CARBON TRUST

Making business sense of climate change

Policy frameworks for renewables

Analysis on policy frameworks to drive future investment in near and long-term renewable power in the UK

A study funded by the Carbon Trust and carried out by L.E.K. Consulting in conjunction with the Carbon Trust

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Preface

This study had two principal objectives:

1. To review the case for renewable electricity generation in the light of the Energy Review; and
2. To explore alternative support frameworks and policies that would allow near and longer-term Government objectives for renewables to be met cost-effectively.

Implications of new policy frameworks were tested in detail on three renewable technologies: onshore wind, offshore wind and marine. These technologies were deliberately chosen because they are at different lifecycle stages. The underlying frameworks could equally be applied to other renewable energy sources and to low-carbon technologies in general.

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1 Executive summary

1.1 Near-term situation — up to 2020 (onshore and offshore wind)

There is a strong case for acting now to promote offshore wind in the UK. Offshore wind has the ability to contribute at scale to the emerging 14GW conventional capacity gap[1] by the end of 2015, a gap equivalent to 18% of required UK generating capacity. It can also assist in achieving both carbon and renewable energy targets, provide longer-term, abundant, cost-competitive electricity generation without fuel source security concerns, and create significant economic and employment benefits for UK industry.

The main pillar of the current renewable energy policy, the Renewables Obligation (RO), will cost consumers c.£14bn by 2020 and c.£18bn by 2027 (in present value terms).[2] It is expected to result in renewables penetration at 7.6%, 9.6% and 10.1% of generation by 2010, 2015 and 2020 respectively. This would mean renewable energy penetration would be only three-quarters towards the target for 2010, and only halfway towards achieving the 2020 aspiration of 20%. Performance against these goals is held back in part by frictions such as planning and grid constraints, which are restricting installed capacity of the lowest cost technology (onshore wind), but also by the inefficiencies of the policy itself.

The overall cost of installed renewable energy to consumers[3] will be higher than necessary, given the current technology cost because the RO is inefficient in a number of ways. First, because the RO is designed to 'pull through' lowest cost technologies sequentially, it is not closing the funding gap for offshore wind fast enough to stimulate the necessary momentum for the 2015 timeframe. It is not succeeding in driving offshore wind installation and reductions in the offshore wind cost curve. Secondly, the RO (by design) passes regulatory risk to the private sector, which the private sector accordingly prices at a premium. This leads to leakage of the subsidy away from developers, as suppliers take a margin to deal with this risk and funding from financiers is therefore available on less favourable terms than it would otherwise be. There is wide and growing consensus that the RO needs to be adapted or changed; not doing so will introduce an element of political risk that may be very difficult to manage, associated with sustained high Renewable Obligation Certificate (ROC) prices and renewables delivery below Government targets.

Without additional support for offshore wind, the development of offshore wind installations at scale in the UK (and very likely worldwide) will be held back; the UK renewable energy targets will be missed by a wide margin, carbon emission reduction targets will be harder to meet and an opportunity for renewable energy to become a

[1] Based on the net capacity of conventional fossil fuel and nuclear plant scheduled for retirement.

[2] Discounted at the UK Gilt rate (2.75% in real terms as of March 2006). Assessment of the cost of the current RO does not assume any extension of the obligation beyond 15% of electricity supply. Costs are presented as monies spent, not committed by a certain date.

[3] In terms of the cumulative subsidy per MWh of renewable energy generated.

meaningful component of the UK's energy mix may pass. UK action is required now to push offshore wind down in cost, to become competitive without subsidy, and to develop an export platform in what is a major growth technology, such as has been achieved by Japan in PV and Denmark in onshore wind.

Various policy choices exist to close this funding gap for offshore wind, each involving different funding requirements and different levels of change to the RO. These different policies attempt to address one or more of the inefficiencies of the RO and result in varying levels of costs, benefits and renewables penetration. While there is no straightforward solution, the analysis suggests that any option that targets and brings forward support for more rapid development of offshore wind is a more efficient use of subsidy than allowing the RO mechanism to run its course over a much longer timeframe. Any option chosen should, in accordance with DTI statements in the last RO Review, involve grandfathering of existing projects.

The most efficient solution in terms of cost per unit of energy and achieving maximum offshore wind capacity by 2015 involves moving away from the current RO towards a fixed mechanism which can take many forms. One such mechanism examined in this study is a Renewable Development Premium, which in effect is a 'stepped' fixed feed-in tariff. A fixed premium on top of the wholesale electricity price and Levy Exemption Certificate (LEC) payment is set at levels appropriate for investment at a given stage of the technology's maturity. The tariff is guaranteed for the life of a given project. The level of the feed-in for new projects would be 'stepped' down with expected cost reduction indicated by installed capacity. Feed-in tariffs have been proven to be successful elsewhere (Spain and Germany) in generating significant deployment of low-cost renewable energy. The analysis suggests that a Renewable Development Premium in the UK will result in 8.8GW of additional wind capacity[4] by 2015, when combined with additional funding of c.£1bn by 2020 (in present value terms). This is c.3.5GW more wind capacity than the base case representing the current RO policy, equivalent to a difference of c.3.5% of electricity generation by 2015. As a result, new wind capacity would make a meaningful contribution of c.16%[5] towards filling the 2015 emerging conventional capacity gap and an even greater contribution in terms of generation. It also provides a mechanism for tapering support away from onshore wind as it becomes more competitive with non-renewable technologies. However, this change would involve ongoing Government involvement and a major shift from the current framework. This option can be designed to cost less, the same, or more than the current RO policy. The analysis suggests that combining this policy with some extra funding of c.£1bn by 2020 (in present value terms) allows the UK to get close to achieving its renewables targets, while still realising a lower subsidy cost per unit of electricity than alternative options. If funding were restricted to the level implied by the RO, the Renewable Development Premium would deliver c.3.1GW more capacity (c.3.1% of electricity generation) in 2015 than the base case. The efficiency of the Renewable Development Premium is perhaps best demonstrated by the fact that it could achieve broadly the same level of renewables capacity as projected for the existing RO, at a saving of c.£1bn by 2020 and c.£3bn overall (in present value terms). This would be achieved by keeping the profitability of future onshore wind development in line with required investment returns, while providing sufficient incentive to encourage offshore wind investment at a level where future deployment is reinforced by offshore wind's move down the cost curve.

Other solutions that deliver offshore wind capacity by 2015 but require minimal change to the current RO are also available. Examples include extra revenue support, capital grants, and npower's suggestion of a Government agency entering into a fixed price agreement with developers. With the exception of npower's proposal (where the cost is more uncertain), these also require additional funding of c.£1bn by 2020 (in present value terms), but none of them deliver the same amount of renewable capacity as the Renewable Development Premium.

If extra funding or moving away from the RO entirely is considered infeasible, there are other alternatives that involve re-distributing funds from onshore to offshore wind within the current system. Examples include multiple/fractional ROCs (a form of banding involving significant change to the RO) and a proposal from Shell which could be modified to include grandfathering. The modified Shell proposal studied in this report involves a £5 cap on onshore recycle premiums with the surplus re-distributed to offshore wind. Multiple/fractional ROCs, like the Renewable Development Premium, provide a mechanism for tapering support, but are complicated and require ongoing Government involvement. However, assuming grandfathering, these 'costless' options do not deliver as much overall wind capacity by 2015 as the other options analysed. For the modified Shell proposal this is because, with grandfathering, it takes time for monies to build up to allow the funding gap to be closed for a significant number of offshore wind projects. Multiple/fractional ROCs can, with firm targeting of funding towards offshore wind and away from new onshore, deliver significant offshore wind in the 2015 timeframe, however, there is a sizeable trade-off against new onshore development which leads overall to a limited amount of additional net wind capacity by 2015.

[4] Additional to current forecast wind capacity by end of March 2007 of c.2.4GW (of which more than three-quarters is onshore).

[5] Assuming a capacity credit of 25% for wind generation, to allow for intermittency, at a level of c.10% of total electricity generation in 2015 (applied to 8.8GW of new wind capacity). The additional wind capacity of 3.5GW deployed as a result of the Renewable Development Premium, over and above that achieved by the existing RO policy, would contribute c.6% towards the 2015 capacity gap (representing a 40% increase in the overall contribution from new wind capacity).

***Figure 1:** Overview of alternative policy support mechanisms*

<table>
<tr><th rowspan="2"></th><th colspan="2">Additional wind capacity to base (GW)*</th><th colspan="2">Renewable energy as % of electricity</th><th rowspan="2">Cumulative subsidy per MWh (£) 2020</th><th colspan="3">Implications for stakeholders</th></tr>
<tr><th>2015</th><th>2020</th><th>2015</th><th>2020</th><th>Onshore wind</th><th>Offshore wind</th><th>Consumer/taxpayer</th></tr>
<tr><td>Existing RO policy</td><td>0.0</td><td>0.0</td><td>9.6</td><td>10.1</td><td>49</td><td>High returns continue</td><td>Investment delayed</td><td>Status quo</td></tr>
<tr><td>Renewable Development Premium</td><td>3.5</td><td>5.3</td><td>13.2</td><td>14.9</td><td>40</td><td>Existing onshore protected
Future onshore support reduced</td><td rowspan="3">Extra support immediately</td><td rowspan="2">c.£1bn extra funding by 2020</td></tr>
<tr><td>Top-up subsidy</td><td>3.2</td><td>2.4</td><td>12.7</td><td>12.3</td><td>43</td><td>Existing onshore protected</td></tr>
<tr><td>npower</td><td>3.2</td><td>2.0</td><td>12.8</td><td>12.0</td><td>41-46***</td><td>Future onshore returns tempered through increased offshore wind deployment</td><td>Up to c.£2bn extra funding by 2020</td></tr>
<tr><td>Modified Shell proposal**</td><td>0.4</td><td>3.5</td><td>10.2</td><td>13.4</td><td>44</td><td rowspan="2">Existing onshore protected
Future onshore support reduced</td><td>Extra support provided over time</td><td rowspan="2">No extra funding required</td></tr>
<tr><td>Multiple/ fractional ROCs</td><td>0.7</td><td>2.1</td><td>10.9</td><td>12.4</td><td>46</td><td>Extra support immediately</td></tr>
</table>

*Additional to current forecast wind capacity by end of March 2007 of c.2.4GW (of which more than three-quarters is onshore); **With grandfathering and a £5 cap on onshore recycle premium re-distributed to offshore wind; ***Range of value depending on the view taken of the additional cost to Government arising from acting as guarantor under the fixed price purchase arrangements.

The analysis in this study shows that there are explicit trade-offs involved in alternative policy frameworks that the Government needs to consider in making its policy decisions. In the UK, there are three broad stakeholder groups with somewhat divergent interests: onshore wind (representing the lower cost technologies); offshore wind (representing the higher cost technologies); and consumers/taxpayers. The interests of these three groups need to be balanced against each other and against broader UK energy objectives including the need for diversity, carbon reductions, economic development and capacity to fill the emerging 2015 gap.

Figure 1 illustrates the decisions that the Government will need to make, based on the five options compared to the base case. In all these options it is assumed the obligation has not been extended beyond 15% by 2015. These options represent different approaches and clearly illustrate the range of trade-offs involved. It is clear, however, that a decision that involves some change to the existing framework needs to be made. All of the suggested options significantly outperform the existing RO, meaning that the option of retaining the current policy in its present form is very costly. All of the alternative policies deliver higher renewables capacity by 2020 than the existing RO and do so at greater levels of efficiency. In addition, it is also worth mentioning that all the alternatives help drive offshore wind to a more cost-competitive position in 2020 (ranging from c.4.0p/kWh for the Renewable Development Premium to c.4.3p/kWh for the top-up subsidy and npower options).

This analysis does not assume offshore wind projects beyond Round 2 as it is not clear at this stage what the size or economic assumptions associated with a further expansion of offshore wind potential might be. However, a policy approach that provides significant support in favour of offshore wind (and provides for a 'Round 3' in support of this) could deliver significantly more capacity in a 2020 timeframe. Indicative analysis suggests that the existing RO policy, with an extension of the RO to 20% of electricity generation and a third round of projects could lead to c.3GW extra capacity above the existing RO base case figure of 6.5GW by 2020, leading to achievement of c.13% of electricity from renewable sources. For the same amount of additional funding and a third round of projects, the Renewable Development Premium could lead to an additional c.9GW over the base and c.19% of electricity from renewable sources.

1.2 Longer-term situation — beyond 2020 (marine energy)

There are many arguments in favour of preserving opportunities for low-carbon electricity generation at scale. These include the need to address uncertainty of future electricity prices and specifically the prices for fossil fuels used to generate that electricity. Moreover, it is not clear which technologies will be viable and cost-competitive in the future. There are also portfolio benefits arising from having diversity of energy supply. Options should be preserved if it is possible that economic development benefits could arise from leading technology development, as Denmark and Japan have seen in the case of the development of valuable export industries for wind turbines and photovoltaic cells.

In addition to these general arguments, the UK has set itself a very tough ambition for carbon reduction by 2050 and power generation is likely to be expected to bear a large share of the required carbon savings. Options for low-carbon generation are needed to help meet these goals.

The UK should focus its efforts on further-from-market low-carbon technologies in order to build UK options such as marine energy where the UK is a 'natural lead', has a comparative advantage, and is likely to achieve economic development benefits.

In terms of emerging low-carbon options for the UK, marine energy, and particularly wave energy, offers the UK the opportunity to develop an export industry. The value of the UK economic development benefit is uncertain as is the technology at this stage; however, this study estimates potential annual revenues by 2050 for the UK in the range of £0.6bn-£4.2bn (in real terms).

Policy measures additional to the RO have been designed to provide extra levels of support for further-from-market technologies, such as the Marine Renewable Deployment Fund (MRDF). The MRDF with its combination of both capital and revenue support is the right mechanism given the current stage of marine technology development; the technology is still very uncertain and the capital element of the support helps developers manage some of that risk. However, in aggregate, these policies are not sufficient; they do not provide long-term market certainty and are not material enough on their own to drive marine down a technology cost curve. Further targeted support is required to provide a sufficient prize in the medium term to motivate sizeable investment.

The policy mechanism that is chosen to drive offshore wind could be extended to marine energy and low-carbon technologies in general, provided that the level of support is tailored to the technology and development stage. However, a 'pull through' revenue mechanism such as the Renewable Development Premium is best suited as it would address all the perceived problems of the current policy framework. Such a mechanism rewards success and can be 'stepped' down for future projects with expected cost reduction indicated by installed capacity with the aim of aggressively driving down costs, thereby matching project returns with levels of risk. If a reduction in costs is not realised in an agreed timeframe then Government would be justified in withdrawing further support. This, in effect allows support to be delivered in stages, thereby limiting the amount of funding commitment long term, while still providing individual projects with appropriate funding and certainty. This approach creates value by preserving multiple options where the UK is a 'natural lead' and is an effective means of promoting diversity of low-carbon technologies.

2 Introduction and scope

In December 2005, L.E.K. was engaged by the Carbon Trust to undertake a study of Renewable Policy Frameworks for the UK. The principal objectives of the study were to:

1. Review the case for renewable electricity generation in the light of the Energy Review,[6] and in particular, examine the case for renewable energy technologies for UK electricity generation at scale taking into consideration:
   - cost-effectiveness and potential to reduce carbon;
   - diversity and security of supply; and
   - potential economic benefits of the technology development (domestic use and export) for the UK industrial and service sectors.
2. Explore alternative support frameworks and policies that would allow near and longer-term Government objectives on renewables to be met cost effectively, and in particular:
   - review the current and predicted success of the existing renewable energy policy framework in the UK;
   - analyse the full range of alternative options (both those already suggested and new framework ideas to be developed through this work) that could improve the delivery of Government targets for renewable energy at scale in the 2010 and 2020 timeframes;
   - determine the favoured policy framework(s) and examine the likely implications; and
   - engage the investor community and developers in order to test and refine the proposals and provide confidence that they could be made to work in practice.

The implications of potential new policy frameworks were tested in detail on three renewable technologies: onshore wind, offshore wind and marine (as an example of a longer-term, low-carbon technology). These technologies were deliberately chosen because they are roughly 10 years apart in their technology lifecycle stages, allowing consideration of applicable policies for technologies through their development cycles.

The study was completed in May 2006, and this report sets out the results and key recommendations arising from this work. In terms of the structure of the report, Section 3 briefly sets out key aspects of the existing renewable energy policy framework. Section 4 presents the case for renewable energy in the near term, up to 2020. The focus here is on wind and its ability to provide a meaningful contribution to the emerging gap in electricity generation and help meet Government targets for renewable energy. The report goes on to examine the effectiveness of the existing policy framework and evaluate possible alternative policy frameworks that may be more effective.

Section 5 sets out the case for maintaining longer-term options for low-carbon energy, with a specific focus on marine technologies as an example, and considers the optimal policy environment for ensuring that options can be preserved.

Throughout the report, there are also a series of 'side boxes' which provide additional detail on specific aspects covered in this study.

