Office of Gas and Electricity Markets

Assessment of the Benefits from Large-Scale Deployment of Certain Renewable Technologies

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Final Report

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CONTENTS

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ABBREVIATIONS AND ACRONYMS

CCC	Climate Change Capital
CCGT	Combined cycle gas turbine
CEPA	Cambridge Economic Policy Associates Ltd
CO_2	Carbon dioxide
COC	Cost of capital
DTI	Department for Trade and Industry
EAC	Equivalent annual cost
ETS	Emissions Trading Scheme
EU	European Union
GH	Garrad Hassan report
GW	Giga watts
IEA	International Energy Agency
KW	Kilo watt
KWh	Kilo-watt hour
MEC	Marine Energy Challenge
MW	Mega watt
MWh	Mega-watt hour
NPV	Net present value
OCGT	Open cycle gas turbine
PR	Progress ratio
RO	Renewables Obligation
ROC	Renewables Obligation Certificate

EXECUTIVE SUMMARY

This report has been prepared by Cambridge Economic Policy Associates and Climate Change Capital for Ofgem as a contribution to its thinking on renewable technologies.

We have been asked by Ofgem to assess the benefits to be derived from the large-scale deployment of certain renewable technologies. The technologies in question are onshore wind, offshore wind, and three marine technologies (tidal lagoon, wave and tidal stream).

The detailed methodology is set out in Section 2. In summary, for each technology we have:

1. Developed and used a financial model to estimate the trajectory of unit costs (progress curve) in the period to 2020 as cumulative installed capacity increases, using three methodologies to project costs forward.

2. Translated the results of the above into an assessment of the benefits (in terms of unit cost reductions) as aggregate installed capacity increases; and

3. Estimated the £/MWh premium over the cost of new CCGT plant that must be paid to each technology to enable it to earn the required return on capital[1] (the 'environmental premium').

Due to a lack of robust differentiating data, the models for wave and tidal stream technologies have been combined.

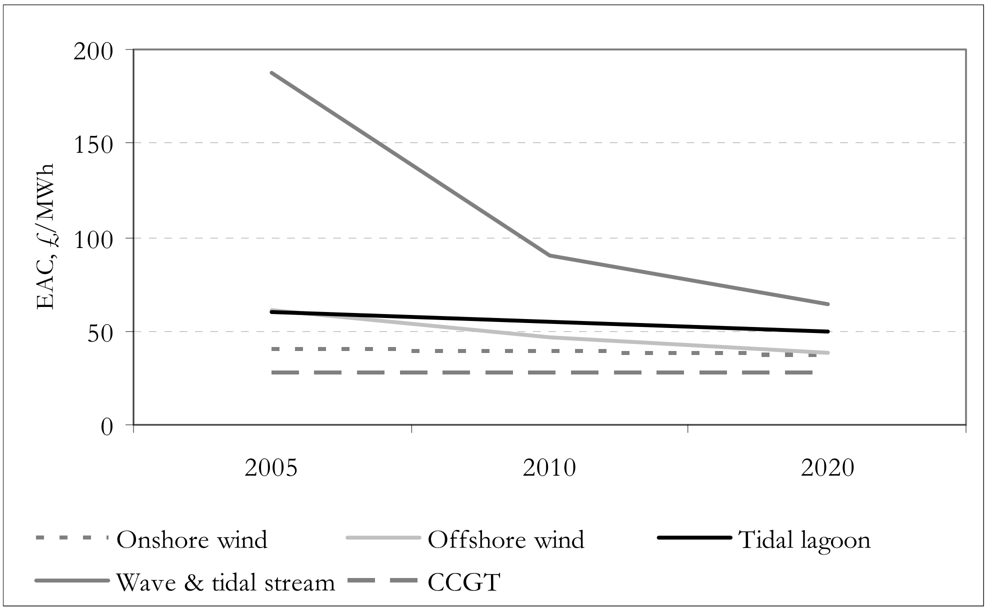
The estimation of progress curves is a useful way to consider the likely evolution of renewable energy production costs, and therefore the magnitude of environmental premia required to induce investment in those technologies. However, progress curves are inherently uncertain, particularly for pre-development technologies such as marine renewables. It is therefore important not to over-interpret the results or to draw conclusions that attribute greater robustness to the analysis than is warranted.

The most robust part of the analysis is the estimation of the current unit equivalent annual cost (EAC). The estimated base case current unit EAC for onshore wind is around £41/MWh, £62/MWh for off-shore wind, £60/MWh for tidal lagoons and £187/MWh for both wave and tidal stream technologies. These are central estimates for a 'typical' project. Actual costs will vary significantly.

[1] *Here i.e. 10% or 12%*

The 'best estimate' of the evolution of unit costs derived from the progress curves estimated in this report (Section 4) for each renewable technology considered and CCGT (assumed to be the marginal conventional technology) are summarised in Figure A.

Figure A: Summary of best estimates of unit cost evolution



The unit costs associated with each of the technologies are expected to decline as aggregate installed capacity increases. However, none of the technologies are projected to be able to compete with conventional generation, absent an environmental premium.

Figure B summarises, for each of the technologies, our estimate of the environmental premium in 2005 and 2020 assuming a growth of installed capacity consistent with achieving the government's renewable energy targets.

Figure B: Summary of estimated environmental premia, total subsidy required and CO_2 abatement costs

		Onshore wind	Offshore wind	Tidal lagoons	Wave / tidal stream
2020 assumed aggregate installed capacity, GW	Global	190.0	42.0	1.26	0.55
	UK	10.4	11.6	1.26	1.11
Environmental premium, £/MWh	2005	12.22	33.47	32.23	159.12
	2020	9.32	10.50	22.05	35.85
CO_2 abatement cost, £/tonne	2005	30.54	83.67	-	397.80
	2020	23.24	26.26	55.13	89.63

The environmental premium in 2020 is £9.32/MWh for onshore wind, £10.50/MWh for offshore wind, £22.05/MWh for tidal lagoons and £35.85/MWh for wave/tidal stream. Figure B also shows the implied CO_2 abatement cost for each technology. In 2020, the abatement cost for onshore wind is £23.24/tonne, £26.26/tonne for offshore wind, £55.13/tonne for tidal lagoons and £89.63/tonne for wave/tidal stream. By contrast, the current CO_2 price on the EU Emissions Trading Scheme (ETS) market is around EUR17.25/tonne (with the range since launch in January 2005 around EUR8-17.50.)

It is important to stress that the unit 'environmental premium' plus the wholesale energy price will not equal the cum-ROCs price for renewable energy. With the current ROC scheme, the ROC premium is determined by the cost of the marginal (most expensive) renewable capacity. This premium accrues to all intra-marginal producers.

It is also important to note that this report has calculated a total environmental premium for the renewable energy technologies which in reality in the UK market today would comprise:

- EU Emissions Trading Scheme allowance price;
- The climate change levy exemption;
- The ROC price;
- Any additional revenue support or grant aid such as that which the government has announced it will provide to wave and tidal projects in their demonstration phase.

Hence where the "ROC premium" is quoted in this report it should be interpreted as the total "environmental premium" and not the actual ROC price.

Total payments to induce investment in a diversified portfolio of renewables will be much higher than the sum of the environmental premia estimated for each individual technology. The report sets out order of magnitude estimates of the 'ROC premium' required if the portfolio of technologies shown in figure B is to be realised by 2020.

With the agreement of Ofgem, the report has limited its attention to the first round financial costs of deploying renewables, and does not provide a full social cost benefit analysis, although it does provide many of the inputs for such an analysis. In particular, if the EU Emissions Trading Scheme (ETS) were to continue, then there would be a financial benefit to the UK of reducing CO_2 emissions from the energy sector as it would reduce the opportunity cost of acquiring and using emissions allowances (trading in mid 2005 at nearly 20 Euros/tonne CO_2). More generally, a large part of the purpose of supporting the deployment of renewables is to hasten the date at which some carbon-neutral technologies become commercially competitive against conventional fossil generation, at which point a wider range of countries are likely to adopt the technology to the global benefit of reducing the threat of global warming. Finally, some of the price estimates for wind include an element of rent to landowners that is a transfer, not simply a resource cost.

1. INTRODUCTION

This report has been prepared by Cambridge Economic Policy Associates (CEPA) and Climate Change Capital (CCC) for Ofgem as a contribution to its thinking on renewable technologies.

We have been asked by Ofgem to carry out an assessment of the benefits (primarily of cost reductions) to be derived from the large-scale deployment of certain renewable technologies. The technologies in question are onshore wind, offshore wind, and three marine technologies (tidal lagoon, wave and tidal stream). The assessment is to examine the research and analysis currently available, to identify and seek to address any gaps and to quantify the benefits that could be expected from large-scale deployment of the technologies.

The report has been prepared over a six week period based on a review of publicly available information supplemented by additional information available to us on current renewable technology developments in the UK.

For this study, we have developed and used a financial model to estimate the trajectory of unit costs for each of the technologies as cumulative installed capacity increases. These models are available to Ofgem.

1.1. Background

The Renewables Obligation (RO), which came into force in 2002, is a key part of the UK Government's climate change programme. Under the RO, electricity suppliers are required to source a minimum percentage of their electricity from renewable sources (or to make a 'buy-out' payment). The target is for the percentage of electricity generated from renewable sources to increase to about 10% by 2010 from just 3% in 2002/03. Further increases in the target to around 15% in 2015 and 20% in 2020 are provided for in the Renewables Order 2005. Ofgem has responsibility for administrating the scheme.

Currently, by far the largest contributor to the RO scheme (in terms of number of RO certificates (ROCs) issued) is generation from landfill gas. However, increasing wind generation – both onshore and offshore wind – is expected to be crucial to meeting the Government's 2010 target. In addition, there is significant potential for the use of marine generation technologies. The UK has some of the best natural resource for wave and tidal technologies in the world and is at the cutting edge of research and development in the field[2]. However, most of these technologies are still in the pre-development stage and few are expected to be deployed on a commercial scale before 2010

Currently, neither wind nor marine generation technologies are competitive with conventional fossil fuel technologies. The reasons for this are diverse, but include the fact that the environmental costs of fossil fuel technologies are not adequately taken into account in the market price for energy[3] and that the nascent stage of wind and marine technologies means that unit costs are high, as are the risks of deployment. It is reasonable to expect, drawing on experience of other technologies, that as these new technologies mature and installed capacity increases that their unit costs will fall substantially.

To the extent that these renewable technologies have the potential to be competitive in the long term (when environmental costs are properly taken into account), there is a case for government intervention to foster investment to enable the industries to reach a scale of deployment where their unit costs are commercially competitive with fossil fuel generation technologies. To this end, various government support schemes including the RO scheme provide for payments to producers of qualifying renewable technologies, ultimately financed by energy consumers. Ideally, these payments (referred to here as the 'environmental premium') should be sufficient to cover the difference between the market price for conventional generation and the unit costs of the renewable technology in question, thereby inducing investment in them. However, the payments should decline over time as the benefits of learning by doing, economies of scale and other factors reduce unit costs.

The central tasks of this study are to assess:

- The current estimated unit costs of each technology;
- The possible unit cost reductions achievable by each technology over time as cumulative installed capacity increases; and
- The implied magnitude of the 'environmental premium' over time for each technology as cumulative installed capacity increases.

It should be recognised that large-scale deployment of renewable technologies can be expected to have a variety of benefits over and above reducing unit costs. For example, these might include lower emissions, diversification of the generation mix, and fostering expertise in the UK. They may also generate external costs, for example the need for additional conventional standby generation, the need for additional investment in grid

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[2] *DTI (February 2005), 'Renewables Innovation Review'*

[3] *Despite CO2 being explicitly costed via the Emissions Trading System (ETS)*

reinforcement[4] and potentially in distribution networks, and/or environmental costs (e.g. impairment of rural scenery).

It has been agreed with Ofgem that consideration of these factors (and a full social cost-benefit analysis of the programme) is beyond the scope of the current limited assignment. If Ofgem so wish, we could extend the analysis to consider these wider factors quantitatively in subsequent work.

1.2. Technologies covered

Figure 1 provides a brief description of the five renewable technologies included in this study. There is a multitude of marine generation technologies currently under development. The three examined here have been chosen to provide a representative suite of technologies that are widely believed to have potential going forward and for which approximate data and information are available.

Figure 1: Technologies covered

Technology	Description
Onshore wind	Wind turbines sited on land
Offshore wind	Wind turbines sited at sea
Tidal lagoon	A system that involves the impoundment of water due to the rise and fall of the tide and the controlled release of that water through hydro power turbines for the generation of power during rising and falling tides
Wave	The extraction of energy from waves
Tidal stream	The extraction of power from the flow of the tidal stream

During the course of this work, we decided to combine the models for the wave and tidal stream technologies. This is clearly a major simplification. However, both technologies are at a very early stage of development and reliable information on both is very sparse. They face similar challenges and not very dissimilar cost drivers. We concluded that there is insufficient data to differentiate between them in a robust way for modelling purposes.

[4] *It is important to note that if reliability and access to the grid are priced appropriately then these costs could be internalised.*

2. METHODOLOGY

2.1. Overview

For each of the five selected renewable technologies we have:

(i) Estimated the current unit generating costs on an equivalent annual cost (EAC) basis for a typical 'good practice' project;

(ii) Estimated progress curves using a 'bottom-up' approach to determine the future evolution of unit costs as aggregate installed capacity increases, and crosschecked the results against evidence from the literature and the application of 'top-down' progress ratios;

(iii) Translated the results of the above into an assessment of the benefits (in terms of unit cost reductions) as aggregate installed capacity increases; and

(iv) Considered the implications for the 'environmental premium' of the preceding analysis for each technology.

The methodology used is summarised in figure 2.

Figure 2: Summary of methodology

Assessment of costs today	• Literature review • Gap analysis • Gap filling	• Assumptions • Calculation of equivalent annual costs (EAC)
Determine range for progress curves	• Determination of relevant factors • Construction of 'bottom up' progress curves	• Construction of 'top down' progress curves • Assessment of current consensus on progress curves in literature
Assessment of benefits	• Assessment of benefits at various levels of deployment • Consideration of implications of speed of roll out	
Consideration of 'environmental premium'	• Plot progress curves against CCGT progress curve • Is the renewable technology likely to become competitive?	• If so, at what level of capacity? • Implications for subsidy and consumer bills

The availability of information to undertake the analysis differs significantly across the technologies. For onshore wind, the most mature of the technologies considered, there is robust information both on current unit costs and installed capacity and historic information on how unit costs have evolved over time as cumulative installed capacity increased. For offshore wind, now in the early stages of development in the UK, there is robust information about current unit costs and current/planned installed capacity, but relatively little information about the historic evolution of costs. For the wave and tidal technologies, all in the pre-development stage, available information about current unit costs are mostly feasibility study estimates, which are subject to considerable uncertainty. There is no historic time-series information for these technologies; hence their estimated EACs and progress curves are necessarily more subjective and more uncertain than for onshore and offshore wind.

In undertaking the analysis, we have adopted 'standard' sector assumptions, where appropriate, and derived technology-specific assumptions from publicly-available information and our own knowledge of the sector. Our assumptions, and the rationale for them, are set out in Section 3 of the report.

2.2. Estimating current equivalent annual costs

The measure of equivalent annual costs (EAC) that we have used is the average real cost per unit of electricity generated by a scheme over its expected project life. We have computed the constant real price per unit of output, which generates a post-tax return on capital equal to the assumed nominal cost of capital. This measure permits comparison of technologies with differing profiles of capital and operating expenditure, different load factors and different project lives.

The first step in estimating the EAC for each of the technologies is to determine the capital and operating costs, load factor and project life. We have adopted assumptions representative of stylised 'good practice' projects. In reality, costs and load factors for many of these technologies are rather location specific. To address this reality, we use central, high and low estimates of the EACs and represent them as a range, with a central tendency (most likely). The ranges are wider for the marine technologies, reflecting the greater uncertainty.

We have made a number of standard assumptions to estimate the EACs.

- ***Tax losses***: For ease of exposition, the owner of the project is assumed to have sufficient tax capacity to utilise all tax losses in the year in which they are incurred[5].

[5] *A social cost-benefit analysis would regard tax as a transfer payment, not an opportunity cost. We have chosen to treat tax as a cost because the focus is on costs from a private sector perspective. It would be simple to re-run the models*

For early stage projects for new technologies this may not be the case (although the development of offshore wind power to date suggests that it might be), and therefore the EAC calculated may be slightly lower than would be the case for a project owner without tax capacity.

- ***Debt***: For simplicity, where debt is included in the model, it is included solely for the purposes of modelling an appropriate tax shield from the interest payments. The model does not check that the project has sufficient debt capacity for the amount of debt being used to calculate this shield. Therefore, debt capacity is an exogenous variable in our analyses, rather than an endogenous function of the costs and revenues of the projects. This does not make a significant difference to the EAC calculated by the model, but it does mean that the EACs should not be regarded as the 'required price' to enable financing of a project.

  Further, the debt tax shield is discounted at the cost of capital for the assets as a whole (rather than the cost of debt) and hence potentially under-estimates the value of the debt tax-shield for the project. The reason for this is that, for all the technologies considered with the exception of onshore wind, there is significant uncertainty about the amount of tax that would be payable and therefore about the value of the tax shield. This assumption does not necessarily hold for onshore wind, but for consistency we have employed this assumption for all the technologies considered.

- ***Working capital***: The working capital requirement is estimated based on an assessment of the number of days of working capital required at the start of the project, which is then released at the end.

- ***Cost of capital***: For ease of interpretation and to ensure comparability across technologies, we have assumed a constant real cost of capital over time. For onshore wind, the most mature of the technologies considered, we assume a cost of capital of 10%, whilst for the remaining technologies, which are less mature, we assume a cost of capital of 12%.[6] This is a somewhat artificial assumption because in reality perceived investor risk of any technology reduces over time and as installed capacity increases – and the cost of capital therefore can be expected to reduce over time. Similarly, the perceived investment risk of early stage, pre-development technologies,

treating tax as a transfer payment should Ofgem so wish. It is also relevant to note that companies investing in conventional fossil technologies operate under the same tax regime assumed here for renewables, and so the comparisons are like for like, and to that extent the comparisons are unlikely to change much under a full social cost-benefit analysis.

[6] As is standard in financial analysis, all financial costs are in nominal terms to properly capture the tax treatment of debt and equity. The "cost of capital" is the weighted average cost of capital, or WACC.

e.g. wave and tidal, is much greater than that of mature technologies such as wind and fossil fuel generation. Hence the cost of capital will differ across technologies at different stages of maturity to a greater extent than assumed here. However, varying the cost of capital over time and across technologies would materially complicate the interpretation of the analysis. Therefore, we have used a standard cost of capital assumption; and note that further work would be needed to take account of changes in the cost of capital over time and differences across technologies.

It is important to note again that the computed EAC is unlikely to correspond closely to the price for renewable energy required in the market (energy prices plus ROCs) if these technologies are to be financed.

An EAC is assumed to have a certain value over the lifetime of a project in a way which supports optimum amounts of debt and equity financing. The mechanism by which the subsidy is distributed will often affect the ability of companies to achieve this optimum and hence to finance projects at the rate required to achieve the assumed cumulative capacity build-up.[7]

It is well known that there are deadweight costs inherent in such systems as ROCs. The cum-ROCs market price required to induce investment in a portfolio of renewable technologies will tend to approximate the EAC of the marginal unit of renewable capacity (generally the most expensive unit).

The environmental premium is calculated assuming that tax costs are incurred by producers of conventional and renewable power generation. Thus although this is not a full social cost-benefit study, it is not misleading to take the current tax system into account when comparing costs within the same privately owned generation sector.

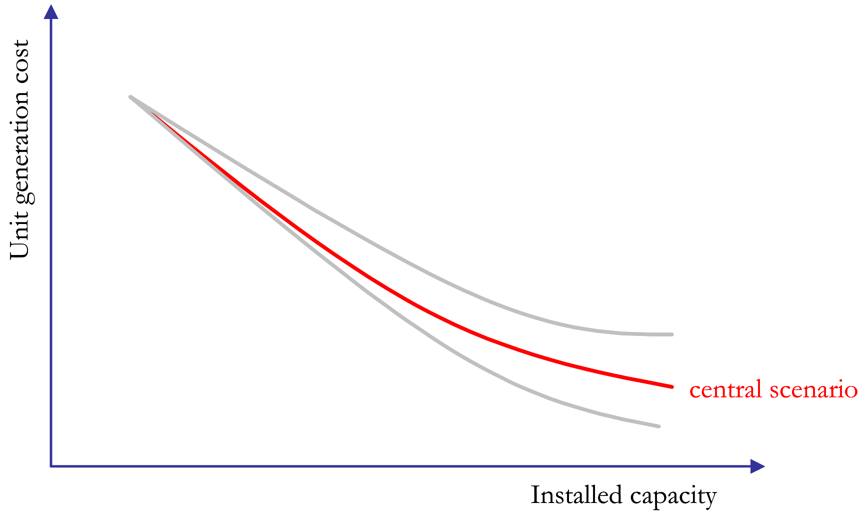
2.3. Estimating progress curves

Progress curves describe a relationship between unit production costs and aggregate installed capacity for a technology (Figure 3). They are widely used to assess and represent the extent to which unit costs of a new technology can be expected to decline as it matures and is increasingly deployed. There are two types of progress curve: (i) top-down progress curves and (ii) bottom-up progress curves (both explained further below). In this report we focus on the bottom-up approach. This is because, with the exception of onshore wind, there is insufficient historic time-series data to enable meaningful top-down progress curves to be computed. In the case of onshore wind, where data is available, there are several existing

[7] An EAC is equivalent to a feed-in tariff for instance – which the UK Renewables Obligation clearly is not. For the same nominal value of ROC and feed-in tariff the feed-in supported tariff will provide the cheaper financing option.

studies that estimate the top-down curves, which we report and use to 'sanity check' our bottom-up estimates.

