 years, the buildings and infrastructure have a much longer operating life, possibly in excess of 50 years. Since the majority of the capital costs relate to plant and machinery and gird infrastructure it was therefore assumed that the operating life of the installation would be 25 years.

Although small hydro generation is a mature technology, the ownership profile is towards private ownership and as such a slightly higher cost of capital would be expected and this was assumed at 12%.

Hydro

Levelised Costs

As a result of the above assumptions, the high, medium and low levelised costs have been calculated for small hydro generation in £/MWh and are presented below.

Small scale hydro - levelised costs

£/MWh	2006	2010	2015	2020
High	97	97	97	97
Medium	71	71	71	71
Low	49	49	49	49

The high levelised costs relate to the smaller projects which are unable to take advantage of economies of scale, both in respect of the capital costs incurred for more expensive technology for less efficient sites and also the higher operating and maintenance costs due to the inability of smaller projects to be managed as efficiently as larger projects. The medium costs relate to those projects without grid connection issues and low efficiency requirements and without any onerous infrastructure requirements. The low levelised costs relate to projects which are able to be developed with available and relatively inexpensive plant and machinery and have favourable infrastructure conditions, ie, proximity to a grid connection.

Micro-hydro schemes are seen to be more expensive than small scale hydro projects at all levels of costs. The high cost micro-hydro schemes are predominately those requiring high capital costs to enable generation for sites with low capacity factors and which require high grid connection and other infrastructure costs due to their location, whilst the medium and low levelised costs are generally higher than those of small scale projects due to the lack of economies of scale.

Mid hydro – (1.25 MW to 20 MW)

Capacity

The current installed generation capacity figure of 1.9TWh has been based on the total ROCs issued in the period 1 October 2005 to 31 September 2006 as published by Ofgem (see Appendix A for further details). The capacity factor of 36% has been assumed to reflect the potential further sites which can be developed in the UK and those currently generating.

As with small scale hydro, there is a greater resource available than is economic to construct and an assumption of the build rate going forward is that there will be a further 7.5MW of installed capacity per annum coming online in the period to 2020. These figures are shown in the table below.

Mid scale hydro - projected installed capacity

TWh	2006	2010	2015	2020
Total	1.9	2.0	2.1	2.3

Capital Costs

Capital costs for mid scale hydro projects have been assumed to benefit both from economies of scale and proportionally lower capital costs than small scale hydro due to the technology involved. The costs ranged from £1.14m/MW to £2.09m/MW and a medium of £1.57m/MW. As with small scale hydro, it has been assumed that there would be no further capital reductions achieved either as a result of economies of scale or other market drivers and hence the capital costs in real terms are unchanged.

The table below demonstrates the assumed capital costs per MW for mid scale hydro projects.

Hydro

Mid scale hydro - capital costs (real)

£000's/MW	2006	2010	2015	2020
High	2,090	2,090	2,090	2,090
Medium	1,568	1,568	1,568	1,568
Low	1,140	1,140	1,140	1,140

The breakdown of capital costs for mid scale hydro projects are different from that applied to small scale hydro projects. Planning costs for mid scale projects can be as low as being negligible in proportion to the total project capital costs in some cases whilst the infrastructure is seen to be a higher proportional cost. This is due to the different technology employed between high and low head installations and a differing approach between 'run of river' and 'reservoir with dam' projects.

Mid scale hydro - capital cost breakdown

Capital cost breakdown	
Planning	5%
Infrastructure – grid	15%
Infrastructure – other	30%
Plant	50%

Operating and Maintenance costs

Mid hydro technologies are able to achieve good economies of scale due to the largest proportional cost being that of the 'fixed' cost of employment of an operator within the total operating and maintenance cost. In light of this, the medium costs are only marginally higher at £25,000/MW per annum to reflect the current market reality, with the low cost at £20,000/MW. The high cost of £50,000/MW per annum reflects smaller and more complex projects not benefiting from the economies of scale of larger standard projects. The table below shows these figures.

Mid scale hydro - operating and maintenance costs (real)

£000's/MW	2006	2010	2015	2020
High	50	50	50	50
Medium	25	25	25	25
Low	20	20	20	20

Cost of Capital and operating life

The operating life of these assets has been assumed to be 25 years to reflect the combined operating life of the plant and machinery and associated infrastructure. Mid hydro generation was assumed to also be a mature technology and as such a 10% pre-tax real cost of capital has been used in the analysis.

Hydro

Levelised Costs

As a result of the above assumptions, a levelised cost for a high, medium and low variance was calculated for mid hydro generation in £/MWh and are shown below.

Mid scale hydro - levelised costs (real)

£/MWh	2006	2010	2015	2020
High	89	89	89	89
Medium	63	63	63	63
Low	46	46	46	46

The high levelised costs reflect smaller installations with complex technology and a need for extensive infrastructure and maintenance whereas projects generally developed at the medium level have standard technology and no issues regarding the infrastructure or grid connection. The low levelised costs reflect the generally larger projects able to maximise economies of scale from an established site.

Sewage Gas

Assumptions

Capacity

The current generation capacity of sewage gas is 0.3TWh in the UK has been based on the total ROCs issued in the period 1 October 2005 to 31 September 2006 as published by Ofgem (see Appendix A). The capacity factor of the generating equipment is assumed to be 80% and accounts for the current generation reality by allowing for regular servicing downtime. The market was assumed to be essentially saturated and as such predicted forward growth was assumed to be 1.5MW per annum and is shown in the table below.

