Next steps on Electricity Market Reform – securing the benefits of low-carbon investment

Committee on Climate Change | May 2013

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 May 2009. 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 fourth carbon budget was legislated in June 2011 at the level that we recommended.

Progress meeting carbon budgets

The Climate Change Act requires that we report annually to Parliament on progress meeting carbon budgets. We have published four progress reports in October 2009, June 2010, June 2011 and June 2012. We will publish our fifth progress report in June 2013.

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, design of the Carbon Reduction Commitment, renewable energy ambition, bioenergy, and the role of local authorities. In September 2010, July 2011 and July 2012, we published advice on adaptation, assessing how well prepared the UK is to deal with the impacts of climate change.

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Other members of the Secretariat that contributed to the report: Ute Collier, Kris Davies, Helena Engelbrecht, Adrian Gault, Jenny Hill, David Joffe, Alex Kazaglis, Swati Khare-Zodgekar, Ewa Kmietowicz, Sarah Leck, Eric Ling, Jo McMenamin, Joanna Ptak, Stephen Smith, and Kavita Srinivasan.

A wide range of stakeholders who engaged with us, provided advice, or met with the Committee bilaterally.

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Foreword

The Climate Change Act provides the UK with the long-term framework necessary for the development of a low-carbon economy. This enables the UK to play its part in avoiding dangerous climate change, while at the same time providing insurance against future high gas prices and enhancing our energy sovereignty. It is the duty of the Climate Change Committee to advise Parliament on the most cost-effective measures necessary to deliver this, based upon the latest science.

The Government recently published a package of measures which would support investment in low-carbon technologies in the years up to 2020. This included the Energy Bill, which will introduce long-term contracts for low-carbon power generation, as well as funding for investments in low-carbon technologies coming on to the system during this period.

In this context, the Committee has considered how best these policies might be advanced particularly in the light of the opportunities presented by the exploitation of shale gas. It has also taken account of the highly uncertain investment conditions relating to the period beyond 2020, which threaten to undermine the Electricity Market Reform and therefore to deliver bad value for money from the funding commitments that have been made. In all this, the Committee has been continually concerned to ensure that the UK's energy needs are fully met.

This report shows that there is a clear benefit in committing to invest in low-carbon generation over the next two decades. This extension of the time frame beyond 2020 will encourage the necessary investment at a very limited additional cost to the consumer, adding £20 to the annual household energy bill in 2030 compared to 2020, while offering significant cost savings thereafter.

This conclusion has been reached after considering whether an alternative strategy of investing in gas-fired generation through the 2020s and delaying investment in low-carbon technologies to the 2030s would be more sensible. The detailed analysis shows that to invest in low-carbon technologies to 2020, then to focus on investment in gas in the 2020s, and to move back to investment in low-carbon generation in the 2030s simply doesn't stand up. Such an approach is likely to drive up costs, by up to £100 billion in some scenarios.

It is therefore important to avoid these unnecessary costs by resolving present uncertainties. The Government should state clearly that it intends to support investments in low-carbon technologies through the 2020s.

We think that the best way to do this is to set in legislation this Parliament a target to reduce 2030 carbon intensity to 50 gCO_2/kWh. Industry has been clear that this would provide them with the confidence that they need to invest large amounts of money in project development and the supply chain.

Lord Deben
Chairman, Committee on Climate Change

The Committee

The Rt. Hon John Gummer, Lord Deben, Chairman
The Rt. Hon John Gummer, Lord Deben established and chairs Sancroft, a Corporate Responsibility consultancy working with blue-chip companies around the world on environmental, social and ethical issues. He was the longest serving Secretary of State for the Environment the UK has ever had. His experience as an international negotiator has earned him worldwide respect both in the business community and among environmentalists. He has consistently championed an identity between environmental concerns and business sense.

David Kennedy (Chief Executive)
David Kennedy is the Chief Executive of the Committee on Climate Change. Previously he worked on energy strategy and investment 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.

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Paul Johnson

Paul is the director of the Institute for Fiscal Studies. He has worked on the economics of public policy throughout his career. Paul has been chief economist at the Department for Education and director of public spending in HM Treasury, where he had particular responsibility for environment (including climate change), transport and public sector pay and pensions. Between 2004 and 2007 Paul was deputy head of the Government Economic Service. He has also served on the council of the Economic and Social Research Council.

Professor Dame Julia King

Professor Dame Julia King DBE 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, as well as holding senior posts in the marine and aerospace businesses. Julia is one of the UK's Business Ambassadors, supporting UK companies and inward investment in low-carbon technologies. She is a Non-Executive Director of the Green Investment Bank, and a member of the Airports Commission.

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 Councils UK Energy Strategy Fellow and Professor of Sustainable Energy at Imperial College London. He was previously Research Director at the UK Energy Research Centre (UKERC) and 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.

Executive Summary

The UK is committed in primary legislation to reduce greenhouse gas emissions by 80% in 2050 compared to 1990 levels. This is an appropriate contribution to global emissions reductions required to limit risks of dangerous climate change.

Decarbonisation of the power sector is key to reducing emissions across the economy and would also enhance energy sovereignty.

This report is about the cost-effective path to a low-carbon power sector and actions that the Government should take to deliver this in practice.

The Electricity Market Reform (EMR) has been introduced to support the transition to a low-carbon power sector.

Enabling legislation for the EMR is currently going through Parliament, to be implemented through a Delivery Plan due to be published by the Government for consultation in July, and finalisation by the end of 2013.

A key pillar of the EMR is the introduction of long-term contracts, which will provide revenue certainty for low-carbon projects once contracts are signed. These are essential in making projects financially viable and therefore ensuring that they proceed. There are several outstanding technical issues relating to contract design and the payment mechanism which are being resolved as the Energy Bill is finalised.

It is also clear that industry needs a strong signal about the future direction of travel for the power system in order to support supply chain investment, which has long payback periods, and development of new projects, which have long lead times.

The report concludes that the currently high degree of uncertainty about development of the power system beyond 2020 threatens fundamentally to undermine the EMR. Unless this is addressed, projects coming on to the system before 2020 are likely to be at high cost and there could well be an investment hiatus for projects coming on after 2020.

Therefore, Government action is necessary to resolve these uncertainties in order that the UK can gain maximum economic and employment benefit from the move to a low-carbon economy.

We recommend the following package of measures that the Government should put in place to improve conditions for investment:

- **Set in legislation this Parliament a target to reduce the carbon intensity of power generation to 50 gCO_2/kWh by 2030, with some flexibility to adjust this in the light of new information.**
- **Set out strategies to support the development of less-mature technologies through to competitive deployment.**
- **Extend to 2030 provisions for the funding of low-carbon technologies (i.e. "the Levy Control Framework").**
- **Publish in the Delivery Plan the amount of capacity that the Government intends to contract over the period 2014/15-2018/19, and prices that it will pay for onshore and offshore wind.**
- **Set out options to support mobilisation of new sources of finance, including roles for the Green Investment Bank and Infrastructure UK.**

These measures would support investment in a portfolio of low-carbon technologies through the 2020s, which the report indicates would result in cost savings of £25-45 billion, in present value terms under central case assumptions about gas and carbon prices, rising to over £100 billion with high gas and carbon prices.

The alternative strategy would be to focus on investment in gas-fired generation in the 2020s, followed by investment in low-carbon technologies in the 2030s. This would result in cost savings only in the event that gas prices were to fall significantly, or with low carbon prices, and even then such savings would be limited.

Only if the world were to abandon attempts to limit the risk of dangerous climate change would there be significant cost savings from a strategy focused on investment in gas-fired generation.

The initial incremental cost to consumers of the recommended carbon-intensity target is around £20 per year for the typical household in 2030 compared to 2020, following which potentially significant cost savings would ensue.

A failure to commit to this now can be justified only on the assumption of low gas prices. It would be a bet on an outcome that is the opposite of most expectations. Even if the proposition were to be true, and low gas prices were to ensue, investment in gas-fired generation through the 2020s would offer very limited cost savings. Such an approach would also lock out the much higher benefits from investment in a portfolio of low-carbon technologies in more likely scenarios.

Box 1: Summary of recommendations to Government and Parliament

Recommendations to improve conditions for investment in the UK power sector

- Set in legislation during this Parliament a target to reduce carbon intensity of power generation to 50 gCO_2/ kWh by 2030 with some flexibility to adjust this in light of new information.
- Publish strategies for the further development of offshore wind and the commercialisation of carbon capture and storage (CCS), setting out the amount of intended investment to 2030 and cost reductions required to sustain this ambition.
- Extend the Levy Control Framework to 2030, with flexibility to adjust this in light of new information, for example about gas prices and technology costs. Our analysis suggests it should rise to around £10 billion by 2030 from around £8 billion in 2020.
- Confirm that the Levy Control Framework will be calculated against the levelised cost of new gas generation.
- Increase the 2020 Levy Control Framework by around £0.5 billion if shorter contracts are to be offered (e.g. 15 years for wind projects).
- Review capital market conditions and set out options to support mobilisation of new sources of finance, such as from banks and institutional investors. This should include possible roles for Infrastructure UK and the Green Investment Bank.

Recommendations for the Electricity Market Reform Delivery Plan

- Set out in the delivery plan the amount of capacity that the Government intends to contract over the period 2014/15 to 2018/19. Our analysis suggests that this should include around 15 GW of renewables capacity, up to around 6 GW nuclear capacity, and up to 3 GW of capacity fitted with carbon capture and storage (CCS).
- Announce contract prices in advance in the delivery plan for wind generation signing contracts over the whole period 2014/15 to 2018/19, rather than only announcing prices for plant to be commissioned during the period, which would provide very limited visibility for investors. These could be subject to review as part of the process for updating the delivery plan based on any new information on key cost drivers.
- Introduce auctions for wind contracts as soon as is practical. To the extent that auctions can be introduced during the period for which contract prices have already been announced, these could effectively operate as reserve prices for the auctions.
- Only pursue shorter contracts (e.g. 15 years for wind projects) if a clear benefit to consumers is demonstrated. This is possible, but is not clear given uncertainties over residual asset value beyond the contract.

Our detailed conclusions are set out below and summarised in Figure 1, with specific recommendations to the Government and Parliament summarised in Box 1:

- **Extensive decarbonisation of the power sector by 2030 is feasible and economically desirable.**
  - **Considerations on the pace of decarbonisation.** In considering the appropriate pace of decarbonisation to 2030 the aims should be: to stimulate investment in cost-effective low-carbon technologies (i.e. where these are cheaper over their lifetimes than unabated gas facing a carbon price); to develop less-mature technologies; to avoid stop-start investment; and to prepare for meeting the 2050 target to reduce economy-wide emissions by 80% relative to 1990.

- **Conclusions on the pace of decarbonisation.** Based on the latest evidence on costs and feasibility, we continue to conclude that aiming to achieve a carbon intensity of around 50 gCO_2/kWh in 2030 through investment in a portfolio of low-carbon technologies is feasible and desirable. There should be some flexibility to adjust this objective based on new information, for example up to 100 gCO_2/kWh if costs for emerging technologies fall less quickly than expected, or if roll-out of energy efficiency, nuclear and onshore wind are more constrained.

- **Benefits of extensive decarbonisation.** Investment in a portfolio of low-carbon technologies in the 2020s is a low-regrets strategy with potentially significant benefits in a carbon-constrained world. Our analysis suggests that this could result in cost savings of £25-45 billion relative to a focus on investment in gas-fired generation in the 2020s, under central case assumptions, and over £100 billion with high gas and carbon prices.[1] Even if gas prices were to fall significantly or if carbon prices were half the level in the Government's central scenario, the benefits of delaying investment in low-carbon technologies by a decade would be relatively low. Only if there were to be a very loose carbon constraint, such that the world has accepted a much higher risk of dangerous climate change, would there be significant savings from a strategy focused on investment in gas-fired generation in the 2020s.

- **Improving conditions for investment.** There is currently a significant risk that supply chain investment and project development will not proceed due to a lack of visibility beyond 2020, given that the Government has not set out its intentions for that period. This would undermine cost reduction and employment associated with investment in low-carbon technologies, and fail to prepare sufficiently for meeting the 2050 target. In order to improve conditions for investment in the UK power sector the Government should: set in legislation this Parliament a 2030 carbon-intensity target embodying the objective to invest in a portfolio of low-carbon technologies; extend the Levy Control Framework to 2030 at a level consistent with successful technology commercialisation; publish commercialisation strategies setting out ambition for investment in less-mature technologies and cost reductions required in order for ambition to be sustained; review capital market conditions and consider options to mobilise new sources of finance.

1 These cost savings are in present value terms and, as other costs in this report, in real 2012 prices. Costs are discounted back to 2013 at the social discount rate of 3.5%, and reflect relative costs across the lifetime of investments. Our central cost assumptions are that carbon prices rise as in the carbon price underpin (i.e. to £32 per tonne in 2020 and £76 per tonne in 2030) and gas prices level off at around 70 pence/therm.

– **Carbon-intensity target.** This should provide a balance of confidence and incentives to industry, signalling the Government's intention to invest in a portfolio of low-carbon technologies to 2030, subject to build rates and cost reductions being achieved. *Plan A* should be to reduce the carbon intensity of power generation to a level of the order of 50 gCO_2/kWh by 2030. A *Plan B* that achieves a carbon intensity of up to 100 gCO_2/ kWh while maintaining a portfolio approach might become appropriate, for example if costs fall less quickly than currently envisaged, or if achievable build rates are lower than expected. This could be captured through some flexibility to change the target in light of new information or by legislating a target range of 50-100 gCO_2/kWh, with clear criteria to guide which end of the range will be appropriate.

– **Levy Control Framework to 2030.** It is important to strengthen the signal provided by the carbon-intensity target through committing funding to achieve this. The Levy Control Framework, which has been agreed at a level of around £8 billion per year in 2020, should therefore be extended to 2030. Our analysis suggests it should increase to around £10 billion by this time. There should be some flexibility to adjust this in response to new information. For example, in a high gas price scenario, the limit could be reduced to £7 billion in 2030. It could also be revised down if technology commercialisation is not fully successful, and deployment is scaled back as a result.

– **Technology commercialisation strategies.** The signal provided by the carbon-intensity target should also be strengthened by publication of commercialisation strategies, setting out ambition for investment in less-mature technologies (e.g. offshore wind and carbon capture and storage, CCS) and cost reductions required in order that this ambition is sustained. Ideally, for example, offshore wind investment should continue through the 2020s at least at the same rate as in the 2010s, provided cost reductions are on track.

– **Capital market conditions.** There is also a risk that current sources of finance will be insufficient to deliver the increased levels of investment required in a low-carbon portfolio. The Government should undertake a full assessment of capital market conditions and consider options to improve these through design of EMR and use of financial instruments, to the extent that these are required.

- **The EMR Delivery Plan.** This should set out the 2030 objective to decarbonise the power sector, and should rule out scenarios focused on investment in unabated gas-fired generation in the 2020s. It should then state the intention to contract a level of capacity compatible with being on course to achieve the 2030 objective. Contract prices for wind generation should be announced in advance for the whole of this period. The Levy Control Framework should represent the cost to consumers; it therefore should be calculated against the cost of new gas-fired generation rather than the wholesale market price, and should be increased if the Government proceeds with its proposed shorter contract lengths.

– **Capacity to be contracted.** In order to provide visibility for developers, the delivery plan should set out the level of capacity the Government intends to sign contracts for during the period 2014/15 to 2018/19. Our analysis suggests contracts should be signed for around 15 GW of renewable capacity, up to around 6 GW of nuclear capacity, and up to 3 GW of CCS capacity.

– **Prices to be announced.** In order to provide visibility and therefore support project development, the delivery plan should include prices for wind generation to be *contracted* during the period 2014/15 to 2018/19, rather than for capacity *commissioning* during the period, which would give very limited visibility. Prices could be reviewed as the delivery plan is updated, based on any new information on key cost drivers.

