The Renewable Energy Review

May 2011

Committee on Climate Change

Preface

The Committee on Climate Change (the Committee) is an independent statutory body which was established under the Climate Change Act (2008) to advise UK and devolved administration governments on setting and meeting carbon budgets, and preparing for climate change.

Setting carbon budgets

In December 2008 we published our first report, *Building a low-carbon economy – the UK's contribution to tackling climate change*, containing our advice on the level of the first three carbon budgets and the 2050 target; this advice was accepted by the Government and legislated by Parliament. In December 2010, we set out our advice on the fourth carbon budget, covering the period 2023-27, as required under Section 4 of the Climate Change Act; the Government will propose draft legislation for the fourth budget in Spring of 2011. We will provide advice on inclusion of international aviation and shipping in carbon budgets in Spring 2012, drawing on analysis of shipping emissions and a bioenergy review to be published later in 2011.

Progress meeting carbon budgets

The Climate Change Act requires that we report annually to Parliament on progress meeting carbon budgets; to date we have published two progress reports (October 2009, June 2010) and will publish our third report in June 2011.

Advice requested by Government

We provide ad hoc advice in response to requests by the Government and the devolved administrations. Under a process set out in the Climate Change Act, we have advised on reducing UK aviation emissions, Scottish emissions reduction targets, UK support for low-carbon technology innovation, and design of the Carbon Reduction Commitment.

Advice on adapting to climate change

In September 2010, we published our first report on adaptation, assessing how well prepared the UK is to deal with the impacts of climate change. We will publish further advice on this in July 2011.

Contents

Foreword

In May 2010, the Government asked the Committee on Climate Change to review the potential for renewable energy development, and to advise on whether existing targets should be reviewed. We were asked to provide advice in two steps: (i) initial advice on whether the targets for 2020 should be raised; (ii) subsequent more detailed advice on appropriate ambition beyond 2020.

In September 2010 we delivered our initial advice in a letter to the Secretary of State. We recommended that the 2020 target should not be increased but that policy should focus on ensuring that this stretching target is met.

In this report we set out our conclusions on the potential for renewable energy – in electricity, heat and transport – in the period to 2030 and beyond.

The report complements the conclusions and recommendations of our December 2010 report, *The Fourth Carbon Budget – reducing emissions in the 2020s,* which set out our recommendations for the fourth carbon budget. Later this year, we will publish a further report looking in particular at bioenergy. This will complete the Renewable Energy Review and will form part of our broader advice on inclusion of aviation and shipping in carbon budgets, as required under the Climate Change Act, and to be published in spring 2012.

Lord Adair Turner

Chair

Committee on Climate Change

Lord Adair Turner, Chair

Lord Turner of Ecchinswell is the Chair of the Committee on Climate Change and Chair of the Financial Services Authority. He has previously been Chair at the Low Pay Commission, Chair at the Pension Commission, and Director-general of the Confederation of British Industry (CBI).

David Kennedy, Chief Executive

David Kennedy is the Chief Executive of the Committee on Climate Change. Previously he worked on energy strategy at the World Bank, and the design of infrastructure investment projects at the European Bank for Reconstruction and Development. He has a PhD in economics from the London School of Economics.

Dr Samuel Fankhauser

Dr Samuel Fankhauser is a Principal Fellow at the Grantham Research Institute on Climate Change and the Environment at the London School of Economics and a Director at Vivid Economics. He is a former Deputy Chief Economist of the European Bank for Reconstruction and Development.

Sir Brian Hoskins

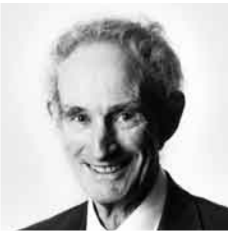
Professor Sir Brian Hoskins, CBE, FRS is the Director of the Grantham Institute for Climate Change at Imperial College and Professor of Meteorology at the University of Reading. He is a Royal Society Research Professor and is also a member of the National Science Academies of the USA and China.

Professor Julia King

Professor Julia King CBE FREng is Vice-Chancellor of Aston University. She led the 'King Review' for HM Treasury in 2007/8 on decarbonising road transport. She was formerly Director of Advanced Engineering for the Rolls-Royce industrial businesses. Julia is one of the UK's Business Ambassadors, supporting UK companies and inward investment in low-carbon technologies.

Lord John Krebs

Professor Lord Krebs Kt FRS, is currently Principal of Jesus College Oxford. Previously, he held posts at the University of British Columbia, the University of Wales, and Oxford, where he was lecturer in Zoology, 1976-88, and Royal Society Research Professor, 1988-2005. From 1994-1999, he was Chief Executive of the Natural Environment Research Council and, from 2000-2005, Chairman of the Food Standards Agency. He is a member of the U.S. National Academy of Sciences. He is chairman of the House of Lords Science & Technology Select Committee.



Lord Robert May

Professor Lord May of Oxford, OM AC FRS holds a Professorship jointly at Oxford University and Imperial College. He is a Fellow of Merton College, Oxford. He was until recently President of The Royal Society, and before that Chief Scientific Adviser to the UK Government and Head of its Office of Science & Technology.

Professor Jim Skea

Professor Jim Skea is Research Director at UK Energy Research Centre (UKERC) having previously been Director of the Policy Studies Institute (PSI). He led the launch of the Low Carbon Vehicle Partnership and was Director of the Economic and Social Research Council's Global Environmental Change Programme.

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A wide range of stakeholders who engaged with us, attended our expert workshops, or met with the Committee bilaterally.

Executive Summary

The Renewable Energy Review

Executive Summary

This review of renewable energy was commissioned by the Government in the May 2010 Coalition Agreement. It requested that we advise on the scope to increase ambition for energy from renewable sources. This has important implications for the sector investment climate and Government policy.

In September 2010 we summarised our analysis of 2020 renewable energy ambition in a letter to the DECC Secretary of State. We argued that the Government's 2020 ambition is appropriate, and should not be increased. Instead the focus should be on ensuring that the existing targets are met: this requires large-scale investment over the next 10 years, supported by appropriate incentives.

Our overall conclusion in this review is that there is scope for significant penetration of renewable energy to 2030 (e.g. up to 45%, compared to 3% today). Higher levels subsequently (i.e. to 2050) would be technically feasible. Equally however, it would be possible to decarbonise electricity generation with very significant nuclear deployment and have limited renewables; carbon capture and storage may also emerge as a cost-effective technology.

The optimal policy is to pursue a portfolio approach, with each of the different technologies playing a role. In the case of renewable technologies such as offshore wind and marine, this will require the resolution of current uncertainties and the achievement of cost reductions. Therefore the message in our previous letter is reinforced: new policies are required to support technology innovation and to address barriers to uptake in order to suitably develop renewables as an option for future decarbonisation.

In this review we do four things:

- We set out new analysis of technical feasibility and economic viability of renewable and other low-carbon energy technologies.
- We present scenarios for renewable energy deployment to 2030 and beyond, and assess whether it is appropriate now to commit to increased ambition for renewable energy in the 2020s.
- We consider implications of these longer-term scenarios for ambition to 2020.
- We assess the key enabling factors for investment in renewable energy technologies, suggesting high-level policy options as appropriate to deliver ambition in 2020 and beyond.

Box 1: Summary of findings of the renewables review

Electricity generation

- A range of promising options exists for delivering decarbonisation of the power sector by 2030 at reasonable cost. This includes renewables, nuclear and carbon capture and storage (CCS).
- A portfolio approach to technology support is appropriate.
- Firm commitments on support for offshore wind and marine generation through the 2020s should be made now.
- These should be implemented through the new electricity market arrangements.
- If renewable energy targets for 2020 can be met in other ways, a moderation of offshore wind ambition for 2020 could reduce the costs of decarbonisation.
- Ambition for offshore wind to 2020 should not be increased unless there is clear evidence of cost reduction.

Heat

- Further funding will be required to support renewable heat in the period 2015-20 and in the 2020s.
- Approaches to renewable heat and energy efficiency (i.e. the Renewable Heat Incentive and the Green Deal) should be integrated.
- Accreditation of installers is crucial if supply chain bottlenecks are to be avoided and consumer confidence improved.

Transport

- A cautious approach to the use of biofuels in surface transport is appropriate until and unless sustainability concerns are resolved.

Renewable energy scenarios

- The Government's plans for renewable energy deployment to 2020 as set out in the Renewable Energy Strategy are broadly appropriate.
- Our scenarios for renewable energy penetration in 2030 include a share of 30% (460 TWh) in a central case, rising to a maximum of 45% (680 TWh). These illustrate the order of magnitude for likely and possible renewable contributions to economy-wide decarbonisation.

Specific conclusions on power generation, renewable heat and transport (Box 1) are:

Power generation

- **The need for sector decarbonisation.** It is crucial in the context of economy-wide decarbonisation that the power sector is almost fully decarbonised by 2030. Options for sector decarbonisation include nuclear, CCS and renewable generation.
- **Current uncertainties.** The appropriate mix of low-carbon generation technologies for the 2020s and 2030s is uncertain. Key factors are: the ability to build nuclear to time and cost; whether CCS can be successfully demonstrated at scale for coal and gas; the extent to which the planning framework will support further investment in onshore wind generation; and the costs of renewable generation, especially offshore wind and marine.
  - **Nuclear power** currently appears to be the most cost-effective of the low-carbon technologies, and should form part of the mix assuming safety concerns can be addressed. However, full reliance on nuclear would be inappropriate, given uncertainties over costs, site availability, long-term fuel supply and waste disposal, and public acceptability.
  - **CCS technology** is promising but highly uncertain, and will remain so until this technology is demonstrated at scale later in the decade. In the longer term, storage capacity may be a constraint.
  - **Onshore wind** is already close to competitive, although investment has been limited by the planning framework, and is limited in the long term by site availability.
  - **Offshore wind** is in the early stages of deployment and is currently significantly more expensive than either onshore wind or nuclear. However, the existence of a large-scale natural resource, reduced local landscape impact compared with onshore wind and the potential for significant cost reduction make it a potentially large contributor to a low-carbon future.
  - **Marine** technologies (wave, tidal stream) are at the demonstration phase and therefore more expensive again, but may be promising, given significant resource potential and scope for cost reduction.
- **A portfolio approach.** Given these uncertainties, a portfolio approach to development of low-carbon generation technologies is appropriate.
  - This should include market arrangements to encourage competitive investment in mature technologies such as nuclear and onshore wind generation.
  - It should also include additional support for less mature technologies including CCS, offshore wind and marine, where there is potential for the UK to drive these technologies down the cost curve. This is in contrast to solar PV, where the pace and scale of development will be determined outside the UK.

- **Commitments for the 2020s.** As part of a portfolio approach, the Government should commit now to an approach for supporting offshore wind and marine in the 2020s. The approach should avoid stop-start investment cycles and provide confidence to supply chain investors of a long-term business opportunity beyond the next decade.
- **Firm commitments.** Given the need to provide investor confidence, support should be provided through firm commitments. Such commitments should be implemented through the new electricity market arrangements. For example, within the Government's proposed Contracts for Differences for low-carbon generation, a proportion of these could be targeted at supporting less mature renewable technologies.
- **Illustrative 2030 scenario.** We set out an illustrative scenario in which commitments on support for offshore wind and marine through the 2020s are broadly in line with planned investment and supply chain capacity to 2020. Together with ongoing investment in onshore wind, this would result in a 2030 renewable generation share of around 40% (185 TWh). Sector decarbonisation would then require a nuclear share of around 40% and a CCS share of 15%, along with up to 10% of generation from unabated gas.
- **Key deployment barriers** to be addressed include finance and planning:
  - Notwithstanding new market arrangements, there is a potentially important role for the Green Investment Bank (GIB) in financing offshore wind projects. Unless it can be demonstrated that risks of a shortage of finance to 2015/16 can be mitigated, allowing the GIB to borrow money from its inception should be seriously considered.
  - Planning approaches should facilitate investments in transmission that are required to support investments in renewable and other low-carbon generation. In addition, a planning approach which facilitates significant onshore wind investment would reduce the costs of meeting the 2020 renewable energy target, and of achieving power sector decarbonisation through the 2020s.

Renewable heat

- **Indicative 2030 ambition.** There is a set of low-carbon heat technologies that are mature but that need to be demonstrated in a UK context. Given successful demonstration, increasing the share of renewable heat from currently very low levels to around 35% of energy demand (210 TWh) by 2030 is likely to be both feasible and desirable. This will require consumer understanding and acceptance of the technologies, along with a willingness to accept the disruption and hassle costs of house retrofit.
- **Developing renewable heat options.** The approach over the next decade should focus on removing barriers and developing options that would allow significantly increased ambition in the 2020s. To facilitate this, approaches to renewable heat and energy efficiency (the Renewable Heat Incentive and Green Deal) should be integrated. Success will also require accreditation of installers, alongside financial support provided under the Renewable Heat Incentive. Firm targets should be set and funding commitments made for the period beyond 2020 as and when current uncertainties are resolved (e.g. between 2015 and 2020).

Renewable transport

- **Electric vehicles.** Significant growth in the number of electric vehicles will increase the share of renewable energy in transport, to the extent that batteries are charged by renewable power generation. In our fourth budget scenario, electric vehicle penetration reaches around 60% of new cars and vans by 2030. Although electric vehicles may still account for a considerably smaller share of total miles in 2030, this will increase significantly in the 2030s as the vehicle stock turns over.
- **Biofuels.** It is currently inappropriate to plan for significantly increased penetration of biofuels in surface transport beyond 2020, given concerns over sustainability (e.g. the tension between biofuels and food production, uncertainties about true lifecycle emissions and biodiversity risks) and competing claims on scarce bioenergy supplies from other sectors (e.g. aviation, industry). Under a cautious assumption of 11% (30 TWh) biofuels penetration in 2030, the total renewable transport share – including renewable electricity used in electric vehicles – would be around 15%.

Renewable energy ambition

- **2030 possible contributions.** Adding across our sectoral scenarios, the share of renewable energy penetration is 30% (460 TWh) in our central scenario[1]. Higher levels of ambition (e.g. up to 45%, 680 TWh) are technically feasible and might be economically desirable, depending on the evolution of relative costs and the development of supply chains. Analysis of maximum feasible levels suggests that:
  - **Power generation.** Renewable penetration of up to 65% (300 TWh) would be technically feasible. How much is economically desirable will depend on the evolution of the relative costs of renewables, nuclear and CCS.
  - **Heat.** Renewable penetration of up to 50% (275 TWh) might be technically feasible and desirable by 2030, depending on availability of bioenergy and ability to rapidly develop supply chains and overcome other barriers.
  - **Transport.** With optimistic assumptions over the availability of sustainable biofuels, up to 25% (60 TWh) of transport energy demand could be met by renewable energy in the form of biofuels.
- **2030 ambition.** The precise level of appropriate ambition will become clear over time. We recommend that the Government keeps ambition for renewable energy under review and revisits this as uncertainties over the economics of different low-carbon technologies are reduced (e.g. in 2017/18 when the first new nuclear plant and CCS demonstration plant are due).
- **2020 ambition.** Renewable energy ambition to 2020 as set out in the Government's Renewable Energy Strategy (RES) and as required under the EU Renewable Energy Directive (RED) would sufficiently develop options for increased ambition in the 2020s.
- **Maintaining flexibility.**
  - The composition of 2020 ambition as set out in the RES is broadly appropriate. The current level of ambition for offshore wind (13 GW capacity installed by 2020) remains appropriate given uncertainties about the feasibility of increasing ambition on other lower-cost options (e.g. onshore wind).
  - If, however, increases in onshore wind (or other low-cost) ambition were achievable and politically acceptable, a slight reduction in 2020 offshore wind ambition would reduce the costs of meeting the RED target.
  - Conversely, the 2020 ambition for offshore wind should not be increased, unless there is clear evidence that costs have fallen significantly.

[1] The total does not exactly equal the sum of the parts due to accounting complexities (as set out in Chapter 5).

We summarise the analysis that underpins our key messages in four sections, and provide more details in the full report:

1) Technical and economic analysis of renewable electricity generation

2) Delivering renewable heat ambition to 2020 and beyond

3) The role of renewable energy in surface transport

4) Scenarios for renewable energy ambition

The broad context for the review is set out in Box 2.

Box 2: Context of the renewables review

The **current share** of renewables in the UK energy mix is around 3% (Table B1).

Table B1: Share of renewables in UK energy consumption (2004-2009)

	2004	2005	2006	2007	2008	2009
Heating and cooling	0.7%	0.9%	1.0%	1.2%	1.4%	1.6%
Electricity	3.5%	4.1%	4.5%	4.8%	5.4%	6.6%
Transport	0.1%	0.2%	0.5%	0.9%	2.0%	2.5%
Total	**1.1%**	**1.4%**	**1.6%**	**1.8%**	**2.4%**	**3.0%**

Source: *DUKES* 2010, Table 7.7.

By 2020, the 2009 EU Renewable Energy Directive (RED) sets a target for the UK to provide 15% of (gross final) energy consumption from renewable sources – consistent with a share of 20% across all EU Member States. The Committee advised in a letter in September 2010 that the UK's current plans for meeting that target are broadly appropriate.

By 2030, the Committee has previously recommended (in our advice on the fourth carbon budget) a reduction in economy-wide emissions of around 60%, requiring that the power sector is largely decarbonised by that date.

The Committee will publish a full **bioenergy** review later in 2011. Given concerns over sustainability and questions over the best long-term use for this limited resource, in this report we adopt a holding position that assumes no increase in bioenergy use in the power or transport sectors beyond 2020.

1. Technical and economic analysis of renewable electricity generation

Our assessment of renewable electricity generation covers two areas:

i) Supporting renewable electricity generation as part of a portfolio approach

ii) Enabling factors and policy implications

i) Supporting renewable electricity generation as part of a portfolio approach

The technical and economic analysis in this review has identified a potentially significant, but uncertain, contribution from renewables to required power sector decarbonisation (Table 1).

- **Power sector decarbonisation.** Deep cuts in power sector emissions through the 2020s are feasible, cost-effective and desirable. Analysis for our fourth budget report suggested the need for 30-40 GW of low-carbon capacity in the decade from 2020, to replace ageing capacity and to drive down average emissions intensity to around 50 gCO_2/kWh.
- **Diversity.** Given current uncertainties over either the deployability or the costs of nuclear and CCS (see below), there is a value in developing other options for power sector decarbonisation. This suggests a potentially important role for renewable generation technologies.
- **Resource.**
  - There is abundant UK renewable resource, as regards wind, marine and solar energy.
  - Nuclear generation is unlikely to be subject to a fuel resource constraint for at least fifty years although this may become an issue in the longer term. In the medium term, availability of sites may become a binding constraint.
  - There is a long-term constraint on cost-effective CCS storage capacity. This could limit medium-term deployment of CCS in power generation, given the likely need for long-term use of CCS in energy-intensive industries.
- **Technical feasibility.** There is an issue about how the system copes with intermittent renewables (i.e. keeping the lights on when the wind does not blow). Our analysis suggests, however, that a high level of intermittent renewable generation is technically feasible, as long as options for providing system flexibility are fully deployed.
  - A range of options exist to address intermittency (demand-side response, interconnection, balancing generation) at a cost that is likely to be low relative to the costs of generation even up to very high penetrations. For example, analysis that we present in Chapter 1 suggests that even for renewable shares up to 65% in 2030 and 80% in 2050, the cost is only up to 1 p/kWh of additional intermittent generation.

– Given the potential to deploy these options, an assessment of achievable build rates suggests that it would be technically feasible to achieve renewable generation penetration of 65% in 2030.

- **Economics.** It is likely that a wide range of low-carbon generation technologies (renewables and others) will be cheaper than fossil-fired generation (Figure 1), given a carbon price compatible with overall progress to a low-carbon economy (e.g. around £70 per tonne in 2030):

  – Nuclear appears likely to be the lowest-cost low-carbon technology with significant potential for increased deployment; it is likely to be cost-competitive with gas CCGT at a £30/tCO_2 carbon price in 2020. As such, it should play a major role in decarbonisation, provided that safety concerns are addressed (Box 3).

  – The economics of CCS generation are likely to remain highly uncertain until this technology has been demonstrated at scale.

  – Onshore wind has a comparable cost to nuclear and is therefore also likely to be cost-competitive with gas CCGT by 2020.

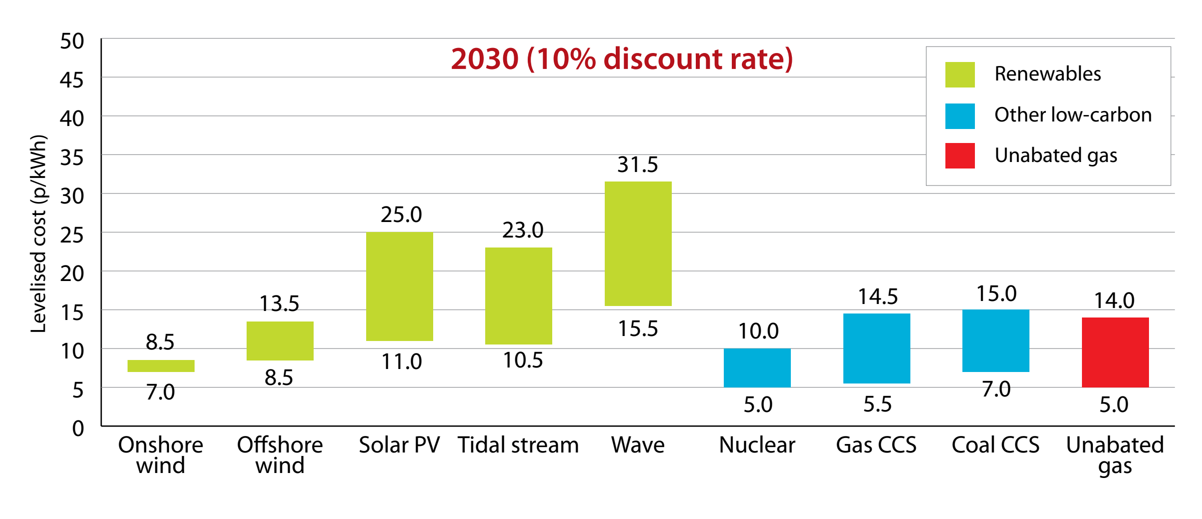
  – Most other renewable generation technologies currently appear relatively expensive and are likely to remain so until at least 2020, and in some cases considerably later.

  – By 2030, however, there are plausible scenarios where these other renewable technologies (e.g. offshore wind, marine, solar) have become cheaper than fossil-fired generation at a carbon price of £70/tCO_2 and to different extents have become competitive or close to competitive with nuclear.

  – Our conclusions on cost are based on a 10% real discount rate for annualising capital costs. Whilst some emerging technologies may currently apply a higher discount rate, we consider 10% to be a suitable basis for longer-term cost comparisons in the power sector, with new market arrangements in place and with wider deployment. Depending on the extent to which technology uncertainties are resolved, and with a supportive policy environment, a lower discount rate may be appropriate (e.g. 7.5%), in which case the low-carbon abatement options are even more attractive against conventional generation (Figure 2).

- **UK role in technology development.** As set out in our 2010 innovation review, the UK should support those technologies where we have a comparative advantage, and where we have the opportunity to be a leader internationally. These include offshore wind, for which the UK has a very favourable resource and a developing industry, and marine, for which the UK is in the lead in developing and demonstrating the technology and has a large share of the world's most promising sites.

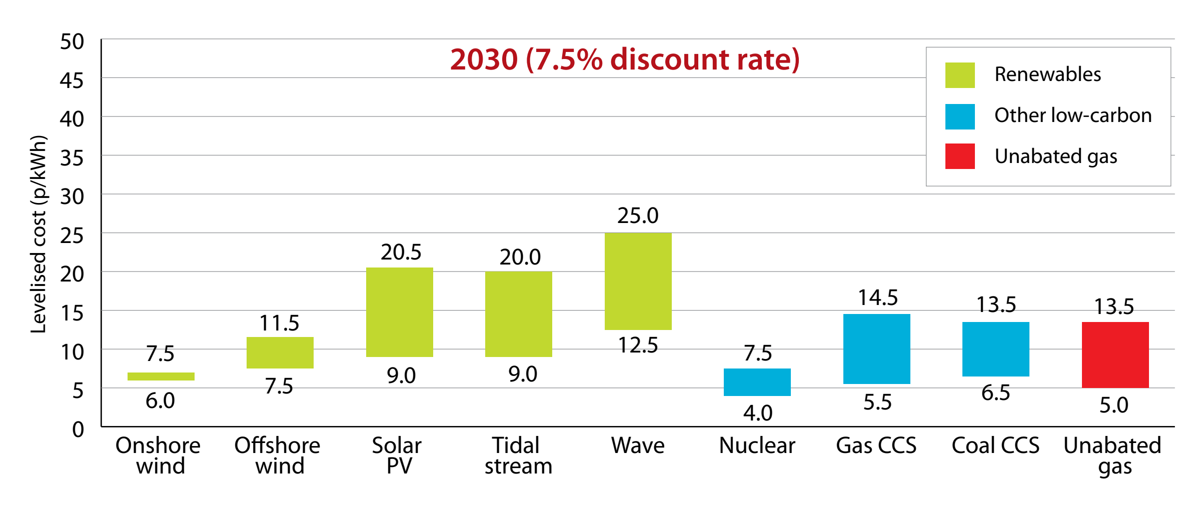
Figure 1: Estimated cost ranges for low-carbon power technologies (2030)



Source: CCC calculations, based on Mott MacDonald (2011) *Costs of low-carbon generation technologies.*

Note(s): 2010 prices, using 10% discount rate, for a project starting construction in 2030. Unabated gas includes a carbon price. Excludes additional system costs due to intermittency, e.g. back-up, interconnection. These ranges take into account capital cost and fuel/carbon price uncertainty, but do not cover all possible eventualities (e.g. they assume that CCS is successfully demonstrated).

Figure 2: Estimated cost ranges for low-carbon power technologies at 7.5% discount rate (2030)



Source: CCC calculations, based on Mott MacDonald (2011) *Costs of low-carbon generation technologies.*

Note(s): As Figure 1, with 7.5% discount rate.

Box 3: The Fukushima nuclear plant and implications for the UK

Events in Japan at the Fukushima Daiichi nuclear plant have raised the issue of nuclear power safety internationally. The UK has launched a review, which will deliver preliminary findings in May. We note that whilst the specific circumstances in Japan differ significantly from those for new nuclear in the UK, in principle this could affect the potential for nuclear power to contribute to decarbonisation in the UK (e.g. the National Policy Statement for nuclear has been delayed to take account of the review, and any tightening of safety requirements may increase costs).

- Nuclear safety was considered at length in the 2008 White Paper on Nuclear Power and associated consultation document. This concluded that the safety risks associated with new nuclear power in the UK are very small:
  - There have been no civil nuclear events with off-site consequences or where all the safety barriers that are an inherent part of the design were breached in the UK.
  - The consultation document cites analysis for the European Commission suggesting that the risk of 'a major accident – the meltdown of the reactor's core along with failure of the containment structure' is of the order of one in a billion per reactor per year in the UK.
  - More broadly, the White Paper found that the safety risk associated with new nuclear in the UK is not comparable with older plant where accidents have occurred overseas because regulatory scrutiny of reactor designs and operations is far more rigorous in the UK today.
- Those conclusions are likely to be robust to events in Japan:
  - Events in Japan were the result of an enormous earthquake and tsunami. These affected back-up power and thereby compromised cooling of some reactors. Subsequently there has been overheating, exposure and radiation release from spent fuel ponds.
  - The likelihood of natural disasters of this type and scale occurring in the UK is extremely small.
  - Plant designs allowed under the UK's Generic Design Assessment have benefited from considerable technological improvement since the 1960s Boiling Water Reactors used at Fukushima, including the incorporation of secondary backup and passive cooling facilities.

- However, the Committee has not undertaken a detailed review of all possible implications for nuclear in the UK.
  – DECC has commissioned such a review from the chief nuclear officer, Dr Mike Weightman. This will report preliminary findings in May, with a final report due in September 2011.
  – A full review is required to ensure that any safety lessons are learnt and to restore public confidence in the safety of nuclear power.

Should the review suggest limiting the role of nuclear generation in the UK in future, then a higher renewables contribution would be required. Alternatively if the review leads to a significant tightening of safety regulations, nuclear costs may be increased, which would improve the relative economics of renewable technologies and argue for potentially increasing their role.

Table 1: Summary: Importance of low-carbon generation technologies in UK decarbonisation strategy

Technology	Cost at commercial (10%) discount rate (p/kWh)[2] 2020	2040	2040 cost at a social (3.5%) discount rate (p/kWh)	Importance of UK deployment for reducing costs
Unabated gas	5.0-11.0	6.0-16.5	5.5-16.0	Reference technology
Technologies that are likely to play a major role in future UK mix				
New nuclear	5.5-10.0	4.5-9.5	2.5-4.5	Equipment costs likely to be driven by global deployment, with some potential for local learning-by-doing.
Onshore wind	7.5-9.0	6.5-8.0	4.0-5.0	Technology is already well-established and is being deployed globally. UK impact on costs therefore likely to be limited.
Offshore wind	10.0-15.0	7.5-12.0	5.0-8.0	UK deployment likely to be important to reducing costs, given significant capability already established and a large share of the global market. Also a requirement for specialised local infrastructure (e.g. ports).
Technologies that could play a major role in the future UK mix, where deployment in the UK is important in developing the option				
CCS	6.0-15.0 (gas) 7.5-15.0 (coal)	5.5-14.5 (gas) 6.5-15.0 (coal)	5.0-13.5 (gas) 5.0-11.5 (coal)	UK deployment will be important alongside global efforts towards cost reductions. UK has existing strengths (e.g. in CO_2 storage and transportation, subsurface evaluation and geotechnical engineering, and in power plant efficiency and clean coal technologies) and likely to be an early deployer internationally.
Tidal stream	12.5-25.0	9.0-21.5	6.0-14.0	UK has an important role. UK companies have significant marine design/engineering experience and already have a sizable share of device developers and patents. UK resource also a large share of the global market.
Wave	19.0—34.5	12.5-29.0	7.0-15.0	As for tidal stream, UK has an important role.
Technologies that could play a major role in the future UK mix, with limited role for UK deployment in developing the option				
Solar PV	17.5-33.0	8.0-19.5	4.5-11.0	Limited role for UK deployment (though UK does have research strength). Technology development likely to be driven by international deployment or by research in the UK that is not dependent on UK deployment.
Tidal range[3]	23.5-41.0	20.5-39.5	8.5-16.0	Limited scope for cost reductions as an established technology, and limited sites to apply any learning from early deployments.
Severn barrage[4]	21.0-31.0		7.5-11.0	

[2] Costs are for a project starting construction in that year. Estimates take into account capital, fuel and carbon price uncertainty. Additional system costs due to intermittency (e.g. back up, interconnection) are not included.
[3] CCC calculations based on Mott MacDonald's assessment of 2 GW site.
[4] Cost estimates for Severn barrage (Cardiff -Weston scheme) from DECC (2010) *Severn Tidal Power Feasibility study*. High end of costs is represented by the Feasibility Study estimate including Optimism Bias (OB), Risk Assessment (RA) and Compensatory Habitat payments. Low end includes Compensatory Habitat payments but not RA and OB.

UK practical resource[5] (i.e. potential to contribute to long-term decarbonisation)	Other considerations	Conclusion: Future role in UK mix and strategic attitude to technology development
		Limited role for building new unabated gas (or coal) beyond 2020, given rising carbon costs and availability of (lower-cost) low-carbon alternatives.
In theory could be very large. In practice may be limited by sites – 8 currently approved sites could provide over 20 GW (e.g. 175 TWh per year)[6].	Mature technology, globally deployed. Waste disposal and proliferation risks. Public attitude and safety concerns.	Given maturity and relatively low cost, likely to play a major role at least to 2050. Potential constraints and wider risks/considerations suggest it would not be prudent to plan for a low-carbon mix entirely dominated by nuclear.
Around 80 TWh per year, depending on planning constraints.	Intermittency. Possible local resistance.	Relatively low cost, therefore likely to play a significant role, within the constraints of suitable sites. Large amounts of other technologies will also be required, given limited site availability.
Very large – over 400 TWh per year.	Lower visual impact (less local resistance). Intermittency.	Promising long-term option, given large resource and potential for cost reductions. Given potential UK impact on global costs, warrants some support to 2030 to develop the option.
May be limited by availability of fuel and storage sites.	Dispatchable. Exposed to fossil fuel price risk.	Future role currently highly uncertain given early stage of technology development. Likely to be valued in a diverse mix, given different risks compared to nuclear and renewables and potential to operate at mid-merit, given lower capital intensity.
Potentially large – 18 to 200 TWh per year.	Intermittency (with possible benefits in wind-dominated mix).	Currently at an early stage therefore will have a limited role in the period to 2020. Important role for UK globally in developing the option to 2030. Given potentially large resource and scope for cost reduction, could play significant role as part of a diverse mix in 2030 and beyond.
Limited – around 40 TWh per year.	Intermittency (with possible benefits in wind-dominated mix).	Currently at an early stage therefore will have a limited role in the period to 2020. Important role for UK globally in developing the option to 2030. Given scope for cost reduction, could play role as part of a diverse mix in 2030 and beyond, but limited by practical resource.
Large – around 140 TWh per year (on the basis of current technology) with more possible with technology breakthroughs.	Intermittency (with possible benefits in wind-dominated mix).	Given current high costs and limited UK impact on global costs, role in the short term (i.e. to 2020) should be limited. Option to buy in from overseas later, and to have a major role in the longer term (subject to significant cost reductions).
Limited – around 40 TWh per year (of which almost a half from the Severn).	Intermittency (with possible benefits in wind-dominated mix).	Given limited opportunities to reduce costs with deployment, should not be pursued where sufficient lower-cost options are available. Should be triggered as an option if relative costs improve or if there are tight constraints on roll-out of lower-cost technologies (e.g. wind, nuclear).

[5] See Chapter 1, section 2. Numbers here are considered 'practical' resource, i.e. taking into account environmental and proximity constraints.

[6] 175 TWh per year in 2030 would require 22 GW, including all current developer plans for 7 sites (18 GW), existing plant expected still to be in operation (1.2 GW) and 2 more reactors (3.2 GW) at the remaining site, or additional at the other 7 sites.

The implication of our technical and economic analysis is that energy and technology policy approaches should promote competition between the more mature low-carbon technologies, while providing support for technologies that are currently more expensive but with a potentially important long-term role. Support is required for technologies at the early deployment phase (e.g. offshore wind) and those at the demonstration phase (e.g. marine). This raises questions about whether it is appropriate to commit now to a specific level of ambition for these technologies in 2030 and if so what the level should be.

Committing now to technology support in the 2020s

The likely scale of investment in the less mature renewable technologies (e.g. offshore wind, marine) during the 2020s is very uncertain. This reflects their currently high costs, and the lack of policy commitment to providing support for new investments beyond 2020.

This uncertainty would be resolved by committing now to a minimum level of deployment or support in the 2020s, therefore underpinning required supply chain investment over the next decade.

A decision on whether to go beyond a minimum commitment, including a decision on the possible contribution from a Severn barrage project, could be taken when better information is available on relative costs and any barriers to deployment (e.g. in 2017/18, when there will be more confidence about costs and performance of offshore wind, marine, nuclear and CCS).

The minimum commitment should also hold only if supply chain investment envisaged to 2020 is delivered in practice.

In order to provide investor confidence, technology support should be provided through firm commitments, to be implemented through new electricity market arrangements (see section 1(ii) below).

An illustrative scenario for technology support

In determining the appropriate level of any such commitment the relevant factors are the level of supply chain investment required, the degree of commitment required to support this investment, and the need to keep the impact on electricity bills at an acceptable level.

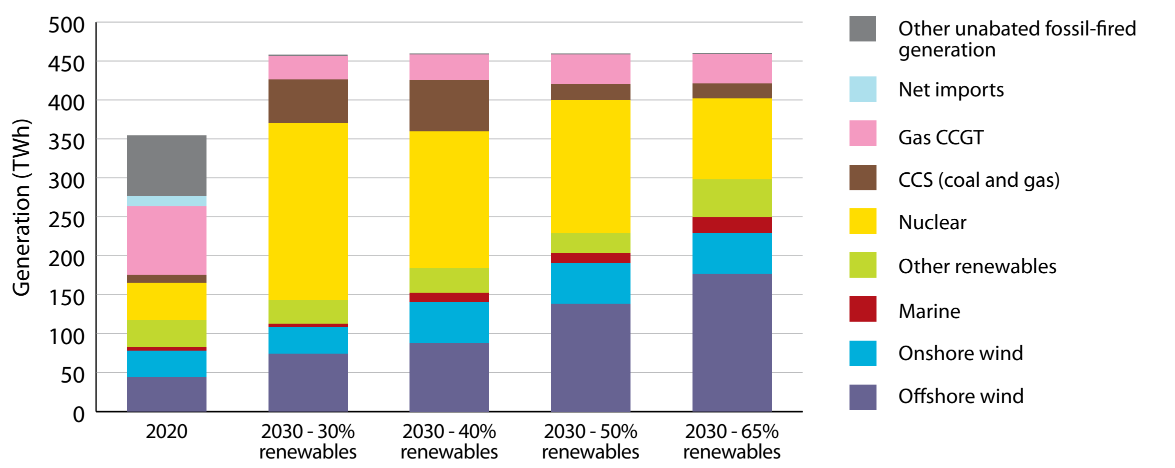
We set out a range of scenarios in this report (Figure 3), of which the 40% (185 TWh) renewable penetration scenario currently appears likely to be the most appropriate. This scenario includes:

- **Offshore wind.** There is investment in offshore wind through the 2020s at levels consistent with planned investment levels to 2020 (as set out in the Government's Renewable Energy Strategy).
- **Marine.** Tidal stream and wave investments proceed in line with rates planned for 2020.

- **Onshore wind.** Our cost estimates suggest that onshore wind is likely to be one of the cheapest low-carbon options. There are however questions over the scale at which it can be deployed given uncertainties relating to site availability and planning, in turn reflecting public concerns about the local visual impact. Our assessment is that over 6 GW (generating 20 TWh a year) could be added in the 2020s.
- **Biomass.** Given sustainability concerns and demands from other sectors we assume no new investment in biomass in the power sector beyond 2020.
- **CCS.** This scenario includes investment in a further 9 GW of CCS, largely coming on to the system in the second half of the 2020s.
- **Nuclear.** Given that nuclear is likely to be relatively low cost, it should have a crucial role, provided safety concerns can be addressed (see Box 3 above). In this illustrative scenario, there is investment on all eight currently approved sites, with around 18 GW new nuclear added to the system through the 2020s, resulting in around a 40% share (175 TWh) in 2030.

In practice, the precise renewables share (including any contribution from other renewables, e.g. solar PV and geothermal) will be determined through a combination of technology support for those currently more expensive technologies, and competition between more mature renewable technologies and other low-carbon alternatives, to be implemented through new electricity market arrangements.

Figure 3: Renewable generation scenarios to 2030



Source: CCC calculations, based on modelling by Pöyry Management Consulting.

Note(s): All 2030 scenarios achieve a comparable level of emissions intensity (around 50 g/kWh) and security of supply.
Includes losses, excludes generator own-use and autogeneration. Other renewables include hydro, biomass (including anaerobic digestion), geothermal and solar PV.

Offshore wind ambition to 2020

In our September 2010 letter to the Secretary of State for Energy and Climate Change, we suggested that the ambition to 2020 for offshore wind was broadly appropriate.

In this report, we have returned to the question of 2020 ambition, and considered whether this could be reduced whilst still providing required technology support to 2030.

The context for this is the electricity price impact of offshore wind ambition, which involves a cost penalty roughly double that of onshore wind generation (as reflected in the current subsidy payment for offshore wind of 2 ROCs[7] per MWh, compared to 1 ROC for onshore wind).

Given the very aggressive pace of investment to 2020 under the Government's plans, ideally this would be smoothed in the context of a 2030 commitment (i.e. by reducing ambition to 2020 to reduce costs, whilst committing to further investment in the 2020s given the long-term importance of offshore wind).

One way to achieve this whilst still meeting the UK's renewable energy target under the EU Renewable Energy Directive would be to increase ambition for onshore wind. This would require that society (and specific communities) accept greater landscape impact in return for slightly reduced electricity bills.

There may also be scope to increase ambition for other options to meet the renewable energy target, including renewable heat, imported renewable energy or renewable energy credits.

Therefore, if evidence emerges that other, lower-cost, options can be delivered at higher levels than currently envisaged, the offshore wind ambition for 2020 could be slightly reduced, even while stretching ambitions for 2030 are maintained.

The level of 2020 offshore wind ambition should not be increased unless there is clear evidence of significant cost reduction. Increasing ambition would adversely impact consumers without any clear offsetting benefits in terms of technology innovation.

ii) Enabling factors and policy implications

Amongst the key enabling factors to deliver 2020 ambition that we consider in the review are the Electricity Market Reform, the role for a Green Investment Bank in financing offshore wind investment, and the planning framework.

The Electricity Market Reform

We have previously highlighted the risks to investment in low-carbon generation under current electricity market arrangements, and the need for new arrangements based on long-term contracts to ensure that investments are made at least cost to the consumer. The Government recently made proposals consistent with this recommendation.

[7] Renewable Obligation Certificates (ROCs) are tradable certificates that electricity suppliers buy from developers of renewable generation projects.

Ideally these arrangements would be technology-neutral, with the range of low-carbon technologies bidding against each other for contracts. However, in practice this would result in investment focused on mature technologies, and not in those currently more expensive technologies that have a potentially important longer-term role.

Therefore, given our conclusion above that a portfolio of low-carbon technologies is desirable, the new market arrangements should be designed to provide additional support for those promising technologies at an earlier stage of development.

For example, the minimum commitments recommended above could be implemented through reserving some of the available contracts for less mature renewable technologies. This would have to reflect different costs across the technologies and be subject to certain conditions (e.g. a declining reserve price in contract auctions) in order to ensure cost reductions and a falling electricity price penalty for consumers.