Sewage gas - projected installed capacity

TWh	2006	2010	2015	2020
Total	0.3	0.4	0.4	0.5

Capital Costs

Capital costs for sewage gas were assumed to range from £1.0m/MW to £1.6m/MW, with these costs dependent on the existing site conditions, specific technology used and other local market factors, for example, the cost of the grid connection.

The table below demonstrates the assumed capital costs per MW for sewage gas generation projects.

Sewage gas - capital costs (real)

£000's/MW	2006	2010	2015	2020
High	1,600	1,600	1,600	1,600
Medium	1,200	1,200	1,200	1,200
Low	1,000	1,000	1,000	1,000

For the purposes of the consultation, these costs were then analysed to produce a breakdown regarding the planning, infrastructure and plant costs associated with this technology. These are shown in the table below.

Sewage gas - capital cost breakdown

Capital cost breakdown	
Planning	5%
Infrastructure – grid	5%
Infrastructure – other	10%
Plant	80%

Operating and Maintenance costs

Operating and maintenance costs have been assumed to range from £50,000/MW per annum to £135,000/MW per annum at the high end of the scale with these values dependent on site specific factors and economies of scale with a medium of £90,000/MW. These installations are not able to take advantage of any economies of scale due to the relatively small size of the installations and the high level of maintenance required to ensure they continue to operate efficiently. These costs are presented in the table below.

Sewage Gas

Sewage gas - operating and maintenance costs (real)

£000's/MW	2006	2010	2015	2020
High	135	135	135	135
Medium	90	90	90	90
Low	50	50	50	50

Cost of Capital and operating life

The operating life of these assets has been assumed to be 15 years due to the expected working life of the generating machinery and a cost of capital of 12% has been assumed, as despite being a proven technology, the size of the installations are decreasing and many sites in the UK use the energy generated on the site itself and only export any excess capacity generated.

Levelised Costs

As a result of the above assumptions, a levelised cost for a high, medium and low variance was calculated for sewage gas generation in £/MWh and are presented below.

Sewage gas, Post Consultation costs

£/MWh	2006	2010	2015	2020
High	53	53	53	53
Medium	38	38	38	38
Low	28	28	28	28

The high levelised costs are derived from sites with large capital expenditure due to expensive technology or grid connection costs from the relatively small sites along with high operating and maintenance costs of the generators. The medium cost reflects the typical site conditions with no planning or grid issues and the low levelised costs reflect the economies of scale able to be achieved with larger installations.

Solar PV

Assumptions

Capacity

The current generation capacity of solar PV is 13MW, however the vast majority of this installed capacity is in domestic dwellings and the large administrative burden of claiming the ROC prohibits most owners from doing so. Due to this, the current generation capacity was assumed to be 0.2GWh based on the total ROCs issued in the period 1 October 2005 to 31 September 2006 as published by Ofgem (see Appendix A for further details). The capacity factor of 16% was agreed amongst the consultees.

Capital Costs

Capital costs for solar PV installations were assumed to range from the low range of £4.5m/MW to a high range of £6.5m/MW with a medium value of £5.25m/MW. The high cost range results from the significant differences in the technology used and level of integration of the individual project to its building. It has been assumed the experience curve for solar PV in the UK will be able to follow that of the global picture and as such will be able to reduce capital costs at 10% initially. The progress ratio for the solar PV was agreed with consultees as being a realistic figure for the UK market. It should be noted that in the current climate, some new build projects may benefit from the installation of integral PV units, not only in terms of an easier planning process but also from an increased sale value of the development.

The table below demonstrates the assumed capital costs per MW for solar PV projects.

Solar PV - capital costs (real)

£000's/MW	2006	2010	2015	2020
High	6,500	5,850	5,200	4,550
Medium	5,250	4,725	4,200	3,675
Low	4,500	4,050	3,600	3,150

For the purposes of the consultation, these costs were then analysed to produce a breakdown regarding the planning, infrastructure and plant costs associated with this technology. These are shown in the table below for solar PV generation.

Solar PV - capital cost breakdown

Capital cost breakdown	
Planning	10%
Infrastructure – grid	15%
Infrastructure – other	10%
Plant	65%

Operating and Maintenance costs

Operating and maintenance costs for solar PV have been assumed to be in the range of £40,000/MW per annum to £76,000/MW per annum, with a medium of £50,000/MW per annum. It should be noted that the range of operating and maintenance costs is not as great as the range for capital costs.

It was also assumed for the operating and maintenance costs that there was the opportunity for these costs to be reduced through experience and therefore the same progress ratios were applied to the operating and maintenance costs as were applied to the capital costs.

The following table shows these figures.

Solar PV

Solar PV - operating and maintenance costs (real)

£000's/MW	2006	2010	2015	2020
High	76	68	61	53
Medium	50	45	40	35
Low	40	36	32	28

Cost of Capital and operating life

The operating life of these assets was assumed to be 25 years which is the length of guarantee some suppliers now attach to their products. Due to the technology being comparatively immature in the UK, a cost of capital of 15% was assumed, but again it should be noted that with a higher level of deployment in the UK, this may fall in future years.

Levelised Costs

As a result of the above assumptions, a levelised cost for a high, medium and low variance was calculated for solar PV generation in £/MWh and are shown below.

Solar PV - levelised costs

£/MWh	2006	2010	2015	2020
High	797	717	637	558
Medium	635	571	508	444
Low	542	488	434	380

The high levelised costs reflect the cost of installing the more complex integrated solar PV installations rather than the modular systems which are less expensive and are generally reflected in the medium and low levelised costs.