[6] The Prime Minister and the Secretary of State for Trade and Industry, Alan Johnson, announced on 29 November 2005 that they asked Energy Minister Malcolm Wicks to lead a Review of UK energy policy. The Terms of Reference of the Review are broad in scope including aspects of both energy supply and demand and in particular the Review is focusing on policy measures to help deliver energy objectives beyond 2010. The Review aims to ensure the UK is on track to meet the goals of the 2003 Energy White Paper in the medium and long term. The twelve week consultation period for the Energy Review closed on 14th April 2006. A statement on energy policy is due to be made in early summer 2006; 'the Energy Review will consider all options including the role of current technologies (e.g. renewables, coal, gas and nuclear power) and new and emerging technologies (e.g. Carbon Capture and Storage)': Government News Network, announcement 29 November 2005.

3 The existing renewable energy policy framework

The main pillar of the current renewable energy policy framework is the Renewables Obligation (RO), which places a requirement on UK electricity suppliers to source a growing percentage of electricity from eligible renewable generation capacity. It applies to all renewable technologies equally, with subsidy flowing to different generating technologies on the basis of the number of MWh of electricity delivered, regardless of the cost of production. It is funded by consumers through payment to suppliers in electricity bills and will have cost consumers in total c.£14bn by 2020 and c.£18bn by 2027 (in present value terms). The RO represents by far the largest part of public funding for renewable energy (see side box 'The Renewables Obligation'). There is a view amongst some in industry that the money that flows to developers from the RO is part subsidy and part payment for capacity additions; the latter can be viewed as a market correction cost as a result of the new trading arrangements in 2001.

In addition to funding received through the RO, generators of renewable energy presently receive a levy exemption certificate (LEC) from the Climate Change Levy (CCL) for each MWh of renewable electricity produced, which provides an additional, but smaller, revenue stream from the suppliers. Government has also chosen to supplement the RO and CCL measures with some technology-specific subsidies in the form of capital grants, R&D grants and additional revenue support. These can be characterised as applying to technologies according to their stage of development.

***Figure 2:** Four stages of technology evolution*

Technology evolution →

	Stage 1 Early Stage – R&D	**Stage 2** Early Stage – Demonstration Projects (e.g. some marine technologies)	**Stage 3** Large Scale Growing (e.g. offshore wind)	**Stage 4** Near Commercial (e.g. onshore wind)
Characteristics	▸ Feasibility uncertain	▸ Several technologies becoming feasible ▸ Technology choices still to be made	▸ Fundamental technology or process selected ▸ Technology refinement and cost reduction underway	▸ Technology proven – Scale projects already operational ▸ Operating returns not yet attractive (without subsidy)
Current policies	▸ DTI Technology Programme ▸ EU Framework Programme for Research and Technical Development ▸ Carbon Trust Applied Research programme ▸ Carbon Trust Technology Acceleration (e.g. Marine Energy Challenge)	▸ Carbon Trust Technology Acceleration (e.g. Marine Energy Challenge) ▸ Marine Renewables Deployment Fund ▸ Renewables Obligation ▸ Climate Change Levy exemption	▸ Renewables Obligation ▸ Capital grants ▸ Climate Change Levy exemption	▸ Renewables Obligation ▸ Climate Change Levy exemption

Broadly, as shown in Figure 2, there are four stages of technology development which have different characteristics. Stage 1 is a Research and Development stage, characterised by technology developments whose feasibility is uncertain. An example may be research and development of new devices suitable for capturing the energy associated with wave motion. In the UK, funding at this stage is supplied, for example, through the DTI Technology Programme, the Carbon Trust's Applied Research Programme and Technology Acceleration activities,[7] and the EU's Framework Programme for Research and Technical Development.

Stage 2 is an early demonstration phase, where technology choices are still being made and several specific designs in the technology area are becoming feasible. For example, various wave devices employing different techniques for capturing energy are being trialled – at this stage it is not clear which, if any, will become the dominant design for the technology area. As they are producing some electricity, support is available from the RO and CCL exemption, but the most important source of public funding for marine technologies is the Marine Renewables Deployment Fund (MRDF – see side box 'The Marine Renewables Deployment Fund'). Assistance here is also available from the Carbon Trust's Technology Acceleration activities.

Technologies that have moved to Stage 3 (for example, offshore wind) can be characterised by the fact that the fundamental technology or process has been selected. In this stage, technology development is focused on refinement and cost reduction. The main support mechanisms include the RO and CCL exemption, and capital grants are also available such as in the case of Round 1 of offshore wind.[8]

In Stage 4 (for example, onshore wind), the technology has been proven and scale projects are already operational.

The Marine Renewables Deployment Fund

The main policy supporting marine energy in the UK is the Marine Renewables Deployment Fund (MRDF). The MRDF represents a fund of £42m which can be distributed as a mix of revenue and capital funding for marine projects. It is provided over and above revenue that marine projects may receive through the operation of the RO. Funding is provided through an open competition, with the first competition having closed in May 2006. As part of the terms of funding, successful applicants will receive offers of specified levels of capital and revenue support.

The fund has capacity for 4-5 projects and the timeframe for support is limited (2 years for capital funding and 7 years for revenue funding). In contrast to the RO, payments under the taxpayer-funded MRDF are made directly to project developers.

Stage 4 technologies are distinguished from fully commercial technologies such as coal and gas in that operating returns for investors are not yet attractive without subsidy, as the technologies are still coming down the cost curve and they therefore still require public support. At present, this support is received through the RO and the CCL exemption.

The Renewables Obligation

The main pillar of the current renewable energy policy framework is the Renewables Obligation, which places a requirement on UK electricity suppliers to source a growing percentage of electricity from eligible renewable generation capacity (increasing to 15.1% by 2015, with the obligation continuing at this level until 2027).

Suppliers are required to produce evidence of their compliance with this obligation to the Office of Gas and Electricity Markets (Ofgem). Evidence is via certificates, referred to as Renewables Obligation Certificates (ROCs). Each ROC represents one MWh of electricity generated from eligible sources. To the extent that suppliers do not provide the sufficient quantity of certificates, they are required to pay a buyout price of £30 per MWh* of the shortfall. This money is paid into a buyout fund which is then 'recycled' by redistributing it to the holders of ROCs, with the intention of providing a continuing incentive to invest in renewable energy. The effect of the recycle premium meant that ROC prices in early 2006 were around £40.

The RO represents a significant public investment in renewable technologies – on the basis of existing electricity demand forecasts it will cost consumers c.£14bn by 2020 and £18bn by 2027 (in present value terms**).

In addition to funding received through the RO, generators of renewable energy presently receive a levy exemption certificate (LEC) from the Climate Change Levy for each MWh of renewable energy produced, which provides an additional, but smaller, revenue stream. LECs attract a payment of £4.3/MWh (although the amount received by the generator is subject to a supplier margin and is therefore generally lower than this).

These subsidies apply to all eligible renewable technologies; there are also some technology specific subsidies in the form of capital grants, R&D grants and additional revenue support. For example, for offshore wind, £117m has been committed by way of capital grants for Round 1 projects; for marine, additional support is provided under the MRDF.

*2002 value – the buyout price increases over time with inflation

**Discounted at the UK gilts rate (2.25% in real terms as of March 2006)

[7] Such as the Marine Energy Challenge – described in Section 5.7.

[8] Shortly after the start of Round 1, a series of capital grants for offshore wind farms through the New Opportunities Fund (£117m) was announced. Consented projects received grants up to £10m per project, approximately 10% of project costs, on condition of the beginning of construction.

4 Near-term situation (up to 2020)

4.1 The emerging gap between electricity demand and generation

A fundamental consideration for the UK Government in the Energy Review will be how to plan for the emerging future gap between electricity demand and generation as conventional generating capacity is decommissioned over the next 10 years.

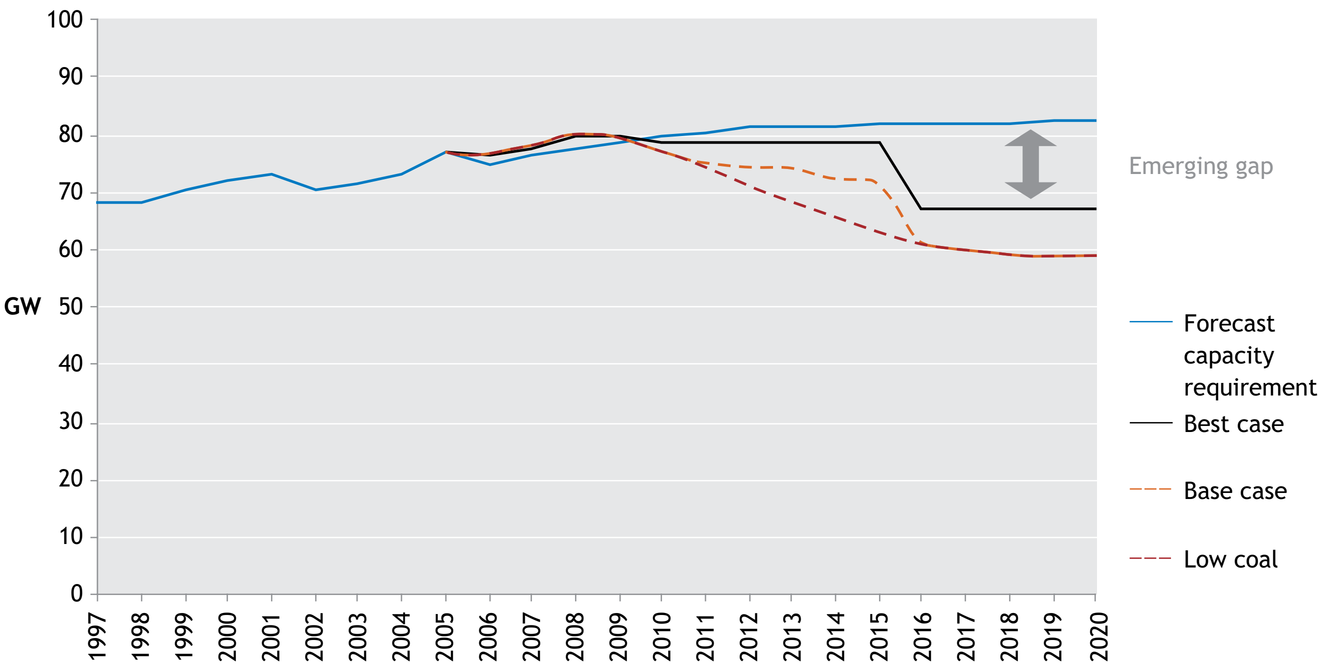
While the consensus of UK demand projections shows relatively modest demand increases in the range of 0.2-0.8% p.a.[9] over the next 10-15 years, there are expected to be significant retirements of capacity (particularly for coal and nuclear) that will require new generating plant to be commissioned in its place. 8GW of the 29GW of coal generation in place in 2005 is expected to be retired by 2020 due to the need to comply with the Large Combustion Plant Directive (LCPD) and Flue Gas Desulphurisation (FGD) requirements[10]. 8GW of the 12GW of nuclear generation is scheduled to be retired over the same period. Specific dates have been announced for the retirement of nuclear reactors although there is expected to be some flexibility in terms of the retirement dates of Advanced Gas-cooled Reactors (AGR), with life extensions of up to 10 years being possible. The additional generating capacity in construction or development will not be sufficient to match the projected retirements.

This study has considered a number of scenarios to help frame the emerging conventional capacity gap. Figure 3 shows the emerging gap for three scenarios. For these purposes, evidence of a gap is defined by the capacity margin falling below a level of 15% (the point at which interruptions to continuous power supply become a potential issue), although it is possible that in the future, demand management tools may allow the network to run effectively with margins lower than this, thereby reducing the difference between forecast supply and demand. In addition, energy efficiency measures could also help alleviate the size of the gap. This study is, however, focused on the role of the supply side of energy generation in filling the capacity gap.

The first scenario ('Base Case') assumes that AGR reactors are retired on time. It also assumes that non-FGD compliant coal is available for generation until the end of 2015. The second scenario 'Low Coal' is similar, but assumes a gradual expiry of non-FGD compliant coal over the period to the end of 2015. In both cases, the 15% capacity margin threshold is breached in 2011, and by the end of 2015 there is a conventional capacity gap of 22GW.

A third scenario 'Best Case' assumes that all the AGRs obtain a 10 year life extension. In addition, non-FGD compliant coal is available for generation until the end of 2015 and there is no coal plant retirement except through LCPD. Even in this more favourable case, a 14GW

***Figure 3:** UK electricity capacity requirement versus supply*



Sources: NGT Seven Year Statement (May 2005); DTI; ILEX; L.E.K. analysis

[9] Sources include: Digest of UK Energy Statistics (DUKES) 5.1.3; DTI Energy Paper 68: Energy projections for the UK (2004); DTI Updated Emissions Projection November 2005; NGT Seven Year Statement (May 2005); Oxera '*Results of Renewables Market Modelling*' (February 2004), ILEX Renewable Results Summary 2006.

[10] Under the LCPD, owners of coal-fired plant must either fit FGD plant to cut emissions of sulphur dioxide by 2008 or face very heavy restrictions on plant usage if they are to continue to operate from the start of 2008 to 2014, when they will have to be closed: EC Directive 2001/80/EC.

conventional capacity gap still emerges by the end of 2015, with the capacity margin falling below 15% in 2010. Hence, it is essential that a clear understanding is laid out between Government and the private sector so that the framework can be set for investment in capacity to allow supply to continue to meet demand.

Suitability of different technologies to fill the conventional capacity gap

In assessing which technologies are suitable to help fill the gap, the following criteria have been applied:

- technology availability: the technology must be available at scale by 2015;
- cost-competitiveness: the full cost of the electricity must be competitive or shown to be capable of becoming competitive in the medium term (c.2020);
- carbon impact: the impact on the UK's carbon targets must be acceptable; and
- security of supply: it should be consistent with long-term security of supply concerns.

New nuclear capacity is unlikely to be available at scale prior to 2015. In the past, developments have taken at least 10-12 years to move through planning and construction phases. In addition, for planning reasons, any new nuclear installation can be expected to be constrained to existing nuclear sites, restricting the role new nuclear can play in addressing the conventional capacity gap by 2015.

Additional coal generating capacity would be available by 2015 and coal is cost-competitive in a number of different forms (for example, Pulverised, Supercritical and Integrated Gasification Combined Cycle (IGCC) technologies). In the absence of the use of Carbon Capture and Storage (CCS) to reduce net emissions, additional coal will have a negative impact on carbon targets, particularly in the case of Pulverised, the oldest and least efficient technology. Although the UK has indigenous coal supply, at present it relies largely on imports from other countries — however, security of supply issues, given the level of reserves held internationally, are likely to be lower, for example, than with gas.

Coal's ability to contribute to the 2015 gap may therefore depend on the development of CCS technologies. While Supercritical coal is a more efficient technology than IGCC, carbon capture needs to be post-combustion. At this stage, post-combustion capture has been trialled at scale with amine technology which, while proven, is very expensive. Post-combustion technology using ammonia is a potentially attractive alternative, but it is not clear that it will be proven at scale by 2015. It is expected that IGCC will eventually allow cost-effective pre-combustion carbon capture through the use of CCS technologies such as selexol, but again the expected time to development of the carbon capture technology at scale is uncertain and could be beyond the 2015 timeframe. In summary, a number of uncertainties remain around technology development and expected cost of CCS technologies. CCS is one of many low-carbon technologies that could prove to be a viable option for the future, and it needs to be assessed with other such options.

The leading gas technology, Combined Cycle Gas Turbine (CCGT), is proven. Even though replacing retiring capacity with CCGT would reduce the carbon intensity of the overall electricity generating mix in 2020 vs. 2005, the entire 2015 gap would need to be filled with zero emissions generation capacity for the UK to remain on track for its 2050 carbon reduction ambition. In addition, dependence on gas for CCGT creates reliability concerns in the very near term and potential security of supply issues in the longer term as domestic reserves run out and the UK becomes reliant on imports, a large proportion of which are expected to come from high-risk countries. Moreover, the absence of a domestic supply base will mean significant investment in storage capacity will be required.

In summary, each of the non-renewable technologies has limitations. As can be seen from Figure 4, in previous cycles of investment in generating capacity, particular technologies have been favoured at different times. In the decade from 1965, almost all new capacity was from coal, while in the following 10 year period nuclear dominated. In the last 15 years, CCGT has been the principal form of new generating capacity.