Figure 3: Estimated progress curve for new technology



2.3.1.

2.3.2. Top-down progress curves

Top-down progress curves estimate an empirical relationship between historical costs (or sometimes prices) and cumulative installed capacity (or other appropriate measure of the size of the industry). The standard has become to consider the percentage reduction in unit costs for each doubling in the installed base of units, using a log-linear formulation of the type shown below.

$$C_{C_{cum}} = C_0 C_{cum}{}^{b}$$

where PR = 2^b and LR = 1 – PR,

$C_{C_{cum}}$ is the unit cost at installed capacity C_{cum}, C_0 is the cost of the first unit, PR is the progress ratio and LR is the learning rate. For example, a technology whose unit costs decline by 10% for each doubling in installed capacity has a learning rate of 10% and a progress ratio of 90%. The higher the learning rate / lower the progress ratio, the steeper the progress curve shown in figure 3, i.e. the quicker unit costs will fall as deployment doubles. Throughout the remainder of this study, we refer to the 'progress ratio' rather than the 'learning rate'.

The top-down approach establishes a statistical relationship between two historic data series. The resulting progress ratio is then extrapolated forward to estimate future unit costs as cumulative installed capacity continues to rise; the rationale being that, for many technologies, "*a constant [percentage] cost decline has been observed … over several orders of magnitude of cumulative capacity*" [8].

Discussion of top-down progress curves

Although top-down progress curves have been widely used, there are significant problems with deriving robust results:

- ***Logarithmic function***: Of perhaps greatest concern is the logarithmic nature of the progress curve function. In aggregate, cost elements of renewable energy technologies are not logarithmic in nature. Indeed, there are number of factors that are clearly not logarithmic with installed capacity. For example, wind speed is a major factor in determining the EAC but it has no logarithmic relationship with aggregate installed capacity. Consequently, small variances in assumptions can lead to variances in predicted costs that are significant for both the developer of the technology and policy-makers. This can be addressed to some extent by considering the underlying physical constraints on the technology imposed by e.g. the laws of thermodynamics, and considering progress towards an underlying irreducible cost estimate. One should not underestimate the difficult of identifying this asymptotic state.

- ***Starting position***: The observed progress curve is highly sensitive to the starting point assumed. The starting EAC is likely to be very uncertain in the demonstration phase of a new technology and so projecting forward progress ratios from a highly uncertain starting point can lead to a wide range of possible future outcomes. This issue is of particular relevance for nascent technologies such as marine generation technologies, where the only available data relates to the demonstration period. Again, this difficulty can be addressed given sufficiently many observations, for all that is required is an improved estimate of the current position of the progress curve and the current best estimate of the rate of progress.

- ***Empirical evidence***: Linked to the above, is the fact that the literature is lacking in predictions based on this type of analysis that have actually materialised. In particular, the literature on the prospects for the costs of renewables appears to be relatively uninterested in the past failures of progress curve analyses and to ignore

[8] *Gielen et al (2004)*

non-cost effects that might have a significant impact on the price required by new renewable technologies.

- Unforeseen events that are not reflected in historical data, can affect the eventual unit cost of a given technology. For example, in the nuclear power industry, the additional costs arising from changes in the regulatory regime in such areas as safety, waste disposal and decommissioning have made past cost predictions very inaccurate. Similarly, onshore wind planning constraints and the capture of rents by landowners at consented sites may push up the price (although not necessarily the resource cost) required to develop proposed investments. One should properly distinguish between the *cost* of the technology, and its performance in any site (i.e. the wind resources available there).Given these reservations, we have avoided placing much reliance on top-down progress curves other than for onshore wind.

2.3.2 Bottom-up progress curves

Bottom-up approaches to estimating unit cost reductions as capacity installed increases aim to overcome the drawbacks of the top down progress ratio approach by looking in more detail at the cost characteristics of each specific technology. These approaches do require a number of assumptions to be made, the robustness of which, and sensitivity of the results to which, need to be understood carefully before the results are relied upon unduly.

The methodology used by us is to estimate 'bottom-up' progress curves for each of the technologies as follows:

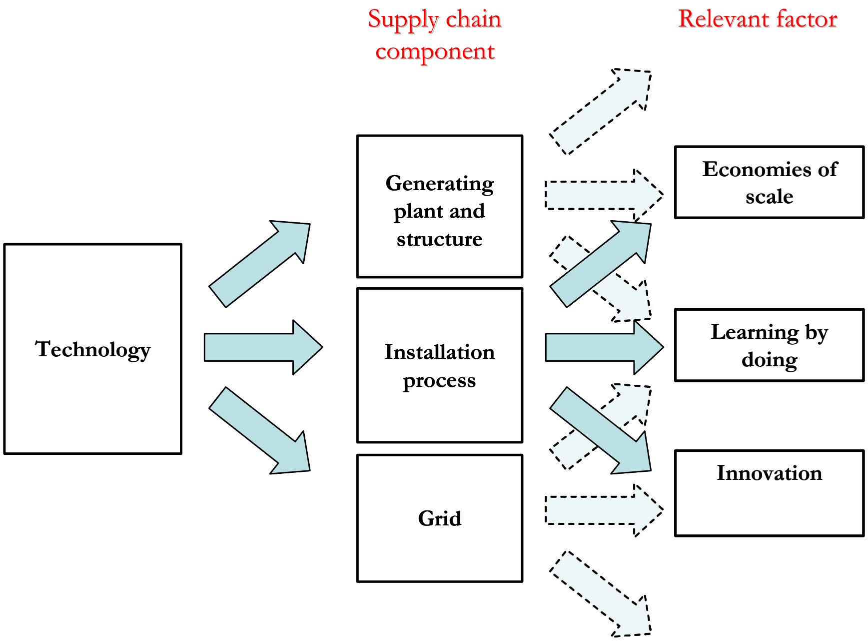
- The supply chain for each technology is broken down into its component parts;

- Relevant factors determining progress are identified and their impact on each of the supply chain components for each technology is considered;

- The progress curve is determined starting from the estimated EAC and then modelling the evolution of costs by quantifying the impact of each relevant factor on each of the supply chain components as aggregate installed capacity increases;

Figure 4 illustrates the methodology.

Figure 4: Methodology for estimating bottom-up progress curves



The bottom-up analysis applies judgements to the potential cost savings that may occur in each technology considered over the period to 2010 and 2020 given the predicted build out in the industry, with high and low scenarios being developed for each case[9].

We have relied on three sources of evidence about the likely progression of unit costs when undertaking the bottom-up progress curve analysis:

- ***Consensus view in literature***: For onshore and offshore wind, where robust current literature is available, we conduct a thorough review of the relevant literature to establish the current consensus view about the potential for cost savings for each technology as installed capacity increases.

- ***Supply chain component progress ratios***: For each technology, we apply a progress ratio to each individual component of the supply chain to provide an assessment of the progress curve for the technology as a whole. The progress ratios used are based on evidence provided in the literature. .

- ***Progress curves for other industries***: Evidence from the literature on progress curves in unrelated but relevant industries is compiled and used as a 'sense check' of our estimates for the renewable technologies (see Annex 1).

[9] *This step requires assumptions about the growth of installed capacity worldwide and in the UK. The assumption for the UK assumes that the RO targets are met.*

The relevant factors

The relevant factors used in conducting the bottom-up analysis are:

- ***Learning by doing***: Experience in carrying out specific tasks, e.g. manufacture and installation of component parts, often results in cost savings as past mistakes are learned and the labour force and contractors accumulate knowledge and experience. In other words, it is usually quicker – and therefore cheaper – to produce / install the last unit in a series than the first.

- ***Economies of scale at the project level***: Increasing the scale of production at the project level often results in significant reductions in unit costs. These take a variety of forms: technical economies of scale arising from the need to use fewer physical inputs per unit of output for larger facilities (e.g. larger wind turbine units, larger tidal lagoons); and commercial economies of scale arising from lower costs per unit of output when contracting installation services (e.g. barge unit rentals decline for larger installation orders).

- ***Economies of scale at the industry level***: As the size of the industry increases, industry-wide economies of scale are generated consequent upon improved supply chain management, economies of scale in the production of inputs and the provision of contracted services. In this regard, whether the market is purely domestic or more truly international is a significant factor influencing the extent and pace at which these economies of scale can be realised. For instance, the wind turbine market is clearly global. Many of the technology elements have global cost drivers and there are considerable spillover effects from earlier progress in the industry elsewhere (in particular from Denmark and Germany). In offshore wind and marine technologies, in contrast, the UK is a pioneer and so there are no comparable spillover benefits that the UK can take advantage of.

- ***Technology innovation***: Successful research and development shifts the technological possibility frontier outwards, sometimes leading to stepwise improvements in unit costs. Consequently, technology innovation can result in unpredictable discontinuities in the progress curve.

  There is clearly a grey area between technology innovation on the one hand and learning by doing on the other, as experience in performing a task may result in a new, more efficient way of doing something. We regard incremental improvements in methods for performing a task to be learning by doing, and more fundamental shifts in the technology used as technology innovation.

- ***Quality***: When considering progress curves, it is important to consider any change in quality resulting from learning by doing and/or invention and innovation; otherwise the true reduction in unit costs for a given technology will be understated. This is clearly of particular importance for 'hi-tech' industries, where technologies often evolve rapidly. For electricity generation technologies, however, quality is less of an issue as, from a consumer's perspective, there is little variation in the quality of the output. Quality is not, therefore, considered explicitly in the analysis.

  However, it should be noted when comparing renewable technologies with each other and with fossil fuel generation that there is one important aspect of quality that does vary between technologies. Wind energy is intermittent, i.e. cannot be relied upon to be available at any given time (because the wind might not blow), whereas other renewable technologies and CCGTs offer much 'firmer; (i.e. more reliable) output. Firm energy is more valuable than intermittent energy because less stand-by capacity (either OCGTs or spinning reserve) is required on the system.

- ***Other industries***: The renewable energy industry may benefit from spill-over effects from other industries. This has not been explicitly considered in this report. For instance the photovoltaic industry has and will probably continue to benefit from the expansion in the capacity of the semiconductor industry in general. To some extent this shows up in the difficulty of defining the relevant installed base. Thus is the installed base for PV the kW of PV installed to date or the volume of chips produced?

- ***Other***: In conducting our analysis, we have also considered a range of other factors that might be expected to impact unit costs as a technology is deployed, including: (i) improved linkages within the industry (e.g. between R&D, manufacturers and policy makers) that enable more rapid dissemination of ideas and learning, and (ii) any contradictory factors (e.g. planning constraints) that might be expected to push up the unit cost of a given technology as installed capacity increases.

2.3.3. Comments on progress curve methodology

A number of comments about the methodology used are necessary:

- Progress curves, especially when estimated for nascent technologies, are both subjective and uncertain. The use of single point estimates can give the invalid impression of greater confidence than can be justified by the facts.

- In particular, the point at which the progress rate decelerates as a technology matures is very difficult to predict. The standard assumption of a constant rate of progress as cumulative installed capacity doubles is unlikely to be valid across a large range of installed capacity for all technologies (e.g. onshore wind progress ratios are expected in future to be significantly lower than in the past).

- When 'progress' starts is clearly a function of when schemes can be financed. Where 'early stage' development costs are very high, they may not get financed and the start of the 'progress' will be deferred (unless there is a global market in which case domestic delay results in future accrual of 'free' spillover benefits arising from progress elsewhere).

- Some in the literature also point out the merits of a progress curve approach which recognises that some costs are irreducible and hence that the progress generally occurs between today's price and the irreducible minimum.

2.4 Assessing the benefits of large-scale deployment

The results of the analysis for each technology have been synthesised to provide:

- A 'bottom-up' central, high and low case progress curve based on the application of progress ratios to components of the supply chain.; and

- A 'top down' progress curve based on the current literature, when available.

From these, we derive our best estimate for each technology of the central, high and low case progress curves, providing our rationale in each case. From these curves we then derive a quantitative assessment of the benefit in terms of reduced unit costs arising from increases in cumulative installed capacity of each technology expressed as a reduction in the £/MWh unit cost from the start point (EAC).

2.5 Implications for the environmental premium

The final step in the analysis is, for each technology, to estimate the 'environmental premium'. This is defined to be the excess of the EAC for each technology over the EAC of the marginal conventional generating technology, assumed to be combined cycle gas turbines (CCGT). Conceptually, the environmental premium is the additional amount per MWh that needs to be paid to the relevant technology over and above the CCGT EAC to enable it, on the stated assumptions, to earn the assumed return on capital.

As noted earlier, to take this step we need to make assumptions about the rate of growth over the period to 2020 of the installed capacity, globally and in the UK, for each technology.

Having computed the environmental premium over the period to 2020, we then consider for each technology:

- Whether there is a level of installed capacity at which the environmental premium becomes zero;
- What the annual environmental premium would need to be at 2010, 2015 and 2020 as global and UK installed capacity grows;
- The monetary value of the environmental premium, being the product of the £/MWh premium and the volume of output from the installed capacity; and
- The implied carbon abatement cost expressed in £/tonne carbon.

Finally, we estimate the magnitude of the monetary value of the environmental premium taking account of the deadweight costs of the ROCs scheme.

For the purposes of this analysis, we assume that the marginal conventional technology is CCGT gas-fired plant. CCGT is clearly the right comparator for the next 20-25 years. Whether it remains appropriate beyond 25 years is uncertain. When calculating the environmental premium for technologies some 10 or 15 years from now (whose project lives run for another 20 years beyond that), it may be that CCGT is not the right comparator. However, it is beyond the scope of this work to explore this further.

Given the uncertainty associated with future CCGT unit costs, we derive three CCGT progress curves representing high, medium and low cost scenarios. The scenarios are driven by (i) the assumed gas price and (ii) assumed unit cost reductions resulting from the relevant factors discussed earlier. The gas price scenarios considered are low (20p/therm), medium (25p/therm) and high (30p/therm), which we believe span a reasonable range of forecasts. The future gas price is assumed to be flat in real terms over the time period considered (to 2020)[10]. For the high and medium cost progress curves, we make the conservative assumption that no further reductions in unit costs are likely to be forthcoming for new CCGT plant[11]; while for the low cost CCGT scenario we assume further unit cost reductions of 1% per annum. Details of the calculation of the EAC and progress curves used for CCGT are set out in Annex 2.

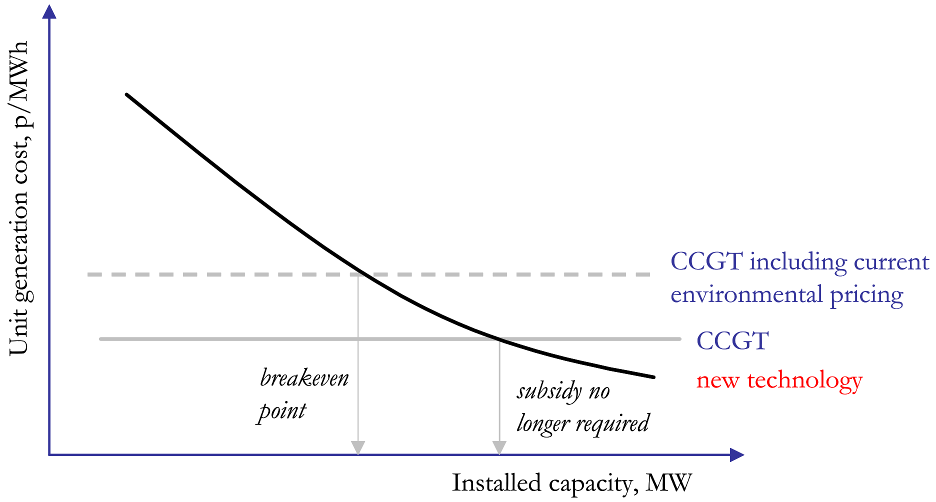
Figure 5 below illustrates the approach taken. A technology becomes globally competitive with CCGT at the point at which its progress curve (solid black line) crosses that of CCGT

[10] *The current forward price for gas in the UK, when oil prices are about US$50/barrel, is around 30p/therm.*

[11] *This is a very conservative assumption. Even if there were no improvements in thermal efficiency of the marginal plant, as all inefficient plant is replaced by more efficient new gas plan, further average efficiency gains are certain.*

(solid grey line). Until aggregate installed capacity exceeds this, and in the absence of conventional technologies being forced to take account of their environmental costs (as they are within the EU under the current ETS), some type of subsidy for the new technology is required. If conventional generation technologies are forced to take into account their environmental costs (as they are under the ETS), raising their unit costs and hence the progress curve, then the new technology becomes competitive at a lower level of deployment (at the point at which the solid black and broken grey lines cross), but with correspondingly higher consumer prices. A more detailed methodology is provided in Annex 4.

Figure 5: Assessing the implications of the environmental premium



From the information contained in figure 5 above, we estimate the total payments that must be made to producers of each technology at different levels of installed capacity to induce the assumed level of investment in those technologies, ie the monetary value of the excess of the costs of the renewable technology over the cost of the marginal conventional technology (the 'environmental premium').

The final step in the analysis is to calculate the cost of carbon abatement implied by the estimated environmental premium. This is done by translating the premium per MWh into a cost per tonne of carbon dioxide abated by dividing the estimated environmental premium by 0.4, the number of tonnes of carbon dioxide emitted by a CCGT plant in the production of 1MWh of electricity[12].

[12] *The carbon abatement cost is calculated on the basis of CCGT plant being displaced for consistency with the rest of this study. If the cost were calculated on the basis of coal displacement, then the implied abatement cost would be lower as coal plant emits 1 tonne of* CO_2 *per MWh of electricity produced compared to 0.4 tonnes for CCGT.*

3. BACKGROUND AND ASSUMPTIONS

This section sets out the standard sector assumptions and technology-specific assumptions used in the analysis. As discussed in section 2.1, these are based on a combination of publicly-available information and our own knowledge of the sector. In each case, the rationale for the assumption is given.

The standard sector assumptions, which are common to all five of the technologies considered, are set out in Figure 6 below; while the technology-specific assumptions follow in the relevant subsection. A more detailed statement of the assumptions is set out in the supplementary Excel spreadsheets.

Figure 6: Standard sector assumptions

	Assumption	Basis for assumption
Tax		
Tax rate, %	30%	UK corporate tax rate
% capex allowable	90%	Allows for fact that not all capital expenditure is allowable for tax purposes
Allowable rate (declining balance), %	25%	Basic allowance for capital goods
Annual inflation, %	2%	UK target inflation rate
Cost of capital, constant nominal %	All except onshore wind: 12% Onshore wind: 10%	The lower rate for onshore wind reflects the greater maturity / lower risks of the technology.
Debt proportion, % (debt/total capital)	All except wave & tidal: 65% Wave & tidal: 40%	Expected capacity for relatively secure infrastructure cash flows (onshore wind farms in the UK usually sustain this level of debt or more). Note, for technologies in the early stage of development like wave and tidal stream, it is unlikely that significant debt can be put in the capital structure
(Nominal) debt interest rate, % p.a.	7% constant	150 to 200 bps over approximate LIBOR forward curve – broadly consistent with observed rates in the wind industry. The sensitivity analysis uses a range of 5-10%.
No. days working capital	45	Consistent with power off-take arrangements
Other charges (e.g. finance etc), % capex	5%	General allowance for other costs

3.1. Onshore wind

3.1.1. Background

There are currently around 45GW of onshore wind capacity installed worldwide[13], and this is anticipated to grow to close to 200GW by 2020. UK onshore wind installed capacity is currently 820MW, with a growth rate of 28% achieved in 2004. The UK ranks as sixth in the EU wind market and seventh world-wide, the leaders being Germany and Spain with 15.2GW and 6.6GW installed capacity, respectively. Scotland has seen the majority of development in the UK with just under half of the total UK capacity, and inclusion of current consented and in-construction projects increases this share to over 65% of all UK capacity. Development is dominated by large utilities and professional developers, with Scottish Power, SSE Generation Ltd., Airtricity and npower (National Wind Power) each having portfolios of projects (known projects in all stages of development) of over 1.2GW.