Wave

Assumptions

Capacity

The current generation capacity of wave power in the UK has been assumed to be 3.9 GWh which is currently being generated by commercial prototypes. Due to the embryonic nature of the sector and a large diversity of technologies being developed, capacity factors for the different technologies do vary, however a capacity factor has been assumed at 30%[8].

It should be noted that in providing the projected installed capacity figures it has been assumed that there will have been revenue support provided for the technology for entry level projects to be built. The capacity limit for wave power in the UK was assumed to be 50.0TWh[9].

The annual growth has been assumed to be initially 5MW per annum to 2010, 30MW per annum until 2015 and then 60MW per annum thereafter.

Projected installed wave capacity

TWh	2006	2010	2015	2020
Total	0.0	0.1	0.5	1.2

Capital Costs

Capital costs for wave installations were assumed to range from £1.75m/MW to £4.0m/MW with a medium of £2.75m/MW. The high cost range results from the different technologies required for near shore and offshore projects, with the technologies involved in the near shore projects being in the region of 25% more expensive than that for offshore projects. The progress ratios for the wave sector were assumed to be 95% for all technologies due to the learning ability applicable to emerging technologies. This progress ratio has been assumed to commence subsequent to 20MW of installed wave capacity in the UK. The table below shows the assumed capital costs per MW for wave projects.

Wave - capital costs (real)

£000's/MW	2006	2010	2015	2020
High	4,000	3,964	3,399	3,154
Medium	2,750	2,725	2,337	2,169
Low	1,750	1,734	1,487	1,380

For the purposes of the consultation, these costs were then analysed to produce a breakdown regarding the planning, infrastructure and plant costs associated with this technology. These are shown in the table below for wave generation.

Wave - capital cost breakdown

Capital cost breakdown	
Planning	10%
Infrastructure – grid	20%
Infrastructure – other	20%
Plant	50%

[8] Source: OXERA, February 2004, Results of Renewables Market Modelling

[9] Source: Carbon Trust, 2006, Future Marine Energy

Wave

Operating and Maintenance costs

Operating and maintenance costs for wave have been assumed to be in the range of £50,000/MW per annum to £110,000/MW per annum with the medium of £82,000/MW. The high range of costs is for offshore projects whilst the low range of costs is predominately for the near shore projects. The progress ratio for operating and maintenance costs was assumed to be 90%, with the sector confident that there will be a positive effect on the operating and maintenance costs once the sector is established, for example with reductions in areas such as insurance costs. This progress ratio is due to commence once 20MW of wave capacity has been installed in the UK. The table below shows these figures.

Wave - operating and maintenance costs (real)

£000's/MW	2006	2010	2015	2020
High	110	108	79	68
Medium	82	81	59	51
Low	50	49	36	31

Cost of Capital and operating life

The operating life of these assets has been assumed to be 20 years and due to this being an emerging technology, a cost of capital of 15% was assumed.

Levelised Costs

As a result of the above assumptions, a levelised cost for a high, medium and low variance was calculated for wave generation in £/MWh and are shown below.

Wave - levelised costs

£/MWh	2006	2010	2015	2020
High	285	282	237	217
Medium	199	196	165	151
Low	125	124	104	96

In light of the emergent nature of the wave sector and the diversity of technologies, the high levelised costs are generally projects unable to take advantage of beneficial market factors either in terms of capital expenditure or operating and maintenance costs.

Low levelised costs are generally only achievable for projects able to reduce either the capital or operating and maintenance costs and are very dependent on the technology. For near shore technologies, a reduction in the capital costs enables a lower levelised cost to be achieved, whilst for offshore technologies, a lower operating and maintenance cost would be the largest driver in achieving a low levelised cost. It was felt that the low cost would only occur in a very few specific cases due to a limited number of these optimal sites.

The medium levelised costs apply to the majority of technologies, both nearshore and offshore, with the balance between high capital costs for near shore technologies being balanced against the low operating and maintenance costs, and vice versa.

Although progress ratios have been incorporated into the process, it should be noted that without support it is unlikely that there will be development in the sector in the UK.

Tidal

Assumptions

The assumption for this report is that the tidal power is generated by the tidal stream using turbine technology rather than tidal lagoons and barrages.

Capacity

The current generation capacity of tidal power in the UK has been assumed at 1.1 GWh. Similarly to wave this is also from commercial prototypes. An annual growth rate of 5MW per annum until 2010, 30MW per annum until 2015 and 60MW per annum until 2020 has been assumed for this report. The capacity factor for tidal technologies has been assumed at 35%. It should be noted that in providing the projected installed capacity figures it has been assumed that there will have been revenue support provided for the technology for entry level projects to be built.

The capacity limit for tidal power in the UK was assumed to be 18.0TWh[10].

Projected installed tidal capacity

TWh	2006	2010	2015	2020
Total	0.0	0.1	0.5	1.4

Capital Costs

Capital costs for tidal installations were assumed to range from £4.0m/MW per annum to £2.0m/MW per annum with the medium value of £3.0m/MW. The high cost range results from the different technologies currently being developed for tidal generation, although these are not as diverse as those for wave projects. The progress ratio for tidal power was assumed to be 95% for the capital costs for all types of technology involved. The table below shows the assumed capital costs per MW for tidal projects.

Tidal - capital costs (real)

£000's/MW	2006	2010	2015	2020
High	4,000	3,936	3,363	3,119
Medium	3,000	2,952	2,522	2,339
Low	2,000	1,968	1,681	1,560

For the purposes of the consultation, these costs were then analysed to produce a breakdown regarding the planning, infrastructure and plant costs associated with this technology. These are shown in the table below.