– **Auction of contracts.** Given that there will always be imperfect information upon which to set administered prices, the aim should be to move to auctions for wind generation as soon as is practical; further work is required to establish precisely when this will be the case. To the extent that auctions can be introduced during the period for which contract prices have already been announced, these could effectively operate as reserve prices for the auctions.

– **Levy Control Framework in 2020.** Our updated assessment is that this should be around £8 billion in 2020. This is in line with the Government's agreed funding of £7.6 billion, noting, for example, uncertainties over assumptions in our analysis such as the current costs for offshore wind. Two important clarifications are required, depending on which more funding may be needed to deliver current ambition:

  - Funding should be calculated relative to the cost of building and running a new unabated gas-fired plant rather than the wholesale price, since the former is the alternative to low-carbon investment and a more accurate measure of the subsidy paid by consumers. The wholesale price could be depressed as a result of the expansion in low-carbon capacity or with the introduction of the capacity market. Therefore, using it would be inappropriate; it would leave a shortfall of around £0.7 billion under our central assumptions, and would introduce an additional element of investor uncertainty since it would be unclear how much capacity the Levy Control Framework could fund when defined in this way.

  - Our estimate assumes contract lengths for wind projects in line with expected lifetimes (i.e. 24 years for onshore wind and 22 years for offshore wind). If the Government were to pursue shorter contracts (i.e. 15 years) – the case for which is uncertain and has not yet been made – additional funding of £0.5 billion would be required in 2020, with potential savings in later years to offset this.

Our analysis assumes a carbon-constrained world where other countries commit to and deliver the emissions cuts required to achieve the Committee's climate objective (i.e. to limit central estimates of global mean temperature increase to as little above 2°C over pre-industrial levels as possible, and to limit the likelihood of temperature change above 4°C to very low levels).

This objective underpins the Climate Change Act, and similar objectives underpin the EU 2050 target, and the UNFCCC[2] process towards agreeing a new deal to reduce global emissions.

If other countries were to depart significantly from this objective, such that the world is exposed to much higher risks of dangerous climate change, this could have implications for UK carbon budgets and associated commitments, for example, on power sector decarbonisation.

We have previously concluded that the climate objective remains both feasible and desirable, with positive developments since our last assessment, albeit also with further commitments needed.

Our fourth carbon budget review will include an assessment of progress towards a global deal. In particular, it will consider the UNFCCC process, and action being taken in key emitting countries. It will include analysis of alternative pathways for future global emissions and any implications that this might have for the fourth carbon budget and the UK's decarbonisation strategy.

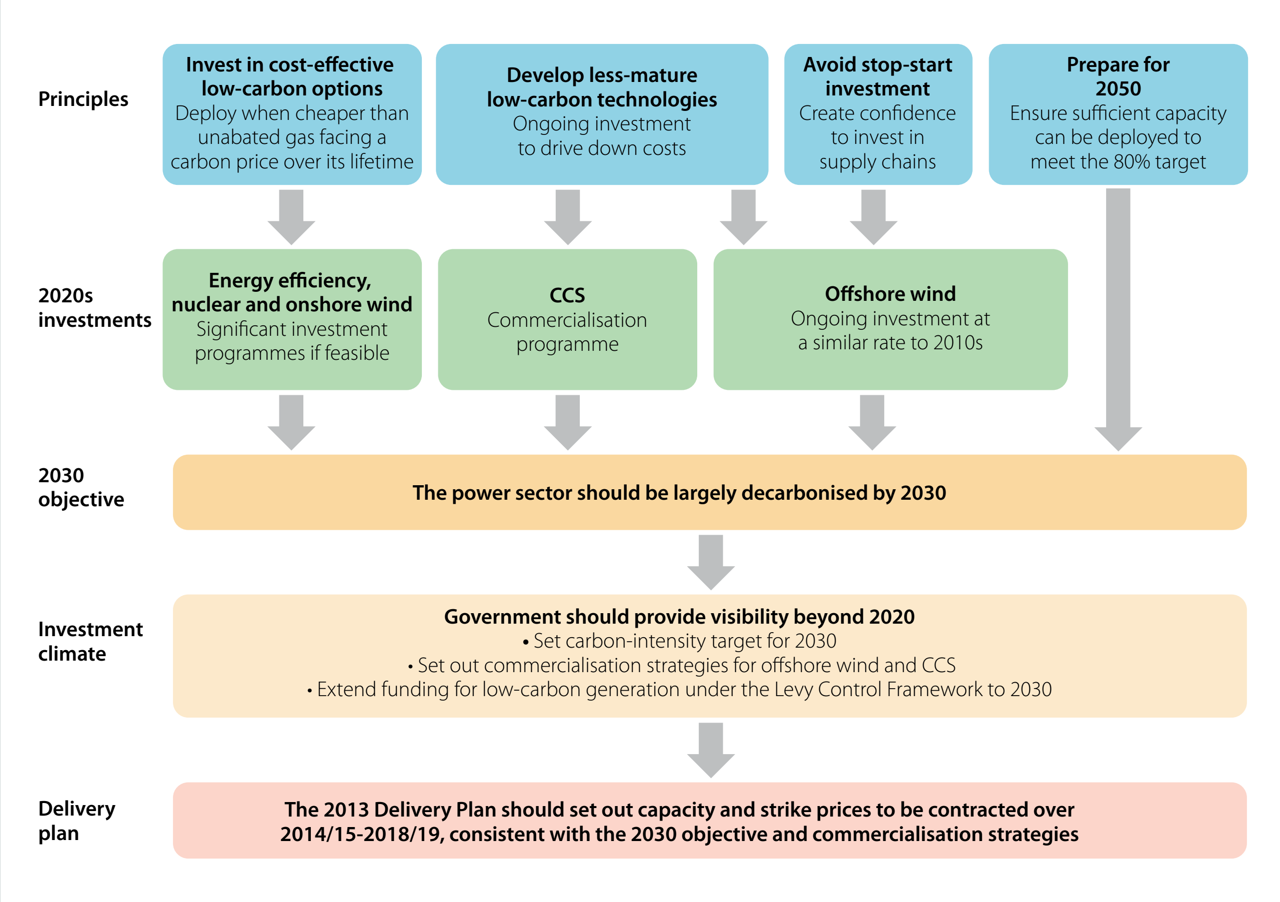
In the meantime, it is important that the Government should support proposals for an ambitious EU 2030 greenhouse gas target and supporting package, and develop approaches to help reach agreement on a similarly ambitious global deal, given the significant economic, environmental and social benefits that this would bring. Domestically, the Government should pursue those policies that will best prepare for a carbon-constrained world, including setting the right conditions to bring forward investment in a portfolio of low-carbon power technologies at the lowest cost.

We summarise our findings in Figure 1, before setting out our underpinning analysis in three sections:

1. Decarbonising the power sector to 2030
2. The need to improve conditions for investment
3. Implications for the first delivery plan.

2 United Nations Framework Convention on Climate Change.

Figure 1: Considerations and key conclusions on power sector decarbonisation



1. Decarbonising the power sector to 2030

(i) The economic rationale for power sector decarbonisation

The 2050 target in the Climate Change Act commits the UK to reducing greenhouse gas emissions by 80% in 2050 compared to 1990 levels. This is an appropriate contribution to global emissions reductions required to limit risks of dangerous climate change.

Given the requirement in the 2050 target, our analysis to date has concluded that in order to manage future costs and risks there is a need for early power sector decarbonisation through investment in a portfolio of low-carbon technologies:

- Early power sector decarbonisation is at the heart of economy-wide decarbonisation because: the power sector is a major source of emissions, accounting for around 27% of total UK greenhouse gas emissions; there are relatively low-cost technologies available for power sector decarbonisation (i.e. nuclear, renewables, carbon capture and storage – CCS); low-carbon power offers opportunities for electrification and decarbonisation of other sectors, such as surface transport through electric vehicles, and heat in buildings through heat pumps.
- There is a very extensive evidence base which shows that economy-wide decarbonisation costs are minimised through early power sector decarbonisation across a wide range of scenarios for technology costs and fossil fuel prices (e.g. our UK modelling, EC modelling of the European energy system, and global modelling by the IEA – see Box 1.1).
- It is appropriate to invest in a portfolio of low-carbon technologies given uncertainty over costs and feasible levels of investment in specific technologies.

Power sector decarbonisation is compatible with achieving policy objectives to ensure that energy supply is affordable and secure.

- **Energy affordability.** Investment in low-carbon technologies can be seen as insurance against risks of climate change and rising energy bills in the future, with a near-term premium that is manageable.
  - **Residential energy bills.** Our reports on energy prices and bills show that the majority of energy bill increases in recent years have been due to the increasing price of gas in international markets.[1] In future, we estimate that support for investment in low-carbon technologies will add around £100 to the annual energy bill for a typical household in 2020. This can be seen as insurance against risks of dangerous climate change, and also risks of rising energy bills, since it reduces exposure to potentially high gas and carbon prices in future.

1 CCC (2012) *Energy Prices and Prices Bills – Impacts of meeting carbon budgets*. Over 60% of the £360 increase in the typical dual-fuel energy bill between 2004 and 2011 was due to increases in the wholesale cost of gas. Support for low-carbon technologies and energy efficiency each contributed less than 10% of the increase.

- **Fuel poverty.** The 2012 Hills Review suggested that the combined effect of low-carbon policies – including energy efficiency – should be broadly neutral for fuel poverty. This will still leave large numbers of households in fuel poverty, which could be addressed through (further) targeted energy efficiency improvement, social tariffs or income transfers.
- **Electricity-intensive industries.** It is important that investment in low-carbon power generation technologies does not undermine the competitive position of industries that are intensive users of electricity. Analysis in our April 2013 report *Reducing the UK's carbon footprint and managing competitiveness risks* showed that while electricity price impacts could affect profits of electricity-intensive industries, current policies such as the exemption on Electricity Market Reform costs for these industries announced in November 2012 should be sufficient to mitigate competitiveness risks.

- **Security of supply.** Low-carbon power offers the opportunity for greater energy independence, which could reduce exposure to fossil fuel price volatility. There are also a number of options for managing risks due to intermittent power generation.
  - **Import dependency**. If the UK does not invest in low-carbon technologies, then it will become increasingly dependent on energy imports, reflecting declining North Sea output of natural gas. This would follow even if significant extraction of shale gas proves possible. It would result in exposure to the risks of high import prices, and possible fuel supply interruptions. Investment in low-carbon technologies reduces reliance on energy imports and therefore provides a hedge against possible high prices and fuel supply interruptions.
  - **Intermittent generation.** Although it is sometimes argued that there would be a security of supply risk associated with intermittent power generation (i.e. that the lights will go out when the wind is not blowing), even high levels of intermittency are manageable through a combination of demand flexibility, energy storage, interconnection, and balancing generation (Box 1.2). All of the scenarios in this report are designed to ensure continued reliability of electricity supply.

Given this analysis, we have recommended that the aim should be to reduce the carbon intensity of power generation from current levels of around 500 gCO_2/kWh to around 50 gCO_2/kWh in 2030 through investment in a portfolio of low-carbon technologies. In particular, the aim should be to invest in cost-effective technologies (i.e. those able to meet electricity demand more cheaply over their lifetimes than unabated gas facing a rising carbon price), and in less-mature technologies with a view to these becoming cost-effective in the 2020s – both emerging technologies like offshore wind and technologies that are yet to be demonstrated like large-scale CCS.

We have also recommended that this objective should be kept under review with respect to new information, for example, about technology costs.

The remainder of this section sets out new evidence of the feasible pace of investment in low-carbon technologies and associated costs. Based on this evidence, we develop alternative investment scenarios to 2030, and consider the economics of portfolio investment in low-carbon technologies compared to the alternative of a strategy focused on gas-fired generation in the 2020s.

Box 1.1: Modelling results highlighting the role for early power sector decarbonisation

Early power sector decarbonisation is a common result across many modelling exercises.

- We have identified it as a priority in our bottom-up modelling, for example in our reports on *The Fourth Carbon Budget* and *The 2050 target*.
- It is a consistent feature of energy system modelling in the UK.
  - This includes MARKAL modelling for the Committee (e.g. by AEA in 2008 and UCL in 2010) and others (e.g. publications by the UK Energy Research Centre over a number of years, DECC for the December 2011 *Carbon Plan*) and runs of the Energy Technologies Institute's ESME model (e.g. see our 2011 *Renewable Energy Review*).
  - In each case, the models have indicated that the need for power sector decarbonisation is robust to a wide range of assumptions around fossil fuel prices (e.g. covering the full range of DECC's published scenarios) and technology costs, but that the precise mix of technologies used to achieve this is less certain.
- It is a common finding of various other studies with a broader approach. For example, the Confederation of British Industry (*Decision Time),* the Energy and Climate Change select committee (e.g. *Fourth report – Electricity Market Reform*) and the Scottish Government (*A Low Carbon Economic Strategy for Scotland*).
- It is also a feature of the European Commission's low-carbon roadmap to 2050.[2] Within this modelling, the EU power sector decarbonises most rapidly to 2030 amongst the CO_2-emitting sectors, and is effectively zero carbon by 2050. More detailed modelling for the EC,[3] consistent with the roadmap, shows the UK power sector decarbonising particularly quickly given the greater share of capacity due to retire during the 2020s and the greater availability of low-carbon options (i.e. including nuclear).

2 European Commission (2011) *A Roadmap for moving to a competitive low carbon economy in 2050.*
3 Capros et al. (2012) *Technical report accompanying the analysis of options to move beyond 20% GHG emission reduction in the EU by 2020: Member State results.*

Box 1.2: Maintaining security of supply at manageable cost in a system with large amounts of intermittent and inflexible generation

In previous reports we identified and assessed options for managing intermittency. This included four main options to increase flexibility, which we assume are all deployed in our scenarios:

- **Demand-side response.** Active management of demand (e.g. charging electric vehicles or running washing machines overnight when other demand is low) can help smooth the profile of demand and reduce the requirement for capacity during peak periods. Widespread deployment and use of smart technologies (such as smart meters) will facilitate increases in demand-side response given sufficient consumer engagement.
- **Interconnection.** Interconnection already provides a valuable source of flexibility to the UK, with around 4 GW of capacity with Ireland, France and the Netherlands. Flows are price-driven according to relative demand and supply, and to the extent that these differ across countries, will continue to be an important source of flexibility.
- **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 a whole period). Other storage options could emerge in future.
- **Flexible generation.** Gas-fired capacity offers the potential to meet demand when output from intermittent technologies is low, and can be operated reasonably flexibly. There may also be some scope for using low-carbon capacity flexibly – for example scheduling maintenance outages for summer when demand is low, or running CCS at slightly reduced load factors.

Given these options, previous work that we commissioned from Pöyry found that high shares of intermittent renewables could be managed (i.e. up to around 60% of generation in 2030 and over 75% in 2050)[4].

The 2030 scenarios we set out later in this section are compatible with maintaining security of supply and involve extensive roll-out of the flexibility mechanisms set out above:

- We assume around 15% of demand is flexible at least within day by 2030.
- We assume over 10 GW of interconnection in 2030.
- We assume pumped storage capacity increases from 2.7 GW today to 3.3 GW by 2030.
- Our scenarios involve a significant increase in gas-fired capacity, such that peak demand can still be met by total despatchable capacity.

We also note that intermittent generation such as wind can make some contribution to system security. For example, during the cold snap in the early months of 2013, historically high levels of wind output coincided with widespread concerns over the security of gas supplies.

(ii) Updated evidence on feasibility and cost of investment

Given the need to regularly update and reassess the evidence base, we commissioned Pöyry to assess the latest information on costs and deployability of low-carbon technologies.[5] This section sets out that assessment for the key sets of low-carbon technologies (i.e. renewables, nuclear and carbon capture and storage), focusing on current costs and future expectations, how costs differ between projects, and the limits to potential deployment of each technology.