More mature renewable technologies (i.e. onshore wind and hydro) would then compete with other mature low-carbon technologies (i.e. nuclear) for contracts. This would provide a least-cost investment programme for sector decarbonisation, and could also reflect considerations around diversity of the generation mix (e.g. it may be appropriate to pay more for technologies that diversify the mix and reduce security of supply risk).

The expectation is that the less mature technologies that would at first need support (e.g. offshore wind, marine and CCS) would ultimately also be able to compete for contracts without additional support.

Transitioning from current support arrangements

There is an important issue of the transition from current arrangements (the Renewables Obligation) to new arrangements, with the risk that the change causes an investment hiatus. To mitigate this risk, existing arrangements need to be effectively grandfathered and available until new arrangements are clear. This could require extending the RO beyond the date (2017) proposed in the Electricity Market Reform consultation.

The Green Investment Bank

Even if greater revenue security is provided through new electricity market arrangements, there will still be significant uncertainties around cost and performance of offshore wind. Therefore new electricity arrangements may not fully address current concerns over availability of equity and debt finance for required investments.

If finance is constrained, there is a potentially valuable role for a Green Investment Bank (GIB), both in terms of providing comfort to investors and providing an additional pool of capital for risk sharing.

The GIB could best fulfil this purpose if it is indeed a bank, rather than a fund, as announced in the March 2011 Budget.

However, as currently proposed, the GIB would only be able to borrow money from 2015/16. This is potentially problematic given that a crucial window of opportunity for the GIB is precisely the period before 2015/16 – as new electricity market arrangements will still be uncertain and there will be few proven examples of offshore wind projects in successful operation. Around £20 billion of investment finance is needed for offshore wind alone in this period, when risks are at their highest.

Therefore, unless it can be demonstrated that risks can be mitigated, allowing the GIB to borrow money from its inception should be seriously considered.

The planning framework for onshore wind and transmission

Planning approval rates for onshore wind projects have historically been low (e.g. less than 50%), and the period for approval long (e.g. almost two years). This reflects an implicit social preference for investment in more expensive renewable technologies, given concerns (held by some but not all people) about the visual impact of onshore wind developments.

However, further approvals will be required in order to deliver the onshore wind ambition in the Government's Renewable Energy Strategy.

Additional approvals beyond this level offer scope for reducing the cost of meeting the 2020 renewable energy target and the cost of power sector decarbonisation through the 2020s (e.g. our analysis suggests scope to add over 6 GW of onshore wind capacity through the 2020s).

In addition, planning approval will be required for transmission investments to support increased renewable generation and sector decarbonisation.

International experience suggests that approaches which achieve community buy-in to onshore wind projects through sharing financial benefits have helped support high levels of investment; it is appropriate that such approaches will be tested in the UK.

However, even with such approaches, there is a significant risk that onshore wind and transmission investments will not gain local public support, given high levels of resistance from some groups.

Achieving higher rates of approval for onshore wind projects and for required investments in the transmission network is therefore likely to require central government decisions in line with national priorities as defined by carbon budgets, possibly under new planning legislation that explicitly sets this out.

2. Delivering renewable heat ambition to 2020 and beyond

We summarise our analysis of renewable heat in two sections:

i) Renewable heat scenarios to 2030

ii) Implied 2020 ambition, barriers and responses

i) Renewable heat scenarios to 2030

We set out detailed analysis of options for renewable heat investment and scenarios to 2030 as part of our advice on the fourth carbon budget.

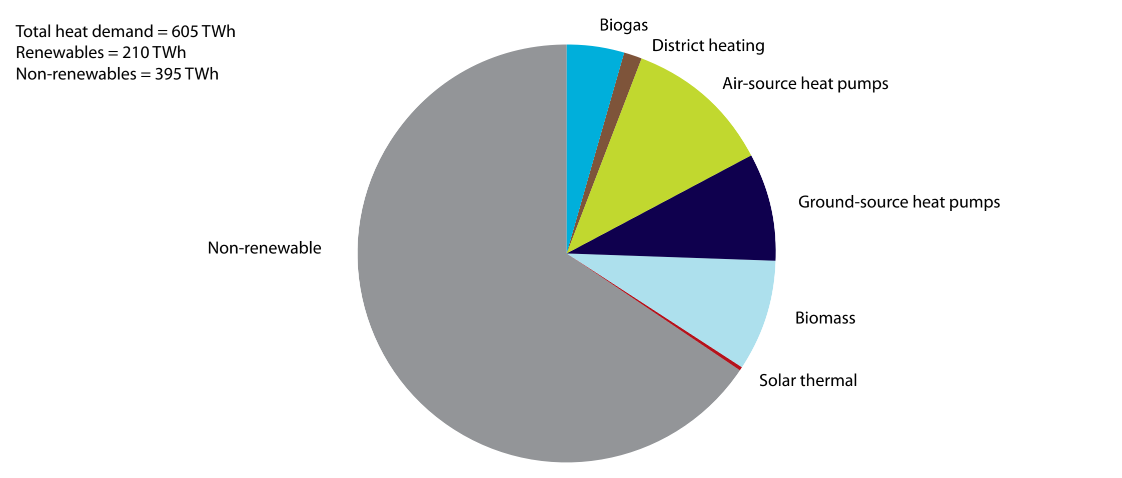
We considered the full range of renewable heat options (Box 4). We showed that these could be competitive given potential for cost reductions and a carbon price rising to £70/tCO_2 by 2030 (Figure 4).

Box 4: Renewable heat technologies

Renewable heat technologies in our fourth budget scenario included heat pumps, biomass and biogas (Figure B4).

- **Heat pumps (air-source and ground-source):**
  - Heat pumps use electricity to extract heat from the surrounding environment (e.g. the ground or air) and transmit this for space and hot water heating. One unit of electricity from heat pumps can generate between 2.5 and 4.5 units of heat, with the extra heat generated classed as renewable.
  - Energy efficiency improvement is a necessary condition for effective deployment of electric heat pumps. Otherwise heat pumps and the associated radiator system need to be significantly larger (and more expensive), and in extreme cases would not be able to provide adequate levels of warmth.
  - While there is currently limited deployment of heat pumps in the UK, these are a relatively mature technology and are widely used in other countries (e.g. France, Sweden). Widespread roll-out in the UK requires buy-in from householders and businesses, which will need effective policy to overcome existing and perceived barriers.
- **Biomass:** There is a range of potential uses of biomass to produce heat, including biomass boilers in residential and non-residential buildings, CHP for community and larger-scale district heating and process heat for industry. The key issues are the level of sustainable biomass that is available and where this is best used.
- **Biogas:** Biogas can be used to produce high-grade heat and can therefore be used as a substitute for fossil fuels in residential, non-residential and industrial sectors.

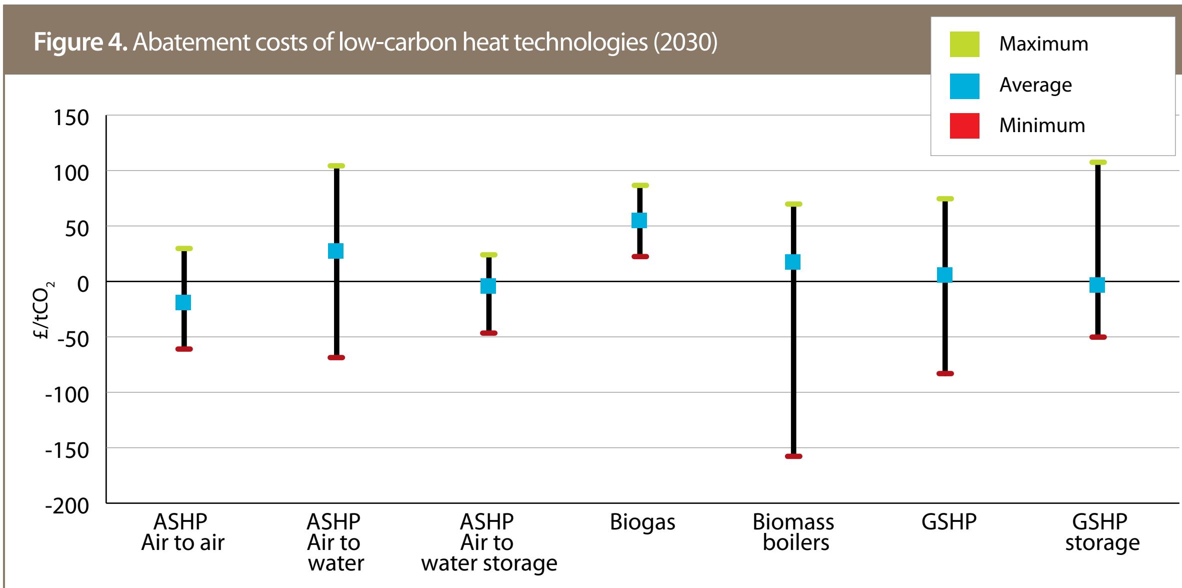
Figure B4: Fourth budget Medium abatement scenario: heat technologies (2030)



Source: CCC modelling.

Note(s): Figure includes all heat demand from buildings and industry.

Figure 4. Abatement costs of low-carbon heat technologies (2030)



Source: CCC modelling; NERA (2010).

Note(s): Cost ranges reflect different demand segments (e.g. the highest cost ground-source heat pumps with storage are in new build detached properties replacing gas). All costs are calculated based on central fossil fuel price projections and do not include a carbon price. ASHP = Air-source heat pump, GSHP = Ground-source heat pump.

We proposed a central scenario for renewable heat penetration reaching around 35% (210 TWh) in 2030, with renewable heat as one of the main contributors to economy-wide emissions reduction required through the 2020s.

In designing appropriate policies to support development of renewable heat options, four considerations are important:

- Renewable heat technologies are relatively mature, and are already widely deployed in some countries.
- Investment cycles for renewable heat are short compared to those for renewable power generation, implying scope for later decisions on commitments to technology support in the 2020s.
- The challenge is to demonstrate the technologies in a UK context, addressing current technical, economic and social barriers.
- Success here is of crucial importance, both because renewable heat technologies are promising from technical and economic perspectives, and because of a lack of alternatives for heat decarbonisation, which is required to meet the UK's 2050 target of an 80% emissions reduction.

We discuss policies to support UK demonstration in the next section, where one of our conclusions is that there will be a need for commitments on financial support for renewable heat in the 2020s, which in turn will require setting of renewable heat targets. Our central scenario shows the order of magnitude of ambition that currently appears appropriate, with the precise ambition to be determined as current uncertainties are resolved (e.g. between 2015 and 2020).

ii) Implied 2020 ambition, barriers and responses

The level of ambition for 2020

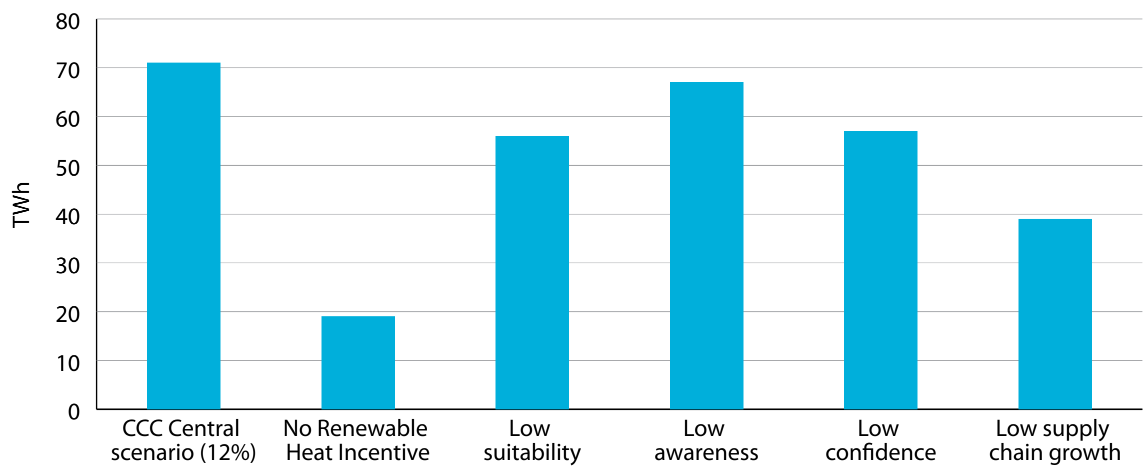
Our 2030 scenarios require significant deployment of renewable heat over the next decade. This will support technology development, build up a supply chain, and improve consumer confidence in technologies where there has been very limited deployment to date in the UK.

Specifically, our 2030 scenarios build in renewable heat penetration of around 12% (70 TWh) in 2020. This will be sufficient in terms of providing critical mass for required deployment in the 2020s, and is consistent with the Government's renewable heat ambition in its Renewable Energy Strategy.

Barriers and responses to achieving ambition

In this report, we present new analysis of barriers to renewable heat deployment to 2020, both financial and non-financial. This analysis suggests that key deployment barriers are likely to include lack of financial support, supply chain constraints, and lack of consumer information and confidence (Figure 5).

Figure 5: Impact of barriers on renewable heat penetration in 2020



Source: CCC analysis based on modelling by Element Energy.

Note(s): 'Low suitability' reduces the number of buildings suitable for renewable heat deployment (e.g. because energy efficiency is not improved as required); see Figure 3.4 in Chapter 3 for other notes.

In assessing financial barriers, our main conclusions are that:

- Current funding commitments for renewable heat are appropriate, but further support will be required in future.
  - The overall level of support provided under the Renewable Heat Incentive (RHI) to 2014/15 is appropriate and the support for specific technologies is broadly in line with expected costs.
  - However, significantly increased funding will be required in the second stage (i.e. after 2014/15), at a level to be finalised in the context of a broader strategy to meet the 2020 renewable energy target.
  - Further support will also be required in the 2020s, either in the form of an extension of the RHI, or the introduction of a carbon price for heat.
- It will be important to ensure that there is disbursement of the RHI across the range of technologies in order that a portfolio of technologies for deployment in the 2020s is developed; lack of deployment in particular niches (e.g. residential heat pumps) would be problematic in this longer-term context.

Non-financial deployment barriers could be addressed through three key policy levers:

- **Accreditation of suppliers.** The analysis highlights the crucial role of supply chain expansion in supporting investment in renewable heat over the next decade, and within this the importance of ensuring that there are sufficient numbers of accredited installers. Therefore it will be important to have arrangements in place both for training and accreditation of installers. Together with validation of equipment, this could also help to increase consumer confidence.

- **Integration of renewable heat and energy efficiency policies.** Separate mechanisms for promoting renewable heat and energy efficiency risk complicating the delivery landscape and confusing consumers. The RHI and Green Deal should therefore be integrated. Integration would help to increase the number of suitable buildings, improve consumer confidence, and information, and provide a possible source of financing for up-front investment costs.
  - **Suitability.** Given that renewable heat technologies work better in well-insulated houses, linking renewable heat and energy efficiency policies would increase the number of suitable houses. This could be achieved by requiring a minimum energy efficiency rating to qualify for payment under the RHI, and through marketing renewable heat as part of the Green Deal (e.g. by including renewable heat technologies in energy audits and follow ups).
  - **Consumer confidence.** Marketing renewable heat as part of the Green Deal would enhance consumer confidence, both because it would ensure deployment in suitable buildings, and because it would offer an opportunity to provide customers with better information. It would also allow reduction of transaction costs if implementation of energy efficiency and renewable heat measures were to form part of a whole-house or one-stop-shop approach.
  - **Financing up-front costs.** These are potentially significant (e.g. around £6,000 to £10,000 for an air-source heat pump in the residential sector) and prohibitive for some applications. Financing constraints could be addressed by integration – allowing financing under the Green Deal for renewable heat investment.
- **Zero-carbon homes.** Renewable heat deployment in new homes does not face as many barriers as retrofit to existing homes. This highlights the opportunity offered by new homes and importance of defining zero-carbon homes in such a way as to promote renewable heat.

It will be important that both financial and non-financial barriers are addressed by the RHI and other policies in order that significantly increased investment in renewable heat occurs over the next decade. This is required, in turn, for longer-term heat decarbonisation in the context of the 2050 economy-wide emissions target.

3. The role of renewable energy in surface transport

Electric vehicles

We set out a detailed assessment of scope for increased penetration of electric vehicles (including plug-in hybrid and fuel cell vehicles) in our advice on the fourth carbon budget. Based on technical and economic analysis, we suggested that it is appropriate to aim for electric vehicle penetration of around 60% of new cars and vans by 2030.

While electric vehicles would account for a smaller share of miles and energy use in 2030, this will increase significantly in the 2030s as the vehicle stock turns over. Electric vehicles would be renewable to the extent that they are powered by renewable electricity.

Biofuels

Our approach to appropriate biofuels ambition is cautious, reflecting concerns about sustainability:

- There is a tension between the use of land for growth of food versus bioenergy feedstocks. The risk is that with high growth of bioenergy feedstocks, there would be limited land available for growth of food, resulting in high prices and supply shortages. This risk is more pronounced given the significant projected increase in global population over the next four decades, and moves to more land-intense diets as incomes increase.
- There are concerns around emissions reductions associated with biofuels when lifecycle emissions including from land use impacts and from growth and processing of feedstocks are accounted for.

Given a scarce supply of bioenergy, this should be used in sectors where there are limited alternatives for decarbonisation (e.g. aviation, industry) as opposed to surface transport, where decarbonisation through electrification is likely to be technically feasible and economically viable. Specifically, we have accepted the findings of the Gallagher Review, which suggested it would be appropriate to plan for biofuels penetration of around 8% by energy in 2020[8].

[8] We show in Chapter 4 that with the electric vehicle roll-out assumed in our scenarios this would still meet the EU 10% renewable energy sub-target for transport, given the specific accounting rules for that target.

In our fourth budget advice, we set out scenarios for biofuels penetration through the 2020s:

- Our Low and Medium abatement scenarios include no increase in penetration through the 2020s from levels consistent with the Gallagher Review recommendations in 2020 (30 TWh, equivalent to around 11% penetration in liquid fuels by 2030, given falling liquid fuel use). Together with the contribution from renewable power used in electric vehicles the total renewable energy share in transport would be around 15% in 2030.
- Our High scenario includes increased penetration through the 2020s in line with the IEA's BLUE Map scenario (60 TWh, equivalent to around 25% penetration in liquid fuels by 2030).

We are currently undertaking a bioenergy review which will:

- Develop scenarios for availability of sustainable bioenergy based on analysis of global land, population growth, diet change, and scope for agricultural productivity improvement.
- Consider where available sustainable bioenergy would best be used (i.e. between power, surface transport, buildings, industry, aviation, shipping) given alternative abatement options available.

We will publish the bioenergy review before the end of 2011.

4. Scenarios for renewable energy ambition

Scenarios to 2020

Our scenarios for renewable energy ambition to 2020 are consistent with the UK's 15% renewable energy target for 2020 under the EU Renewable Energy Directive (Figure 6). Although we assume slightly lower levels of biofuels than in the Government's Renewable Energy Strategy, the overall target is still met through increased energy efficiency (e.g. improving fuel efficiency of conventional vehicles, replacement of conventional vehicles with electric alternatives).

We estimate that the cost of supporting renewable electricity to 2020 will add up to 2 p/kWh to the electricity price, increasing the average annual household electricity bill by around £50-60 in real terms.

- Around half of this cost is due to supporting offshore wind.
- There is also some cost from onshore wind, though by 2020 new projects are likely to be competitive without specific support.
- This represents around a 10% increase on what household electricity bills would otherwise be in 2020.
- It is around a 4% increase on households' total energy bills, where electricity accounts for 40% of total energy costs and gas accounts for the remainder.

There is the opportunity to offset the impact of higher prices through energy efficiency, which we estimate could reduce residential energy consumption by around 14% in the period to 2020.

This would therefore more than compensate for impacts of renewable electricity investment, and ensure that the share of expenditure on energy relative to income remains roughly flat when allowing for upward pressure on bills from rising gas and carbon prices along with expectations of rising incomes.

For non-residential consumers, higher electricity prices could lead to impacts on competitiveness of a small number of energy-intensive UK industries which compete in global markets (e.g. iron and steel, aluminium).

To the extent that there are competitiveness risks, there is a range of potential measures (e.g. tax rebates) which would help mitigate any impacts.

Delivering renewable heat ambition will not increase energy bills under the current financing approach. It could require fiscal support of the order of £2 billion a year by 2020.

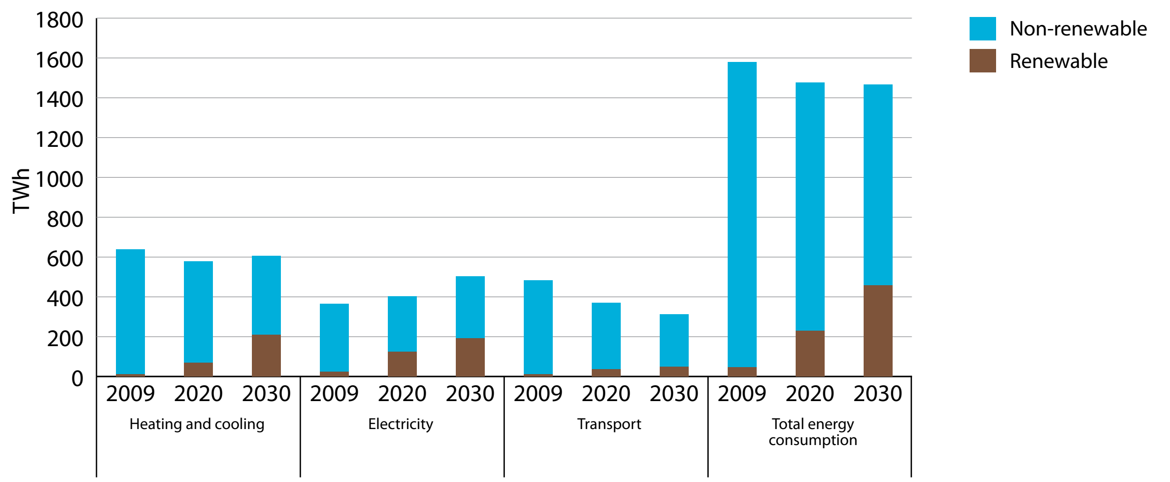
Renewable energy in transport is not expected to add to motoring costs as biofuels are expected to be a similar cost to petrol and diesel under central assumptions for the oil price. We have factored the increasing cost of electricity into our analysis of the cost effectiveness of electric vehicles and electric heat pumps.

Scenarios to 2030

Our power, heat and transport scenarios for 2030 imply a renewable energy share of up to 45% (680 TWh) in 2030.

Our illustrative scenario for power alongside our central scenarios for heat and transport in 2030 are consistent with a 30% (460 TWh) economy-wide renewable energy share (Figure 6), with the possibility of going further as uncertainties are resolved (e.g. over the relative cost of renewable power generation, or deployability of renewable heat).

Figure 6: Renewable shares in energy consumption (2009, 2020 and 2030)



Source: CCC calculations.

Note(s): Total energy consumption is gross final consumption calculated on the basis as set out in the EU Directive. Energy consumption shown in the heating sector is taken from the CCC heat model and is calculated on a slightly different basis. Electricity use is shown both in the sectors within which it is consumed and in the electricity sector; it is only counted once in total consumption. Includes autogeneration and generator own use. 2030 figures are for our illustrative central scenarios. Demand assumptions are taken from our fourth budget analysis, based on CCC's bottom-up modelling and energy projections from the DECC energy model using central assumptions for population growth from ONS and GDP growth from the Office of Budget Responsibility.

The costs associated with delivering this level of ambition are of the order of under 1% of GDP in 2030 compared to a scenario where there are no carbon constraints.

The 2030 energy bill impacts over and above those to 2020 are limited:

- **Electricity.**
  - An increasing proportion of electricity will be paid for under long-term contracts at prices below those of unabated gas with a £30/tCO_2 carbon price in 2020.
  - Whilst unabated fossil-fired generation will become more expensive with an increasing carbon price in the 2020s, this will account for a declining share of total generation (e.g. providing less than 10% of generation in 2030).
  - Whilst there will be some ongoing investment in more expensive offshore wind and marine, this will be limited unless there have been significant cost reductions.

- **Heat.** During the 2020s there is scope for some renewable heat technologies to become cost-competitive and possibly lower cost than conventional heating technologies.

The story in the 2020s is therefore likely to be one of more modest price rises than during the 2010s, and with average energy bills falling relative to income, assuming incomes continue to grow.

Developing a full range of renewable and low-carbon options for required economy-wide decarbonisation in the 2020s, and deployment at this time according to least-cost principles, could give the UK a competitive advantage in a carbon-constrained world.

There are a range of levers for addressing any ongoing fuel poverty impacts (e.g. social tariffs, income transfers) and competitiveness impacts (e.g. tax rebates, sector agreements, border tariff adjustments).

* * *

Our analysis suggests that there is both scope and need for ongoing investment in renewable energy through the 2020s as part of a least-cost strategy for meeting carbon budgets. We recommend that the Government recognises the important role of renewable energy in meeting carbon budgets by providing technology support for less mature technologies in new electricity market arrangements, and integrating the RHI with the Green Deal. The focus of policy should be on removing barriers and putting in place incentives to significantly increase renewable energy supply over the next decade – thereby developing a range of renewable energy options for decarbonisation in the 2020s and beyond. Given these options, we will be better able to meet carbon budgets at an affordable cost, resulting in a range of benefits including mitigation of climate change risks, reduced reliance on imported fossil fuels, and industrial opportunities associated with building a green economy.

Chapter 1

Renewable electricity generation scenarios

Introduction and key messages

In our advice on the fourth carbon budget (2023-2027), we set out a path for decarbonisation of the power sector. Specifically, we suggested that the aim should be to reduce average emissions from current levels of 500 gCO_2/kWh to around 50 gCO_2/kWh by 2030. This reflected our assessment of the optimal investment strategy based on consideration of capital stock turnover, technology costs, projected carbon prices and demand growth.

Our fourth budget advice noted the need to plan for power sector decarbonisation based on a range of technologies including renewable, nuclear and carbon capture and storage (CCS) generation. However, we did not consider in any detail the appropriate balance of investment between the various technologies.

In this chapter we take the power sector decarbonisation path underpinning the recommended fourth carbon budget as a given, and consider possible roles for renewables within this:

- We start by considering the scope for deployment of renewable and other low-carbon technologies, including resource constraints, any limits on renewables penetration associated with intermittency, and build constraints.
- We then consider the economics of renewables relative to other generation technologies, both as regards current and future costs, and allowing for learning through innovation.
- Given these technical and economic assessments, we consider the role for renewables within a portfolio approach to power sector decarbonisation and set out a range of scenarios for renewable generation to 2030 and beyond. Our scenarios reflect different assumptions on renewable costs relative to those for other low-carbon generation technologies, and limits on deployability of renewable and other low-carbon technologies.

The key messages in the chapter are:

- **The need for sector decarbonisation.** It is crucial in the context of economy-wide decarbonisation that the power sector is almost fully decarbonised by 2030. Options for sector decarbonisation include nuclear, CCS and renewable generation.
- **Current uncertainties.** The appropriate mix of low-carbon generation technologies for the 2020s and 2030s is highly uncertain. Key factors are: the ability to build nuclear to time and cost; whether CCS can be successfully demonstrated at scale for coal and gas; the extent to which the planning framework will support further investment in onshore wind generation; and the costs of renewable generation, especially offshore wind and marine (wave, tidal stream).
  - **Nuclear power** currently appears to be the most cost-effective of the low-carbon technologies, and should form part of the mix assuming safety concerns can be addressed. However, full reliance on nuclear would be inappropriate, given uncertainties over costs, site availability, long-term fuel supply and waste disposal, and public acceptability.

- **CCS technology** is promising but highly uncertain, and will remain so until this technology is demonstrated at scale later in the decade. In the longer term, storage capacity may be a constraint.
- **Onshore wind** is already close to competitive, although investment has been limited by the planning framework, and is limited in the long term by site availability.
- **Offshore wind** is in the early stages of deployment and is currently significantly more expensive than either onshore wind or nuclear. However, the existence of a large-scale natural resource, reduced local landscape impact compared with onshore wind and the potential for significant cost reduction make it a potentially large contributor to a low-carbon future.
- **Marine** technologies (tidal stream, wave) are at the demonstration phase and therefore more expensive again, but may be promising, given significant resource potential and scope for cost reduction.

• **A portfolio approach.** Given these uncertainties, a portfolio approach to development of low-carbon generation technologies is appropriate.
  - This should include market arrangements to encourage competitive investment in mature technologies such as nuclear and onshore wind generation.
  - It should also include additional support for less mature technologies including CCS, offshore wind and marine, where there is potential for the UK to drive these technologies down the cost curve. This is in contrast to solar photovoltaic (PV), where the pace and scale of development will be determined outside the UK.

• **Commitments for the 2020s.** As part of a portfolio approach, the Government should commit now to an approach for supporting offshore wind and marine in the 2020s. The approach should avoid stop-start investment cycles and provide confidence to supply chain investors of a long-term business opportunity beyond the next decade.

• **Firm commitments.** Given the need to provide investor confidence, support should be provided through firm commitments rather than vague aspirations. Such commitments should be implemented through the new electricity market arrangements. For example, within the Government's proposed Contracts for Differences for low-carbon generation, a proportion of these could be targeted at supporting less mature renewable technologies.

• **Illustrative 2030 scenario.** We set out an illustrative scenario in which commitments on support for offshore wind and marine through the 2020s are broadly in line with planned investment and supply chain capacity to 2020. Together with ongoing investment in onshore wind, this would result in a 2030 renewable generation share of around 40% (185 TWh). Sector decarbonisation would then require a nuclear share of around 40% (175 TWh) and a CCS share of 15%, along with up to 10% of generation from unabated gas.

We set out the analysis that underpins these messages in five sections:

1. Sector context: the need for early decarbonisation of the power system and future expansion
2. Scope for renewable generation: resource potential and technical constraints
3. Renewable and other electricity generation costs
4. Renewable generation scenarios from 2020
5. Recommendations on ambition for renewable generation

1. Sector context: the need for early decarbonisation of the power system and future expansion

The overall decarbonisation path

We highlighted in our fourth budget report[1] the need for early power sector decarbonisation in the context of economy-wide emissions reduction to achieve the 2050 target in the Climate Change Act. Specifically, we set out a range of scenarios for investment in low-carbon generation capacity, and proposed a planning scenario in which emissions are reduced from current levels of around 500 gCO_2/kWh to around 50 gCO_2/kWh in 2030 (Figure 1.1).

- This could be achieved through the addition of around 35 GW baseload-equivalent[2] low-carbon capacity through the 2020s, in addition to planned investments in renewable, CCS and nuclear generation over the next decade.
- The resulting stock of low-carbon generating capacity would be sufficient to meet demand from existing markets together with significantly increased demand from new markets for charging of electric vehicle batteries and electric heat (Figure 1.2).
- The combination of increasing demand and falling carbon intensity of generation would result in emissions reduction from current levels of around 170 $MtCO_2$ to 16 $MtCO_2$ in 2030.

Analysis for the fourth budget report and new analysis that we commissioned from the Energy Technology Institute suggests that this rate of decarbonisation is robust to a range of different assumptions, including costs of low-carbon technologies and fossil fuel prices (Box 1.1).

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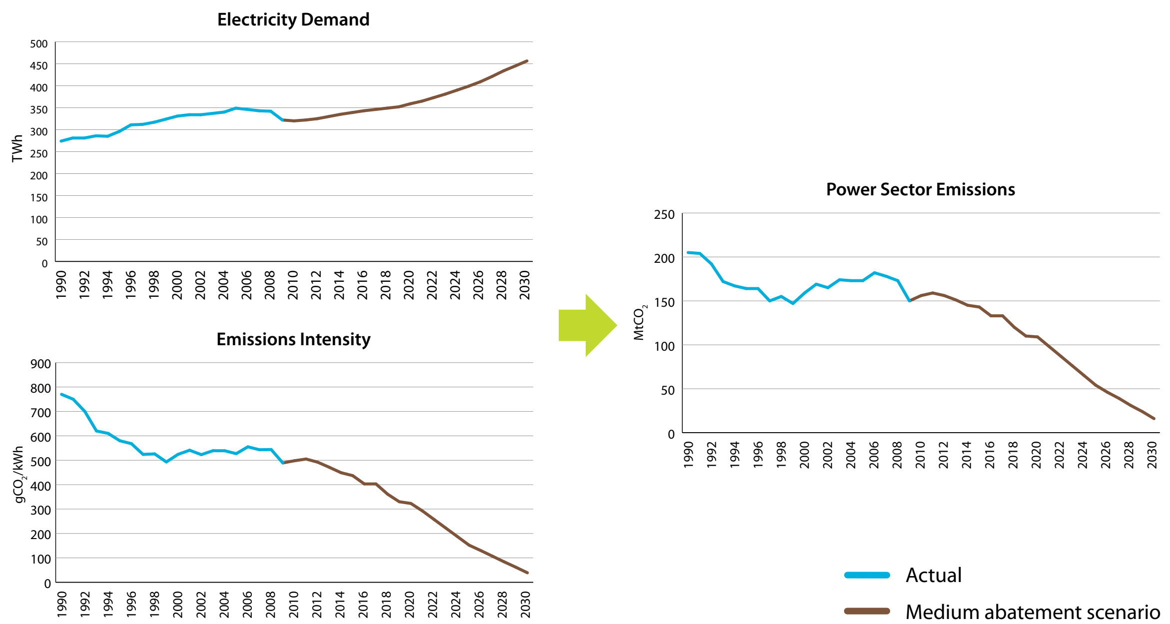
[1] CCC (2010) *The Fourth Carbon Budget: Reducing emissions through the 2020s.*

[2] Intermittent technologies are adjusted in this figure by the difference between their average availability and the availability of non-intermittent plants in order to put all plants on an equivalent GW basis.

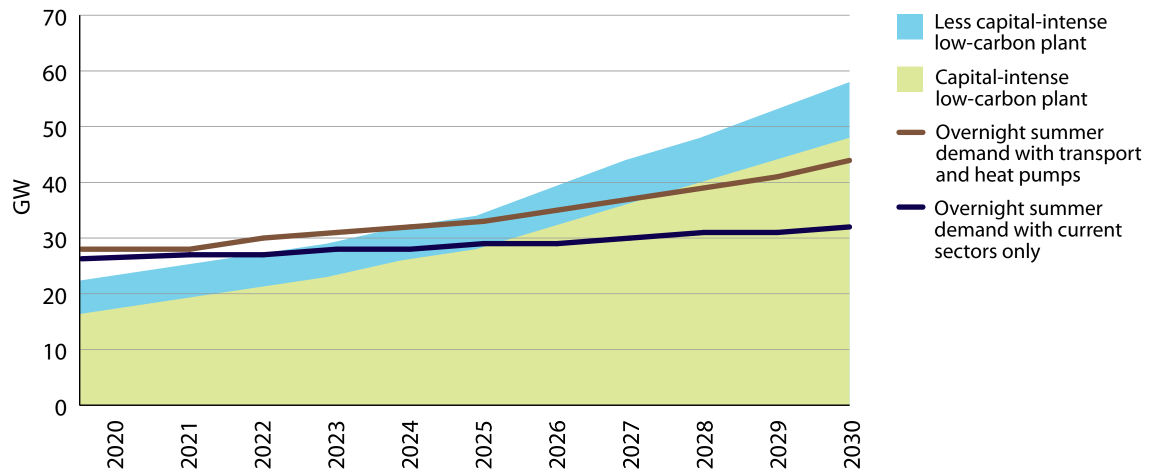
Figure 1.1: Electricity demand, emissions intensity and power sector emissions (1990-2030)



Source: DECC (March 2011) *Energy Trends*, Table 5.1, 5.2, 5.5; CCC modelling; DECC emissions inventory.

Note(s): Electricity demand: Electricity consumption is net of energy industry electricity use and transmission and distribution losses; autogeneration is included. Emissions intensity: intensity is based on energy supplied from major power producers and all renewable generators and is net of transmission and distribution losses.

Figure 1.2: Low-carbon capacity and overnight summer demand (2020-2030)



Source: CCC calculations for CCC response to DECC Electricity Market Reform consultation (2011).

Box 1.1: Rates of decarbonisation to 2030 under range of assumptions

The detailed modelling presented in the fourth budget report indicated that a path reaching around 50 g/kWh in 2030 would be cost-effective for the power sector, given DECC's projected carbon price for 2030 of £70 per tonne CO_2. This was based on detailed bottom-up modelling by Pöyry[3] of the power system on an assumption that minimum levels of renewables and carbon capture and storage (CCS) were built for technology policy reasons, and then the cheapest low-carbon technology (nuclear) was built where cost-effective.

Runs of energy system models that require emissions reduction to occur entirely within the UK, without purchase of international emissions credits, suggest that the 2030 decarbonisation goal is robust across a range of scenarios:

- MARKAL modelling for the Committee's fourth carbon budget analysis showed that this path for power sector emissions was robust to significant increases in assumed technology costs (e.g. a 60% increase in capital costs) or in a low gas price world (e.g. DECC's low gas price of 37 p/therm, rather than 79 p/therm in our central case[4].
- Runs of the ETI's ESME model (described later in Box 1.14) for the Committee show that decarbonising to around 50 g/kWh is desirable across a wide range of fossil fuel prices, even in the absence of one of CCS or new nuclear. However, the absence of both of these options increased the overall costs of meeting the emissions targets substantially, by around 0.5% of GDP in 2030.

This reflects the significantly lower costs of reducing emissions in the power sector, compared with other marginal options to 2030 and also suggests that the 2030 power sector decarbonisation goal is robust to a lower carbon price (though not tested in this modelling).

[3] Pöyry (2010) *Options for low-carbon power sector flexibility to 2050.*
[4] University College London (2010) *UK MARKAL Modelling - Examining Decarbonisation Pathways in the 2020s on the Way to Meeting the 2050 Emissions Target.*

Technology mix to deliver decarbonisation

Whilst we have a high level of confidence over the broad rate of decarbonisation likely to be appropriate, we did not in the fourth budget report consider the specific mix of technologies to deliver power sector decarbonisation. We noted that there were a range of options for low-carbon investment (Box 1.2).

However, assessment of potential technology mixes is useful in informing both energy and technology policy. Therefore in this report we develop scenarios for the technology mix with different levels of renewable versus other forms of low-carbon generation (section 4). Before doing this, however, we provide a context by summarising the evidence base on resource potential, costs and technical constraints for the range of power generation technologies.

Box 1.2: Technology options for generating low-carbon electricity

There are three broad categories of low-carbon technologies that can contribute to the decarbonisation of the UK power system, each of which has its own characteristics:

- **Renewables.**
  - Renewable energy comes from sources that are naturally replenished, such as sunlight, wind, rain, tides, and geothermal heat (heat from the Earth).
  - This category encompasses a wide range of technologies, from those that are established and currently cost-effective (e.g. hydro power) to those in the demonstration phase (e.g. wave) or in the early stages of deployment (e.g. offshore wind).
  - The output of many renewable technologies varies according to the natural resource being harnessed, although some (e.g. tidal range) are highly predictable and some (e.g. biomass) can generate on demand.
- **Nuclear.**
  - Nuclear power is well established, although new plants that are being constructed and planned use a new generation of designs.
  - It produces long-lived radioactive waste products and uses finite, though widely available, fuel.
  - Recent estimates indicate that its costs (including those for decommissioning and waste) are among the lowest of the low-carbon options.
  - Given its capital intensity and low marginal cost of generation, it is best suited to operating at baseload.

- **Carbon capture and storage (CCS).**
  - CCS involves the removal of CO_2 from the flue gas of fuel-fired power plants and its transportation and long-term sequestration in geological formations.
  - It is currently in the demonstration phase and as a consequence there is uncertainty over its future viability.
  - CCS based on fossil fuels competes for a finite supply of resources globally.
  - As a 'dispatchable' form of generation, its output can be varied as required to respond to variations in demand or the output of intermittent renewables.

Lifecycle emissions (i.e. including emissions resulting from construction, fuel supply and decommissioning) across the renewable technologies are generally well below 50g/kWh[5]. Lifecycle emissions from nuclear are also low, estimated to be around 20 g/kWh.

Carbon capture and storage (CCS) has higher lifecycle emissions. Residual emissions from fuel combustion, assuming a 90% CO_2 capture rate, are around 50 and 110 g/kWh for gas and coal CCS respectively, with further potentially significant emissions from extraction and delivery of the fuel, related to energy use and methane leakage, depending on its source (e.g. it has been suggested that shale gas production may lead to high rates of methane leakage).

There is scope for lifecycle emissions to fall as other sectors decarbonise.

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[5] As indicated by a number of studies, including the review of the literature by the Parliamentary Office of Science and Technology (2006) *Carbon Footprint of Electricity Generation*, which will be updated in 2011. Emissions from hydro, offshore wind and large-scale offshore wind are estimated to be below 25 g/kWh. Those from solar PV are slightly above 50 g/kWh, reflecting the UK's relatively weak insolation, but with potential to reduce as production methods improve.

2. Scope for renewable generation: resource potential and technical constraints

The extent to which investment in renewable generation capacity can potentially contribute to power sector decarbonisation over the next decades depends on its resource potential, and any barriers to unlocking this potential. We now consider in turn:

(i) Resource potential of renewables and other low-carbon technologies

(ii) Technical constraints on the level of intermittent renewable generation

(iii) Build constraints through the 2020s

(i) Resource potential of renewables and other low-carbon technologies

A necessary condition for decarbonisation of the power system is that there is sufficient resource potential across the range of low-carbon technologies. Within this, resource potential for specific technologies places an upper limit on the contribution that they may make to sector decarbonisation.