Tidal - capital cost breakdown

Capital cost breakdown	
Planning	5%
Infrastructure – grid	20%
Infrastructure – other	20%
Plant	55%

Operating and Maintenance costs

Operating and maintenance costs for tidal have been assumed to be in the range of £60,000/MW per annum to £85,000/MW per annum with the medium of £75,000/MW per annum. The range

[10] BWEA

Tidal

of these costs is quite small, this being due to the technologies being developed being subject to similar operating and maintenance costs. Following industry consultation it was felt that there would be the possibility of improvements in these operating and maintenance costs and as a result a progress ratio of 90% has been assumed for tidal projects, commencing when 20MW of capacity has been installed in the UK. The table below shows these figures.

Tidal - operating and maintenance costs (real)

£000's/MW	2006	2010	2015	2020
High	85	82	60	51
Medium	75	73	53	45
Low	60	58	42	36

Cost of Capital and operating life

The operating life of these assets has been assumed to be 20 years and a cost of capital of 15% was assumed due to this technology being not commercially proven.

Levelised Costs

As a result of the above assumptions, a levelised cost for a high, medium and low variance was calculated for tidal generation in £/MWh and are shown below.

Tidal - levelised costs

£/MWh	2006	2010	2015	2020
High	236	232	195	179
Medium	181	177	149	137
Low	124	121	101	93

The high levelised costs are in the main for the specific projects which require a high capital spend, either in respect of the cost of the turbine or for sites with a complicated or remote grid connection and other associated infrastructure.

The low levelised costs are in respect of those sites able to reduce these capital costs by either using inexpensive technology or by utilising a site with advantageous infrastructure, for example a good grid connection and site access. The current high capital costs within the sector would make these low costs very unusual. The medium value is generally seen as being the current commercially available figure for tidal installations in the UK.

ACT

Advanced Combustion Technology

Within the Advanced Combustion Technology category the separate technologies of Gasification/Pyrolysis, Anaerobic Digestion CHP and EfW CHP have been considered.

Gasification/Pyrolysis

Capacity

To our knowledge there are currently no commercially operational plants in the UK. Based on discussion with Defra and Gasification developers it has been assumed that by 2010 the three projects that Defra have provided capital support will be operational, it should be noted that the tendering, planning and construction period for such facilities is around five years. Thereafter an additional nine facilities are expected by 2015 and a further nine by 2020. The table below presents the total annual generating capacity.

ACT - total annual generating capacity

TWh	2006	2010	2015	2020
Total	0.0	0.1	0.3	0.7

Capital Costs

Capital costs are based on data provided by Defra and estimates for a commercial project which is about to be constructed. The table below presents the expected Gasification/Pyrolysis capital costs per MW installed, and how the costs are expected to change over time. The view of Defra and the consultees was that the recent increases in waste infrastructure costs were expected to continue in real terms to approximately 2012 and then flatten off.

Gasification/Pyrolysis - capital costs (real)

£’000/MW	2006	2010	2015	2020
High	8,267	9,304	9,871	9,871
Medium	6,585	7,412	7,863	7,863
Low	5,119	5,762	6,113	6,113

Operating Costs

Gasification/Pyrolysis - operating costs (real)

£’000/MW/yr	2006	2010	2015	2020
High	515	557	557	557
Medium	444	480	480	480
Low	368	399	399	399

The table above presents the expected Gasification/Pyrolysis operating costs per £’000 MW installed per annum and how the costs are expected to change over time. The costs are based on data provided by Defra and developers. The operating costs are expected to increase in real terms to approximately 2010, due to the recent above inflation increases in construction labour costs, and then flatten off. The operating costs are shown net of a small proportion of recyclate income.

Other income

Gasification/Pyrolysis – gate fee income (real)

£/MWh	2006	2010	2015	2020
Base	79	79	79	79

The table above presents an estimate of the gate fee income generated from handling waste (refuse derived fuel). The gate fee has been assumed to be £45 per tonne and that a tonne of waste is able to produce 0.5MWh of electricity, which is based our proprietary information and discussions with developers, current gate fees that have been quoted when tendering for commercial waste handling contracts were cited to support this.

Cost of Capital and operating life

Based on discussions with Defra and developers it has been assumed that the technology will have a 20 year operating life. It has been assumed that a 15% real pre tax cost of capital is appropriate for this technology, due to the immaturity of the technology.

Levelised Costs

Gasification/Pyrolysis - levelised costs (real)

£/MWh	2006	2010	2015	2020
High	174	202	215	215
Medium	127	150	160	160
Low	85	103	111	111

It should be noted that only the bio-degradable content of the refuse derived fuel is eligible for ROC support.

Anaerobic Digestion CHP

To calculate the levelised costs for anaerobic digestion CHP we used recent assumptions provided by the Renewable Energy Association.

Capacity

Anaerobic Digestion - CHP - total annual generating capacity[11]

TWh	2006	2010	2015	2020
Total	0.0	0.1	0.2	0.3

Capital Costs

The table below presents the current capital costs as provided by the Renewable Energy Association. It has been assumed that these costs will change over time in a similar manner to the Gasification and Pyrolysis capital costs.

[11] Renewable Energy Association data

ACT

Anaerobic Digestion - CHP - capital costs (real)

£'000/MW	2006	2010	2015	2020
High	7,696	8,662	9,189	9,189
Medium	6,343	7,139	7,574	7,574
Low	5,530	6,225	6,604	6,604

Operating Costs

The table below presents the current operating costs. It has been assumed that these costs will change over time in a similar manner to the Gasification and Pyrolysis capital costs.