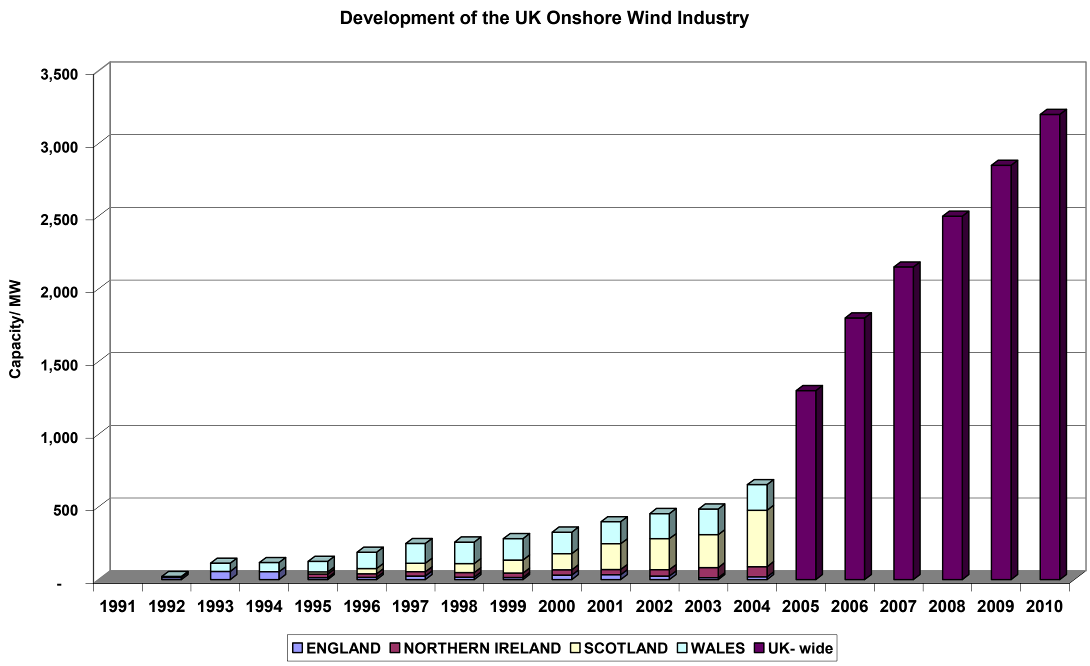
Growth in UK onshore wind has been steady over the last few years, and is predicted to grow more rapidly in the future, as the chart below illustrates (Figure 7). 2005 is expected to be a record year for the industry, with total installed capacity increasing to just under 1.3GW.

Known plans for onshore wind projects in addition to the 820MW of operational capacity, amount to 680MW currently in construction, close to 1.3GW consented and awaiting construction, 5.7GW in the planning process, and a further 9.5GW which is at scoping or preliminary consultation stage. By 2010, UK installed capacity is expected to be around 3.2GW. Both empirical evidence to date and practical constraints of grid and planning indicate that only a limited proportion of this potential stands to be completed under present conditions.

The industry has seen significant cost reductions over the past 20 years, driven by the growth in the size of turbines and the general growth in the industry.

[13] *Source: Wind Power Monthly January 2005*

Figure 7: Historic and potential future development of UK onshore wind



Source: CCC

3.1.2. Literature review

There is a significant body of publicly available information on the evolution of costs in onshore wind and related energy technologies, both in the academic literature and from industry sources.

There are also several studies that estimate top-down progress curves for the onshore wind industry, and other energy and related industries. Junginger et al (2005) provide an excellent overview of progress curve theory and the relevant data for onshore wind. They illustrate the potential for cost savings from project scale by showing the percentage of unit list cost for which turbines can be bought as a function of the number of turbines in the order – 100 turbines per order give a price of less than 70% of the individual list price for Vestas V47, according to their analyses.

Junginger et al (2005) also summarise the results of other authors on progress curves for onshore wind capital cost as a function of capacity built, and show that the range of historical progress ratios in the literature is 85% to 96%, i.e. unit costs have fallen by 4-15% for each doubling in capacity. They further illustrate geographical differences, showing a 91% progress ratio for Germany for a period before a plateau in the cost curves, and progress ratios of 81% for the UK's early small wind farms and between 82% and 85% for larger Spanish wind farms.

Other studies of relevance include IEA (2000), which estimated a progress ratio for wind energy technology in the EU for 1980-1995 of 82%; Madlener and Schneider (2004), Neij (1999) and Ibenholt(2002), which suggest progress ratios in the range 92% to 101% for onshore wind[14], but also quote recent studies by Junginger suggesting progress ratios of 77% to 88%. The final report for the Admire Rebus project in 2003 assumed a 90% progress ratio for onshore wind in Europe; Durstewitz (2003) for the IEA estimated progress ratios across various countries in the range of 87% to 94% for the 'sold cost' of turbines, and 91% to 96% for the installed cost of onshore wind turbines; and EWEA (2004) estimates that progress ratios in the range of 83% to 91% are appropriate for wind power systems. It is clear that, even for European onshore wind, there is a wide range of values estimated for the progress ratio based on historical data.

Garrad Hassan (2003), a study undertaken for the DTI Innovation Review, takes a prospective approach to determining progress curves, similar to the one used in this study. Their report concludes, based on a review of the available data, that for certain large components of wind energy costs a progress ratio of 90% is appropriate, suggesting that overall progress in the onshore wind industry over the next 15 years is likely to be relatively low.

3.1.3. General production assumptions

Figure 8 lists the general production assumptions used throughout the onshore wind analysis. Additional assumptions used to estimate current unit EAC and for each approach to estimating the progress curve are then set out in the subsequent subsections. Further details of the assumptions used are provided in the companion Excel spreadsheet, 'Onshore wind model.xls'.

Figure 8: Production assumptions - onshore wind

	Assumption	Basis for assumption
Load factor, %	30%	Acceptable average for a good wind site and consistent with the literature. Sensitivity analysis is conducted on the range 25-33%.
Project life, yrs	20	Life generally used in industry analysis
Debt, max. life, yrs	15	Consistent with significant infrastructure projects

[14]*Progress ratios of above 100% imply that unit costs actually rise as installed capacity increases. The rationale for this is that one or more components of the supply chain becomes constrained, e.g. availability of high potential sites, grid, and so cost increases in the constrained component(s) outweigh any reductions in cost experienced elsewhere in the supply chain as deployment rises*

3.1.4. Current unit EAC

The current references with respect to onshore wind are the Oxera (2004) and Garrad Hassan (2003) studies conducted for the DTI Innovation Review, both of which assume relatively low incremental progress in the onshore wind industry over the next 15 years. Numbers from these studies have been used to estimate the current unit EAC.

The key assumptions used in determining our estimate of the current unit EAC are set out in figure 9.

Figure 9: Assumptions used for the estimation of current unit EAC – onshore wind

	Assumption	Basis for assumption
Turbine size, MW	2	Approximately the maximum size of turbine being installed onshore at present
Installed capacity, GW	40	Garrad Hassan report
Investment costs, £m/MW	0.7	Garrad Hassan report. A sensitivity analysis has been conducted for the range £0.6m-£0.8m /MW (i.e. £600-88/kW).
Initial annual operating costs, £ /kW/yr	28	CCC estimate. A sensitivity analysis has been conducted for the range £25-£30/kW/yr

3.1.5. Discussion of relevant factors

Economies of scale at the project level

There are two main potential sources of economies of scale at the project level. The most important of these relates to the size of the turbine; while the other relates to the installation process and the potential for large-scale farms to be installed at lower costs per unit of output.

The amount of energy capture for a wind turbine is proportional to the square of the blade length of the turbine and hence is broadly proportional to the square of the absolute size of the turbine. Consequently, growth in the size of wind turbines results in considerable economies of scale and so marked reductions in unit costs.

The end of the growth in size of wind turbines and cost reductions that go with that have been incorrectly forecast by many people in the industry over the past 20 years. However, while onshore wind turbines deployed in the US and elsewhere may have the potential to continue to grow further in size, it is now increasingly apparent that in the UK planning consents and access to onshore sites will constrain the growth in the absolute size of wind turbines. It is therefore unlikely that the absolute size of the turbines deployed onshore in the UK will grow significantly.

With respect to the installation process, the largest reductions in unit installation costs generally arise when moving from very small to mid-size developments. Further reductions moving from mid-size to larger installations tend to be more modest. They arise because contractor costs then do not rise in proportion to the number of turbines to be installed (i.e. consider mobilisation, supply chain preparation and the benefits of enhanced utilisation).

Economies of scale at the industry level

There is likely to be continued improvement in the cost of turbines within the absolute constraints of size described above. As the UK develops a supply industry of critical mass for the key components then we are likely to see the effects of this in the supply chain as larger orders result in lower costs of the technology.

Technology innovation

There is also scope for continuing innovation in the design of turbines, blade design and fabrication, and in the design of gear boxes and control systems for the turbines; each of which may further reduce unit costs.

Learning by doing

It is unlikely that either the fabrication of towers or the installation process will be subject to learning effects beyond the incremental supply chain benefits described above.

Other

Within the UK market there are a number of potentially negative cost drivers that have the potential to increase the unit costs of onshore wind:

- As the better sites for wind in the UK are used by early projects, then the average output of a new wind farm may start to fall. The extent to which this is a concern is a function of the planning and grid issues in high wind areas;

- Grid reinforcement will increasingly be required as more onshore wind farms come onto the system. Although it should be noted that there is innovation in the area of grid design that has not been formally considered as part of this study which could, over time, mitigate some of these costs.

- Access is a major issue given the increased size of turbines and the need potentially to open up less well developed areas of the UK in order to deploy greater amounts of wind power;

- As the size of turbine increases then the cost of road building, cranage and other construction and maintenance related costs tend to grow.

One further interesting factor is the cost of capital and the rent in the value chain for onshore wind. At present, unlike all the other technologies considered in this study, onshore wind is being financed at relatively low costs of capital, which are consistent with what one might expect of a mature set of infrastructure developments.

However, if the support system – in this case the Renewables Obligation – provides for pricing of the projects in a way that is not cost reflective, then the rent in the value chain will accrue to the various parties within the value chain, including the landlord, rather than appear as a tangible cost reduction. For instance, despite the cost of onshore wind power seeming to be in the range of £0.7m/MW for construction, newly constructed wind farms have transacted at values in excess of £1m / MW in recent times.

Summary

While there remains potential for further cost improvements, it is clear that the progress in reducing cost is likely to be lower going forward than historically, as the wind turbine industry is at a much more mature state than it was in the period when it experienced progress ratios of the level discussed previously.

The primary conclusions for onshore wind are therefore the following:

- The technology exists in a mature world market that has already installed significant capacity – the UK is likely to continue to benefit from technology innovations in the core turbine technology that occur in that global industry;

- The UK of itself is a constrained market and this has an impact on the potential for cost savings in the onshore wind market;

- Size of turbine is likely to be constrained by planning and access considerations;

- Grid and back-up issues have the potential to mitigate against further cost savings;

- The supply of sites with appropriate wind resource is finite and will reduce over time;

- Under the Renewables Obligation and the other constraints in the market, pricing does not appear to be reflective of the costs.

3.1.6. Assumptions for bottom-up analysis

The key assumptions used in the bottom-up analysis for onshore wind are provided in Figure 10.

Figure 10: Assumptions used for the bottom-up analysis – onshore wind

Global aggregate capacity installed (yr)	40 GW (current)	84 GW (2010)		190 GW (2020)		Basis for assumption
Scenario	DTI base	High progress	Low progress	High progress	Low progress	
Turbine size, MW	2.0	3.0	2.0	3.0	2.0	Technology innovation, but maximum size constrained by planning constraints
Investment costs, £m/MW	0.7	0.600	0.670	0.580	0.620	Continued cost improvement in particular in areas such a gear box design; and efficiencies in local supply chain
Annual operating costs, £m/MW/yr	0.028	0.019	0.028	0.017	0.028	Scale effects from increased turbine size. More efficient local supply chains and improved reliability.

3.1.7. Assumptions for consensus view from literature

As noted above, Oxera (2004) and Garrad Hassan (2003) conducted for the DTI Innovation Review are the current references for onshore wind. We have therefore used numbers taken from these two studies as the current consensus view on the costs of onshore wind projects. These costs fit reasonably well with our experience of real onshore wind projects. The key assumptions used are set out in Figure 11.

Figure 11: Assumptions used for consensus view – onshore wind

Global aggregate capacity installed (yr)	**40 GW (current)**			**84 GW (2010)**	**190 GW (2020)**
Scenario	**DTI base**	**DTI low cost**	**DTI high cost**	**DTI mid**	**DTI mid**
Turbine size, MW	2.0	2.0	2.0	2.0	2.0
Total investment cost, £m/MW	0.700	0.600	0.800	0.650	0.580
Total annual operating costs, £m/MW/yr	0.028	0.025	0.030	0.025	0.024

3.1.8. Assumptions for the application of bottom-up progress curves analysis

For the purposes of this part of the analysis we have assumed relatively conservative incremental progress ratios in a number of components of the costs of onshore wind, based on the progress ratios estimated/assumed in the literature.

Figure 12 sets out the progress ratios used for each supply chain component. Sensitivity analyses are performed in the above progress ratios by varying them by 5% in either direction.

Figure 12: Assumptions used for 'bottom-up progress curve' analysis – onshore wind

Supply chain component	Progress ratios applied	Basis for assumption
Investment costs		
Development costs	100%	Limited economy of scale, learning by doing or innovation from current state
Preliminary and management	100%	
Wind turbine supply	95%	Low end of previous progress rates in literature due to maturity and scale of the industry
Foundation supply	95%	
Monitoring systems	100%	Standard technology now mature
Installation	100%	Straightforward engineering process now mature on a generic basis
Grid	100%	
Operating costs		
Operations cost	95%	Low end of previous progress rates in literature due to maturity and scale of the industry
Maintenance cost	95%	
Use of system	100%	Standard costs determined on a site-specific basis
Insurance	100%	Mature conditions; variations owing to project-specific risks
Misc.	100%	Mature conditions

3.2. Offshore wind

3.2.1. Background

Offshore wind power is still in its infancy as an industry. However, the technologies that it uses are drawn from mature industries such as onshore wind power and marine/coastal construction and offshore oil and gas installation.

The global installed capacity of offshore wind is currently around 500MW. To date, the UK has two functioning wind farms (North Hoyle and Scroby Sands), two in construction (Barrow and Kentish Flats) and a large number of projects that have been consented under the Round One regime, but which have yet to commence construction.

Offshore wind farms have been developed since the early 1990s in Denmark, but the projects involved have, until very recently been small and might best be considered demonstration projects. (Vindeby was constructed in 1991 and has a capacity of just 5MW; and no project in excess of 20MW was constructed until Mittelgrunden in 2000-01.)

The interaction of different markets is very apparent in offshore wind. First, it is clear that offshore wind is, for the time being, largely an issue for Europe, and the North Sea basin in particular. Of the published plans of various countries in Europe, the UK's are the most ambitious for offshore wind and constitute about 50% of the planned global installation over the coming period.

This means that the UK market is a major driver for the development of offshore wind and, that in areas such as installation, foundation design and offshore operations and maintenance, there is little potential for the UK to 'free-ride' on developments in other countries. It also means that progress in reducing unit costs will be a function of how rapidly UK installed capacity increases.

3.2.2. Literature review

There has been a range of studies performed on the costs of offshore wind. For this study the DTI Innovation Review, published in early 2004, is used as the main reference for the current costs. This provides estimates of the current costs of offshore wind and of the incremental progress curves for onshore and offshore wind development. For capital costs, the report provides a specific range for current costs of £1.1m to £1.3m / MW. The report also suggest load factors of around 38% for offshore wind farms (higher load factors are one key reason for going offshore and compensate in part for higher costs).

As part of this study we have also had access to the Econnect report for the Renewables Advisory Board which looks at the estimated costs of connecting Round Two offshore wind farms to the grid. This study presents a range of costs from £104,000/MW to £230,000/MW for the various projects. The implied cost in the base case capital cost assumption for this study is £132,000/MW (based on £1.2m/MW). The Econnect work shows the inherent location-related variability of cost today, and the potential increased cost over and above the mid-range assumption used in this study.

3.2.3. General production assumptions

Figure 13 lists the offshore wind specific assumptions used throughout the analysis. Additional assumptions used to estimate current unit EAC and for each approach to estimating the progress curve are set out in the subsequent subsections. Further details of the assumptions used are provided in the companion Excel spreadsheet, 'Offshore wind model.xls'.

Figure 13: Production assumptions - offshore wind

	Assumption	Basis for assumption
Load factor, %	38%	The load factor is a function of each site. The base case, taken from the Garrad Hassan range (33%-40%), is representative of what might be expected across a range of sites. Sensitivity analysis is conducted on the range 30%-42%
Project life, yrs	20	Life time generally used in the industry
Debt, max. life, yrs	15	Consistent with large infrastructure projects of this kind if the cash flows are secure

3.2.4. Current unit EAC

The key assumptions used in determining our estimate of the current unit EAC for offshore wind are set out in Figure 14.

Figure 14: Assumptions used for the estimation of current unit EAC – offshore wind

	Assumption	Basis for assumption
Turbine size, MW	3	Limit of turbine size likely to be warranted and therefore capable of securing debt finance.
Investment costs, £m/MW	1.2	Garrad Hassan report; A sensitivity analysis has been conducted for the range £1.1m-£1.3m/MW (£1,100-1,300/kW).
Initial annual operating costs, £/kW/yr	34	Information is difficult to obtain. Even if project-specific information were available it would be obscured by warranty provisions and other contractual arrangements. The number used is based on the DTI Innovation Review.

3.2.5. Discussion of relevant factors

Much of the potential for unit cost reduction in the offshore wind industry comes from wind technology being relieved of the constraints imposed on it by operating in the onshore environment, and therefore the more effective application of a set of technologies within this less constrained environment. These issues are discussed in more detail below.

Economies of scale at the project level

In the area of turbine technology, there continues to be potential for the UK to benefit from larger turbines manufactured specifically for the offshore market. Progress in this area is likely to be driven by the UK offshore market. A counter-argument to this is that there are other parts of the world where space is less constrained than in Europe, where larger turbines can also be used onshore as well as in offshore applications.

Turbine size and space

One of the key advantages of going offshore is that space is much less constrained than onshore. In the marine environment there are few physical limits on the size of wind turbines. Therefore much of the potential cost savings from offshore wind is assumed to come from the increase in the size of turbines that can be deployed. Already some manufacturers are deploying prototype 5MW devices.

Unit operating, maintenance and installation costs are likely to fall with the size of the turbine, which reduces the overall equivalent annual cost of the electricity generated. However, scaling of the existing design of turbines is unlikely to go on indefinitely. Energy capture increases with the swept area of the blades and therefore with the square of the scale of the turbine, however the moments in the beam elements of the structure generally increase with the cube of scale, which means that as the scale factor becomes more dominant it may limit the absolute size of turbines.

Technology innovation

The physics of wind turbines discussed above, which are likely to limit the growth in turbine size, could, however, lead to new and innovative designs of offshore wind turbines in the future. Already some companies are beginning to look at the potential for vertical axis turbines of greater scale. While such devices are far from scale deployment, as the offshore wind industry grows there is an avenue of innovation that could lead to alternative designs.

A number of other innovations in the market that are being driven by the development of offshore wind are also observable. For example:

- There are a number of companies pursuing development programmes in new forms of transmission system for wind turbines, which may lead to lower capital costs and lower ongoing maintenance costs through increased reliability (Clipper and Artemis Intelligent Power being two examples);

- Considerable work is being performed on optimising foundation design and installation techniques;

- The Beatrice project offshore Scotland (sponsored by Talisman and Scottish and Southern Energy) is developing deep-water technology for offshore wind and in the process it is both creating an early market for large-scale wind turbines and also driving innovation in the fabrication process which is a key element of cost in such projects;

- Many of the turbine manufacturers are developing large-scale wind turbines targeted at the offshore wind market;

- There are a number of companies pursuing innovative techniques for the installation of offshore wind turbines (for instance the Merlin project by The Engineering Business), which again suggests that there is potential for cost reduction in this area;

- Similarly offshore access for maintenance purposes is the subject of innovative new ideas.

Whilst the success of such innovation is not assured, it suggests that there remains significant potential for future cost savings from offshore wind developments.

Learning by doing

The offshore wind industry offers considerable potential for reductions in operating and maintenance costs via learning by doing.