The evidence on resource potential, which we set out in our advice on the fourth carbon budget and which we expand on here, suggests that this is sufficient to support sector decarbonisation, and for each of the low-carbon technologies to make a significant contribution:

- **Renewables**[6]. The resource potential for renewable electricity sources is commensurate with electricity demand projections that in some scenarios reach over 500 TWh by 2050 (i.e. if resource potential were the only consideration, sector decarbonisation based wholly on renewables would be feasible, Box 1.3).
  - **Onshore Wind.** Estimates of the resource potential for onshore wind typically include judgments about limited public acceptability of this technology. An assessment on this basis is that it could provide around 80 TWh/year (i.e. around 15% of projected 2030 demand)[7].
  - **Offshore Wind.** Offshore wind resource is estimated to be over 400 TWh/year, with significant potential for generation around Scotland and the East and West coasts of England[8].
  - **Marine.** The UK has significant potential for wave, tidal stream and tidal range generation. The practical potential for wave energy is considered to be 40 TWh/year[9], while that for tidal range exploitation around the UK (including the Severn) is also estimated at around 40 TWh/year[10]. The tidal stream resource is the most uncertain of the marine resources due to uncertainty around the correct physical estimation methodology, with estimates ranging from 18-200 TWh/year[11].
  - **Solar.** There is significant resource potential for solar photovoltaic (PV) generation in the UK (e.g. around 140 TWh/year based on the resource potential from south-facing roofs and facades[12]), although this currently appears to be a very expensive option (see section 3). There is also the option

[6] As well as potential discussed for wind, marine, solar and bioenergy there is a considerable resource for geothermal power (e.g. around 35 TWh in DECC (2010) *2050 Pathways Analysis*) and some additional hydro power (3 TWh).
[7] Maximum practical resource from Enviros Consulting (2005) *The Costs of Supplying Renewable Energy* p.35.
[8] Offshore Valuation Group (2010) *The Offshore Valuation* p34-35.
[9] Offshore Valuation Group (2010) *The Offshore Valuation* p34-35.
[10] DECC (2011) *2050 Pathways Analysis – The Government's response to the call for evidence*, Part 2 p.89.
[11] Black and Veatch (2005) *Phase II Tidal Stream Energy Resource Assessment;* Mackay (2008) *Sustainable Energy: Without The Hot Air.*
[12] DECC (2010) *2050 Pathways Analysis* p.217.

to import solar power produced in Europe and possibly North Africa, using PV or concentrated solar power (CSP). In the longer term, imported solar power could make a significant contribution to meeting electricity demand in the UK to the extent this is not problematic from a security of supply perspective (Box 1.4).

- **Bioenergy.** There could in principle be a substantial resource from sustainable bioenergy, but the extent to which this can be used in the power sector will depend on competing demands from other sectors (Chapter 2).

- **Nuclear**. Notwithstanding potential for recent events in Japan to impact on public acceptability (Box 1.5), on the basis of resource potential alone, nuclear generation could make a significant contribution to sector decarbonisation:
  - Although there is a finite supply of uranium available, this will not be a limiting factor for investment in nuclear capacity for the next 50 years.
  - IEA analysis suggests that there is scope for investment in a new generation of nuclear plant globally within known sources of uranium, and potential to extend resources further (e.g. through better fuel production technology, closed cycle or fast breeder reactors).
- **CCS**. Abundant supplies of coal and gas suggest that if CCS technologies can be shown to be viable, these could make a significant contribution to sector decarbonisation, although there may be limits on available storage capacity.
  - Global reserves of coal will last around 150 years at current production rates[13].
  - Total global recoverable natural gas resources, including unconventional sources, will last for around 250 years at current rates of production.
  - CO_2 storage capacity, especially in saline aquifers, is considerably less certain and may imply a constraint over the long term (Box 1.6).

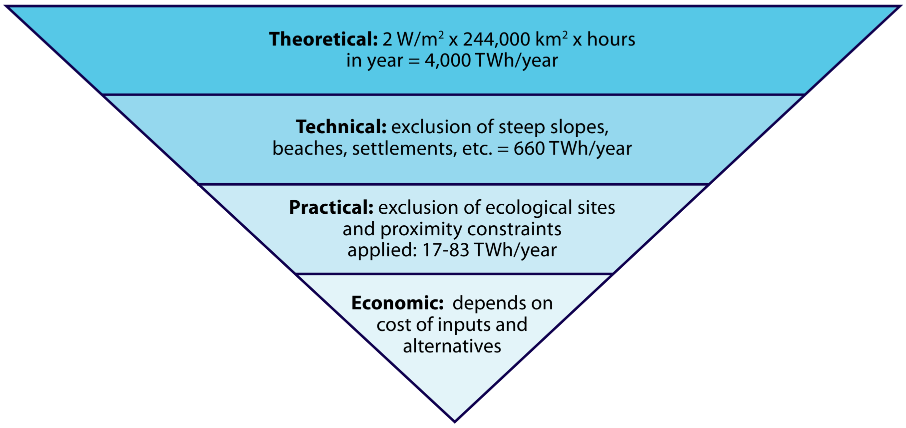
Box 1.3: Defining the UK's renewable resource – theoretical, technical, practical and economic

Resource can be defined as theoretical, technical, practical or economic:

- **Theoretical resource** is the energy embodied in the source, for example the total energy of wind over the UK landmass.
- **Technical resource** constrains this estimate to take into account realistic technical constraints such as the difficulty of building turbines on steep slopes, on beaches, over existing settlements, roads and airports.
- **Practical resource** is a judgement regarding the level that would be acceptable to society. In the case of onshore wind (Figure B1.3a), this excludes national parks, Areas of Outstanding Natural Beauty, Sites of Special Scientific Interest and greenbelt land, as well as applying a 'proximity' constraint to account for public acceptability of wind farms near settlements.
- **Economic resource** for each technology will vary considerably through time, depending upon the costs of inputs, the regulatory regime and the costs of alternative technologies amongst other things. We consider costs in section 3.

[13] IEA (2010) *World Energy Outlook 2010.*

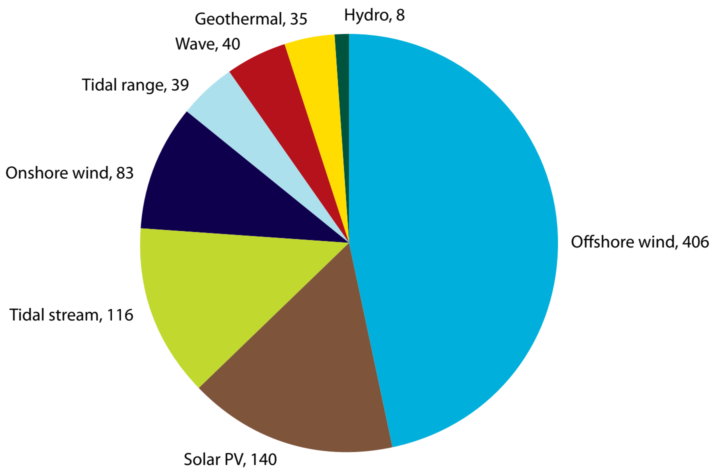
Figure B1.3a: Resource pyramid for onshore wind



Source: Theoretical resource: Mackay (2008) *Sustainable Energy: Without The Hot Air*. Technical and practical resources from ETSU (1997), cited in Enviros (2005) *Costs of Supplying Renewable Energy.*

The public acceptability limitation due to proximity to human populations is unique to onshore wind amongst renewables. However, the exclusion of ecologically sensitive areas, existing manmade structures and usages such as shipping lanes is applied to all of the practical resource estimates.
In considering renewable resource we have focused on practical potential – Figure B1.3b.

Figure B1.3b: Estimated practical resource for UK renewables (TWh/year)



Source: Offshore Valuation Group (2010) *A valuation of the UK's offshore energy resource* (wave, tidal stream, offshore wind); DECC (2010) *2050 pathways* (onshore wind, solar PV and geothermal).

Note(s): The credible range in the literature is 18-197 TWh/year for tidal stream. The Offshore Valuation Group also estimated a large resource potential for floating wind turbines. This has not been included here due to uncertainty about the feasibility of deployment at scale of this development stage technology. Onshore wind resource high end from ETSU (1997), cited in Enviros (2005) *Costs of Supplying Renewable Energy.*

Box 1.4: Potential for imported solar (and other) power to contribute to UK electricity supply

Technology characteristics of solar CSP

Concentrated Solar Power (CSP) generates electricity by using an array of mirrors to focus the sun's rays onto a small area (e.g. the top of a tower) to produce high temperatures that are then used to drive a steam turbine.

Solar technologies tend to generate most in the middle of the day and in the summer, rather than at times of UK peak electricity demand, in early evening and in the winter. However, CSP plants could generate and store heat in molten salts during the day and then release this at times of peak demand (e.g. extending generation into the early evening peak), adding an element of flexibility to their generation profiles.

Available solar CSP resource

The scale of the solar resource – in theory CSP could meet all of Europe's electricity demand in 2050 using around 4% of the Sahara desert (360,000 km^2) – means that it is likely to play an important role in decarbonising European and global electricity supplies, especially in the longer term.

However, CSP is not suitable for generation within the UK, as it requires intense sunshine and little cloud cover to be economic. If sited in southern Europe or northern Africa, it could potentially make a significant contribution to the supply of renewable electricity for the UK, via interconnectors and the European grid.

Potential for imported renewables to contribute to UK power supply by 2020

Although CSP is a relatively immature technology, it could start to generate energy on a multi-gigawatt scale in the second half of the 2010s. Whether it can contribute to the UK's renewable energy target for 2020 depends on whether Article 9 of the EU Renewable Energy Directive, which enables power imported from outside the EU to contribute towards the target, is incorporated into UK legislation and on whether electricity market reform provides incentives for such imports.

The UK may also be able to access imports of other renewable technologies through interconnection and imports – Icelandic geothermal, Scandinavian hydro and biomass resources from around the world.

Box 1.5: Japan: The Fukushima nuclear plant and implications for the UK

Events in Japan at the Fukushima Daiichi nuclear plant have raised the issue of nuclear power safety internationally. The UK has launched a review, which will deliver preliminary findings in May. We note that whilst the specific circumstances in Japan differ significantly from those for new nuclear in the UK, in principle this could affect the potential for nuclear power to contribute to decarbonisation in the UK (e.g. the National Policy Statement for nuclear has been delayed to take account of the review, and any tightening of safety requirements may increase costs).

- Nuclear safety was considered at length in the 2008 White Paper on Nuclear Power and associated consultation document[14], which concluded that the safety risks associated with new nuclear power in the UK are very small:
  - There have been no civil nuclear events with off-site consequences or where all the safety barriers that are an inherent part of the design were breached in the UK.
  - The consultation document cites analysis for the European Commission suggesting that the risk of a 'major accident – the meltdown of the reactor's core along with failure of the containment structure' is of the order of one in a billion per nuclear reactor, per year in the UK.
  - More broadly, the White Paper found that the safety risk associated with new nuclear in the UK is not comparable with older plant where accidents have occurred overseas because regulatory scrutiny of reactor designs and operations is far more rigorous in the UK today.
- Those conclusions are likely to be robust to events in Japan:
  - Events in Japan were the result of an enormous earthquake and tsunami. These affected back-up power and thereby compromised cooling of some reactors. Subsequently there has been overheating, exposure and radiation release from spent fuel ponds.
  - The likelihood of natural disasters of this type and scale occurring in the UK is extremely small.
  - Plant designs allowed under the UK's Generic Design Assessment have benefited from considerable technological improvement since the 1960s Boiling Water Reactors used at Fukushima, including the incorporation of secondary back-up and passive cooling facilities.
- However, the Committee has not undertaken a detailed review of all possible implications for nuclear in the UK.
  - DECC has commissioned such a review from the chief nuclear officer, Dr Mike Weightman. This will report preliminary findings in May, with a final report due in September 2011.

[14] DTI (2007) *The Role of Nuclear Power in a Low Carbon Economy: Consultation Document.*

– A full review is required to ensure that any safety lessons are learnt and to restore public confidence in the safety of nuclear power.

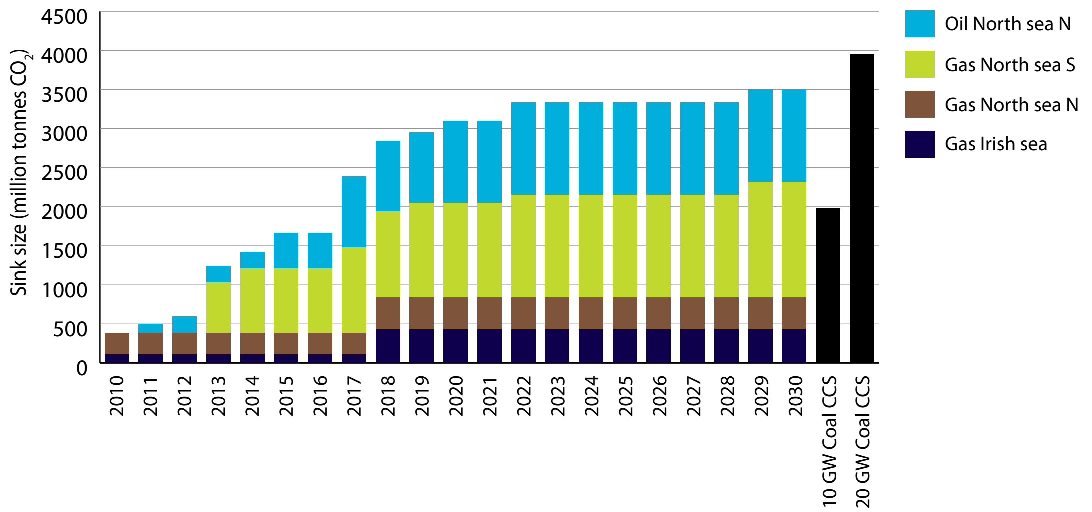
Should the review suggest limiting the role of nuclear generation in the UK in future, then a higher renewables contribution would be required. Alternatively if the review leads to a significant tightening of safety regulations, nuclear costs may be increased, which would improve the relative economics of renewable technologies and argue for potentially increasing their role.

Box 1.6: Availability of CO_2 storage capacity

Estimates of UK CO_2 storage potential generally start from a high-level characterisation of geological formations, to arrive at a theoretical storage capacity. Filters are then applied to reflect the unsuitability of various aspects of these possible stores (e.g. size, proximity to possible streams of CO_2, residual water, reservoir pressure), to arrive at a practical storage capacity.

Work for the Committee by Pöyry[15] in 2009 suggested that practical UK CO_2 storage capacity in depleted oil and gas fields alone might total 3,500 $MtCO_2$ by 2030 (Figure B1.6). Translating the capacity available in these fields into numbers of CCS facilities, this could store 30 years of output from nearly 20 GW of coal-fired plants, operating at 75% load factor (or at least 40 GW of gas-fired plants, due to the lower carbon-intensity of gas).

Figure B1.6: Potential CO_2 storage capacity available in depleted oil and gas fields by 2030



Source: Pöyry (2009) *Carbon Capture and Storage: Milestones to deliver large-scale deployment by 2030 in the UK.*

15 Pöyry (2009) Carbon Capture and Storage: *Milestones to deliver large-scale deployment by 2030 in the UK*, available at http://www.theccc.org.uk.

The theoretical CO_2 storage capacity within saline aquifers (deeply buried porous sandstones filled with salt water) is likely to be considerably larger than in those depleted hydrocarbon fields. A recent study by the Scottish Centre for Carbon Storage[16] identified Scotland's available capacity within saline aquifers to be in the range 4,600 to 46,000 $MtCO_2$. This wide range reflects the uncertainty over the storage capacity of saline aquifers; relatively little physical testing has been undertaken to confirm their suitability and integrity, in contrast to oil and gas fields which have been fully evaluated during decades of exploration and production.

While the focus so far in relation to CCS has been mainly on fossil fuel power generation, it may well turn out that this application is less important in the long term than capturing and sequestering industrial emissions (especially for those industrial processes that produce CO_2 from chemical reactions as well as fuel combustion) and those from bioenergy applications or direct air capture of CO_2, for negative emissions. Both of these applications could be required well beyond 2050. Once sufficiently reliable estimates of CO_2 storage capacity are available, consideration should be made of its best use over time, including any limits to fossil fuel power generation in the medium term and whether it should be used solely for UK emissions.

It is still clear, however, that demonstrations and some use in power generation will be desirable. We will look at biomass CCS in more detail in the context of our bioenergy review later in 2011 and within this will consider the long-term best use of CO_2 storage capacity.

(ii) Technical constraints on the level of intermittent renewable generation

The intermittency challenge

Some types of renewable electricity generation are intermittent[17], meaning that their output is driven by variable climatic or environmental conditions such that they cannot be relied on to generate electricity on demand. This raises a question over whether and to what extent intermittency can be managed, with possible implications for maximum levels of intermittency consistent with maintaining security of supply.

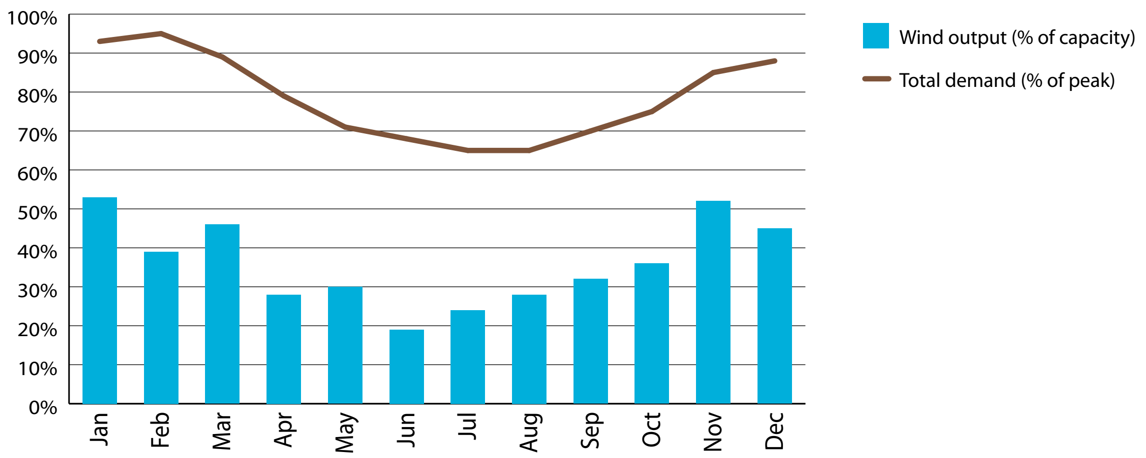
In answering this question, the challenges presented by intermittency should not be overstated:

- Wind patterns are positively correlated with seasonal demand (Figure 1.3).
- Aggregate intermittency from geographically dispersed sources will be lower than intermittency at individual sites (e.g. due to different wind patterns at offshore wind sites near shore and in deeper waters).
- Different intermittent renewables have different availability patterns, implying reduced aggregate variability in a diverse portfolio (Figure 1.4).

[16] SCCS (2009) *Opportunities for CO_2 Storage around Scotland - an integrated strategic research study.*
[17] Wind, marine and solar PV are considered intermittent. Concentrated solar power has some potential to be dispatchable, using heat storage in molten salts. Biomass is flexible and geothermal is considered as baseload plant.

Given this combination of factors, managing intermittency of renewable generation at the system level will be easier than the pattern of output from specific plant may suggest.

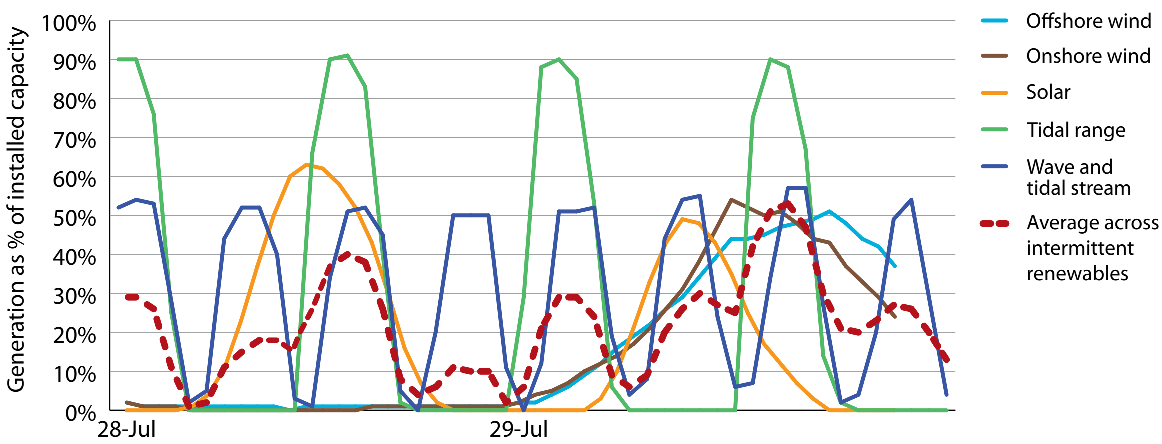
Figure 1.3: Seasonality of wind generation versus seasonality of demand



Source: CCC calculations based on modelling by Pöyry.

Note(s): Based on observed patterns in 2006, 2007, 2008 and 2009 (averaged) and for indicative 2030 wind deployment and demand.

Figure 1.4: Variability of renewable generation technologies (over two illustrative days for 2030 mix)



Source: CCC analysis based on modelling by Pöyry.

Note(s): Based on observed patterns 28-29 July 2006, scaled up to 2030 levels. Chart shows the generation that would be produced by the different renewable technologies (as a percentage of installed capacity) in the Pöyry Very High scenario over a two-day period.

Options for managing intermittency

We commissioned Pöyry Management Consulting to examine scope for maintaining security of supply with very high shares of renewable generation. They found that high shares of renewables need not materially impact security of supply given a range of options for addressing system-level intermittency (Box 1.7):

- **Demand response**. There is scope for significant demand response, with a particular opportunity from electric vehicle batteries:
  - Pöyry's analysis suggests around 15% of demand could be flexible, at least within-day, in 2030.
  - Just over half of the flexible demand is in heating, with the remainder primarily in the transport sector. This reflects our fourth budget assumption that electric car penetration has reached 60% of new cars by 2030, resulting in an electric vehicle fleet of around 11 million.
  - Smart technologies and pricing that reflects electricity costs at time of use, and encourages consumer response, would be necessary in order to unlock this potential. Current Government proposals for smart meter roll-out have recognised this requirement (Box 1.8).
- **Interconnection**. Increased interconnection with European and Scandinavian systems offers scope for flexibility, given that load factors for renewable generation and storage technologies are likely to vary significantly across systems. Pöyry analysis suggests that interconnection could provide 16 GW of flexibility (i.e. 16 GW import capacity) by 2030; modelling for the European Climate Foundation considered up to 35 GW of interconnection to the UK by 2050.
- **Storage.** Bulk storage, such as pumped storage, can be used both to provide fast response and to help provide flexibility over several days (providing supply at times of peak daily demand rather than continuously over the whole period). In addition, investing in thermal storage alongside heat pumps can help shift electricity demand within the day and electric vehicle batteries can also be used as a form of electricity storage[18].
- **Balancing generation.** Gas-fired generation offers the potential for balancing intermittent renewable generation. Assuming other flexibility options are deployed, Pöyry analysis suggests that residual balancing generation would be around 6% of total generation when all other generation is from renewables. This suggests that it is not possible to have a system running on 100% renewable electricity[19], although a very high renewable share would be technically feasible.

[18] In the longer term new storage opportunities may emerge, possibly on a distributed basis (e.g. compressed air, heat storage in molten salts), which we have not included in the modelling, but which would tend to make intermittency easier to manage.

[19] A 100% renewable system would be achievable only if balancing requirements were met through renewable sources, e.g. generation from biogas. However, this would raise questions of resource availability given that bioenergy resources are constrained and may be required to decarbonise other sectors of the economy (see Chapter 2).

Box 1.7: Evidence on supporting high levels of intermittent renewables in the electricity system

Pöyry modelling for the CCC

Pöyry's wholesale electricity model simulates the dispatch of each unit on the system for each hour of every day. The model accounts for minimum stable generation and minimum on and off times, which allows a realistic operational simulation of different plant.

Our new analysis builds on work we commissioned from Pöyry for our fourth budget report[20]. That work emphasised the importance of increased flexibility in any decarbonised system (i.e. even without an increase in renewables share after 2020); almost all flexibility options reduced CO_2 emissions and generation costs.

The new analysis tests the ability of the system to accommodate much higher levels of intermittent renewable generation. This work shows that, technically, the system can accommodate high levels of renewables (e.g. up to 80% in 2050 – Table B1.7). Both interconnection and active demand-side management were found to be very important at high penetrations, along with back-up capacity that may not be able to earn sufficient returns in the wholesale electricity market.

Table B1.7: Modelled scenarios for intermittent renewables: deployment of flexibility options and impact on security of supply and emissions (2030, 2050)

	2030		2050	
Scenario	**High**	**Very High**	**High**	**Very High**
Renewable share	~ 50%	~ 65%	60%	80%
Flexible demand	~ 15%	~ 15%	~ 33%	~ 33%
Interconnection	16 GW	16 GW	24 GW	24 GW
Bulk storage	4 GW	4 GW	4 GW	4 GW
Security of supply (expected energy unserved)	2 GWh (max)	2 GWh (max)	4 GWh (max)	4 GWh (max)
Emissions intensity	≤ 50g CO_2/kWh	≤ 50g CO_2/kWh	Close to zero	Close to zero

20 Pöyry (2010) *Options for low-carbon power sector flexibility to 2050.*

Sensitivities

Pöyry also tested various sensitivities (e.g. less demand-side response, reduced interconnection, more variable wind conditions), which suggest:

- Maintaining security of supply is not dependent on any one flexibility mechanism (e.g. lower demand-side response or interconnection can be compensated by increased back-up capacity).
- Our conclusion that intermittency can be managed is robust to different assumptions and conditions (e.g. in scenarios where consumers are less responsive to price signals, or wind conditions are more variable).
- There is potential to optimise the flexibility packages further than in Pöyry's scenarios (e.g. deployment of some options could be reduced, avoiding some costs, without significant impacts).

Other studies

Other studies using different models have made similar findings, most notably the European Climate Foundation's (ECF) Roadmap 2050 study[21].

The ECF study investigated, at a European level, the technical and economic feasibility of achieving at least an 80% emissions reduction by 2050 (compared to 1990 levels), with scenarios for 40%, 60%, 80% and 100% renewable shares in electricity generation. All scenarios maintained or improved electricity supply reliability and energy security. The ECF analysis also found that a significant increase in integration and interconnection of electricity markets across Europe was a key enabler, along with additional flexibility in demand and increased back-up capacity.

Box 1.8: Government smart meter proposals

The Government's Smart Metering Implementation Programme seeks to roll out a smart meter to every home in Great Britain and to ensure all small and medium non-residential consumers have 'smart or advanced energy meters suited to their needs'.

In March 2011, the Government published a Consultation Response which includes the following key proposals:

- Suppliers will be required to provide an 'In-Home Display' which will show usage information for gas and electricity in pounds and pence and kWh.
- Electricity usage will be updated every five seconds.
- Meters will allow supply to be controlled remotely for demand-side management, with the functionality for real-time price signals to be sent to the meter.

[21] www.roadmap2050.eu.

- Communication to and from smart meters in the domestic sector will be managed by a new 'Central Data Communications Entity' to be operating by the final quarter of 2012.
- Full roll-out is proposed for 2019.

Therefore the Government proposals appear to be consistent with the requirements for unlocking demand-side flexibility (i.e. they include functionality for remotely controlling demand and providing real-time price signals). To ensure this is delivered, there are a number of technical issues for resolution, including security, data transmission and interactions between supply companies, distribution companies and consumers.

Costs of managing intermittency

Given that demand-supply balancing would be possible, the main implications of intermittency for investment in renewable generation are via its impact on costs:

- **Demand-side response**. The main cost of facilitating demand-side response is the installation of smart technologies which will be rolled out over the next decade (Box 1.8). These technologies have an important role in smoothing demand even in scenarios with low renewables penetration, given the improved economics of nuclear and CCS when running at baseload.
- **Interconnection**. Costs associated with interconnection are likely to be relatively small compared to generation costs (e.g. annualised costs are around £0.5 billion per year in Pöyry's highest interconnection scenario in 2030 compared to generation costs of over £40 billion). Some increased interconnection is also likely to be desirable in scenarios with low renewable generation.
- **Storage**. Bulk storage is a relatively expensive option at present, with significant investment costs for pumped storage; it is not clear that significant increases in the amount of pumped storage would be more desirable from an economic perspective than balancing generation.
- **Back-up capacity.** The costs of back-up capacity are currently relatively small, but will increase as more low load factor plant is required to back up intermittent renewables (e.g. Pöyry's analysis showed that in 2030, a scenario with around 65% renewables penetration required around an extra 10 GW of back-up capacity – with annualised costs of around £0.3 billion per year – to remain on the system compared to a scenario with 30% renewables). Costs of back-up and balancing based on gas CCS would be relatively high given limited scope for spreading capital costs at low load factors.
- **Impact on economics of low-carbon plant**. Where there are relatively high levels of renewable generation, this will result in load shedding for other low-carbon plant (e.g. when the wind is blowing and demand is low, CCS or nuclear generation may not run). This raises the unit cost of other plant (i.e. because capital costs are spread over a lower level of generation), which can therefore be regarded as a cost penalty associated with renewables.

- **Transmission costs**. More generation capacity is required on a system with high levels of intermittent renewables (reflecting low load factors) and renewable sites will tend to be selected based on available resource rather than proximity to demand centres. This may imply the need for more transmission capacity, with potentially significant associated costs at higher levels of renewables penetration. These costs can be reduced where intermittent generation cost-effectively 'shares' transmission capacity, or where generation sources are close to major demand loads (e.g. some of the Round 3 offshore wind sites will connect to the grid in the south/east of England).

Therefore, the cost implications of intermittency are unlikely to be prohibitive until very high levels are reached. For example, even for renewables shares up to 65% in 2030 and 80% in 2050, Pöyry's analysis suggests that the cost associated with intermittency is only up to around 1p per kWh of additional intermittent renewable generation.

(iii) Build constraints through the 2020s

In the longer term build constraints may not be a limiting factor, given scope for significant supply chain expansion with sufficient lead time. However these could be binding in the medium term (e.g. the technology mix in the 2020s may be influenced by build constraints).

In order to better understand this potential impact, we commissioned technical analysis from Pöyry to identify potential supply chain constraints for each of the low-carbon technologies.

The Pöyry analysis suggests that there are likely to be limits on scope for investment in each technology, and implies that a mix of renewables and other low-carbon technologies is likely to be required through the 2020s in order that the power sector is largely decarbonised by 2030.

- **Renewables**. Scope for adding renewable capacity in the early 2020s is limited by site availability and the level of ambition to 2020. Pöyry's analysis suggests that significant ramp up through the second half of the 2020s will be feasible:
  - **Onshore wind**. Potential to increase onshore wind capacity during the 2020s will depend on the availability of suitable sites with planning approval, and on the scope for repowering existing sites with larger turbines. Pöyry's analysis suggests up to 5 GW of additional capacity could feasibly be added during the 2020s, some of this through repowering, with scope for further investment if planning constraints can be addressed.
  - **Offshore wind**. We envisage additions of offshore wind capacity going into the 2020s of around 1.7 GW each year. Analysis from Pöyry suggests that this could in principle be ramped up significantly in the early 2020s (e.g. to achieve annual average investment through the 2020s of 3.4 GW), although in section 3 we question whether this would be desirable given the risk of continuing high costs.

- **Marine**. Given the timeline for demonstration of marine technologies, there would also be constraints on scope for ramping up supply chain capacity in the early 2020s. However, if it were the case that these technologies are shown to be potentially competitive, significant expansion in the second half of the 2020s would be feasible (e.g. Pöyry's analysis suggests capacity could reach 8 GW by 2030 before inclusion of the Severn barrage, which could provide a further 9 GW).
- **Solar PV**. To reach the level of solar PV deployment set out in DECC's National Renewable Energy Action Plan (2.7 GW by 2020), the UK will need to develop a robust supply chain. Analysis from Pöyry suggests that, as long as there is sufficient labour to install new panels, deployment of 2.2 GW per year on average through the 2020s would be feasible.

- **Nuclear**. Pöyry analysis suggests that over 20 GW of capacity by 2030 is feasible while remaining well below the annual build rate suggested by current developer plans (2.5 GW per year). This rate would require new plants at all eight sites currently proposed in the revised National Policy Statement for Nuclear Power Generation, implying that site availability may be a limiting factor in going further. In principle a higher build rate would be technically possible (e.g. France – a similar sized economy – added 48 GW of nuclear capacity over a 10-year period).
- **CCS.** Given demonstration of CCS in the period to 2020, the next round of investments would come onto the system towards the mid-2020s. Beyond this, the Pöyry analysis suggests that, assuming CCS is successfully demonstrated at scale, future deployment is most likely to be constrained by access to infrastructure (i.e. CO_2 pipelines and storage facilities), including issues around planning approval, licensing and consents.

3. Renewable and other electricity generation costs

Uncertainty in underlying cost drivers

Our analysis in section 2 suggests that high levels of renewable penetration are potentially feasible, and therefore that a significantly increased share for renewables after 2020 is an option. Whether high penetration is desirable depends on the cost of renewable generation relative to other low-carbon technologies (and to fossil-fired plant facing a carbon price) and on their value in a diverse portfolio.

However, costs of low-carbon technologies are likely to remain uncertain for the foreseeable future, given uncertainty in drivers of investment costs and operating costs, including potential cost reductions as technologies mature:

- **Capital costs**.
  - The key driver of capital costs is usually the labour cost (on-site or embedded in components), with commodity (e.g. steel and cement) prices generally less important; UK costs for imported components are exposed to exchange rate risk.
  - Each of these has changed significantly in the past and is highly uncertain in the future (as reflected in recent changes to cost estimates, set out below).
  - The impact of changes in key drivers will vary across renewable technologies given different capital intensity, particularly as regards renewables and nuclear relative to CCS coal and gas (Figure 1.5). For example, where capital costs increase, this will have a disproportionately high impact on renewable and nuclear generation, making CCS more attractive.
- **Cost of capital**. Given capital intensity, this is a key driver of renewables and other low-carbon technology costs; in this chapter, we follow the convention and use a commercial cost of capital (10%) on the basis that this is a proxy for a risk-adjusted social cost of capital, whilst also considering sensitivities based on lower rates (Box 1.9).
- **Fossil fuel prices**. Fossil fuel prices will impact the relative costs of renewables and nuclear versus coal and gas CCS. There is a high degree of uncertainty over future fossil fuel prices (Figure 1.6), which may be particularly important in relation to gas CCS, given the high share of fuel costs in total costs (65%) and the possibility that lower than expected gas prices (e.g. due to shale gas) will make gas CCS more attractive. The impact of fossil fuel prices on the relative capital costs of different technologies is of limited importance given the very low contribution of materials to overall costs.
- **Operating performance**. Attractiveness of renewables will depend on uncertain performance in terms of annual availability and load factors.

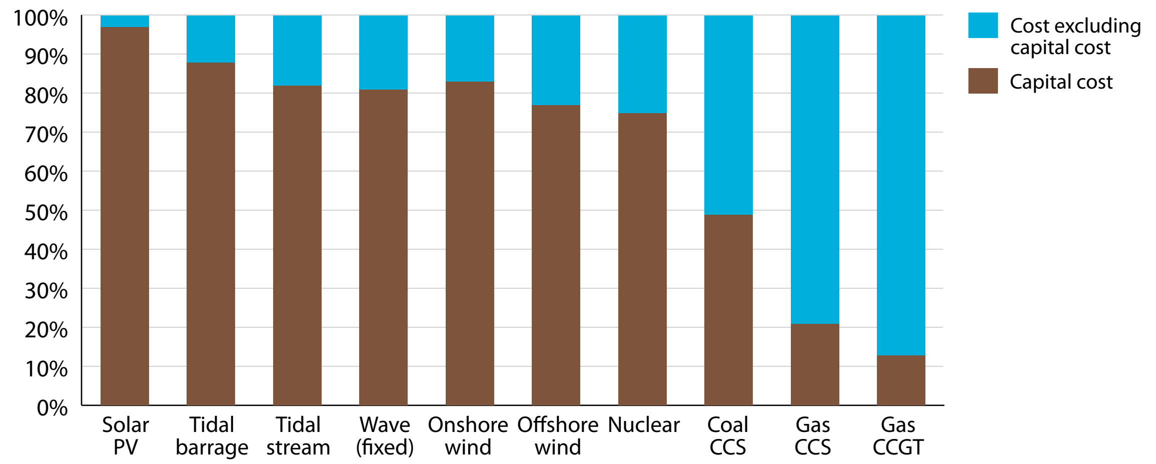
– There is uncertainty over what load factors will be achievable in future, particularly as regards relatively untested offshore wind and marine generation. Given sensitivity of costs to load factors, this could have a significant impact on the economics of these technologies (Figure 1.7).

– A related point is that gas CCS could be particularly attractive for mid-merit generation, given its relatively low capital intensity (Figures 1.5 and 1.8).

- **Technology maturity**. Given the different stages of technology maturity, we would expect costs of renewable and other technologies to fall at different rates over time as a result of learning, although the extent of this is highly uncertain (see below for a discussion of the potential for costs to fall in future and related uncertainties).

The high degree of uncertainty is reflected in DECC's estimates of costs for the various power generation technologies. For some technologies these more than doubled in real terms between 2006 and 2010, mainly reflecting higher than expected costs for technologies deployed in intervening years, in turn largely reflecting exchange rate movements and supply chain constraints (Figure 1.9).

Figure 1.5: Share of capital costs in long-run marginal costs



Source: CCC calculations, based on Mott MacDonald (2011) *Costs of low-carbon generation technologies.*

Note(s): Based on projects starting in 2011, using 10% discount rate and central scenario for capital costs and fuel prices. Non-renewable plants operating at baseload (i.e. a load factor of 90%); the proportion of capital costs would be higher for operation at mid-merit (e.g. 50%). Capital cost category excludes the costs of CO_2 transportation and storage, which are around 3% for gas CCS and 6% for coal CCS.

Box 1.9: Discounting: using a commercial cost of capital in cost estimates

Alongside Mott MacDonald's work on costs we commissioned Oxera to consider costs of capital (or discount rates) applied to generation technologies.[22]

Current costs of capital

Oxera identified a number of risks faced by generation investors (including those relating to technology performance, load factors, wholesale electricity prices). Given these risks they estimated that costs of capital are typically well above the social discount rate of 3.5%[23]:

- For established dispatchable technologies (unabated gas, hydro) they estimate pre-tax real rates around 6-9%.
- For less mature technologies – which include most of the low-carbon technologies – they estimate that higher ranges are currently applicable (e.g. 10-14% for offshore wind).

Future costs of capital

The higher discount rates applied to low-carbon technologies reflect three key factors that can be reduced by effective policy and by deployment over time:

- **Cost structure.**
  - Most low-carbon technologies are capital-intensive, incurring most of their costs during construction. They are therefore exposed to fluctuations in wholesale electricity prices (reflecting fuel and carbon costs being passed through to consumers by marginal plants such as gas CCGT).
  - Market reform can remove this risk from generators while giving consumers increased price certainty, for example by providing long-term contracts with a guaranteed return and price, as we have previously proposed and as included in the Government's recent consultation (see Chapter 2).
- **Policy risk.**
  - Where a project's financial viability is reliant on policy interventions, such as the carbon price or the Renewables Obligation, developers are exposed to the risk that policy may change and undermine the economics of their project.
  - This will become less important as costs fall and the technology's return is less reliant on policy intervention; the risk can also be reduced by ensuring maximum credibility in policy instruments (e.g. based on legally-enforceable contracts).
- **Technology maturity.**
  - Early-stage technologies are generally riskier as their costs and future performance are more uncertain.
  - This risk will reduce as currently immature technologies become more established and are deployed at scale.

22 Oxera (2011) *Discount rate for low-carbon and renewable generation technologies,* available at www.theccc.org.uk.
23 HMT (2003) *Green Book.*

Oxera estimate that supportive policy and technology deployment could reduce costs of capital for immature technologies by as much as 2-3% in the next decade, and a further 1-2% by 2040. Therefore, in the long term, costs of capital for low-carbon technologies could be comparable to unabated gas today, and could fall below the 10% conventionally assumed.

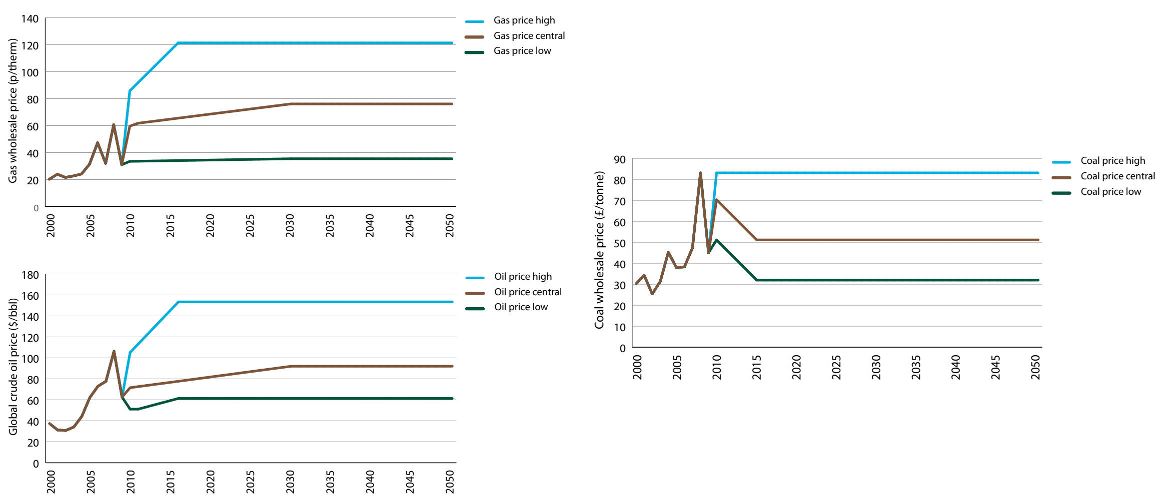
Given the above, and for transparency, we use a 10% discount rate across technologies and time periods and report sensitivities on 7.5% (current central estimate for unabated gas) and 3.5% (risk-free social discount rate).

Importance of cost of capital on relative costs of generation technologies

Applying a lower cost of capital will favour those technologies that are capital-intensive and have long lifetimes. This would favour all low-carbon technologies versus unabated fossil-fired plant, and favour nuclear and most renewables versus CCS and bioenergy (see Figure 1.11). By contrast, if current higher rates continue the cost penalty of low-carbon technologies could be significantly higher – emphasising the importance of effective market reforms and a stable supportive policy environment.