4 Pöyry (2010) *Options for low-carbon power sector flexibility to 2050.* CCC (2011) *Renewable Energy Review. CCC (2012) The 2050 target – achieving an 80% reduction including emissions from international aviation and shipping.* Available at: www.theccc.org.uk

5 Pöyry (2013) *Technology Supply Curves for Low-Carbon Generation.*

The project pipeline

The Pöyry analysis shows that there is currently a strong project pipeline for onshore and offshore wind and biomass conversion. Nuclear and CCS are at an earlier stage in the project cycle, but all have the potential to make a major contribution to 2030 decarbonisation.

- **Onshore wind.** Deployment is currently slightly ahead of the indicators against which we monitor when reporting to Parliament, and which reach 15 GW of installed capacity by 2020. New project proposals continue to be brought forward and planning approval rates have remained fairly steady. Given the 8 GW capacity already commissioned or in construction, the 4.4 GW already consented, the 8.8 GW already awaiting planning consent and the continuing stream of new projects, Pöyry consider deployment of 25 GW total installed capacity to be achievable by 2030 (capable of generating around 60 TWh in an average year). The implied quadrupling of the UK's capacity would result in capacity density (i.e. the number of GW per km^2) in line with current levels in Germany.
- **Offshore wind.** At the end of 2012 there were 3.0 GW of offshore wind installed and operating effectively in UK waters. Through its licensing rounds the Crown Estate has granted leases for a total of around 47 GW of capacity. Availability of sites are therefore unlikely to be a constraint on deployment for the foreseeable future, although supply chain capacity and availability of finance could limit roll-out. Pöyry estimate that 25 GW total installed capacity could be comfortably delivered by 2030, and 40 GW or more would be possible with sufficient funding to incentivise a further ramp-up of the supply chain.
- **Biomass conversion.** There is a large number of coal plants that could potentially convert to run on woody biomass instead of coal, and significant developer interest in converting. We demonstrated in our *Bioenergy review* that potential generation from converted coal plants could be more than enough to meet the Government's ambition for biomass power generation (i.e. 32-50 TWh/year in 2020 is included in the 2011 Renewable Energy Roadmap, equivalent to 4-6 GW). As we have previously recommended to Government, investment should be subject to stringent sustainability standards, otherwise emissions reductions may not follow.
- **Nuclear.** Negotiations between the Government and EDF for the first new nuclear plant at Hinkley are ongoing. The Horizon venture was acquired by Hitachi in November 2012, and has announced plans to build four to five 1.3 GW advanced boiling water reactors by 2030. The NuGen consortium also maintains an interest in nuclear development. The existing sites owned by these three consortia and approved for new nuclear development under the National Policy Statement of July 2011 could accommodate 21-25 GW of new nuclear projects. Pöyry identify existing plans for 16 GW as being more realistic by 2030, with potential to reach deployment of over 20 GW if new players and/or financiers enter the market.

- **Carbon capture and storage (CCS).** The Government announced in March that it had selected two preferred bidders to be supported under its CCS Commercialisation Programme: a gas post-combustion project at Peterhead and a coal oxy-fuel project at Drax. The next step for these projects is to proceed with detailed Front End Engineering Design (FEED) studies, with a view to taking final investment decisions by early 2015. Two projects remain in reserve, having been included in the shortlist of four announced in October. Several other projects had been put forward for the DECC programme and/or EU funding, some of which may be viable in the future, while new projects may also emerge, both as retrofit to modern 'capture-ready' plants and as new-build. Pöyry suggest the need for a second phase of pre-commercial deployment before commercial plants can be rolled out in the late-2020s. This could give a total of around 10 GW of capacity by 2030, with higher levels (e.g. 15 GW) only achievable if roll-out timescales are compressed, allowing less time between phases for the transfer of learning to new projects.

The analysis suggests potential to add up to 60 GW of low-carbon capacity in total over the next two decades, on a baseload-equivalent basis[6], compared to around 45 GW required to reduce carbon-intensity to 50 gCO_2/kWh. This suggests scope to achieve carbon-intensity of around 50 gCO_2/kWh through different combinations of nuclear, renewables and CCS.

Before setting out our 2030 scenarios, it is important to establish the economics of investment in low-carbon technologies, which determines whether it is desirable to turn this potential into actual investment. We now summarise analysis of technology costs, before turning to sector investment scenarios.

Current costs of low-carbon technologies

As part of their assessment Pöyry considered the current costs of projects based on evidence in published reports and their experience of existing projects where available. Even though these estimates do not involve projections, they still involve uncertainty, especially for nuclear and CCS, where no existing projects have been completed in the UK in recent years.

6 We adjust the capacity of intermittent technologies to a baseload-equivalent basis to account for the fact that they do no generate at their full rated capacity throughout the year. For example, assuming a non-intermittent plant is available to generate for 90% of the year, and offshore wind is available to generate at its full rated capacity for 42% of the year, 1 GW of offshore wind is equivalent to (42%/90%) * 1 GW = 0.47 GW of baseload-equivalent capacity.

Pöyry's assessment suggests broadly comparable costs for mature technologies (i.e. onshore wind, nuclear, biomass conversion), with costs of less-mature technologies (i.e. offshore wind, CCS) still relatively high in 2020. Uncertainty over costs reflects uncertainty over construction costs, operational performance and differences between projects.

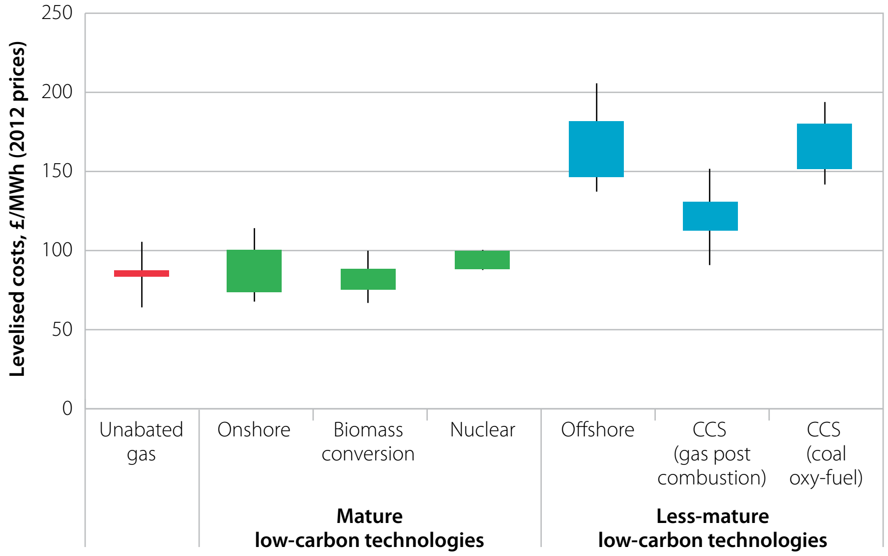
- **Onshore wind.**[7] Pöyry estimate significant differences in costs between individual projects, for example due to different load factors, project size and connection costs. They estimate costs of up to around £100/MWh for the marginal project consistent with ambition required to meet the UK's renewable energy target under the EU Renewable Energy Directive. Further uncertainties over construction cost and required rate of return imply a potentially wide range for levelised cost estimates.
- **Biomass conversion.** The levelised cost of converting existing coal plants and running them with solid biomass fuels is estimated at around £80-90/MWh under central fuel price assumptions[8]. This concurs with our previous assessment, as set out in our December 2011 *Bioenergy Review.*
- **Nuclear.** Pöyry have assumed a cost of around £85-100/MWh for the first UK project, with the range reflecting construction cost uncertainty; costs would be lower if the rate of return is lower than the 11% assumed by Pöyry. This estimate is slightly higher than our previous assumptions, reflecting further delays in delivering European projects at Flamanville and Olkiluoto (although projects outside Europe have progressed to time and budget).
- **Offshore wind.** Current costs for the majority of the project pipeline are estimated at around £140-165/MWh. This assumes larger turbines are used (i.e. 6-7 MW) and a higher financing cost than for onshore wind (e.g. Pöyry assume hurdle rates of 12.4% offshore and 9.6% onshore). As for onshore wind, costs vary significantly between sites, reflecting differences such as water depth, distance to shore, wind speeds and seabed conditions.
- **CCS.** Pöyry estimate costs for the first CCS projects of up to £180/MWh under central fuel prices, with gas projects estimated to be significantly cheaper than coal. These estimates involve a significant premium, reflecting high risks translating to a high hurdle rate (15%) and high costs in deploying a new technology at scale for the first time. They assume initial oversizing of pipes, with costs spread over emissions captured from current and future projects, otherwise costs would be higher, particularly for gas projects, which produce a lesser CO_2 stream.

These estimates suggest that the costs of all options will have to come down in order to be competitive with unabated gas generation facing a carbon price (Figure 1.1).

7 DECC has recently conducted a Call for Evidence, which requested the latest costs of onshore wind projects, including capital and operating costs from developers and industry. This has not yet been published, but could potentially reveal new evidence that is not included in our analysis.

8 Our central price projections for high quality (i.e. 17 GJ/t) biomass pellet feedstock is £7.3/GJ (2012 prices), equivalent to around £26/MWh, with a range £6.3-8.5/GJ.

Figure 1.1: Current costs of low-carbon technologies, relative to unabated gas



Source: CCC calculations based on Pöyry, Parsons Brinckerhoff.
Notes: Costs for projects starting in 2013 and coming online towards the end of this decade (i.e. 2015 onshore/biomass conversion, 2016 offshore, 2020 nuclear, 2018/19 for CCS demo's). Fuel price assumptions consistent with latest DECC Projections (October 2012). Carbon price rises in line with Carbon Price Floor, to £32/t in 2020 and £76/t in 2030. Cost over project lifetime assuming pre-tax real rate of return of 9% for unabated gas, 9.6% onshore, 12.4% offshore, 11% nuclear, 15% CCS demo, 10% biomass conversion. Solid boxes represent range for high/low capex and central fuel prices (central load factor for wind); thin extending lines show sensitivity to combined high/low capex and high/low fuel prices (high/low load factor for wind).

Future costs of low-carbon technologies

Pöyry identify potential for the costs of all technologies to come down in future through a combination of learning in deployment and de-risking leading to reductions in the cost of capital. The less-mature technologies offer the biggest opportunities for cost reduction through both of these mechanisms.

- **Onshore wind.** Potential cost reductions for onshore wind are limited as the technology is already mature. There may be small gains in the cost of capital once new market arrangements are tested and proven to work, and some projects involving repowering of existing sites are likely to be cheaper than entirely new projects.
- **Biomass conversion.** We have recommended, in our *Bioenergy Review*, that long-term use of bioenergy in the power sector should be limited without carbon capture and storage, and that biomass capacity should be focused on conversion of existing coal plants, which is likely to be limited to the near term, given the current age of these assets. We therefore do not include cost estimates for further biomass conversions beyond 2020.
- **Nuclear.** Pöyry identify significant scope for costs to fall after the first plant (e.g. to £60-75/MWh by 2030). This primarily reflects the premium built into 'first of a kind plants' in both construction costs and cost of capital, in turn reflecting the challenges in deploying new nuclear projects for the first time under the UK's current regulatory regime, even though this has been set up to minimise costs. It also captures both domestic and international learning effects.

- **Offshore wind.** Pöyry assume significant cost reductions as the technology matures (e.g. to £110/MWh in 2030 under central assumptions). This partly reflects learning in construction and operation. It also reflects a significant reduction in the cost of capital as the perceived risk associated with the technology declines as the industry matures and gains experience of deployment and the new market mechanisms (i.e. from the 12.4% currently assumed to 10.4% by 2020 and closer to 9% by 2030 in line with other established technologies). Both these effects rely on continued deployment in the UK, given UK-specific conditions and market arrangements.

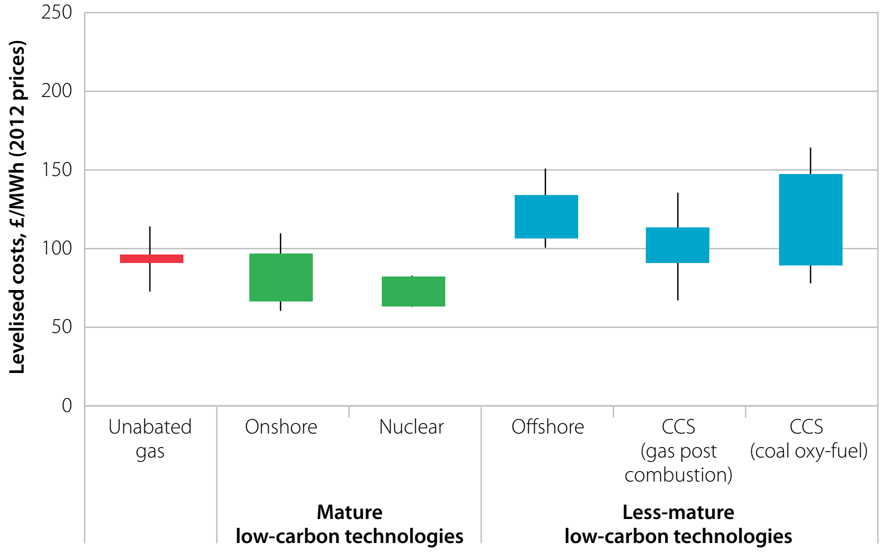
- **CCS.** Pöyry assume that costs for commercial projects in the late 2020s could be reduced to under £100/MWh.[9] This would require a concerted and successful commercialisation programme, including measures to 'commoditise' and de-risk transport and storage infrastructure. This could reduce required rates of return to 10%, whilst construction costs are also assumed to fall with learning and a scaling up from the early demonstration plants. These cost estimates are also reliant on effective leveraging of learning from both UK and international projects. These estimates suggest that all options have the potential to be competitive with unabated gas generation facing a carbon price in the 2020s (Figures 1.2 and 1.3).

This assessment reinforces the portfolio investment approach, which is aimed at driving down the costs of low-carbon technologies such that these become increasingly competitive with gas-fired generation over time.

It forms the basis for our 2030 scenarios below, and the economic assessment of these scenarios against the alternative of a strategy focused on investment in gas-fired generation through the 2020s.

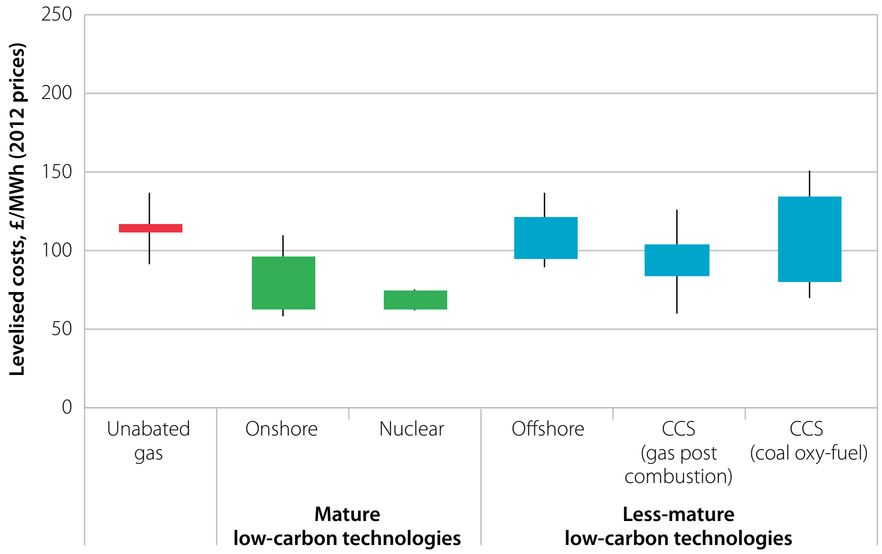
9 This is for post-combustion gas plants, but Poyry note that complexities over different fuels and capture technologies alongside the immaturity of the technology make uncertainty particularly great for CCS.