Anaerobic Digestion - CHP - operating costs (real)

£'000/MW/yr	2006	2010	2015	2020
High	787	851	851	851
Medium	709	768	768	768
Low	649	703	703	703

Other income

The table below presents the income assumptions, which include heat income and gate fee income. It has been assumed that half of the tonnes input into the anaerobic digestion plant would be waste and attract approximately £40 per tonne of gate fee income, slightly lower than £45 per tonne used for gasification since not all sources will be municipal waste, and the rest of the tonnage would be provided at without any income or cost.

Anaerobic Digestion - CHP - other income (real)

£/MWh	2006	2010	2015	2020
High	146	146	146	146
Medium	129	129	129	129
Low	119	119	119	119

Cost of Capital and operating life

It has been assumed that the technology will have a 20 year operating life. It has also been assumed that a 15% real pre tax cost of capital is appropriate for this technology, due to the immaturity of the technology.

ACT

Levelised Costs

The above assumptions result in the levelised costs as reflected in the table below.

Anaerobic Digestion - CHP - levelised costs (real)

£/MWh	2006	2010	2015	2020
High	132	162	173	173
Medium	107	133	143	143
Low	92	115	123	123

EfW CHP

The analysis for EfW CHP is based on the Ilex 'Extending ROC Eligibility to Energy from Waste with CHP' report. The report focused on the incremental costs and income for an EfW CHP in comparison with a conventional EfW facility. The underlying assumption is that conventional EfW facilities are economically viable without ROC income due to the gate fee income received for handling waste.

Capacity

The table below presents the slow growth scenario per Ilex's report which is based on 15 EfW CHP facilities becoming operational by 2020.

EfW CHP - total annual generating capacity[12]

TWh	2006	2010	2015	2020
Total	0.0	0.7	1.2	1.6

Levelised costs

The incremental costs and savings for an EfW CHP include the additional capital and operating costs for the heat network, the lost wholesale electricity revenue due to generating less electricity than a conventional EfW, the additional electricity revenue for the element of electricity generation qualifying for ROCs, assumed to be 60%; and the additional steam revenue from the heat sales.

The Ilex report indicates that using a 12% cost of capital in would be economically viable to build a 400,000 tonne per annum EfW CHP instead of a conventional CHP providing that the installed heat capacity is less than or equal to the installed electricity capacity.

[12] Source: Ilex Energy Consulting, September 2005, Extending ROC eligibility to Energy from Waste with CHP

ACT

EfW CHP – levelised costs (real)

£/MWhe	2006	2010	2015	2020
High	83	83	83	83
Medium	79	79	79	79
Low	75	75	75	75

The table above presents the levelised costs for a 400,000 tonne per annum EfW CHP configured for 20.6 MWe and 20 MWth using a 12% cost of capital, and based on £32/MWhe[13] wholesale electricity prices at the time of the Ilex report. The high and low presents the heat network costs in the Ilex report for the 20.6 MWe and the 19.9 MWe capacities. The levelised costs are assumed to remain flat in real terms since heat networks are already a mature technology.

[13] Source: Ernst & Young analysis of Elexon wholesale electricity prices September 2005

Geothermal

Hot Dry Rock geothermal energy was investigated extensively in the UK in the period 1975 to 1995, such as at the Camborne School of Mines project at Rosemanowes Quarry in Cornwall. A substantial resource was identified in the Hercynian granites in the UK. The final stages of the project in Cornwall involved circulations between boreholes up to 2.5 km deep and water at typically 80 degrees Celsius was recovered in substantial quantities. The main project was funded by the then UK Department of Energy and the EU.

However, to consider the production of electricity a project would have involved recovering water at close to 200 degrees Celsius with an implication of borehole depths in excess of 5 km. In a commercial review led by Rio Tinto it was concluded (and confirmed by staff working on the project) that the risk of failure was too high for a prototype project and further field research would be required with the deeper boreholes. It was decided that the research would not be funded. The main risks were the uncertainty regarding the structure and intensity of the rock fracture network at the greater depths, the possibility of unfavourable in-situ stress conditions and the increased difficulties associated with borehole drilling and subsequent rock mass stimulations and treatments. All of these risks carried substantial financial implications.

To take the example of Cornwall (one of the best suited areas in Europe for this technology), if the work is ever to restart, a deep hole reaching depths of between 5 and 7km will be needed to assess conditions at depth at a 2007 cost of approximately £12m.

Hot Dry Rock geothermal energy research and commercial activity continues in Japan, Europe, Australia and USA but there have been no successful commercial projects yet. Projects in France Switzerland and Australia have reached rock at full commercial temperature and are testing the reservoir conditions. The USA has just completed a feasibility study to develop 100GW of electrical capacity from deep geothermal resources by 2050 (report to be published in January 2007). Increasing energy costs may bring Hot Dry Rock back into early consideration for some specialised applications however, Professor Robert Pine, head of the Camborne School of Mines and Chair in Geotechnical Engineering at Exeter University has stated that the prudent approach is to keep a watching brief on the other projects in similar conditions before reconsidering the position in the UK.

PPA and Key Development Decision Points

Power Purchase Agreements ("PPA"s)

The value of the PPA is a function of the value of a number of components, and the percentage of this value earned by the generator.

The main components are:

- Wholesale power
- ROC Buy-out
- ROC Recycle
- Levy Exemption Certificate
- Embedded benefits

Wholesale Power

The value of the power is ultimately determined by the market. Two of the key contributors to the value paid to the generator are the intermittency and the downside risk protection.