The possibility for costs of capital to differ between technologies increases the uncertainty involved in assessing relative costs.

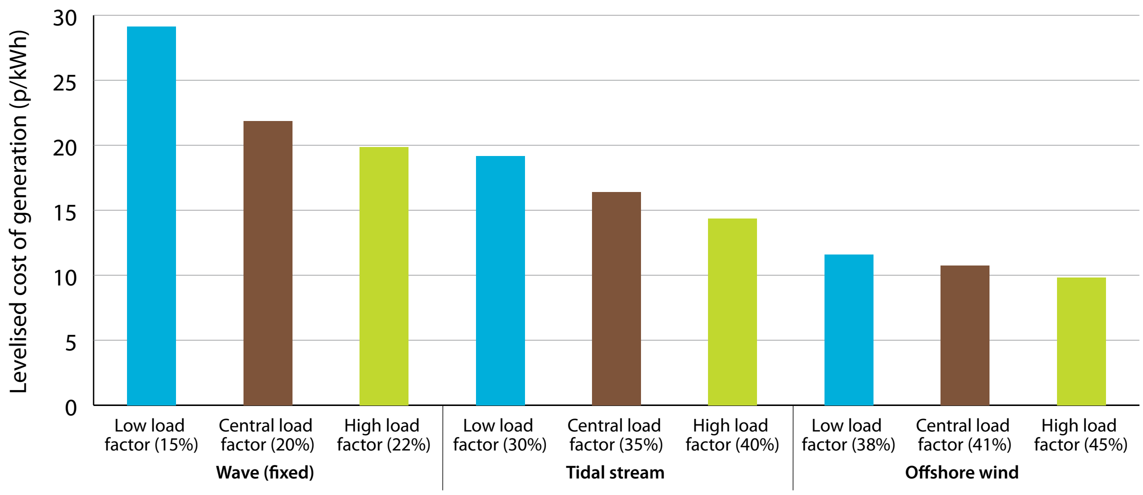
Figure1.6: Fossil fuel price assumptions to 2050



Source: DECC (2010) *Energy and Emissions Projections Annex F: Fossil fuel and retail price assumptions*, 'Low', 'Central' and 'High-High' scenarios; CCC assumptions beyond 2030.

Note(s): 2009 prices. Fossil fuel prices are highly uncertain and highly volatile – none of these individual projections reflect a likely future world (e.g. in reality prices will fluctuate widely from year to year) but the range across scenarios aims to capture the range of uncertainty involved.

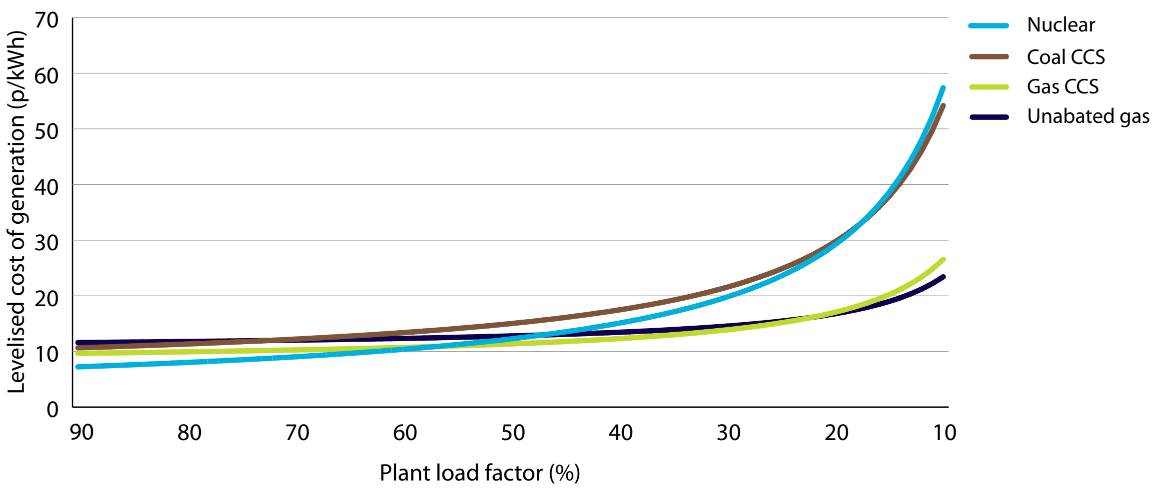
Figure 1.7: Sensitivity of levelised cost to load factor for wave, tidal stream and offshore wind (2030)



Source: CCC calculations, based on Mott MacDonald model (2010) *UK Electricity Costs Update* and (2011) *Costs of low-carbon technologies*.

Notes: 2010 prices. Costs are for projects starting construction in 2030, and are based on central capital cost assumptions and a 10% discount rate.

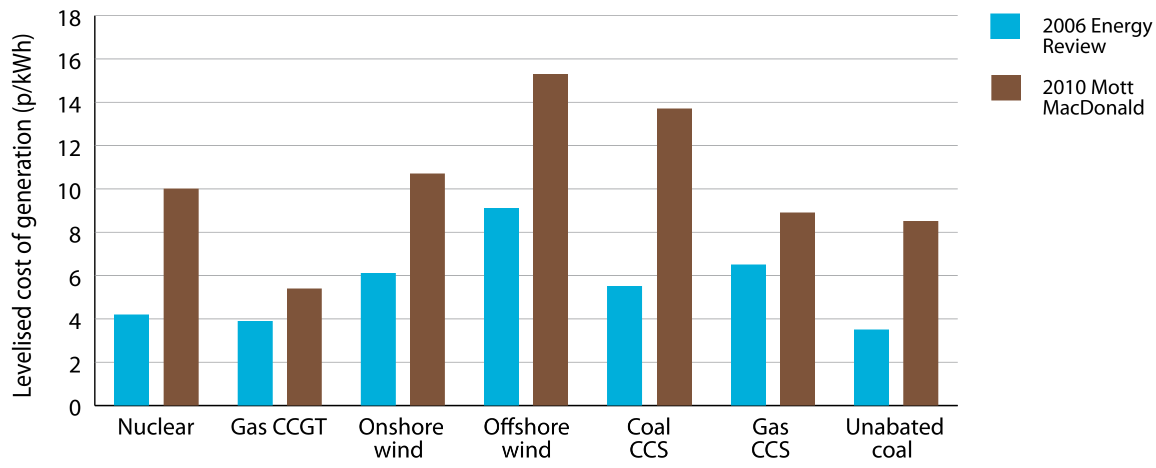
Figure 1.8: Estimated levelised cost of low-carbon technologies by load factor (2030)



Source: CCC calculations, based on Mott MacDonald model (2010) *UK Electricity Costs Update* and (2011) *Costs of low-carbon technologies*.

Note(s): 2010 prices. Costs are for projects starting construction in 2030, and are based on central capital, fuel and carbon prices and a 10% discount rate.

Figure 1.9: Government estimates of generation costs, estimated in 2006 and 2010 for projects starting immediately



Source: CCC calculations, based on DTI (2006) *The Energy Challenge*, Mott MacDonald (2010) *UK Electricity Generation Cost Update.*

Note(s): 2010 prices, all technologies on nth-of-a-kind basis, no carbon price included. Fuel prices are as for Energy Review 2006 in both cases. Coal costs present average of range from pulverised fuel to IGCC. Project start date for Mott McDonald (2010) is 2009, for DTI (2006) it is 2006.

Estimating future generation costs

Given these significant uncertainties, we have developed a range of future cost estimates corresponding to varying assumptions on key cost drivers, using a model built for us by Mott MacDonald (Box 1.10).

Box 1.10: CCC model for calculating levelised costs for power generation technologies

We commissioned Mott MacDonald to conduct an in-depth assessment of the capital cost of low-carbon technologies. Capital costs are typically the largest component of costs for low-carbon technologies (excluding CCS). Drawing on data from recent projects where possible, Mott MacDonald broke down capital cost (capex) into relevant sub-components to provide an estimate of current and future capital costs.

Across technologies Mott MacDonald found three key themes:

- There is considerable **uncertainty** over capital costs, in particular for early-stage technologies (CCS, marine). Technology performance and cost varies on a project-by-project basis. These factors make estimates of current and future costs hugely uncertain, and inevitably based on judgement.
- **Market congestion** drives a wedge between quoted prices and underlying costs, caused by an imbalance of supply and demand. This 'premium' can be of the order of 15-20% for some technologies (e.g. offshore wind, nuclear), and may be eroded with new entrants.

- **Raw materials** (e.g. steel, cement) are generally not significant drivers of capex, with labour (either on-site or embedded in component manufacture) generally being the largest item.

Building on this work, we have constructed a range of estimates of future capital costs across the low-carbon technologies:

- **Low:** Congestion in the market is completely eroded by 2020, coupled with high-end estimates of cost reductions (consistent with high deployment).
- **Central:** Congestion is maintained until 2020 (reflecting tight supply chains in the context of the EU renewables target). After 2020, supply chains ease and prices reflect underlying costs. This is coupled with a central view of cost reductions (consistent with steady deployment).
- **High:** Market congestion is maintained throughout the period and cost reductions are modest (consistent with low deployment).

Further adjustments were made to take into account starting point uncertainty; for more mature technologies (e.g. onshore wind) this was a small adjustment on the central view of current capital costs (e.g. ± 5% adjustment). For less mature technologies or where there is more uncertainty over outturn of first plant (CCS, new nuclear) the adjustment was larger (e.g. ± 20%). Estimates of capital costs are combined with other assumptions on operational expenditure (e.g. fuel prices, plant efficiency or availability, and discount rate – see Box 1.9) to produce an estimate of the overall levelised cost of generation.[24]

The range of costs that we have constructed shows that there are plausible scenarios where each type of renewable generation could form part of a cost-effective generation mix, but that there are other scenarios where high levels of newer renewable technologies (i.e. offshore wind, marine, solar PV) would be expensive relative to alternative investment strategies for sector decarbonisation, at least in the 2020s (Figure 1.10):

- **Renewables.** Cost reductions are likely to be limited for established technologies, with scope to reduce significantly the costs of less mature technologies:
  - **Onshore wind and hydro.** Both are established technologies, and are likely to be cost-competitive against new gas CCGT facing a carbon price of £30/tCO_2 in 2020 (i.e. in line with the carbon price floor announced in the 2011 Budget). Given maturity, there is limited scope for innovation of each technology, and therefore only limited further cost reductions are envisaged.
  - **Offshore wind.** Offshore wind is at an earlier stage of deployment, with cost reductions up to 50% possible by 2040 (i.e. to as low as 7.5 p/kWh from our high estimate of 15.5 p/kWh today). This requires, for example: larger turbines, larger arrays, erosion of market congestion/premia, and efficiency improvements in turbine production and installation (Box 1.11).

[24] Levelised cost of generation is the discounted cost of generation (both capital and operational expenditure) divided by the discounted stream of net generation. We express these in p/kWh throughout the report for consistency and comparability with consumer bills. However, £/MWh is also commonly used; to convert from p/kWh to £/MWh multiply by 10.

- **Marine.** Marine technologies (tidal stream, wave) are at an early stage of development, with uncertainty over what costs will be for demonstration projects and what subsequent cost reductions are achievable through learning. Our estimates start high and fall considerably, but are likely to remain above offshore wind costs to 2040.
- **Solar PV.** Solar PV costs have fallen rapidly in recent years, with studies suggesting scope for further reductions of between 50-60% over the next decade, and 70-80% by 2040 (Box 1.12). These large reductions (which are likely to be largest for the costs of the module and of installation) could make solar PV economically viable in the UK by 2030 (e.g. at around 11 p/kWh costs could be comparable to offshore wind).
- **Biomass.** Anaerobic Digestion (AD) is commercially proven but relatively small scale (i.e. below 5 MW) with current cost estimates ranging from 13.5-17.5 p/kWh for food waste AD. Dedicated biomass plants are typically larger (e.g. 150 MW units) with current costs in the order of 8-17.5 p/kWh, falling to 7-15 p/kWh by 2040. Approximately 40% of the costs are fuel costs.
- **Geothermal.** Geothermal power generation is not currently deployed in the UK and its costs are therefore highly uncertain. Potentially it could be competitive with new gas and with other low-carbon options, depending on success demonstrating this technology in the UK.

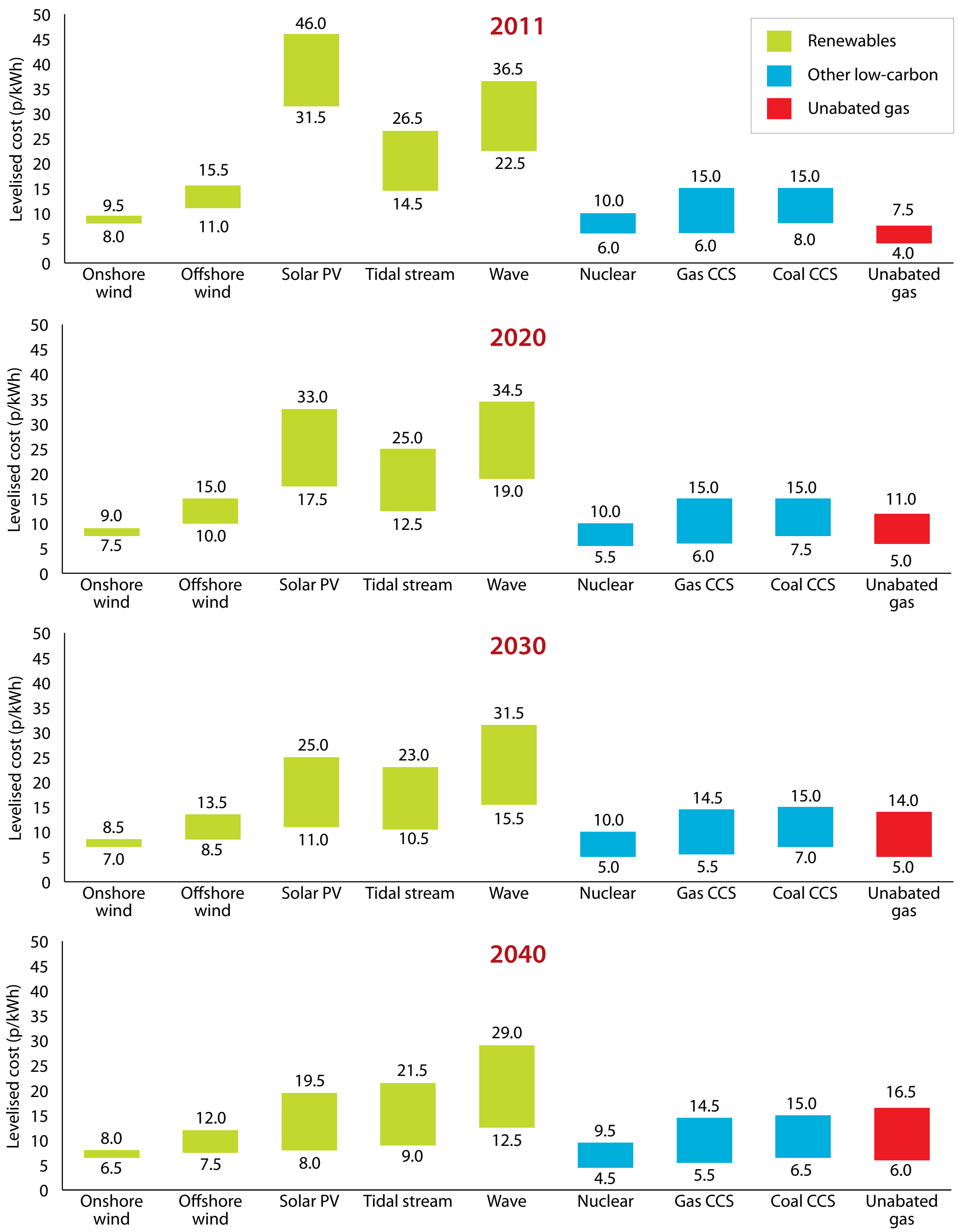
- **Nuclear:** Nuclear generation is a mature technology, with investments envisaged in the next decade and beyond based on an evolution of existing models. However, there is a high degree of uncertainty over how much nuclear costs will be for the first new plant in the UK, and how much this will fall as a result of location-specific learning and scale economies in moving towards a programme of roll-out (e.g. the 2010 Mott MacDonald study[25] for DECC suggests a 40% cost differential between the first nuclear plant and a programme in the UK).
- **CCS.** Carbon capture and storage technologies are also still at the demonstration stage, implying current costs and potential learning are highly uncertain. This is reflected in wide ranges for future costs.
- **Unabated fossil fuels.** Costs of unabated fossil-fired generation will increase as the carbon price increases, but are highly uncertain given uncertainties over fuel prices. Costs will also rise if load factors or lifetimes are reduced to accommodate low-carbon generation.

• **Discount rate sensitivities.** The above costs are estimated using a 10% real discount rate. In sensitivities using discount rates of 3.5% and 7.5%, the economics of renewables improve relative to less capital-intense technologies, suggesting that solar PV and tidal stream technologies could be more competitive and at an earlier stage (Figure 1.11).

Given these ranges for costs, together with uncertainties over how quickly and how much of each technology can be deployed, investment in renewable generation could be, or could become, part of a least-cost solution, and could exert competitive pressure on other low-carbon technologies.

[25] Mott MacDonald (2010) *UK Electricity Generation Costs Update.*

Figure 1.10: Estimated cost of low-carbon technologies (2011, 2020, 2030, 2040)



Source: CCC calculations, based on Mott MacDonald (2011) *Costs of low-carbon generation technologies.*

Note(s): 2010 prices, using a 10% discount rate. 2011 – project starting in that year; 2020-2040 project starting construction in that year.

Unabated gas and CCS include a carbon price (high–low range). Excludes additional system costs associated with intermittency, e.g. back-up and interconnection.

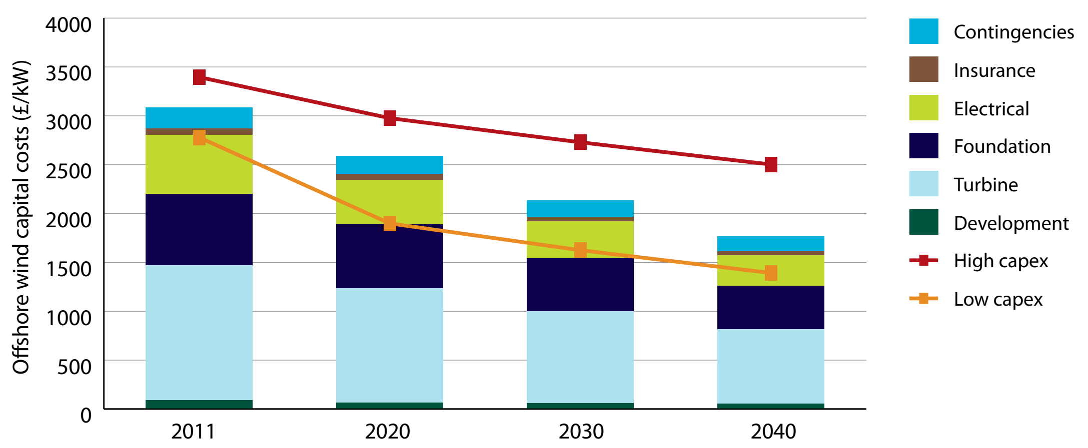
Box 1.11: Learning potential for offshore wind

Estimates of the capital cost for an early Round 3 scheme in the UK are of the order of £3,000/kW. Given there are comparatively few players in the UK market, Mott MacDonald estimate current prices are around 15% higher than underlying costs ('market congestion'). The extent to which congestion persists will depend on new entrants in the market keeping pace with demand to meet the 2020 target.

Figure B1.11 sets out the breakdown of capital costs, and our projected range out to 2040.

- The turbine constitutes the largest component (45%) of costs.
- Current costs range by ±10% on central view, to reflect starting point uncertainty.
- In our central scenario, capital costs fall by 16% by 2020 and 43% by 2040, with significant savings on the turbine (45%). This is achieved whilst moving into successively deeper waters and further distance, through moving to bigger turbines (up to 20 MW by 2040, compared with around 3.5 MW today) and increased total wind farm capacity (up to 250 turbines in an array, compared to 25 today).

Figure B1.11: Projected offshore wind capital costs (2011, 2020, 2030, 2040)



Source: CCC calculations based on Mott MacDonald (2011) *Costs of low-carbon generation technologies*.
Note(s): 2010 prices.

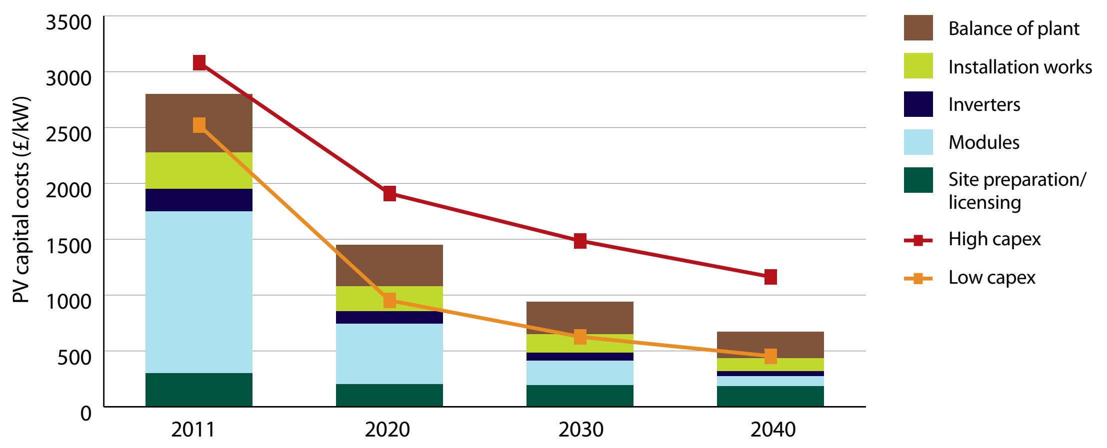
These estimates assume major advances in wind turbine technology, but do not assume a shift to floating foundations or new vertical-axis machines. Sourcing components from lower-cost jurisdictions (e.g. China) than at present could also bring savings. Such impacts are difficult to quantify, making future estimates of costs uncertain.

Box 1.12: State of solar photovoltaic technology and scope for cost reductions

Globally the cost of solar PV is falling rapidly – over the past 30 years, the price of PV modules has reduced by 22% for each doubling of cumulative installed capacity.[26] Current costs are estimated to be in the order of £2,800/kW, of which half is the cost of the module (£1,450/kW) and a further 12% for the installation (£330/kW).[27]

There is significant scope for further cost reductions across all components, in particular the module – increased production capacity, industry learning and savings in material costs are expected to lead to a reduction of around 63% in module costs by 2020. Figure B1.12 below sets out our range of projected capital costs, falling to around £450-1,160/kW by 2040.

Figure B1.12: Projected solar PV capital costs (2011, 2020, 2030, 2040)



Source: CCC calculations based on Mott MacDonald (2011) *Costs of low-carbon generation technologies.*

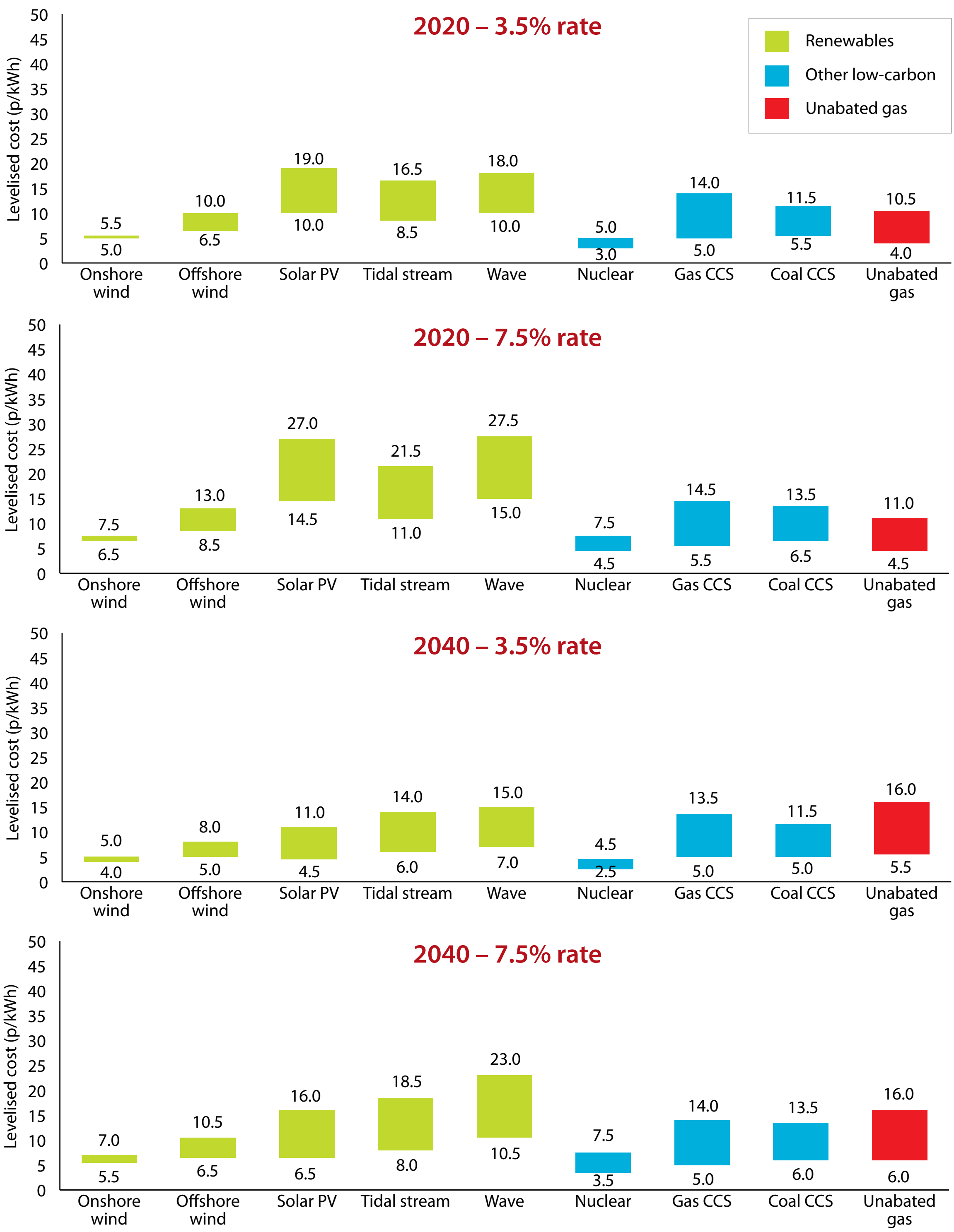
Note(s): 2010 prices. Based on a ground-mounted crystalline system (10MW). Balance of plant includes costs of mounting structure, cables, junction boxes, monitoring equipment and other electrical equipment such as grid interconnection panels and meters.

Given these estimates of capital costs, by 2030 cost per unit of generation (11-25 p/kWh) would be within the range of offshore wind (8.5-13.5 p/kWh) and unabated gas with a carbon price (5-14 p/kWh) if high-end cost reductions are achieved (Figure 1.10).

[26] EPIA (February 2011) *Solar Voltaic Energy Empowering The World*, quoted in Mott MacDonald (2011) *Costs of low-carbon generation technologies.*

[27] The numbers presented here are based on a 10 MW, ground mounted system using crystalline technology. For rooftop and thin film, see Mott MacDonald (2011) *Costs of low-carbon generation technologies.*

Figure 1.11: Estimated cost of low-carbon technologies at 3.5% and 7.5% discount rate (2020, 2040)



2020 – 3.5% rate	Onshore wind	Offshore wind	Solar PV	Tidal stream	Wave	Nuclear	Gas CCS	Coal CCS	Unabated gas
High	5.5	10.0	19.0	16.5	18.0	5.0	14.0	11.5	10.5
Low	5.0	6.5	10.0	8.5	10.0	3.0	5.0	5.5	4.0

2020 – 7.5% rate	Onshore wind	Offshore wind	Solar PV	Tidal stream	Wave	Nuclear	Gas CCS	Coal CCS	Unabated gas
High	7.5	13.0	27.0	21.5	27.5	7.5	14.5	13.5	11.0
Low	6.5	8.5	14.5	11.0	15.0	4.5	5.5	6.5	4.5

2040 – 3.5% rate	Onshore wind	Offshore wind	Solar PV	Tidal stream	Wave	Nuclear	Gas CCS	Coal CCS	Unabated gas
High	5.0	8.0	11.0	14.0	15.0	4.5	13.5	11.5	16.0
Low	4.0	5.0	4.5	6.0	7.0	2.5	5.0	5.0	5.5

2040 – 7.5% rate	Onshore wind	Offshore wind	Solar PV	Tidal stream	Wave	Nuclear	Gas CCS	Coal CCS	Unabated gas
High	7.0	10.5	16.0	18.5	23.0	7.5	14.0	13.5	16.0
Low	5.5	6.5	6.5	8.0	10.5	3.5	5.0	6.0	6.0

Source: CCC calculations, based on Mott MacDonald (2011) *Costs of low-carbon generation technologies.*

Note(s): 2010 prices. 2011 – project starting in that year; 2020-2040 project starting construction in that year. Unabated gas and CCS include a carbon price (high–low range). Excludes additional system costs associated with intermittency (e.g. back-up capacity and interconnection).

4. Renewable generation scenarios from 2020

Our scenarios for renewable electricity generation reflect the range of possible costs and the value of having a diverse mix. High penetration scenarios correspond to relatively low renewable generation costs or limits on deployability of other low-carbon technologies, and low penetration scenarios correspond to relatively high renewable generation costs with low-carbon alternatives fully deployable.

We develop the scenarios in four steps:

- We first recap our assessment of ambition in the period to 2020.
- We then set out four scenarios for renewable generation deployment in the period 2020 to 2030, each of which is consistent with achieving a largely decarbonised power sector by 2030.
- We briefly consider the outlook for the share of renewable generation to 2050.
- We calculate costs and investment requirements.

Renewable electricity generation in the period to 2020

The starting point for our renewable generation scenarios is the Government's ambition to 2020 set out in the Renewable Energy Strategy, which is in line with our framework of progress indicators (and which remains appropriate given our assessment in Chapter 2). We developed this scenario based on an assessment of what is feasible and desirable in the period to 2020, and it is characterised as follows:

- The scenario includes a total of 28 GW wind capacity (split 13 GW offshore and 15 GW onshore) and just over 10 GW of non-wind renewables (all on a nameplate basis[28]), alongside four CCS demonstration plants by 2020 (1.7 GW), with two new nuclear plants by 2020 (around 3 GW in total).
- This would result in a total of around 45 GW (approximately 25 GW baseload-equivalent when intermittent renewables are adjusted for their lower annual availability) of low-carbon plant on the system in 2020 after allowing for closure of existing nuclear plant in the 2010s.
- Emissions reduction of around 30% in 2020 would ensue relative to 2009 (110 $MtCO_2$). This would be due to both a fall in average emissions from around 490 gCO_2/kWh in 2009 to around 300 gCO_2/kWh in 2020, as well as efficiency-driven demand reductions offsetting underlying demand growth.

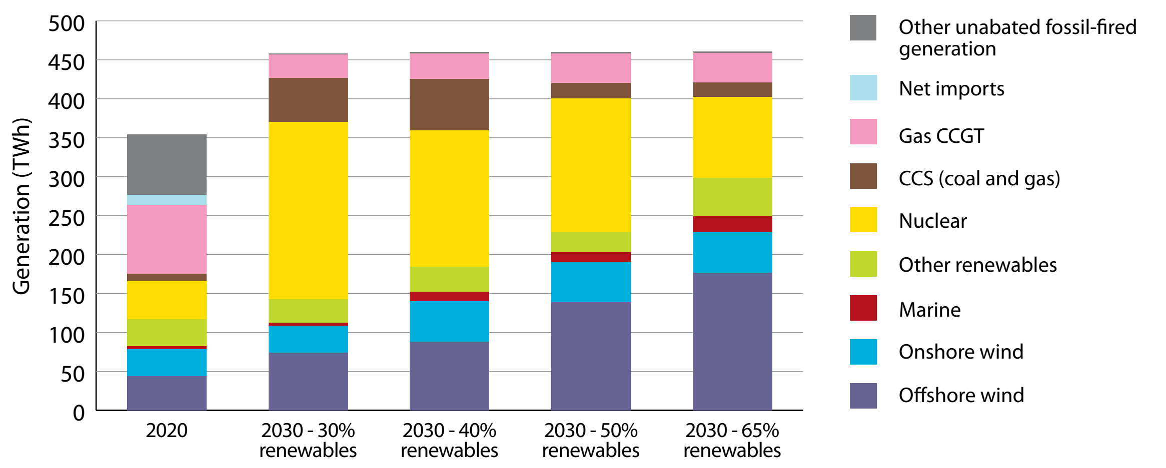
Although there are currently delivery risks associated with this scenario – for example, as regards planning approval for projects, financing, supply chain expansion, see Chapter 2 – we assume that these risks are addressed and that we enter the 2020s with around 38 GW of renewable capacity on the system accounting for around 30% of total demand (120 TWh in total).

[28] Nameplate capacity refers to generating capacity at peak output, in contrast to baseload-equivalent capacity, which adjusts for average load factors.

Scenarios for investment in renewables from 2020

In setting out possible paths for renewable generation through the 2020s, we define four scenarios with increasing levels of renewables penetration and contribution to required sector decarbonisation (Figure 1.12):[29]

Figure 1.12: Range of renewable electricity penetration scenarios to 2030



Source: CCC calculations, based on modelling by Pöyry Management Consulting.

Note(s): All 2030 scenarios achieve a comparable level of emissions intensity (around 50 g/kWh) and security of supply.
Includes losses, excludes generator own-use and autogeneration. Other renewables include hydro, biomass (including anaerobic digestion), geothermal and solar PV.

- **140 TWh (30%) penetration by 2030.**
  - This is the indicative scenario used in our fourth budget cost calculations and assumes that renewables are added more slowly after 2020 than before.
  - It reflects a world where no further progress is possible in onshore wind beyond 2020 (e.g. due to planning restrictions), and where newer technologies (marine, solar and geothermal) are not deployed in the 2020s. Offshore wind is deployed at a slower rate than through the 2010s, reaching just under 20 GW in total by 2030.
  - Sector decarbonisation is therefore achieved largely through a combination of CCS and nuclear, requiring that deployability constraints for these technologies are not binding.
  - Given increasing demand for electricity from the heat and transport sectors, whilst total renewable generation increases from 120 TWh in 2020 to 140 TWh in 2030 this is sufficient only to keep the share of renewables in generation constant at around 30%.

[29] Includes losses, excludes generator own use (around 5%) and autogeneration. Overall totals are rounded to the nearest 5 TWh.

- **185 TWh (40%) penetration by 2030.**
  - This scenario allows for continued progress deploying cost-effective onshore wind through developing new sites and repowering old ones. The scenario adds offshore wind and marine in line with planned investment levels during the 2010s. It assumes no new biomass or hydro capacity is built beyond 2020.
  - Delivering sector decarbonisation requires a substantial roll-out of nuclear and CCS (together reaching around 33 GW of installed capacity in 2030). This involves development at all currently approved nuclear sites and is within the feasibility constraints identified by Pöyry, as set out in Chapter 1.
- **230 TWh (50%) penetration by 2030.**
  - This scenario constrains CCS investment, reflecting a world where CCS demonstration shows this technology to be either not technically feasible or not economically viable.
  - Nuclear continues to be built at all currently approved sites and offshore wind investment in the 2020s roughly doubles compared to the 2010s.
  - This scenario could be appropriate where renewables are cheaper than CCS and nuclear investment cannot be increased beyond current plans.
- **300 TWh (65%) penetration by 2030.**
  - This scenario deploys renewables at close to the maximum feasibly achievable and would require rapid supply chain expansion.
  - Alongside very substantial offshore wind investment (around 3.5 GW a year to just under 50 GW by 2030) it would need significant contributions from marine, solar and geothermal technologies, including a possible contribution from the Severn barrage project (Box 1.13) and from imported renewables (see Box 1.4 above).
  - To decarbonise to 50 g/kWh this scenario would still require around 12.5 GW of new nuclear and CCS capacity during the 2020s, in addition to the 5 GW added by 2020.
  - It would be appropriate to aim to deliver this scenario if renewable generation costs were to be significantly lower than those for other low-carbon technologies, which would require cost reductions at the most optimistic end of our range of assumptions.

Box 1.13: The Severn barrage

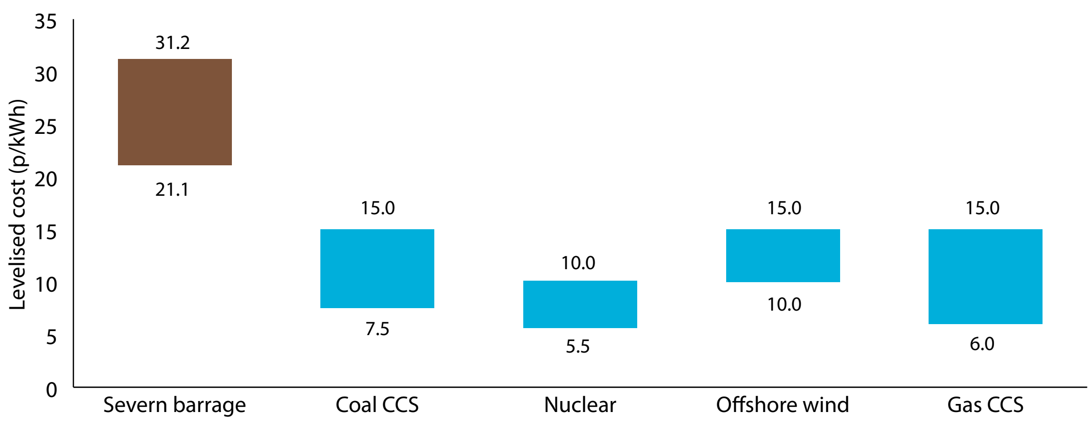
We have previously set out that a Severn barrage could play a useful role in power sector decarbonisation if it can be shown to be economically viable from a societal perspective, and that environmental concerns can be mitigated. The recent DECC Severn Feasibility Study ruled out the construction of a barrage for the immediate term.

The Severn barrage could be an attractive investment when viewed from a public interest (low discount rate) perspective if other technologies turn out to be at the higher end of current cost estimates (in particular CCS). In any case, environmental considerations would have to be adequately addressed for this project to proceed.

Economics of Severn barrage

Comparing the DECC study (2010) with our own cost estimates based on Mott MacDonald at a 10% discount rate, a Severn barrage is more expensive than other low-carbon alternatives (Figure B1.13a). However, due to its very capital-intensive nature, the barrage is very sensitive to the discount rate. At a 3.5% (Green Book) discount rate, a Severn barrage looks potentially attractive from an economic perspective if CCS and offshore wind costs turn out to be at the high end of their ranges (Figure B1.13b).

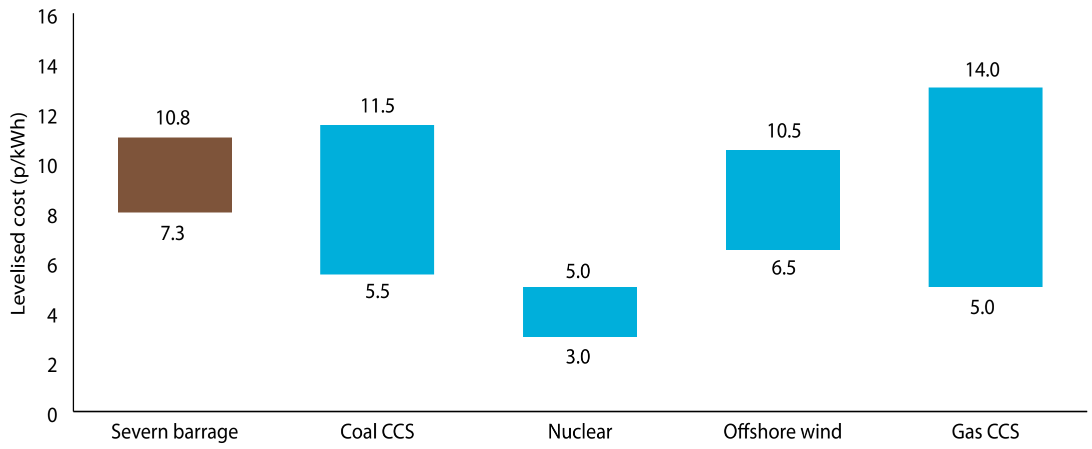
Figure B1.13a: Severn barrage relative to alternatives at 10% discount rate



Source: DECC (2010) *Severn Tidal Power Feasibility Study - Phase 2 Impact Assessment* and CCC calculations based on Mott MacDonald (2011) *Costs of low-carbon generation technologies.*

Note(s): 2010 prices. Severn barrage here refers to Cardiff-Weston scheme. High end of costs is represented by the Feasibility Study estimate including Optimism Bias (OB), Risk Assessment (RA) and Compensatory Habitat payments. Low end includes Compensatory Habitat payments but not RA and OB. Range for alternative low-carbon technologies based on CCC calculations for project starting construction in 2020.

Figure B1.13b: Severn barrage against other low-carbon options at 3.5% discount rate



Source: DECC (2010) *Severn Tidal Power Feasibility Study - Phase 2 Impact Assessment* and CCC calculations based on Mott MacDonald (2011) *Costs of low-carbon generation technologies*.

Note(s): See notes to figure above.

Contribution to renewable deployment scenarios:

Given a project lead time of at least 13 years including planning and construction (but not habitat relocation), the earliest the proposed Severn barrage could become operational is 2024. It could then contribute 16-20 TWh/year through an asset life of around 120 years. There is also potential to invest in tidal range elsewhere in the UK, with a total resource of 44 TWh/year.

Analysis for this review by Pöyry[30] shows that deploying a diverse mix of renewables, including significant levels of tidal range, tidal stream and wave power as opposed to a mix largely reliant on wind power, reduces the need for peaking plant, energy shedding and also facilitates a lower-carbon mix of thermal plant.