Figure 1.2: Projected costs of low-carbon technologies (2020), relative to unabated gas



Source: CCC calculations based on Pöyry, Parsons Brinckerhoff.
Notes: Costs for projects starting construction in 2020. Excludes biomass conversion which comes on in 2010s. Fuel price assumptions consistent with latest DECC Projections (October 2012). Carbon price rises in line with Carbon Price Floor, to £32/t in 2020 and £76/t in 2030. Beyond 2030 rises in line with Government 'central' carbon price values (£147/t in 2040 and £217/t in 2050). Cost over project lifetime assuming pre-tax real rate of return of 9% for unabated gas, 9.1% onshore, 9.1% offshore, 9.2-10.2% nuclear, 13% CCS. Solid boxes represent range for high/low capex and central fuel prices (central load factor for wind); thin extending lines show sensitivity to combined high/low capex and high/low fuel prices (high/low load factor for wind).

Figure 1.3: Projected costs of low-carbon technologies (2030), relative to unabated gas



Source: CCC calculations based on Pöyry, Parsons Brinckerhoff.
Notes: Costs for projects starting construction in 2030. Excludes biomass conversion which comes on in 2010s. Fuel price assumptions consistent with latest DECC Projections (October 2012). Carbon price rises in line with Carbon Price Floor, to £76/t in 2030; beyond 2030 rises in line with Government 'central' carbon price values (£147/t in 2040 and £217/t in 2050). Cost over project lifetime assuming pre-tax real rate of return of 9% for unabated gas, 9.1% onshore, 9.1% offshore, 9.2% nuclear, 10% CCS. Solid boxes represent range for high/low capex and central fuel prices (central load factor for wind); thin extending lines show sensitivity to combined high/low capex and high/low fuel prices (high/low load factor for wind).

Scope for demand reduction

Rather than building new low-carbon capacity to decarbonise electricity supply, sector emissions could also be cut by reducing demand through improvements in the efficiency of electricity use. This would potentially be beneficial for all power sector objectives of decarbonisation, security of supply and affordability – reducing demand through energy efficiency can be cheaper than meeting demand by building new low-carbon power stations, whilst demand that does not need to be met cannot be interrupted and has no emissions.

Although it is clear that there are significant opportunities for energy efficiency improvement in electricity use, there is uncertainty over the precise amount of potential, and the best policy levers to address this:

- **Potential for improved electricity efficiency.** Our analysis suggests that there may be significant scope to reduce electricity demand, largely through purchase and use of more energy efficient lights and appliances in homes, possibly supplemented by behavioural changes that save energy (e.g. turning off lights in empty rooms), and through efficient drives, motors and compressed air systems in industry. Analysis recently published by DECC[10] suggests more scope for energy efficiency improvement (e.g. up to a 19% reduction in industrial electricity use in 2020, compared with our previous estimate of 8%). It is clear from the available evidence that there is significant scope for energy efficiency improvement, although the precise scale of this opportunity is uncertain.
- **Policy levers.** There are already policies in place to encourage energy efficiency improvement, from product standards for new appliances, to the CRC Energy Efficiency Scheme (formerly the Carbon Reduction Commitment), which raises the price of electricity for large non-energy intensive firms and organisations. Incentives under these polices may not be sufficient, and it has been suggested that these should be buttressed through including further incentives for demand reduction under the Electricity Market Reform. The Government recently consulted on this and will publish its response shortly.

Our approach in this report is to include some demand reduction (i.e. as identified in our previous analysis) in all our medium-term scenarios, and to reflect scope for further reduction (i.e. as in DECC's recent analysis) in one particular scenario.

10 DECC (2012) *The Energy Efficiency Strategy: The Energy Efficiency Opportunity in the UK.*

(iii) Scenarios with investment in a portfolio of low-carbon technologies to 2030

Outlook to 2020

The likely development of the power sector to 2020 is fairly well understood, with plant retirements due under air quality regulations, new investments required to meet the EU Renewable Energy Directive and funding for low-carbon capacity agreed under the levy control framework:

- **Demand.** Demand is expected to fall slightly as efficiency improvements driven by new product standards continue.
- **Retirements.** A significant amount of existing generation is due to retire by 2020 as it reaches the end of its economic lifetime, or fails to comply with new air quality regulations (i.e. the Large Combustion Plant Directive). We assume around 1 GW of gas, 7.5 GW of coal, 3.5 GW of oil and 3.5 GW of nuclear capacity retires by the end of 2020.
- **Renewables.** The Renewable Energy Directive requires that the UK sources 15% of all energy demand from renewables by 2020, which is likely to require around 30-35% of electricity generation from renewables, given limits to potential for renewable heating and transport fuels.[11] We assume that renewable generation is rolled out in line with the indicators set out in our progress reports to Parliament (i.e. by 2020 there is 15 GW of onshore wind, 12 GW of offshore wind and 4 GW of solid biomass capacity). This would be sufficient to meet the Renewable Energy Directive and would balance sustainability concerns relating to biomass (i.e. with biomass generation at the low end of the Government's ambition).
- **CCS commercialisation.** The Government has stated its commitment to deliver four CCS demonstration projects by 2020. However, delays in the programme raise questions over whether this will be deliverable, given a 4-6 year construction period and pre-construction development time of up to 2 years. We therefore include only two projects coming on the system by 2020, while noting that the need to commercialise CCS remains an urgent priority, and that delivering four demonstration projects on this timescale, rather than with a delay, would be desirable.
- **Nuclear.** The first new nuclear plant is currently negotiating a contract under the Electricity Market Reform (EMR) and is due to commission around 2020 or soon after.
- **Unabated gas.** In order to maintain system security of supply, a significant amount of new unabated gas capacity is likely to be required alongside the expected low-carbon generation. Our modelling suggests around 5 GW of new unabated gas capacity is likely to be needed by 2020 to maintain current levels of system security. More than 5 GW may be required, for example to the extent that: demand is higher than we assume, more existing plant retires, or less low-carbon capacity is added.

11 See, for example, our 2011 Renewable Energy Review.

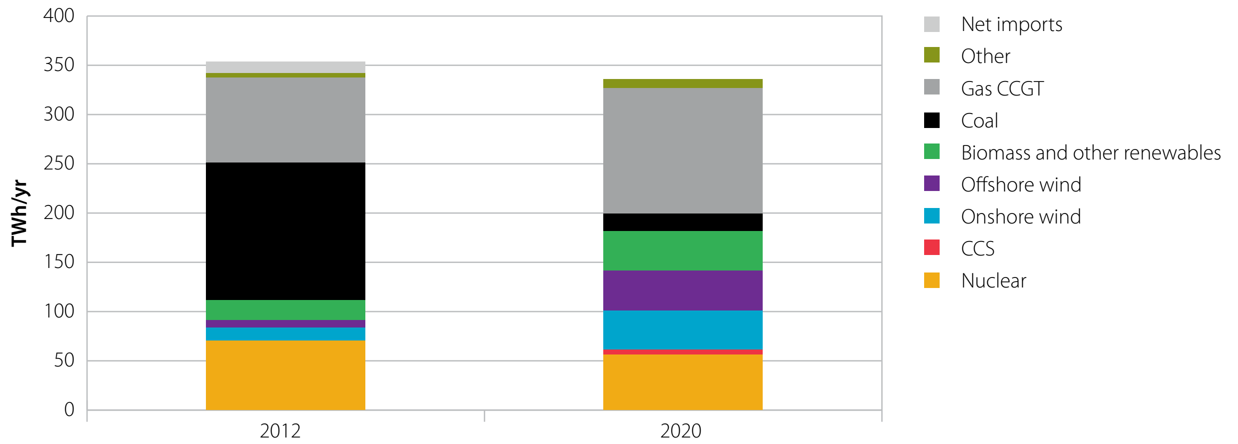
The overall outlook for the power sector to 2020 is therefore relatively clear and is broadly constant across our scenarios (Figures 1.4a and 1.4b).

The path from 2020-2030

Beyond 2020 the possible path for the power sector is more open, as a large amount of capacity is expected to retire and the long investment lead time means that all generation technologies are available for its replacement.

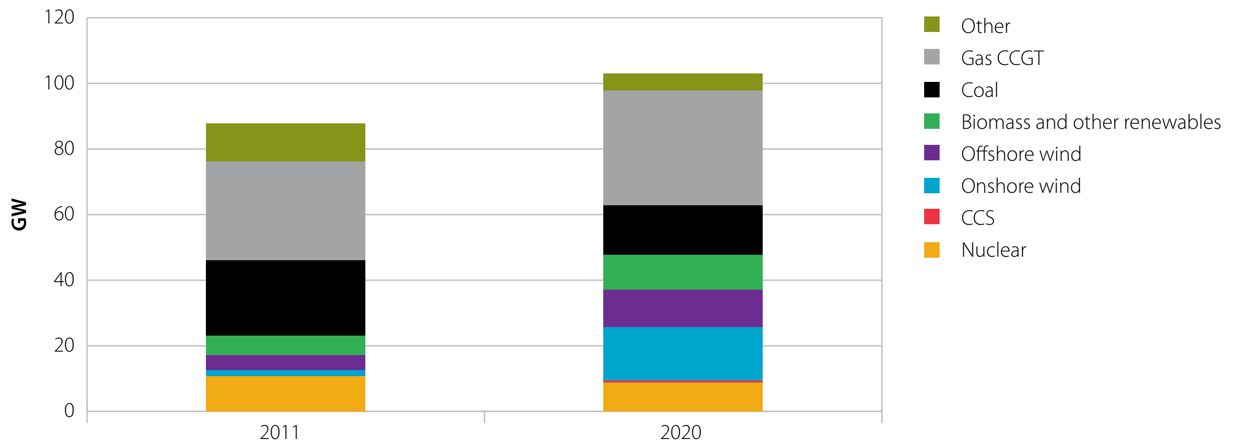
The economically desirable path should be consistent with four key principles (Figure 1.5):

Figure 1.4a: UK power sector generation in 2012 and 2020



Source: DECC *Energy Trends* (March 2013), Redpoint, CCC calculations.
Notes: Generation from major power producers only; renewable generation all generators. Other category includes pumped storage, Gas CHP and Oil. Other renewables includes solar PV, marine and hydro. CCGT: Combined Cycle Gas Turbine. We have assumed no net imports, although if EU carbon prices do not rise then imports could potentially be significant.

Figure 1.4b: UK power sector installed capacity in 2011 and 2020



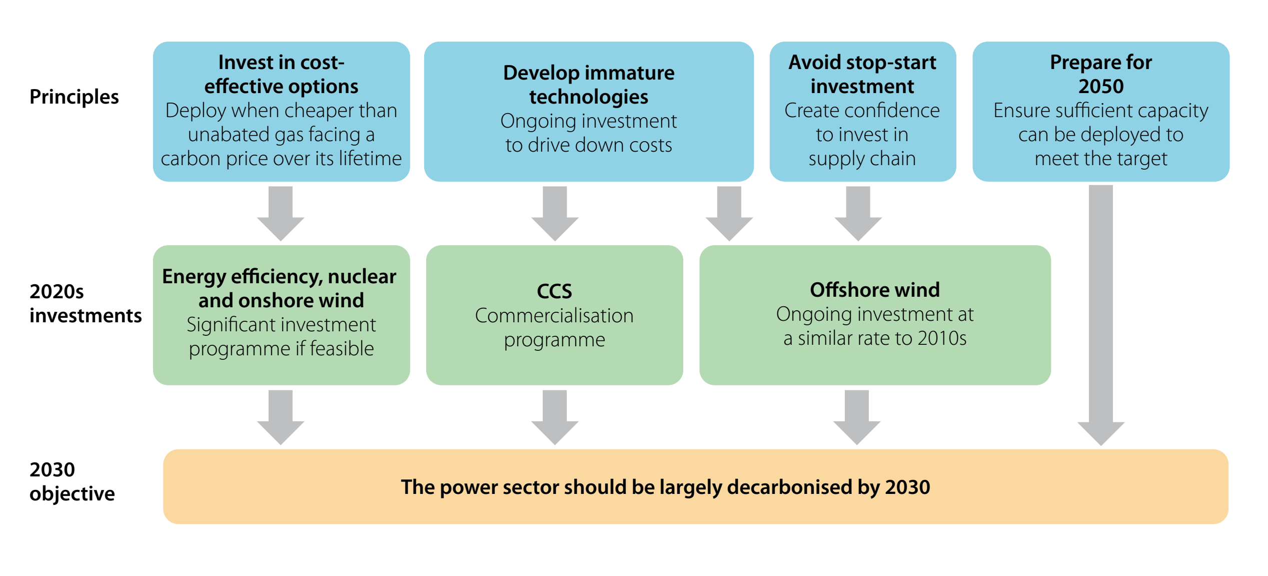
Source: DUKES (July 2012), Redpoint, CCC calculations.
Notes: Nameplate capacity (not de-rated for availability). Capacity of major power producers only; renewable generation all generators. Other category includes pumped storage, Gas CHP and Oil. Other renewables includes solar PV, marine and hydro. CCGT: Combined Cycle Gas Turbine. Data on 2012 installed capacity is not available, therefore we have shown 2011.

- It should **invest in cost-effective options** – those that are able to provide low-carbon generation (or reduce demand) at lower cost across their lifetimes than unabated gas generation including a carbon price. This will minimise costs to consumers.
- It should have **ongoing investments in less-mature low-carbon technologies** that could provide cost-effective low-carbon power from the late-2020s onwards, and require UK deployment to drive cost reductions. This will ensure a portfolio of options remain available and mitigate risks of very high prices in the long term.
- It should **avoid stop-start investment cycles**. This will create confidence required to drive down costs of capital, will allow supply chains to develop and continue without overheating, will maximise the opportunity for learning in deployment and will support a stable workforce and financing flow.
- It should involve sufficient investment by 2030 to ensure the **2050 target** remains attainable, given long asset lifetimes and potential lags in developing project supply chains. This would be consistent with the legal requirement under the Climate Change Act to prepare policies with a view to meeting the 2050 target, and mitigate the risk of very high prices in the long term.

Given our cost assumptions set out above and our analysis on the 2050 target, these principles imply that the aim should be to ensure that energy efficiency improvement and portfolio investment are continued through the 2020s.

Our analysis also demonstrates the uncertainty over when each technology will become cost-effective relative to gas generation and other low-carbon options. We have therefore developed several scenarios for the development of the power sector to 2030 that reflect these uncertainties; one set of scenarios reaches a carbon intensity of around 50 gCO_2/kWh by 2030 and the other reaches around 100g.

Figure 1.5: Principles behind the economically-sensible path for the power sector in the 2020s



Power sector scenarios reaching around 50 gCO_2/kWh by 2030

Our first set of scenarios reflects generally favourable conditions for power sector decarbonisation, allowing the sector to largely decarbonise to around 50 gCO_2/kWh by 2030. If they can be achieved, then under our central assumptions these scenarios would represent the most economically efficient path (i.e. they would minimise discounted costs of electricity generation – see section 1(iv) below).

We consider four scenarios, which all reach 50 gCO_2/kWh through a portfolio of low-carbon technologies, with differing emphasis on the four key options for decarbonisation (i.e. nuclear, renewables, CCS and energy efficiency) – see Figure 1.6a and Figure 1.6b.