At present, operating and maintenance costs are perhaps the greatest area of cost uncertainty in offshore wind. This affects the direct costs of operating the turbines but, more importantly, it also affects the ability of the industry credibly to back the operation of wind turbines offshore with appropriate contracting structures. In other words, the inherent uncertainty of these costs makes effective risk allocation in contracts extremely difficult and hence the real costs quite opaque. The situation at Horns Rev, where considerable maintenance was required after initial installation, is often quoted and, without labouring that particular issue, it does illustrate the challenges in effectively warranting the operation of large-scale farms.

This is a key progress effect that links directly to the ability of the industry to put appropriate contracting structures in place in order to drive down unit costs and attract the necessary finance for large-scale build-out of offshore wind. Only with sustained growth of installed capacity will the experience be gained that provides the operational experience on the basis of which contractors and the financial community can assess and manage the installation and operating risks.

However, the Horns Rev experience also suggests that, given the mature nature of marine construction, it may well be that learning effects are quickly realised as experienced companies in one field quickly learn how to apply their skills in another.

3.2.6. Assumptions for bottom-up analysis

The key assumptions used in the bottom-up analysis for offshore wind are provided in Figure 15.

Figure 15: Assumptions used for the bottom-up analysis – offshore wind

Global aggregate capacity installed (yr)	0.5 GW (current)	6 GW (2010)		42 GW (2020)		Basis for assumption
Scenario	**GH base**	**High progress**	**Low progress**	**High progress**	**Low progress**	
Turbine size, MW	3	5	3	5	5	Around 3MW represents the limit of turbine size currently likely to be warranted by manufacturers and therefore capable of securing debt finance. Higher levels of deployment by 2020 suggest greater investment in larger-scale (5MW) turbines likely.
Investment costs, £m/MW	1.200	0.813	1.154	0.763	0.924	Scale effects from increased turbine and project size and installed base of projects are main driver.
Annual operating costs, £m/MW/yr	0.034	0.023	0.034	0.021	0.023	Scale effects from increased turbine and project size and installed base of project are main driver.

3.2.7. Assumptions for consensus view from literature

The Garrad Hassan report is the principal current source on offshore wind, and so the numbers used for this part of the analysis are based largely on this study. The key assumptions used are set out in Figure 16.

Figure 16: Assumptions used for consensus view – onshore wind

Global aggregate capacity installed (yr)	**0.5 GW (current)**			**6 GW (2010)**	**42 GW (2020)**
Scenario	**GH base**	**GH low cost**	**GH high cost**	**GH**	**GH**
Turbine size, MW	3	3	3	5	5
Total investment cost, £m/MW	1.200	1.100	1.300	0.912	0.741
Total annual operating costs, £m/MW/yr	0.034	0.034	0.034	0.025	0.025

3.2.8. Assumptions for the application of bottom-up progress ratios analysis

The bottom-up progress curve approach applies progress ratios to individual components of the costs of offshore wind based on the progress ratios that are generally observed in the literature for onshore wind.

Figure 17 sets out the progress ratios used for each supply chain component. Sensitivity analyses are performed in the above progress ratios by varying them by 5% in either direction.

Figure 17: Assumptions used for 'bottom-up' analysis – offshore wind

Supply chain component	Progress ratios applied	Basis for assumption
Investment costs		
Development costs	85%	Largely a function of project scale, which is increasing, resulting in potential for significant reductions
Preliminary and management	85%	
Wind turbine supply	90%	Likely to be subject to scale effects and, to an extent, innovation, although both are reasonably mature technologies
Foundation supply	90%	
Monitoring systems	100%	Standard technology now mature
Installation	85%	Clear economies of scale, potential for learning by doing and evidence of innovation occurring.
Grid	110%	Based on Econnect report, which shows limited potential for economies of scale and the possibility of increased costs in connection
Operating costs		
Operations cost	85%	Considerable potential for economies of scale, learning by doing and innovation
Maintenance cost	85%	
Use of system	100%	Standard engineering-derived costs determined on a site-specific basis.
Insurance	100%	Variations are a function of project-specific risks
Misc.	100%	Default assumption

3.3. Tidal lagoons

3.3.1. Background

Tidal lagoons, as proposed for development by Tidal Electric, is used as one of the prospective marine technologies. This provides an interesting contrast to many of the 'device based' marine devices as the tidal lagoon construction, while entirely novel, is a combination of standard civil and mechanical devices and structures.

Due to oceanographic factors, there is more limited absolute global potential for the technology then for any of the other renewable technologies considered here. There are currently no active projects, although there is considerable potential for the technology in the UK, Canada and China.

3.3.2. Literature review

The reference for all work on tidal lagoons is information contained in a 2004 report by WS Atkins (the engineering consultancy) for Tidal Electric, who are the sole promoter of this technology in the UK and elsewhere at present. The Atkins report is a pre-feasibility study and there remains significant uncertainty about the costs and output until more detailed work is undertaken.

3.3.3. General production assumptions

Figure 18 lists the technology-specific production assumptions used throughout the tidal lagoons analysis. Additional assumptions used to estimate current unit EAC and for each approach to estimating the progress curve are set out in the subsequent subsections. Further details of the assumptions used are provided in the companion Excel spreadsheet, 'Tidal lagoons model.xls'.

Figure 18: Production assumptions - tidal lagoons analysis

	Assumption	Basis for assumption
Load factor, %	36%	Atkins report for Tidal Electric; Sensitivity analysis conducted for the range 33%-39%.
Construction period, yrs	2	Atkins report for Tidal Electric
Project life, yrs	50	Atkins report for Tidal Electric Sensitivity analysis conducted using 20 year
Debt, max. life, yrs	15	Consistent with a large infrastructure project with stable cash flows

3.3.4. Current unit EAC

The current position is assumed to be as set out in the WS Atkins report undertaken for Tidal Electric. The key assumptions used in determining our estimate of the current unit EAC for tidal lagoons are set out in Figure 19.

Figure 19: Assumptions used for the estimation of current unit EAC – tidal lagoons

	Assumption	Basis for assumption
Project size, MW	60	Atkins report
Installed capacity, MW	60	Atkins report
Investment costs, £m/MW	1.358	Atkins report. A sensitivity analysis has been conducted for the range £1.019m-£1.698m/MW (£1,019-1,698/kW).
Initial annual operating costs, £/kW/yr	30	Atkins report. A sensitivity analysis has been conducted for the range £28-£31m/kW./yr

3.3.5. Discussion of relevant factors

In contrast to the other technologies analysed as part of this study, the majority of the cost reduction from tidal lagoons comes from the scale of the projects themselves rather than from economies of scale at the industry level, learning by doing or innovation.

Economies of scale at the project level

Project costs have two main drivers: (i) the length and height of the impoundment walls and (ii) the output of the turbines. The turbine related costs go up linearly with the output of the project, which is related to the amount of water impounded and the tidal range at the site. The tidal range is highly project specific, but has a very significant effect on the output of the project. The West coast of the UK has some of the highest tidal ranges in the world.

The volume of water impounded, meanwhile, increases with the square of the diameter of the impoundment, but the amount of material and construction in the impoundment structure increases linearly with the diameter of the impoundment structure. Hence there is a very clear economy of scale at the project level related to the size of the lagoon.

Economies of scale at the industry level

The scope for economies of scale in the supply chain is limited as the supply chain components, e.g. low head hydro turbines and rock for impoundment, are already mature industries in their own right. There may, however, be some local efficiency improvements in the development of a construction and supply infrastructure for the development of tidal lagoons, but it is unlikely that there will be significant benefits in the overall global supply chain.

Learning by doing

There is likely to be some scope for unit cost reductions via learning by doing in the efficiency of construction of the lagoons and in the design and materials used to create the impoundment.

Technology innovation

The scope for innovation is limited as the technologies used are coastal impoundment and low head hydro turbines, neither of which are likely to be subject to further innovation.

Other

Another extremely important factor determining the unit cost of tidal lagoons is the project cost of capital. Whilst the technology remains unproven, the ability to raise finance may well constrain project size and the cost of capital obtained will be relatively high.

However, once proven as a technology, this type of power generation will be very low risk with very long project lives (the impoundment structure has a life of well in excess of 50 years), and hence should attract a low cost of capital. For such a capital intensive project this is a very important factor in developing the equivalent annual cost. The learning effects in the capital markets, resulting in a declining cost of risk-adjusted capital, may well be the most important learning by doing factor in the progress of the costs of this technology.

3.3.6. Assumptions for bottom-up analysis

In our bottom-up analysis, the key drivers of unit costs for tidal lagoons are the scale and location of the projects. As capital market confidence improves, markets will be willing to provide larger amounts of capital, and hence allow the project scaling benefits to become apparent. Although this will also result in a lower cost of capital over time, for the purposes of clarity, a constant cost 12% of capital is assumed over the life of the project. Consequently, economies of scale at the project level are the most important factor, though some learning effects are also assumed.

Further key assumptions used in the bottom-up analysis for tidal lagoons are provided in Figure 20.

Figure 20: Assumptions used for the bottom-up analysis – tidal lagoons

Global aggregate capacity installed (yr)	60 MW (current)	360 MW (approx. 2010)	1,260 MW (approx. 2020)	Basis for assumption
Project size, MW	60	300	300	Considered optimum size for unit deployment; (Company info)
Investment costs, £m/MW	1.358	1.019	1.019	CCC interpretation of Atkins report for increased project scale
Annual operating costs, £m/MW/yr	0.030	0.028	0.028	CCC interpretation of Atkins report for increased project scale

3.3.7. Assumptions for the application of bottom-up progress curves analysis

Given the nature of tidal lagoon projects and the fact that most of the cost benefits come from the scale of the project and the ability of larger projects to raise finance, the application of bottom-up progress curves is not an approach of particular relevance for this technology. However, it is reasonable to assume some moderate learning effects across the development of new projects as this type of project has not been built before.

Figure 21 sets out the progress ratios used for each supply chain component. Sensitivity analyses are performed in the above progress rate by varying them by 5% in either direction.

Figure 21: Assumptions used for 'bottom-up progress curve' analysis – tidal lagoons

Supply chain component	Progress ratios applied	Basis for assumption
Investment costs		
Development costs	100%	Limited scope for improvement
Impoundment	95%	Moderate learning effects possible given technology is still in development stages
Turbine hall	95%	
Turbine and plant	95%	
Maintenance equipment	100%	Standard equipment for low head hydro systems
Access and navigation	100%	Limited scope for scale or innovation
Grid	100%	Set by regulation
Operating costs		
General maintenance cost	95%	Moderate learning effects possible given technology is still in development stages
Special maintenance cost	95%	
Use of system	100%	Set by regulation
Insurance	100%	Limited scope for scale or innovation
Misc.	100%	

3.4. Wave and tidal stream

As noted in section 1, we have used a single model for the device-based wave and tidal technologies. This is because both technologies are sufficiently nascent that reliable information on both is very sparse. The two forms of marine power generation face similar challenges and cost drivers.

3.4.1. Background

The wave and tidal stream industry has developed to the stage where there are a number of companies that have deployed single prototypes and a vast array of companies that are still developing early stage devices for the extraction of energy from the sea. Globally there is only between 5MW and 10MW of wave and tidal power deployed. Therefore there is high cost uncertainty and significant potential for innovation and cost saving in future.

The UK is widely regarded as the leading country for the development of such marine technologies, but there are limited deployments elsewhere, notably in Portugal and Australia.

The timeline for the development of the industry, and its capacity, is very hard to judge. The Marine Deployment Fund announced by the DTI in 2004 is though by DTI to be sufficient to support the deployment of around 25MW of wave and tidal devices in the UK. As the UK is the leading country in encouraging the development of such technologies we have assumed that it constitutes around half of the global market by 2010.

3.4.2. Literature review

Climate Change Capital produced the 'Into the Blue' report for the British Wind Energy Association in 2004, which has broadly been adopted in the DTI's recent consultation on an enhanced support regime for the demonstration phase of the industry. The best information on current costs comes from the reaction of the industry to CCC's work and the DTI consultation on wave and tidal financing.

The scheme proposes up to a 25% capital grant (of eligible costs) and a £100/MWh premium (on top of ROC and power revenues) for marine devices in their first five years of operation. This scheme provides a revenue stream of the order of £170/MWh for the first five years based on current ROC prices. The reaction from a number of players in the industry was that this might still not be sufficient to support early projects on a fully arms length basis.

The proposed UK scheme is similar in form to the Portuguese tariff, which provides a similar level of support in the form of a feed-in tariff that is available for up to 12 years for any given project.

This market feedback supports the view that the current EAC of marine devices is likely to be in the range £150 - £200/MWh, which is consistent with a capital cost for wave and tidal devices of the order of £2.5m/MW for early small projects.

The Carbon Trust is currently sponsoring a Marine Energy Challenge (MEC) which pairs marine device developers with engineering companies in order to undertake a 'bottom-up' analysis of the costs and potential future cost savings for each of the devices. There are no tidal devices participating in the MEC, but there are a wide range of wave devices.

The MEC has not yet reported publicly and we have not had (or sought) access to the results of the bottom-up analyses of costs that are being performed as part of the MEC. It would be wise to review judgements made about the progress curves in this study in light of the MEC findings when they become available.

It is generally accepted that if scale deployment of wave and tidal devices is proved to be feasible then it is likely to begin to occur in bulk in the period 2010 to 2020. Hence we have made the relatively arbitrary assumption that a capacity of 1.1GW might be installed by 2020, this is broadly equivalent to the UK and one other country (say Portugal) executing a consenting programme for projects that is similar to the Round One for offshore wind in the UK. Should Round One reach an installed capacity of 500MW then it is likely to have taken around a decade from its initial inception to achieve this, hence this seems a reasonable assumption for wave and tidal power.

3.4.3. General production assumptions

Figure 22 lists the general production assumptions used throughout the wave and tidal stream analysis. Additional assumptions used to estimate current unit EAC and for each approach to estimating the progress curve are set out in the subsequent subsections. Further details of the assumptions used are provided in the companion Excel spreadsheet, 'Wave and tidal stream model.xls'.

Figure 22: General production assumptions – wave and tidal stream

	Assumption	Basis for assumption
Load factor, %	36%	Approximation generally used for generic analysis of this nascent industry. Sensitivity analysis conducted for range 33%-40%.
Operating life, yrs	10	Variable for the early projects, but likely to be low for demonstration projects
Debt, max. life, yrs	5	Debt terms likely to be short in the early phase (if debt used at all)

3.4.4. Current unit EAC

Almost all the cost and performance characteristics of wave and tidal devices are uncertain at present. It is also unclear as to the extent to which the early devices will be able to achieve a significant operating life, and the costs of capital for early projects are likely to be large.

Therefore the analysis of current unit EAC is based on a capital cost of £2.5m/MW discussed above, but with significant variation assumed in capital cost, production, operating life and cost of capital.

The key assumptions used in determining our estimate of the current unit EAC for wave and tidal stream technologies are set out in Figure 23.

Figure 23: Assumptions used for the estimation of current unit EAC – wave and tidal stream

	Assumption	Basis for assumption
Turbine size, MW	1	Current approximate size of prototype devices
Investment costs, £m/MW	2.592	BWEA (2004); Sensitivity analysis conducted for range £2.074m-£3.240m/MW (£2,074-3,240/kW)
Initial annual operating costs, £/kW/yr	81	Extremely uncertain. Assumed costs for a 1MW wave / tidal device are similar to those of a 3MW offshore wind turbine (i.e. close to tripling the operating cost of offshore wind). In a period of high oil prices, this might only represent a few days of operation of a marine support vessel. Sensitivity analysis conducted for range £65-£101/kW/yr.

3.4.5. Discussion of relevant factors

The fact that these technologies are still very much in their infancy means that there is likely to be considerable scope for reductions in unit costs via economies of scale, learning by doing and technology innovation. However, quantifying these at this stage is extremely difficult.

Learning by doing

As the technologies develop, there are likely to be considerable reductions in unit installation and maintenance costs due to learning by doing. In particular, one of the key design issues for wave and tidal devices is to make them easier to maintain (for instance a number of devices are designed to be disconnected and brought to shore for maintenance, or are designed to be maintained out of the water).

Economies of scale at the project level

Economies of scale at the project level are likely to be significant in certain areas such as grid connection, project development cost and decommissioning requirements. There are also large potential scale benefits given the high mobilisation costs for offshore work.

Economies of scale at the industry level

Scale benefits at the industry level are also likely to be very significant. Individual demonstration projects have high one-off costs and allow for no build out of any dedicated supply chain in any area. As the industry develops to scale we can expect volume benefits in the orders of components, the construction of dedicated plant and machinery etc.

Technology innovation

The industry is at a very early stage of development and there is much potential for continued innovation. Areas where we know companies are looking to make significant steps include: installation techniques, maintenance techniques and access, power off-take, materials technology, and energy capture. All these area have potential to produce significant improvements in the cost of the technologies involved.

3.4.6. Assumptions for bottom-up analysis

As noted above, some extremely broad assumptions are used, which Ofgem should validate (and potentially correct) when the results of the MEC are available. The key assumptions used in the bottom-up analysis for wave and tidal stream technologies are provided in Figure 24.

Figure 24: Assumptions used for the bottom-up analysis – wave and tidal stream

Global aggregate capacity installed (yr)	5 MW (current)	50 MW (2010)	1 GW (2020)	Basis for assumption
Investment costs, £m/MW	2.592	1.602	0.840	Assumed that many of component approach cost of offshore wind today and continue to fall. Considerable scope for innovation is realised.
Annual operating costs, £m/MW/yr	0.081	0.034	0.034	Significant reduction based on gaining from offshore wind experience and the fact that key design issues for wave and tidal devices make them easier to maintain. Device and installation assumed to be at the level of offshore wind today by 2020. Other costs assumed to be similar to offshore wind today.

3.4.7. Assumptions for application of bottom-up progress curves analysis

Given the extremely early stage of the development of the industry, it is fair to assume that there is considerable scope for innovation, that scale effects will be significant and that there is much to be learned from doing. The literature for the development of onshore wind shows that progress rates of as good as 80% were achieved from the early development phase. Hence with the exception of grid, insurance and miscellaneous costs each cost component is assumed to have a progress ratio of 80% or 85% in the base 'bottom-up progress curve' analysis.

Figure 25 sets out the progress ratios used for each supply chain component. Sensitivity analyses are performed in the above progress ratios by varying them by 5% in either direction.

Figure 25: Assumptions used for 'bottom-up' progress curve analysis – wave and tidal stream

Supply chain component	Progress ratios applied	Basis for assumption
Investment costs		
Development costs	85%	Large potential for economies of scale
Preliminary and management	85%	
Equipment supply	80%	High progress end of range observed in the literature for onshore wind and other technologies
Installation	80%	
Grid	100%	Limited scope
Operating costs		
Operations cost	80%	High progress end of range observed in the literature for onshore wind and other technologies
Maintenance cost	80%	
Use of system	100%	Set by regulation
Insurance	100%	Set by insurance market
Misc.	100%	

As wave and tidal stream technologies are still in the demonstration phase, the 'bottom-up progress curve' analysis conducted here is purely indicative and will become more meaningful once deployment has increased, i.e. in 2010.

4. RESULTS

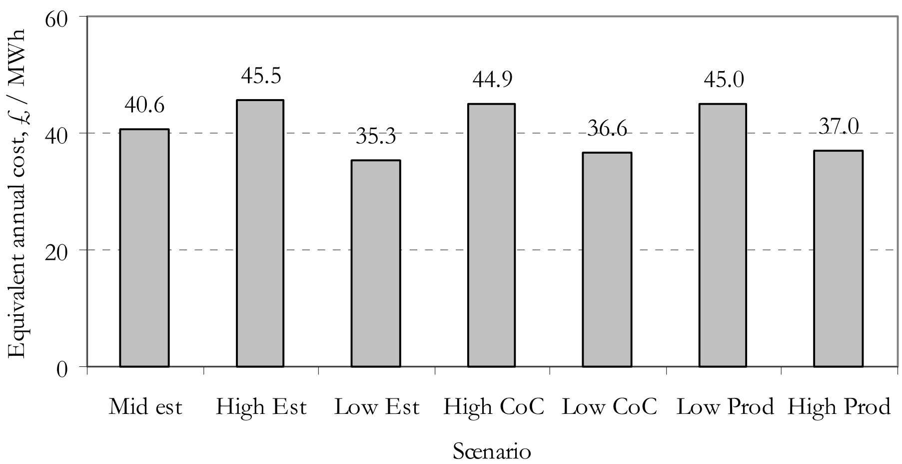
This section summarises the results of our analysis for each of the technologies examined. In each case, the estimated range for current unit EAC is shown, the progress curves derived from each of the three methodologies are set out and synthesised into a best estimate of the progress curve for each technology concerned, and the implications for the 'environmental premium' are discussed.