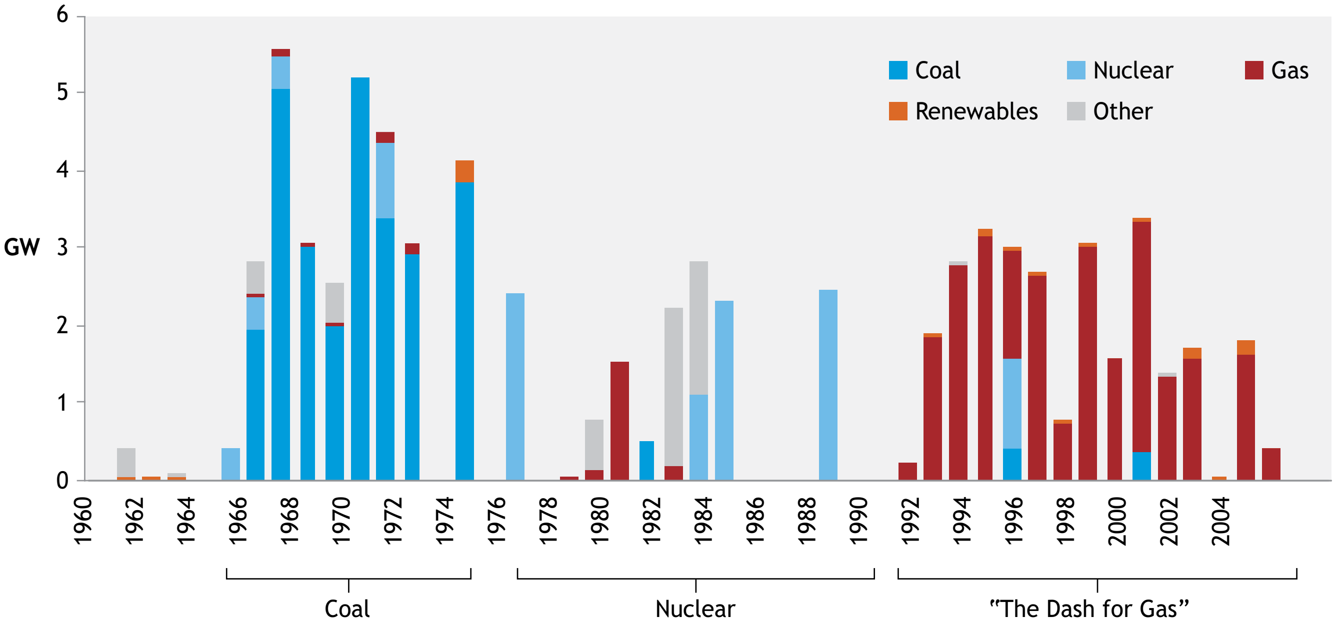
Today, there are disadvantages or barriers to the use of one technology to meet all the requirements in the near term. A combination of generation technologies are likely to be required to fill the 2015 gap.

4.2 The role of renewables and wind specifically in contributing to the 2015 gap

Renewable technologies also need to be examined to determine their ability to help fill the 2015 gap on the basis of the same criteria. All renewables score well in terms of their carbon impact. However there are specific concerns regarding technology, resource availability and cost-competitiveness which limit the role of some technologies in contributing significantly to the 2015 gap. For example, there is insufficient resource for hydro and landfill gas to play a significant role, and while it is uncertain whether marine technology will be cost-competitive by 2020, it is unlikely to be available at scale by 2015. For biomass, it is not clear that the technology can become cost-competitive for electricity production in this timescale and there are issues relating to the ability of the UK to supply sufficient feedstock domestically for scale generation in the near term. Under existing eligibility rules, co-firing is to be phased out although there is currently a review of the restrictions on co-firing within the RO as part of the Energy Review[11].

[11] The terms of reference for this review were announced on 31 March 2006. It will have the following objective: To assess the scope for co-firing to provide a greater contribution to the Government's renewable energy, carbon reduction and wider energy policy objectives, while maintaining investor confidence in the RO. This review will be conducted during 2006 within the context of the wider Energy Review. If any changes to the current rules are proposed these would be subject to a statutory consultation and may be introduced to come into force for 1 April 2007 or later than this if there is a policy need to do so, or if they would require primary legislation.

***Figure 4:** Previous cycles of investment in generation capacity* (1960-2005)*



*Power plants in operation May 2005

Sources: DUKES 2005

Onshore wind technology is relatively mature with low levels of uncertainty. Offshore wind technology, while less mature than onshore and still undertaking improvements and modifications to reduce cost, is now at a stage where the technology has been deployed successfully and the investor community is comfortable with the level of technical risk involved. In addition, there is significant wind energy resource in the UK both onshore and offshore. Wind can assist in achieving both carbon targets and renewable energy targets.

Onshore wind is nearly cost-competitive[12] today, with current cost estimates at around 5p/kWh net of balancing costs (to deal with intermittency issues). This compares to a current wholesale price in the order of 4.5p/kWh[13]. The analysis suggests that by 2020, the cost of onshore wind generation will be in the range of 3.3-4.0p/kWh[14]. Offshore wind has the potential to be cost-competitive in 2020, with costs expected to fall as installed capacity increases and the experience from ongoing development brings the technology down the cost curve. As Figure 5 shows, the analysis suggests that it is expected to be in the range of 4.0-4.7p/kWh by 2020[15].

Reasonably conservative assumptions have been used in projecting these cost levels: for example, in the learning curve analysis, while all forecast UK capacity installations have been taken into account for reducing cost, only 20% of the estimate of overseas offshore wind deployment[16] has been included for these purposes. In addition, a learning rate of 15% per doubling of capacity has been applied, lower than the rate of 18%[17] achieved in a similar stage of onshore wind's development. This analysis does not assume availability of a further round of licensing of offshore wind sites beyond Round 2. As a result, the analysis shows offshore wind additions in the UK tapering off at the end of the next decade. However, a policy approach that provides significant support in favour of offshore wind (and provides for additional offshore wind locations such as a 'Round 3' in support of this) could deliver significantly more capacity in a 2020 timeframe and provide further opportunity to benefit from learning to reduce costs.

Wind also injects a wider degree of diversity into the UK electricity generation portfolio and it does not suffer from security of energy supply issues. The intermittency effects of wind have been examined in great detail in a UKERC[18]

[12] At wholesale electricity prices in the range of c.3-5p/kWh.

[13] The average UK wholesale electricity price for the 12 months to May 2006 (Source: Datastream, APX Power UK-Elec.Spot Index).

[14] L.E.K. analysis on the basis of 8% learning effect per doubling of installed capacity and Oxera forecasts of worldwide installed capacity to 2020. Range shows forecast cost with and without balancing costs included.

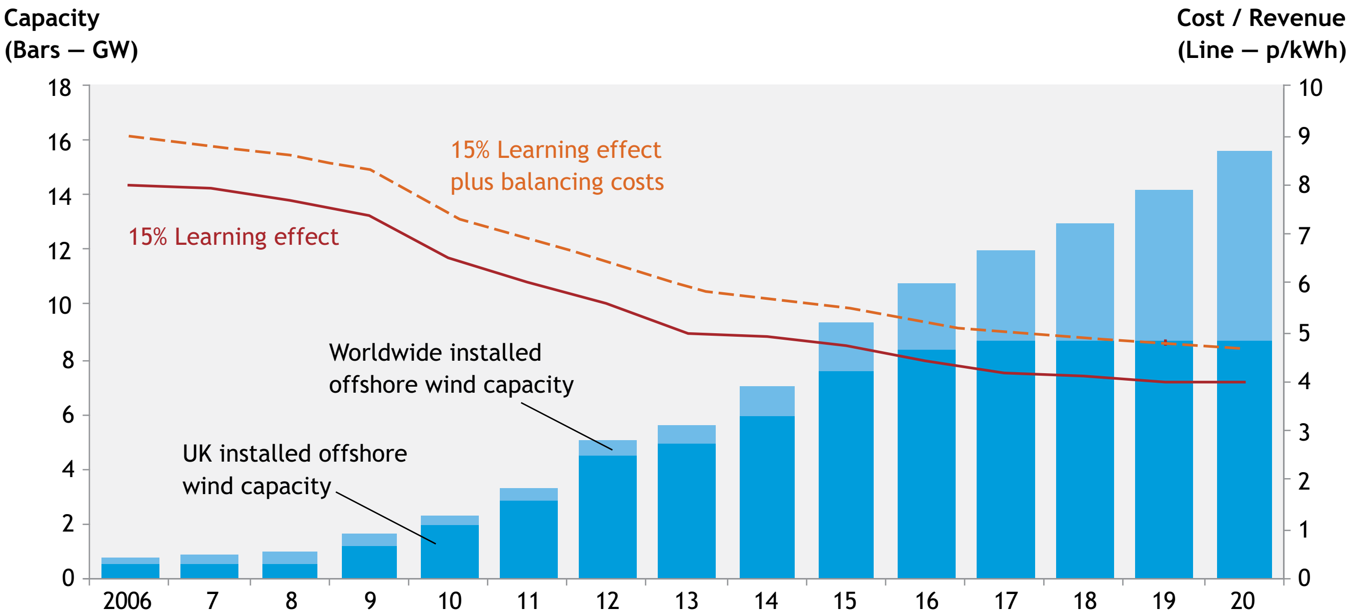
[15] L.E.K. analysis. The UK capacity additions forecast are from a scenario favourable to offshore wind, where restrictions to development that apply relate to grid access and supply chain issues only. Range shows forecast cost with and without balancing costs included.

[16] Oxera forecasts of worldwide offshore installations, from '*Results of Renewables Market Modelling*', February 2004.

[17] Experience curves for energy technology policy, IEA/OECD, 2000.

[18] UK Energy Research Centre, 'The costs and impacts of intermittency', April 2006. Intermittency costs in Britain were estimated at c.£5 to £8/MWh (0.5-0.8 p/kWh of wind output), made up of £2 to £3/MWh from short-run balancing costs and £3 to £5/MWh from the cost of maintaining a higher system margin. These estimates assume that intermittent generation is primarily wind, that it is geographically widespread, and that it accounts for no more than about 20% of electricity supply. At current penetration levels costs are much lower, since the costs of intermittency rise as penetrations increase. A capacity credit needs to be applied to wind capacity in assessing its contribution to the 2015 conventional capacity gap due to the intermittent nature of its electricity generation. In evaluating the economics of wind projects, the analysis takes into account the cost of additional (or retained) conventional plant required to maintain the higher system margin. In this study we have conservatively used a range of 0.5-1.0p/kWh, and have assumed that the supplier keeps 20% of the wholesale electricity price to cover these costs (c.0.8p/kWh with an assumed electricity price of 4p/kWh).

***Figure 5:** Forecast worldwide offshore wind deployed capacity and cost*



Note: Scenario based on support mechanism favourable to offshore, 15% learning, 20% of forecast non-UK capacity and no Round 3 site licensing in the UK
Sources: Oxera, L.E.K. analysis

study and have been shown not to be material in terms of overall system stability at the levels of capacity anticipated (up to 20% renewable energy by 2020). In addition, the UK can expect to benefit from leading the development of offshore wind, particularly in the development of a UK supply chain that services an export industry. This study estimates a benefit to UK plc of £2bn per annum in revenues by 2020, which could be expected to grow thereafter as it is likely that the global offshore wind industry would continue to expand once offshore wind becomes cost-competitive (see side box — 'The economic benefit to the UK from the development of an offshore wind industry').

Wind is the only low-carbon resource available at scale by 2015, and is a credible option to assist in filling the capacity gap. However, given wind's current cost position, subsidy will be required in order to encourage investment in wind generation and to move the technology down the cost curve. The remainder of this section assesses the current support mechanisms applicable to near-term renewable technologies and evaluates whether:

- they are effective and cost-efficient in supporting investment in renewables;
- they can assist in renewables (wind) providing a meaningful contribution to the 2015 gap; and
- alternative policies might be more effective.

4.3 The inefficiencies of the current renewable policy framework

The RO has been designed to pull through the lowest cost technologies sequentially, which has the effect of limiting the amount of support given to less mature technologies. During the period of the RO's operation, renewables penetration from eligible renewable sources has increased from 1.5% in 2001 to c.4% in 2005[19]. However, development of new capacity from offshore wind is lower than had been expected a few years ago and appears to have stalled. This is because offshore wind costs have turned out to be higher than originally expected, due to higher steel and turbine prices and an increase in installation and construction costs as the industry has moved away from turn-key contracts. Most of the Round 1 projects already operating or under construction have benefited from the previously lower turbine and construction prices. In addition, many developers have committed to build one offshore wind farm for strategic reasons and to gain onsite experience, and were therefore willing to invest in these projects at lower levels of return. None of these conditions can be expected to apply going forward.

Currently, onshore wind is the only economically viable renewable technology under the RO that can contribute to future generation at scale. Before the next technology can be pulled through, there is a timing delay as Renewable Obligation Certificate (ROC) prices have to rise to a high enough level for the technology to provide economic returns to an investor in the next technology (offshore wind) — a period characterised by the inefficiency of high returns for the lowest cost technology (onshore). The larger the gap between the technology costs, the longer this delay can be expected to be.

[19] Source: DTI.

The economic benefit to the UK from development of offshore wind

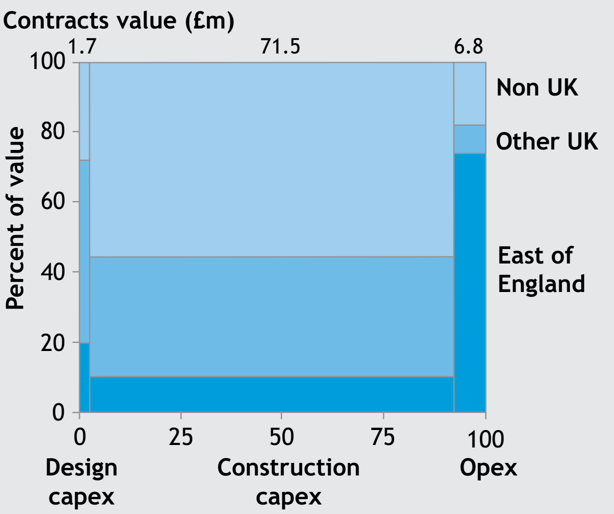
Development of an offshore wind industry in the UK is likely to result in significant benefits for the UK, particularly if the UK develops a technology lead and is able to service an export industry.

The benefits to UK industry from the development of the Scroby Sands offshore wind site have been closely studied. Work orders to the value of c.£40m were sourced from UK companies, accounting for nearly half of the entire contract value. While the majority of the UK's contribution has been due to successful penetration of the lower tiers of the supply chain, all environmental monitoring, survey, insurance/legal and onshore installation work for the project was provided by the UK. This resulted in significant employment benefits for the UK supply chain and the contracts awarded to the UK accounted for 73% of the hours worked on the project, as depicted in Figure 6 (below).

In the future, growth in UK industry involvement is expected to be most significant in offshore wind installation, where UK companies have the required capabilities to perform all key tasks gained from the considerable experience of developing North Sea oil and gas.

If offshore wind develops in line with UK and international expectations, we estimate that the potential opportunity for the UK could amount to revenues of c.£2bn per annum by 2020, around half of which will be from export revenues. This will provide a stepping stone for future revenue as the global offshore wind market would be expected to grow significantly from there.

Figure 6: *Scroby Sands value to UK*



Source: Scroby Sands Supply Chain Review

At the same time, installation of onshore capacity is restricted by grid and planning constraints. The combination of these restrictions and the timing delay results in high ROC prices and a policy that is unable to deliver capacity fast enough to make a meaningful contribution to the 2015 gap.

As depicted in Figure 7, high ROC prices are providing good returns to onshore developers, but are not providing sufficient subsidy to close the funding gap for offshore wind development, which could be cost effective and can provide significant capacity in the near term. All technology blind policy support options will have these characteristics by design. A more efficient means of support would be to aim to close the funding gap for offshore wind and taper away support from onshore.

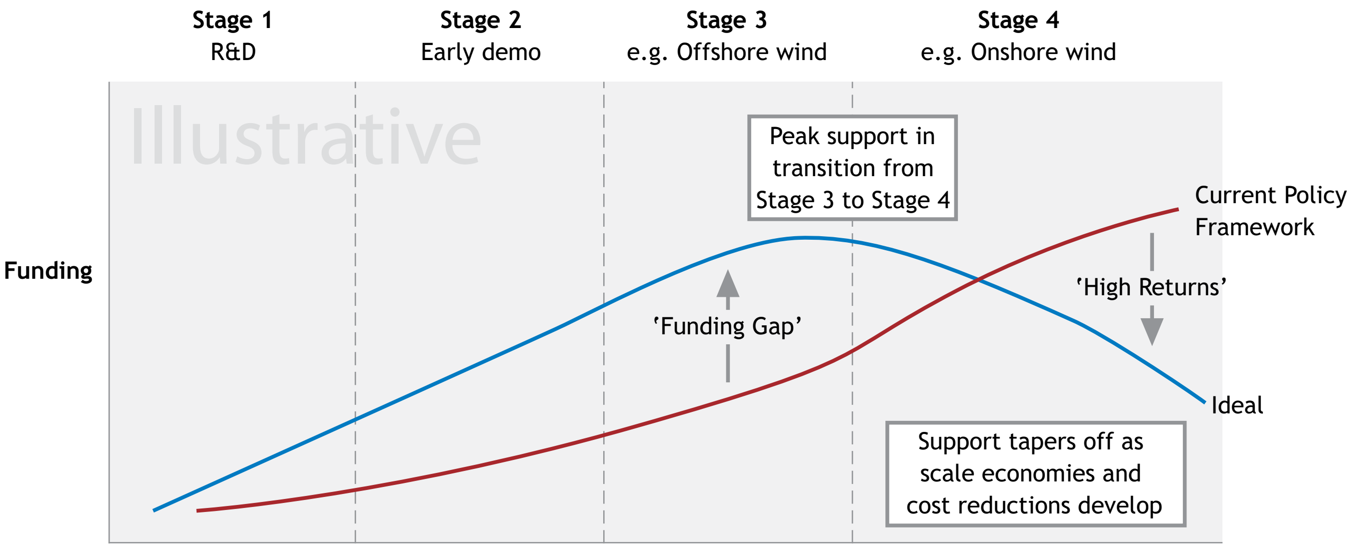
In addition, the RO is a mechanism that transfers regulatory risk to the private sector, and the private sector accordingly prices that risk at a premium. Power Purchase Agreement (PPA) providers (the electricity suppliers) demand a significant percentage of the ROC value[20] (which can vary by technology) to compensate for the perceived political risk connected with the RO when providing long-term contracts. Financiers also discount the ROC value considerably when making their lending decisions, meaning that financing terms become less favourable for developers. Overall, there is a leakage of subsidy in the RO system away from developers.