A Severn barrage could make a useful contribution to a manageable low-carbon system if viewed from a societal perspective. This is particularly relevant under circumstances where other technologies turn out to be unavailable or at the high end of their cost ranges and where environmental concerns can be adequately addressed.

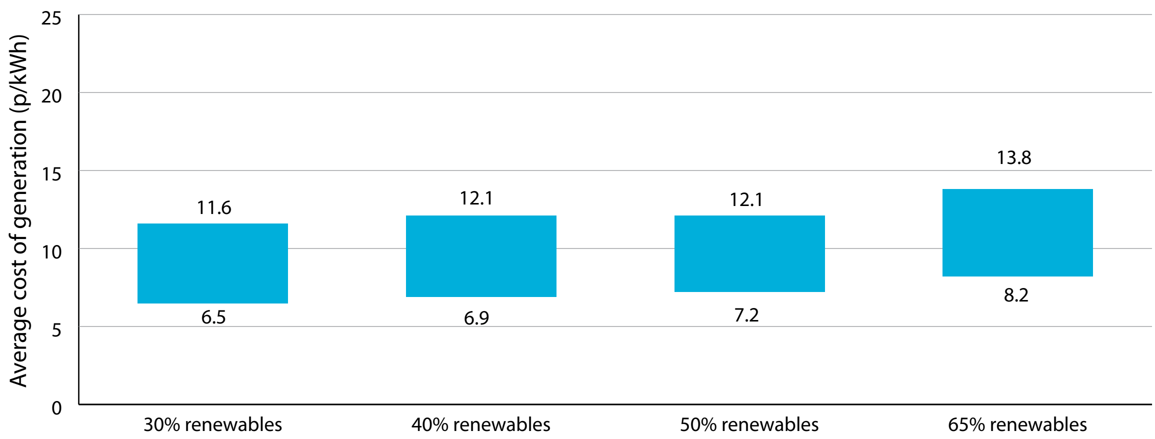
[30] Pöyry (2011) *Analysing Technical Constraints on Renewable Generation.*

Although we have not developed scenarios for the period beyond 2030, it is clear that these would also reflect a wide range for renewables penetration, with scope for very high penetration following significant investment through the 2020s, in a world where renewables are cost-competitive or where there are barriers on deployability of other technologies.

Scenario costs and investment requirements

There is a high degree of uncertainty over scenario costs and investment requirements, given underlying uncertainty around the costs of specific technologies. In order to reflect this uncertainty, we have estimated scenario costs and investment requirements under a range of assumptions about costs of specific technologies (Figures 1.13 and 1.14). Our analysis suggests that generation mixes with high renewables shares would be very expensive if technology costs do not reduce towards the optimistic ends of the ranges for future estimates. However, it is also plausible for generation mixes with high renewable shares to be lower cost than mixes with low renewable shares if renewable costs come down rapidly, whilst nuclear and CCS costs do not.

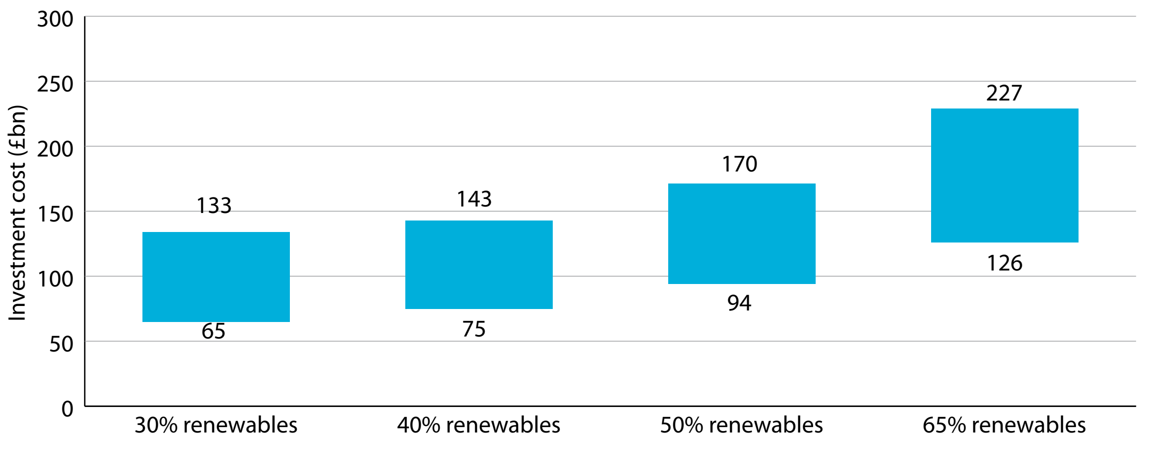
Figure 1.13: Range for average electricity generation costs in renewable generation scenarios (2030)



Source: CCC calculations, based on Mott MacDonald (2011) and Pöyry (2011).

Note(s): 2010 prices. Average cost of generation - low end of the range reflects low estimate of generation costs for all technologies; high end of the range reflects high estimate of generation costs, based on 10% discount rate. Excludes intermittency costs.

Figure 1.14: Ranges for investment requirements in power generation scenarios (2030)



Source: CCC calculations, based on Mott MacDonald (2011) and Pöyry (2011).

Note(s): 2010 prices. Investment requirement is the undiscounted capital cost (capex) of all plant added to the system in the 2020s. Low end of the range reflects low capex estimates, high end of the range reflects high capex estimates.

5. Recommendations on ambition for renewable generation

Developing renewable generation options as part of a portfolio approach

Our technical and economic analysis has identified a potentially significant contribution by renewables to required sector decarbonisation (Table 1.1):

- **Diversity.** Given current uncertainties over either the deployability or the costs of nuclear and CCS (see below), there is a value in developing other options for power sector decarbonisation. This suggests a potentially important role for renewable generation technologies.
- **Resource.** In the very long term, renewables could provide the dominant form of generation given their technical potential, lack of waste products and ultimate limitations to the alternatives.
  - There is abundant UK renewable resource, including wind, marine and solar energy.
  - Nuclear generation will not be subject to a fuel resource constraint for the next fifty years although this may become an issue in the longer term. In the medium term, availability of sites may become a binding constraint.
  - There may be a binding resource constraint in terms of CCS storage capacity in the long term.
- **Technical feasibility.** This should not be a binding constraint on the level of renewable generation where options for providing system flexibility are fully deployed.
- **Economics.**
  - Through the 2020s and 2030s a widening portfolio of low-carbon options is likely to be cost-competitive with gas-fired (and coal-fired) generation facing a carbon price at £30/tCO_2 in 2020 and £70/tCO_2 in 2030.
  - Renewable generation technologies (with the exception of onshore wind) currently appear to be relatively expensive compared to nuclear generation in 2020, but could become cost-competitive in the 2020s and 2030s.
  - The economics of CCS generation will remain highly uncertain until better information is available following demonstration.
- **UK role in technology development.** As set out in our July 2010 innovation review, the UK should support those technologies where we have a comparative advantage, and where we have the opportunity to be a leader internationally. These include offshore wind, for which the UK has a very favourable resource and a developing industry, and marine, for which the UK is in the lead in developing and demonstrating the technology and has a large share of the world's most promising deployment sites.

Table 1.1: Summary: Importance of low-carbon generation technologies in UK decarbonisation strategy

Technology	Cost at commercial (10%) discount rate (p/kWh)[31] 2020	2040	2040 cost at a social (3.5%) discount rate (p/kWh)	Importance of UK deployment for reducing costs
Unabated gas	5.0-11.0	6.0-16.5	5.5-16.0	Reference technology
Technologies that are likely to play a major role in future UK mix				
New nuclear	5.5-10.0	4.5-9.5	2.5-4.5	Equipment costs likely to be driven by global deployment, with some potential for local learning-by-doing.
Onshore wind	7.5-9.0	6.5-8.0	4.0-5.0	Technology is already well-established and is being deployed globally. UK impact on costs therefore likely to be limited.
Offshore wind	10.0-15.0	7.5-12.0	5.0-8.0	UK deployment likely to be important to reducing costs, given significant capability already established and a large share of the global market. Also a requirement for specialised local infrastructure (e.g. ports).
Technologies that could play a major role in the future UK mix, where deployment in the UK is important in developing the option				
CCS	6.0-15.0 (gas) 7.5-15.0 (coal)	5.5-14.5 (gas) 6.5-15.0 (coal)	5.0-13.5 (gas) 5.0-11.5 (coal)	UK deployment will be important alongside global efforts towards cost reductions. UK has existing strengths (e.g. in CO_2 storage and transportation, subsurface evaluation and geotechnical engineering, and in power plant efficiency and clean coal technologies) and likely to be an early deployer internationally.
Tidal stream	12.5-25.0	9.0-21.5	6.0-14.0	UK has an important role. UK companies have significant marine design/ engineering experience and already have a sizable share of device developers and patents. UK resource also a large share of the global market.
Wave	19.0—34.5	12.5-29.0	7.0-15.0	As for tidal stream, UK has an important role.
Technologies that could play a major role in the future UK mix, with limited role for UK deployment in developing the option				
Solar PV	17.5-33.0	8.0-19.5	4.5-11.0	Limited role for UK deployment (though UK does have research strength). Technology development likely to be driven by international deployment or by research in the UK that is not dependent on UK deployment.
Tidal range[32]	23.5-41.0	20.5-39.5	8.5-16.0	Limited scope for cost reductions as an established technology, and limited sites to apply any learning from early deployments.
Severn barrage[33]	21.0-31.0		7.5-11.0	

[31] Costs are for a project starting construction in that year. Estimates take into account capital, fuel and carbon price uncertainty. Additional system costs due to intermittency (e.g. back up, interconnection) are not included.
[32] CCC calculations based on Mott MacDonald's assessment of 2 GW site.
[33] Cost estimates for Severn barrage (Cardiff -Weston scheme) from DECC (2010) *Severn Tidal Power Feasibility study*. High end of costs is represented by the Feasibility Study estimate including Optimism Bias (OB), Risk Assessment (RA) and Compensatory Habitat payments. Low end includes Compensatory Habitat payments but not RA and OB.

UK practical resource[34] (i.e. potential to contribute to long-term decarbonisation)	Other considerations	Conclusion: Future role in UK mix and strategic attitude to technology development
		Limited role for building new unabated gas (or coal) beyond 2020, given rising carbon costs and availability of (lower-cost) low-carbon alternatives.
In theory could be very large. In practice may be limited by sites – 8 currently approved sites could provide over 20 GW (e.g. 175 TWh per year)[35].	Mature technology, globally deployed. Waste disposal and proliferation risks. Public attitude and safety concerns.	Given maturity and relatively low cost, likely to play a major role at least to 2050. Potential constraints and wider risks/considerations suggest it would not be prudent to plan for a low-carbon mix entirely dominated by nuclear.
Around 80 TWh per year, depending on planning constraints.	Intermittency. Possible local resistance.	Relatively low cost, therefore likely to play a significant role, within the constraints of suitable sites. Large amounts of other technologies will also be required, given limited site availability.
Very large – over 400 TWh per year.	Lower visual impact (less local resistance). Intermittency.	Promising long-term option, given large resource and potential for cost reductions. Given potential UK impact on global costs, warrants some support to 2030 to develop the option.
May be limited by availability of fuel and storage sites.	Dispatchable. Exposed to fossil fuel price risk.	Future role currently highly uncertain given early stage of technology development. Likely to be valued in a diverse mix, given different risks compared to nuclear and renewables and potential to operate at mid-merit, given lower capital intensity.
Potentially large – 18 to 200 TWh per year.	Intermittency (with possible benefits in wind-dominated mix).	Currently at an early stage therefore will have a limited role in the period to 2020. Important role for UK globally in developing the option to 2030. Given potentially large resource and scope for cost reduction, could play significant role as part of a diverse mix in 2030 and beyond.
Limited – around 40 TWh per year.	Intermittency (with possible benefits in wind-dominated mix).	Currently at an early stage therefore will have a limited role in the period to 2020. Important role for UK globally in developing the option to 2030. Given scope for cost reduction, could play role as part of a diverse mix in 2030 and beyond, but limited by practical resource.
Large – around 140 TWh per year (on the basis of current technology) with more possible with technology breakthroughs.	Intermittency (with possible benefits in wind-dominated mix).	Given current high costs and limited UK impact on global costs, role in the short term (i.e. to 2020) should be limited. Option to buy in from overseas later, and to have a major role in the longer term (subject to significant cost reductions).
Limited – around 40 TWh per year (of which almost a half from the Severn).	Intermittency (with possible benefits in wind-dominated mix).	Given limited opportunities to reduce costs with deployment, should not be pursued where sufficient lower-cost options are available. Should be triggered as an option if relative costs improve or if there are tight constraints on roll-out of lower-cost technologies (e.g. wind, nuclear).

[34] See Chapter 1, section 2. Numbers here are considered 'practical' resource, i.e. taking into account environmental and proximity constraints.

[35] 175 TWh per year in 2030 would require 22 GW, including all current developer plans for 7 sites (18 GW), existing plant expected still to be in operation (1.2 GW) and 2 more reactors (3.2 GW) at the remaining site, or additional at the other 7 sites.

The implication of our economic and technical analysis is that energy and technology policy approaches should promote competition between the more mature low-carbon technologies, while providing support for technologies that are currently more expensive but with a potentially important long-term role. Support is required for technologies at the early deployment phase (e.g. offshore wind) and those at the demonstration phase (e.g. tidal stream and wave). This conclusion, which is also borne out in modelling carried out for us by the Energy Technologies Institute (Box 1.14), raises questions about whether and what ambition for renewables in the 2020s it is appropriate to commit to now.

Box 1.14: Energy Technologies Institute energy system modelling for the Committee

The Energy Technologies Institute (ETI), a collaboration between Government and six private companies, has developed its Energy System Modelling Environment (ESME), a peer-reviewed energy system model, to look at the possible evolution of a low-carbon energy system out to 2050. The ETI undertook some runs for the Committee, using a dataset of future technology costs and performance that included contributions from the Carbon Trust, the ETI itself and the outputs of the Mott MacDonald cost work (outlined earlier in section 3).

ESME uses ranges and distributions for key input parameters, rather than simple point estimates. The model undertakes many (e.g. 2,000) runs, each of which samples from these distributions and performs an optimisation to meet energy service demands at least cost, while meeting specified limits on CO_2 emissions. Rather than producing a single set of results, the model then produces distributions, for example on the deployment levels of each low-carbon technology.

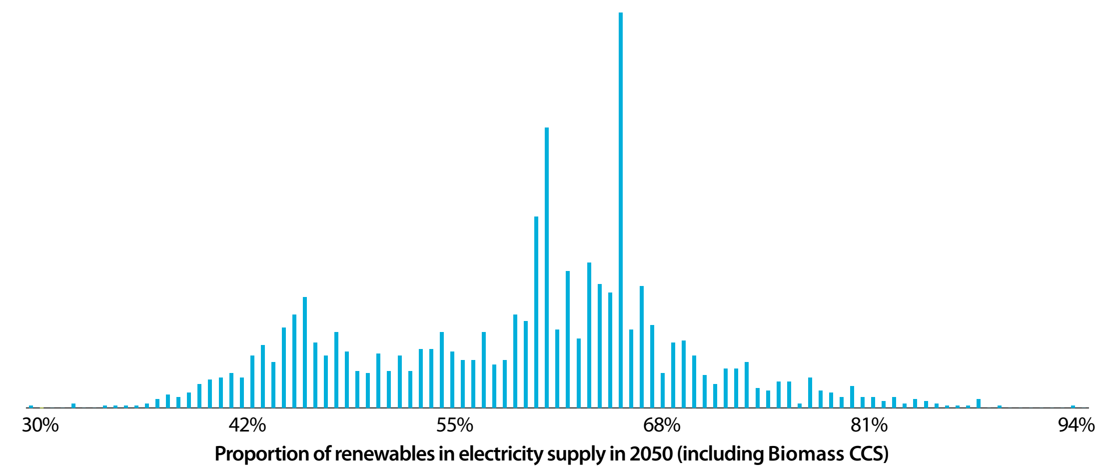
We undertook runs for 2050, and in each of these years variants were also modelled in which nuclear and/or CCS were made unavailable. The key parameters on which we placed uncertainty within these simulations – each of which contained 2,000 runs – are:

- **Technology costs, efficiency and availability:** the ranges for technology capital costs and either efficiency (for thermal plants) or availability (for intermittent renewables) were taken from the Mott MacDonald work, with a uniform distribution assumed.
- **Fossil fuel prices:** we assumed a uniform distribution of fossil fuel prices between DECC's lowest and highest scenarios (for oil this is \$63 to \$158 per barrel in real 2010 terms).
- **Bioenergy availability:** we specified a range of 100-300 TWh of available bioenergy, again with a uniform distribution. This range encompasses the resource of 260 TWh assumed for the CCC's fourth carbon budget analysis.

The scope of emissions covered in this modelling excludes non-CO_2 emissions and those from international aviation and shipping. Consequently, we have imposed a reduction target of 90% versus 1990 levels for the energy sector, due to the expected difficulties in reducing emissions by 80% in those other sectors (as laid out in our 2010 fourth budget report).

The results of this modelling show that the least-cost mix of low-carbon technologies in the power sector in 2050 is highly uncertain. For example, in the simulation with both nuclear and CCS available the preferred renewables share ranged from 30% to 94%, although most solutions were in the range of 40% to 70% (Figure B1.14).

Figure B1.14: ETI modelling results for the proportion of renewables within a least-cost power system (2050)



Source: Modelling by the Energy Technologies Institute for the CCC.

Note(s): Biomass CCS power generation is included in the renewables category here; its average contribution across these 2,000 runs is 8.5% of power generation.

Committing now to technology support in the 2020s

The likely scale of investment in the less mature renewable technologies (e.g. offshore wind, tidal stream, wave) during the 2020s is very uncertain. This reflects their currently high costs, and the current lack of policy commitment to providing support for new investments beyond 2020.

This uncertainty would be resolved by committing now to a minimum level of deployment or support in the 2020s. This would underpin required supply chain investment over the next decade.

A decision on whether to go beyond a minimum commitment, including a decision on the possible contribution from a Severn barrage project, could be taken when better information is available on relative costs and any barriers to deployment (e.g. in 2017/18, when there will be more confidence about costs and performance of offshore wind, marine, nuclear and CCS).

The minimum commitment should also hold only if supply chain investment envisaged to 2020 is delivered in practice.

In order to provide investor confidence, technology support should be provided through firm commitments, to be implemented through new electricity market arrangements (Chapter 2).

An illustrative scenario for technology support

In determining the appropriate level of any such commitment the relevant factors are the level of supply chain investment required, the degree of commitment required to support this investment, and the need to keep the impact on electricity bills at an acceptable level.

The 40% (185 TWh/year) renewable penetration scenario set out above best illustrates the kind of commitments on offshore wind and marine that might be made.

In practice, the precise renewables share (including any contribution from other renewables, e.g. solar PV and geothermal) will be determined through a combination of technology support for those currently more expensive technologies, and competition between more mature renewable technologies and other low-carbon alternatives, to be implemented through new electricity market arrangements.

We now turn to development of renewables as an option within a portfolio of technology options in the period to 2020, focusing on the level of ambition and the supporting framework to deliver this ambition.

Chapter 2

Developing options for renewable electricity

1. The level of renewable generation ambition to 2020
2. Financing of renewable projects
3. Addressing non-financial risks: planning and transmission

Introduction and key messages

Our conclusion in Chapter 1 was that promising renewables should be developed as part of a portfolio approach to power sector decarbonisation. We presented an illustrative scenario that reached a 40% renewables share in 2030 (185 TWh) and took the 2020 level of ambition as a given. We assumed a renewables share of around 30% in total generation in 2020, in line with our forward indicator framework and the Government's Renewable Energy Strategy.

We start this chapter by revisiting ambition for 2020[1], focusing within this on the level of offshore wind ambition. Specifically, we consider cost and electricity price impacts associated with current ambition, possible reductions in price impacts through adjusting ambition, and other options for meeting the UK's 15% renewable energy target under the EU's Renewable Energy Directive.

We then consider a range of enabling factors for delivering significantly increased renewable generation over the next decade including:

- Design of new electricity market arrangements to support ongoing investment in renewable generation.
- Possible financing constraints and means by which these could be addressed.
- Alternative approaches to planning approval for investments in generation and transmission.
- Investments required in the transmission grid, and any further actions as regards network access pricing.

The key messages in the chapter are:

- If renewable energy targets for 2020 can be met in other ways, a moderation of offshore wind ambition for 2020 would reduce the costs of decarbonisation. Ambition for offshore wind to 2020 should not be increased unless there is clear evidence of cost reduction.
  - The current level of ambition for 2020 could be more than required to stimulate innovation and drive offshore wind down the cost curve.
  - Given relatively high costs, some of the ambition to 2020 might then be reallocated to the 2020s.
  - However, current ambition is appropriate in the context of meeting the UK's legally-binding 2020 renewable energy target; it will add of the order 5% to household electricity bills (2% to household energy bills) in 2020.
  - A flexible approach should be adopted. This would retain the possibility to adjust ambition as uncertainties are resolved around potentially lower-cost alternatives for meeting the renewable energy target (e.g. onshore wind, imports, renewable heat).
  - Safeguards should also be introduced to prevent escalation of offshore wind ambition unless there is clear evidence of significant cost reduction.

[1] Our assessment in this chapter is in line with the recommendations set out in a letter to the Secretary of State for Energy and Climate Change in September 2010, available at www.theccc.org.uk.

- New electricity market arrangements should incorporate the possibility of additional support for less mature technologies in order to develop a portfolio for decarbonisation in the second half of the 2020s and beyond.
- Notwithstanding new electricity market arrangements, there is a potentially important role for the Green Investment Bank (GIB) in financing offshore wind projects. Unless it can be demonstrated that risks of a shortage of finance to 2015/16 can be mitigated, allowing the GIB to borrow money from its inception should be seriously considered.
- Planning approaches should facilitate investments in transmission that are required to support investments in renewable and other low-carbon generation. In addition, a planning approach which facilitates significant onshore wind investment would reduce the costs of meeting the 2020 renewable energy target, and of achieving power sector decarbonisation through the 2020s.

We set out the analysis that underpins these messages in three sections:

1. The level of renewable generation ambition to 2020
2. Financing of renewable projects
3. Addressing non-financial risks: planning and transmission

1. The level of renewable generation ambition to 2020

Overview of ambition to 2020

We have previously assessed the feasible and desirable level of renewable generation ambition to 2020. This is reflected in the power generation scenario to 2020 underpinning our indicators of progress in meeting carbon budgets. The ambition for specific renewable technologies in this scenario is in line with the Government's Renewable Energy Strategy, which includes 15 GW of onshore wind and 13 GW of offshore wind on the system in 2020, together with 2.3 GW of biomass capacity and 1.3 GW of marine technologies[2].

Since first presenting this scenario, projected costs for onshore and offshore wind, and other generating technologies, have increased significantly. In addition, we have raised questions about the level of sustainable biomass available for use in power rather than other sectors where alternative abatement options are limited.

Our assessment of costs in Chapter 1 suggests that onshore wind is likely to be competitive in 2020, and raises a question about whether the level of ambition to 2020 should be increased.

Our overall assessment in Chapter 1 was that offshore wind should be developed as an option within a portfolio approach to power sector decarbonisation.

However, the increase in projected costs of offshore wind (which is now expected to be significantly more expensive than new-build gas-fired generation including a carbon price in 2020) raises a question about the cost and price implications of adding 12 GW of offshore wind to the system from 2010-2020, and whether the level of ambition could be reduced without undermining required technology innovation.

We now assess those costs and alternative options for delivering the EU renewable energy target in 2020, and conclude that, whilst a flexible approach is appropriate, the 2020 ambition for offshore wind should not be reduced at this point.

Cost implications of investing in offshore wind

Offshore wind cost penalty

The investment costs associated with adding 12 GW of offshore wind to the system are around £30 billion (compared to, e.g., £100 billion investment cost for the 33 GW total resource potential of all sites in Rounds 1, 2 and 3).

The cost penalty on consumer bills to 2020 will be lower than this investment cost, given that once investments have been made, the running costs of offshore wind are very low. This is allowed for in a comparison of levelised costs, suggesting around 6.5 p/kWh penalty for offshore wind in 2020 (versus unabated gas with a carbon price on central assumptions), falling through the 2020s as the carbon price increases.

[2] This is very close to the level of ambition built into the Committee's indicator framework, which is an indicative trajectory that is suitable for planning and monitoring purposes and should be kept under review.

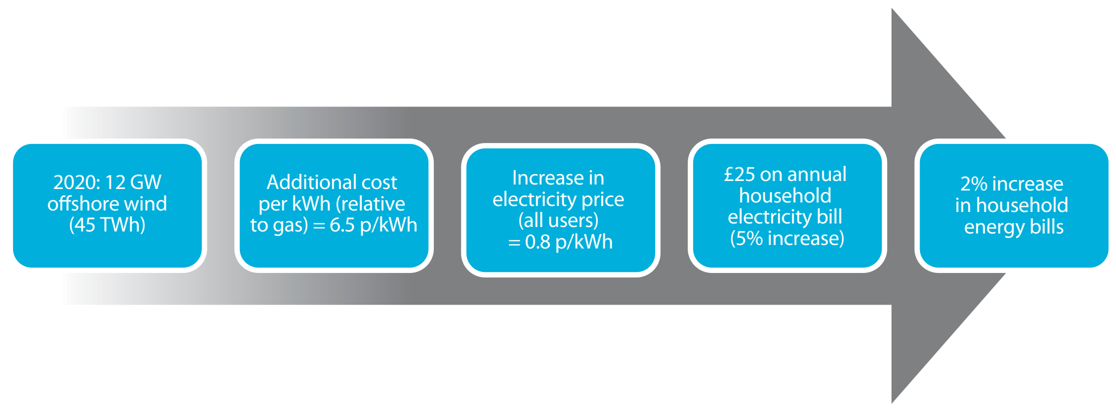
There is a lower cost penalty for onshore wind (as reflected in the current subsidy payment for offshore wind of 2 ROCs per MWh, compared to 1 ROC for onshore wind). Increasing onshore wind ambition would require that society (and specific communities) accept greater landscape impact in return for slightly reduced electricity bills.

Offshore wind bill impacts

We estimate that the additional household energy bill increase due to adding offshore wind rather than unabated gas under rising fuel and carbon prices is around 2% (Figure 2.1):

- We estimate that over the next decade, offshore wind will be around 6-7 p/kWh more expensive than new unabated gas facing a carbon price (central assumptions, reaching £30/tCO_2 in 2020)[3]. Uplifting the electricity price to cover this cost penalty for the 45 TWh from offshore wind (12% of generation in 2020) suggests an increase of around 0.8 p/kWh or just over 10% on the wholesale electricity price in 2020, against what it would otherwise have been.
- A 0.8 p/kWh increase in the wholesale electricity price would result in around a 5% increase in household electricity bills in 2020 (i.e. an increase of around £25 per year).
- A 5% increase in electricity bills implies a 2% increase in household energy bills (as electricity accounts for around 40% of total energy bills on average).

Figure 2.1: Price and bill impacts of offshore wind ambition, 2020



Source: CCC calculations based on cost estimates by Mott MacDonald; DECC *Quarterly Energy Prices.*

Note(s): Based on central assumptions, offshore wind average cost 13.5 p/kWh displacing a mixture of new and existing gas. Average annual consumption 3,300 kWh per household.

[3] Gas CCGT estimate based on central fuel and carbon prices (around 6-7 p/kWh) compared with 13-14 p/kWh for offshore wind – see Chapter 1.

Possible adjustments in offshore wind ambition

In making a judgement about whether this impact is acceptable, or whether a slightly lower level of ambition is appropriate, a number of factors are relevant:

- Whether a lower level of ambition would support technology innovation.
- Required supply chain expansion to provide an option for decarbonisation beyond 2020 and the need to provide a steady, predictable environment to support this.
- Whether there are alternative means to meet the UK's legally-binding obligations under the EU's renewable energy target. Options where there may be additional potential are onshore wind (e.g. in section 3 we consider opportunities to increase ambition through higher planning approval rates or more favourable transmission charging), imported Concentrated Solar Power (see Chapter 1), and the purchase of Renewable Energy Certificates in the European market (Box 2.1). There may also be further potential from renewable heat (see Chapter 3).
- The net cost saving allowing for costs of increasing effort in other technologies.

Box 2.1: Potential to supplement domestic renewable deployment with international effort

The Renewable Energy Directive allows for Member States to meet their national renewable energy targets through a number of flexibility and cooperation mechanisms:

- **Statistical transfers.**
  - A virtual transfer of renewable energy produced in one Member State to another, as occurs for EU Emissions Trading System allowances (EUAs) currently.
- **Joint projects.**
  - A Member State may finance a project in other countries, and count part of the energy (renewable electricity or heat, not fuel) produced towards its own national target.
  - Joint projects can be between Member States and third/non-member countries. The latter involves physical imports of renewable energy from outside the EU that meet specific criteria to qualify as contributing towards national targets. For example, electricity produced must be generated by a newly constructed installation that began operation after the Directive was introduced, or from one that was refurbished and had its capacity increased after the Directive entered into force.

Renewable Energy Certificates (RECs) specify the source of renewable energy production, and the date and place at which this occurred; these are proof that energy was produced from sources in line with the Directive. Member States must ensure a REC is issued on request in respect of any energy generated from renewable energy sources.

Given the very aggressive pace of investment to 2020 under the Government's plans, ideally this would be smoothed in the context of a 2030 commitment (i.e. by reducing ambition to 2020 to reduce costs, whilst committing to further investment in the 2020s given the long-term importance of offshore wind). The target would then be met through increased contributions from the other options (onshore wind, renewable heat, etc).

Therefore, if evidence emerges that other, lower-cost, options can be delivered at higher levels than currently envisaged, the offshore wind ambition for 2020 could be slightly reduced, even while stretching ambitions for 2030 are maintained.

The level of 2020 offshore wind ambition should not be increased unless there is clear evidence of significant cost reduction. Increasing ambition would adversely impact consumers without any clear offsetting benefits in terms of technology innovation. Support mechanisms – the Renewables Obligation (RO) and new electricity market arrangements – should be designed to avoid unintended escalation in ambition. We discuss this in more detail in section 2.

Biomass ambition

In our advice on the fourth carbon budget we raised the question of whether we should be planning for use of biomass in power generation:

- It is likely that there will be tight limits on land available for growth of biomass feedstocks given the need to feed a significantly growing and increasingly wealthy global population over the next four decades. The implication is that there will be limits on the level of sustainable bioenergy available.
- There are questions over the lifecycle emissions associated with biomass production.
- There is a range of alternatives available for decarbonisation of the power sector (i.e. other renewables, nuclear, fossil fuel CCS).
- There are limited options apart from bioenergy for reducing emissions in other key sectors (e.g. industrial heat; biofuels for aviation and HGVs, and possibly for plug-in hybrid vehicles to the extent that the range of battery electric vehicles remains constrained).

Our preliminary conclusion was that, without CCS, biomass would probably be of more value when used outside the power sector; with CCS, use in the power sector may be more attractive.

In the context of the 2020 renewables target, biomass used in the power sector will contribute less towards meeting the target than if it were used in the heat sector (because of the way the target is defined, on a 'final energy' basis[4]).

However, where there is limited near-term scope for use in heat, biomass in the power sector could help build supply chains in sustainable bioenergy production, which could later be redirected to other sectors.

Given the above, there are three implications for the strategic approach over the next decade:

- Where possible, it is likely to be preferable to use biomass resources in the heat sector, both in terms of the relative contribution towards the 2020 renewables energy target and consistency with the longer-term path for economy-wide decarbonisation.
- To the extent that biomass resource is available to the UK power sector on the 2020 timescale (e.g. because of constraints in deployment of bioenergy heat options), this should be used in ways that avoid locking a large part of the resource into power generation for the longer term (i.e. focused towards co-firing in existing coal plants or new biomass generating capacity designed to operate flexibly in a back-up or 'mid-merit' role rather than at baseload).
- Any long-lived biomass generating capacity designed to operate at baseload and added before CCS has been proven should be designed to allow CCS retrofit. Given current uncertainties over viability of CCS, a cautious approach under which there is limited investment in biomass assets would be appropriate.

We will set out a more detailed assessment of biomass power generation as part of our broader review of bioenergy to be published later in 2011.

Marine ambition

The National Renewable Energy Action Plan[5] includes investment in 1.3 GW of wave and tidal stream technologies by 2020, which is likely to be very stretching from current low levels (around 2 MW).

There is merit in the UK supporting demonstration and deployment of marine technologies:

- Our assessment of costs suggests that, by 2040, tidal stream and possibly wave could offer a cost-effective alternative to offshore wind.
- Pöyry's intermittency analysis suggests that marine could usefully add diversity to the generation mix (Chapter 1).
- Our 2010 innovation review found that the UK has an important role to play in developing marine technologies for both domestic and global markets.

Although some support is currently available, more is likely to be required over the next decade in order to support development of marine technologies. Current support offered under the ROC regime in England and Wales is insufficient to cover likely costs (marine generation earns 2 ROCs/MWh, equivalent to a subsidy of around 8-10 p/kWh, compared to a cost penalty to 2020 estimated at 10-24 p/kWh in Chapter 1).

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4 The target under the Renewable Energy Directive is measured on a final energy basis, which means that it aggregates the total energy consumed in a useful form, such as electricity or useful heat energy. Because the conversion efficiency of biomass used in heat generation (e.g. 70-85%) is considerably higher than that of electricity generation (e.g. 30-40%), a given amount of biomass resource can contribute more final energy as heat than it can as power.

5 DECC (2010) *UK National Renewable Energy Action Plan* (NREAP).

Therefore we recommend that further support should be provided through the ROC regime or under the new electricity market arrangements. Further R&D funding should also be considered in the context of the next spending review, given the early stage of marine technologies.

Microgeneration ambition

In considering appropriate ambition for microgeneration and small-scale renewables (i.e. sub 5 MW), there are two key factors:

- Micro and small-scale power is relatively expensive compared to larger-scale low-carbon technologies. Based on the feed-in tariff (FIT) levels that came into effect in April 2010[6]:
  - Micro wind generation costs up to 35 p/kWh for systems below 1.5 kW (e.g. compared to around 9 p/kWh for larger-scale onshore wind generation), with limited scope for significant cost reduction.
  - Solar PV currently costs around 35-40 p/kWh for installations up to 10 kW, and around 30 p/kWh for installations between 10 kW and up to 5,000 kW. Although there is significant scope for cost reduction, there is still a high degree of uncertainty over when it will become commercially viable in the UK (see Chapter 1).
  - Given the Government's current ambition to incentivise around 2.7 TWh per year of additional generation from micro and small-scale generation by 2020 (of which 1.6 TWh is solar PV), support for these technologies under the FIT scheme (Box 2.2) could add around 0.1 p/kWh to household bills in 2020 (around £4 per year).
- There is significant effort globally to reduce solar PV costs, including deployment in countries with more advantageous levels of insolation, with limited scope for the UK to influence the pace of cost reduction.

This suggests an appropriate strategy for the UK would be to monitor closely the results of solar PV support in other countries, and to buy in this technology at a later stage depending on cost reductions achieved.

Given the current high costs, it is appropriate that solar PV, and microgeneration more generally, makes only a very limited contribution to achieving the UK's 2020 renewable energy target. Significantly increasing ambition for microgeneration technologies would escalate associated costs considerably, with little in terms of offsetting benefits in technology innovation.

[6] We note at the time of writing that the Government is consulting on the tariff rates for installations above 50 kW.

Box 2.2: Current approach to microgeneration support

Introduced in April 2010, feed-in tariffs (FITs) give installers of small-scale electricity generation a payment for each unit (kWh) of energy generated. This varies depending on technology type, scale and year of installation. Current tariffs range from 4.5 p/kWh (for 2-5 MW hydro schemes) to 41.3 p/kWh (for small <4 kW retrofit PV). FITs also provide generators with a payment for energy exported to the grid, currently set at a flat rate of 3 p/kWh across all technologies and scales.

In March 2011, the Government published a consultation on the tariff levels for large PV installations (>50 kW), proposing up to a 70% reduction on the initial rates. In addition, the consultation proposed to increase tariffs for farm-scale Anaerobic Digestion (AD) installations, increasing them by up to around 20%.

2. Financing of renewable projects

Given a level of ambition, financial incentives will be required in order that investments are delivered. Those incentives are currently provided under the Renewable Obligation Certificate regime, although this is to be replaced by new electricity market arrangements aimed at supporting all low-carbon generation technologies (i.e. renewable and other) expected to start in 2013/14. There will be a transition period (proposed to run until 2017), during which both old and new arrangements may be available. Under both mechanisms there remains a question of whether sufficient investment finance will be forthcoming given possible limits on available equity and debt.

We now consider these points in turn:

i) The Renewable Obligation Certificate regime

ii) The new electricity market arrangements

iii) The role for a Green Investment Bank

i) The Renewable Obligation Certificate regime

Design of the scheme

Currently investment in renewable electricity generation is supported by the Renewable Obligation Certificate regime, under which electricity suppliers are required to purchase renewable generation at a level set by the Government:

- Suppliers are required to surrender Renewable Obligation Certificates (ROCs) at a level consistent with increasing shares for renewables to 2020 (e.g. the target for 2011/12 is that 12.4% of electricity supplied should come from renewable sources, rising to 15.4% by 2015/16).
- Developers of renewable generation receive income from those ROCs on top of any earnings in the wholesale electricity market.
- In the event that there are insufficient ROCs available, suppliers may instead pay a buy-out price set by the Government, with the revenue recycled to renewable generators. Therefore when ROCs are in short supply, the buy-out price (along with any recycling) determines the value of a ROC. Where the level of ROCs available is commensurate with the target, the ROC value is determined by the underlying costs of renewable technologies.
- To ensure ROC price stability, in 2009 the Government introduced the headroom mechanism, to allow the target to increase and thereby prevent the price crashing and undermining investment incentives if the expected amount of generation exceeds the fixed target.

Current and future support

Current levels of support provided by the ROC regime range from around 1.2 p/kWh to 24 p/kWh depending on the technology and ROC price; multiple ROCs are issued for each unit of generation from earlier-stage technologies, recognising that these have higher costs (Table 2.1).

Table 2.1: Renewables obligation: levels of ROC support by technology

Generation type	ROCs/MWh	Implied subsidy on top of wholesale price (p/kWh)
Landfill gas	0.25	1.2
Sewage gas, co-firing of biomass	0.5	2.4
Hydro, onshore wind, geopressure, energy from waste with CHP, pre-banded gasification, pre-banded pyrolysis, standard gasification, standard pyrolysis, co-firing of energy crops, co-firing of biomass with CHP	1	4.8
Offshore wind, co-firing of energy crop with CHP, dedicated biomass	1.5	7.2
Wave, tidal stream, tidal barrage, tidal lagoon, solar PV, geothermal, advanced gasification, advanced pyrolysis, anaerobic digestion, dedicated energy crops, dedicated biomass with CHP, dedicated energy crops with CHP	2	9.6
Tidal stream (Scotland)	3	14.4
Wave (Scotland)	5	24.0

Source: DECC (2010) *UK National Renewable Energy Action Plan* (NREAP); CCC calculations.

Note(s): Implied subsidy assuming ROC price of £48/MWh (4.8 p/kWh) (average price in 2010). Small-scale hydro below 1 MW receives increased support in Northern Ireland varying from 4 ROCs to 2 ROCs according to scale. Small-scale onshore wind 250 kW or below in Northern Ireland receives 4 ROCs per MWh. Offshore wind receives 2 ROCs subject to meeting specific criteria from 1 April 2010. Small-scale PV 50 kW or below in Northern Ireland receives 4 ROCs per MWh.

DECC is currently considering ROC banding (i.e. levels of support for each renewable generation technology) for the period 2013/14 onwards, and will announce the bands for the new period in autumn 2011.

- The key issue for the banding review will be to determine where within the range of costs and electricity price assumptions (and within this gas and carbon price assumptions) ROC buy-out price and multiples are set, trading off risks of under-investment against risks of high electricity prices.
- A specific issue is whether the RO or successor arrangements (see section ii below) include the possible import of Concentrated Solar Power (or other renewables).
  - Given the possibility of cost-effective imports as early as 2016 (see Chapter 1), this is something which should be seriously considered, both in terms of a contribution at the margin to meeting the 2020 renewables target and to sector decarbonisation beyond 2020.

– In considering ROCs for imported resources, it will be important to ensure additionality is tightly controlled (i.e. it should be clear that UK subsidies are leading to greater deployment than would otherwise occur, and opportunities in the resource's home market are not crowded out) and to assess technology innovation benefits compared to deployment of UK renewables.

Limiting electricity price impact of ROCs

Another crucial aspect of the ROC regime is the level of ambition which this embodies. Currently, ambition is a moving target which increases with the expected level of renewable generation (through the headroom mechanism).

However, continuation of a target designed to maintain headroom raises the risks that there could be significantly more investment than is required to drive technology innovation and at high cost to consumers. Based on our analysis in section 1 above, for example, if all offshore Round 3 sites were to be deployed by 2020 (33 GW, 115 TWh), this would add a further 13% to residential electricity bills, i.e. £70 per household, per year.

In order to prevent such a situation, the level of targeted ambition should be fixed (e.g. such that no more than 13 GW offshore wind capacity is subsidised by 2020). Upward departure from this level of ambition could only be justified if the costs of offshore wind were to be significantly lower, reflected in a correspondingly lower level of support (i.e. significantly less than 2 ROCs).

ii) The new electricity market arrangements

There is current uncertainty about the extent to which the Renewables Obligation will deliver investment in renewables to 2020, or whether this will be superseded by new electricity market arrangements (e.g. the Government has proposed in its consultation on Electricity Market Reform (EMR) that the ROC regime will only apply for capacity coming on to the system to 2017). These new arrangements will determine the level of renewable generation ambition to 2020, and ongoing ambition through the 2020s.