4.1. Onshore wind

4.1.1. Current unit EAC

As shown in Figure 26 below, our estimate of the current EAC per MWh for a 'good practice' onshore wind project is in the range £35.27-£45.53/MWh, with a central estimate of £40.59/MWh based on a load factor of 30%, a cost of capital of 10% and operating life of 20 years. Varying the cost of capital by 2 percentage points from the base case or the load factor by 3 percentage points impacts the EAC by around £4/MWh.

Figure 26: Estimated current unit EAC – onshore wind



Key to scenarios

Mid est	*EAC using base cost, production, and CoC assumptions (see Section 3.1 for all)*
High est	*EAC using high cost and base production and CoC assumptions*
Low est	*EAC using low cost and base production and CoC assumptions*
High CoC	*EAC using high CoC and base cost and production assumptions*
Low CoC	*EAC using low CoC and base cost and production assumptions*
Low Prod	*EAC using low production and base cost and CoC assumptions*
High Prod	*EAC using high production and base cost and CoC assumptions*

4.1.2. Estimated progress ratios

Our estimated progress curves based on the bottom-up analysis, review of the literature and application of top-down progress ratios are shown in Figures 27, 28 and 29, respectively. In each case, our central estimate of current unit EAC is taken as the starting point.

Figure 27: Bottom-up analysis – onshore wind

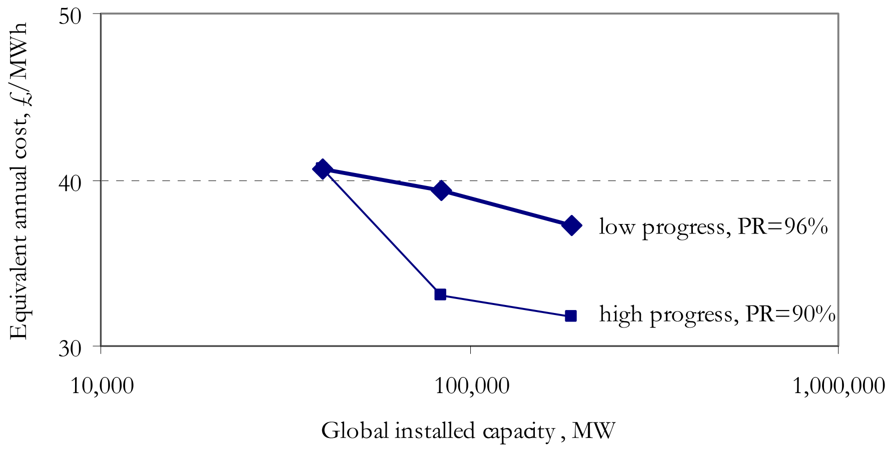


Figure 28: Consensus view based on literature review – onshore wind

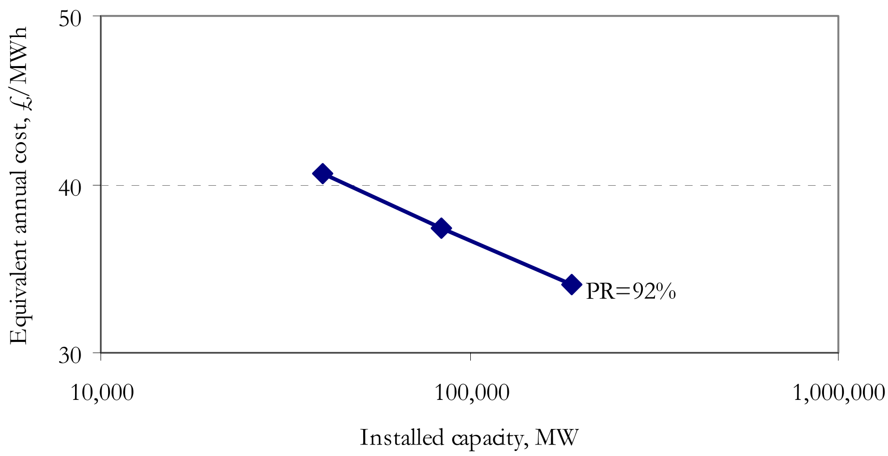
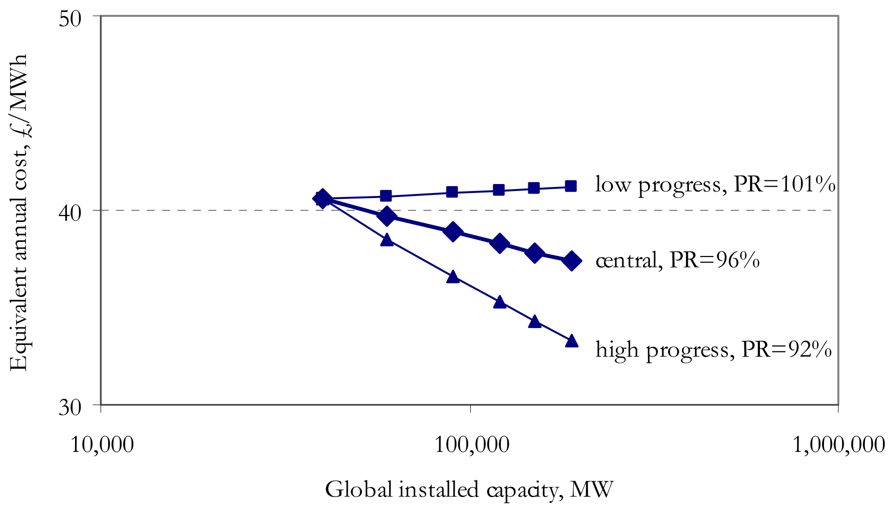


Figure 29: Progress curves based on the application of top-down progress ratios – onshore wind



It is clear from the figures that, except in the high case scenario for the bottom-up progress ratio analysis where rising grid costs outweigh any improvements in other cost components, unit costs for onshore wind are expected to fall as installed capacity increases.

The results of the bottom-up analysis are driven largely by an assumed reduction in the cost of certain of the large components of wind turbines where we are aware that there is currently innovation taking place. In the long-term we have also assumed that the cost of transmissions falls. The assumed increase in turbine size and output could be challenged given the size of current wind turbines and planning restrictions – however, predictions of the end of increase in turbine size have been consistently wrong in the past.

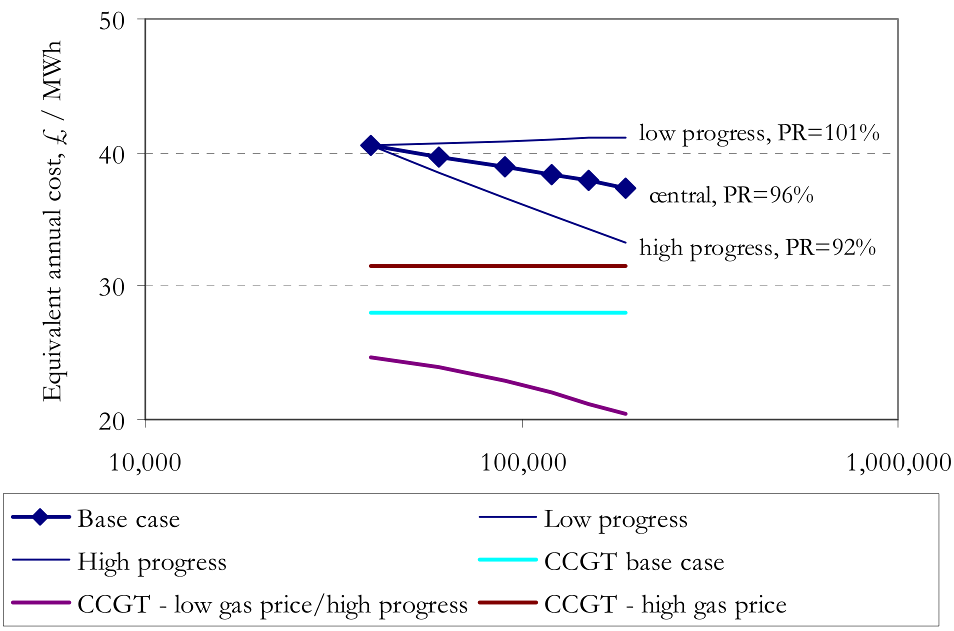
Rationale for selected 'best estimate' of the progress curve

For the purposes of assessing the implications for the environmental premium, in this case we give greatest weight to the results obtained from the application of top-down progress ratios. The reason for this is that, as the onshore wind market is well established, there is solid literature that permits robust estimation of bottom-up progress curves for the industry and robust estimates of future installed capacity. In fact, all the approaches give comparable central case estimates.

4.1.3. Implications for the environmental premium

Figure 30 plots our 'best' estimate of the progress curve for onshore wind as well as high and low scenarios against the assumed progress curve for CCGT for central, high and low gas price scenarios. Under out 'best' estimate the progress ratio is 96%.

Figure 30: Implications for the environmental premium – onshore wind



In our 'best estimate', unit costs fall from around £40.59/MWh (4.1p/KWh) currently to around £37.39/MWh (3.7p/KWh) at a global installed capacity of 190GW (i.e. by 2020), a total reduction of 8%. Under the high progress scenario, unit costs would fall to £33.27/MWh (3.3p/KWh), or by a total of 18%; and in the low progress scenario, unit costs rise to £41.17/MWh, or by 1.4%.

In the 'best estimate' scenario, the unit costs of onshore wind remain above those of CCGT even in the high gas price scenario at an aggregate global installed capacity of 190GW (as anticipated by 2020). Under our base case for CCGT, an environmental premium is required throughout the period, equal to £12.22/MWh in 2005 and reducing to £9.32/MWh by 2020. However, the declining unit subsidy applies to an increasing number of MW of capacity, so the annual monetary value of the premium increases over time (figure 31).

For the projected build-up in onshore wind capacity in the UK, this implies a total NPV of the environmental premium at a discount rate of 3.5% real of £3,037m. Alternatively, applying the discount rate used in our analysis of unit EACs for onshore wind (10% real) gives an NPV of £1,354m.

The implied CO_2 abatement cost where onshore wind is the marginal renewable technology declines from £30.54/tonne in 2005 to £23.29/tonne by 2020. In reality, onshore wind is unlikely to be the marginal renewable technology, with offshore wind defining the margin currently.

Figure 31: The implications of large-scale deployment for the environmental premium – onshore wind

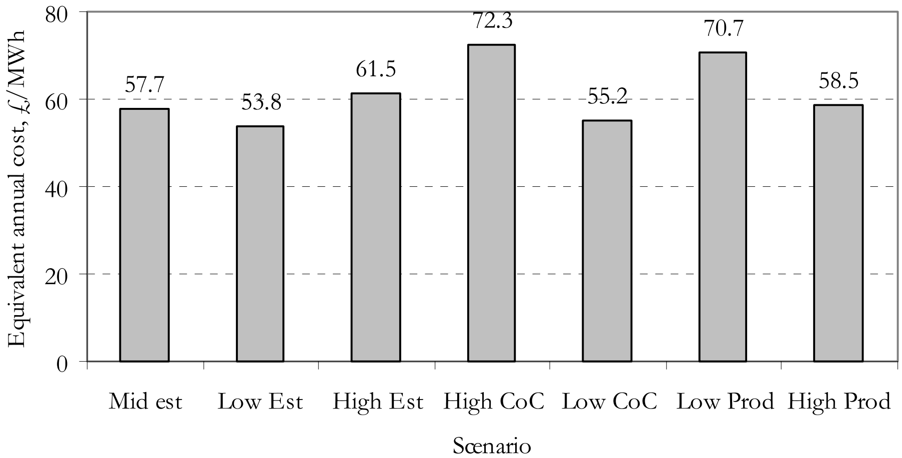
	2005	**2010**	**2020**
Global installed capacity, GW	47	84	190
UK installed capacity, GW	1.5	4.2	10.2
Annual increment in UK installation, GW	0.75	0.6	0.6
Base case			
Premium, £/MWh	12.22	10.98	9.32
Premium, p/KWh	1.2	1.1	0.9
Annual environmental premium required in each year for aggregate capacity, £m, '04 prices	24	103	261
Implied CO_2 abatement cost, £/tonne	30.54	27.44	23.29

4.2. Offshore wind

4.2.1. Current unit EAC

As shown in Figure 32, our estimate for the current unit EAC for offshore wind is £53.81-£72.26MW, with a central estimate towards the lower end of this range of £57.67/MW.

Figure 32: Estimated current unit EAC – offshore wind



Key to scenarios

Mid est	*EAC using base cost, production, and CoC assumptions (see Section 3.2 for all)*
High est	*EAC using high cost and base production and CoC assumptions*
Low est	*EAC using low cost and base production and CoC assumptions*
High CoC	*EAC using high CoC and base cost and production assumptions*
Low CoC	*EAC using low CoC and base cost and production assumptions*
Low Prod	*EAC using low production and base cost and CoC assumptions*
High Prod	*EAC using high production and base cost and CoC assumptions*

4.2.2. Estimated progress curves

Our estimated progress curves based on the bottom-up analysis, review of the literature and application of top-down progress ratios are shown in Figures 33, 34 and 35, respectively.

Figure 33: Bottom-up progress curve – offshore wind

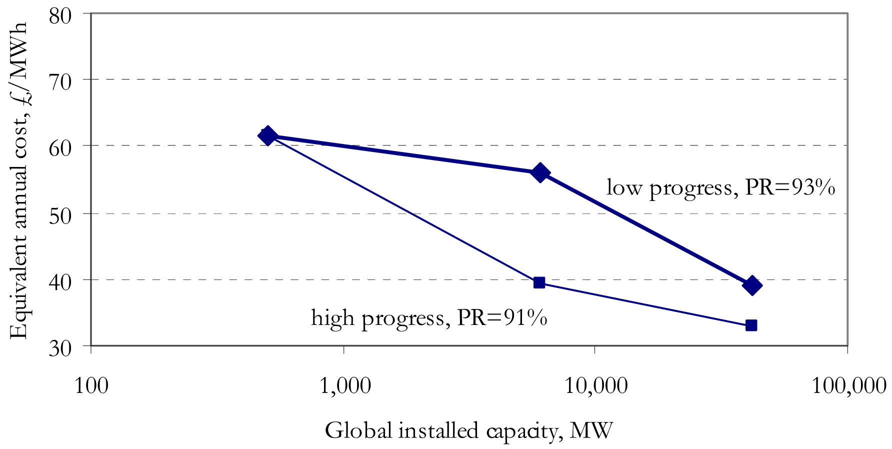


Figure 34: Consensus view based on literature review – offshore wind

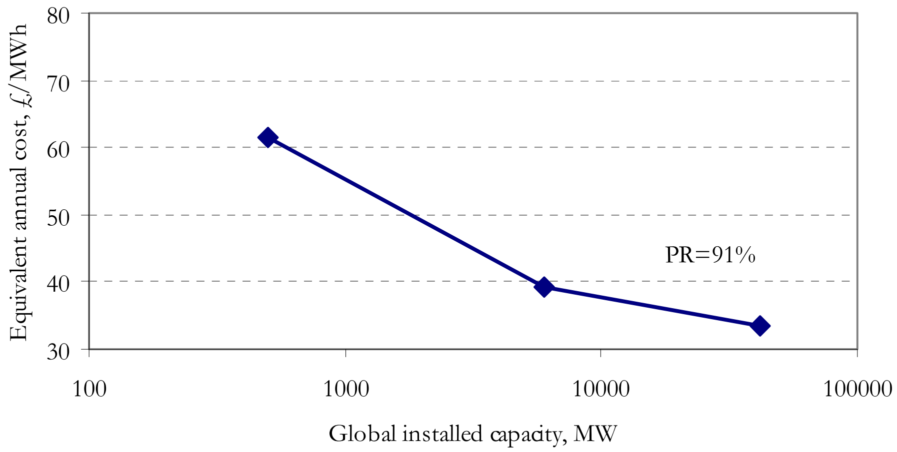
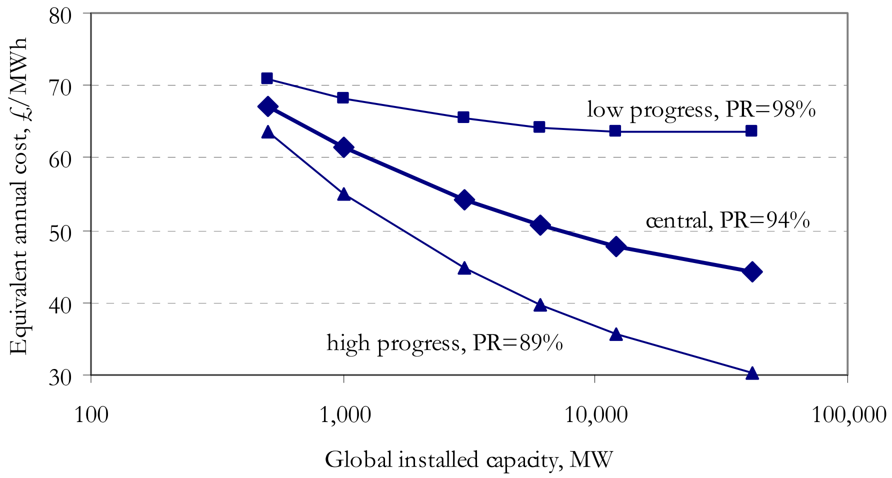


Figure 35: Progress curves based on the application of top-down progress ratios – offshore wind



The results of the bottom-up analysis for offshore wind are driven primarily by the benefits of increased turbine size that can be achieved offshore. We have assumed that 'per turbine' costs improve or remain the same as turbine size grows to 5MW, resulting in a reduction in the costs per MW. There is also assumed to be a degree of learning by doing and innovation in turbine installation and foundation costs and operating and maintenance activity. Also, as we move from Round One to Round Two of offshore wind, we assume that there is a scale effect in all significant 'per farm' costs (i.e. development costs).

Rationale for selected 'best estimate' of the progress curve

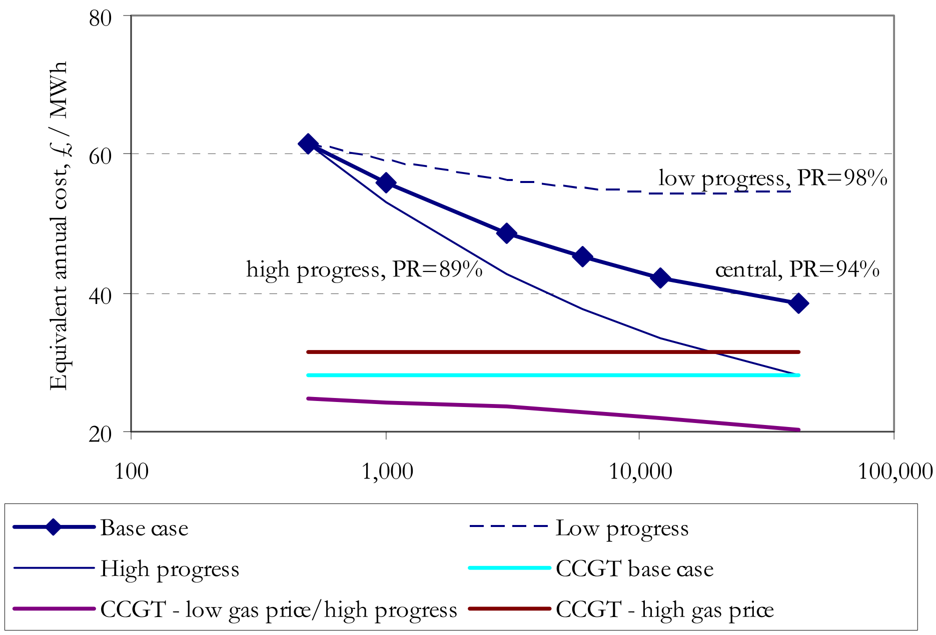
There is reasonable convergence between the central estimates obtained from the three approaches, although the consensus view from the literature is somewhat more optimistic. Convergence between the results of the bottom-up and application of top-down ratios approaches is to be expected given the similar logic used to generate these results.

To derive our 'best' estimate of the progress curve, which is used for considering the implications for the environmental premium, we have adopted the progress ratios resulting from the application of top-down progress ratios but applied them to the high estimate of current unit EAC, reflecting industry consensus on the current level of costs (as opposed to the consensus contained in the literature as reflected in the mid estimate of current EAC).

4.2.3. Implications for the environmental premium

Figure 36 plots our best estimate of the range for the progress curve for offshore wind against our three scenarios for the progress curve for CCGT.