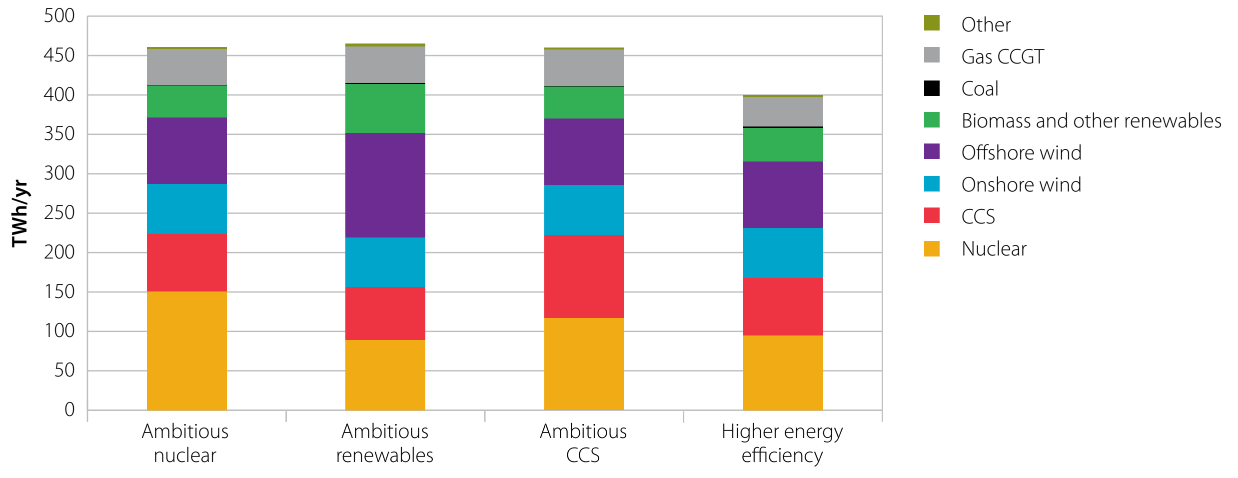
- All scenarios include a minimum roll-out of the less-mature technologies – with around 25 GW of offshore wind and 10 GW of CCS installed by 2030. This is intended to develop a portfolio of options for ongoing provision of low-carbon electricity after 2030 and creates flexibility to respond to changing relative costs.
- All scenarios include some continued roll-out of onshore wind, albeit at a slower rate than in the 2010s, and a significant new nuclear programme (i.e. 10-18 GW). This reflects that under our central assumptions these technologies are expected to be cost-effective compared to unabated gas facing a carbon price by the early 2020s.
- Total emissions from the power sector in the scenarios are around 20-25 $MtCO_2$ in 2030. Emissions are lower by around 2 $MtCO_2$ in the scenario with high energy efficiency, since broadly the same emissions intensity is achieved, but over a lower level of demand.
- The individual scenarios then differ in terms of how far each major technology can deliver – potentially going further with nuclear (if sufficient capital and developer interest is available), CCS (if the technology develops more quickly and favourably), renewables (e.g. if offshore wind costs fall towards the low end of our range), or demand reduction (if cost-effective opportunities can be found and delivered). Each of these brings their own challenge, as discussed in Section 1(ii) above.
- The scenarios involve limited roll-out of other renewables (e.g. marine technologies, solar) given currently high costs and limited use of imported low-carbon electricity. However, these options may be viable and could provide alternatives should the others deliver less (Box 1.3).

The preferred scenario will depend on how the options develop, particularly in terms of costs and deliverability.

All scenarios also involve a significant increase in deployment of flexibility options – demand-side response, interconnection, storage and back-up gas capacity (see Box 1.2 above). These are important in limiting costs and maintaining system security as the scenarios involve more generation from intermittent and capital-intensive technologies.

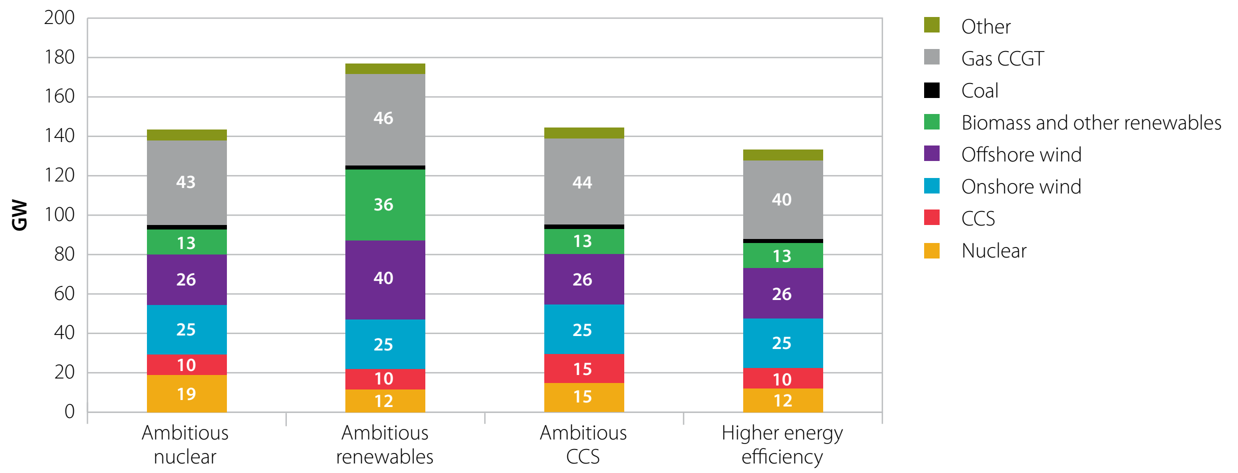
Specifically, the scenarios involve 25-40 GW of new unabated gas capacity, which by 2030 acts largely as a back-up for when wind output is low and demand is high (e.g. by 2030 the average load factor for new unabated gas capacity is less than 20% in these scenarios). We reflect this in our Section 3 analysis of the EMR Delivery Plan.

Figure 1.6a: Power sector scenarios reaching 50gCO_2/kWh by 2030 – generation (TWh)/yr



Source: Redpoint, CCC calculations.
Notes: Other includes Pumped Storage and Gas CHP. Other renewables includes solar PV, marine and hydro. Excludes autogeneration consumed onsite.
CCGT: Combined Cycle Gas Turbine. All the scenario data are presented at UK level, including a small adjustment to add Northern Ireland to the GB-level outputs of the Redpoint modelling.

Figure 1.6b: Power sector scenarios reaching 50gCO_2/kWh by 2030 – capacity (GW)



Source: Redpoint, CCC calculations.
Notes: Other includes Pumped Storage and Gas CHP. Other renewables includes solar PV, marine and hydro. Excludes autogeneration consumed onsite.
CCGT: Combined Cycle Gas Turbine. Nameplate capacity (not derated for availability).

Box 1.3: Other options that could contribute to decarbonisation

There are a number of sources of low-carbon generation which could potentially play a more prominent role than we have assumed in our scenarios – subject to cost and feasibility constraints.

- **Solar.** In our Renewable Energy Review, we identified the significant technical potential of solar photovoltaics (PV) in the UK (i.e. up to 140 TWh, equivalent to around 160 GW installed capacity). We also noted that technology development is likely to be driven globally rather than in the UK, and given relatively high costs is likely to have a limited role in the period to 2020. Costs have fallen rapidly recently, leading to a reduction in support rates to current levels of up to around 15p/kWh, comparable with the cost of offshore wind. We assume that PV generation increases from around 1.3 TWh in 2012 to 4 TWh by 2020; deployment could well be higher to this, subject to continued cost reductions.
- **Tidal Range.** We have previously identified technical potential of around 40-45 TWh from tidal range technology, with the majority of this (20 TWh) located in the Severn estuary[12]. A two-year Government study into the feasibility of the Severn project concluded in 2010 that investment in the immediate term would not be appropriate. Whilst our scenarios do not include generation from tidal range generation, projects in the Severn and other locations (such as the Mersey, Solway Firth and North Wales) remain a possibility in the future.
- **Tidal stream and wave.** Although these technologies are at a very early stage of development, (with around 6 MW of prototype capacity installed at the end of 2012), they have significant technical potential (between 50-150 TWh generation per year)[13]. The Government's 2011 Renewable Energy Roadmap identified a central estimate of 0.3 GW (0.9 TWh) of deployment in the period to 2020. Our scenarios are in line with this to 2020, rising to 6.5 TWh by 2030, within the range identified by ARUP in their assessment of potential[14].
- **Biomass.** In our reports to date (including our Bioenergy review), our analysis has focused on the combustion of solid woody biomass, which is the most significant form of biomass power expected to be deployed at scale over the next decade. Other forms of generation from bioenergy include combustion of biodegradeable municipal solid waste, sewage gas, landfill gas, bioliquids, anaerobic digestion (AD) and advanced conversion technology (gasification and pyrolysis). We assume up to around 6 TWh of generation from other sources of biomass power generation in 2020 and beyond. It is also plausible that solid woody biomass could contribute more than assumed in our scenarios, if sufficient sustainable resource can be sourced.
- **Imports**. It may be possible to interconnect to other markets with surplus low-carbon generation, such as Concentrated Solar Power (CSP) from North Africa, Icelandic geothermal or wind generation from Ireland. These options are not yet well developed and involve a number of challenges, but the UK has expressed an interest in exploring them and in principle they could provide a cost-effective source of low-carbon power. For example, the UK has recently signed a Memorandum of Understanding with the Irish government to further investigate the potential for Irish wind imports.

Our approach is not to build significant amounts of these options into our scenarios, but to note that they could potentially compensate for lower delivery elsewhere, subject to cost and feasibility.

12 CCC (2010) *The Fourth Carbon Budget: Reducing emissions through the 2020s*. Figure 6.10.

13 CCC (2011) *Renewable Energy Review*. Figure B1.3B – technical potential for wave power is 40 TWh; the credible range in the literature for tidal stream is 19-197 TWh. The lower end of the range assumes the full wave potential and the low-end of the range of estimate for tidal stream; the high end of the range assumes the high end of the range for tidal stream.

14 ARUP (2011) *Review of the generation costs and deployment potential of renewable electricity technologies in the UK*

Departures from 50 gCO_2/kWh

The scenarios above are an appropriate basis for policy under the best evidence currently available about costs and feasible investment rates, and may be regarded as a *Plan A*.

However, there are circumstances under which assumptions underpinning these scenarios are not borne out in practice, under which it would be appropriate to switch to a *Plan B*.

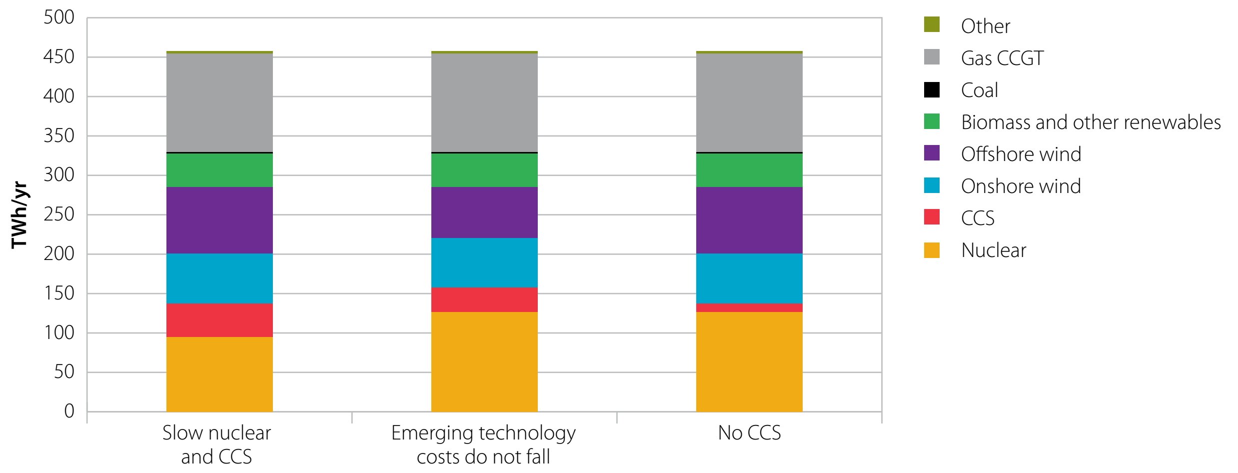
We reflect this in a set of scenarios in which conditions for decarbonisation are less favourable, making 50 gCO_2/kWh undesirable or unachievable. This could be because, for example: nuclear costs turn out to be much higher than expected and do not come down or developers are not able to finance projects; CCS does not progress as an effective decarbonisation technology; or costs of offshore wind do not fall with deployment. These scenarios also assume that the further demand reduction from our 'High Energy Efficiency' scenario cannot be delivered.

Whilst progress could be slower under less favourable conditions it should still be significant. We capture this possibility with three scenarios, one with slower progress on nuclear and CCS, one which scales back ambition on offshore wind if costs fail to come down and one with no CCS (Figure 1.7a and 1.7b). These scenarios result in an average carbon intensity of around 100 gCO_2/kWh.[15]

- **Slow progress on both nuclear and CCS.** This scenario constrains new nuclear deployment to 11 GW and CCS deployment to 5 GW. This nuclear programme could be consistent with a failure to agree terms for the first nuclear project, pushing the nuclear programme back by four years or delaying deployment at the sites owned by EDF until the mid-2020s (i.e. until the first Horizon projects are expected). This CCS programme could still be consistent with commercialisation of the technology if the UK is able to leverage a very strong international effort to develop the technology.
- **Slow progress on cost reduction.** This scenario has less deployment of offshore wind (capacity only reaches around 20 GW in 2030) and CCS (4 GW by 2030). This would not be a suitable scenario to aim for, but could be consistent with a case where costs of less-mature technologies do not fall as expected and deployment is scaled back accordingly (but not completely).
- **'No CCS'.** This scenario assumes no deployment of CCS beyond the first two projects selected in the Government's competition, consistent with a failure to demonstrate the technology effectively. It will be crucial that the other technologies deliver in this case, so the scenario builds in a significant nuclear and offshore wind programme (around 15 GW and 25 GW respectively).

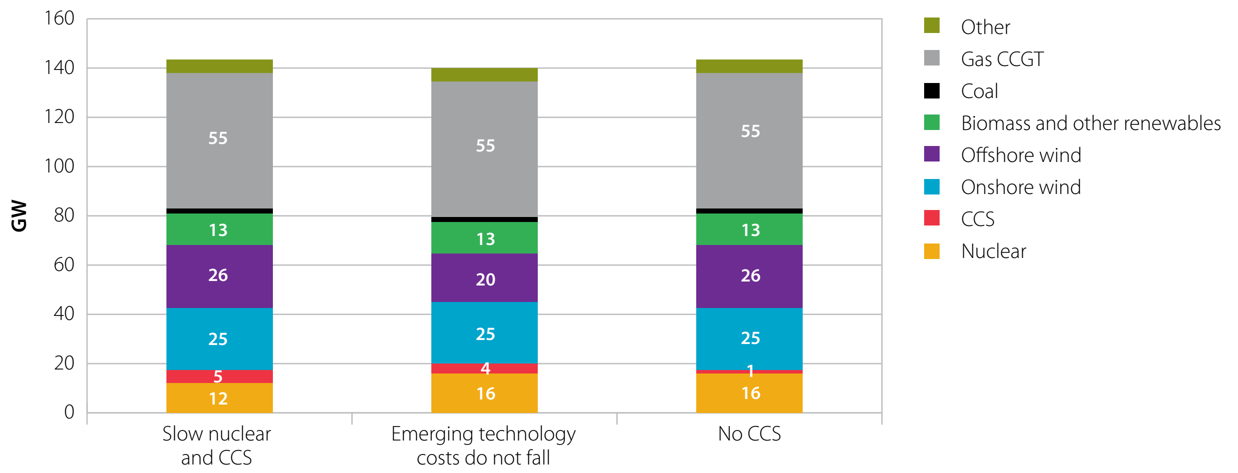
15 We also note the possibility that the demand and investment levels assumed in our 50g scenarios could result in an outturn carbon intensity closer to 100 gCO_2/kWh if the UK has decarbonised significantly quicker than our electricity trading partners. This could lead the UK to export significant amounts of power to other countries, with increased generation from efficient UK gas plants allowing reduced generation from higher-carbon plants elsewhere in Europe. That would reduce European carbon emissions, but would increase the UK's emissions and carbon-intensity. We estimate this could add around 30 gCO_2/kWh to the UK's carbon intensity, which would be offset by trading of emissions permits, provided the EU power sector remains part of an emissions trading system with a suitably tight emissions cap. In relation to our Section 2 discussion of a carbon-intensity target, this uncertainty could be dealt with through the definition of the target (e.g. with an adjustment for net exports) or through the flexibility we suggest should be built in.