Background on the EMR

In our reports to Parliament and our advice on the fourth carbon budget[7], we have suggested that current electricity market arrangements are unlikely to support required investment in low-carbon capacity, and that new arrangements based on long-term contracts would best deliver a decarbonised system:

- Given the combination of fluctuating gas and carbon prices and therefore electricity prices, the incentives under current arrangements are to invest in (unabated) gas-fired rather than low-carbon capacity.
- The optimal risk allocation requires insuring generators from exogenous risks (gas price, carbon price, etc.), but leaving them with construction and operation risks, through providing long-term contracts.

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[7] CCC (2010) *The Fourth Carbon Budget: Reducing emissions through the 2020s.*

The Government accepted our advice and proposed a new system of long-term contracts to support investment in low-carbon capacity; these have the potential to provide adequate support for renewables subject to caveats about specific contract design (e.g. the price index in the contract should reflect the actual wholesale market price – see Box 2.3), and subject to there being a technology policy element to the new arrangements.

Box 2.3: Contracts for Difference and their application to renewable generation

The Government's consultation on electricity market reform[8] proposed a 'contract for difference' (CfD) model for low-carbon generation to provide stable and certain returns.

- The CfD would be a long-term contract with an agreed tariff level. It requires generators to sell their output into the wholesale electricity market. The Government then provides a top-up payment equal to the difference between the tariff level and a market price index.
- The CfD is intended to provide similar revenue certainty to a standard feed-in tariff (FIT), whilst preserving incentives for generators to be available when prices are high.

A detailed design issue that has not yet been determined is the choice of market price index (e.g. it could be an index of average price over a year, a month, a day, or even an hour-to-hour spot price).

CfDs for renewable generators

The choice of index will be important for intermittent renewable generators (e.g. wind, marine) since they are not able to control when they are available to generate. For an index with a long base period (e.g. a year) these generators face the risk that their capture price (the average price they receive when generating) is below the average in the index. Since the top-up payment is based on the index, this would take their total return to below the agreed tariff level.

Therefore for new arrangements to provide revenue security to intermittent renewable generators they would need access to a CfD based on a short-term index of the wholesale market price (e.g. based on an hour or a day). A longer index could present a major barrier to accessing finance without yielding a significant efficiency benefit, given limited opportunities for intermittent generation to respond to short-term fluctuations in market price.

Biomass operators face a different risk – that the fuel price for their feedstock is uncertain, which may require some sharing of fuel price risk in CfDs (as we have previously identified for gas CCS)[9].

8 DECC (2010) *Electricity Market Reform Consultation Document*.
9 In our March 2011 letter to the DECC Secretary of State in response to the consultation, available at www.theccc.org.uk.

Technology policy support for renewables under new electricity market arrangements

Ideally these arrangements would be technology-neutral, with the range of low-carbon technologies bidding against each other for contracts. However, in practice this will not be feasible for the foreseeable future given different stages of maturity for low-carbon generation technologies.

Therefore new arrangements should be designed to develop a portfolio of low-carbon technologies through providing additional support for those promising technologies at an earlier stage of development.

For example, the minimum commitments recommended above could be implemented through reserving some of the available contracts for less mature renewable technologies, subject to conditions on cost reduction being met.

More mature renewable technologies (i.e. onshore wind and hydro) would then compete with other mature low-carbon technologies (i.e. nuclear) for contracts, in order to bring about a least-cost investment programme for sector decarbonisation, subject to any considerations around diversity of the generation mix (e.g. it may be appropriate to pay more for a diverse mix with lower security of supply risk).

The expectation is that the less mature technologies that would at first need support (e.g. offshore wind, marine and CCS) would ultimately also be able to compete for contracts without additional support.

Managing the transition

Although it would be possible to design new electricity market arrangements based on Contracts for Difference in a way that would support investment in renewables, there is a risk of investment hiatus in moving away from the Renewables Obligation.

In managing the transition to avoid a hiatus, there are two key challenges:

- **Ensuring investment under the Renewables Obligation** continues, given additional electricity price uncertainty associated with new arrangements (i.e. new arrangements, and the investments that will follow, may mean wholesale prices are lower and more volatile than would previously have been expected). This could require paying a higher ROC premium or grandfathering both ROCs and electricity prices (i.e. effectively paying a feed in tariff to capacity secured under the RO).
- **Ensuring sufficient overlap between the two sets of arrangements.** The risk is that under the current proposal, projects to come on the system after 2017 will have to be developed in a context where there is a lack of clarity over the detailed support arrangements. This could be addressed by prompt design and implementation of the new arrangements, or by extending the RO beyond the date proposed in the EMR consultation.

It will be important that these challenges are addressed in order that there continues to be a sufficient pipeline of projects under development, both to meet the 2020 renewable energy target and to support required sector decarbonisation through the 2020s.

iii) The role for a Green Investment Bank

The new electricity market arrangements are aimed at addressing revenue risks for investments in low-carbon generation, and could also address cost risk depending on whether proposed Contracts for Difference include any risk sharing.

Although the new arrangements should result in an improved investment climate, it is not clear that this will be sufficient to mobilise the very large amounts of finance required for investments to 2020 and beyond, and possible constraints on available equity and debt funding:

- **The investment challenge.**
  - Investment costs[10] (generation only) associated with our scenario to 2020 are of the order £75 billion, of which offshore wind investment costs are around £30 billion.
  - We estimated in our fourth budget report that delivering power sector decarbonisation through the 2020s will require an additional £100 billion.
- **Equity**.
  - It is highly unlikely that UK energy utilities currently have sufficient balance sheet strength to support this level of investment on a corporate finance basis. For example, annual investment in electricity generation assets by UK energy companies over 2007-2010 was around £3-5 billion a year.
  - There is limited appetite for raising new capital, particularly given concerns over credit ratings, and risks associated with renewables projects (e.g. there remains considerable uncertainty over costs and performance of offshore wind).
  - However, it is possible that utilities and independents together could provide required equity finance within a project finance structure.
- **Debt**.
  - There is very limited debt available for project finance of renewables investments.
  - For example, up to the start of 2011 no offshore projects had secured project finance for the construction phase.
  - Although increased appetite in the future cannot be ruled out, this is highly uncertain, particularly given the need for banks to increase capital under new regulatory arrangements, and given risk ratings of renewable projects.

[10] Investment cost is the undiscounted capital cost in real terms of generation capacity added to the system in the 2010s.

Given these possible constraints, a Green Investment Bank could complement available private finance, providing comfort around evolving market arrangements and acting as an additional source of capital for sharing risk. It could catalyse deals through offering a range of financial instruments to different investors and potential investors:

- **Insurance products**, aimed at addressing risks associated with uncertainties in construction cost, maintenance cost and performance, therefore supporting mobilisation of equity and debt financing.
- **Straight equity financing.** If further evidence suggests that sector cash flows are currently insufficient relative to required equity contributions within a project finance structure, and that there are barriers for energy companies in accessing additional equity, a Green Investment Bank could aim to leverage its capitalisation through establishing an equity investment fund.
- **Debt financing**, for example, based on leveraging through money raised from institutional investors, and/or the Green Investment Bank leading on syndication of debt finance. A Green Investment Bank might also act as an intermediary buying and selling completed projects, possibly in conjunction with insurance products (see above), therefore freeing up balance sheets of utilities to support further investment.

A Green Investment Bank operating as a bank rather than a fund, in line with the announcement in the March 2011 Budget, would have the flexibility to provide the full range of financing instruments and therefore make best use of Government capital.

However, as currently proposed the bank would only be able to raise money from 2015/16. This is potentially problematic given that the period before 2015/16 is an important window of opportunity for the Green Investment Bank:

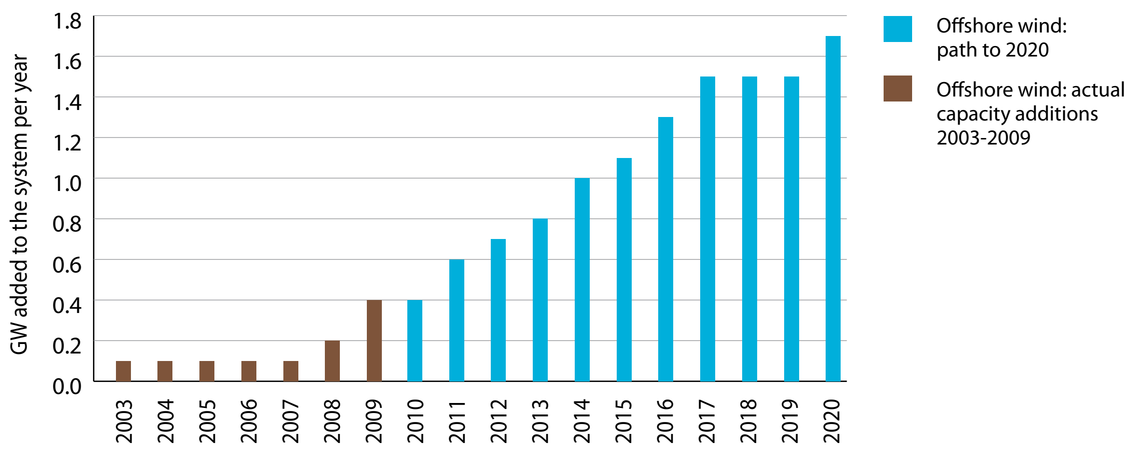
- In order to meet the 2020 target, financial close on around 6 GW of offshore wind projects with investment costs of around £18 billion will be required prior to 2015/16.
- It is likely that there will be uncertainties over market arrangements and offshore wind costs and performance, along with constraints on energy company balance sheets through this period.
- Given uncertainties and constraints, it is not clear that there will be corporate finance and syndicated project finance at levels consistent with ambition to 2020.

Therefore unless it can be demonstrated that this risk is mitigated, allowing the Green Investment Bank to borrow money from its inception should be seriously considered.

3. Addressing non-financial risks: planning and transmission

In addition to financial barriers to delivering 2020 ambition, there are also non-financial barriers related to planning and transmission access. For example, financial incentives will be irrelevant for projects that are unable to gain planning approval or access to the transmission network. These aspects will have to be addressed if projects are to proceed, and if the step change in the pace of adding capacity to the system is to be achieved (Figure 2.2).

Figure 2.2: Offshore wind capacity added to the system, 2003-2009 and required to 2020



Source: DECC (2010) *DUKES* for capacity added to 2009; DECC (2010) *UK National Renewable Energy Action Plan* for capacity added 2010 to 2020.

We now consider each of these aspects in the period to 2020 and beyond.

i) The crucial importance of planning in supporting renewables investments

Current and required planning approvals for generation investments

Our lead scenario for power sector investment to 2020 includes addition of 11 GW of onshore wind (15 GW in total) and 12 GW of offshore wind (13 GW in total) in the decade from 2010.

In considering risks to delivery of these investments, it is important to note the historically low rate of planning approval for onshore wind projects (i.e. less than 50%) and long approval periods (e.g. 22.5 months is the UK average)[11].

Going forward, further planning approvals will be required in order that the ambition for onshore wind investment is achieved:

- Assuming all projects awaiting construction are built, this would take total operational capacity up to 8.6 GW.

[11] Renewable UK (2010), *State of the Industry Report.*

– As of December 2010, there were 3.9 GW of operational onshore wind farms in the UK, with a further 1.9 GW in construction, of which the majority (1.6 GW) were in Scotland.

– A further 2.8 GW have received approval and are awaiting construction, of which 1.3 GW are in Scotland.

- A further 7.3 GW are in the system and awaiting planning approval, of which 4.1 GW are in Scotland. If historical approval rates continue, around 3 GW of the Scottish projects, and 1.8 GW of projects elsewhere in the UK will proceed, bringing total installed capacity to 13.3 GW.
- Further approvals of those projects already in the planning process, together with new applications and approvals, will be required in order to maintain a project pipeline commensurate with achieving 15 GW by 2020 (Table 2.2).

Additional approvals beyond this level offer scope for reducing the cost of meeting the 2020 renewable energy target and of power sector decarbonisation through the 2020s (e.g. our analysis suggests scope to add over 6 GW of onshore wind capacity through the 2020s).

Table 2.2: Current pipeline of onshore wind projects (GW)

	England	Scotland	Wales	Northern Ireland	**UK total**
Operational	0.8	2.4	0.4	0.3	**3.9**
In construction	0.1	1.6	0.0	0.1	**1.9**
Approved, awaiting construction	1.1	1.3	0.2	0.3	**2.8**
Total	**2.0**	**5.3**	**0.6**	**0.7**	**8.6**
Awaiting planning approval	1.1	4.1	1.2	0.8	**7.3**
Approval rates*	47% for large; 49% for small	76% for large; 66% for small	100% for small**	61% for small**	
Estimated capacity that will get approval*	0.5	3.0	0.8	0.5	**4.8**
Total	**2.5**	**8.3**	**1.4**	**1.1**	**13.3**

Source: RenewableUK (2010) *State of the Industry Report*; DECC Renewable Energy Planning Database (December 2010 data).

Note(s): *Average approval rate for the period October 2008 to September 2010; **There were no applications for large (Section 36) projects in Wales and Northern Ireland during this time, for calculations we have used the approval rate for England (47%). Figures may not sum due to rounding.

The indicator framework for our progress reports[12] requires approvals to be resolved within 12 months. This is in line with announcements in the March 2011 Budget, applicable to small (less than 50 MW) projects, and will also be required for large projects.

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[12] CCC (2009) *Meeting Carbon Budgets - the need for a step change.*

Planning approaches to deliver required approvals

However, the Government is reforming the planning system in England and Wales, which may introduce new risks of delays and low approval rates:

- The Localism Bill will give a bigger role for local communities in approving small-scale (i.e. under 50 MW) projects; the risk is that this will delay projects or stop them gaining approval.
- For larger projects (i.e. over 50 MW), new arrangements will involve a political decision on approval; as with small-scale projects, the risk is that approval rates will fall and that target timelines will not be met.

The Government's strategy is to ensure stronger local participation in projects, and sharing of benefits via local communities; there is evidence that this approach has worked in other countries (Box 2.4).

Box 2.4: International evidence on impacts of community benefit-sharing and the UK's new approach

Experience in Denmark and Germany

Germany currently boasts the largest installed wind capacity in the EU (around 27 GW), substantially more than the UK (just over 5 GW) or Denmark (3.7 GW)[13]. Unlike the UK, where the majority of onshore wind projects are developed and owned by commercial companies, the majority of projects in Germany and Denmark are characterised by a 'community ownership'[14] model (in Denmark around 80% of all wind turbines are community owned):

- Communities pool resources to finance the purchasing, installation and maintenance of projects, either through savings or loans (communities are generally able to secure finance at rates below those commercially available, meaning financial costs are likely to be lower).
- A cooperative or partnership style of ownership (which is the most common) involves individuals purchasing shares in the project, with entitlement to a share of the annual revenue in proportion to their initial investment.

New UK approach

In February 2011 the Government announced that business rates paid by renewable energy developers will be retained for investment directly back into the local community. RenewableUK's 'Wind Protocol', reached through voluntary negotiations with the industry, specifies minimum payments by wind projects of £1000/MW per year into a community benefit 'fund', the allocation of which will be determined by individual communities. The intention is that these financial incentives will assist in generating more local support for wind projects in the UK.

[13] EWEA, (2010) *Wind in Power: 2010 European Statistics*.
[14] Note that the term community may refer to individuals living in close proximity to a project, as well as groups that share a common goal with regard to the project, and may include local households, farmers, schools, businesses and investors.

Given risks under the new arrangements, there are two potential (complementary) approaches to ensuring onshore wind projects contribute effectively to meeting the 2020 target and to further sector decarbonisation required through the 2020s:

- Focus on meeting the 2020 target through adding onshore wind capacity in Scotland, where there has historically been a higher rate of planning approval, and where much of the UK resource is located (Box 2.5).
- Aim to complement efforts in Scotland with adding capacity in England and Wales, where there remains significant resource potential. If evidence suggests the new arrangements are not providing a sufficient pipeline of projects with planning approval, a greater emphasis on national priorities as implied by carbon budgets (e.g. this approach to be stated explicitly in new planning legislation) should be considered.

Box 2.5: The Scottish planning system

Scotland has higher approval rates for both small- and large-scale projects (56% and 100% respectively in the year to September 2010, compared to 34% and 47% in England). There could be a number of reasons for this:

- **Effective and positive engagement,** as well as information and experience sharing, between authorities at the local (e.g. Local Planning Authority) and the national (Scottish Government) level.
- **Clear guidance and scoping procedures** to facilitate developers when making applications. Statutory consultees such as Scottish National Heritage and RSPB Scotland are very engaged and effective, providing advice and guidance on site availability and suitability early on in the planning process (e.g. bird sensitivity maps highlighting where developments could be a risk for bird populations).
- **Close working with other stakeholders** to overcome barriers to developments e.g. technical solutions to radar issues, and the creation of a Scottish Ornithological Steering Group to share environmental information has enabled environmentally informed decisions to be made.
- **Strong political will** at all levels translates into real action and progress – Ministers have intervened where projects are considered of 'national interest'.
- **Lower population density** in Scotland compared to England, meaning there is physically more room for projects to be developed.

The political judgement required here involves a trade-off between the potential effect on the local area (e.g. visual impact) of investment in onshore wind generation, against the higher cost of alternative investments in offshore wind generation (e.g. substituting 3 GW (10 TWh/year) of onshore for offshore wind would reduce the electricity bill impact on households by around 1 percentage point, or £5 per year on the average household bill).

Planning approval of transmission investments

Significant investments in new transmission lines will be required over the next two decades to support power sector decarbonisation (section 3(ii)), with planning approvals required in 2011 and further approvals required in 2013/14.

Under new planning arrangements, the Secretary of State will decide whether approval will be granted, with advice from the Major Infrastructure Planning Unit.

As with onshore wind projects, there is a visual impact associated with transmission infrastructure. One response to this could be to invest in underground transmissions lines, but at a significant cost (Box 2.6).

Box 2.6: Costs and price impacts of underground transmission investments versus overground

There are a range of estimates of the costs of undergrounding (Table B2.6). These differences are significant and very site-specific, of the order of £10 million/km, compared to around £1 million/km for lines built overground. Therefore extensive use of undergrounding could add significantly to transmission charges, which currently contribute around 4% to average household electricity bills[15].

Table B2.6: Costs of undergrounding compared to overhead transmission lines

	Cost multiple (relative to overground)
Scottish Power	8 to 41
National Grid	12 to 17
Energy Networks Association	2 to 20

Source: Scottish Power (2010) *Beauly-Denny Overhead Transmission Line Project: Stirling Visual Impact Mitigation Scheme* Consultation Leaflet; Energy Networks Association (2006) *Environment Briefing 02 – Transporting Electricity*, available at http://www.energynetworks.org/ena_env_briefings/ENV2TransportingElectricity.pdf.

Alternatives to undergrounding which may help mitigate the visual impact of transmission lines include:

- Re-routing lines or planting trees to reinforce the landscape.
- Re-sizing and painting towers.
- Re-conductoring: either bundling lines together (to reduce the total number of individual stretches of cable needed) or unbundling them (although more lines are then likely to be needed).
- Building new transmission lines overground in the place of existing overground distribution lines which are moved underground (distribution lines tend to be smaller than transmission lines and could be moved underground more cheaply).

15 Ofgem (January 2011) *Household Energy Bills Explained*, available at http://www.ofgem.gov.uk/Media/FactSheets/Documents1/updatedhouseholdbillsjan11.pdf.

However, for the least-cost approach (i.e. based on investments in overground lines), timely planning approval is required, for example under a new planning approach where approval is explicitly linked to national priorities as defined by carbon budgets. This would mitigate the current risk that required approvals are delayed or not granted, in which case transmission bottlenecks will remain, undermining system operation and required investments in low-carbon generation.

ii) Access to an expanded power transmission network

Required investment to ease transmission bottlenecks

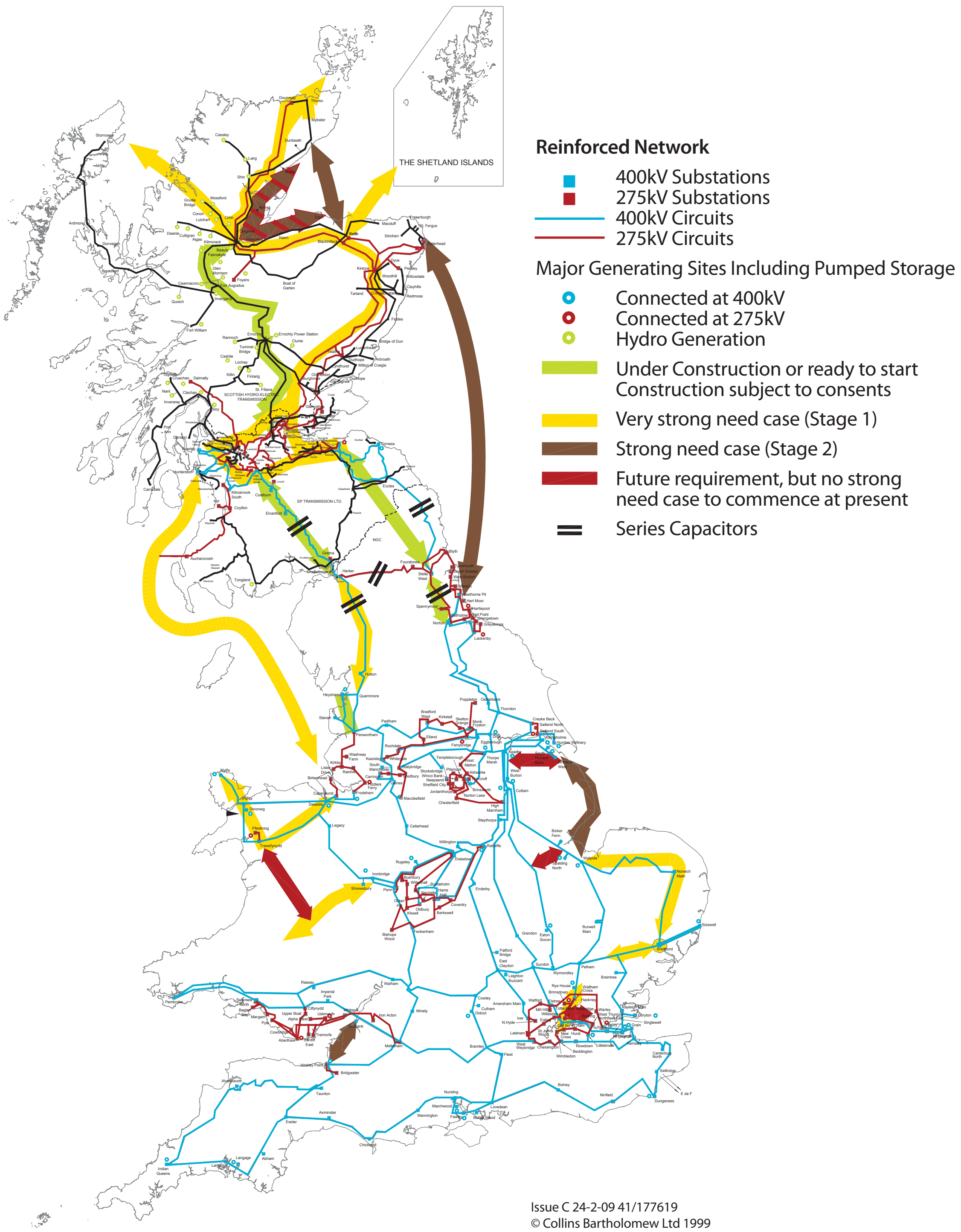
There are bottlenecks in the current power transmission network which, if not addressed, will constrain investment in renewable generation, with a particular need for investment in the Scottish grid, as identified by the Electricity Network Strategy Group (ENSG) (Box 2.7):

Box 2.7: Transmission reinforcements identified by ENSG

Key parts of the investment programme identified by ENSG in order to deliver required levels of renewable energy to 2020 are (Figure B2.7):

- Connections to the Scottish islands, new lines and reinforcements in the North of Scotland for connection of renewables.
- Reinforcements around the Anglo-Scottish border to ease congestion in delivering renewable energy from Scotland to England, where demand is concentrated (the 'Incremental Scottish upgrade').
- New High Voltage Direct Current (HVDC) offshore 'bootstraps' off the east and west coasts of Britain to deliver renewable electricity from North to South.
- Reinforcements in North and Central Wales, the English east coast, London and the South West to ensure that security and quality of supply standards are maintained as renewables are connected in and around the North and Irish seas.

Figure B2.7: Map of ENSG reinforcements required to 2020



Source: ENSG (2009) *Our Electricity Transmission Network, A Vision for the Future.*

The ENSG analysis indicates that this programme of investments will be robust to an ambitious programme of low-carbon investment in the 2020s, where reinforcements to accommodate further nuclear and renewables can be carried out alongside the timeline for construction of these plant in the 2020s[16].

We have previously set out a timeline for investments in transmission consistent with the required trajectory for investment in generation:

- 'Stage 1' of the investments (North Scotland, Scottish border, Western HVDC, Central Welsh and English East Coast) to be agreed by Ofgem in 2010, gain planning permission in 2011 and be operational by 2015.
- 'Stage 2' (further North Scotland, Eastern HVDC, North Welsh and South West of England reinforcements) to gain planning permission in 2013-14 and be operational by 2017-18.

Some progress has been made against this timeline, with approval of £400m funding for feasibility studies and some construction work to date. However, there has not been agreement between the Transmission Owners (National Grid, Scottish Power and Scottish Hydroelectric Transmission) and Ofgem on funding for most of the Stage 1 investments, and this remains a priority for the near term if bottlenecks are to be addressed and generation investments to proceed.

Access to the transmission network

Our indicator framework includes implementation of an enduring regime for transmission access so that project developers can have confidence in obtaining timely connection to the transmission network at reasonable cost before proceeding with project construction.

Progress has been made here with the August 2010 implementation of 'Connect and Manage' as the enduring regime for network access[17].

However, the charging system for use of the transmission network is still under review. Decisions here could potentially bring forward more onshore capacity (Box 2.8). A timely decision on charging would enable project developers to fully assess project economics (which are sensitive to the charging regime) such that new projects enter construction on a schedule consistent with delivering required ambition to 2020.

16 ENSG (July 2009) *Our Electricity Transmission Network: A Vision for 2020- Addendum Report, Further Analysis- 2030 Generation and Demand Scenarios*

17 Connect and Manage allows generators to connect to the system in advance of the completion of wider transmission reinforcement works, mitigating previous risks of delays in connecting.

Box 2.8: Effect of rebalancing transmission charging on onshore wind deployment

Background

Ofgem are currently reviewing the Transmission Network Use of System (TNUOS) charges, which are levied on generators and electricity users to cover the costs of providing a transmission network that is fit for purpose. This review is called Project Transmit.

- Currently, transmission charges are partly paid by generators and partly by electricity users. Part of the charge paid by generators varies according to where in the UK they are located, from low or negative charges in the South East to around £20/kW for projects in the north of Scotland.
- The current locational charge could be replaced with a 'postage stamp' system which would apply a uniform charge for connection to all generators. Supporters of this approach argue that this would incentivise more renewable generation (wind, marine) which tends to be located in remote locations, where there is significant resource.
- However, there is the danger that if developers do not face the true cost of delivering electricity from more remote locations, this will lead to sub-optimal locational decisions, with more congestion and bottlenecks, resulting in higher costs to the consumer.

A postage stamp system could bring forward more onshore wind capacity:

- A shift to postage stamp charging would reduce costs for projects facing high locational charging (e.g. Scottish renewables). Oxera analysis suggests this could mean that 9-12% more of the theoretical onshore wind resource would become economic[18].
- Oxera conclude that this could increase deployment in 2020 by up to 1.6 GW (given the current target of 15 GW by 2020).
- Current transmission charges amount to around 0.8 p/kWh in remote areas for onshore wind generators[19]. Given the attractiveness of onshore wind from an economic perspective (current costs are between 8-9.5 p/kWh as opposed to around 11-15.5 p/kWh for offshore wind), incentivising further deployment in this way might be desirable since the subsidy entailed could be far smaller than the avoided costs of deploying offshore wind.

A postage stamp system could make a useful contribution to meeting the renewable energy target at least cost, and further analysis on the overall effects of a change in the transmission charging system is needed.

[18] Oxera (November 2010) *Principles and Priorities for Transmission Charging Reform.*

[19] CCC calculation on basis of Mott MacDonald levelised cost of 9 p/kWh at 10% discount rate, current £20/kW charge, 27% load factor, 20 year lifetime, 16 MW wind farm.

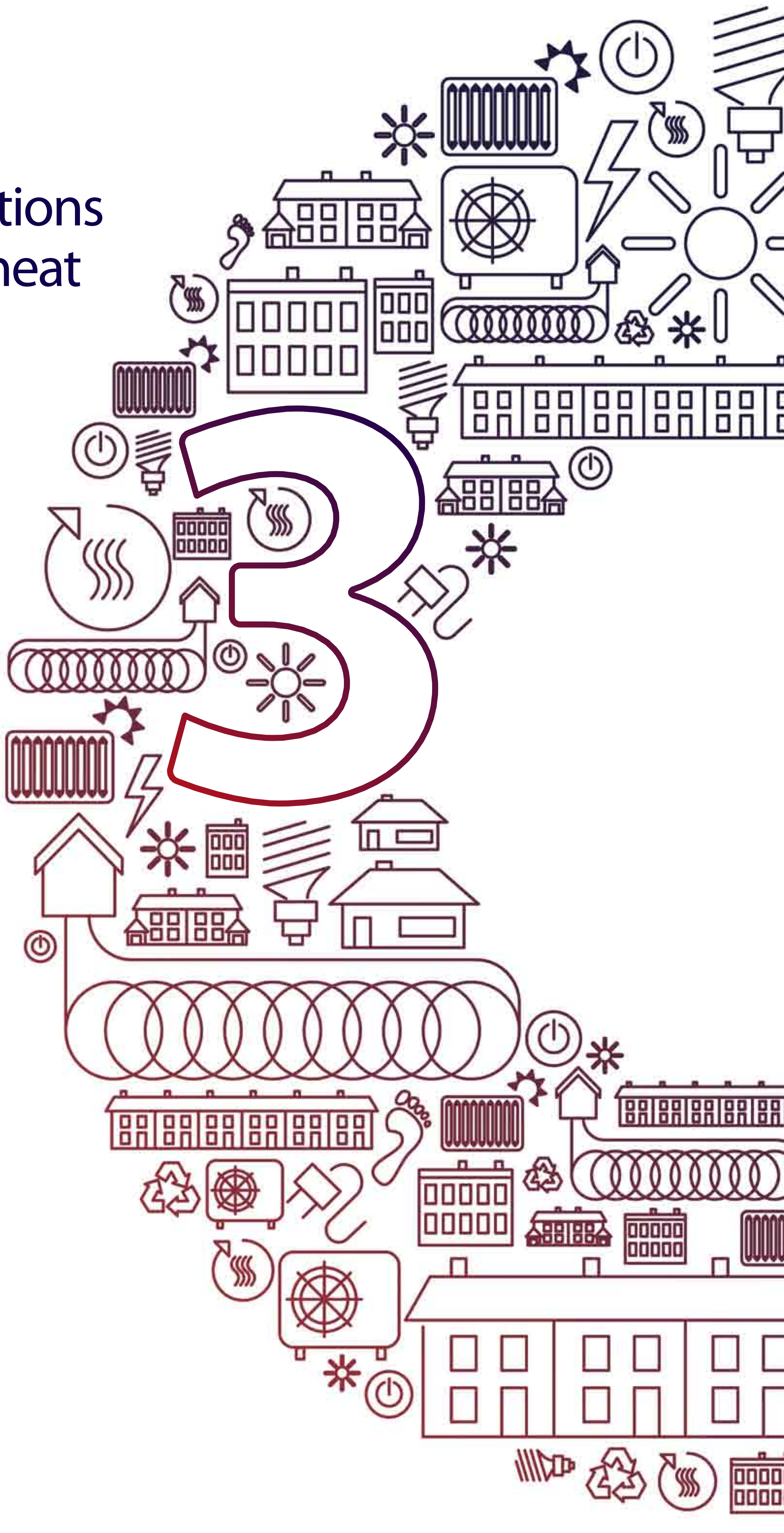
Offshore transmission

There remains uncertainty over the final design of the regime to govern the offshore transmission network (which is currently governed by transitional arrangements). Although this has not been a problem as regards early-stage investments in the offshore transmission network, it could become a barrier to investment in a more extensive offshore network.

Whilst the decision as to whether this should be developed as a set of point-to-point connections, or as an integrated network goes beyond the remit of the Committee, it is clear that a timely decision on an enduring regime is required in order that projects further offshore proceed as planned.

Chapter 3

Developing options for renewable heat



Introduction and key messages

In order to achieve the economy-wide target to cut emissions by 80% in 2050 relative to 1990 levels, there is a need for almost total decarbonisation of heat in buildings and deep cuts in industry emissions.

As part of our fourth carbon budget report[1], we set out detailed analysis of the scope for heat decarbonisation in buildings and industry to 2030 through a range of renewable heat options (i.e. electric heat pumps, biomass boilers, biogas).

In this chapter, we start by summarising our previous analysis of renewable heat ambition to 2020 and 2030. We then focus on financial and non-financial barriers to delivering 2020 ambition and developing options for deployment in the 2020s, including the policy levers by which these could be addressed.

The key messages in the chapter are:

- Ambition to increase the level of renewable heat penetration from currently very low levels to penetration of around 35% by 2030 is appropriate on the path to meeting the 2050 target.
- Achieving 2020 penetration of around 12% would be consistent with this 2030 ambition. This will support technology development, build up a supply chain and improve consumer confidence in technologies where there has been very limited deployment to date in the UK. Without new policy approaches to address both financial and non-financial barriers, a lower level of penetration inconsistent with the appropriate 2030 ambition and the 2020 EU Renewable Energy Directive target, would be likely.
- Our key conclusions on levers to address financial barriers are:
  - The overall level of support provided under the Renewable Heat Incentive (RHI) to 2014/15 is appropriate and the support for specific technologies is broadly in line with expected costs.
  - However, significantly increased funding will be required in the second stage (i.e. after 2014/15), at a level to be finalised in the context of a broader strategy to meet the 2020 renewable energy target.
  - Further support will also be required in the 2020s, either in the form of an extension of the RHI, or the introduction of a carbon price for heat.
  - It will be important to ensure that there is disbursement of the RHI across the range of technologies in order that a portfolio of technologies for deployment in the 2020s is developed; lack of deployment in particular niches (e.g. residential heat pumps) would be problematic in this longer-term context.

[1] CCC (2010) *The Fourth Carbon Budget - Reducing emissions through the 2020s.*

- Key policy levers to address non-financial barriers include:
  - Accreditation of installers to ease potential supply chain bottlenecks and provide consumer confidence.
  - Integration of renewable heat and energy efficiency polices to ensure a greater pool of suitable houses, to improve consumer confidence and information, to reduce hassle costs and to provide a potential source of finance for up-front costs.
  - Zero-carbon homes, which will result in significant demand for renewable heat.

We set out the analysis that underpins these messages in three sections:

1. Scenarios for renewable heat deployment
2. Achieving deployment of renewable heat
3. Impact of renewable heat support on energy bills

1. Scenarios for renewable heat deployment

We set out our scenarios for renewable heat deployment in four sections:

(i) Renewable heat technologies

(ii) Renewable heat in buildings

(iii) Renewable heat in industry

(iv) Renewable heat scenarios and ambition

(i) Renewable heat technologies

There is a range of renewable heat technologies which are technically feasible and likely to become cost-effective over the next two decades.

- **Air-source heat pumps (ASHPs).** This electricity-based technology draws heat from air outside and pumps this into buildings (i.e. like air-conditioning working in reverse). It is potentially applicable in residential and non-residential buildings, and is particularly attractive in conjunction with the vent-based systems widely used in the non-residential sector. It can also work with water-based (i.e. radiator) systems in the residential sector, where it is best suited to well-insulated houses with energy-efficient glazing. Current penetration rates are low in the UK relative to many other countries (e.g. Germany, France).
- **Ground-source heat pumps (GSHPs).** These use electricity to draw heat from the ground, and are suitable for residential and non-residential applications. Where space is available, the performance of GSHPs is slightly better than that of ASHPs. However, scope for deployment is limited by the requirement for sufficient space to locate ground loops or suitability for boreholes.
- **Biomass.** Biomass for heat applications offers potential for reducing emissions in buildings (e.g. biomass boilers in homes and non-residential buildings, or in CHP plant supplying district heating networks) and industry. Given limits on available sustainable biomass, other (i.e. electricity-based) options for decarbonising buildings, and currently limited options for decarbonising industry, it is likely to be preferable to use biomass resources predominantly to reduce emissions in industry. We will look at the best use of biomass in more detail in our bioenergy review later in 2011.
- **Biogas.** This is produced primarily through the anaerobic digestion of wastes and/or dedicated energy crops, and can be used on-site for small-scale power generation and CHP. It can also be upgraded to 'biomethane' and injected into the gas grid, where it can be used for larger-scale power generation, for heat in buildings or industry, or for use in transport. As for biomass, given limited availability of biogas, other options for decarbonising heat in buildings, and limited options for decarbonising industry, it is likely to be preferable to use biogas resources predominantly to reduce emissions in industry.

(ii) Renewable heat in buildings

Role for energy efficiency in supporting renewable heat deployment

In our advice on the fourth carbon budget and our central abatement scenario for 2030, we highlighted the important ongoing role for energy efficiency improvement to 2020 and beyond. The central scenario underpinning our fourth budget recommendations assumed:

- All lofts and cavity walls will be insulated by 2015.
- More difficult/expensive measures (e.g. floor insulation, energy efficient glazing) would be deployed in the 2020s.
- Cost-effective energy efficiency measures in the non-residential sector are delivered, through policies in place (e.g. the Carbon Reduction Commitment offers scope for a 30% emissions reduction) or new policies (e.g. covering small and medium-sized enterprises).
- Over 2 million solid walls should be insulated by 2020, with a further 1.5 million to follow in the 2020s.

Energy efficiency improvement is important in the context of carbon budgets and renewable energy for at least four reasons:

- Emissions reduction from energy efficiency improvement has the potential to make a significant contribution to meeting carbon budgets.
- Resulting reductions in energy consumption and bills provide an opportunity to offset energy price increases over the next decade which could otherwise be problematic from fuel poverty and political acceptability perspectives.
- Energy efficiency improvement is a necessary condition for deployment of electric heat pumps. Otherwise the heat pumps would need to be significantly larger (and more expensive), with larger radiator systems in poorly-insulated buildings, and in extreme cases would not be able to provide adequate levels of warmth.
- In the specific context of the 2020 renewable energy target, energy efficiency improvement reduces energy demand and therefore requires less supply-side investment to meet the target.

Given the importance of energy efficiency improvement in the context of renewable energy specifically and carbon budgets generally, it will be crucially important to incentivise this through new policies (e.g. the Green Deal, new policies to encourage uptake of measures by small and medium-sized enterprises).

In this review, we assume that new policies are effective, and that energy efficiency is improved, reducing energy demand and supporting wide-scale deployment of renewable heat in buildings.

Scenarios for use of renewable heat in buildings to 2030

The heat decarbonisation scenarios in our advice on the fourth carbon budget were developed using a model that we commissioned from NERA and AEA, and in which deployment depends on a range of factors including capital stock turnover, technology costs (capital and operating) and fossil fuel prices (Box 3.1).

Box 3.1: NERA/AEA low-carbon heat model

Our scenarios for the uptake of low-carbon heat in the fourth budget report were underpinned by a detailed cost-effectiveness model, developed by NERA and AEA. This model draws upon and extends the evidence base used for previous low-carbon heat work for DECC and the Committee that looked at the period to 2020. Technology assumptions and input data were extended to 2030, and additional technologies were incorporated to reflect possible future developments (e.g. synthetic biogas from the gasification of biomass, and heat pumps with heat storage that can shift electricity load profiles).

The model calculates uptake by considering the cost effectiveness of low-carbon heat technologies relative to a carbon price projection of £70 per tonne abated in 2030 and rising through the 2030s. Where technologies are cost-effective, the level of uptake in each year depends upon a number of factors including the size of the heat market, the ability of industry to deploy low-carbon heat and a range of suitability constraints.

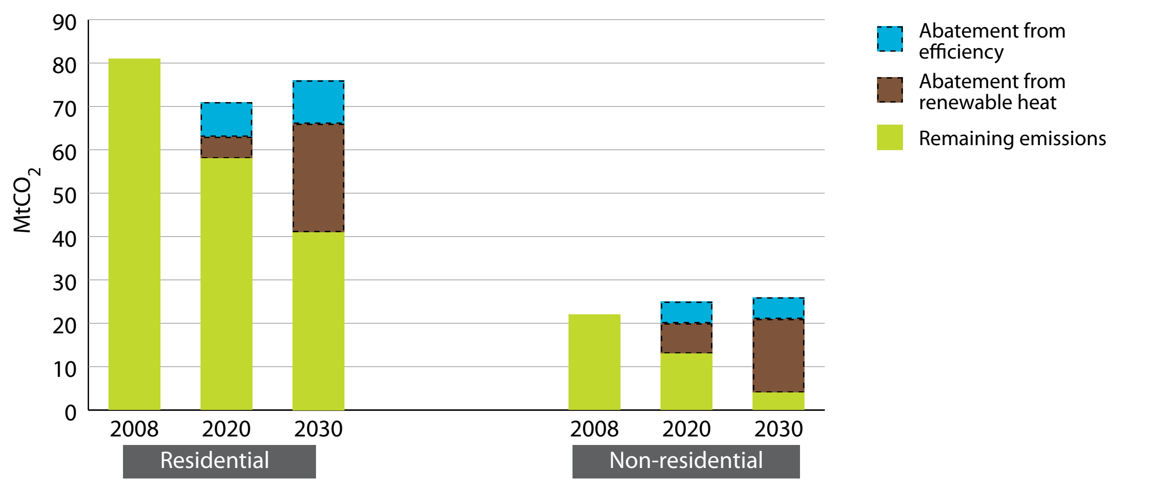
The sensitivity of the results was tested by varying many of the key input parameters, including technology performance and cost, levels of building insulation and energy efficiency, availability of biomass resource, fuel prices and discount rates. The results of these sensitivities were reflected in our uptake scenarios for the 2020s.