Figure 36: Implications for the environmental premium – offshore wind



Under all the scenarios considered, offshore wind costs are expected to fall significantly as capacity builds up, although under the low progress scenario this decline begins to tail off for levels of installed capacity above 10GW as increased grid costs outweigh cost reduction factors. Under our central scenario, unit costs fall from £61.54/MWh (6.2p/KWh) currently to around £38.6/MWh (3.9p/KWh) at a global installed capacity of 42GW, a total decline of 37%. Under the high progress scenario, unit costs would fall to £28.3/MWh (2.8p/KWh), or by a total of 54%; and in the low progress scenario, unit costs fall by 12% to £54.4/MWh (5.4p/KWh). Consequently, while unit costs for offshore wind are currently around 50% higher than those for onshore wind, by 2020 they are expected to be roughly equal based on our assumed increase in the capacity installed for each.

Under our 'best estimate', unit costs for offshore wind remain above those for CCGT even under the high gas price scenario at an aggregate global installed capacity of around 42GW. Only in the high progress for offshore wind/high gas price scenario does offshore wind become competitive.

In the 'best estimate' scenario for offshore wind and base case for CCGT, an environmental premium is required throughout the period, equal to £33.47/MWh in 2005 and reducing to £10.50/MWh by 2020. However, the declining unit subsidy applies to an increasing number of MW of capacity, so the annual money amount of the premium increases over time (Figure 37).

For the projected build-up in offshore wind capacity in the UK, this implies a total NPV of the environmental premium at a discount rate of 3.5% real of £7,085m. This number reduces to £2,431m if the 12% real discount rate used in our modelling is used instead.

The implied CO_2 abatement cost where offshore wind is and remains throughout the period the marginal renewable technology declines from £83.67/tonne in 2005 to £26.26/tonne by 2020.

The implications for the environmental premium as deployment increases are set out in Figure 37 below for the base case.

Figure 37: The implications of large-scale deployment for the environmental premium – offshore wind

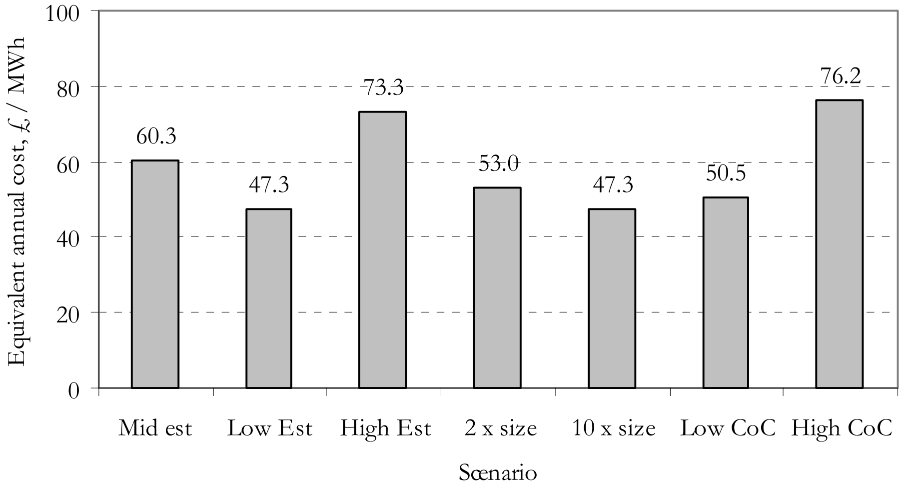
	2005	2010	2020
Global installed capacity, GW	0.5	4.8	42
UK installed capacity, GW	0.2	3.3	11.6
Annual increment in UK installed capacity, GW	0.12	1.25	0
Base case			
Premium, £/MWh	33.47	18.49	10.50
Premium, p/KWh	3.3	1.8	1.1
Annual environmental premium required in each year for aggregate capacity, £m, '04 prices	13	220	613
Implied CO_2 abatement cost, £/tonne	83.67	46.23	26.26

4.3. Tidal lagoons

4.3.1. Current unit EAC

Our estimated range for current unit EACs for tidal lagoon technology is £47.31-£76.20/MWh, with a central estimate of £60.30/MWh (Figure 38). Due to the high upfront capital costs associated with constructing tidal lagoons and the long project life, unit costs are particularly sensitive to the cost of capital assumption. Our base case scenario assumes a cost of capital of 12%. Assuming a cost of capital of 10%/15% reduces/increases the current EAC by approximately 16%/26%.

Figure 38: Estimated unit EAC – tidal lagoons



Key to scenarios

Mid est	*EAC using base cost, CoC and impoundment size assumptions (see Section 3.3 for all)*
High est	*EAC using high cost and base CoC and impoundment size assumptions*
Low est	*EAC using low cost and base CoC and impoundment size assumptions*
2x size	*EAC using impoundment size of 2x base case and base cost and CoC assumptions*
10x size	*EAC using impoundment size of 10x base case and base cost and CoC assumptions*
Low CoC	*EAC using low CoC and base cost and impoundment size assumptions*
High CoC	*EAC using high CoC and base cost and impoundment size assumptions*

4.3.2. Estimated progress curves

Our estimated progress curves based on the bottom-up analysis and application of top-down progress ratios are shown in Figures 39 and 40, respectively. In each case, our central estimate of current unit EAC is taken as the starting point. (Due to the lack of available literature, a progress curve based on the current consensus in the literature could not be derived.)

Figure 39: Bottom-up progress curves – tidal lagoons

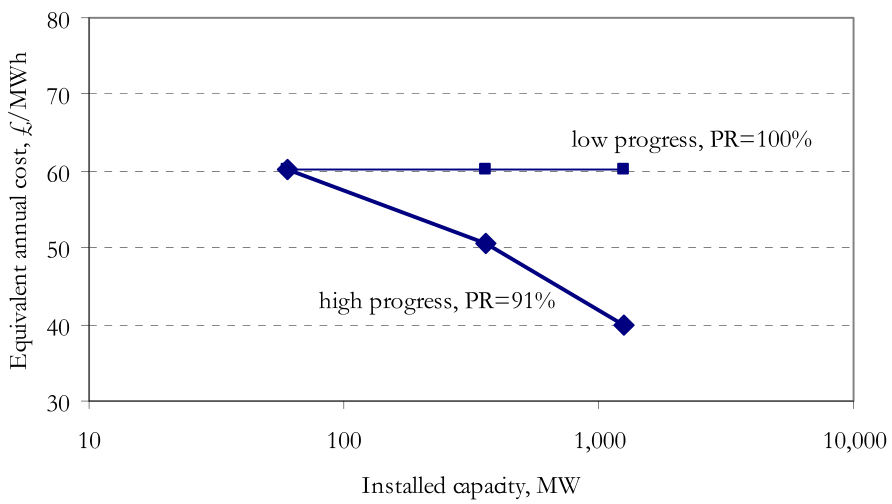
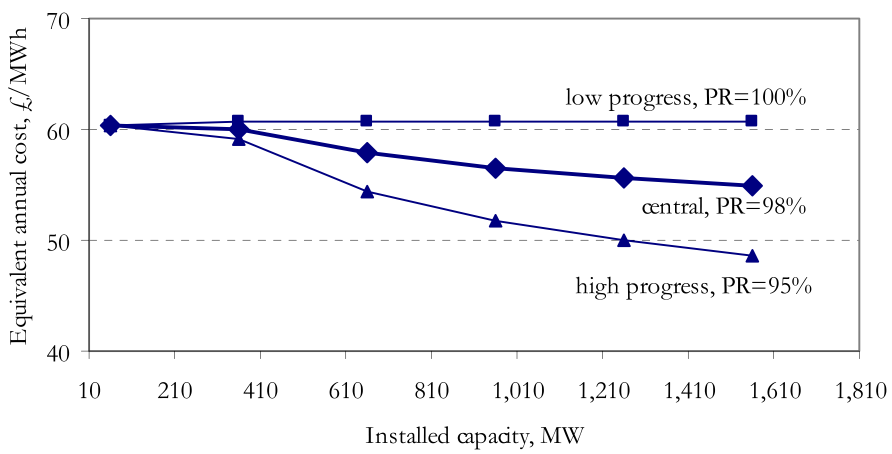


Figure 40: Progress curves based on application of top-down progress ratios – tidal lagoons



The cost reductions portrayed in the results of the bottom-up analysis come from two sources. First, we assume an increase in the scale the individual lagoons, as documented in the Atkins report. Second, we assume a reducing cost of capital for the project. This is a key differentiator for this technology because, once proven in concept, tidal lagoons are extremely low risk and low technology systems, which ought to attract a very low cost capital. Such capital intensive projects as these have a significant sensitivity to the learning effect that occurs in the financial markets.

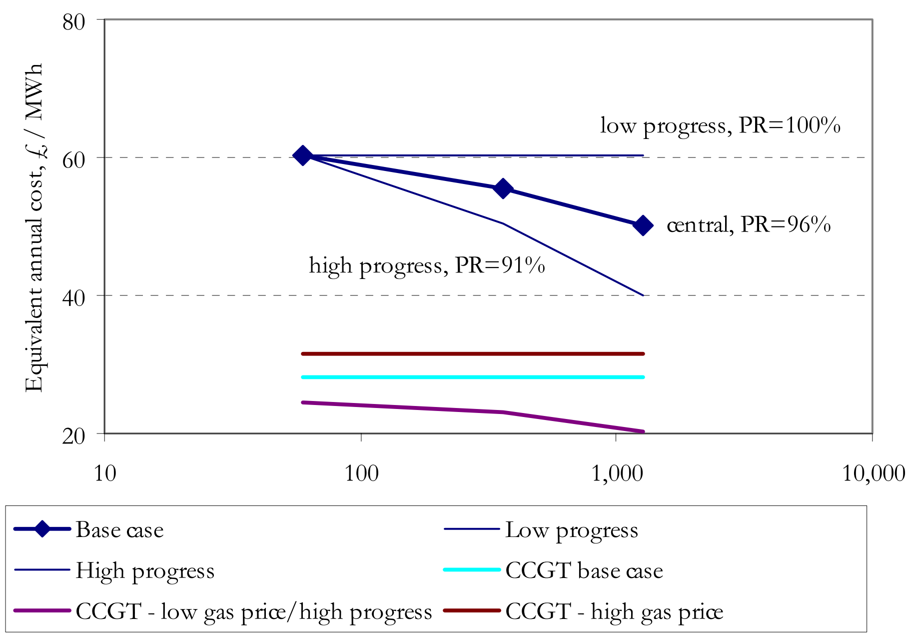
Rationale for selected 'best estimate' of the progress curve

There is only one source of detailed cost information for tidal lagoons, which is Tidal Electric and their consultants. The detail and timeliness of the Atkins report, however, mean that the results are as robust as can be expected for a technology that is still in the early phases of development. Further, the 'bottom-up' progress ratio approach used in this study is of limited relevance to this technology as the dominant effects on the EAC are the cost of capital and project scale. We therefore rely on the results of the bottom-up analysis to inform our assessment of the environmental premium.

4.3.3. Implications for the environmental premium

Figure 41 superimposes our best estimate of the progress curve for tidal lagoons on those for CCGT.

Figure 41: Implications for the environmental premium – tidal lagoons



As illustrated in Figure 41 above, tidal lagoon unit costs are expected to fall significantly as capacity builds, the main driver being the increase in size of project that can be financed once the technology is proven. (Although reductions in the cost of capital are also likely, for consistency, the cost of capital assumed has been held constant for the purposes of this analysis.) Under our central scenario, based on the assumption that project size increases to an optimum level of around 300MW, unit costs fall from £60.3/MWh (6.0p/KWh) currently to around £50.1/MWh (5.0p/KWh) at a global/UK[15] installed capacity of 1.26GW, a total decline of 17%. Under the high progress scenario, unit costs fall to £39.9/MWh (4.0p/MWh), or by a total of 34%; and under the low progress scenario, unit costs remain unchanged.

Under our 'best estimate', unit costs for tidal lagoons remain above those for CCGT even under the high gas price scenario at an aggregate installed capacity of around 1.26GW. For our base case for gas prices, an environmental premium is required throughout the period, equal to £32.23/MWh based on the current unit EAC and a project of just 60MW (as currently planned for Swansea Bay), reducing to £22.05/MWh by 2020. However, once again, the declining unit subsidy applies to an increasing number of MW of capacity, so the annual money amount of the premium increases over time (Figure 42).

For the projected build-up in UK tidal lagoon capacity, this implies a total NPV of the environmental premium at a discount rate of 3.5% real of £1,048m. Using a discount rate of 12%, as used in our modelling of unit EAC for tidal lagoons, this number reduces to £301m.

The implied CO_2 abatement cost where tidal lagoon is the marginal renewable technology declines from £80.59/tonne for the project size currently envisaged (60MW) to £55.13/tonne by 2020.

The implications for the environmental premium as deployment increases are set out in Figure 42 below for the base case.

Figure 42: The implications of large-scale deployment for the environmental premium – tidal lagoons

	2005	2010	2020
Global/UK installed capacity, GW	0	0.36	1.26
Annual increment in UK installed capacity, GW	-	0.36	0.30
Base case			
Premium, £/MWh	-	27.36	22.05
Premium, p/KWh	-	2.7	2.2
Annual environmental premium required in each year for aggregate capacity, £m, '04 prices	-	31	99
Implied CO_2 abatement cost, £/tonne	-	68.39	55.13

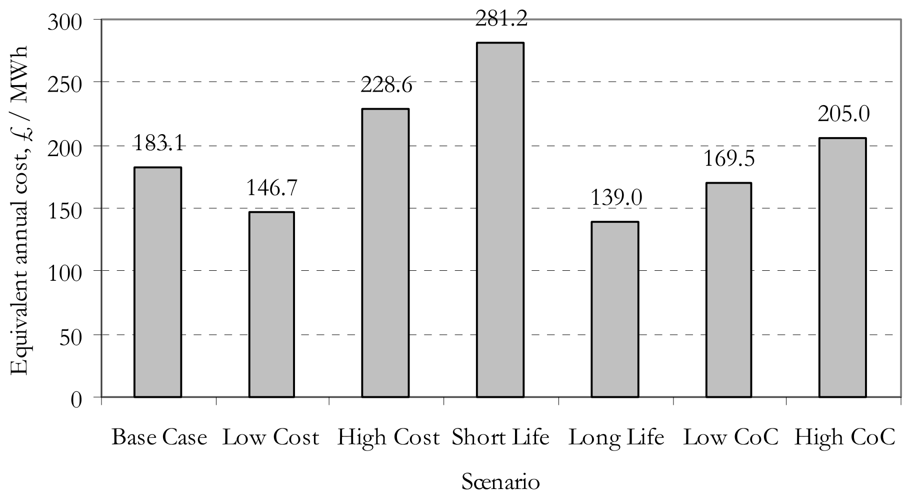
[15] *All capacity built in the period 2005-20 is assumed to be built in the UK.*

4.4. Wave and tidal

4.4.1. Current unit EAC

As shown in Figure 43, our estimated range for the current unit EAC for wave and tidal stream technologies is £147-£281/MWh, with a central estimate in the bottom half of this range of £183/MWh. This estimated range for current unit EAC is very wide, reflecting the considerable uncertainty surrounding even current costs.

Figure 43: Estimated current unit EAC – wave and tidal stream



Key to scenarios

Mid est	*EAC using base cost, CoC and operating life assumptions (see Section 3.4 for all)*
High est	*EAC using high cost and base CoC and operating life assumptions*
Low est	*EAC using low cost and base CoC and operating life assumptions*
Short life	*EAC using short operating life base cost and CoC assumptions*
Long life	*EAC using long operating life and base cost and CoC assumptions*
Low CoC	*EAC using low CoC and base cost and operating life assumptions*
High CoC	*EAC using high CoC and base cost and operating life assumptions*

4.4.2. Progress curves

Our estimated progress curves based on the bottom-up analysis and application of top-down progress ratios are shown in Figures 44 and 45, respectively. In each case, our central estimate of current unit EAC is taken as the starting point. (Due to the lack of available literature, a progress curve based on the current consensus in the literature could not be derived.)

The key issue with wave and tidal devices is that they are currently very much in the demonstration phase where it is very hard to apply the progress curve and other techniques to the costs in the industry. The current schemes in place in the UK to support these forms of devices are likely to establish the industry to the point where it is valid to look at progress curves by the end of the decade.

Figure 44: Bottom-up progress curves – wave and tidal stream

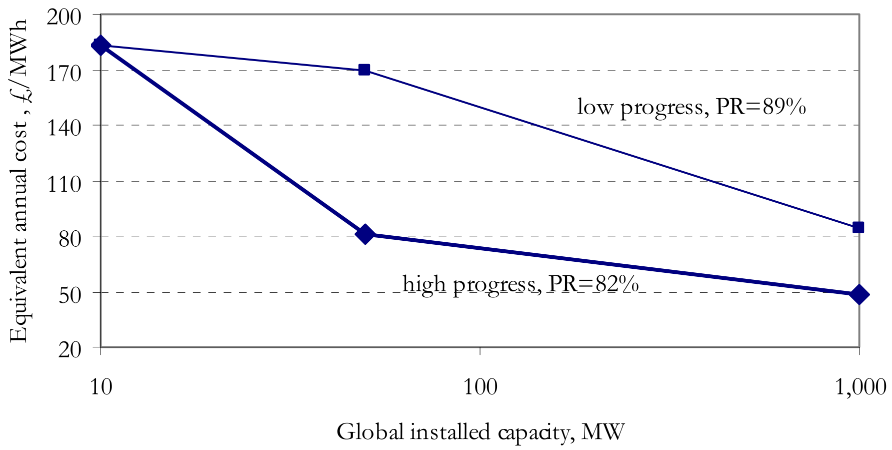
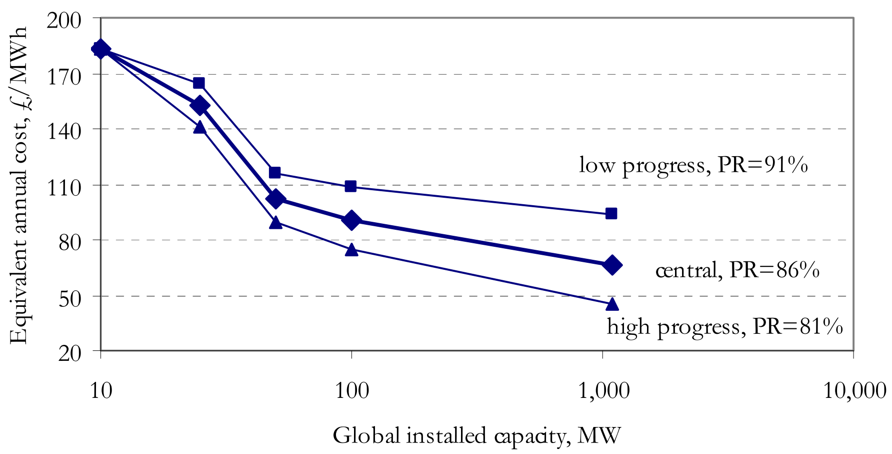


Figure 45: Progress curves based on application of top-down progress ratios – wave and tidal stream



Long-term bottom-up analysis for such a nascent industry is highly speculative. The main drivers for the bottom-up results are an assumed fall in operating and maintenance costs to figures that are close to and then potentially improve on offshore wind, and a hypothetical reduction in capital cost in the major machine components that are very similar in many cases (tidal in particular) to those observed in wind power. Hence we see the potential for the cost to fall in the long term to that of offshore wind.

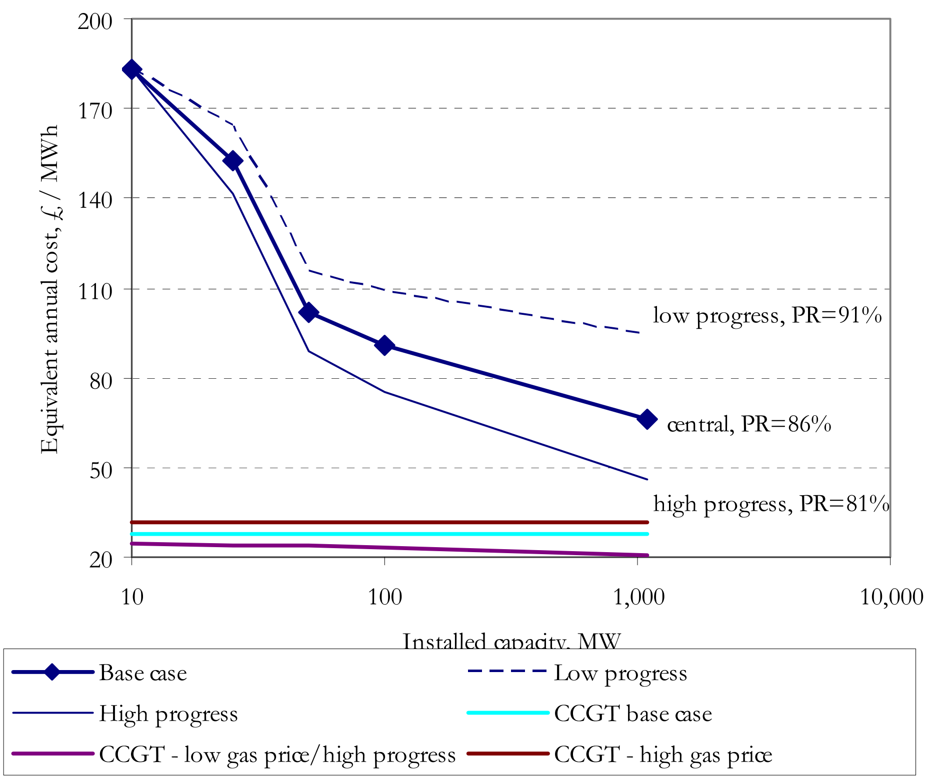
Rationale for selected 'best estimate' of progress curve

In assessing the implications for the environmental premium, we have relied upon the 'bottom-up' progress curve numbers as the base case. The rationale for this is that, given the time to market, it is very hard to undertake robust bottom-up analysis.