Figure 1.7a: 2030 scenarios under less favourable conditions – generation (TWh/yr)



Source: Redpoint, CCC calculations.
Notes: Other includes Pumped Storage and Gas CHP. Other renewables includes solar PV, marine and hydro. Excludes autogeneration consumed onsite. All the scenario data are presented at UK level, including a small adjustment to add Northern Ireland to the GB-level outputs of the Redpoint modelling.

Figure 1.7b: 2030 scenarios under less favourable conditions – installed capacity (GW)



Source: Redpoint, CCC calculations.
Notes: Other includes Pumped Storage and Gas CHP. Other renewables includes solar PV, marine and hydro. Excludes autogeneration consumed onsite.

These scenarios could become economically preferred under less favourable conditions for the costs and deliverability of low-carbon technologies. They would still prepare sufficiently for the 2050 target, and would still enable the legislated 4th carbon budget to be met through UK emissions reductions.

- The 100g scenarios would need slightly faster roll-out after 2030 to achieve the same levels of decarbonisation by 2050 (e.g. an average of 3-3.2 GW per year, rather than 2.5-2.7 GW under the 50g scenarios). These roll-outs are likely to be achievable, given that the scenarios do develop a portfolio of low-carbon options to 2030, since they still involve minimum and steady levels of investment in less-mature technologies.
- Power sector emissions during the fourth carbon budget period (2023-2027) would be higher by up to around 15 $MtCO_2$ per year in these scenarios compared to the 50g scenarios. This could be made up in other sectors, so that the budget would still be met across the economy. For example, latest projections for waste and industrial process emissions have been revised down by 15 $MtCO_2e$ per year in the budget period.

Other scenarios would not prepare sufficiently for longer-term challenges, implying increased risks and costs in the long run:

- There are other scenarios that also reach 100 gCO_2/kWh in 2030, but that would not be desirable. For example, a scenario with high nuclear deployment, but low investment in CCS and offshore wind during the 2020s (e.g. as assumed in the Government's emissions projections)[16] could deliver a similar emissions intensity but would leave the UK overly reliant on a single low-carbon technology. This would imply unacceptable costs and risks of achieving the 2050 target and/or of very high electricity prices required to deploy uncommercialised low-carbon options at scale after 2030.
- Scenarios which do not achieve 100 gCO_2/kWh face this same problem of a lack of option development to 2030. They are also likely to involve increased costs by foregoing cost-effective investment in the 2020s, and could leave unachievable build requirements after 2030, particularly given the limited range of options implied.

Therefore, when considering commitments that the Government should make on carbon-intensity targets, commercialisation strategies, commitments on contracts to be offered and funding, the relevant scenarios to consider are those that reach 50 gCO_2/kWh and those that reach 100 gCO_2/kWh while maintaining a portfolio investment approach. See Sections 2 and 3 below.

16 DECC (2012) *Energy and Emissions Projections.*

(iv) Economics of portfolio investment compared to a strategy focused on unabated gas

The Government's 2012 *Gas Generation Strategy*[17] keeps open the possibility of a 'dash for gas' in the 2020s (i.e. where investment in low-carbon technologies largely stops in 2020, with a focus instead on investment in unabated gas-fired generation in the 2020s).

Although the gas generation strategy does not cover the period beyond 2030, the need for power sector decarbonisation by 2050, as identified in our analysis and as set out in the Government's *Carbon Plan*[18], suggests that a 'dash for gas' in the 2020s would have to be followed by a 'dash for low-carbon technologies' through the 2030s and 2040s. This is necessary, given the UK's legislated target to reduce emissions by 80% by 2050 relative to 1990.

We consider the gas generation strategy in more detail in Section 2, including implications for investment conditions in the sector.

In the remainder of this section, we consider whether a strategy focused on unabated gas-fired generation through the 2020s rather than a portfolio of low-carbon technologies offers a desirable alternative, or if it would increase costs and risks.

Global implications of investment focused on gas-fired generation

At the global level, significant continued use of unabated gas-fired generation in the long term would be incompatible with achieving the climate objective. This reflects the fact that gas involves significant carbon emissions, albeit less so than coal, and cannot be regarded as a low-carbon fuel if burnt without application of carbon capture and storage (CCS) technology. It is apparent in the International Energy Agency (IEA)'s scenarios for the global energy system:

- **The IEA 4°C scenario** projects global trends based on implemented and announced energy policies, resulting in a central estimate of eventual global temperature rise of around 4°C. It projects continued growth in unabated natural gas use for power. Global gas-fired generation increases from 5,500 TWh in 2015 to 10,000 TWh in 2050, although the carbon intensity of the power sector still falls as gas and renewables displace coal generation.
- **The IEA 'Golden Age of Gas' scenario** assumes China and others move strongly towards gas-fired power generation and away from coal and nuclear, in a world of plentiful supply from unconventional gas sources. Global energy-related CO_2 emissions in 2035 are only slightly lower than those in the 4°C scenario, implying that this scenario would also have an eventual expected rise in global temperatures of close to 4°C.

17 DECC (2012) *Gas Generation Strategy.*
18 DECC (2011) *The Carbon Plan: Delivering our Low Carbon Future.*

- **The IEA 2°C scenario** shows how the world can maintain an 80% chance of keeping global warming within the internationally-agreed limit of 2°C. In this scenario, global use of unabated gas generation declines from 2025, halving by 2050, whilst use in Europe falls by 90% by 2050 compared to current levels.[19]

Therefore, although there would be emissions reductions from near-term investment in unabated gas-fired generation rather than coal, there is a need to move quickly from investment in any conventional fossil fuel to low-carbon technologies in order that the climate objective is achieved.

Turning this around, continued increases in gas-fired generation beyond 2020 at the global level would increase the costs and risks of meeting the climate objective, with continued investment well beyond 2020 making the climate objective unattainable.

This reinforces our conclusion at the UK level given the 2050 target in the Climate Change Act, that the question is not *whether* to move away from unabated gas-fired generation, but *when* (i.e. whether this should be in the 2020s or 2030s). This is our focus for the remainder of this section.

UK investment in gas-fired generation

In order to assess the economics of investment in low-carbon technologies, it is necessary to define a counterfactual, which in the UK is investment in unabated gas-fired generation (i.e. new combined-cycle gas turbine (CCGT) plants).

Projecting costs for gas-fired generation requires assumptions on technology costs, gas prices, and carbon prices.

- **Technology costs**. CCGT is a well established technology with a high degree of confidence around technology costs in the UK. Our key assumptions on CCGT are construction costs of around £600/kW, cost of capital at 9%, and a 53% thermal efficiency of power generation[20].
- **Gas prices.** Consensus projections are that gas prices will rise in future, from the current level of around 60 pence/therm even in a world where shale gas reserves are brought to market (Figure 1.8, Box 1.4).
  - The IEA projects a slightly increasing gas price under optimistic assumptions about supply of unconventional (i.e. shale) gas, with higher increases under less optimistic assumptions about shale gas.
  - DECC's 'central' gas price scenario is similar to the IEA's optimistic case. The 'high' DECC scenario assumes future gas prices that are above the IEA's less optimistic case.

19 IEA (2012) *Energy Technology Perspectives* and IEA (2011) *World Energy Outlook Special Report: Are we entering a golden age of gas?*
20 Higher Heating Value basis (i.e. gross).

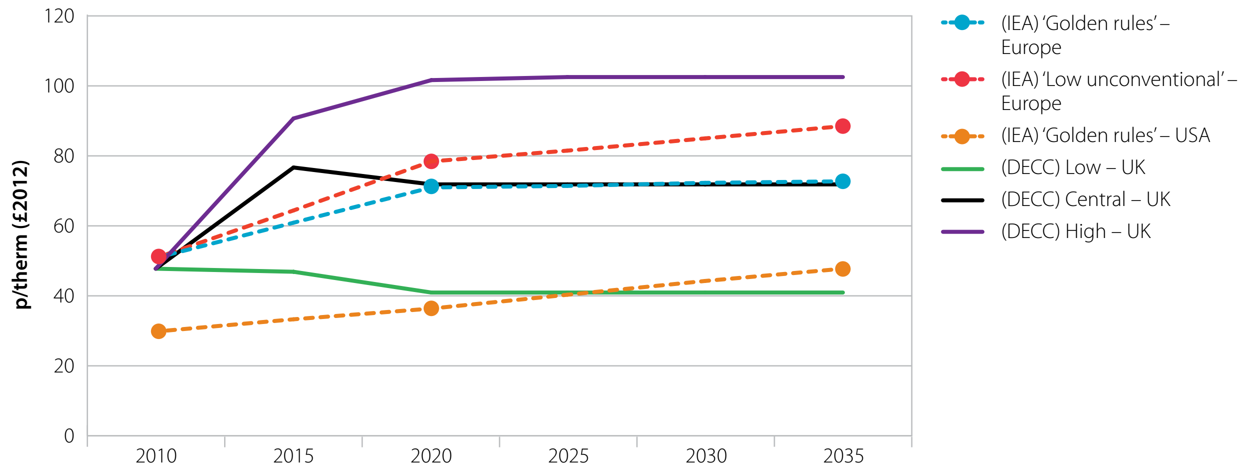
- DECC also has a low gas price projection that assumes a large fall from current levels, to below even those in the US in the IEA's optimistic case. This requires plentiful supply, subdued Asian demand and weak European economic growth, and that gas supplies to Europe are at the very low end of estimates of long-run marginal cost. It is also likely that the consequence of lower gas prices would be higher carbon prices for a given carbon constraint, so as to make investment in cost-effective low-carbon technologies viable. The implication of this, that low gas prices in combination with low carbon prices are unlikely, is relevant for our analysis below.

- **Carbon prices.** The Government's carbon values rise to around £215/tCO_2e in 2050 in a central case. This projection assumes cost-effective decarbonisation of the global economy. Higher carbon prices could ensue with a departure from the assumption of a cost-effective path. Significantly lower carbon prices would imply lower costs of low-carbon technologies such that the economics of investment in these technologies is unchanged or a departure from the climate objective.
  - The Government's carbon price underpin rises to £32/tCO_2 in 2020 and £76/tCO_2 in 2030, based on its central case carbon values, which rise to around £215/tCO_2e in 2050 (Figure 1.9). There is a range around this of £110-325 per tonne, reflecting different assumptions and comparisons with other models. However, the economics of investment in low-carbon technologies are likely to be broadly unchanged across these scenarios (e.g. since the low carbon price scenario in part reflects low abatement costs and/or high fossil fuel prices).
  - Our analysis suggests higher prices are possible. For example, modelling using UCL's TIAM model suggests a global carbon price rising to around £500/tCO_2e in 2050.[21]
  - These projections make relatively benign assumptions of an optimal path for global emissions reductions to achieve the climate objective, and an active global carbon market taking advantage of trading opportunities to minimise abatement costs. A departure from these assumptions, including for example continued use of unabated gas generation requiring more expensive reductions in other sectors or later years, would raise carbon prices further (e.g. our TIAM modelling suggests prices in 2050 could more than double if weak early action requires even deeper 2050 emissions reductions to deliver the same level of cumulative emissions).
  - Significantly lower carbon prices in the long term that are not a result of lower technology costs or higher fossil fuel prices can only be assumed with a looser emissions constraint and therefore a departure from the climate objective.

We model different scenarios for the cost of new gas-fired generation, reflecting the full range in the Government's assumptions on gas and carbon prices (Figure 1.10). This covers all gas and carbon prices that could plausibly be consistent with a carbon-constrained world.

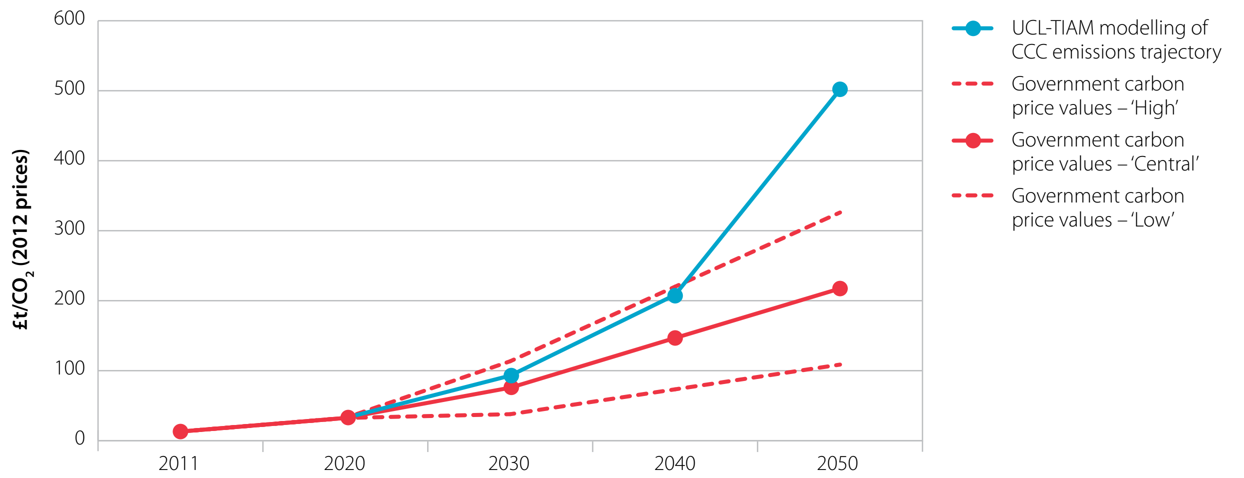
21 UCL Energy Institute (2012) *Modelling carbon price impacts of global energy system scenarios*. The higher price in part reflects the assumption that bioenergy use in 2050 is limited to around 10,000 TWh globally (the UK share of which could meet 10% of UK primary energy demand), in line with our assessment of sustainable resource in our 2011 *Bioenergy review*.

Figure 1.8: Gas price scenarios



Source: IEA (May 2012) *Golden Rules for a Golden Age of Gas*. DECC (October 2012) *Fossil Fuel Price Projections*.
Notes: IEA projections adjusted to £2012. £:$ = 0.62. 'Golden Rules' scenario assumes a 'continued global expansion of gas supply from unconventional (i.e. shale) resources, with far reaching consequences for global energy markets'. The 'Low unconventional' case assumes 'only a small share of the unconventional resource base is accessible for development'. For 2035, DECC projections have been held flat at 2030 levels.

Figure 1.9: Carbon price scenarios



Source: UCL Energy Institute (2012) Modelling for the CCC, DECC (2013) GHG Emissions and Energy Appraisal Toolkit. Values assume carbon price rises in line with the proposed carbon price floor until 2020. Our modelling in this report uses the range from the Government's scenarios.

We do not model carbon price scenarios corresponding to a significant departure from the climate objective, which would raise wider questions about the appropriate ambition in carbon budgets and the value of investing in low-carbon technologies.

Therefore, our analysis and the recommendations that follow apply in a carbon-constrained world. This is the premise for the Climate Change Act. It is desirable, given the costs and risks

associated with dangerous climate change. It is also feasible given international processes and action, albeit with further commitments required (Box 1.5).