Overall, the existing renewable energy policy suffers from inefficiencies, resulting in a unit cost of renewable energy to consumers that is higher than necessary given the current technology cost. Moreover, given the renewable and carbon reduction targets and the 2015 gap, diversity of investment in renewable energy is needed. Diversity requires that different technologies be installed in meaningful amounts in parallel, and the RO is not a mechanism that can achieve this given the current costs of the different technologies.

In the past, the private sector has been clear in its view that the RO should not be changed in order to build confidence for investors in this highly regulated sector. However, there is now a wide consensus (and expectation) that the RO needs to be adapted or changed — not doing so would introduce a greater amount of risk to the future of renewables policy due to it becoming associated with sustained high ROC prices and failure to achieve targets.

[20] In the analysis, it has been assumed that only 70% of the ROC value passes through to the developer.

Figure 7: *Funding under the current policy framework by stage of technology development vs. ideal funding profile*



4.4 The likely outcome of the current renewable policy framework

In order to understand and explain the economics and constraints of the existing policy framework and to evaluate the impact of different policy options, this study has analysed the level to which renewables can, under different scenarios, provide a meaningful contribution to the 2015 gap and towards meeting Government targets (see the appendix for more detail on the analytical methods used).

The analysis suggests that the current policy framework[21] will fall short of renewables targets and aspirations, with 7.6%, 9.6% and 10.1% of electricity being met by renewable energy in 2010, 2015 and 2020 respectively. In terms of added capacity (from 2007 and onwards)[22] this represents an additional 5.3GW of wind by 2015, providing only a limited contribution to the 2015 conventional capacity gap. Critically, all of the additional capacity for 2015 is forecast to come from onshore as the level of support for offshore wind is not sufficient to overcome unfavourable economics and begin to drive offshore wind projects' costs down the learning curve. In addition, offshore wind investment is not expected to take place at scale until nearly 2020.

ROC prices rise significantly (to £52 in real terms by 2015) as renewables investment falls behind target. Onshore investments achieve very high rates of return, with IRRs of up to 15% representing nearly twice the estimated real required rate of return of 7.75% for these projects.

These outcomes are consistent with messages obtained from the renewables investment community during the course of the study.

The roll-out of onshore wind is limited significantly by grid and planning constraints (see side box — 'Planning, supply chain and network constraints' on page 20). Although complex and challenging, policy should provide for these constraints to be released as much as practically possible in order to encourage renewables investment. Releasing planning and grid constraints for onshore wind would help drive additional renewable penetration. Onshore wind could theoretically reach a capacity of 7GW by 2015 (vs. 5GW under the base scenario) if fairly aggressive assumptions[23] are made for releasing planning and grid constraints. However, this does not represent a significant improvement against the base case in terms of contribution to the 2015 gap, and the inefficiencies associated with the RO (in terms of high returns for onshore investment and no delivery of offshore wind capacity) would still exist.

The investment case for offshore wind (as for all generation technologies) improves if the electricity price proves to be higher over the period of investment than current expectations. Using electricity price forecasts[24] about 25% higher than in the base case leads to an additional 1.7GW of wind by 2015 and 5.0GW by 2020 over the base case, as offshore wind projects clear investment hurdles. An increase in electricity prices of 50% from base case levels would lead to an additional 5.6GW of wind over the base case being installed by 2015, with renewables achieving 14.7% of electricity generation by 2015. Some investors

[21] Does not assume any extension of the obligation beyond 15% of electricity supply, and no offshore wind Round 3.

[22] Additional to current forecast wind capacity by end of March 2007 of c.2.4GW (of which more than three quarters is onshore).

[23] These assumptions include: 100% of approved projects proceeding to construction (vs. 90%); s36 planning approval rates increasing from 50% to 70%; local planning authority approvals in Scotland increasing to 70% from 59%; the time from post-approval to construction being decreased to 1 year (from up to 3.5 years); planning approval times cut to 1 year (from up to 3 years); faster progression of pipeline projects through the pre-planning application phases; grid capacity issues are resolved immediately; key grid reinforcement projects (Beauly-Denny, Sloy reinforcement, Keldoon reinforcement and the Scotland-England interconnectors) completed by 2009; and transmission links to other Scottish Islands completed in 2010-12 timeframe.

[24] This uses ILEX's 'high price' electricity forecasts which are c.25% higher than the ILEX 'central case' forecasts used in the base case (Source: ILEX Renewable Results Summary 2006).

have shown a willingness to take a more aggressive view on future electricity prices. However, it is likely that a sustained period of high electricity prices would be required before significant investment from a broad range of participants could occur.

The real potential for scale development exists in closing the funding gap for offshore wind and driving offshore wind development. Under current conditions, offshore wind is forecast not to contribute any further capacity by 2015 and only c.1.5GW by 2020 under the existing policy framework, out of a total planned Round 1 and 2 capacity of c.8GW. Integrated developers, or utilities, can be expected to have lower hurdle rates than assumed in this analysis (of c.10.25% real return), resulting in a smaller funding gap than for independent developers. In addition, some developers today are proceeding with investing relatively small amounts of money to push projects through planning and consent, with the aim of creating an option to be ready for future investment if the investment case improves. In this way, if the policy framework became more favourable, then the developer would be able to move quickly to installation and commissioning. However, until the funding gap is closed, investment at the scale required to make a meaningful contribution to the 2015 gap is unlikely to occur. In the meantime, many developers are in dialogue with Government on the future of the policy framework.

4.5 Options to drive offshore wind development

In considering alternative policy frameworks to the existing RO regime, this study reviewed a number of different options, including policies in place in other countries at different times, as well as specific suggested changes to the current RO regime. Of the wide range of possible options, five policy types were selected for detailed analysis in order to help illustrate the differing effects of policy alternatives. These were as follows:

- Renewable Development Premium: replacing the RO with a form of fixed subsidy tailored to each technology, with different tariffs for onshore and offshore wind. Tariffs are set as a fixed premium on top of the wholesale electricity price and LEC payment which is 'stepped' down for future projects with expected cost reduction;
- Top-up subsidy: a capital grant for offshore wind on top of the RO;
- npower proposal: a fixed price ROC purchase agreement by Government providing a fixed level of subsidy per MWh for 2GW of offshore wind capacity;
- Modified Shell proposal: a capping of the ROC recycle value, with the surplus funds being directed to offshore wind in the form of capital grants; and
- Multiple/fractional ROCs: varying the proportion of ROC value given to different technologies by providing a differential number of ROCs per MWh.

Details of these proposals are set out in the side box 'Alternative policies to drive offshore wind development' (page 22).

4.6 Evaluation of different options

The suggested policy mechanisms have been evaluated qualitatively (to assess matters such as the level of disruption to the RO, its effect on different wind constituencies, and the simplicity and ability to implement the scheme) and quantitatively (in terms of potential capacity additions, additional cost and general efficiency). The output from the analysis in terms of quantitative performance is set out in Figure 8. Each option is then assessed in broader terms in turn. As stated above, the analysis does not assume availability of offshore wind sites beyond Round 2, nor any extension of the RO beyond the current 15% level.

Renewable Development Premium

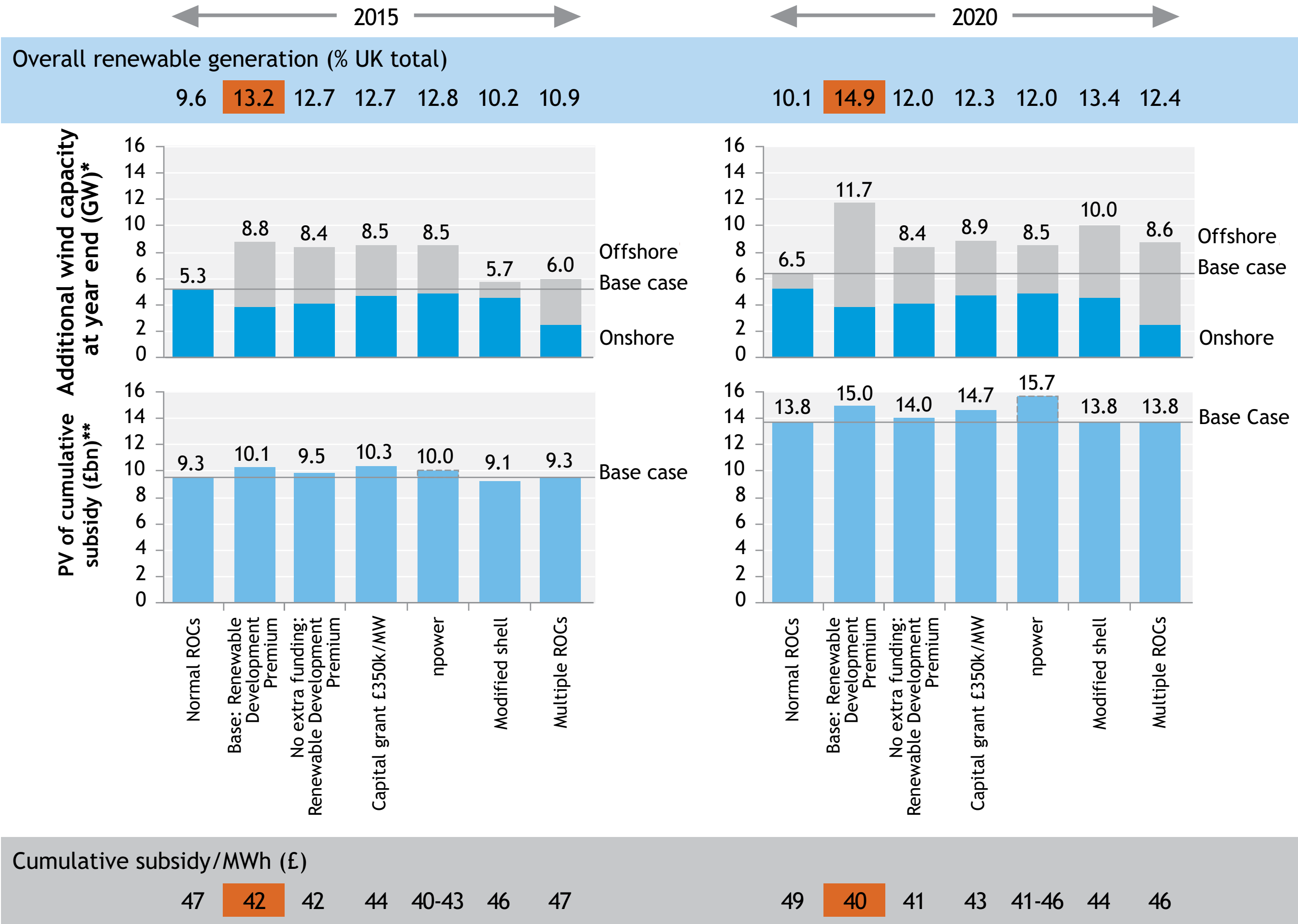
The base Renewable Development Premium subsidy delivers the greatest amount of capacity in both the 2015 and 2020 timeframes. It delivers 8.8GW of additional wind capacity by 2015 and 11.7GW by 2020 (13.2% and 14.9% of generation from renewable sources respectively). This would mean that new wind capacity of 8.8GW could be relied on to fill c.16% of the 14GW emerging 2015 capacity gap.[25] The base Renewable Development Premium is also the most efficient policy mechanism with a subsidy cost of £40/MWh[26] over the timeframe. It achieves this by driving greater offshore wind investment than other mechanisms through use of differential support by technology and by providing increased funding certainty to developers, reducing risk and subsidy leakage. It also provides a mechanism for tapering support from technologies. However, a number of issues would arise with its implementation: most significantly, it moves completely away from the RO market based mechanism, removing the annual cap on the level of renewables support (although the level of subsidy for new investments could be reduced as technology costs reduce with increased capacity over time), and costs an additional c.£1bn by 2020[27] in present value terms. Administratively, it would also be more burdensome on Government involving a continuous governmental role, with levels of support needing to be reviewed and set by an independent Government agency.

[25] Using a capacity credit of 25% for wind generation at a level of c.10% of total electricity generation in 2015, in line with the findings in the UKERC study '*The costs and impacts of intermittency*', April 2006. In evaluating the economics of wind projects, the analysis assumes that the cost of additional conventional plant retained or built to handle wind intermittency is taken into account. Such conventional plant will also have a capacity value and provide an additional contribution to the 2015 gap.

[26] The subsidy cost per MWh is calculated by dividing cumulative subsidy by cumulative renewable generation. As a result, options that lead to capacity installation earlier rather than later tend to be more efficient on this measure given that such capacity will have been generating electricity for a longer period.

[27] Plus an additional c.£1.4bn by 2027. Cost presented as monies spent, not committed, by a certain date.

***Figure 8:** Overview of the additional wind capacity deployed post 2005/6 and the cumulative funding required for the different policies*



*Additional to current forecast wind capacity by end of March 2007 of c.2.4GW (of which more then three-quarters is onshore)

**Costs presented as monies spent, not committed, by a certain date. Discounted at the UK Gilt rate (2.75% in real terms as of March 2006)

Note: Different capacity factors are assumed for onshore and offshore wind (see Appendix for further details). As a result a MW of offshore wind capacity contributes more generation than a MW of onshore wind

Source: L.E.K. analysis

The Renewable Development Premium discussed above costs c.£1bn more than the current policy by 2020. However, the option can be designed to cost less, the same, or more than the current RO. If the total amount of funding were to be restricted to the aggregate level under the RO, the Renewable Development Premium still delivers 8.4GW by 2015, more than any other option without increased funding, and it remains the most efficient in terms of the cost of delivered renewable energy at £41/MWh by 2020. The efficiency of the Renewable Development Premium as compared to the current RO is perhaps best highlighted by the potential to deliver broadly the same amount of renewables capacity as projected under the current RO over the timeframe and still save c.£1bn by 2020 and c.£3bn by 2027 in present value terms.

Top-up subsidy

The top-up subsidy via capital grant also delivers significantly more capacity than the current RO, achieving 12.7% and 12.3% of renewables capacity in the 2015 and 2020 timeframes as a greater level and certainty of funding encourages offshore wind investment. It involves a similar additional funding cost as the Renewable Development Premium at c.£1bn by 2020[28] in present value terms, but results in lower installed capacity, meaning that overall efficiency is lower at £43-44/MWh. One of its principal advantages is that it does not disrupt the RO mechanism; it is an example of a measure that has been used with the RO in the past (for example, Round 1 offshore wind capital grants). However, it would require pre-allocation of the capital funding. The mechanism also requires additional funding, and would need to be carefully designed – the experience of Round 1 capital grants shows that making funds available by pre-allocation does not guarantee that investment in renewables will take place.

[28] Plus an additional c.£0.8bn by 2027. Cost presented as monies spent, not committed, by a certain date.

npower proposal

The analysis shows that the npower proposal produces similar capacity additions in the 2015 and 2020 timeframes as the top-up subsidy. It is also potentially one of the most efficient mechanisms in terms of cost per MWh of renewable electricity produced, with a range of £40-43/MWh in a 2015 timeframe and £41-46 in a 2020 timeframe, depending on the view taken of the additional cost to Government arising from acting as guarantor under the fixed price purchase arrangements. If acting in this role is assumed to be 'costless' then the npower option is in the same range of efficiency as the base Renewable Development Premium. The chief disadvantage of the proposal lies in this hidden cost, which requires Government to assume the risk (e.g. recycle shortfall, buyer credit default and working capital) involved in providing these long-term contracts for 2GW of offshore wind capacity. It is difficult to assess the price of this risk, but at a maximum it can be estimated by reference to the price the private sector attaches to this risk, which in this study is assumed to be reflected in the 30% discount to ROC prices[29]. Otherwise this approach provides minimal interference with the RO.

Modified Shell proposal

The timing delay associated with raising (through a capping of the recycle premium) and re-distributing funds to offshore wind means that in a 2015 timeframe, the Modified Shell proposal delivers little additional capacity over the existing RO policy. The projections show 10.2% of renewable energy by 2015, well behind the other alternatives. This is due to the surplus for re-distribution from capping taking time to build up, in particular because with grandfathering, only a small proportion of the renewables base is initially subject to the cap. However, over the 2020 timeframe, this mechanism is capable of delivering better results than most alternatives (although not as strong as the Renewable Development Premium) as the capital raised is spent in later periods, by which time offshore wind economics have improved. Because the capacity additions come so late in the timeframe examined, it is one of the least efficient mechanisms in terms of the cost per MWh of delivered renewable electricity, at £44-46/MWh. In addition, there would be a requirement to pre-allocate funding, assuming that the funds would be paid to offshore wind investments through capital grants. However, the proposal does have attraction in that it is less disruptive to the RO than some of the other mechanisms (preserving the market-based mechanism where the ROC value is under the cap) and requires no extra funding.