4.4.3. Implications for the environmental premium

Figure 46 plots our best estimate of the progress curve for wave and tidal stream technologies against our scenarios for CCGT.

Figure 46: Implications of the environmental premium – wave and tidal stream



As is clear from the figure, there is considerable scope for reductions in unit costs for these technologies as deployment increases. Indeed, under the central scenario, unit costs fall by a total of around 64% as global installed capacity rises to 1.1GW, from £183/MWh (18.3p/KWh to £66/MWh (6.6p/KWh). Under the high progress scenario the reduction totals 75%, to £46.5/MWh (4.6p/KWh); and under the low progress scenario, 48% to £94.5/MWh (9.4p/KWh).

Under our 'best estimate', unit costs for wave and tidal devices remain above those for CCGT even under the high gas price scenario at an aggregate global installed capacity of 1.1GW. For our CCGT base case, an environmental premium is required throughout the period, equal to £159.1/MWh in 2005 and reducing to £35.9/MWh by 2020. However, the declining unit subsidy applies to an increasing number of MW of capacity, and so again the annual monetary value of the premium increases over time (Figure 47). The monetary value of the premium is smaller for wave/tidal stream than the other renewable technologies considered in absolute terms because there are far fewer MWh generated from these sources.

For the projected build-up in UK wave and tidal stream capacity, this implies a total NPV of the environmental premium at a discount rate of 3.5% real of £577m. Applying a discount rate of 12% real, as used in our modelling of unit EACs for wave and tidal stream devices, reduces the NPV to £233m.

The implied CO_2 abatement cost where wave / tidal stream is the marginal renewable technology declines from £397.8/tonne currently to £89.6/tonne by 2020.

The implications for the environmental premium as deployment increases are set out in Figure 47 below for the base case.

Figure 47: The implications of large-scale deployment for the environmental premium – wave and tidal stream

	2005	2010	2020
Global installed capacity, GW	0.008	0.108	1.108
UK installed capacity, GW	0.004	0.054	0.554
Annual increment in UK installed capacity, GW	0.004	0.01	0.05
Base case			
Premium, £/MWh	159.12	62.57	35.85
Premium, p/KWh	15.9	6.3	3.6
Annual environmental premium required in each year for aggregate capacity, £m, '04 prices	2	14	75
Implied CO_2 abatement cost, £/tonne	397.80	156.42	89.63

5. DISCUSSION AND CONCLUSIONS

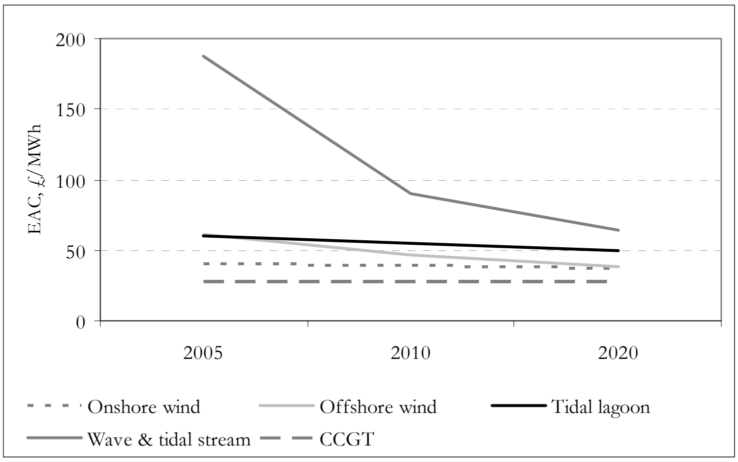
The development of estimated progress curves is a useful way to consider the likely evolution over time of renewable energy production costs, and therefore the magnitude of environmental premia required to induce investment in those technologies.

However, progress curves are inherently uncertain, particularly for pre-development technologies, which is what most of the marine generation technologies are. It is therefore important not to over-interpret the results or to draw conclusions that attribute greater robustness to the analysis than is warranted.

This study is based on a very limited exercise. The results should be regarded as useful indications of probable ranges of unit costs for the five renewable technologies as installed capacity increases. However, the high degree of uncertainty surrounding, in particular, the marine technologies must be stressed. Also, the actual reductions in unit costs are a function of the rate at which installed capacity increases, which is itself a policy variable given that all the technologies considered are uncompetitive, absent an 'environmental premium'. Further, although traditional progress curve analysis assumes a constant percentage reduction in unit costs as installed capacity doubles and then doubles again, our knowledge of the five technologies considered in this report suggests that constant rates of 'progress' are implausible, at least for some of the technologies.

The most robust part of the analysis is the estimation of the current EAC for each technology. The 'best estimate' of the evolution of unit costs for the five technologies derived from the estimated progress curves are summarised in Figure 48. It shows that the estimated base case current unit EAC for onshore wind is around £41/MWh, £62/MWh for off-shore wind, £60/MWh for tidal lagoons and £187/MWh for both wave and tidal stream technologies. These are central estimates for a 'typical' project and actual costs will vary significantly around these central estimates.

Figure 48: Summary of best estimates of unit cost evolution

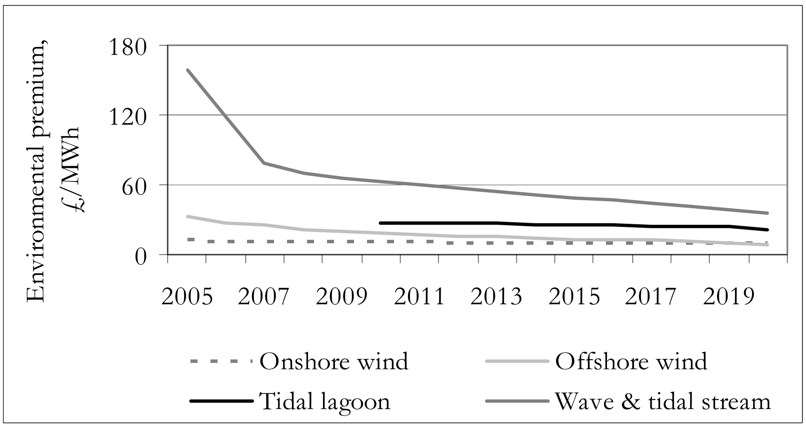


The central estimate for the progress curve for onshore wind has a low point of £37.39/MWh, which is 33% above our central estimate for the unit cost of CCGT. For offshore wind the numbers are £38.57/MWh, or 37% above CCGT; for tidal lagoons, £50.12/MWh, or 79% above CCGT; and for wave and tidal stream, £63.92/MWh, or 128% above CCGT.

None of the technologies are projected to be able to compete with conventional generation, absent payment of an environmental premium, unless conventional generation is required fully to pay for its external costs imposed on the environment.

Figure 49 summarises our estimates of the environmental premium for each of the technologies, expressed as a £/MWh amount over the period 2005-20, based on the assumed rate of deployment .

Figure 49: Summary of estimated environmental premia



To provide some indicative feel for the level and trend in 'subsidies' to renewable energy we have estimated for each technology the total payments required to bring forth the build up in installed capacity of each technology. Total payments to induce investment in the build-up of the portfolio of these renewable technologies is estimated as the sum across all technologies of the annual unit excess cost over CCGT unit cost times the projected annual output for each technology, assuming a growing contribution of each technology over time. The total 'subsidy' is the sum of the payments required to induce the build of the assumed portfolio of these technologies. Note that this does not include any benefit to the UK economy in reducing emissions under the ETS, where surplus allowances could be sold to other countries (or fewer purchased) and will include some inframarginal transfers. We have expressed this as a NPV, discounted at the public sector discount rate (3.5% real) as well as at the rate assumed for the cost of capital for each technology. The results of these calculations are summarised in Figure 50.

Figure 50: Total 'subsidy' required by technology

	Assumed aggregate installed capacity in 2020, GW		**Total 'subsidy' required, NPV, £m**	
	UK	**Global**	**Discount rate = 3.5% real**	**Discount rate = 10%/12% real ***
Onshore wind	10.4	190.0	3,037	1,354
Offshore wind	11.6	42.0	7,085	2,431
Tidal lagoon	1.26	1.26	1,048	301
Wave and tidal stream	0.55	1.11	577	233
Total	**23.8**	**234.4**	**11,748**	**4,318**

** Discount rate is 12% for all technologies except onshore wind where 10% is used.*

Figure 51 summarises the implied CO_2 abatement cost per tonne for each of the technologies assuming that that technology is and remains throughout the period the marginal renewable technology. In 2020, the abatement cost for onshore wind is £23.24/tonne, £26.26/tonne for offshore wind, £55.13/tonne for tidal lagoons and £89.63/tonne for wave/tidal stream. By contrast, the current CO_2 price on the EU Emissions Trading Scheme (ETS) market is around EUR17.25/tonne (slightly less than £12/tonne, with the range since launch in January 2005 around EUR8-17.50 or £5-12.)

Figure 51: CO2 abatement cost by technology

£/tonne CO2	2005	2010	2020
Onshore wind	30.54	27.44	23.29
Offshore wind	83.67	46.23	26.26
Tidal lagoons	-	68.39	55.13
Wave/tidal stream	397.80	156.42	89.63

It is important to reiterate that the sum of the unit 'environmental premium' and the wholesale energy price will not equal the cum-ROCs price for renewable energy. With the current ROC scheme, the ROC premium is determined by the cost of the marginal (most expensive) renewable capacity. This premium accrues to all intra-marginal producers. Therefore, total payments to induce investment in a diversified portfolio of these technologies with the current ROCs scheme will be much higher than the sum of the environmental premia estimated above.

The UK Government renewables target envisages 10% of total energy output generated by renewables by 2010, 15% by 2015 and 20% by 2020. Of these total amounts, the shares of onshore and offshore wind, marine technologies and 'other' renewables is set out in Figure 50 above. Up to 2010, the 'marginal' renewable is expected to be offshore wind. The marginal additions over the period 2010-2020 are expected to come from a mix of offshore wind and marine technologies.

We have used the progress curves and the assumed build up of each renewable technology to estimate an order of magnitude 'marginal' environmental premium. If the assumed cost of capital reflects the true market cost of capital then these calculations provide an estimate of the monetary value of the ROC premium required (if all the subsidy is delivered via this mechanism) over the period to 2020. The estimates for the ROC premium and total subsidy required are set out in Figures 52 and 53.

Figure 52: Estimated ROC premium per MWh

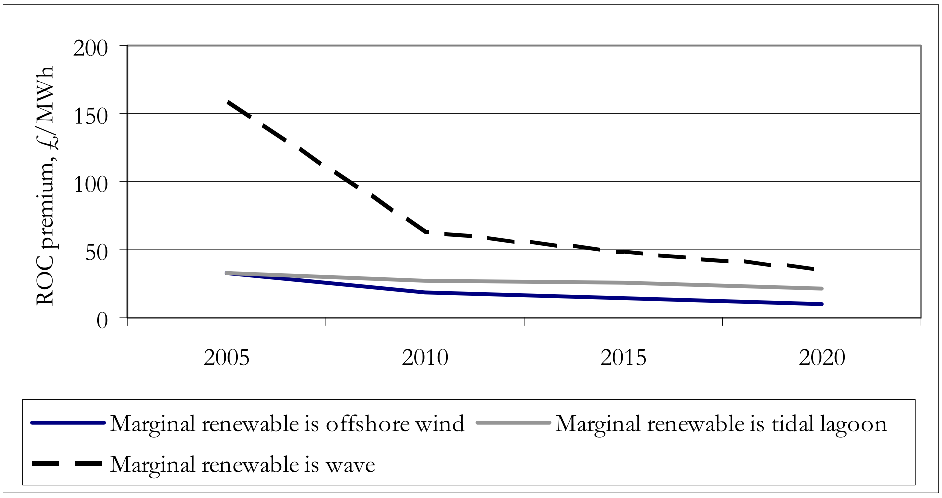
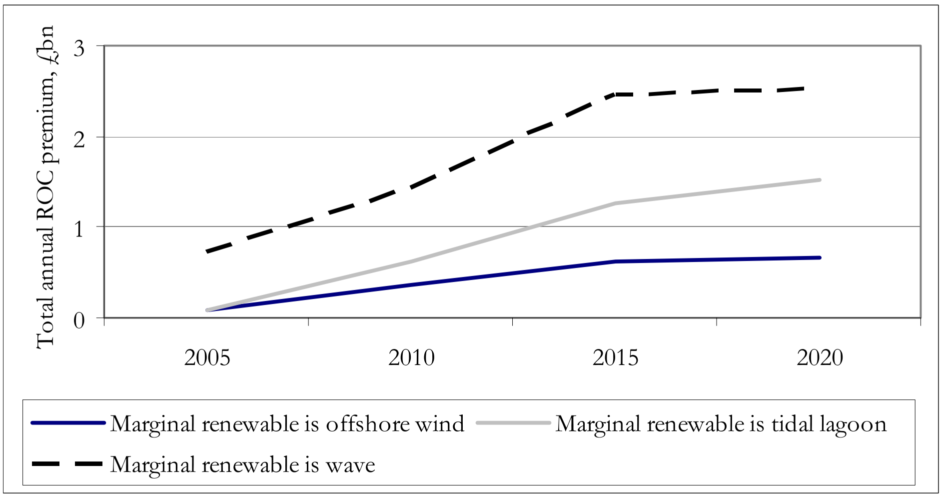


Figure 53: Estimated total ROC subsidy required



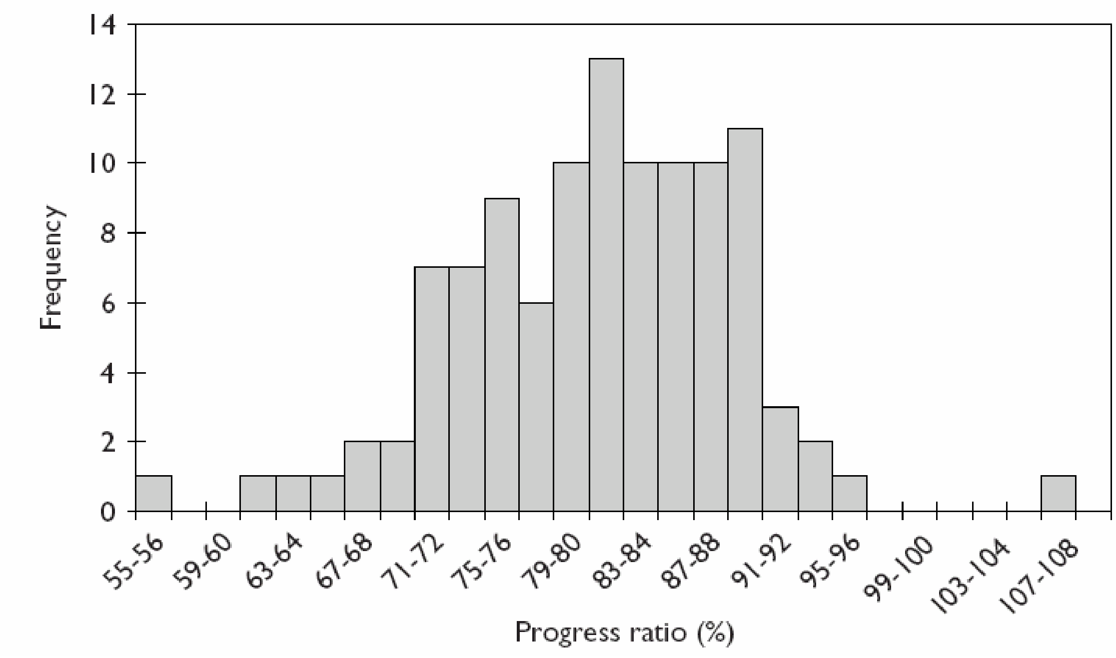
ANNEX 1: EVIDENCE ON PROGRESS CURVES FROM OTHER INDUSTRIES

Top-down progress curves have long been estimated for a wide variety of technologies in a range of industries. Indeed, the progress curve concept goes back more than a century and was first formally used in an industrial context in 1936 in a paper by Wright on the cost of airplanes[16]. There is consequently a rich literature on the historical evolution of unit costs for emerging technologies. It is notable, however, that there is extremely limited evidence on the accuracy of estimated progress curves as forecasts for the future evolution of unit costs.

This Annex provides a flavour of the available literature on progress curves, focussing particularly on energy-related technologies.

Perhaps the most comprehensive cross-sectoral review of top-down progress curves in recent times is that of Dutton and Thomas (1984). Their study recorded the observed progress ratio for manufacturing processes in 108 individual firms spanning a range of industries, including energy, aircraft manufacture, electronics, steel and car production. The results of their study, summarised in Figure A1.1, suggest a modal value for the progress ratio of 81-82%, within a range of 60-96% (ignoring outliers).

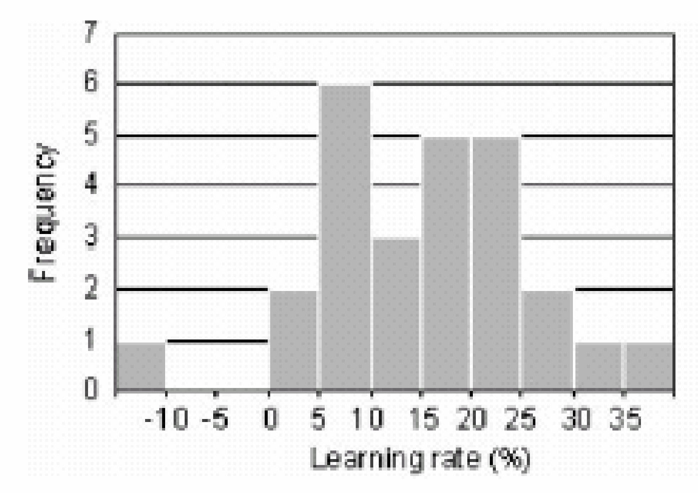
Figure A1.1: Summary results of Dutton and Thomas (1984)



Source: Dutton and Thomas (1984) in IEA (2000)

McDonald and Schrattenhholzer (2000), meanwhile, provides a (more recent) comprehensive collation of top-down progress curve analyses conducted in mainly energy industries, including renewables, in the OECD. As shown in Figure A1.2, the distribution of progress ratios is broadly similar to that provided in Dutton and Thomas (1984), spanning the range 60-100% (again ignoring outliers), with a central estimate of around 85% (though the mode is higher at 90-95%).

Figure A1.2: Summary results of McDonald and Schrattenholzer (2000)



Source: McDonald and Schrattenholzer (2000), p4

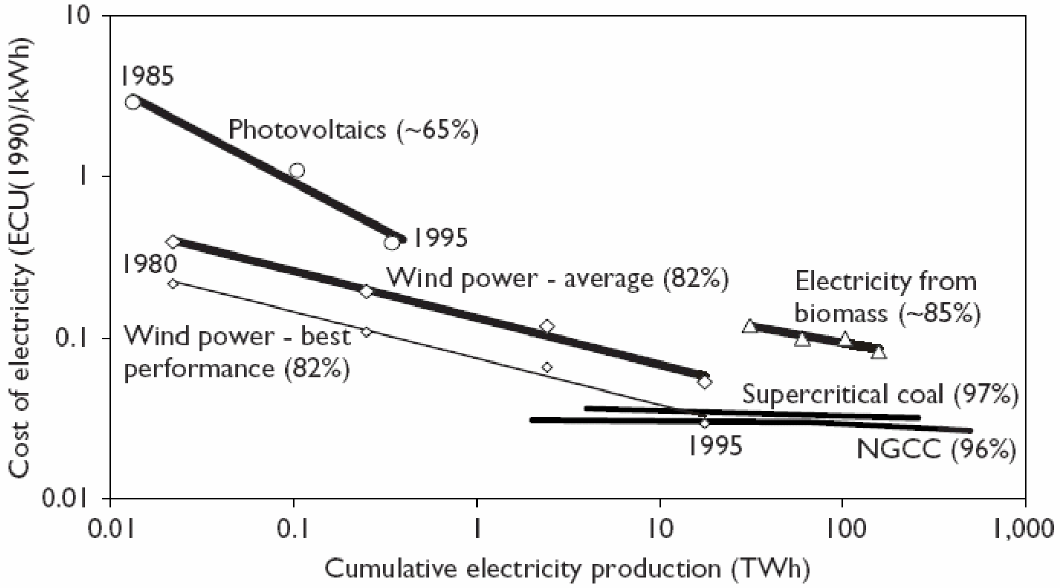
McDonald and Schrattenholzer (2000) also makes two additional observations of interest. First, they note that the results and goodness of fit of individual studies reviewed vary widely, even across for the same technology. Second, they point to evidence suggesting that progress ratios increase (i.e. percentage unit cost reductions decline for a given percentage increase in cumulative capacity) as a technology matures, leading to 'kinked' progress curves, an observation supported by a number of other studies (e.g. Gielen et al (2004).