Intermittency

A major contributor to the value of the power is the extent to which it can be seen as predictable ("Base Load"). If it is Base Load then the purchaser is likely to pay more for it as it will avoid potential system penalties which it may need to pay if it is short or long on the system. Technologies intermittency is therefore a key factor in determining its value.

We have grouped the technologies into ones which are intermittent and those that can be deemed to be Base load.

Intermittent technologies are: Wind (onshore and offshore), small scale Hydro, Wave, and Solar PV

Base load technologies are: Landfill Gas, Biomass[14], Tidal, ACT, co-firing, Sewage Gas

The discount for intermittent technologies is generally seen to be around 5-10%[15] for short term contracts. The purchasers of the power argue that the discount could be considerably more in the future as more intermittent power is introduced to the grid. A significant premium is therefore added to long term PPAs of c. 10-15%.

Effect of banding on discounts

One reason given by purchasers of green power for the larger long term intermittency discount is the risk that the increasing percentage of renewable generation, and in particular wind, will increase the cost of intermittency.

If banding is therefore introduced at a level that encourages intermittent technologies, purchasers may increase the discount they need to take this risk both in short and long term contracts.

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[14] We have assumed that biomass CHP is predictable however this varies from project to project.

[15] Ernst & Young proprietary information

PPA and Key Development Decision Points

If base load technologies are encouraged it could mean that the long term intermittency discount is reduced or at least becomes a point of negotiation.

Downside risk protection and credit wrap

Generators that cannot trade the power themselves often need to raise project finance. To do this they need to acquire some downside risk protection from the purchasers of the power in order to satisfy the demands of the lenders to the project. The downside protection is usually in the form of a floor price (providing a level below which the power price cannot fall) and in agreeing the intermittency discount at the beginning of the PPA. Purchasers will often provide this protection however they charge for this by taking an increased discount off the value of the power and other sources of revenue. The cost of this downside protection is generally recognised to be the difference between the discounts offered on short and long term PPAs.

Credit wrap is also implied in the PPA pricing mechanism with credit rating agencies assessing the suppliers exposure to long term PPAs along with the bank providing funding to the project requiring a long term PPA by a supplier with a strong credit rating which is also reflected in the discounts offered to intermittent technologies.

An estimate of the current PPA discounts are illustrated below.

Long and short term value attributable to the generator

Long term PPAs generally incorporate a floor price. It is recognised that the higher the floor price, the higher the discounts which means that the percentage retained by the generator is reduced.

Shorter term PPAs are generally between one and three years in length and reflect the anticipated value of the power without the ‘risk premium’. Some generators take the view that the short term PPA figures will continue over the life of the project.

The impact of the Renewables Obligation extension to 2020 and any possible effect of ROC banding has not yet been reflected in the PPA discounts offered.

Indications of PPA terms offered to generators of renewable Energy

Component	Indicative pricing over the contract term	
	Short	**Long**
Wholesale electricity		
Intermittent	90-95%	70-85%
Base Load	95-100%	85-95%
ROC Buy-out	90-95%	80-95%
ROC recycle	90-95%	70-90%
LEC	80-90%	70-80%

It should be noted that the figures in the above table are subject to fluctuation and tendering.

PPA and Key Development Decision Points

Key Decision Points

As projects and portfolios are developed the developer is constantly assessing its view as to the future risk and rewards of the project or portfolio. Within the life cycle of projects there are key decision points at which the investor needs to commit to spending more funds. These are generic in nature across various technology groups. This section therefore looks at the generic key decision points and brings out key considerations for each technology group.

Initial evaluation of whether to develop a project:

Initial development of the project:

The evaluation of whether to develop a project is dependent on a number a factors, the potential commercial attractiveness, the probability of success (land access, planning, feed source/wind, grid, grant, revenue support) and the financing (availability of debt and equity, cost and terms of finance) for a proposed development.

The table below sets out the technology groups and the key value drivers for each. The wind resource group includes onshore wind, both large and small and offshore wind. The fuel resource group includes biomass (CHP, regular and energy crops), co-firing and ACT. The mature technologies are landfill gas, sewage gas and hydro (large and small) and the emerging technologies are classed as solar PV and marine. The development period is from initial site identification through to the financial close.

Technology Group	Key Value Drivers	Development period
Wind	Planning Permission, Grid Connection, Met Mast, Land agreements, EIA	2-3 years (onshore) 2-5 years (offshore)
Biomass	Planning Permission, EIA, Fuel Supply, Grid connection	2-3 years
Mature Technologies	Planning Permission, Regulatory Issues, Grid Connection, Resource assessment	1-2 years
Emerging Technologies	Ability to Finance, Planning Permission, Research Costs, Revenue Support, EIA, Grid Connection, Resource assessment	3-5 years

The expenditure up to financial close includes installation of a met mast (in the case of wind resources), the employment of technical, legal and financial consultants, planning fees and legal costs and management time.

Wind

In the case of wind resource, a key decision points are the installation of a met mast on the site to measure the wind resource available, of the negotiation of land lease agreements, the application document, the undertaking of an environmental impact assessment of the site. These costs are generally greater in respect of offshore projects, especially in regard to the installation of the met mast.

PPA and Key Development Decision Points

Biomass

For the fuel resource technologies such as a biomass plant, the key decision points are the EIA and submission of planning and the establishment of a fuel supply strategy.