We set out three scenarios for heat decarbonisation through the 2020s:

- **Low abatement scenario.** The Low abatement scenario includes low levels of heat pump, biomass and biogas penetration, together with some district heating. It reflects low levels of energy efficiency improvement, limited suitability and high costs (including hidden costs such as loss of space due to solid wall insulation).
- **Medium abatement scenario.** The Medium abatement scenario includes significantly increased heat pump penetration, together with some further biomass deployment. It is consistent with the wider uptake of energy efficiency measures and hence building stock suitability, technology innovation to reduce costs, and the potential to reduce hidden costs.
- **High abatement scenario.** There is further penetration of both heat pumps and district heating in our High abatement scenario, based on faster district heating network roll-out and further energy efficiency improvements.

Renewable heat penetration in these scenarios ranges from around 20% to 50% of total heat consumption in buildings by 2030. Abatement from renewable heat is expected to deliver the majority of the emissions reduction in buildings in 2030 (Figure 3.1). The cost of the Medium abatement scenario is less than 0.1% of GDP (ranging from a saving of £1.1 billion to a cost of £3.9 billion depending on fossil fuel and capital cost assumptions).

Figure 3.1: Medium scenario for residential and non-residential buildings (2008, 2020 and 2030)



Source: CCC modelling.

Note(s): Direct emissions only.

Decarbonising buildings by 2050

In order to achieve the legislated target to reduce emissions in 2050 by 80% relative to 1990 levels, and given limits on scope for emissions reduction in some key sectors (e.g. aviation, shipping, industry, agriculture), it is likely that heat from buildings will have to be almost fully decarbonised over the next four decades.

In moving from 2030, where we envisage remaining direct emissions from buildings to be around 45 $MtCO_2$ (compared to around 100 $MtCO_2$ today), to near-full decarbonisation, there are three principal sets of heat options, as well as further fabric energy efficiency improvements to the building stock:

- **Further decarbonisation based on air-source and ground-source heat pumps.** Although there are limits on the suitability of these technologies, our analysis suggests that these could meet 55% to 75% of residential heat demand and around 70% to 90% of non-residential space heat demand in the UK.
- **Increased penetration of resistive heat technologies.** There may be niche applications for conventional electric heating technologies, for example in highly energy-efficient houses with a low heat demand or where there are space constraints. These are less efficient and therefore more expensive than heat pumps, would ideally operate at off-peak times in conjunction with thermal storage, and would require additional investments in power generation and networks. Therefore to the extent that heat pumps are suitable, they are also preferable to resistive electric heat.
- **District heating.** District heating based on use of waste heat from low-carbon power generation (e.g. nuclear, CCS) could be viable from technical and economic perspectives, based on a preliminary and high-level assessment. Further analysis is required to develop the evidence base on district heating, with the possibility that this could complement or substitute heat decarbonisation in buildings from heat pumps or resistive electric heating.

The precise balance of these technologies is currently highly uncertain, with our best estimate that in the long term renewable technologies could be used to meet 70% to 90% of heat demand from buildings.

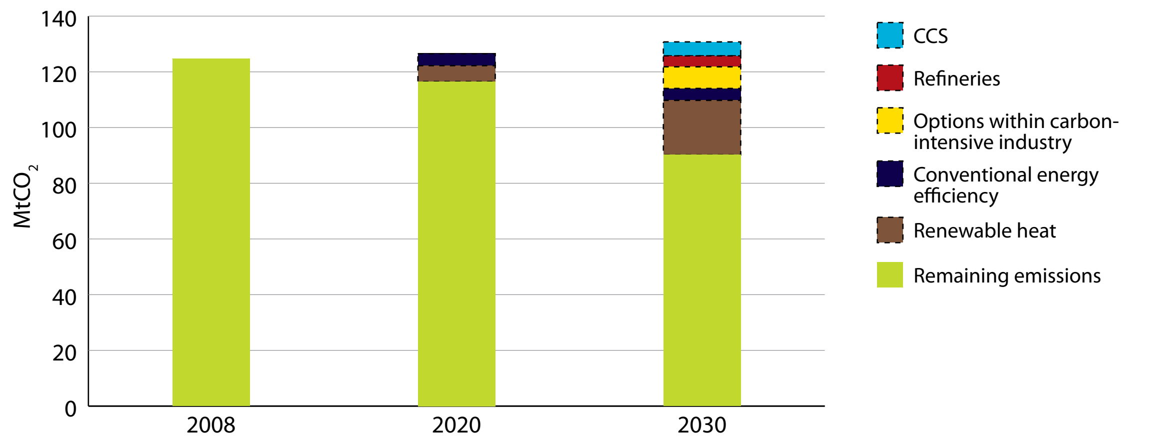
(iii) Renewable heat in industry

Scenarios for industry decarbonisation to 2030 and 2050

The scenarios for decarbonising industry in our fourth carbon budget report include renewable heat (i.e. biomass and biogas) and other abatement options (e.g. CCS).

Renewable heat is the main driver of emissions reduction in these scenarios in the 2020s, reaching around 35% of industrial heat demand in the Medium abatement scenario and resulting in emissions reduction of around 20 $MtCO_2$ (17%) in 2030 (Figure 3.2), at a cost of less than 0.1% of GDP.

Figure 3.2: Medium abatement scenario in industry (2008, 2020 and 2030)



Source: CCC modelling.

Note(s): Direct emissions only. Industry includes refineries and other energy supply.

Going beyond 2030, we envisage scope for increased penetration of renewable heat in industry. This is, however, limited by available sustainable bioenergy, and other options will also be required:

- **Bioenergy.** We base our projections on availability of sustainable bioenergy on IEA work in relation to biomass, and a range of sources for biogas, including WRAP (2009)[2], NNFCC (2009)[3] and Defra (2005[4] and 2009[5]). If all available bioenergy were to be used in industry (e.g. reflecting higher availability of low-carbon alternatives elsewhere) this could supply around 65% of heat demand from industry and could reduce emissions by around 30 $MtCO_2$.
- **Other options.** It will be important to develop other options for reducing industry emissions including CCS, materials efficiency and product substitution.

Emissions reduction from industry is a key area where further evidence is required, and one that the Committee will consider in the context of the bioenergy review, to be published later in 2011.

[2] WRAP (2009) *Household Food and Drink Waste in the UK.*
[3] NNFCC (2009) *Evaluation of Opportunities for Converting Indigenous UK Wastes to Fuels and Energy.*
[4] Defra (2005) *Assessment of Methane Management and Recovery Options for Livestock Manures and Slurries.*
[5] Defra (2009) *Developing an Implementation Plan for Anaerobic Digestion.*

(iv) Renewable heat scenarios and ambition

Renewable heat scenarios to 2030

Taken together, our central scenarios for renewable heat in buildings and industry imply around a 35% renewables share in heat. We reflected these scenarios in our recommendations for the fourth carbon budget, with renewable heat as one of the main contributors to emissions reductions required through the 2020s.

In designing appropriate policies to support development of renewable heat options, four considerations are important:

- Renewable heat technologies are relatively mature, and are already widely deployed in some countries.
- Investment cycles for renewable heat are short compared to those for renewable power generation, implying scope for later decisions on commitments to technology support in the 2020s.
- The challenge is to demonstrate the technologies in a UK context, addressing current technical, economic and social barriers.
- Success here is of crucial importance, both because renewable heat technologies are promising from technical and economic perspectives, and because of a lack of alternatives for heat decarbonisation, which is required to meet the UK's 2050 target of an 80% emissions reduction.

We discuss policies to support UK demonstration in section 2, where one of our conclusions is that there will be a need for commitments on financial support for renewable heat in the 2020s, which in turn will require setting of renewable heat targets. Our central scenario shows the order of magnitude of ambition that currently appears appropriate, with the precise ambition to be determined as current uncertainties are resolved (e.g. between 2015 and 2020).

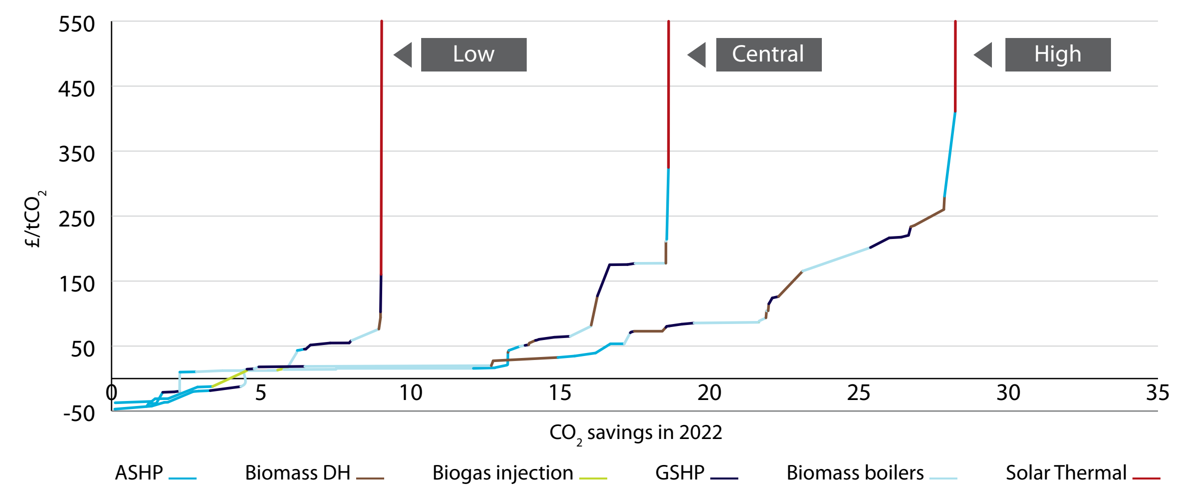
Renewable heat scenarios and ambition to 2020

Our scenarios for renewable heat penetration to 2020 are designed to be consistent with required decarbonisation through the 2020s, and include significant investment over the next decade in each of the promising options considered above.

In our 2009 progress report[6] we presented three renewable heat scenarios for 2020 based on a technical and economic assessment that we commissioned from NERA (Figure 3.3):

- Our central scenario achieved an emissions reduction of 18 $MtCO_2$ in 2020.
- The Government's aim is to deliver 12% renewable heat penetration in 2020, which is at the limits of our central scenario.
- We therefore argued that this level of ambition could be very expensive at the margin (e.g. of the order £100s per tonne of CO_2 abated for solar thermal).

Figure 3.3: Extended Ambition scenario marginal abatement cost curve (2022)



Source: CCC analysis.

Note(s): Where a technology appears at different points of the curve this relects different applications. Whilst the figure shows 2022 (the last year of the third budget), achievable savings in 2020 will be comparable.

The High scenario in this analysis delivered a 50% greater emissions reduction in 2020. This reflected the possibility of faster growth of supply capacity, which could enable greater deployment of the lower-cost technologies. Delivery may be desirable if, for example, renewable heat costs were to be low relative to offshore wind generation costs.

There may be a specific opportunity for increasing biogas ambition in 2020 depending on the extent to which the currently small industry can be expanded, and on wet waste feedstocks not being locked into other waste management options (e.g. incineration) – see Box 3.2.

[6] CCC (2009) *Meeting Carbon Budgets – the need for a step-change.*

However, given uncertainties over the extent to which barriers to deployment can be addressed, the level of ambition for renewable heat in 2020 should not be increased now. Rather, a flexible approach is appropriate, with scope for adjusting the level of renewable heat ambition as uncertainties relating to economics and deliverability are resolved.

Whatever the level of ambition, there is a range of financial and non-financial barriers which will have to be addressed in order that significant deployment is achieved; we now consider financial and non-financial barriers and levers with which these can be addressed.

Box 3.2: Scope for increasing the contribution from biogas

The potential for biogas to contribute to the 2020 renewables target is a product of the quantity of gas production, together with the efficiency with which it can then be turned into final energy. Recent work by SKM for DECC[7] suggests that there is greater potential for biogas to contribute to the renewables target in 2020 than was previously allowed for in DECC's National Renewable Energy Action Plan (NREAP).

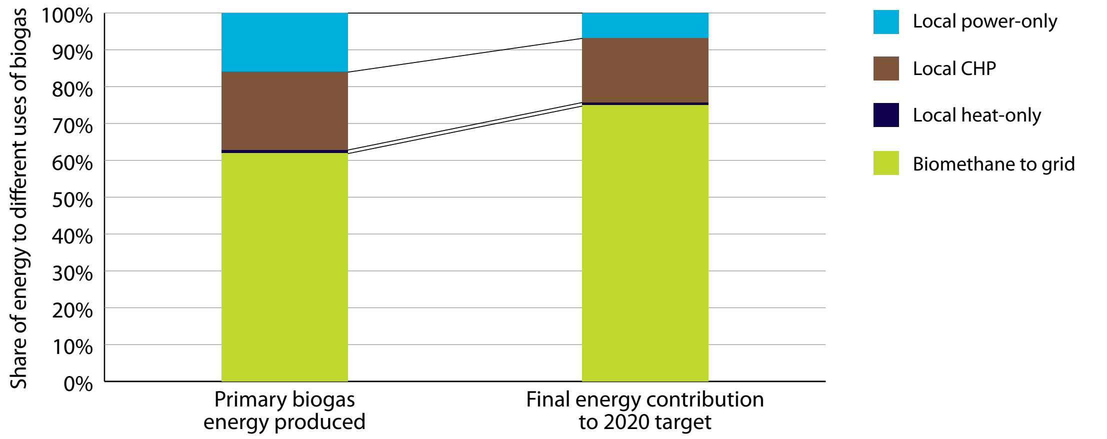
The difference lies mainly in the assumed conversion efficiency to final energy as defined under the EU Renewable Energy Directive target, as a result of shifting biogas from local power generation towards the upgrading of the gas to biomethane and with injection into the gas grid. The NREAP figures imply primary biogas production of around 20 TWh but, because most of this is assumed to be used for local power generation, conversion to final energy yields only 9 TWh.

SKM's Central growth scenario has a similar quantity of primary biogas production (21 TWh) to the NREAP; however, because the majority of this is assumed to be used for grid injection, the final energy production is considerably higher, at 15 TWh. Their Low, Central and High growth scenarios represent different extents to which non-financial barriers can be overcome. This work suggests that further biogas potential is available in the decade after 2020, with the main constraint being feedstock availability. It will therefore be important that this is not locked into long-term contracts, e.g. for incinerators.

As well as providing a greater contribution to the renewable energy target than local power generation, grid injection is a more flexible solution. It allows the renewable energy to be used in existing boilers, transport, CHP or high-efficiency power generation in CCGT plant (e.g. at 55% rather than 35% efficiency for local power generation), depending on what is most appropriate.

7 SKM (2011) *Analysis of Characteristics and Growth Assumptions Regarding AD Biogas Combustion for Heat and Biomethane Production and Injection to the Grid.*

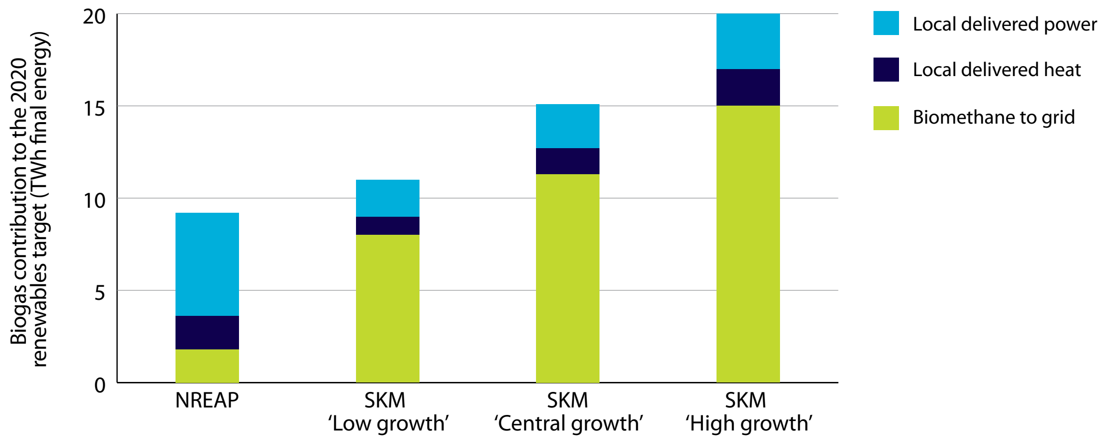
Figure B3.2a: Breakdown of primary and final biogas energy shares in SKM scenarios



Source: CCC calculations based on SKM analysis for DECC.

Note(s): Shares are presented for the Central growth scenario, although the shares are similar across the three scenarios.

Figure B3.2b: Possible contributions of biogas to the 2020 renewables target



Source: National Renewable Energy Action Plan; SKM analysis for DECC.

Note(s): The NREAP presents an aggregated total of the contributions of local heat generation and biomethane injection; an equal split between these uses has been assumed here.

2. Achieving deployment of renewable heat

(i) Barriers to deployment of renewable heat

To better understand barriers to renewable heat deployment, we commissioned work led by Element Energy, which explores the relative importance of both financial and non-financial barriers (Box 3.3):

Box 3.3: Methodology used by Element Energy

Our assessment of the relative importance of different barriers to uptake of renewable heat is underpinned by quantitative modelling we commissioned from Element Energy and NERA. The modelling is based on a representation of consumer choices of heating technologies, subject to constraints on resources, supply capacity, and other factors. The model is segmented to represent different technologies as well as consumer groups, each of which may face different costs, barriers, and other constraints on the adoption of renewable heat technologies.

Barriers are represented in the model through three main approaches:

- **Restrictions on supply and demand.** These include the rate at which new heating equipment is purchased, the share of heat demand and different end-user applications that are suitable for different technologies, and the total available supply potential and rate at which this can grow over time.
- **Time discounting.** End-users' approaches to the trade-off between up-front and ongoing costs and benefits is represented through 'willingness-to-pay' curves.
- **Cost impacts.** Selected barriers are represented through adjustments to capital and operating costs.

The significance of different types of barriers and uncertainty about their magnitude has been captured through scenario analysis.

- **Financial barriers.**
  - For a transitional period, and given the absence of a carbon price for heat outside the energy-intensive sectors, renewable heat options are likely to involve additional costs compared to conventional alternatives.
  - Access to finance may be a barrier, given that renewable heat technologies are capital-intensive, with large up-front costs.
- **Non-financial barriers.** Barriers considered by Element Energy include lack of suitability for renewable heat, lack of awareness and confidence, and supply chain constraints:

– **Suitability.** Renewable heat works best in well-insulated buildings, and may not be able to heat poorly-insulated buildings adequately. Scope for deployment of renewable heat is therefore limited to buildings that are currently well-insulated, or new zero-carbon homes, or those buildings that will become better insulated (e.g. under the Green Deal).

– **Awareness.** Given limited deployment of renewable heat to date and therefore low visibility, there is a lack of consumer awareness about opportunities for switching from conventional to renewable heat technologies.

– **Consumer confidence.** Given that renewable heat technologies are relatively new in UK applications confidence is currently limited. Recent trials of air-source heat pumps have highlighted potential risks of low consumer confidence (Box 3.4).

– **Supply chain constraints.** The renewable heat supply chain is under-developed in the UK, with potential bottlenecks relating both to equipment supply and installation.

Box 3.4: Performance of heat pumps in Energy Saving Trust trials

The Energy Saving Trust (EST) recently published the results of the first large-scale trial of heat pumps at 83 residential sites in the UK[8]. A key finding was that heat pump performance can vary considerably between installations, and is particularly sensitive to installation and commissioning practices and customer behaviour.

The performance of a heat pump is described in terms of its Coefficient of Performance (COP), or the amount of heat the heat pump produces compared to the total amount of electricity needed to run it. The higher the COP, the lower the electrical energy required to deliver a given amount of heat, and therefore the better the performance.

Our fourth budget analysis assumed that COPs start from current levels of 2.0 to 2.5 for the residential sector. They are projected to increase towards an eventual plateau in the 2020s, with space heating COPs up to 4.5.

In the trials, GSHPs had a mid range of COPs around 2.3-2.5, with the highest figures above 3.0. The mid range of COPs for ASHPs was around 2.2, with the highest figures over 3.

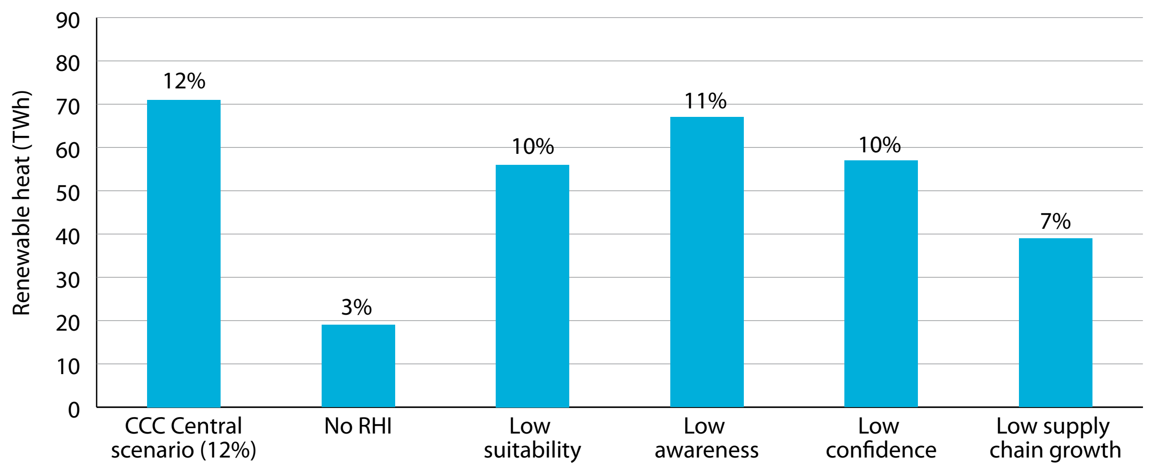
The results of the EST field trial have important implications for the roll-out of heat pumps in the UK:

- In general, well-installed and well-operated heat pumps are a suitable technology for reducing emissions in the UK.
- Given the sensitivity of performance to design and commissioning, there is a requirement for improved training and accreditation of installers.
- Many customers expressed difficulty understanding the instructions, and this underlines the importance of improved information provision.

[8] http://www.energysavingtrust.org.uk/Media/node_1422/Getting-warmer-a-field-trial-of-heat-pumps-PDF.

The Element Energy analysis suggests that a failure to address both financial and non-financial barriers could significantly reduce take-up of renewable heat (Figure 3.4):

Figure 3.4: Impact of barriers on heat demand met by renewable heat technologies in 2020



Source: CCC analysis based on modelling by Element Energy.

Note(s): Chart shows the impact on the CCC Central scenario of varying different barriers. Scenarios that meet the CCC Central scenario 2020 ambition are presented in section 5.5 of the Element Energy report. The CCC Central scenario biogas uptake (8 TWh) has been included in each of the bars shown. Element Energy assessed the impact of barriers for biogas separately because it represents a different form of investment decision.

- The analysis suggests that penetration rates would only reach around 3% in 2020 without financial support (i.e. this would limit take-up to those applications where cost savings are available, and by 'green' consumers).
- Non-financial barriers could significantly reduce uptake in 2020 compared to full potential, even where financial barriers are addressed, with a particularly important role for supply chain expansion:
  - Penetration rates in the analysis fall to 10% in 2020 in a scenario where there are fewer buildings suitable for renewable heat (e.g. because energy efficiency is not improved as required).
  - Where there is a lack of awareness about opportunities, penetration rates fall to 11%.
  - Penetration falls to around 10% in 2020 where consumer confidence in renewable heat technologies is low.
  - With low supply chain growth, this reduces penetration rates to 7% in 2020.
  - Therefore combinations of the above barriers could result in very low levels of penetration.
- Where supply chain constraints can be effectively addressed, along with other barriers, there is scope for achieving higher deployment of renewable heat without targeting more expensive technologies and therefore raising costs.

It is therefore important to address both financial and non-financial barriers to deliver 2020 ambition on renewable heat. Successfully addressing these barriers could, in theory, deliver a higher level of renewable heat ambition in 2020.

ii) Providing financial incentives for investment in renewable heat

Overview of the Renewable Heat Incentive

Although there is scope for at least some renewable heat technologies to become cost-competitive over the next two decades, almost all renewable heat technologies are likely to be more expensive than conventional alternatives for at least the next decade.

Therefore if there is to be significant renewable heat deployment over the next decade, transitional financial support will be required before technology costs fall, and following which support can be reduced or removed.

The need for a financial support mechanism has been recognised by the current Government, which has committed to provide financial support through the Renewable Heat Incentive (RHI):

- Funding will start with a first phase in June 2011, and a second phase from October 2012.
  - In the first phase, long-term tariff support will be targeted in the non-residential sectors.
  - During the first phase, the residential sector will receive some 'premium tariffs' (up to 25,000 installations) and in return the householder will provide information on the performance of the technologies.
  - The second phase will begin with the launch of the Green Deal in October 2012 and will see households moved to the same form of long-term tariff support offered to the non-residential sector in the first phase. This timing offers the possibility for greater integration of renewable heat and energy efficiency policies than currently planned (see section 2(iii)).
- Funding will be paid per unit of heat generated (e.g. rather than as an up-front contribution towards capital costs).
- In bioenergy applications, recipients of funding will be required to report on the sustainability of their biomass feedstock, with compulsory sustainability criteria to apply from 2013.

Success of the RHI in tackling financial barriers will depend on the support that the scheme provides for specific technologies and the overall level of funding.

Support for specific technologies

Our Element Energy analysis suggests that, based on current technology, operating and fuel costs, support of up to 20 p/kWh is required for the most expensive renewable heat technologies, compared to current costs in the range 4-10 p/kWh for gas boilers (Box 3.5):

- **Air-source heat pumps.** In the non-residential sector, support required for ASHPs is currently around 1.5 p/kWh. In the residential sector, support requirements are in the range 4-6 p/kWh (depending on the dwelling type[9]).
- **Ground-source heat pumps.** In the non-residential sector, support required for GSHPs is currently in the range 4-5 p/kWh. In the residential sector, support requirements are in the range 6-9.5 p/kWh (depending on the dwelling type).
- **Biomass boilers.** In the non-residential sector, support required for biomass boilers is currently in the range 3-6 p/kWh. In the residential sector, support requirements are in the range 9-13 p/kWh (depending on the dwelling type).
- **Solar thermal.** In the non-residential sector, support required for solar thermal is currently around 20 p/kWh. In the residential sector, support requirements are in the range 16-20 p/kWh (depending on the dwelling type). As noted below, the possibility of limiting support for technologies like solar thermal that are currently expensive should be considered to ensure that these do not crowd out support for lower-cost technologies with more promise for the 2020s.

Although assessing support levels was not the main focus of the Element Energy study, recently announced support levels for the non-residential sector are broadly aligned with the requirements indentified in that analysis (Table 3.1):

- **Air-source heat pumps:** Government is not initially proposing any support for ASHPs in the non-residential sector, to allow it to assess ongoing work to develop a robust methodology for measuring heat delivered in the form of hot air. Eligibility for this technology is intended for 2012, and will be important given the large role for ASHPs towards meeting our recommended low-carbon heat trajectories in both 2020 and 2030 (e.g. ASHPs provide around 40% of abatement in residential buildings in 2030 under our Medium abatement scenario).
- **Ground-source heat pumps:** Support for non-residential GSHPs has been set at 4.3 p/kWh for smaller pumps and 3 p/kWh for larger pumps.
- **Biomass boilers:** Support for non-residential biomass boilers has been set at between 2.6 p/kWh and 7.6 p/kWh depending on the size of the boiler[10].
- **Solar thermal:** Support for non-residential solar thermal has been set at 8.5 p/kWh. This is an expensive technology and the RHI tariff is higher than for the other technologies but still not sufficient to mean solar thermal becomes competitive with a gas boiler.

[9] For example, whether the dwelling is a new build property, and what kind of insulation has been installed.

[10] For small and medium-sized boilers the support is reduced to 1.9 p/kWh once annual heat generation passes a 'Tier break'. The Tier Break is defined as: installed capacity (kWth) x 15% peak load hours (i.e. 1,314 hours per year).

Box 3.5: Comparison of levelised costs of conventional and renewable heat technologies

Levelised cost of energy (LCOE) can be defined as net annual cost divided by energy produced (kWh/yr) in p/kWh. The annual cost of generation includes annualised capital cost, operating costs and fuel costs.

Some examples of LCOE values in 2011 for gas boilers and various renewable heat technologies are given in the table below for a selection of consumer types. These estimates indicate the current level of support that would be required for renewable heat technologies to achieve competitiveness with gas boilers.

Table B3.5: Levelised cost comparison

		Property type				
		Domestic, House, Suburban, New build	Domestic, House, Suburban, Other	Domestic, House, Suburban, SWI	Commercial, Public, Small private	Industrial, Large space
LCOE (p/kWh)	*Gas boiler*	*10.5*	*7.7*	*6.8*	*4.7*	*3.7*
	ASHP	16.5	12.6	10.9	6.3	5.1
	GSHP	18.6	17.2	12.8	9.7	7.6
	Biomass boiler	23.7	18.3	15.3	10.5	7.1
	Solar thermal	26.6	26.6	26.6	25.1	25.1

Source: Element Energy (2011) *Achieving deployment of renewable heat.*

Note(s): Costs are for current installations. Values are based on 2011 cost data and capital costs are annualised over a 15-year period at an interest rate of 8%. SWI refers to properties fitted with solid wall insulation.

Table 3.1: Announced support levels compared to estimates of cost penalties, by technology (for new installations)

	Residential		Non-residential	
	Estimated cost penalty (p/kWh)	Announced support (p/kWh)	Estimated cost penalty (p/kWh)	Announced support (p/kWh)
ASHP	4-6	Residential tariff levels to be announced in 2012	1.5	TBC in 2012
GSHP	6-9.5		4-5	3-4.3
Biomass boiler	9-13		3-6	2.6-7.6
Solar thermal	16-20		20	8.5

Source: Element Energy (2011) *Achieving deployment of renewable heat*; DECC (2011) *Renewable Heat Incentive.*

Note(s): Estimated cost penalties are illustrative only, and were not the main focus of the Element Energy analysis. Cost penalties are calculated versus a gas boiler.

Biogas plants are potentially eligible for support under three different mechanisms – the RHI, the Renewables Obligation and the feed-in tariff scheme. Element Energy undertook a high-level comparison of the different incentive schemes (Box 3.6). They concluded that the combined effect of these different incentives is that, in general, CHP is likely to be the most attractive economic proposition. For larger installations, if it is not feasible to use the heat produced then biomethane injection is economically viable. There is a question about support for small installations without a heat load, with the possibility that more funding may be required to make projects viable. We will look at the best use of biogas in more detail in our bioenergy review later in 2011.

Box 3.6: The impact of different biogas support schemes

With the introduction of the RHI, biogas plants of different scales may be eligible for support under one of three mechanisms:

- The **Renewables Obligation** – this is the primary support scheme for renewable electricity generation in the UK, and places an obligation on electricity suppliers to source an increasing proportion of their electricity from renewable sources. ROCs are 'green certificates' issued to renewable electricity generators (one ROC per MWh of eligible electricity produced) and can be traded (their value therefore varies).
- **Feed-in tariff** support – introduced in Great Britain in April 2010, the FiT provides guaranteed incentive payments to sub-5 MWe renewable electricity generators.
- The **Renewable Heat Incentive** – the RHI is expected to support heat produced from on-site combustion of biogas (up to 200 kWth); and injection of biomethane into the gas grid (at all capacities).

These different incentives have implications for the end-use of biogas plants, as biogas producers will be eligible for different levels of support depending on the scale of the plant and the choice to produce heat, electricity, or biomethane for injection to the grid.

Element Energy undertook a high-level comparison of the different incentive schemes to provide an insight into their effects. They made the following observations:

- For larger-scale plants (5 MW) with access to a suitable heat load, CHP operation (subsidised under the RO or FiT) is likely to remain a relatively attractive economic proposition and offers the highest CO_2 saving.
- The main impact of the RHI is for sites where it is not feasible to use the heat produced. For example, for a 5 MW waste anaerobic digestion plant RHI-supported injection becomes a viable option. Similarly, for a 1 MW sewage gas plant, injection becomes an economically-viable alternative to power-only operation.
- For small installations (e.g. on-farm anaerobic digestion, with 100 kW biogas output capacity), either heat-only or CHP operation could offer reasonable returns, provided that the RHI is available for the heat produced in both cases. If there is no heat load, FiT and RHI levels may not be sufficient to make biomethane injection or power generation attractive enough to overcome high plant costs.
- Biogas injection is not an attractive economic prospect for small biogas generators, due to the high capital and operating costs involved.

The delay in introducing residential tariffs could still be consistent with the 2020 ambition, given the greater contribution required from the non-residential sector (e.g. over 50% of emissions reduction from renewable heat technologies in 2020 is in the non-residential sector).

However, to minimise any risks associated with the delay, certainty on the continuation of residential tariffs for the period beyond 2014/15 should be provided when tariffs are announced in 2012.

More generally, given current uncertainties it will be important to monitor cost evolution closely, and to adjust support accordingly (e.g. if it becomes clear that support levels for a technology are too low as evident in limited uptake, or that they are unnecessarily high, such that similar levels of uptake could be achieved with less support).

Overall level of financial support

The overall level of financial support (i.e. across all the renewable heat technologies) was initially set at around £1 billion for the period to 2014/15. This was subsequently reduced to £860 million, as announced in the October 2010 Spending Review.

Given this level of funding, achieving the Government's 2020 ambition of 12% renewable heat penetration will require increased support beyond 2014/15:

- Renewable heat technologies will continue to incur additional costs relative to conventional alternatives. Commitment to continued support is therefore required in the short term to give confidence to suppliers and support supply chain expansion.
- Analysis suggests total support of around £2 billion could be required in 2020.
  - Support per unit of renewable heat should fall in the future as technology learning is reflected in lower costs.
  - Offsetting this, total support should increase as renewable heat ambition increases.
- Beyond 2020 the Element Energy analysis suggests that there will be ongoing costs for some renewable heat technologies, such that further support will be required, either in the form of the Renewable Heat Incentive or a carbon price applied to heat.

As for support levels for specific technologies, it will be important to monitor cost evolution closely and adjust total support for renewable heat accordingly to deliver current (or possibly adjusted) 2020 ambition.

Balance of support between technologies and sectors

Given a total funding envelope of £860 million in the period to 2014/15, it will be important to ensure that there is balanced spending across the range of technologies in order that a portfolio of options for deployment in the 2020s is developed.

There is a risk that available support is focused on certain market niches, at the expense of technologies that are likely to be needed in the 2020s (e.g. focus on deployment of heat pumps in the commercial sector to 2020 would be inconsistent with the need to roll out heat pumps predominantly in the residential sector through the 2020s).

This risk could be mitigated in a number of ways:

- Having a clear strategy that identifies as a priority the need to achieve a critical mass of roll-out for each technology in each sector. For example, our analysis suggests that the aim should be to add around 500,000 air-source and ground-source heat pumps in the residential sector over the next decade.
- Monitoring of support for specific technologies would reveal whether too much or too little is being provided, resulting in over- or under-investment; flexibility in banding of support for different technologies would allow such distortions to be corrected.
- Monitoring should not be restricted to financial incentives but should also cover effectiveness in addressing non-financial barriers. For example, if it were the case that there were low uptake of air-source heat pumps in the residential sector, the appropriate response might be to introduce new levers for addressing non-financial barriers rather than necessarily increasing financial support (section 2 (iii)).
- The possibility of limiting support for specific technologies or application in specific sectors could be considered. This point applies in general but particularly for the more expensive technologies (e.g. solar thermal), where limits on support under the RHI would help to ensure that these do not crowd out support for lower-cost technologies with more promise for the 2020s.

(iii) Levers for addressing non-financial deployment barriers

Three key levers for addressing non-financial barriers are accreditation of suppliers, integration of renewable heat and energy efficiency policies, and zero-carbon homes:

- **Accreditation of suppliers.** The Element Energy analysis highlights the crucial role of supply chain expansion in supporting investment in renewable heat over the next decade, and within this the importance of ensuring that there are sufficient numbers of accredited installers. Therefore it will be important to have arrangements in place both for training and accreditation of installers. Together with validation of equipment, this could also help to increase consumer confidence.
- **Integration of renewable heat and energy efficiency policies.** Separate mechanisms for promoting renewable heat and energy efficiency risk complicating the delivery landscape and confusing consumers. The RHI and Green Deal should therefore be integrated. Integration would help to increase the number of suitable buildings, improve consumer confidence, and information, and provide a possible source of financing for up-front investment costs.

– **Suitability.** Given that renewable heat technologies work better in well-insulated houses, linking renewable heat and energy efficiency policies would increase the number of suitable houses. This could be achieved by requiring a minimum energy efficiency rating to qualify for payment under the RHI, and through marketing renewable heat as part of the Green Deal (e.g. by including renewable heat technologies in energy audits and follow-up).

– **Consumer confidence.** Marketing renewable heat as part of the Green Deal would enhance consumer confidence, both because it would ensure deployment in suitable buildings, and because it would offer an opportunity to provide customers with better information. It would also allow reduction of transaction costs if implementation of energy efficiency and renewable heat measures were to form part of a whole-house or one-stop-shop approach.

– **Financing up-front costs.** Installation costs are potentially significant (e.g. around £6,000 to £10,000 for an air-source heat pump in the residential sector) and prohibitive for some applications. Financing constraints could be addressed by integration – allowing financing under the Green Deal for renewable heat investment.

- **Zero-carbon homes.** Renewable heat deployment in new homes does not face as many barriers as retrofit to existing homes. New build homes tend to be more thermally efficient and can be designed to incorporate low-temperature heat distribution. This highlights the opportunity offered by new homes and the importance of defining zero-carbon homes in such a way as to promote renewable heat (Box 3.7).

Box 3.7: Zero-carbon homes

From 2016, new homes in England will have to be built to level 6 of the Code of Sustainable Homes, as 'zero-carbon homes'. The exact definition of 'zero-carbon' is yet to be decided but it is likely to require high energy efficiency standards (e.g. with energy demand for space heating expected to be around 40 kWh/m^2, compared to an average of around 200 kWh/m^2 in the existing stock), as well as on-site or off-site renewable energy generation for all building-related energy demand (e.g. lighting, ventilation). The devolved administrations are also introducing zero-carbon building standards. By 2030, we can therefore expect a stock of new homes built to zero-carbon standards of around 2-3 million, primarily driven by the demand for extra dwellings.

3. Impact of renewable heat support on energy bills

In our 2008 report *Building a low-carbon economy* we highlighted potentially significant energy bill and fuel poverty impacts associated with the Renewable Heat Incentive:

- In line with the Government's draft Renewable Energy Strategy, we assumed that the RHI would result in a 25% increase in the price of heating fuels.
- This underpinned our assessment of the fuel poverty impact from meeting the first three carbon budgets. This assessment suggested that there was scope to reduce the number of households in fuel poverty through energy efficiency improvement, but that that this would be broadly offset by rising electricity and gas prices.

Since this report, however, the Government has announced that from 2011/12 to 2014/15 the RHI will be funded by the Exchequer rather than through increased prices for fossil heating fuels. No decision has yet been taken on the mechanism for financing after 2014/15.

If the RHI continued to be funded by the Exchequer, then it would have no impact on energy bills. Compared to our 2008 report, this suggests significant scope for reducing the number of households in fuel poverty through energy efficiency improvement more than offsetting costs of renewable electricity.

Chapter 4

Developing options for renewable transport

Introduction and key messages

In this chapter we summarise our advice on the fourth carbon budget[1] as this relates to renewable energy in surface transport. In particular, we focus on the use of biofuels in surface transport.

We have previously highlighted that limits on deployment of biofuels are likely to relate to sustainability rather than technical or economic barriers. Sustainability concerns include the tension between use of land for growth of food versus biofuels feedstocks; lifecycle emissions in the growth and processing of biofuels feedstocks (which question to what extent biofuels can be regarded as zero carbon); and wider environmental considerations (e.g. impacts of growing biofuels feedstocks on biodiversity).

Given sustainability concerns, we have adopted a cautious approach to the use of biofuels in surface transport:

- We have accepted the findings of the Gallagher Review and reflected this in our emissions scenarios, which include 8% penetration in liquid fuels by 2020.
- Our emissions scenarios for the 2020s reflect ongoing sustainability concerns and include only very limited growth:
  - Our Medium abatement scenario retains the amount of biofuels available through the 2020s at the level suggested by Gallagher for 2020.
  - Our High scenario includes increased penetration reflecting global scenarios set out by the International Energy Agency.
- These scenarios are consistent with a longer-term path to economy-wide decarbonisation where scarce supplies of sustainable bioenergy are used predominantly in sectors with limited alternative abatement options (e.g. aviation, industrial heat), and in surface transport niche markets (e.g. HGVs and possibly plug-in hybrid vehicles).

Given our current review of bioenergy, it would be premature to present new analysis in this chapter, which therefore includes only our advice to date as regards the approach to biofuels in surface transport. However, our bioenergy review – to be published later in 2011 – will include detailed analysis of and scenarios for sustainable bioenergy: where this should best be used across sectors and an assessment of emissions savings associated with biofuels.

We now provide more detail as follows:

1. Renewable energy in the transport sector to 2020
2. Renewable energy in the transport sector beyond 2020
3. Next steps: the Committee's bioenergy review

[1] CCC (2010) *The Fourth Carbon Budget - Reducing emissions through the 2020s.*

1. Renewable energy in the transport sector to 2020

Policies to support uptake of biofuels

Current transport biofuels penetration in the UK is driven by the Renewable Transport Fuel Obligation, with longer-term options for meeting EU directives (the Renewable Energy Directive and the Fuel Quality Directive) still under review:

- **Renewable Transport Fuel Obligation (RTFO)**: The RTFO came into effect on 15 April 2008, and requires fossil fuel suppliers (those who supply at least 450,000 litres per year) to ensure that a specified percentage of their fuels for road transport in the UK – rising from 3.5% in 2010/11 to 5% by volume (4% by energy) in 2013/14 – comes from renewable sources.
- **Renewable Energy Directive (RED)**: In addition to the overall renewable energy target, the RED sets a binding UK target of 10% energy from renewable sources in transport by 2020. The feasibility of reaching the 10% transport sub-target whilst ensuring sustainability will be subject to review by the European Commission by the end of 2014.
- **Fuel Quality Directive**: The transport sector also has to comply with the Fuel Quality Directive, which requires a 6% reduction in the greenhouse gas intensity of transport fuels by 2020.