Multiple/fractional ROCs

Similar to the Modified Shell proposal, the base case Multiple/fractional ROCs is not able to deliver significant overall extra wind capacity in a 2015 timeframe (10.9% of generation in 2015), given that no new money is applied. A significant amount of offshore wind (3.4GW) is delivered by 2015, but the targeting of funding towards offshore wind is (without extra funding) at the expense of onshore, leading to a much lower level of onshore development than in other options. While the support for new onshore and offshore wind projects can be adjusted by changing the relevant multiples (with corresponding effect on the installed capacity for each technology), this does not lead to a greater overall level of wind installation. Whichever fractions are used, a lower amount of new wind capacity is achieved than the options with additional funding in the 2015 timeframe.

Capacity additions by 2020 for this option are at a level similar to the top-up subsidy and npower options. Overall efficiency, in terms of the cost per MWh of delivered capacity is the least efficient of the schemes, due to investment in capacity coming later rather than earlier. While this policy allows targeting of support to different technologies, provides a mechanism for tapering support from technologies and requires no additional funding, it is inherently complex with the impact on ROC prices being difficult to predict and it is also likely to be administratively burdensome to deliver. It is possible that this additional complexity could act as an obstacle to investment.

Summary of policy alternatives

Various policy choices exist to close the offshore wind funding gap and drive development. These different policies attempt to address one or more of the inefficiencies of the RO and result in varying levels of cost/benefit and renewable penetration. Each involves different funding requirements and levels of disruption to the RO and they can usefully be compared as shown in Figure 9 on these parameters:

The most efficient option in terms of cost per unit of energy and achieving maximum offshore wind capacity by 2015 involves moving away from the current RO towards a fixed mechanism, such as a Renewable Development Premium. Feed-in tariffs have been proven to be successful elsewhere[30] (for example, Spain and Germany) in generating significant deployment of lower cost renewable energy. A fixed mechanism addresses both the time delay of the RO and the leakage associated with transferring the regulatory risk to the private sector. It is the most efficient policy mechanism in terms of funding requirement per unit of renewable energy.

[29] The private sector price of this risk assuming a 30% discount on ROCs represents a maximum cost of c.£1.9bn by 2020.

[30] See, for example, '*The support of electricity from renewable energy sources*', Commission of the European Communities, SEC (2005) 1571.

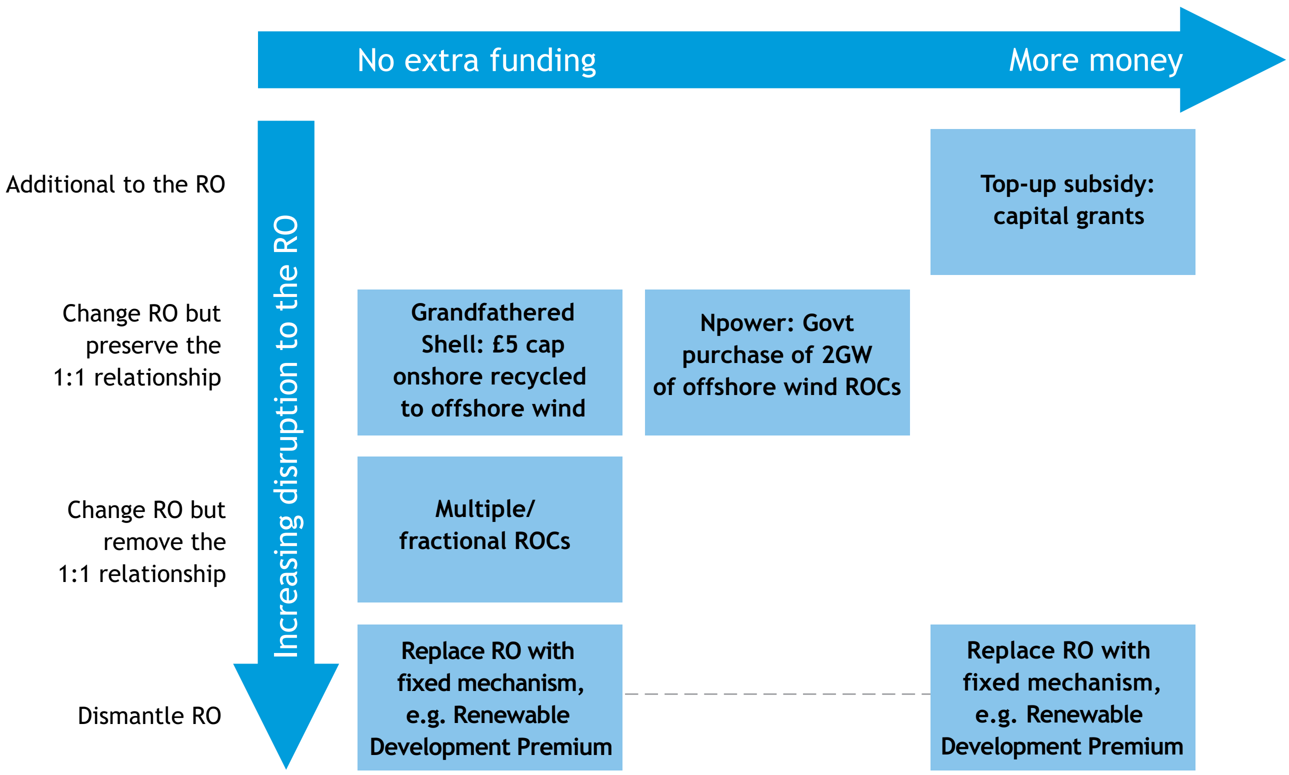
However, the Renewable Development Premium would involve ongoing Government involvement and a major shift from the current framework. This option can be designed to cost less, the same, or more than the current RO policy. The analysis suggests that combining this policy with some extra funding of c.£1bn by 2020 (in present value terms) allows the UK to get close to achieving its renewable energy targets, while still realising a lower subsidy cost per unit of electricity than alternative options. If funding is restricted to the current level committed under the RO, then the restricted funding variant of the fixed feed-in still provides the most favourable results in terms of capacity additions to 2015 and efficiency.

The other two options, that deliver offshore wind capacity by 2015 whilst needing minimal change to the current RO (i.e. Top-up subsidy and the npower proposal), require additional funding, but neither of them delivers the same amount of renewable capacity as the base Renewable Development Premium.

If extra funding or moving away from the RO entirely are considered infeasible, the alternatives that involve re-distributing funds from onshore to offshore wind within the current system (Modified Shell and Multiple/fractional ROCs) should be considered. While these 'costless' options do not deliver as much net wind capacity by 2015 as the options mentioned earlier, they still represent a step change improvement in capacity additions and efficiency from the existing policy.

The policies also differ to the extent that funding is targeted towards different technologies. The projected level of new onshore capacity is significantly lower under the Renewable Development Premium and Multiple/fractional ROCs options, due to support being more targeted at offshore wind. While there are investors and interests in common between the technologies, the effects on different participants are not fully aligned and this tension will need to be taken into account, particularly given that most of the current momentum in terms of capacity additions is with onshore. In this context it needs to be considered that further benefits to offshore wind could be delivered if a third round of offshore wind sites were to be identified and licensed during the installation of Round 2 as many new sites could have wind speeds and economics that are more attractive than the later sites for Round 2 projects. This would offer the potential for more offshore wind capacity at lower cost than has been assumed in this study.

Figure 9: *Comparison of the different policy suggestions based on amount of extra funding required and level of change to the current RO*



All of the options examined lead to more favourable results than the existing RO. There is no straightforward solution, but the analysis suggests that targeting and bringing forward support for more rapid development of offshore wind is a more efficient use of subsidy than allowing the RO mechanism to run its course over a much longer timeframe. In addition, it is also worth mentioning that all the options help drive offshore wind to a more cost-competitive position in 2020 (ranging from c.£40/MWh for the Renewable Development Premium to £43/MWh for the top-up subsidy and npower options) than under the existing RO. However, driving offshore wind capacity quickly to meet the 2015 gap without overly compromising onshore returns involves extra funding, while options that require no extra funding or a less significant shift from the current RO do not deliver on 2015 capacity (although they deliver reasonable capacity by 2020).

Other policy elements

In addition to these options, the study has also examined the impact of other elements of policy that could apply in conjunction with some of the options. These include:

- the formalisation of the 2020 aspiration of 20% of electricity from renewable sources;
- the opening up of a third round of offshore wind development; and
- the use of other mechanisms in conjunction with the RO such as fixed headroom and 'ski slopes', designed to provide greater certainty in ROC prices.

Moving to a 20% target will result in an increase in funding of c.17% by 2027 — an additional £1.1bn by 2020 and £3.1bn by 2027 (in present value terms). The effect of extending the obligation to 20% is to deliver more capacity in the RO related options, particularly in a 2020 timeframe, with options generating c.1.5-2.7GW additional capacity by 2020 than they would without this extension (c.1.5-2.5% of electricity generation). However, the impact of this measure is considerably less in the 2015 timeframe, with a maximum additional capacity of 0.7GW delivered towards the emerging 2015 gap (c.0.5% of electricity generation) compared to their additional capacity with the 15% obligation. It should be noted that extending the RO to 20% without adapting it to drive offshore has almost no effect in the 2015 timeframe (0.1GW). And even though it allows for 2.7GW of additional capacity by 2020, this only increases renewable generation in 2020 by 2.4% to 12.5%.

Capacity additions in the 2020 timeframe are in part restricted due to the 'inventory' of offshore wind projects included in the detailed analysis not extending beyond Round 2. Indicative analysis suggests that the introduction of a Round 3[31] combined with the extension of the existing RO to 20% would lead to an additional c.3GW of capacity by 2020 over the base case of 6.5GW, not significantly higher than achieved from extension of the obligation alone. It would still have little impact on capacity additions in the 2015 timeframe. However, the effect of a Round 3 can be expected to bring the UK closer to its 2020 aspiration for renewables under an alternative policy framework aimed at driving offshore. For example, while under the Renewable Development Premium policy the addition of a Round 3 would not greatly enhance 2015 capacity, it could increase 2020 capacity by another c.4GW, leading to a total additional c.9GW[32] over the base case (c.19% of electricity from renewables generation), for the same overall cost as the RO extension to 2020.

The analysis also considers an option[33] where the RO is combined with the following policy measures: fixed headroom[34] of 1% ahead of the existing renewables base (so that the RO target stays 1% above the installed base)[35], which applies up to a maximum of 20% generation from renewable sources; and a 'ski-slope'[36] mechanism to avoid a crash in ROC prices if the target in any year is reached. This package has been suggested by a variety of people in the industry to remove uncertainty around the level of ROC prices, and hence lessen the amount of 'leakage' of the ROC value to PPA providers. Combined with the existing RO, these policy elements do not lead to additional capacity on top of the base case in the 2015 or 2020 timeframes, because renewable penetration in the base case is so far away from the 15% obligation. Similarly, combined with Multiple/fractional ROCs the package does not deliver any significant increment over the capacity expected from a Multiple/fractional ROCs scenario without these policy elements. However, if the combination of policies suggested in this package succeed in decreasing the level of ROC price uncertainty and regulatory risk, then it is possible that this could reduce the discount that PPA providers demand, thereby driving further capacity and generation. Given the general uncertainty in this area, such a reduction in discount has not been assumed in the analysis.

[31] This study has assumed a Round 3 of a scale similar to the combined capacity of Round 1 and Round 2 projects, with similar economics.

[32] This also requires more aggressive supply chain capability, which the industry would be likely to gear up for with a strong Governmental signal for offshore wind.

[33] The analysis for this option does not include a third round of offshore wind.

[34] The headroom applies on top of the 15% obligation from 2015, and applies only once the 15% threshold is met.

[35] Analysis by Cornwall Energy Associates suggests that a guaranteed headroom of 1% would provide more than sufficient protection to deal with most credible risks to exceeding obligation levels. Combining a headroom option with a ski slope provides further protection to ROC holders. Alternative proposals in the industry have proposed a higher headroom level of 2%. The choice of level for the guaranteed headroom will effect the cost of renewable energy to the consumer, with lower levels resulting in lower total cost.

[36] The 'Ski-slope' mechanism, as per the method set out in '*Creating ski-slopes from cliff-edges: removing volume risk from the renewables obligation*', ILEX Energy Consulting, June 2005, which utilises the existing buyout fund redistribution mechanism to give value to ROCs redeemed in excess of a cap or the total obligation. If the Obligation as a whole is exceeded all redeeming parties will face an additional call to pay into the fund (instead of receiving recycle value). The result is a smooth transition to lower ROC prices in the event of excess ROCs, rather than the present 'cliff-edge'.

Planning, supply chain and network constraints

Making an investment case for a wind farm is only one of the conditions that need to be satisfied before construction can get underway. Constraints relating to planning, obtaining access to supply chain resources and obtaining access to the grid have all held up potential investments in the past. In order to reflect these realities in the analysis, constraints were applied on the speed at which projects in the pipeline could move through planning and their ability to obtain access to supply chain resources and obtain network connection.

Planning

Planning constraints (including both the ability of a project to obtain consent and the speed at which relevant approvals can be obtained to free up the project for commissioning) for onshore were informed by historic timings in gaining clearance from relevant authorities during the various stages of project development, and anticipated timings for each of these steps going forward. As a result, the 'inventory' of projects available for construction in any year is restricted, constituting only those for which all required approvals have been obtained. Differential assumptions were used to reflect planning timing differences and success rates in Scotland and England, and according to the size of the project. The combined effect of these assumptions is set out in Figure 10.

For offshore wind, Crown Estate leases have already been granted in relation to the sites. Although many projects have yet to complete the consenting process, the analysis assumes that all relevant clearances would be in place to commence construction once other constraints such as grid connection and supply chain had been cleared, and the investment case was favourable.

Network connection

Past studies have shown that significant upgrades of the transmission network would be required to accommodate onshore wind generation at levels that would meet the 2010 target. In particular, as is set out in Figure 11 upgrades are required in Scotland and the North West.

In Scotland, all remaining grid capacity has been allocated to projects under development. Many projects have been given connection offers which are contingent on planned upgrades of the transmission network (such as the Beauly-Denny line). Wind projects in the North of Scotland which apply for grid connection offers, now expect to be given estimated dates of connection of 2015 or later, which are conditional on completion of the Beauly-Denny line.

The key upgrades proposed by the network operators, as set out in Figure 12, are primarily aimed at increasing capacity in the North of Scotland and reinforcing the transmission link between Scotland and England.

Figure 10: *Approval rates and timing constraints for onshore projects*

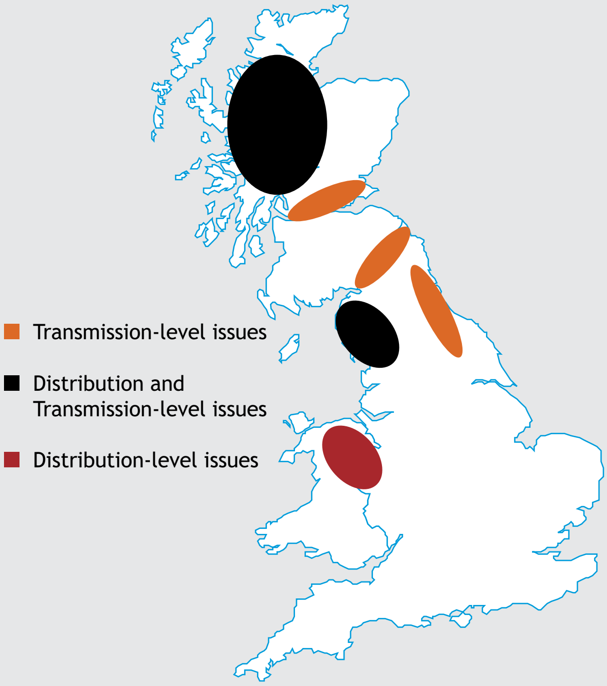
Stage of development	Location of project	Size of project	Speculative	Possible	Proposed	In planning	Production of electricity begins Post approval
Characteristics of projects in stage			Proposed target capacity not defined in individual projects	Projects individually named	Projects yet to apply for planning consent but close to applying	Projects which have applied for, but not yet received, planning consent. Includes appeals	Projects which have received planning approval, but for which construction has yet to start
Average time in each stage (mths)	Scotland	<50MW	12	12	12	20	29
		>50MW	12	12	12	36	36
	England	<50MW	12	12	12	16	29
		>50MW	12	12	12	36	44
Probability of proceeding to production†	Scotland	<50MW	25%	33%	44%	59%	90%
		>50MW	21%	28%	38%	50%	90%
	England	<50MW	32%	43%	58%	77%	90%
		>50MW	21%	28%	38%	50%	90%

†Note: Other than for economic reasons.

Sources: The Red Book; BWEA; L.E.K. analysis

The total cost of required grid investment may therefore be in the order of £1bn, but much of this investment will not take place until after 2010, restricting overall investment in renewables. The transmission upgrade required is carried out and paid for by the Transmission Service Operator (TSO) and the assets developed are taken onto the balance sheet of the TSO to be subsequently charged through the transmission charging mechanism.