Mature Technologies

Mature technologies such as landfill gas are highly dependent on the planning process to develop sites, and regulatory issues which are also involved in the development process. For technologies such as small scale and micro hydro power the smaller sites are more heavily dependent on planning issues.

Emerging Technologies

The development of projects utilising emerging technologies normally involves a significant investment in R&D. This is due to the costs of developing the right technology for the specific site parameters. This is particularly true for wave and tidal developments. Often significant time and resources are dedicated to convincing the sponsor that the project should be supported despite the technology risk.

Initial commitments towards the end of the development period:

Towards the end of the development phase (last 3-6 months), there are often significant commitments being made. This stage of the project involves a far higher capital expenditure than the previous stage and the developer is committed to contracts for the project.

A firm commitment often needs to be made with regards to the grid connection offer, there is often the commitment to purchase wayleaves and/or land to enable the project to be commissioned. The construction contracts are negotiated and then signed (often on financial close). In the case of fuel resource technologies, the commitment to purchase and/or process fuel on a long term basis is entered with a suitable supplier at this stage.

The financial aspects of the project are negotiated to ensure funds are available for the construction of the contract in the form of either debt and/or equity, and in the case of project financing, the terms for this are also agreed.

The consequence of the withdrawal of the developer from developing the project at this stage would lead to a considerable loss of expenditure which has been invested to date in the project and also the unwinding of the commitments outlined above, involving further expense.

Construction of the project:

The construction phase of the project may be seen to have commenced when the project has passed financial close and hence committed to construct the project. This construction period is dependent on the technology being developed and may range from less than one year to two years before commissioning of the site.

Onshore wind sites generally take in the region of one year to construct once the development process is complete, whilst technologies such as offshore wind and biomass plants may take up to two years to be commissioned. Some emerging technologies such as solar have considerably shorter timescales with construction being achieved in less than a year, with the more complex marine technologies having a longer timeframe, sometimes up to two years. The mature technologies such as landfill gas and sewage gas generally have much shorter construction periods of less than one year, however some hydro projects may have a longer construction period due to the higher proportion of capital expenditure needed for the buildings and infrastructure and may take in the region of two years to construct.

Appendix A

Ofgem ROC Register

Total ROCs issued from October 2005 to September 2006 (Ofgem)

Month and Year of Generation	Biomass	Biomass and waste using ACT	Co-firing biomass with fossil fuel	Hydro 20 MW DNC or less	Landfill gas	Micro Hydro	Off-shore wind	On-shore wind	Photo-voltaics	Sewage gas	Number of ROCs issued to date
October	86,436	703	263,490	207,317	339,991	4,742	49,729	273,289	0	27,094	**1,252,791**
November	76,721	617	329,770	237,077	341,820	5,283	53,882	256,526	0	25,725	**1,327,421**
December	88,602	780	274,949	192,608	357,267	4,978	49,160	239,003	0	28,510	**1,235,857**
January	86,790	680	339,209	207,250	359,892	5,405	48,833	245,279	1	26,310	**1,319,649**
February	77,431	983	492,124	148,896	326,724	3,846	55,140	253,956	2	26,389	**1,385,491**
March	84,317	1,009	350,835	151,436	358,083	6,021	71,694	300,075	67	28,360	**1,351,897**
April	94,439	786	125,457	192,326	345,368	5,579	52,288	310,432	7	28,327	**1,155,009**
May	92,388	963	106,693	152,752	360,339	3,968	63,618	289,487	17	29,896	**1,100,121**
June	83,661	980	104,590	101,309	335,635	2,723	33,891	193,013	34	28,397	**884,233**
July	84,227	959	116,246	92,020	327,790	2,890	38,293	158,529	32	27,615	**848,601**
August	80,442	1,144	107,386	94,403	338,664	2,746	65,084	207,358	21	27,577	**924,825**
September	47,536	1,447	120,171	147,559	335,800	4,668	44,826	253,362	16	26,236	**981,621**
Total	**982,990**	**11,051**	**2,730,920**	**1,924,953**	**4,127,373**	**52,849**	**626,438**	**2,980,309**	**197**	**330,436**	**13,767,516**

Appendix B

Industry Consultees

Arkady Feed (UK) Limited

Bical Limited

British Hydropower Association

Camborne School of Mines

CHPA Services Limited

DRAX Group PLC

Dulas Limited

E.ON UK PLC

ECO2 Limited

Ener-G PLC

HG Capital Trust PLC

Marine Current Turbines Limited

Novera Energy Limited

Ocean Power Delivery Limited

Postscriptum Limited

Renewable Energy Systems Limited

Renewable Fuel Supply Limited

RWE Npower Holdings PLC

Scottish and Southern Energy PLC

Scottish BioPower Limited

Scottish Power PLC

Solar Century Holdings Limited

South West Water Limited

Thames Water Utilities Limited

The Co-operative Bank PLC

The Energy Crop Company Limited

Viridor Waste Disposal Limited

We would like to place on record our thanks to the industry consultees in responding to this consultation

Appendix C

Reference Material

Additional Support for Marine Electricity Generation in Scotland, AEA Technology, October 2006

Bio Powerswitch, Imperial College London, May 2004

Biomass Sector Review, The Carbon Trust, October 2005

BWEA's response to the UK Government Energy Review, April 2006

BWEA and REA joint response to the Reform of the Renewables Obligation (Preliminary Consultation), 2006

Economic Analysis of Biomass Energy, DTI, December 2006

Eligibility of Energy from Waste, Ilex Consulting, March 2005

Evaluating the Sustainability of Co-firing in the UK, Themba Technology, September 2006