We will continue to monitor closely progress towards a global deal to reduce emissions and meet the climate objective and assess any implications for carbon budgets.

Box 1.4: What might shale gas mean for the UK?

The emergence of shale gas production in the US has caused a sharp fall in natural gas prices (to a low in 2012 of around $2/MMBtu or 13p/therm, although they have since recovered partially), leading to speculation that a similar pattern may occur in other places, including the UK. It is important to understand which parts of the US experience are transferrable to other contexts, and what it might mean for the role of shale gas in the UK.

In considering whether these prices are replicable in the UK it is important to consider how interconnected gas markets are, how physical and regulatory conditions differ in the UK and the US and relative sizes of economically recoverable reserves:

- **Interconnections.**
  - The natural gas system in the US is not well connected to other countries' networks – it is effectively an 'island system' – which helps to explain why the expansion of shale gas production has had such a large impact on the price. Until very recently, it was not permitted to export natural gas from the US; that now appears to be changing, with the announcement in March that initial exports will be allowed from 2018. However, the infrastructure and energy required to liquefy natural gas for export has a high cost, estimated to be around $5-6/MMBtu[22] or 35-40p/therm, meaning the UK should not be expecting any imports from the US to be significantly below current UK wholesale prices around 60p/therm. Furthermore, given strong demand from elsewhere (e.g. Asia), it is not clear that significant volumes would end up in the UK.
  - In contrast to the US, the UK natural gas system is well connected to the rest of Europe, via interconnectors to Belgium, Norway and the Netherlands. As well as providing a substantial proportion of our gas supply, these connections mean that UK prices are strongly linked to those elsewhere. The UK can therefore be regarded as being part of a continent-wide natural gas system, with changes in volumes of gas supply and demand causing relatively small ripples in prices at hubs across multiple countries. Given these interconnections, it would take a huge volume of low-cost gas production across Europe to lower prices significantly, especially in the context of declining European conventional gas production. Unlike in the US, therefore, strong growth of shale gas production within the UK at a cost below the market price would be unlikely to drive a substantial fall in the wholesale gas price from today's levels, as the effect would be diluted across the large volumes of gas traded across Europe. This would be positive for gas producers, and for tax revenues, as production would remain profitable at Europe's relatively high gas prices. This contrasts with the US experience, in which the sharp fall in gas prices has rendered some shale gas production uneconomic.
- **Country-specific challenges.** Shale gas production in Europe is likely to face greater challenges than it has done in the US. These include a range of issues associated with the greater population density (especially in the UK), notably public acceptability of fracking and environmental protection. Further important differences from the US context are around required planning consents, for example UK land owners do not own subsurface mineral extraction rights, providing less incentive to support development. These considerations, together with the recent exits of companies from shale gas exploration activities in Poland, suggest that the US experience may well not be repeated in Europe.
- **Reserves.** The volume of UK shale gas reserves (the amount of gas that could be extracted economically) is uncertain, and is likely to remain so until significant exploration has been done to make a detailed assessment of the geology, and of the challenges and costs of extraction in the UK context. Existing estimates indicate that UK reserves could make a significant contribution to UK gas supply, but that it is unlikely to be sufficient to meet the UK's full gas demand. A new estimate of UK reserves by the British Geological Survey is expected imminently.

22 International Energy Agency (2012) *Golden Rules for a Golden Age of Gas – World Energy Outlook Special Report on Unconventional Gas*. Available at http://www.worldenergyoutlook.org/goldenrules/

Box 1.4: What might shale gas mean for the UK?

Our recent assessment of lifecycle emissions showed that well regulated shale gas production within the UK could potentially have lower lifecycle emissions than imported liquefied natural gas (LNG). Appropriately regulated, in order to ensure that methane releases are no more than a minimal level and to avoid wider environmental impacts, UK shale gas production could therefore have a slightly positive impact on global emissions, if it is displacing LNG at the margin, in meeting a given level of gas demand.

The overall picture, therefore, is one in which well regulated production of shale gas could have economic benefits to the UK, in a manner consistent with our emissions targets, while reducing our dependence on imported gas.

However, a dash for gas in the power sector is not necessary to realise any potential benefits, nor is it desirable given the importance of power sector decarbonisation.

This reflects the broader point that climate policy should focus on the *use* of fossil fuels, while economic policy may be more relevant when considering the merits of the *production* of fossil fuels.

Box 1.5: Progress towards a global deal

We considered global progress towards constraining emissions as part of our advice on the fourth carbon budget in 2010. Our conclusion at this time was that the climate objective remained achievable given commitments in the Copenhagen Accord, but that further commitments would be needed, particularly on deep emissions cuts through the 2020s, together with action to deliver these cuts.

There have been some positive developments since 2010:

- Emissions in the United States have continued to fall through a combination of coal-to-gas switching in power generation, energy efficiency improvement in buildings, and fuel efficiency improvement in new vehicles. US emissions in 2010 were 6% below 2005 levels, and there is evidence to suggest that the US could deliver its Copenhagen commitment to reduce emissions in 2020 by 17% on 2005 levels without the need for new federal legislation.[23]
- China has committed to reduce its carbon intensity by 45% by 2020; this compares to a 30% reduction in carbon intensity implicit in the UK's third carbon budget. Emissions trading pilot schemes in 7 major Chinese cities (including Beijing and Shanghai) will start operating in 2013 and 2014.
- Important climate change legislation has been passed in a number of developed countries and emerging economies (e.g. Mexico and South Korea).[24]
- The pricing of carbon emissions is expanding, with new schemes setting prices above the current EU price. For example, California's cap-and-trade programme is due to merge with Quebec next year and has auctioned at around $14/tCO_2$.
- The EU has started early negotiations on a package of measures to further reduce emissions through the 2020s.
- The UN process is moving towards a global deal in 2015 and could embody commitments on deep cuts in global emissions to 2030.

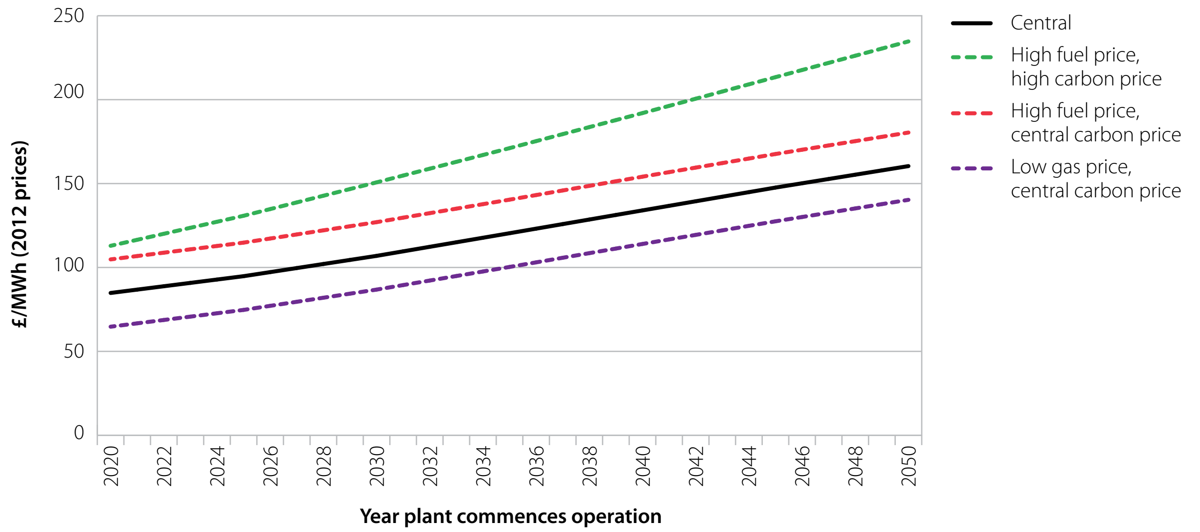
Our fourth carbon budget review will include an assessment of global progress. In particular, it will consider the process under the United Nations Framework Convention on Climate Change (UNFCCC), and action being taken in key emitting countries. It will include analysis of alternative pathways for future global emissions and any implications that this might have for the fourth carbon budget and the UK's decarbonisation strategy.

In the meantime, it is important that the Government should support proposals for an ambitious EU 2030 greenhouse gas target and supporting package, and develop approaches to help reach agreement on a similarly ambitious global deal, given the significant economic, environmental and social benefits that this would bring.

23 World Resources Institute (2013) *Can The U.S. Get There From Here?* http://www.wri.org/publication/can-us-get-there-from-here. Burtraw, D. and Woerman, M. (2012) *US status on climate change mitigation*. Resources for the Future. http://www.rff.org/RFF/Documents/RFF-DP-12-48.pdf

24 *Globe 3rd climate legislation study*, http://www.globeinternational.org/index.php/climate-study-home

Figure 1.10: Projected levelised cost of new unabated gas (2020-2050)



Source: CCC calculations, based on Parsons Brinckerhoff *Electricity Generation Cost Model 2012 Update of Non Renewable Technologies*.
Notes: Fuel price assumptions: consistent with the range in DECC (October 2012) Fossil Fuel price Projections. Carbon price assumptions: Central scenario rises in line with the Government's carbon price floor from £32/t in 2020 to £76/t in 2030. Thereafter, rises in line central Government's values in the GHG Emissions and Energy Appraisal Toolkit (see Figure 1.9). High carbon price scenario rises from £32/t in 2020 and in line high scenario in the GHG Toolkit beyond 2020, to £113/t in 2030 and £326/t in 2050 (see Figure 1.9). As discussed in the text we do not model a scenario with low gas prices and low carbon prices since this would imply departure from the carbon objective. Assumes 20 year lifetime.

We now compare the costs of UK portfolio investment in low-carbon technologies through the 2020s with the alternative of a strategy focused on gas investment in the 2020s followed by a ramping up of investment in low-carbon technologies in the 2030s, as required to meet the 2050 target. We first consider costs of investment in mature generation technologies, and then costs of commercialising less-mature technologies such as offshore wind and CCS.

Investment in mature low-carbon technologies compared to gas-fired generation in the 2020s

Our cost estimates in Section 1(ii) suggest costs for both nuclear and onshore wind are likely to be around £90/MWh at the start of the 2020s, falling to less than £80/MWh for nuclear and staying fairly stable in the case of onshore wind. Therefore they both offer an opportunity for cost saving relative to investment in unabated gas in the 2020s, given costs for unabated gas rising to over £100/MWh by 2030 in a central case, including the Government's carbon price underpin of £76/tCO_2 in 2030. Future low-cost projects will only be available if the more expensive early projects are delivered first; we therefore focus on the costs of the investment programme rather than individual projects.

Analysis that we presented in our 2012 Progress Report to Parliament suggests that investment in nuclear rather than gas-fired power generation through the 2020s would result in around a £20-25 billion cost saving under central case assumptions. Higher benefits would ensue under assumptions of higher gas and/or carbon prices, and costs would be broadly comparable with unabated gas under assumptions of lower gas or carbon prices (Figure 1.11).

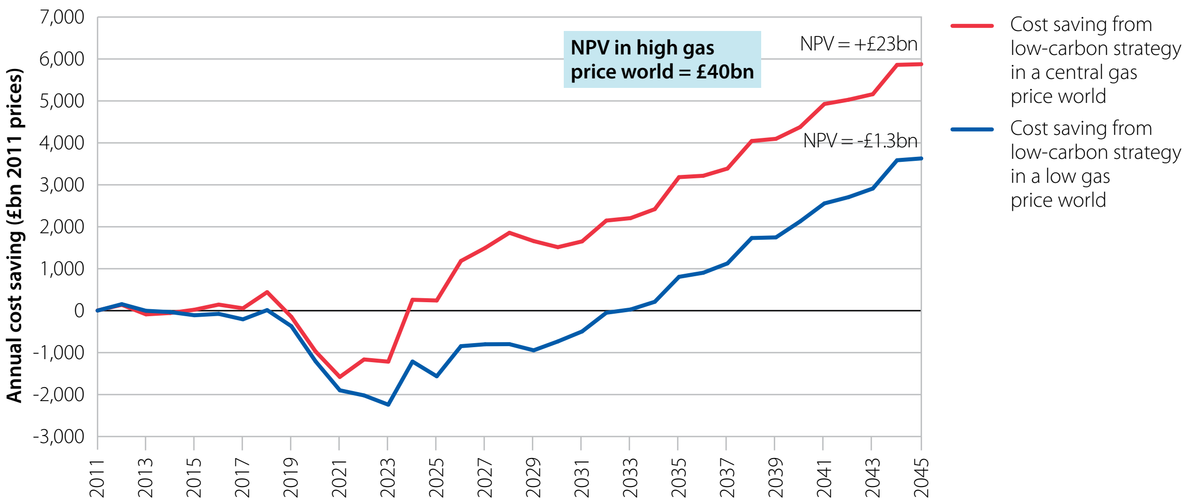
- The analysis was based on modelling we commissioned from Redpoint Energy.[25] This compared costs between investment scenarios focused on low-carbon technologies or unabated gas. The low-carbon scenario included around 18 GW more nuclear investment (and 3 GW more onshore wind investment), with the difference made up by around 20 GW extra unabated gas capacity in the gas scenario.
- The analysis estimated a present value benefit of £23 billion across project lifetimes from investment primarily in nuclear rather than gas-fired generation in the 2020s under central case assumptions. This is due to the rising carbon price through the 2020s and beyond.
- The analysis suggested significantly higher benefits under assumptions of high gas and/or carbon prices. The present value of the cost saving is around £40 billion in DECC's 'high' gas price scenario, rising by a further £20 billion (i.e. to £60 billion) if carbon prices are also high.
- Although benefits would be eroded under assumptions of lower gas or carbon prices, it is unlikely that these would become significantly negative. For example, costs of investment in nuclear and gas-fired generation would be broadly comparable under DECC's extreme scenario for low gas prices, or if carbon prices were at half the central levels (i.e. well below the planned floor price, at £38/tCO_2 in 2030).
- Only with a significant departure from the climate objective, under which combinations of low gas prices and low carbon prices could ensue or carbon prices could be negligible in the long term, would costs be potentially significant.

Therefore investment in nuclear generation through the 2020s is a low-regrets strategy in a carbon-constrained world, with potentially significant benefits in all but the most optimistic of scenarios for gas prices.

A similar argument applies to investment in onshore wind generation through the 2020s, given that this has similar projected costs to nuclear generation. For example, investment in 10 GW of onshore wind capacity – generating equivalent to around 3 GW of baseload capacity – could result in benefits of the order £2-3 billion under central case assumptions.

25 Redpoint (2012) *Modelling the trajectory of the UK power sector to 2030 under alternative assumptions.*

Figure 1.11: Cost savings from investing in low-carbon generation



Source: Redpoint modelling.
Notes: The red line shows net present value saving of £23bn from low-carbon investment, under central assumptions. The blue line shows low-carbon investment is a low-regrets strategy with a similar net present value, even if gas prices turn out far lower than expected. Low-carbon strategy decarbonises to around 40 gCO_2/kWh by 2030, deploying just over 20 GW of new nuclear capacity. Scenario with investment in predominantly gas achieves 130g CO_2/kWh by 2030, deploying 3 GW of new nuclear. Both scenarios achieve at least 30% renewable generation by 2020 and assume technology policy continues to support minimum levels of offshore wind and CCS in the 2020s. Negative values imply a cost penalty from investing in low-carbon, while positive values imply a cost saving. NPV = Net Present Value, discounted at 3.5%. Low and Central gas price worlds as in DECC (October 2011) Fossil Fuel Price Projections.