With respect to electricity generation in particular, IEA (2000) provides a useful graph (replicated below) that plots estimated top-down progress curves for various generation technologies.

[16] *Wright, T (1936), "Factors affecting the cost of airplanes", Journal of Aeronautical Science, Volume 4, No. 4. In IEA (2000) op. cit.*

Figure A1.3: Progress curves for electricity generation technologies in the EU (from IEA (2000))

Figure 1.5. Electric Technologies in EU, 1980-1995



Cost of electricity and electricity produced from selected electric technologies installed in the European Union 1980-1995. Numbers in parentheses are estimates of progress ratios. Data for renewable technology are from the EU-ATLAS project. The curve for Natural Gas Combined Cycle (NGCC) is calculated for EU based on the information in Claeson (1999). The progress ratio for supercritical coal power plants is based on a US study of Joskow and Rose (1985). For the fossil technologies, the fuel prices have been set constant at the 1995 level. EU-ATLAS data are available for five-year intervals for the period 1980-1995 (Marsh, 1998) and do not permit more than very rough estimates of the progress ratios for photovoltaics and electricity from biomass.[6] The two curves for wind power show the average production cost and the production cost from the plants with the best performance.

E2I/EPRI (2004) in their study into the economics of offshore wave power quote a range of progress ratios from other industries in related fields including an analysis showing a progress ratio of 82% for solar PV technology. Their study also quotes literature sources that suggest that in the US progress rates of 80% have been observed in gas turbine, onshore wind and solar PV technology.

There are also a number of studies that have looked specifically at experiences within the onshore wind industry. Most recently, Junginger et al (2005) estimates progress ratios for the UK and Spanish onshore wind industries (Figure A1.4) as well as citing the results of studies for other country studies (Figure A1.5).

Figure A1.4: Estimated progress ratios for onshore wind

	Progress ratio
UK 1992-2001	79-81%
Spain 1990-2001	80-85%
Spain 1990-98	77-82%

Source: Adapted from Junginger (2005)

Figure A1.5: Progress ratios for onshore wind estimated/used by other studies

Country	Study*	Progress ratio estimated/used
Denmark	Ibenholt (2002)	88-93%
	Neij (1997, 1999a and b)	91-96%
	Dannemand Andersen & Fuglsang (1996)	80%
	Lund (1995)	85%
Germany	Ibenholt (2002)	92-103%
	Durstewitz & Hoppe-Klipper (1999)	92%
UK	Ibenholt (2002)	75%
EU	EWEA and Greenpeace (2002)	85% (to 2010), 90% (2011-26), 100% post 2026
US	MacKay & Probert (1998)	85.7%

Source: Adapted from Junginger et al (2005)

* *op. cit. Junginger et al (2005)*

ANNEX 2: ESTIMATING THE EAC AND PROGRESS CURVES FOR CCGT ELECTRICITY GENERATION

In estimating the progress curve for CCGT, we have adopted the approach used to conduct the bottom-up progress analysis for the renewable technologies identified, using the same underlying general assumptions as set out in Figure 6 in Section 3. Consequently, the resulting progress curve should be directly comparable to those used elsewhere in this study.

As discussed in Section 3, for transparency, we have derived low, medium and high cost scenarios for the progress curve, with the scenarios differing according to the assumptions made on (i) the gas price and (ii) the reductions in unit costs likely to be forthcoming as a result of learning by doing, innovation or any of the other relevant factors (Section 2.3.2).

These assumptions are set out in Figure A2.1.

Figure A2.1: CCGT progress curve scenarios

Scenario	Reduction in unit costs, % pa	Gas price, p/therm
Low	1	20
Medium	0	25
High	0	30

Additional CCGT-specific assumptions are set out in Figures A2.2 and A2.3.

Figure A2.2: Production assumptions for CCGT

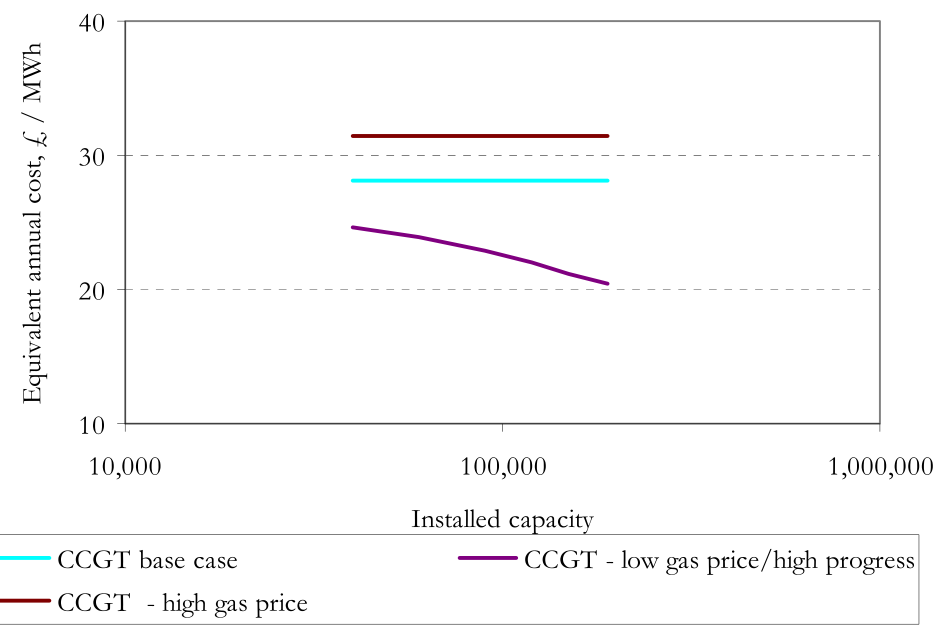
	Assumption	Basis for assumption
Annual load factor, %	90%	High load factor assumes plant will run close to base load
Fuel efficiency, %	55%	Conservative and consistent with current technology (some new technologies may operate higher, but this is also dependent on site conditions)
Construction period, yrs	2	Accepted build period for a CCGT
Operating life, yrs	20	Normal working assumption for investment case
Assumed debt tenor, yrs	15	Typical debt tenor for a large infrastructure project with stable cash flows

Figure A2.3: Cost assumptions for CCGT

	Assumption	Basis for assumption
Gas price, p/therm	30	Part of a range of estimates
Investment cost, £m/MW	0.40	CCC estimate – consistent with literature
Annual operating costs, £ /kW	19	CCC estimate (varies by location)
Annual maintenance costs, £/kW	14	CCC estimate

The resulting progress curves are shown in Figure A2.4 below.

Figure A2.4: Estimated progress curves for CCGT



ANNEX 3: ASSESSING THE IMPACT OF GRID COSTS

Within the context of this benefits assessment it is appropriate to consider the impact of grid costs associated with additional capacity in the three classes of renewable generation under scrutiny.

Three principal sources have been adopted to inform cost estimates, the SCAR report of 2002[17], the Renewables Network Impact Study of 2004[18] (the Impact Study) and the SKM Technical Evaluation of Transmission Network Reinforcement Expenditure Proposals of 2004[19] (SKM). These reports differ in their approach insofar as both the Impact Study and SKM incorporate a bottom-up assessment of near-term network requirements, the former reflecting proposals within developers' business plans and the latter the transmission licensees' estimates of expenditure requirements. The Impact Study goes on to use a scenario approach to assess the impacts of higher levels of renewables capacity, an approach that is mirrored in the SCAR report. The Impact Study and the SCAR report are to some extent comparable. The former considers the effects of securing a target of 10% of electricity supply from renewable sources by 2010 and a 20% target for 2020. The SCAR report assumes a baseline of 10% of demand met by renewables from 2010, and considers the effect of low and high scenarios under which renewables meet 20% and 30% of demand in 2020 respectively.

Outputs of the various studies are summarised in Figures A3.1 and A3.2 below.

Figure A3.1: Summary of bottom-up analysis

Study	Scenario	Transmission reinforcement (£bn)		Distribution reinforcement (£bn)
		3.6 GW by 2009/10	72% of 2010 target	
SKM	Regulated costs	0.8		
	Costs of complete works	1.6		
Network Impacts	High		2.1	0.5
	Low		1.4	

[17] *Quantifying the System Costs of Additional Renewables in 2020, Ilex Energy Consulting and UMIST, October 2002*

[18] *The Carbon Trust and DTI, Renewables Network Impacts Study, Mott McDonald, April 2004*

[19] *Technical Evaluation of Transmission Network Reinforcement Expenditure Proposals by Licensees in Great Britain – Draft Report for Public Release, SKM, August 2004*

Figure A3.2: Summary of scenario analyses

		Transmission reinforcement			Distribution reinforcement		
		Percentage renewables					
Study	**Scenario**	**10%**	**20%**	**30%**	**10%**	**20%**	**30%**
SCAR	North wind – high demand		1.1 (2.4)	3.0 (4.3)	0.6	0.4 (1.0)	0.8 (1.5)
	Wind & biomass – low demand		0.1 (1.4)	0.2 (1.5)	0.6	0.1 (0.7)	0.2 (0.8)
Network Impacts	High	0.7 (2.1)	1.1 (3.2)		0.3 (0.8)	1.0 (1.8)	
	Low	0.4 (1.4)	0.9 (2.3)		0.2 (0.7)	0.7 (1.4)	

The SCAR report uniquely presents estimates in terms of costs per unit of output for both transmission and distribution costs (Figure A3.3). Note that the transmission costs include reinforcement and losses, unlike other studies that have concentrated upon reinforcement only.

Figure A3.3: Unit costs for transmission and distribution

Scenario	**Renewables as % of demand**	**Unit Costs (£/MWh) by additional generation**			
		Transmission reinforcement & losses		**Distribution**	
		Renewables	**Wind**	**Renewables**	**Wind**
North Wind – High Demand	30%	2.84	2.84	0.64	7.3
North Wind – Low Demand	20%	2.33	2.33	0.52	6.23
Wind & Biomass – High Demand	30%	-0.09	-0.18	0.15	0.29
Wind & Biomass – Low Demand	20%	-0.10	-0.21	0.17	0.34
Diverse Mix – High Demand	30%	1.21	1.51	0.63	0.79
Diverse Mix – Low Demand	20%	0.80	1.00	0.54	0.67

Beyond the specific results, a review of these studies reveals a number of important considerations.

- Firstly, the estimates are highly uncertain, particularly in respect of the longer-term, scenario-based projections. The SCAR report suggests that the estimates it presents should be taken as indicative of the order of magnitude of the likely costs.

- Secondly, the cost estimates are highly location-specific. The most significant spatial factor is the siting of additional renewables capacity with respect to the major transmission constraints that exist between northern Scotland and the north of England. However the SCAR report also illustrates the sensitivity of distribution network cost projections to local concentrations of generation[20] and to the availability of land area for renewable development[21]. Also significant in the spatial context is the availability of a transmission connection; in its *North Wind* scenarios, the SCAR report sees an approximate halving of distribution network costs if all offshore wind is transmission-connected, and a further halving if 50% of onshore wind is similarly configured. Transmission costs are unaffected between these scenarios.

- Further factors reflecting the inter-relationship between generating plant and network configuration are also significant, particularly with respect to distribution costs. These include the size distribution and operating characteristics of other embedded plant and the availability of active voltage management[22].

The pattern of costs that emerges from this complex set of factors and interrelationships between grid and generator presents difficulties in assimilating grid costs within the overall benefits analysis.

At a practical level there is no apparent scientific relationship between capacity growth and grid costs. Grid-related costs facing any individual project will arise through a combination of factors including planning, project design and configuration, and network constraints that may be binary or cumulative in nature. When viewed across Great Britain as a whole, the relationship between cumulative generating capacity and output becomes highly stochastic and is not amenable to incorporation within the modelling approach. Added to this:

- The variability in grid costs facing renewable generators that are intrinsically similar but which face different grid conditions suggests that these costs are properly considered an exogenous factor;

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[20] *When compared to a uniform distribution case, 'clustering' is estimated to increase costs by between 7% and 21%.*

[21] *Reducing the land available for renewable development from 70% to 20% effectively doubles the distribution costs under both the 'North Wind High' scenarios active voltage management is demonstrated to reduce distribution reinforcement costs by c.40%.*

[22] *Under the SCAR North Wind 30% scenarios*

- With the high degree of uncertainty highlighted by various studies, there is a risk that the wider modelling outputs may be distorted;

- Should grid costs be incorporated in the consideration of generator costs for renewable technologies, the counterfactual conditions applied in this analysis – specifically the construction and operation of a CCGT – should similarly encompass grid-related costs.

At the level of principle, it is worth highlighting that many of the costs incurred in the connection of new renewable generation are a function of the legacy of a network configuration that has been determined over time by a set of historic constraints and preserved by the long-term capital characteristics of the sector. Supply independence, concern over nuclear safety, central planning and public ownership of assets have all been shaping factors. However, under today's constraints a very different configuration of network would emerge that would likely provide for greater efficiency in the integration of grid and renewable generation sources.

On the basis of these considerations it is considered inappropriate to reflect grid costs in the analysis.

Intermittency and backup

All forms of generation display intermittency characteristics that will impact upon security of supply and present impose a requirement for backup, balancing or other forms of system support within an interconnected network. The variable nature of many renewable energy sources means that individual generating plant can display a higher degree of intermittency and a lesser degree of predictability, particularly over the very short time horizon, than is typical for thermal plant.

The SCAR report provides a comprehensive attempt to quantify these system costs, and some of the key results are summarised in Figure A3.4, broken down between costs of maintaining capacity margin and system balancing costs. The latter appear consistent with NGT estimates[23] that suggest:

- with 8,000 MW of wind needed to meet the 10% renewables target in 2010, balancing costs are expected to increase by around £2 per MWh of wind production, representing an additional £40 million per annum; and

[23] *Enterprise and Culture Committee: Evidence Received for Renewable Energy in Scotland Inquiry, National Grid Transco, February 2004*

- with sufficient wind to meet 20% of energy sales balancing costs might reach an additional £3 per MWh of wind produced, increasing balancing costs by around £200 million per annum.

Figure A3.4: System costs for transmission

Scenario	**Renewables as % of demand**	**Annual capacity**	**Annual balancing**	**Annual balancing & capacity**	**Unit costs (£/MWh) by additional generation**	
	(£m)	(£m)	(£m)	(£m)	Renewables	Wind
North wind – high demand	30%	407	217	624	7.3	7.3
North wind – low demand	20%	168	77	246	6.23	6.23
Wind & biomass – high demand	30%	216	103	319	3.74	7.48
Wind & biomass – low demand	20%	84	40	124	3.14	6.29
Diverse mix – high demand	30%	315	170	485	5.68	7.10
Diverse mix – low demand	20%	114	66	181	4.58	5.72

Wind, above all other sources, displays a high degree of intermittency and considerable analysis has been directed towards assessing the costs of this aspect of wind generation.

In contrast to the situation observed with respect to system reinforcement, it is apparent that a clear, scientific relationship exists between the levels of installed wind capacity and system effects. With specific regard to capacity, a number of studies have demonstrated that the capacity credit for wind declines as the capacity rises above a few giga-watts in the UK, but remains non-negligible for contributions of up to 20% of electricity supply[24]. The SCAR report notes, for instance, that the marginal contribution to capacity (capacity credit) made by wind declines with increasing penetration of wind; while 4GW of wind generation displaces c.1.5GW of conventional plant, 20GW will displace only 4GW of conventional plant.

[24] *Diversity and Security in UK Electricity Generation: The Influence of Low Carbon Objectives, CMI Working Paper, Grubb, Butler & Sinden.*

However, while the level of wind capacity on a system is evidently a determining factor that can be ascribed to the wind generation, other factors that are independent of the technology will also contribute to the pattern of costs . In particular, the contribution of diversity of the generation mix[25] and geographical distribution of wind generating sites[26] are identified as factors that have a significant bearing on cost.

As with reinforcement these suggest a significant impact of external factors in contributing to the overall cost profile. This suggests that with respect to this analysis of technological benefits it is appropriate to exclude backup and system costs at this stage.

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[25] *Submission to The Science and Technology Select Committee of the House of Lords: The Practicalities of Developing Renewable Energy Stand-by Capacity and Intermittency, Environmental Change Institute, University of Oxford, 2004. This paper demonstrates empirically that a combination of intermittent generating sources (wind, PV, microCHP) are highly reliable in meeting peak demand, with this combination of technologies achieving an 87% reduction in standby capacity requirement as compared to wind alone.*

[26] *Grubb et al demonstrates that wind speed correlation decreases with increasing distance between wind generating sites. In cases where new sites are developed that show a low correlation with existing sites, the overall variability of electricity supplied from the wind power portfolio would be reduced and hence the reliability of supply improved.*

ANNEX 4: METHODOLOGY FOR CONSIDERING THE IMPLICATIONS FOR THE ENVIRONMENTAL PREMIUM

This Annex sets out the methodology used in Section 4 for assessing the implications for the 'environmental premium' for each of the technologies considered, and in particular the cost per annum over and above the cost of CCGT that would need to be paid in the case of each renewable technology considered.

The first step is to map the base case progress curves estimated for each of the technologies onto an assumed annual build-out trajectory for both the industry as a whole (i.e. globally) and for the UK. The 'environmental premium', i.e. the difference unit cost of the renewable technology over and above that of CCGT, is then calculated for the global installed capacity assumed in each year. To illustrate, the assumed trajectories for onshore wind and the implied environmental premium in each year are show in Figure A4.1 below for the first five years of the period under consideration.

Figure A4.1: Illustration of the build out trajectories and associated environmental premia for onshore wind

Base case	2005	2006	2007	2008	2009
Global installed capacity, MW	47,000	54,000	61,000	68,000	76,000
UK installed capacity, MW	1,570	2,020	2,520	3,020	2,620
Environmental premium, £/MWh	£12.22	£11.91	£11.62	£11.43	£11.20

This provides the £/MWh 'environmental premium' for additional capacity installed in the year in question required throughout the operational life of the project. This is used to estimate the annual monetary value of the premium by multiplying the premium by the number of MWh/year.

To translate this into a total premium required by the UK industry to move from the current position to the assumed position by 2020, the net present value (NPV) of the sum of the premia required by incremental projects installed in each year is computed. The annual premium required by a single project is the environmental premium relevant to the build year multiplied by the number of hours in a year multiplied by the assumed load factor multiplied by the project size. As different project lives have been assumed for the different projects considered, the stream of annual premia over the assumed project life need to be put on a NPV basis to make them comparable across technologies.

Given the long period over which output is generated, the NPV is highly sensitive to the discount rate used. A detailed analysis of the appropriate discount rate is beyond the scope of this study, and so the precise numbers derived should be interpreted with care. Instead we have presented the NPV using two alternative discount rates:

- 3.5% real, in line with the public sector discount rate; and

- The (nominal) rate assumed for the cost of capital in our modelling of unit EACs, i.e. 10% for onshore wind and 12% for the other technologies considered (i.e. 8% real for onshore wind and 10% real for other technologies).[27]

The sum of the NPVs for all the incremental projects then provides the NPV of the total premium required by the UK industry. Figure A4.2 illustrates for onshore wind (again for the first 5 years of the period under consideration).

Figure A4.2: Illustration of computation of total premium required by UK onshore wind industry

		2005	2006	2007	2008	2009	…	NPV
Load factor	30%							
Project life	20 yrs							
Real discount rate	3.5%							
Incremental UK capacity, MW		750	450	500	500	600		
Premia required, £m								
2005 build		24.08	24.08	24.08	24.08	24.08	…	354
2006 build		0	14.09	14.09	14.09	14.09	…	200
2007 build		0	0	15.27	15.27	15.27	…	210
2008 build		0	0	0	15.01	15.01	…	199
2009 build		0	0	0	0	17.66	…	226
TOTAL (for 5 yrs considered), @ 3.5% real discount rate							…	1,190

[27] Note that the tax shields in the commercial analyses are influenced by the rate of inflation so the translation of the private cost of capital to a discount rate for the programme cost should be used with care.

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