Figure 11: *Capacity constraints of the transmission and distribution networks (upgrades required to accommodate onshore wind generation to meet the 2010 renewable generation target)*



Source: The Carbon Trust and DTI Renewables Network Impact Study, 2003

In order to reflect connection constraints, the analysis uses National Grid's non-contingent grid connection offers* as the maximum total new renewable capacity for Scotland until 2012. Thereafter it has been assumed that capacity contingent on the Beauly–Denny line is released. It has also been assumed that the interconnector investments and North West upgrades will be in place by 2012. (Offshore wind will not require significant large scale upgrading of the existing onshore grid except for some projects in the North West region because the grid is generally better developed in the key offshore areas.)

Supply chain constraints

Supply chain constraints, particularly for offshore wind, are also likely to affect the development of wind projects. For offshore wind the supply chain is presently immature (particularly in term of its willingness to invest in key equipment and assume EPC risk**, where all design development and construction risk is with the contractor) and requires a strong signal from Government to gear up. The analysis has made assumptions in line with BWEA*** estimates of the potential offshore wind build rate in each year.

* 'GB Queue Update' presentation given by Nigel Williams of the National Grid at the National Grid's 'Managing Access to the GB Transmission System User Seminar' held on the 22nd & 23rd February 2006.

** Engineering Procurement Construction.

*** BWEA submission to the Energy Review, Appendix B, 'Offshore wind at a crossroads'.

Figure 12: *Transmission upgrades considered by Ofgem†*

Transmission company	Project	Estimate of costs (£m)	Stage of development	Estimated completion dates
SPTL/SHETL	Beauly to Denny	332	In planning	2010-2015 (depending on planning)
NGC/SPTL	Interconnector	168	Construction expected to begin Summer 2006	2010-11
SPTL	Kendoon	40	Funding approved by Ofgem	Unknown
SHETL	Sloy	21	Funding approved by Ofgem	Unknown
NGC	NE Ring	140	Ofgem to reconsider in 2006	3-5 years (from start date)
NGC	Heysham Ring	65	Ofgem to reconsider in 2006	3-5 years (from start date)
SHETL	Beauly to Keith	N/A	Ofgem to reconsider in 2006	3-5 years (from start date)
SHETL	Beauly to islands	N/A	Ofgem to reconsider in 2006	Unknown
Total cost may be in the order of £1bn				

†Note: In its Consultations on Transmission Investment for Renewable Generation (2004)

Alternative proposals to drive offshore wind development

Renewable Development Premium

Fixed subsidy mechanisms can take various forms such as the feed-in models employed in Spain and Germany, or carbon contracts. The basis of the Renewable Development Premium is a 'stepped' fixed feed-in revenue subsidy that is set at levels appropriate for investment at a given stage of the technology's maturity. A fixed rate per MWh of electricity generated applies for the life of a given project, and is not subject to change. In this policy option, the mechanism has been applied both to onshore and offshore wind in place of the RO for new projects and has been designed as a fixed premium on top of the wholesale electricity price and LEC payment. Other technologies would also receive fixed rates according to their cost position and the level of desired incentive; however, for the purposes of this study, the analysis assumes that other technologies continue to receive support as if the RO was still in operation. Existing renewables projects would be grandfathered under the RO.

The level of subsidy for newly installed projects would be set so that the subsidy decreases with expected cost reduction (indicated by annual electricity production), with targeted returns (IRRs) for developers also decreasing as the technical risks reduce. Therefore, while an individual project's subsidy is set for the life of that project, subsidy per MWh is reduced for later projects (which use technology further down the cost curve) as the economics of new wind projects in time become more competitive with other major forms of generation.

Two versions of the Renewable Development Premium are included in the detailed analysis: the base case version in which there is no restriction on the aggregate level of funding; and a second with a funding restriction to the level of the RO commitment. In addition, the analysis undertaken also includes calculations for a third version where the projected level of installation is similar to that expected under the current RO policy, which helps highlight the inefficiencies in the current policy regime due to the lower cost of achieving this level of capacity. In the base case version of the analysis, the Renewable Development Premium initially provides £55/MWh of support to offshore wind on top of the wholesale electricity price, tapering to £40/MWh in 2010, £35/MWh in 2012 and £30/MWh from 2017 onward. Throughout the period onshore receives £25/MWh on top of the electricity price.*

Top-up subsidy

Under this scenario, additional funding for offshore wind is provided on top of the RO by way of capital support at the project outset of £350k/MW of capacity installed. This figure has been chosen as it represents the central figure in terms of the funding gap arising from engagement with the investment community. Funding would be provided for all projects commencing operation up until 2012; no further grant is provided for projects after this time as offshore wind is assumed to have been able to have benefited from the learning curve sufficiently by then. The RO continues to apply to all other technologies in an otherwise unchanged form. A top-up subsidy can also be delivered in the form of additional revenue support, where a payment of £15/MWh to the developer on top of the RO is broadly equivalent to a £350k/MW capital grant. As the results of these options are very similar, we present the analysis of the £350k/MW top-up capital grant option only.

npower proposal

Under the npower proposal a new Government agency would enter into fixed price ROC purchase agreements directly with offshore wind developers. This agency would then sell these ROCs to electricity suppliers at the prevailing ROC market price. This places market and political risk with the agency and effectively provides offshore wind developers with a fixed feed-in tariff.

The scheme would only apply to 2GW of offshore wind capacity and would be allocated prior to construction to allow developers to go ahead with confidence. In addition, the scheme should only be available for a limited period (2006-12) to incentivise developers to drive through the cost savings necessary to change the underlying economics of offshore wind.

Although the overall cost could be interpreted to be zero, a suitable reserve of funds would be required to cover potential recycle shortfalls, buyer credit default and working capital and accordingly the transfer of risk to Government is not 'costless'.**

Modified Shell proposal

We have also examined a modified version of the Shell proposal submitted to the DTI which proposed a £10/MWh cap on the ROC recycle value, with the excess funds created being primarily used for capital grants to Round 2 offshore wind projects. The Shell proposal did not provide for grandfathering of existing investments (see side box – 'Grandfathering of existing investments'), which is likely to be considered a politically unacceptable change due to the impact on existing investors. Accordingly, a modified version of the Shell proposal provides for grandfathering of existing projects under the RO scheme; in addition, the terms have been modified so that it applies with a lower £5/MWh cap. An excess fund is then created over time, which the analysis assumes is primarily used for capital grants for offshore wind projects. This fund takes time to build up. The analysis has assumed that developers apply for a capital subsidy and that Government selects those projects that require the lowest subsidy per MW.

Multiple/fractional ROCs

Under a Multiple/fractional ROCs policy, each technology would receive a different multiple of a ROC certificate per MWh of electricity produced. There are many potential Multiple/fractional ROC scenarios. The base Multiple/Fractional ROCs option in the analysis involves the following elements:

- existing investments would be 'grandfathered', continuing to receive ROC payments on the basis of 1 ROC per MWh of electricity produced;
- 1.4 ROCs would be received per MWh for offshore wind and 0.5 ROCs for onshore wind and other lower cost renewable technologies such as landfill gas (others such as biomass and hydro continue to receive 1 ROC);
- the buyout fund is calculated on the basis of renewable electricity generated in relation to target and the recycle value is returned to ROC holders on the basis of number of ROCs held; and
- no extra overall funding is required.

* In the second version, offshore wind receives £55/MWh until 2011, £40/MWh in 2012 and 2013, and £30/MWh from 2014 onward. In the third version, offshore wind receives £45/MWh until 2010, £35/MWh from 2011 until 2014, and £30/MWh from 2015 onward. In all cases, onshore wind receives £25/MWh throughout the period.

** For the purpose of estimating this cost, we have assumed that the cost to the Government would range from zero to a maximum based on the full supplier margin applied to ROC support for all offshore wind installed by 2012 (first 2GW of capacity), c.£0.7bn by 2015 and c.£1.9bn by 2020.

Grandfathering of existing investments

In order to respect the expectations of those who have invested in renewable energy prior to a policy change, most options include 'grandfathering' for already installed capacity or capacity in development. The principle behind grandfathering is that existing investments should as much as possible continue to receive support (in terms of the cash flow profile over time) post a policy change as they might have expected at the time they invested under the RO regime.

There are a number of different means of effecting grandfathering for existing investments. The mechanics we have used (where there is a change to the regime that requires grandfathering)* are as follows:

- the grandfathered capacity includes capacity operating or in construction at the time of the policy change;
- in the Multiple/fractional ROCs options, grandfathered plant continues to receive 1 ROC per MWh of electricity produced;
- in the Modified Shell option, the value of the ROC for existing investments is not capped – that is, there are no contributions to the central fund from a cap on the ROC value from existing investments; and
- in the Renewable Development Premium option, it is assumed that the RO regime continues to apply to existing investments, with new build capacity under the fixed feed-in regime counting towards the total amount of renewable energy supplied, and hence influencing the level of the ROC recycle value.

* In the npower and Top-up subsidy options, no grandfathering is required as the ROC regime, with adjustments, continues

4.7 Conclusions

There are three broad stakeholder groups that need to be considered when making a decision on the future policy framework — the onshore and offshore wind investment communities and consumers/taxpayers. The groups have somewhat divergent interests: onshore wind (representing the lower cost technologies) has an interest in preserving the status quo or at least guaranteeing future returns in the event of any change; offshore wind (representing the higher cost technologies) has an interest in increasing the level of funding for offshore wind to enable a return on investment to be generated; and consumers and taxpayers have an interest in limiting the amount of new funding required, whether that be in the form of actual funding or an increase in risk. The interests of these three groups need to be balanced not only against each other, but also against broader UK energy aims including the need for diversity, carbon reductions and capacity to fill the emerging 2015 gap.

Given the tensions and trade-offs associated with choosing between the various policy alternatives, Government needs to agree a set of objectives for a successful wind policy framework to help navigate between these different concerns.

This study suggests the following objectives:

- wind at sufficient scale to contribute meaningfully to the gap in 2015;
- offshore wind cost-competitive by 2020; and
- subsidy efficiency characterised by a low subsidy per unit of electricity produced.

On this basis, the most efficient policy mechanism (the base Renewable Development Premium) can most effectively meet the objectives. It delivers the greatest amount of capacity by 2015, makes most progress towards renewables targets and provides a foundation for the cost of offshore wind to be reduced to a level in the range of 4.0-4.7p/kWh in 2020. Given that it involves significant change from the RO, a specific proposal would benefit from being tested further with the investment community to understand the potential effects on investor confidence and the level of political risk involved due to the need for increased level of Government involvement.

It is clear that a different set of objectives could lead to a number of different perspectives on the tensions and trade-offs involved in the policy choice. In this case, and as the Government refines its objectives, some of the other policies may also come into consideration.

It is clear, however, that a decision that involves some change to the existing framework needs to be made. All of the suggested options significantly outperform the existing RO, meaning that the option of retaining the current policy in its present form is very costly. All of the policies deliver higher renewables capacity by 2020 than the existing RO and do so at greater levels of efficiency. It is becoming clearer that doing nothing will introduce an element of political risk that may be very difficult to manage, associated with sustained high ROC prices and delivery below targets. Undoubtedly any change in policy will need to be communicated very carefully in order to manage investor confidence; however this should not be insurmountable as there is wide and growing consensus amongst the developer and investor community that the RO needs to be adapted or changed. Government reassurance to investors through measures such as grandfathering will also go a long way to preserving the confidence of the sector.

5 Longer-term situation (beyond 2020)

5.1 The need to preserve multiple low-carbon opportunities for the future

There are many arguments in favour of preserving opportunities for low-carbon electricity generation at scale which apply, in some measure, to all countries prepared to take action to reduce climate change.

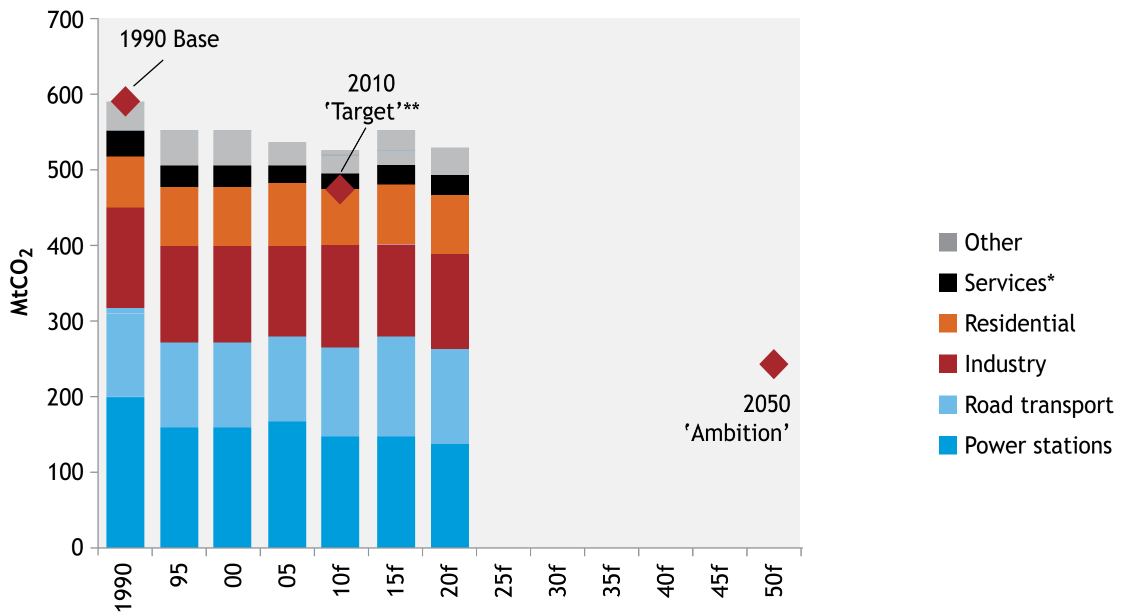
These include the need to address uncertainty of future electricity prices and specifically the prices for fossil fuels used to generate that electricity. There has, for example, been considerable recent volatility in gas prices, which has led to increases in electricity costs for businesses and consumers in the last few years. Moreover, it is not clear which technologies will be viable and cost-competitive in the future: a low-carbon technology that is highly uncertain or expensive today could prove to be one of the cheaper options in the future. The shares of different technologies' contributions to overall electricity generation are very different today compared with 50 years ago.

There are also portfolio benefits arising from having diversity of energy supply: in a similar manner to the way that financial investors can diversify away financial risk by holding a basket of investments, an economy can position itself better to cope with changes in fuel input prices or technology changes by having a range of generating technologies.

In particular, options should be preserved if it is possible that economic development benefits could arise from leading technology development. In Denmark and Japan, governments supported the technological lead held by those countries in the manufacturing of wind turbines and photovoltaic cells, which has led to the creation of valuable export industries. Between 1993 and 2003, the Danish Government invested £1.3bn in R&D and market stimulation measures; this has helped create a turbine manufacture and service and maintenance industry that earns £2.0bn in annual export revenues and employs 20,000 people; today, Denmark maintains a c.40% share of the worldwide industry. Japan, over the same period invested £1.0bn in photovoltaic technology and has created a manufacturing industry which has 50% of the world market, earns £600m in annual export revenues and supports 15,000 jobs.

In addition to these general arguments, the UK has set itself a very tough ambition for carbon reduction by 2050. Under the Kyoto Protocol, the UK has committed to a reduction in greenhouse gas emissions of 12.5% from 1990 levels by 2012. While this reduction is on track to be achieved, it is unlikely that the additional Government aspiration of a 20% reduction in CO_2 emissions by 2010 will be attained. The Government has also set a 2050 'ambition' of 60% reduction from 1990 levels which is a massive further reduction (as can be seen from Figure 13), and power generation is likely to be expected to bear a disproportionate share of the

Figure 13: *UK CO_2 emissions by sector*



Note: Quotas were introduced in six key industries in the EU ETS in 2005: energy, steel, cement, glass, brick-making, and paper/cardboard
*Includes agriculture **UK target of 20% reduction in CO_2 emissions by 2010, beyond the 12.5% reduction outlined in the Kyoto Protocol (which the UK is expected to meet)

Source: DTI (1990-2020 forecast, Central Gas Case), PointCarbon required carbon savings. Options for low-carbon generation are needed to help meet these goals.

Historically a large proportion of electricity has been generated from locally sourced fuel: for the UK this has been coal and gas. As the North Sea gas fields start to run out over the next 10-20 years, the UK will become more reliant on imports, and the vast proportion of world gas reserves are held in higher risk countries such as Russia, Iran, Saudi Arabia and Qatar. Preserving options for locally sourced generation assists with security of supply issues.

Accordingly, the UK needs to ensure that several low-carbon generation alternatives for the longer term are available. However, there is significant uncertainty associated with both the delivery (at scale) and cost of development of prospective low-carbon generation alternatives such as marine energy, biomass, CCS, and 3rd generation photovoltaic technology. In such circumstances, an options approach is the correct way of viewing and assessing the decisions that need to be made to ensure that sufficient alternatives remain open for the future.

5.2 An options approach

Option theory provides a framework for assessing decisions where developments in the future are particularly uncertain. An options approach can take a number of forms, for example:

- if an initial investment in a technology works out well, then an investor may decide to expand the commitment to the technology through further investment; or
- alternatively, an investor may begin with a relatively small trial investment in a technology and create an option to abandon the project if results are unsatisfactory. Research and development spending in pharmaceuticals is a good example. A company's future investment in product development may depend on specific performance targets achieved in the lab. The option to abandon research projects is valuable because a company can make investments in stages rather than all up-front.