Extending ROC Eligibility to Energy from Waste with CHP, Ilex Consulting , September 2005

Future Marine Energy, The Carbon Trust, January 2006

Grid Integration Options for Offshore Wind Farms, DTI, December 2006

Oxera-work on energy review 2006

Policy Frameworks for Renewables, The Carbon Trust, July 2006

Potential for Micro Generation Study and Analysis, Energy Savings Trust, November 2005

Renewable Energy Country Attractiveness Indicies, Ernst & Young, 2006

Renewable Heat & Heat from CHP Plants – Study and Analysis, AEA Technology plc, 2005

Renewables Innovation Review, The Carbon Trust, February 2004

Renewables Obligation: Third Annual Report, Ofgem, 27 February 2006

Results of Renewables Market Modelling, OXERA, February 2004

RO-Low Cost Technologies, Enviros Consulting, September 2005

The Costs of Supplying Renewable Energy, Enviros Consulting, September 2005

The Economics of Co-firing, IPA Consulting, July 2006

Appendix D

Transmittal Letter

Private and confidential

Dr Michael Duggan 3 April 2007
Department of Trade and Industry
1 Victoria Street
LONDON
SW1H 0ET

Dear Dr Duggan

Consultancy support on the impact of banding the Renewables Obligation ("RO") at different levels

In accordance with Ernst and Young LLP's response, dated 13 November 2006, to the DTI tender ref: CCCK/003, ITT no 00949A and the terms and conditions agreed between Ernst & Young LLP ("E&Y") and the Department of Trade and Industry (the "DTI") we enclose our report which covers our findings in relation to the economics of renewable energy technologies (Part A of the tender).

Scope of Work

This report provides the DTI with the economics of the following renewable energy technologies:

Onshore Wind – Large	Sewage Gas
Onshore Wind – Small	Wave
Offshore Wind	Tidal
Landfill Gas	Solar PV
Biomass - CHP, dedicated biomass, energy crops	Micro CHP
Co-firing - regular & energy crops	ACT
Hydro – Large and small	

We have assessed the costs of installed generating capacity from each of the technologies listed above (and where applicable broken down into suggested sub divisions) and commented on how this is likely to change in the period between 2006 – 2020, with specific reference to likely costs in 2010 and 2015.

We have suggested how these costs might change over time to facilitate an assessment of the appropriate length of time any additional support should be provided for each technology through banding.

We have also considered the likely timescales for the development of each type of technology type, and key decision making points. This information will facilitate the consideration of

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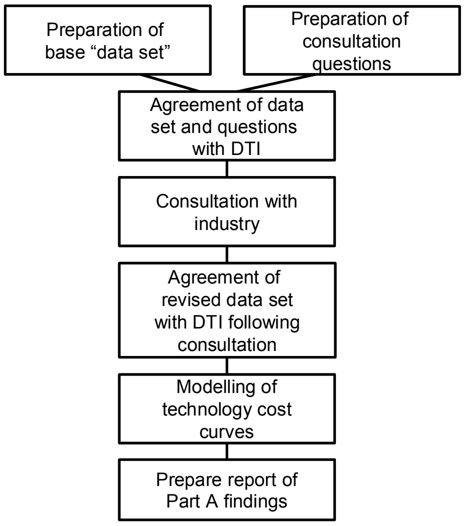
appropriate notice periods for any reduction in support, and the appropriateness of the possible options for grandfathering.

To calculate the levelised costs of each of the technologies we have used previous report commissioned by the DTI and other DTI specific information as well as Ernst and Young proprietary data to produce initial cost data, which has subsequently been validated in discussions with members of the renewable energy industry, in January and February 2007. We have used the validated cost and capacity data to derive a cost per MWh for each technology and to comment on how this might change over time. This is demonstrated in the following schematic:



Purpose of our report and restrictions on its use

This report was prepared on your instructions solely for the purpose of investigating the cost of generating facilities, their potential capacities and the deployment timescales of agreed renewable energy technologies to enable the modelling of different RO banding structures and should not be relied upon for any other purpose. In carrying out our work and preparing our report, we have worked solely on the instructions of the DTI and for the DTI's purposes. Ernst and Young accepts no responsibility or liability in relation to the report to any other party.

Our work has been limited in scope and time and we stress that a more detailed review of each of the technologies may reveal material issues that relate to the data in this report that this review has not.

Whilst making every reasonable effort to provide representative cost and capacity data using the above procedures it should be noted that the costs of renewable generation will vary from site to site and over time including exchange rate and interest rate movements and as such the data is this report is unlikely to reflect any particular project. As the cost of capital used in this report is a pre-tax figure, no allowance has been made for tax assumptions. Any party wishing to use this report for investment purposes should make their own independent appraisal of the data contained in the report.

Structure of the Report

Section 1: Executive Summary, providing an overview of the key findings of our report;

Sections 2 – 15: Technology sections, providing details of our assumptions taken, the results of the consultations undertaken and the levelised cost of power generation for each technology;

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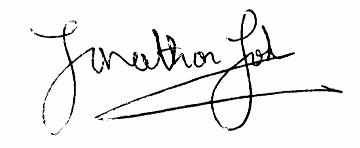
Section 16: PPA and Key Decision Points, providing current market PPA offerings and the key decision points for the implementation of technologies.

Our report is supplemented by Appendices providing further detail on various aspects of our work.

We would like to place on record the assistance that we have received from Michael Duggan and Georgiana Glaysher in the preparation of this report.

Yours sincerely



Jonathan Johns
Partner