The current UK situation

In 2009, biofuels made up 2.9% of total petrol and diesel sales in the UK[2], with the majority of this being accounted for by biodiesel:

- Biodiesel for use in diesel vehicles accounted for 77% of total biofuels (~1 billion litres, ~4% of diesel sales).
- Bioethanol for use in petrol vehicles accounted for 23% of total biofuels (~0.3 billion litres, ~1.5% of petrol sales).
- The relatively higher share of biodiesel reflects that, in general, bioethanol must be blended with petrol close to the point of sale (rather than at the refinery), which requires greater capital investment in the supply chain.

Approximately 10% of UK biofuels are produced using domestic feedstocks[3]:

- Around 9% of biodiesel and 14% of bioethanol in the UK market are produced using domestic feedstocks.
- Feedstocks for domestic production include recycled cooking oils, agricultural by-products (e.g. tallow), and mainstream agricultural crops (such as cereals and root crops for bioethanol and oil seed crops for biodiesel).
- The feedstocks providing the greatest proportion of imports are soy (around 41% of UK biodiesel consumption) and sugar cane (around 67% of UK bioethanol consumption).

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2 http://www.dft.gov.uk/pgr/roads/environment/renewable-fuels/biofuels/report09/pdf/report09.pdf.
3 http://www.renewablefuelsagency.gov.uk/sites/rfa/files/_documents/24_RFA_quarterly_report_Apr_2009_Apr_2010%20vpdf%20v2.pdf.

Scenarios to 2020

We have previously noted sustainability concerns related to biofuels (see our December 2008 and December 2010 advice on carbon budgets, and 2009 review of aviation emissions):

- There is a tension between the use of land for growth of food versus bioenergy feedstocks. The risk is that with high growth of bioenergy feedstocks, there would be limited land available for growth of food, resulting in high prices and supply shortages. This risk is more pronounced given the significant projected increase in global population over the next four decades, and moves to more land-intense diets as incomes increase.
- There are concerns around emissions reductions associated with biofuels when lifecycle emissions including from land use impacts and from growth and processing of feedstocks are accounted for.
- Given a scarce supply of bioenergy, this should be used in sectors where there are limited alternatives for decarbonisation (e.g. aviation, industry, as opposed to surface transport, where decarbonisation through electrification is likely to be technically feasible and economically viable).

Specifically, we have accepted the findings of the Gallagher Review (Box 4.1), which suggested it would be appropriate to plan for biofuels penetration of around 8% by energy in 2020.

However, given the particular accounting rules in the EU renewable energy sub-target for transport, our 2020 scenario for transport decarbonisation (described below) would be sufficient to meet the 10% sub-target with only an 8% biofuels share (Box 4.2).

Box 4.1: Recommendations from the Gallagher Review

The Gallagher Review[4] called for a slowdown in the growth of the use of biofuels. This recommendation reflected uncertainties surrounding the role of biofuels in rising food prices, its contribution to deforestation, the future availability of land for cultivation of feedstocks and doubts about the net greenhouse gas impact of biofuels when indirect land-use change is considered.

Some of the specific recommendations were as follows:

- The proposed increase in biofuels under the RTFO should rise to a maximum of 5% (by volume) in 2013/14. Under the RTFO as originally proposed, 5% (by volume) would have been reached in 2010.
- Targets higher than 5% (by volume) should only be implemented beyond 2013/14 if biofuels are shown to be demonstrably sustainable. Failure to deliver demonstrably sustainable biofuels should result in a reduction in the target after 2013/14.
- The proposed EU biofuels target of 10% by energy is unlikely to be met sustainably and the introduction of biofuels should therefore be slowed. New targets should be set of between 5% and 8% (by energy) for the EU for 2020, including 1-2% from advanced technologies.
- There should be a specific EU-wide obligation to encourage advanced or second generation technologies to commence in 2015 rising to 1-2% by energy in 2020.
- If a global policy framework were in place to ensure sustainable production of biofuels and new evidence was to provide further confidence in the net greenhouse gas savings of biofuels then a higher trajectory could be embarked upon starting in 2016 and rising to 10% by energy in 2020.

[4] Renewable Fuels Agency (2008) *The Gallagher Review of the indirect effects of biofuels production.*

Box 4.2: Meeting the Renewable Energy Directive transport sub-target

The transport sub-target in the Renewable Energy Directive, set at 10% for all EU member states, is calculated in a different way to the overall renewable energy target:

- Renewable energy consumed in all forms of transport including road, rail, aviation and national navigation (UK shipping) can be taken into account, but only needs to provide 10% of the energy used in *surface* (road and rail) transport.
- Biofuels from wastes, residues, non-food cellulosic material, and ligno-cellulosic material are allowed to count twice.
- Renewable electricity used in electric and plug-in hybrid vehicles is allowed to count two and a half times.
- These 'multiplied rewards' do not contribute to the achievement of the overall renewable energy target. It is therefore possible to meet the 10% transport sub-target without transport contributing a full 10% towards the overall renewable energy target.

In line with Gallagher recommendations, our recommended 2020 scenario includes a lower level of biofuels than Government plans set out in the DECC Renewable Energy Strategy (2009). The scenario still meets the sub-target, mainly through a higher penetration of electric vehicles, with a very small contribution from aviation biofuels; it does not build in increased renewables contributions from rail or shipping (Table B4.2).

Table B4.2: Extended Ambition contributions towards 10% transport sub-target (2020)

	Road transport biofuels	Electricity	Aviation	Total
Scenario	8% by energy (Gallagher)	1.7 million electric vehicles	'Likely' scenario from aviation emissions review	
Contribution to sub-target	8%	1.6%	0.3%	10%

Note(s): Assumes around 30% of electricity is renewable and electricity used in electric and plug-in hybrid vehicles counts two and a half times. Electricity used in rail assumed to stay constant at 2009 levels and does not get the multiplied reward.

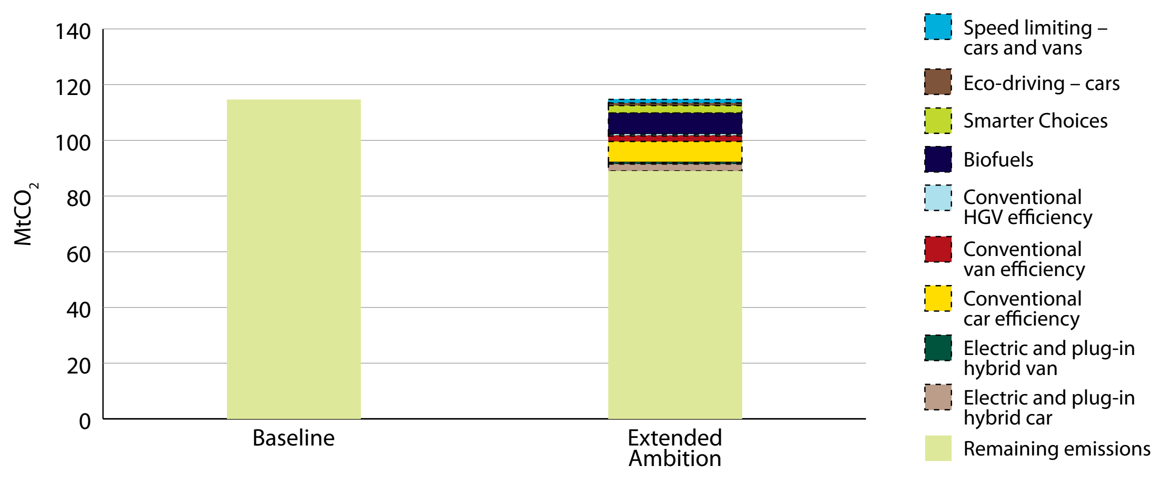
Other options for reducing emissions to 2020

Alongside biofuels, our scenarios for transport decarbonisation include abatement from improving fuel efficiency of conventional vehicles, replacement of conventional vehicles with electric alternatives, and various options for consumer behaviour change:

- **Fuel efficiency improvement.** Significant improvements in conventional vehicle efficiency are both feasible and likely over the next decade, to reach agreed EU targets for new vehicle sales of 95 gCO_2/km for cars (compared to a UK average of 150 gCO_2/km for new cars in 2009) and 147 gCO_2/km for vans by 2020 (compared to 206 gCO_2/km for new vans in the UK in 2009).
- **Electric vehicle take-up.** Battery electric and plug-in hybrid cars and vans should play an increasingly important role through the next decade, reaching 16% of new vehicle sales in 2020. This is subject to Government support for market development being in place, both as regards financial support for vehicle purchase and development of a battery charging network; it could make a direct contribution to meeting the UK's transport sub-target under the EU Renewable Energy Directive, and an indirect contribution to meeting the overall target.
- **Reduction in car miles.** There is an opportunity to reduce car miles by around 5% through implementation of Smarter Choices policies (i.e. workplace and school travel plans, travel awareness promotion, teleworking, teleconferencing and home shopping, and car clubs and car sharing schemes).
- **More efficient driving.** Eco-driving techniques if widely applied would result in fuel consumption reduction up to 0.3% (for cars and vans) and 4% (for HGVs) in 2020.
- **Limiting speed.** Keeping speed on motorways within the current legal limits would reduce fuel consumption by around 2%.

These measures account for around 70% of the total emissions reduction in the road transport sector in 2020, with biofuels accounting for around 30% (Figure 4.1).

Figure 4.1: Extended ambition abatement and remaining emissions (2020)



Source: CCC analysis.

2. Renewable energy in the transport sector beyond 2020

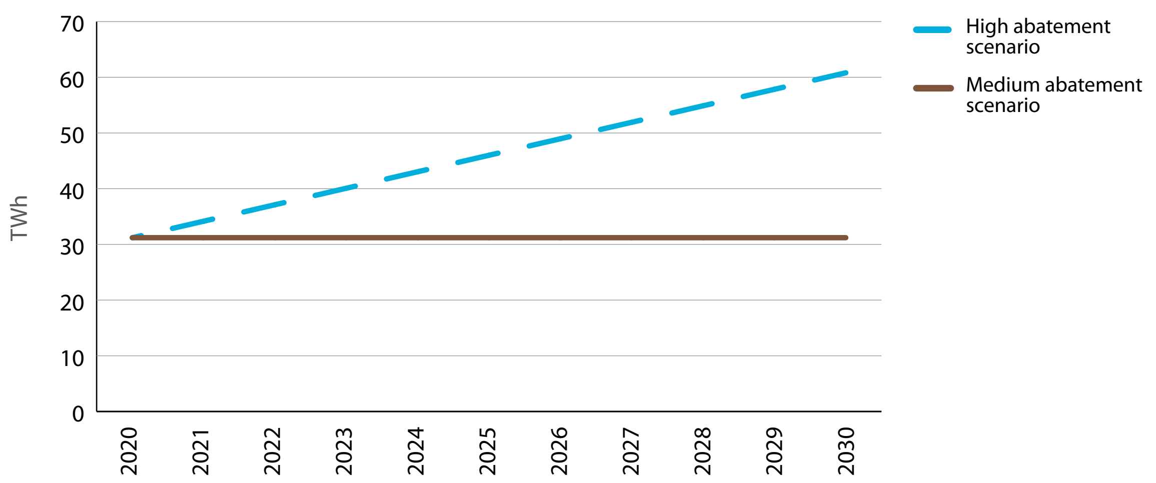
Renewable transport fuels through the 2020s

Although there may be scope for increased use of sustainable biofuels through the 2020s, this is currently highly uncertain:

- Available land for growth of sustainable bioenergy feedstocks is likely to be highly constrained unless there are significant increases in agricultural productivity.
- Although there are biofuels technologies which do not require land that could potentially be used in agriculture (e.g. algae) these require significant further progress in the development of the technology.
- Waste and residues, as well as bioenergy feedstocks grown on marginal land, might be more highly valued in aviation or industry rather than surface transport (e.g. we assume a range for biofuels penetration in aviation of 10% to 30% by 2050)[5].

Therefore we have adopted a cautious approach under which any growth in biofuels penetration through the 2020s is limited, with a range of penetration in the scenarios underpinning our fourth carbon budget advice of around 30-60 TWh (11-25% by energy[6]) in 2030 (Figure 4.2):

Figure 4.2: Fourth budget biofuels penetration (2020-2030)



Source: CCC analysis.

[5] CCC (2009) *Meeting the UK aviation target – options for reducing emissions to 2050.*

[6] Around 30 TWh is equivalent to 8% of liquid fuels consumed in the surface transport sector in 2020 but 11% in 2030 as we assume total liquid fuel consumption declines through the 2020s.

- **Low/Medium abatement scenario**: the level of UK biofuels suggested in the Gallagher Review for 2020 defines the amount of biofuels available in the 2020s, resulting in around 30 TWh (11% by energy in liquid fuels) by 2030.
- **High abatement scenario**: includes biofuels penetration according to the Gallagher Review in 2020 (30 TWh), rising above this in line with the IEA's BLUE Map scenario through the 2020s[7], resulting in around 60 TWh (25% by energy in liquid fuels) by 2030[8].

Together with electric vehicle penetration and charging of batteries by renewable generation, our Medium abatement fourth budget scenario would result in a renewable transport share of around 15% in 2030[9].

Cost of renewable transport fuels

Biofuels abatement costs are a function of production costs, the abatement achieved by different types of biofuel and the relative cost of petrol and diesel, all of which are highly uncertain. IEA analysis aims to reflect this uncertainty and provides a range of cost estimates compared to the oil price:

- For an oil price of $60/bbl the IEA analysis suggests that there is a 39% cost penalty for biofuels.
- At $120/bbl the IEA estimates that biofuels are 16% cheaper than conventional fuels.
- DECC's central projection is of an oil price around $90/bbl in 2030[10], in which case the cost of biofuels and conventional fuels is broadly similar.

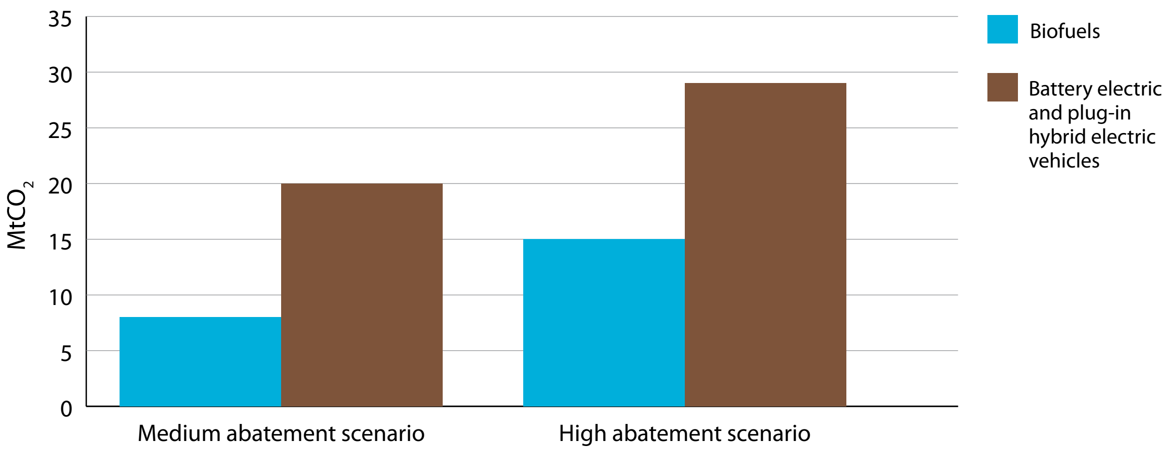
Therefore our scenarios for biofuels penetration do not involve any additional cost under DECC's central case price projection. Under a low oil price projection, costs in the Medium scenario would be around 0.02% of GDP in 2030, whereas under a high oil price projection there would be a saving of around 0.01% of GDP in 2030.

Surface transport scenarios to 2030 and beyond

The Medium and High abatement scenarios in our fourth budget advice include high penetration of electric cars and vans by 2030: 60-85% penetration of new vehicles, and around 30-40% penetration of the vehicle fleet, based on analysis suggesting that these options are likely to become cost-effective over the next decades. Electrification is therefore likely to make a relatively high contribution to required surface transport emissions reduction in 2030 compared to biofuels (Figure 4.3).

[7] Our High scenario is based on the principle that the UK's share of total global biofuel consumption should be equal to its share of total transport energy consumption. To establish the appropriate UK share of total transport energy consumption, we estimate UK energy consumption in 2030 if it were on a path consistent with the IEA BLUE Map scenario (1.2% of global transport fuel use). This implies a share of biofuels for the UK of 1.2% of the global total of around 4,800 TWh in 2030 (equivalent to 61 TWh). We model linear take-up from around 30 TWh in 2020 to around 60 TWh in 2030.
[8] The High abatement scenario also assumes further improvements to conventional car efficiency and increased penetration of electric vehicles.
[9] This assumes around 40% of electricity generation is from renewable sources.
[10] Recent prices have been considerably higher than the DECC projections (e.g. around $110/bbl in March 2011), emphasising the high uncertainty attached to oil prices and the importance of considering a range of future prices.

Figure 4.3: Abatement in 2030: biofuels, EVs and PHEVs (Medium and High scenarios)



Source: CCC analysis.

Note(s): Assessment of abatement includes rebound effects.

Increasing electrification of transport is consistent with an increasing renewable energy share. For example, a 30% share of electric cars and vans in the fleet, along with a 40% renewable share in power generation, would constitute a 5% renewable share in transport (allowing for the higher efficiency of electric vehicles compared to conventional vehicles). As the vehicle stock turns over after 2030 the contribution of electric vehicles to emissions reduction and renewable energy use will increase quickly.

Our 2030 scenarios are consistent with a longer-term path where surface transport is almost fully decarbonised by 2050, largely based on electric vehicles (battery and possibly hydrogen), with possible use of biofuels in plug-in hybrid and HGV niches subject to availability of sustainable biofuels and cost.

3. Next steps: the Committee's bioenergy review

Our approach to the use of biofuels in surface transport and bioenergy more generally (e.g. in aviation, industry, power) reflects significant uncertainties relating to key drivers of sustainable bioenergy availability, and to the best use of available biofuels:

- **Demographics and socio-economic changes.** Growth in population and increased income resulting in changed diet will, without major advances in productivity, significantly increase the demand for land to grow food.
- **Agricultural productivity improvement.** Although pressures on land may be eased through agricultural productivity improvement, it is not clear to what extent this will be feasible without increasing carbon intensity (e.g. increased fertiliser application) or breakthrough technologies (e.g. genetically modified crops).
- **Available land.** The combination of uncertainties around demographic and socio-economic changes and agricultural productivity results in significant uncertainty around residual land available for growth of bioenergy feedstocks. This is more pronounced given lack of evidence about currently unused land, and the extent to which this could be used in agricultural or bioenergy feedstock production.
- **New technologies.** Although there is the possibility of new technologies for bioenergy feedstocks which do not require land that could potentially be used in agriculture (e.g. algae), these would require technology breakthroughs and therefore remain highly uncertain.
- **Best use of bioenergy.** Given limited available sustainable bioenergy, this should be best used in sectors where there are limited alternatives for decarbonisation. However, further evidence is required to better understand whether scarce bioenergy should be used in aviation, industry, niche surface transport markets, etc.

In our bioenergy review, to be published before the end of 2011, we will develop scenarios for key drivers (e.g. dietary change, agricultural productivity improvement, residual land available for growth of bioenergy feedstocks) and assess best use of available bioenergy across sectors. In the meantime, we use the biofuels scenarios in this chapter as the basis for economy-wide renewable energy scenarios set out in Chapter 5.

Chapter 5

Overview of renewable energy scenarios and impacts

1. Scenarios for renewable energy penetration
2. Impacts of renewable energy ambition
3. Next steps in developing renewable energy options
4. Further work of the Committee

Introduction and key messages

In this chapter we do three things:

- We set out renewable energy scenarios based on the scenarios for renewable electricity, heat and transport in Chapters 1-4.
- We summarise energy bill, competitiveness, fiscal and environmental impacts, largely based on more detailed analysis from our advice on carbon budgets[1].
- We highlight next steps in addressing challenges for renewable energy investment.

The key messages in the chapter are:

- Our scenarios for 2020 result in a renewable energy share of around 15% (230 TWh) and are therefore consistent with the UK's target under the EU Renewable Energy Directive. The aim to deliver the target through around 30% (120 TWh) penetration in electricity, around 12% (70 TWh) penetration in heat, and around 8% (30 TWh) penetration in transport, is currently appropriate. However, a flexible approach should be adopted with scope for rebalancing as uncertainties over costs and deliverability of various options are resolved.
- Under the current financing approach, delivering a 15% renewable energy share is likely to increase household energy bills by around 4% in 2020 against what they would have been without renewables ambition. There is scope to more than offset these potential energy bill impacts through energy efficiency improvement.
- Our scenarios for 2030 imply a renewable energy share of up to 45%.
- Tailoring ambition in the 2020s to the cost of renewable technologies would mitigate energy bill impacts through the 2020s.
- Next steps in introducing incentives to support required investment in renewable energy include:
  - **Electricity generation.** Include provisions for technology support in new electricity market arrangements; establish a Green Investment Bank with the flexibility to provide the full range of financial instruments; implement a planning approach consistent with national priorities to build a low-carbon economy and deliver carbon budgets.
  - **Heat.** Confirm RHI tariffs for the residential sector as soon as possible; provide clarity about long-term RHI financing; address non-financial barriers through accreditation of installers, integration of renewable heat and energy efficiency policies (i.e. the RHI and the Green Deal).
  - **Transport.** Introduce safeguards to ensure biofuels deployment is consistent with sustainability objectives; further develop the evidence base on availability and best use of sustainable biofuels; provide support for electric vehicle market development.

[1] CCC (2008) *Building a low-carbon economy - the UK's contribution to tackling climate change;* CCC (2010) *The Fourth Carbon Budget - Reducing emissions through the 2020s.*

1. Scenarios for renewable energy penetration

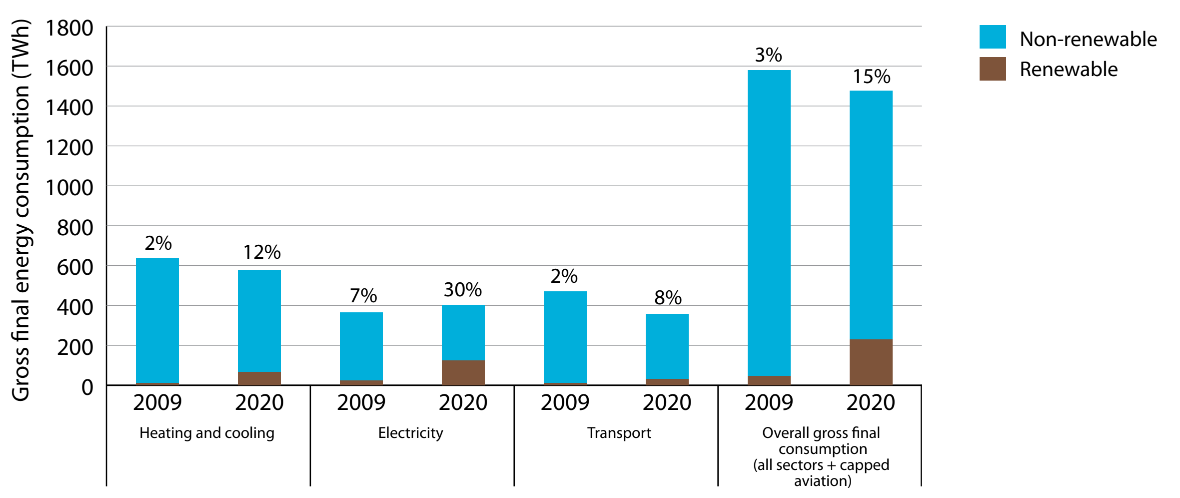
i) Renewable energy penetration in 2020

Our renewable energy scenario to 2020 incorporates the various sectoral scenarios in Chapters 2-4 and reaches penetration of around 15% (230 TWh) by 2020. This is in line with the UK's target under the EU Renewable Energy Directive and current Government plans (Figure 5.1):

- **Renewable electricity.** We assume a renewable electricity share of around 30% (120 TWh) in total electricity consumption in 2020, based on investment predominantly in wind generation, and demand reductions due to energy efficiency improvements in lighting and appliances.
- **Renewable heat.** We assume penetration of around 12% (70 TWh) in 2020 through a range of technologies including electric heat pumps, biogas and biomass, alongside demand reductions due to energy efficiency improvement through buildings fabric measures and boiler replacement.
- **Biofuels.** We assume 8% (30 TWh) penetration, by energy, of sustainable biofuels in 2020 in line with recommendations of the Gallagher Review[2], together with assumptions that demand for travel will increase in the period to 2020, and fuel efficiency of new vehicles will improve from current levels of around 150 gCO_2/km to 95 gCO_2/km in 2020.

Whilst this balance is appropriate now as a planning assumption, we have stressed the need for monitoring and flexibility in the balance of effort between technologies and sectors (e.g. possibly substituting offshore wind effort for onshore wind or renewable heat depending on feasibility and relative cost, or purchasing renewable credits in the European market).

Figure 5.1: Share of renewable energy by sector (2009 and 2020)



Source: DECC (2010) *DUKES;* CCC calculations.

Notes: Overall gross final consumption is calculated on the basis as set out in the EU Directive. Energy consumption shown in the heating sector is taken from the CCC heat model and is calculated on a slightly different basis. Demand assumptions are taken from our fourth budget analysis, based on CCC's bottom-up modelling and energy projections from the DECC energy model using central assumptions for population growth from ONS and GDP growth from the Office of Budget Responsibility.

[2] Renewable Fuels Agency (2008) *The Gallagher Review of the indirect effects of biofuels production.*

ii) Renewable energy scenarios to 2030 and 2050

Scenarios to 2030

Our scenarios to 2030 include renewable energy penetration of up to 45% (680 TWh), reflecting an underlying range for renewable electricity penetration and potentially high levels of renewable energy penetration in transport and heat (Figure 5.2):

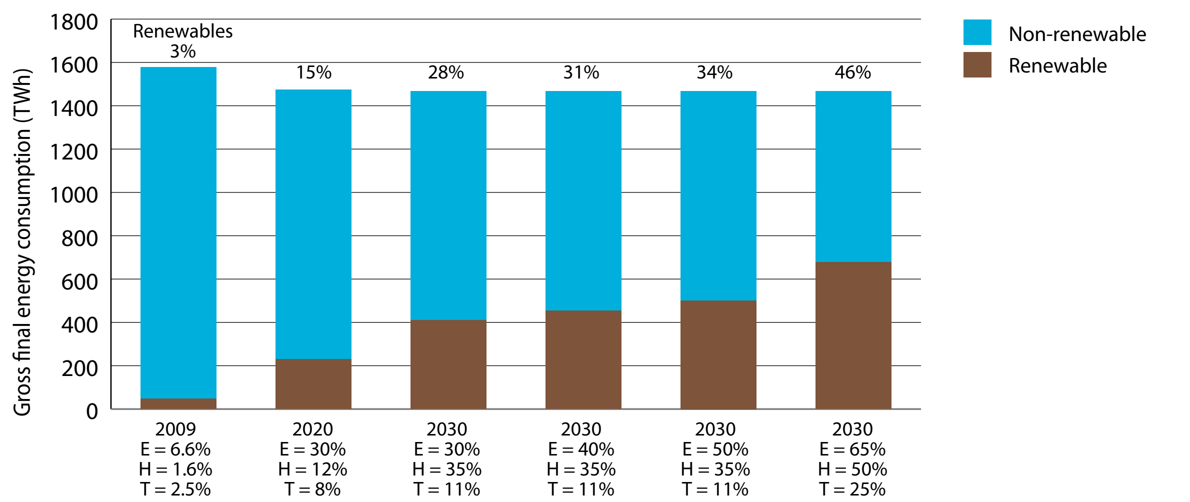
- **Renewable electricity.** Our renewable electricity scenarios range from limited investment beyond 2020, to very high levels of investment depending on relative costs and feasibility constraints for other low-carbon technologies. The range for the share of renewable electricity in 2030 in our scenarios is up to 65% (300 TWh), with 40% (185 TWh) in a central scenario.
- **Renewable heat.** Our renewable heat scenarios are based on significant penetration of heat pumps in residential and non-residential buildings, and the use of bioenergy primarily in industry, with some applications in buildings. Renewable heat shares relative to heat demand are estimated based on an assumption that there is ongoing energy efficiency improvement (e.g. through solid wall insulation in the residential sector). The resulting share of renewable heat in our scenarios in 2030 is up to 50% (280 TWh), with a central scenario of around 35% (210 TWh).
- **Renewable transport.** Our renewable transport scenarios are based on continued penetration at volumes recommended in the Gallagher Review, with a high scenario including a penetration based on the IEA's BLUE Map scenario. In estimating renewable transport shares in total transport energy consumed, we factor in ongoing growth in demand for travel through the 2020s, and ongoing fuel efficiency improvements. The resulting share of renewable energy in transport in 2030 in our central scenario is around 11% (by energy), and in our highest scenario is around 25%.
- **Renewable energy scenarios.** The sum across sectors weighting for energy consumption in 2030 is around 30% (460 TWh) in our central scenario[3]. Higher levels of ambition (e.g. up to 45%, 680 TWh) are technically feasible and might be economically desirable, depending on the evolution of relative costs and the development of supply chains.

The precise level of appropriate ambition will become clear over time. We recommend that the Government keeps ambition for renewable energy under review and revisits this as uncertainties over the economics of different low-carbon technologies are reduced (e.g. in 2017/18 when the first new nuclear plant and CCS demonstration plant are due).

The costs associated with delivering our scenarios are of the order of under 1% of GDP in 2030 compared to a scenario where there are no carbon constraints.

[3] When summing across sectors we also add in renewables in electricity generator own use and biofuels in aviation, and we convert renewable heat to an input basis in line with accounting in the EU Directive. The total is therefore higher than the sum of the individual sectors.

Figure 5.2: Renewable energy and overall gross final consumption in 2009, 2020 and illustrative scenarios for 2030



Source: *DUKES* (2010); CCC calculations.

Note(s): E = Electricity; H = Heat; T = Transport. Overall gross final consumption is calculated on the basis as set out in the EU Directive. Demand assumptions are taken from our fourth budget analysis, based on CCC's bottom-up modelling and energy projections from the DECC energy model using central assumptions for population growth from ONS and GDP growth from the Office of Budget Responsibility.

The path from 2030 to 2050

Beyond 2030 there will be a need for ongoing decarbonisation, with the appropriate contribution from renewable energy currently highly uncertain:

- **Renewable electricity.** Between 2030 and 2050, additional low-carbon capacity will need to be added to the system. This will support the further electrification of the transport and heat sectors, given the increased take-up of electric vehicles and heat pumps (potentially supplemented with hydrogen vehicles and resistive electric heat). Renewables are likely to continue to play a significant part, with the potential to provide the majority of generation, depending on achieved cost reductions and availability of alternatives.
- **Renewable heat.** The path from 2030 to 2050 requires substantial further decarbonisation of heat after 2030, including the further roll-out of heat pumps to suitable residential and non-residential buildings and the use of bioenergy, particularly in the industry sector (possibly combined with CCS). Where limits to heat pumps and bioenergy apply, there is likely to be a role for district heating and/or resistive electric heating, both of which have the potential to be renewable.
- **Renewable transport.** From a situation in 2030 in which the majority of new cars are electric (including plug-in hybrids and hydrogen vehicles), this will need to reach nearly 100% by around 2035 in order for the fleet to turn over fully to electric by 2050. If expected limits on the availability of biofuels do not transpire, then there could be a substantial role for biofuels in 2050 (e.g. a large proportion of cars could be plug-in hybrids). If not, surface transport fuel would be renewable to the extent that the sources of low-carbon electricity and hydrogen production are renewable.

2. Impacts of renewable energy ambition

Impact on energy bills to 2020

Under the current financing approach, the cost of renewable electricity generation will be passed on to consumer bills, and the cost of renewable heat will be funded by the Exchequer (with fiscal implications discussed below).

We estimate that, under central fuel and cost assumptions, achieving the renewable power generation ambition in our 2020 scenario would increase annual energy bills for the average household by around £50-60 in real terms, or 4% (Table 5.1):

- We estimate that the costs of renewable power would add 1.7 p/kWh to the electricity price by 2020, largely due to costs associated with bringing forward investment in offshore wind, which could add around 0.8 p/kWh onto the electricity price under central cost assumptions.
- This would increase the average household electricity bill by £50-60 (10%), relative to what they would otherwise be in 2020.
- Given that electricity accounts for around 40% of household energy bills on average, this translates to a 4% increase in total household energy bills in 2020.

Table 5.1: Average annual household energy bills in 2020 and impact of renewable energy ambition

	2020 (no renewables)	2020 - including cost of renewable energy			2020 - including renewables and energy efficiency		
		Low renewables costs	Central renewables costs	High renewables costs	Low renewables costs	Central renewables costs	High renewables costs
Average unit price, electricity (p/kWh)	15.6	16.7	17.3	17.8	16.7	17.3	17.8
Average household electricity bill	£520	£550	£570	£590	£470	£490	£510
Average household gas bill	£850	£850	£850	£850	£730	£730	£730
Average household energy bill	£1,360	£1,400	£1,420	£1,430	£1,200	£1,220	£1,230

Source: *DECC Quarterly energy prices*; CCC calculations.

Note(s): 2010 prices. Numbers may not sum due to rounding. Range for cost of renewable energy under low, central and high generation cost estimates (see Chapter 1), includes additional system costs due to intermittent renewables e.g. back-up and interconnection, and is inclusive of VAT at 5%. Based on central gas and carbon price projections for 2020 (69 p/therm, £30/tonne).

The costs of renewable generation are additional to the costs of a rising carbon price. The Government's announced carbon price floor of £30/tCO_2 in 2020 will add around 0.6 p/kWh to the electricity price compared to today's levels, adding around £20 to the average household's annual electricity bill. Other rises in electricity bills to 2020 are attributable to expected rises in the price of gas, independent of climate change policy.

Renewable energy in transport is not expected to add to motoring costs as biofuels are expected to be a similar cost to petrol and diesel under central assumptions for the oil price. We have factored the increasing cost of electricity into our analysis of the cost-effectiveness of electric vehicles and electric heat pumps.

Scope for offsetting bill impacts through energy efficiency improvement

It is also important to consider opportunities for reducing energy bills through energy efficiency improvement:

- In the residential sector, we estimate that there is scope for a 14% reduction in heat consumption to 2020 through buildings fabric measures, boiler replacement and behavioural measures.
- Our analysis also suggests that there is scope for a 14% reduction in electricity consumption through the purchase and use of more efficient appliances.

Therefore if the full range of cost-effective measures for improving energy efficiency are implemented, the aggregate bill impacts associated with renewable energy costs can be offset (Table 5.1). This would more than compensate for impacts of renewable electricity investment, and ensure that the share of expenditure on energy relative to income remains roughly flat when allowing for upward pressure on bills from rising gas and carbon prices along with expectations of rising incomes.

There are a range of levers for addressing any ongoing fuel poverty impacts (e.g. social tariffs, income transfers).

Energy bill impacts beyond 2020

The costs associated with delivering this level of ambition are of the order of under 1% of GDP in 2030 compared to a scenario where there are no carbon constraints.

The 2030 energy bill impacts over and above those to 2020 are limited:

- **Electricity.**
  - An increasing proportion of electricity will be paid for under long-term contracts at prices below those of unabated gas with a £30/tCO_2 carbon price in 2020.
  - Whilst unabated fossil-fired generation will become more expensive with an increasing carbon price in the 2020s, this will account for a declining share of total generation (e.g. providing less than 10% of generation in 2030).
  - Whilst there will be some ongoing investment in more expensive offshore wind and marine, this will be limited unless there have been significant cost reductions.
- **Heat.** During the 2020s there is scope for some renewable heat technologies to become cost-competitive and possibly lower cost than conventional heating technologies.

The story in the 2020s is therefore likely to be one of more modest price rises than during the 2010s, and with average energy bills falling relative to income, assuming incomes continue to grow.

Competitiveness impacts

Higher electricity prices could lead to impacts on competitiveness of a small number of energy-intensive UK industries which compete in global markets (e.g. iron and steel, aluminium).

Options for addressing these impacts could include increasing the rebate on the Climate Change Levy, rebating tax as allowed under the European Union Emissions Trading System (EU ETS) Directive, and possibly exempting energy-intensive industries from that part of the electricity price which relates to renewables support (e.g. as in some EU countries).

More generally, competitiveness impacts from renewable energy ambition are likely to be limited to 2020:

- Competitiveness risks are most pronounced as regards possible leakage to other EU countries. These risks are mitigated given ambitious EU-wide renewable energy targets under the Renewable Energy Directive.
- Risks are also mitigated through limited energy bill impacts under the current policy approach to financing of renewable heat investment.

Any increase in UK energy prices through the 2020s due to investment in renewable energy should ideally occur in the context of an EU-wide approach.

To the extent that there are competitiveness risks for this period – inside or outside the EU – there is a range of potential mitigating measures (e.g. as above, plus sectoral agreements, border tariff adjustments).

More generally, developing a full range of renewable and low-carbon options for required economy-wide decarbonisation in the 2020s, and deployment at this time according to least-cost principles, could give the UK a competitive advantage in a carbon-constrained world.

Fiscal impacts

The main fiscal impacts of meeting the renewable energy target are through proposed financing of investment in renewable heat by the Exchequer, rather than via energy bills. It is estimated that this cost will rise from around £100 million in 2011/12 to around £2 billion in 2020, reflecting the additional cost of renewable heat technologies at a penetration of around 12% compared to conventional alternatives.

Environmental impacts

Our scenarios reflect consideration of environmental impacts including impacts on nature, ecosystems and biodiversity, and air quality impacts:

- **Nature.** Our assessments of resource potential for renewable power generation exclude resource where this could impact adversely on national parks, areas of outstanding beauty and nature reserves. Particular concerns relating to a Severn barrage are addressed in Box 1.13.
- **Biodiversity and ecosystems.** Our cautious approach to use of bioenergy reflects a range of considerations including potential impacts on ecosystems and biodiversity associated with changing land use to grow bioenergy feedstocks.
- **Air quality impacts.**
  - Although there is potential for adverse air quality impacts due to burning of biomass in densely populated areas, our scenarios envisage this will primarily be used in industry, away from urban centres.
  - The move away from fossil fuel burning in the transport sector in our scenarios would have positive air quality impacts, given that road transport is currently a key source of air pollution in the UK.

3. Next steps in developing renewable energy options

In our assessment of renewable electricity and heat we have identified key actions to develop options for deployment required to meet carbon budgets in the 2020s, and in the case of renewable transport we have identified the need to improve the evidence base on sustainable biofuels:

- **Renewable electricity.** Key determinants of the investment climate for renewable electricity include Electricity Market Reform, the ROC banding review, mechanisms to increase the availability of finance, the transmission investment regime, and the planning framework:
  - New electricity market arrangements should provide ongoing support for immature renewable generation technologies where UK deployment will be important in driving cost reductions. For example, within the Government's proposed Contracts for Differences for low-carbon generation, a proportion of these could be targeted at supporting less mature renewable technologies. Within this support, the 2020 ambition for offshore wind (12 GW) should not be increased, and could be reduced if other means can be found to meet the EU renewable energy target.
  - Existing arrangements need to be effectively grandfathered and available until new arrangements are clear. This could require extending the RO beyond the date proposed in the Electricity Market Reform consultation.
  - The Green Investment Bank could address potential finance bottlenecks that may otherwise work against delivery of offshore wind ambition through providing a full range of products (i.e. equity, debt and insurance), particularly if is allowed to borrow money from its inception.
  - Approval by Ofgem is required for investments in transmission to ease bottlenecks and support investment in renewable electricity (e.g. onshore and offshore wind).
  - Planning approaches should facilitate investments in transmission that are required to support investments in renewable and other low-carbon generation. In addition, a planning approach which facilitates significant onshore wind investment would reduce the costs of meeting the 2020 renewable energy target, and of achieving power sector decarbonisation through the 2020s.

- **Renewable heat.** Key determinants of the investment climate for renewable heat include detailed design of the Renewable Heat Incentive (RHI).
  - Early clarification is needed about RHI tariffs for the domestic sector to ensure they become available in 2012.
  - Accreditation and possible training of renewable heat installers will be important in easing supply chain constraints and increasing consumer confidence.
  - The RHI and the Green Deal should be integrated. This would provide a number of benefits, including increasing the number of houses suitable for renewable heat technologies, improving confidence and reducing hassle costs, and offering a source of finance for up-front investment costs.
  - Close monitoring of renewable heat deployment will be required, with flexibility to change the financing for specific technologies and review the overall ambition.
  - A decision on financing the RHI after 2014/15 will be required in light of further evidence on fiscal constraints, impacts on consumer bills and potential leakage of energy-intensive industry.
- **Renewable transport.** The key issue here is the level of sustainable biofuels likely to be available given land constraints and alternative uses of bioenergy. These aspects are highly uncertain and further evidence is required. A prudent approach to use of biofuels in surface transport is currently appropriate.

4. Further work of the Committee

There are two key areas where the Committee will provide further evidence and analysis relevant in the context of renewable energy strategy:

- **Bioenergy review.** This will be published before the end of 2011 and consider two key questions:
  - How much sustainable bioenergy is there likely to be available?
  - In which sectors should this best be used given alternatives for decarbonisation (e.g. biofuels in surface transport or aviation, biogas and biomass in heat for buildings and industry, biomass power generation with carbon capture and storage)?
- **Progress reports to Parliament.** We will continue to monitor progress on increasing the level of renewable energy penetration as part of our broader reports to Parliament on progress reducing emissions and meeting carbon budgets. Our next report to Parliament will be published in June 2011.

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