Each of these options owes its value to the flexibility it gives the option holder to make decisions dependent on future results. This applies in just the same way to future low-carbon alternatives. For example, while current costs of generation from emerging low-carbon technologies remain high compared with fossil fuel technologies (and even wind), given the uncertainty and potential volatility of future fossil fuel costs, it is prudent to continue to invest in a range of alternative technologies to create an option for deployment if the technology becomes economic. This is depicted in Figure 14.

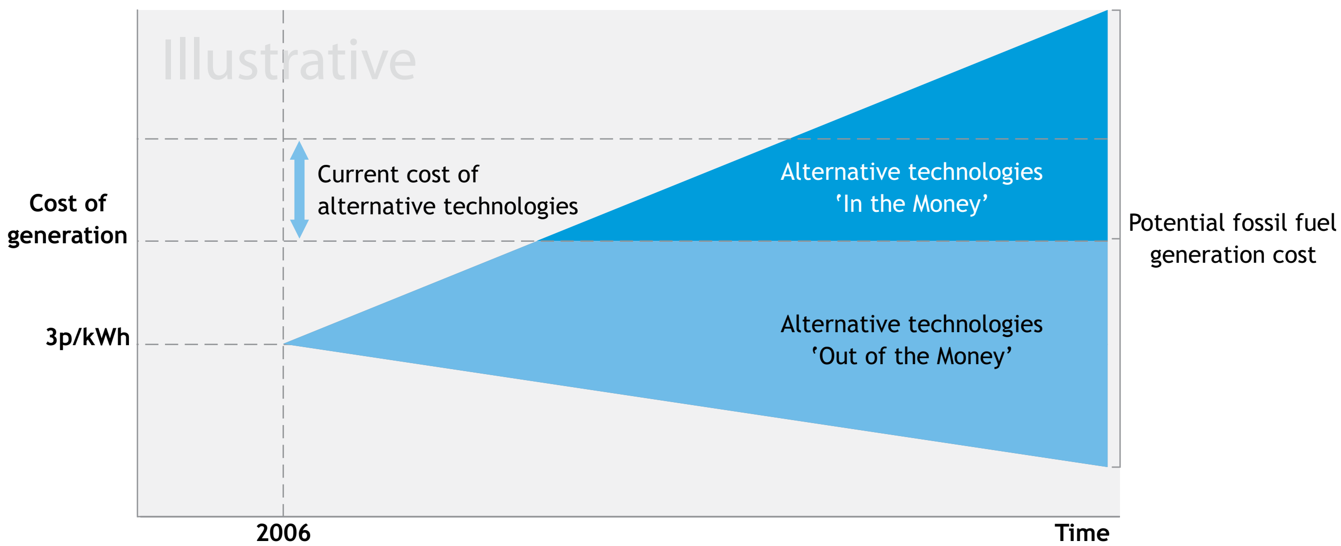
Should, in time, the cost of generation from fossil fuels rise above the cost of alternative technologies, then the option would be 'exercised' through scale investment in the new technology. This would not be possible if development of the technology were not kept alive in the interim, perhaps involving relatively small amounts of investment in the short-to-medium term.

5.3 The UK's role in preserving options

There is a range of low-carbon technologies that could be available by 2050 but the UK does not need to take the lead for all of these new developments. However, there are specific circumstances in which the UK should play an active role in the development of a low-carbon prospect which are based on:

- the existence of sufficient resources in the UK to support or fuel the technology;

Figure 14: *Option value of alternative low-carbon technologies*



- the ability of the technology to make an important contribution to UK electricity demands;
- the existence of a UK comparative advantage; and
- the ability to derive UK economic development benefits.

These should be applied to relevant technologies that are capable of delivering significant carbon savings and have the potential to become cost-competitive.

5.4 The case for marine energy

Marine energy, in the form of wave and tidal stream, is a good example of a technology area that meets all of these criteria, and hence forms an option that should be preserved.

The UK has the best natural resources for marine energy in Europe: in terms of wave energy potential, the UK has around twice the resources of any other European country. There is theoretical potential for marine to contribute up to 25% of current UK electricity consumption (80% of which would come from wave technologies).

In terms of comparative advantage, there are more developers engaged in development of marine technologies in the UK than in any other country. At least 80 concepts are in development as well as three UK device developers at an early deployment stage. In addition, in the form of EMEC[37], the UK has the only dedicated test centre/shared development infrastructure in the world. Moreover, the UK remains one of only two countries (the other being Portugal) with specific marine energy funding being available for the early-stage deployment of marine technologies.

Finally, the opportunity to derive commercial benefits outside the UK through intellectual property (IP) and know-how exists through the development and export of marine technology. In comparison to some other technologies such as nuclear, there are unlikely to be any security concerns with the export of IP and know-how to other countries, meaning that the market, once proven, could be very large. Benefits are expected to arise across the supply chain from design and testing, fabrication and installation of capacity, through to the operation and maintenance of equipment. The UK is well positioned in all these areas through a significant number of developers, infrastructure bases such as EMEC, and manufacturers, contractors and operating companies such as cable manufacturers and installers, offshore wind contractors and utility operations contractors. Total benefits to the UK from a wave option have been estimated at c.£0.6-4.2bn in annual revenues by 2050 (in real terms) and this is discussed in more detail in Section 5.7.

5.5 Deficiencies in the current renewable energy policy framework

Marine currently operates in Technology Stages 1 and 2: R&D and Early Demonstration (see Figure 2). Through engagement with the renewables investment community, this study obtained feedback on issues and concerns with the current subsidy framework for marine.

R&D support in Stage 1 appears to be functioning satisfactorily. Subsidy at this stage is necessarily in the form of capital grants, and levels of funding appear to be sufficient. Specific concerns are that the application process was somewhat burdensome, relative to the scale of each grant and more importantly that feedback from later stages of technology development into the R&D programme is limited. R&D spending can be more effective and focused with greater visibility of the performance of devices that are moving into the demonstration phase.

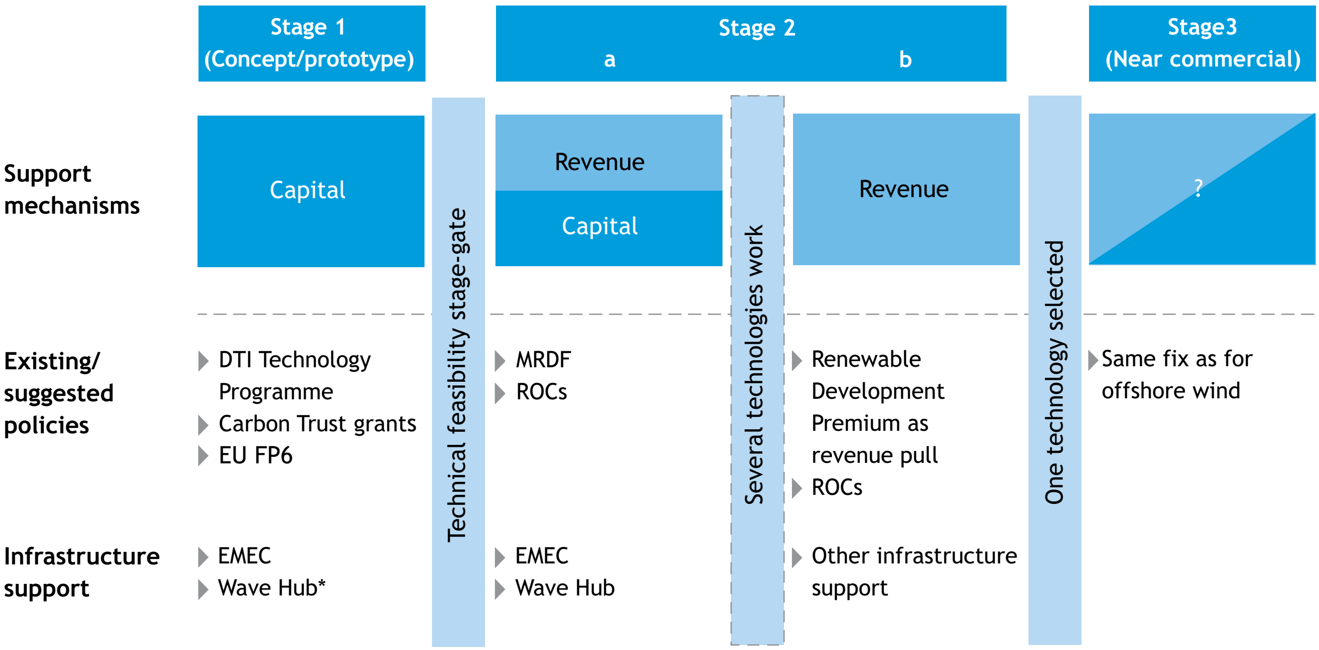
The MRDF with its combination of both capital and revenue support is the right mechanism given the current stage of marine technology development; the technology is still very uncertain, and the capital element of the support helps developers manage some of that risk. However, the most critical concern affecting technologies in, or on the verge of entering, Stage 2 is that the MRDF is limited in scope and marine policy is silent on long term industry funding. The MRDF fund size is not large enough to support projects of sufficient size to start substantial movement along the learning curve. In addition, there is still a high degree of uncertainty over the viability of technologies likely to be funded under the MRDF. Marine technologies which are currently lowest cost may not be the same ones that have the best long term potential.

The combination of these uncertainties brings into focus the lack of a support mechanism beyond the MRDF and the absence of a sufficient prize in the medium term to motivate sizeable investment. The RO is not capable of performing this role due to its focus on the lowest cost solutions — although marine energy may receive a trickle of funding from the RO for the electricity it produces, this is not sufficient for marine technology demonstrations.

In summary, the private sector is held back by this poor visibility of the longer-term market potential. The current policies lack an adequate mechanism between the MRDF and policies designed for Stage 3 and beyond. This will limit the ability to draw through marine technologies into the next stage of development, where offshore wind is today.

[37] European Marine Energy Centre.

Figure 15: *Potential policy framework for marine and low-carbon technologies in general*



*The Wave Hub proposal is to build an electrical grid connection point c.10 miles offshore into which wave energy devices would be connected

5.6 Suggested policy framework for early-stage technologies

An additional 'pull through' revenue subsidy is required

A policy solution is required across technology stages that incorporates a revenue 'pull through' mechanism in Stage 2 to act as an incentive for technologies in the early demonstration phase to prove themselves and move to Stage 3. The framework set out in Figure 15 presents a possible solution.

The framework suggests no change to the existing policies in Stage 1. In addition, there is no reason why a policy fix chosen for offshore wind (as discussed earlier in this document) could not apply to marine once it moves to Stage 3.

In between (in Stage 2), there is a need for two distinct funding mechanisms. While the MRDF acts as a support mechanism for technologies that have proven their technical feasibility but are still in the earlier stages of demonstration (i.e., in Stage 2a), the revenue support mechanism in Stage 2b would act as an additional spur for the development of technologies that are more mature and can substantiate their ability to effectively produce electricity. Such revenue support which rewards success provides a mechanism that can feed back the status of technological progress to the Government; developers and financiers will only be willing to sign up to receive subsidy support solely from electricity delivery when technology risk is reduced to the extent that it functions effectively, thereby allowing them to make a return on the project investment. The mechanism applied could be the same structure that is applied in Stage 3, provided that appropriate adjustment is made to the levels of funding so that it maintains relevance for the higher-cost, less developed technologies in Stage 2; the analysis suggests that a Renewable Development Premium would be most efficient.

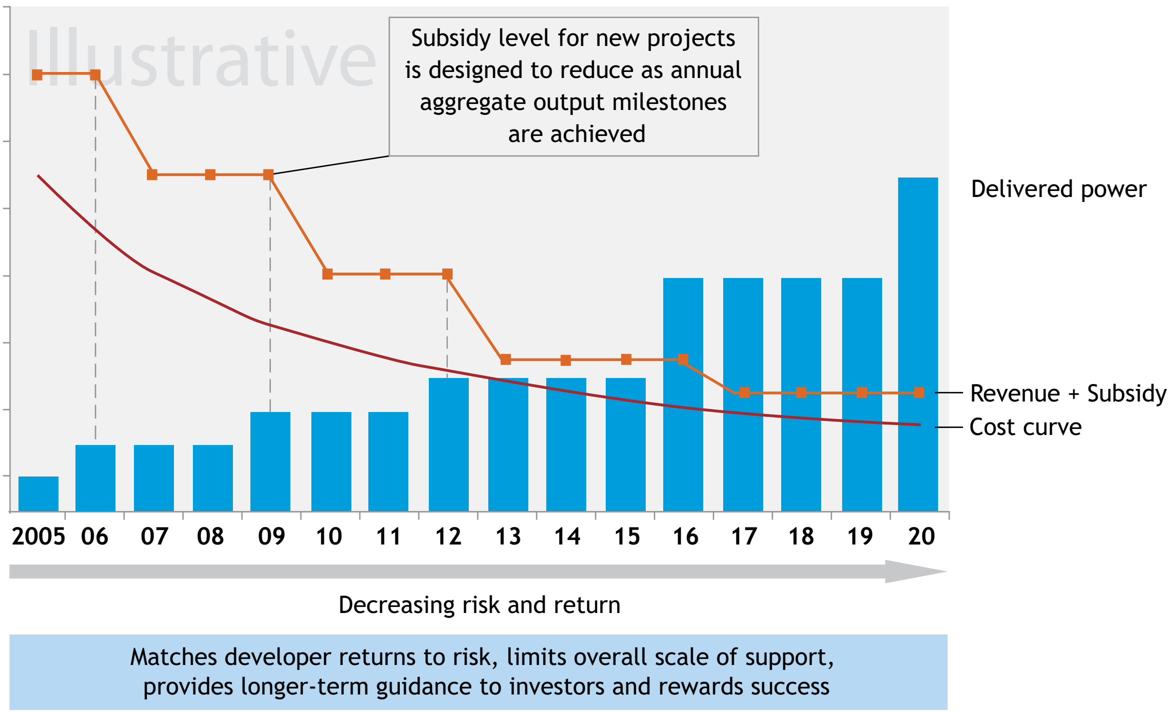
The Renewable Development Premium mechanism as revenue subsidy

The addition of a Renewable Development Premium subsidy, as set out in the Figure 16, to operate alongside the MRDF and either in addition to or instead of the RO would address the perceived problems with the current framework for marine and can be used to illustrate the value of a marine option.

A feed-in tariff is set and fixed at levels appropriate for investment at a given stage of the technology's maturity. It is (on average) set at an appropriate level above the technology's cost of producing electricity to allow the developer an adequate return on the investment, given the risks involved. This can be set either in addition to the RO or instead of the RO. The tariff is guaranteed for the life of a given project, not subject to change. The level of the feed-in for new projects would be 'stepped' down with expected cost reduction indicated by installed capacity, thereby matching project returns with levels of risk and cost. Targeted returns for developers also decrease as the technical risks reduce over time. In this way, the policy is broken down into a series of options that limit the amount of commitment long term, while still providing individual projects with appropriate funding and certainty. It also rewards success, providing subsidy only to projects that deliver electricity. In addition, if the technology is not delivering, a policy decision can be made to abandon the marine option by stopping the support with no further feed-in tariffs being provided for new projects.[38]

[38] Although existing projects would retain support as part of the subsidy's commitment for the life of an individual project.

***Figure 16:** Overview of a technology specific Renewable Development Premium*



Note: Individual projects are grandfathered at the subsidy level in use at the start of electricity production

The MRDF remains an essential part of the support framework in Stage 2 and should not be abandoned. However, there is a strong need for further support beyond the MRDF and for greater certainty on long-term industry funding. This requires putting in place a revenue 'pull through' mechanism such as the Renewable Development Premium sometime within the next year or two. The policy framework would benefit from a period of overlap between the MRDF and the Renewable Development Premium; this will provide a signal to Government on the status of technological progress demonstrating that developers and financiers are comfortable enough with the level of technology risk to receive all support on delivery of electricity. It is possible that, in a given period, no technology may seek support from the 'pull through' revenue mechanism. Provided that the overall level of support and other barriers to marine deployment are assessed, this could reflect the natural phases of development in the technology cycle. Accordingly, if the technology is not ready for a revenue 'pull through' mechanism, then the MRDF should be repeated as a subsidy instrument.

Other recommendations for the policy framework

The wider policy framework also suggests a stage gating process to filter access to the MRDF more stringently. To create this filter mechanism, the Government should take active involvement through the development of a formal Review Board with stable and long-term membership to evaluate the technologies consistently against a rigorous set of criteria. To a certain extent this filter already exists in the MRDF, however, a greater degree of stringency and consistency in decision-making would be provided by such a Board to ensure that the most suitable projects are chosen for MRDF funding.

It would also be helpful to ensure a functioning link (facilitating, for example, the commissioning of relevant R&D or feedback of know-how and generic experience) back to Stage 1 technology developers from Stages 2a and 2b. This could be effected by requiring developers receiving Stage 2a (MRDF) funding to develop their technology with periodic reviews with a Review Board to feed back information into the R&D stage. This process would of course need to be carefully managed to address developer concerns and recognise the importance of commercial IP. In contrast, the funding in Stage 2b provides a market mechanism for information flow to technology developers by signalling which specific technologies are most successful. The increased revenue pull provides the incentive for project developers to fund R&D directly or to purchase IP, device development and research from outside.

The revenue support would continue to apply to developing technologies until such time as the technology area developed to a point where a favoured design is selected (similar as to what has happened in terms of wind turbine design) and costs move down the learning curve to the point where they resemble near commercial platforms such as offshore wind. MRDF and R&D funding for a technology would be withdrawn either when the Review Board is satisfied that sufficient good technologies are operating under revenue support, or when it becomes clear that the industry has selected a single technology.

The Marine Energy Challenge

The Marine Energy Challenge (MEC) was a £3.0m, 18-month Carbon Trust Technology acceleration project based on targeted engineering support, intended to improve understanding of wave and tidal stream generation technologies by helping technology developers advance their designs. The programme had a particular focus on cost of energy, and sought both to clarify current costs and identify potential for future cost reductions.

The MEC was completed in summer 2005. Subsequently, the Carbon Trust has conducted a detailed study to assess the future cost-competitiveness and potential growth of marine renewables. In January 2006, the Carbon Trust presented the findings of this analysis in the Future Marine Energy Report, together with conclusions on specific aspects of marine renewables technology development (the report is available on the Carbon Trust website: www.carbontrust.co.uk). The analysis includes three scenarios relating to technology cost reduction: (1) A slow long-term learning rate of 10% to the upper bound of the current lowest-cost group (25p/kWh); (2) A faster long-term learning rate of 15% to the lower bound (22p/kWh); and, (3) A step change in costs to 10p/kWh after 50MW of capacity installed and a learning rate of 15% thereafter. The Future Marine Energy report also included two capacity deployment scenarios up to 2020 (c.1-2.5GW).

The *Policy frameworks for renewables* study has used this analysis to prepare two deployment scenarios up to 2050: a slower development case (15GW of marine energy deployed worldwide by 2050 of which c.4GW is in the UK) and a faster development case (195GW of capacity installed in the same timeframe of which c.26GW is in the UK). In each case the analysis is based on a central cost development scenario from the MEC (15% learning and no step change in costs). Under both scenarios c.£2bn in cumulative financial support is required for wave to reach a cost-competitive position of under 5p/kWh (by c.2030 in the fast development case and by 2040 in the slow development case). The analysis in the *Policy frameworks for renewables* study does not examine the effect on total subsidy level of a step change in technology cost. In the MEC analysis the Carbon Trust identified routes to cost reduction based on possible future engineering design improvements, which (if they were implemented) could lead to a step change in cost beyond current levels. Such a step change would clearly reduce the level of financial support required.

5.7 Potential costs and benefits of developing the marine option

As discussed above, for uncertain further-from-market technologies, an option approach is favourable, and so support would be best implemented in stages in order to preserve option value. Based in part on data obtained from the Marine Energy Challenge (see side box 'The Marine Energy Challenge') regarding the current and potential future cost-competitiveness and potential growth of marine renewables, this study has estimated the potential benefits to the UK from preserving the marine option.

On the basis of the growth of marine renewables in the MEC's slower development case, the additional (present value) cost of preserving the marine energy option by continuing to support technology development is c.£150m by 2010 (over and above the cost of the RO). This would require committed funds to be made available now as part of the introduction of a 'revenue pull' mechanism, providing the strong signal of long-term commitment required by the private sector to encourage investment. The commitment of additional funds for projects installed beyond this period would be reviewed as part of the option approach of continuing support for the industry. Assuming that it remained favourable to preserve the option, the total commitment would become c.£400m by 2015 and c.£600m by 2020. These costs would be higher under the faster development case (c.£800m by 2020).

This additional funding compares with the potential prize of £600m to £4.2bn annual UK revenue (slow vs. fast development case) from domestic and export markets by 2050, and £300m to £900m (slow vs. fast development case) by 2030. The prize in terms of economic benefit could therefore be very significant, in the order of the industries developed by Denmark in wind and Japan in photovoltaic cells.

5.8 Conclusions

The UK should support further-from-market low-carbon technologies in order to build UK options where the UK is a 'natural lead', has a comparative advantage, and is likely to achieve economic development benefits. Marine energy is an example of such an option.

Marine energy, and particularly wave energy, offers the UK the opportunity to develop an export industry. The value of the UK economic development benefit is uncertain as is the technology at this stage; however, this study estimates potential annual revenues by 2050 in the range of £0.6bn-£4.2bn.

Policy measures additional to the RO such as the MRDF have been designed to provide extra levels of support for further-from-market technologies. However, in aggregate, these policies are not sufficient; they do not provide long-term market certainty and are not material enough on their own to drive marine down a technology cost curve. Further targeted support is required.

The addition of a Renewable Development Premium subsidy for marine either instead of or in addition to the RO would address the perceived problems with the current framework and improve visibility of the longer-term market potential for participants.

Recommendations for policy change are as follows:

- put additional policy support mechanism in place within the next year or two. This could be an extension of whichever option the Government chooses for offshore wind, but ideally would be a revenue support mechanism such as the Renewable Development Premium;
- filter access to the MRDF more stringently using an objective Review Board of independent experts;
- periodic reviews and Review Board to feed back information to the R&D stage, recognising the importance of commercial IP;
- repeat MRDF support if marine technology is not yet at a stage where it is ready for a pure revenue 'pull through' mechanism (with no developers committing to projects under a Renewable Development Premium);
- withdraw MRDF and R&D funding when either:
  - the Review Board is satisfied that sufficient good technologies are operating under fixed feed-in support; or
  - it becomes clear that the industry has selected a single technology.
- withdraw support if technology does not deliver capacity and move down the cost curve.

6 Appendix — analytical approach

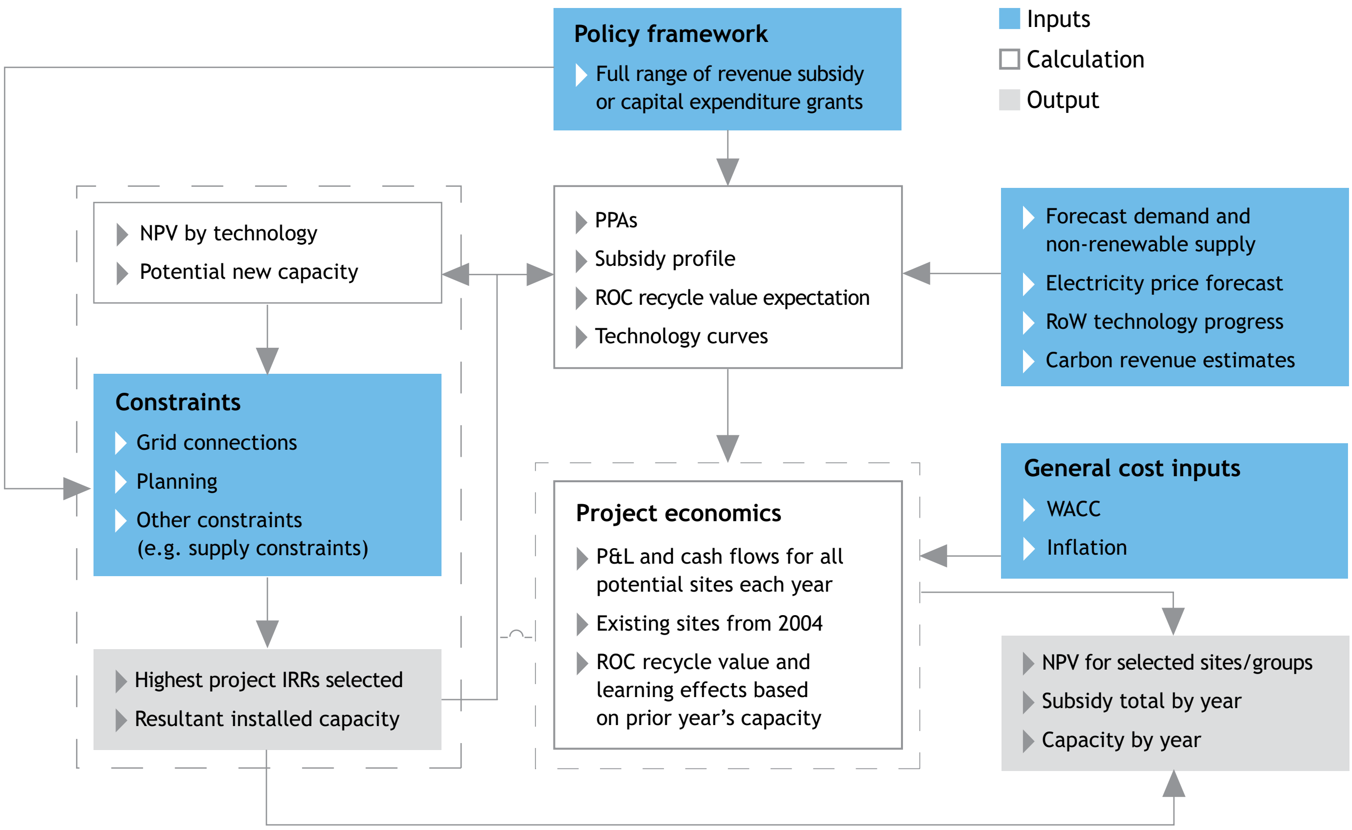
In order to understand and explain the economics and constraints of the existing policy framework and to evaluate the impact of different policy options, potential renewables investment under different scenarios has been modelled for the period from 2007[39] to 2027, the year until which committed Government funding under the RO runs. The analysis also provides the facility to assess renewables' ability to meet stated Government targets and provide a meaningful contribution to the 2015 gap. It is assumed that policy change takes effect in 2007.[40] A flow diagram of the modelling approach is set out in Figure 17.

A key principle driving the modelling approach was that subject to constraints such as planning, supply chain and grid connection, any wind project that can show positive economic returns for an investor (that is, a positive net present value at the time of the investment decision) should get built. Prospective projects are drawn from an 'inventory' of onshore and offshore wind projects in the pipeline (whose economics vary according to matters such as wind speed, location, and grid connection and usage costs). Projects in the pipeline are assumed to proceed to commissioning as the investment cases are proven, provided that the relevant planning, supply chain and grid constraints are not invoked. As renewables capacity is added in each year, a feedback loop applies so that the ROC prices (and hence revenue) applicable to a potential project are adjusted to reflect the current gap (at any time) between the level of the obligation and the amount of renewable generation achieved.

The model is predominantly a wind model. For other renewable technologies such as biomass, co-firing and hydro, the analysis draws on ILEX's[41] assumptions regarding future deployment, which assume ROC prices in a central range of potential values and no significant change in Government policy. The analysis also used investment 'trigger points' supplied by ILEX as a cross-check to ensure that these investments would in general take place given the ROC prices forecast in the model under the different scenarios.

The model operates on an annual basis, with new onshore and offshore capacity assumed to be commissioned on 1 April in any year, following construction finish during the previous year. Accordingly, no part year adjustments are made in the calculation of generated renewable electricity. By way of example, for the 2010 year running from

Figure 17: *Schematic explanation of the model structure*



[39] 2006 levels have been set on the basis of existing capacity and expectations of commissioning of new capacity during the course of this year.

[40] Years used in the modelling exercise run in line with the timing of changes in the RO; for example, 2007 represents the period from April 2007 until March 2008. Accordingly, in the analysis policy change is assumed to take place with effect from April 2007.

[41] As of June 2006, ILEX Energy Consulting changed its name to Pöyry Energy Consulting.

1 April 2010 to 31 March 2011, total wind generating capacity is for the whole year assumed to be at the level in place as at 1 April 2010. This is estimated by the model to have reached 5.1GW[42] under the existing RO policy, of which c.90% is onshore. During the course of the 2010 year, an additional 1.0GW is estimated to be built, meaning that for the 2011 year, there is a total of 6.1GW of wind capacity in operation, counting towards the level of generation in the 2011 year.

The model was built with functionality to test a range of potential policy options. The principal outputs from the model are the level of wind capacity installed in each year to 2020 and the total cost to taxpayers and consumers, which allows comparison of the cost effectiveness of different options and evaluation of the extent to which wind can make an effective contribution to the emerging conventional capacity gap.

Key assumptions in the model regarding costs for onshore and offshore wind installations and forward electricity prices are set out in Figures 18, 19 and 20 (below and overleaf).

Figure 18: *Forecast electricity prices*

ILEX electricity price central case (with carbon) estimates are used throughout the forecast period. Averages for the periods 2006-10, 2011-15 and 2016-20 for the ILEX central case and high case (both with carbon) are as follows:

£/MWh	2006-10	2011-15	2016-20
Central	42.1	38.9	37.4
High	51.5	50.9	49.5

Figure 19: *Key economic assumptions for Onshore*

Revenue (2006)

Electricity price	ILEX central case	
LEC	4.3 £/MWh	Deflates in real terms as held at 4.3 £/MWh (2006 prices) until 2010
ROC		
– buyout	33.1 £/MWh	For 2006, then varies over time according to modelled capacity additions against target
– recycle	9.3 £/MWh	
ROC applies to 2027		
Of these revenue items, it is assumed that the utility supplier retains 20% of the electricity price and LEC (to compensate for balancing costs) and 30% of the ROC (buyout and recycle) value to compensate for market and political risk		
Capacity factor range	17-35%	Dependent on wind speed estimates by project
Operating life	20 years	

Costs (2006)

	£000's/MW	
Operating cost	28-61	Large range due to variations in transmission charge
Capital expenditure		
Turbines	464	
Civil works	94	
Electrical infrastructure	58	
Grid connection	44	
Other	65	
Total Capital Expenditure	**725**	

Other inputs

WACC	7.75% (real)
Tax	30%
Capital allowances (depreciation)	25% declining balance

Note: Values in real terms as of April 2006

Source: L.E.K. analysis based on reports/data and 4 interviews with various industry participants (reports/data include: DTI, '*You want the confidence to invest in renewable energy*', November 2004; DTI, '*Impact of GB transmission on renewable electricity generation*', February 2005; Enviros '*The cost of supplying renewable energy*', February 2005 (and responses); Redfield Consulting, '*The Red Book*', April 2006; DTI Restats database; DTI Wind speed database; National Grid, '*The statement of use of system charges*', April 2006; and, Local distribution companies' statements of charges for the use of distribution)

[42] Including current forecast wind capacity by end of March 2007 of c.2.4GW (of which more than three quarters is onshore).

Figure 20: *Key economic assumptions for Offshore*

Revenue (2008)

Electricity price	ILEX central case	
LEC	4.2 £/MWh	Deflates in real terms as held at 4.3 £/MWh (2006 prices) until 2010
ROC		
– buyout	33.1 £/MWh	For 2008, then varies over time according to modelled capacity additions against target
– recycle	17.0 £/MWh	
ROC applies to 2027		
Of these revenue items, it is assumed that the utility supplier retains 20% of the electricity price and LEC (to compensate for balancing costs) and 30% of the ROC (buyout and recycle) value to compensate for market and political risk		
Capacity factor range	29-41%	Dependent on wind speed estimates by project
Operating life	20 years	

Costs (2008)

	£000's/MW
Operating cost	44
Capital expenditure	
Turbines	673
Civil works	417
Electrical infrastructure	88
Grid connection	148
Other	151
Total Capital Expenditure	**1,478**

Other inputs

- WACC 10.25% (real)
- Tax 30%
- Capital allowances (depreciation) 25% declining balance

Note: Values in real terms as of April 2006

Source: L.E.K. analysis based on reports/data and 4 interviews with various industry participants (reports/data include: BWEA, '*Fortis Round II economic gap analysis*', December 2004; Garrad Hassan '*Offshore wind, economies of scale, engineering resource and load factors*', December 2003; National Grid, '*The statement of use of system charges*', April 2006; Redfield Consulting, '*The Red Book*', April 2006; and, Econnect, '*Study on the development of the offshore grid for connection of the round two wind farms*', January 2005)

7 Glossary and abbreviations

Term	Description
2010 target	The Government's target of achieving 10% of electricity generation from eligible renewable sources by 2010
2015 gap	The emerging conventional capacity gap arising through the scheduled retirement of conventional capacity by the end of 2015
2020 aspiration	The Government's declared aspiration of achieving 20% of electricity generation from eligible renewable sources by 2020
AGR	Advanced gas-cooled reactor
CCGT	Combined Cycle Gas Turbine
CCL	Climate Change Levy
CCS	Carbon Capture and Storage
DTI	Department of Trade and Industry
EMEC	The European Marine Energy Centre
FGD	Flue Gas Desulphurisation
GW	Giga watt
IGCC	Integrated Gasification Combined Cycle
IRR	Internal rate of return
KW	Kilo Watt
LCPD	Large Combustion Plant Directive (EC Directive 2001/80/EC)
LEC	Levy Exemption Certificate
MEC	Marine Energy Challenge
MRDF	Marine Renewables Deployment Fund
MW	Mega watt
MWh	Mega watt hour
PPA	Power purchase agreement
PV	Photovoltaic
RO	Renewables Obligation
ROC	Renewables Obligation Certificate

Notes

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