Investment in less-mature technologies compared to gas-fired generation in the 2020s

The choice in commercialising less-mature technologies is to do this through the 2020s, with relatively low levels of investment, or in the 2030s, when investment may need to be significantly higher to remain on track to meeting the 2050 target:

- Our scenarios above include a commercialisation programme for offshore wind and CCS based on investment of around 15 GW (in baseload-equivalent terms)[26] in total through the 2020s. To the extent that the same cost reductions could be achieved with a smaller programme – this could be established through detailed analysis in the context of developing commercialisation strategies – the programme would be cheaper and offer greater net benefits.
- Prior to commercialisation, these less-mature technologies involve a cost premium relative to unabated gas. Delaying commercialisation to the 2030s therefore offers a cost reduction due to discounting of these costs further out in the future.
- However, delay could also increase costs given the need for higher rates of investment in these technologies in the 2030s before costs have been reduced (e.g. required investments could be up to 35 GW through the 2030s).

26 See footnote 5 above.

- The balance depends on how much capacity is needed in the commercialisation programme, how much low-carbon generation is needed in the long term and how much nuclear or other mature low-carbon technologies can be deployed. Together these determine the long-term role for less-mature technologies and therefore the required pace of investment.

We have assessed this choice based on our cost assumptions from Section 1(ii) and our analysis of what may be needed to meet the 2050 target from our May 2012 report (*The 2050 target*) – see Box 1.6.

Our analysis suggests potentially significant benefits in a carbon-constrained world of investment in less-mature technologies through the 2020s rather than delaying until the 2030s:

- We calculate a net present value of up to £40 billion under central cost assumptions – the benefit would be small if the long-term requirement for these less-mature technologies is low, but would reach £40 billion where this is high, reflecting limits to deployment of mature technologies and/or a very high level of electricity demand in 2050.
- There would be significantly higher savings (e.g. up to £70 billion) if gas and carbon prices are high, and limited net costs if gas or carbon prices are lower (e.g. at most £15 billion, and only where the long-term need for these technologies turns out to be low).

Therefore investment in less-mature technologies as part of an early commercialisation programme rather than investment in gas-fired generation in the 2020s is a low-regrets option with potentially significant benefits in a carbon-constrained world.

Box 1.6: Estimating the net present value of commercialising emerging technologies in the 2020s

Assumptions and approach

Our cost assumptions for low-carbon technologies in Section 1(ii) suggest that commercialisation programmes could reduce costs for both offshore wind and CCS to around £100/MWh by 2030, with scope for further reductions in the 2030s. These are competitive with unabated gas in 2030 under our central assumptions. In our modelling, we also consider uncertainties over gas and carbon prices.

We assume that in a case where commercialisation is delayed to the 2030s, costs of offshore wind and CCS in the UK neither fall nor rise through the 2020s, but thereafter fall as in our central assumptions for technology commercialisation.

- The assumption that costs do not fall in the 2020s reflects that the UK is a key international player in driving down the costs of these technologies. It also reflects that much of the cost reduction potential relates to local effects, such as development of shared infrastructure for CCS, and reduced costs of capital through proven deployment under UK regulatory regimes, rather than merely changes in costs of component technologies. For example, the CCS Cost Reduction Task Force estimates that around 75% of the potential cost reductions to 2030 relate to reducing the cost of capital and to the scale/utilisation of CO_2 infrastructure, both of which depend on the roll-out strategy within the UK.
- There is a risk that costs may rise if there is no deployment in the UK through the 2020s, for example if there were supply chain overheating in the 2030s due to a rapid increase in the pace of investment, or if the implied stop-start investment translates to higher risks for investors.

We model two possible investment profiles: one with a commercialisation programme of 15 GW, in baseload-equivalent terms, in the 2020s (i.e. in line with our scenarios)[27], and one with new build of unabated gas capacity in the 2020s followed by commercialisation in the 2030s. We constrain each to be consistent with decarbonisation by 2050.

In determining the required build rates in the 2030s and 2040s we draw on our report on *The 2050 target*, which concluded that almost all electricity demand in 2050 will need to be met by low-carbon technologies. Specifically, this would require around 80-100 GW of baseload-equivalent capacity, given the need to electrify large parts of the heat and surface transport sectors, and possibly some industrial processes, as well as to meet existing demand. Much higher levels could be needed, for example if electric heating is dominated by inefficient resistive heating rather than heat pumps.

We therefore model three possible requirements for less-mature technologies, consistent with reaching a 2050 capacity of 45-90 GW (in baseload-equivalent terms).

- **'Low requirement for less-mature technologies'.** If half of 2050 demand could be met by mature technologies then the less-mature technologies would need to deliver 40-50 GW of capacity by 2050, implying a required programme in the 2030s of at least 20 GW. For example, this could involve a very major nuclear programme going well beyond existing sites (e.g. 30 GW or more), supplemented by a large amount of onshore wind and hydro capacity.
- **'Constraints on mature technologies'.** If the contribution of mature technologies is limited, or the requirement for low-carbon power is larger, then more capacity could be needed from the less-mature technologies. Required investment in the 2030s would be around 30 GW if new nuclear capacity is limited to 16 GW or in a scenario where more electrification is required to decarbonise the rest of the economy.
- **'No new nuclear'.** In an extreme case with no new nuclear or very high 2050 electricity demand, 2030s investment in the less-mature technologies may need to reach close to 40 GW.

We calculate the relative costs of the two possible investment profiles as a net present value of generation costs discounted back to 2013 using the 3.5% social discount rate.

27 Our scenarios generally build in 13 GW of offshore wind investment and 9 GW of CCS investment in the 2020s. This is equivalent to 15 GW of baseload capacity, allowing for the lower load factors achievable for offshore wind.

Box 1.6: Estimating the net present value of commercialising emerging technologies in the 2020s

Findings

Our analysis suggests a potentially significant cost saving through commercialising technologies in the 2020s rather than the 2030s under central cost assumptions:

- The present value of costs of commercialisation in the 2020s and 2030s are broadly equal in the case with a **'low requirement for less-mature technologies'** (i.e. around 20 GW through the 2030s).
- For higher rates of investment in the 2030s, commercialisation in the 2020s offers significant cost savings. For example, in the case with **'constraints on mature technologies'**, the cost saving has a present value of £20 billion, rising to almost £40 billion where there is **'no new nuclear'**.

Cost savings would be higher in cases with higher gas and/or carbon prices, and lower if prices are lower, although the effects are unlikely to be symmetric given the opportunity to diversify to or from gas CCS:

- Cost savings increase by around £15 billion under DECC's high gas price scenario, and also under DECC's high carbon price scenario. This implies a net present value from commercialisation in the 2020s of up to £70 billion in a world where nuclear is not an available option and gas and carbon prices are high. To the extent that the case with earlier commercialisation would also have the option to diversify away from use of gas CCS to generating options that do not use gas, cost savings could be even higher.
- Low gas prices could reduce costs for both early commercialisation, given the role for gas CCS (and the increased fuel demand when CCS is applied), and delayed commercialisation, given the role for unabated gas. Assuming limited opportunity to adjust post-commercialisation investment to focus more on gas CCS the cost saving from commercialising early would be reduced by up to £10 billion under DECC's low gas price scenario. In reality, the possibility of low gas prices is likely to increase the benefits of early commercialisation as that would allow a focus on gas CCS in the 2030s and 2040s.
- If carbon prices were to be around half the levels of our central case then the present value cost saving from commercialising early would be reduced by around £15 billion. This would still imply an overall benefit in the case with 'constraints on mature technologies', or would imply a net cost of around £15 billion in the case with a 'low requirement for less-mature technologies'.
- Only with a significant departure from the climate objective, leading to very low carbon prices in the long run, or a combination of low prices for gas and carbon, along with a limited requirement for these technologies in the long run, would costs of early commercialisation reach very high levels.

Therefore investment in offshore wind and CCS through the 2020s as part of an early commercialisation programme is a low-regrets strategy in a carbon-constrained world, with potentially significant benefits where other options are able to contribute less in the long run or where gas or carbon prices are high.

Further questions and further work

There is also a question as to the feasibility of a strategy that has no investment in emerging technologies through the 2020s, and then attempts to scale up deployment very rapidly. That could lead to continued use of unabated gas in 2050 and beyond, which could be very expensive itself and/or would require very expensive emissions reductions elsewhere in the economy to meet the 2050 target.

More broadly, the relative value of a commercialisation programme depends on uncertainties relating to decarbonisation costs across the entire economy – commercialisation creates an *option* whose value will depend on how it performs relative to and alongside other decarbonisation options. We will return to this issue of *option value*, using energy system modelling to address a wider set of uncertainties, in our review of the fourth carbon budget, towards the end of 2013.

Benefits of portfolio investment in low-carbon technologies rather than gas generation through the 2020s.

The combined benefit of investment in mature and less-mature technologies through the 2020s is around £25-45 billion under central gas and carbon price assumptions, rising to over £100 billion in scenarios with higher gas and carbon prices, and limited downside risk in a carbon-constrained world.

There are also significant additional benefits from avoiding delay in this portfolio investment:

- **Spillovers.** CCS is a crucial technology for broader decarbonisation; developing CCS therefore has major spillovers for other sectors. Specifically, use of CCS in industry and as a route to negative emissions in combination with bioenergy are key options for meeting the 2050 target. Analysis for our 2012 report *The 2050 target* suggested that not having CCS available as an option could increase the costs of meeting the 2050 target by 0.4% of GDP in 2050. CCS is also likely to be a key abatement option globally, with significant spillovers to international action to reduce emissions from the UK contribution to commercialisation.
- **Flexibility.** Earlier deployment of low-carbon power technologies gives more time to respond to difficulties and develop other decarbonisation options should they be needed (e.g. if CCS is unsuccessful, then more focus can be put on developing offshore wind and electrifying processes in industry).
- **Economic benefits.** Preparing to invest in a low-carbon portfolio in the 2020s will put the UK amongst the early movers on decarbonisation and continue investment programmes currently underway. That may allow the UK to gain an industrial advantage in supply chains for low-carbon technologies, which may bring economic benefits given expected ongoing domestic and international markets for these technologies, and could contribute to objectives to increase employment in manufacturing industries.
- **Import dependency.** Investing in a portfolio of low-carbon technologies would enhance the UK's energy sovereignty. It would also reduce exposure to volatility in fossil fuel prices, and the associated risk of damaging economic impacts.

Given potentially significant benefits and low regrets, investment in a portfolio of low-carbon technologies is a sensible strategy to commit to in a carbon-constrained world. As we now argue in Section 2, such a commitment would help to improve the conditions for investment and bring forward investments in low-carbon technologies and associated benefits.

Not to commit would be to bet on very low gas prices and a very large nuclear programme in future going well beyond the currently approved sites, with relatively low benefits even if these optimistic scenarios transpire.

2. The need to improve conditions for investment

(i) Current investor uncertainties

Investment conditions in the UK power sector will be improved in the long run by the introduction of long-term contracts ('Contracts for Difference') under the Energy Bill, and by the setting of the levy control framework to 2020:

- The contracts[1] will provide revenue certainty for investors in low-carbon technologies, therefore providing more confidence that investment will come forward at a lower cost to the consumer. We recommended this model to the Government based on our analysis which showed that liberalised electricity markets are not well suited to encouraging the transition to a low-carbon power sector, and that long-term contracts are the best option to make this happen.[2]
- The levy control framework[3] allocates (and puts a limit on) funding for investments to come on the system to 2020. It therefore provides confidence for development of such investments, and allows contracts to be signed in the context of the Electricity Market Reform (EMR). Our analysis suggests that the agreed limit in the levy control framework of £7.6 billion in 2020 is broadly sufficient to support investment in a portfolio of low-carbon technologies including nuclear, CCS, wind and biomass generation subject to important caveats (see Section 3).

There are a number of outstanding technical issues relating to contract design and the payment mechanism, which are being resolved as the Energy Bill is finalised and in negotiations of specific contracts.

However, assuming that these are resolved, there remains a high degree of uncertainty about the period beyond 2020, given that the Government has not set out its intentions for that period. This uncertainty was increased by scenarios set out in the Government's *Gas Generation Strategy* in December 2012, and later in the Impact Assessment on Contracts for Differences accompanying the draft Energy Bill (Figure 2.1).[4]

1 Under the Contracts for Difference (CfDs), generators will sell their electricity into the wholesale market, and be paid a top-up equal to the difference between the market price (defined as a specific 'reference price') and the 'strike price' agreed in the contract. If the market price is above the strike price then the contract would be settled in the other direction (i.e. the generator would pay the difference to the counterparty). Difference payments will be funded by a compulsory levy for licensed electricity suppliers, who in turn will pass on the cost to consumers.

2 CCC (2009) *Meeting Carbon Budgets – the need for a step change*; CCC (2010) *The Fourth Carbon Budget: Reducing Emissions through the 2020s.*

3 The levy control framework sets a limit on the funding for certain DECC policies that are paid for via levies on consumers' energy bills. The overall cap is agreed as part of the Spending Review and the framework intends to ensure that other objectives are achieved in a way consistent with minimising the impact on consumer bills. In this report, it refers to the support for low-carbon generation under the Renewables Obligation, Feed-in Tariffs and Contracts for Differences under the EMR.

4 DECC (2012) *Gas Generation Strategy*; DECC (2013) *CfD Impact Assessment: Electricity Market Reform – ensuring electricity security of supply and promoting investment in low-carbon generation*. The estimates in Figure 2.1 have been calculated based on the share of generation reported in the CfD Impact Assessment, and generation and capacity retirements as reported in the DECC October 2012 publication *Energy and Emissions Projections.*

- Our analysis shows that it is economically sensible to invest in a portfolio of low-carbon technologies through the 2020s in the context of the 2050 target in the Climate Change Act. We show in Section 1 that this should reduce the carbon intensity of power generation to no more than 100 gCO_2/kWh by 2030, ideally reaching around 50 gCO_2/kWh where conditions allow this.
- The Government's gas generation strategy includes scenarios where carbon intensity is reduced to 50 gCO_2/kWh and 100 gCO_2/kWh, but with limited portfolio investment after 2020, being focused on the more mature technologies only. This would fail to develop options sufficiently and store up costs and risks for the future.
- A further scenario involves almost no low-carbon investment after 2020 such that carbon intensity remains at around 200 gCO_2/kWh through the 2020s. As set out in Section 1, this would not be an economically sensible scenario and would fail to prepare sufficiently for meeting the 2050 target.

The fact that the Government is the market-maker under the EMR and has published such widely varying scenarios for sector development creates a high degree of investor uncertainty.

This uncertainty is problematic as regards supply chain investment required to drive innovation and cost reduction, project development for investments to come on the system after 2020, and possibly for investments to come on the system before 2020.

- A competitive supply chain is needed to unlock the cost reduction potential that we identified in Section 1, particularly for offshore wind, but current uncertainties may prevent such a supply chain developing.
  - There is currently not a competitive supply chain in place, as evident in overheating and cost increases for wind generation in recent years.
  - A competitive supply chain is needed to drive innovation and cost reduction. While in principle this could be located in the UK or elsewhere, development of a local supply chain would bring additional benefits. A UK supply chain could support cost reduction by minimising transport costs (which can be significant for the very large turbines required offshore) and by ensuring equipment is adapted to specific UK conditions (e.g. ports, water depth, seabed conditions). UK development could also offer wider economic and employment benefits.
  - Supply chain investment has a payback period lasting into the 2020s. The high degree of uncertainty about the 2020s, and the possibility of very limited investment in low-carbon technologies at this time, therefore undermines supply chain investment.
  - Without action to resolve current uncertainties, we cannot be confident that there will be supply chain investment in the UK. Potential investors (e.g. Alstom UK, Areva, Doosan, Gamesa, Mitsubishi Power Systems, Siemens and Vestas)[5] have been very clear about this.

5 *'Go green or we quit'* The Times, October 2012.

– Investment is unlikely to be forthcoming elsewhere to supply the UK market beyond 2020, given the uncertainties over the UK programme and limited prospects of increased demand in other markets.

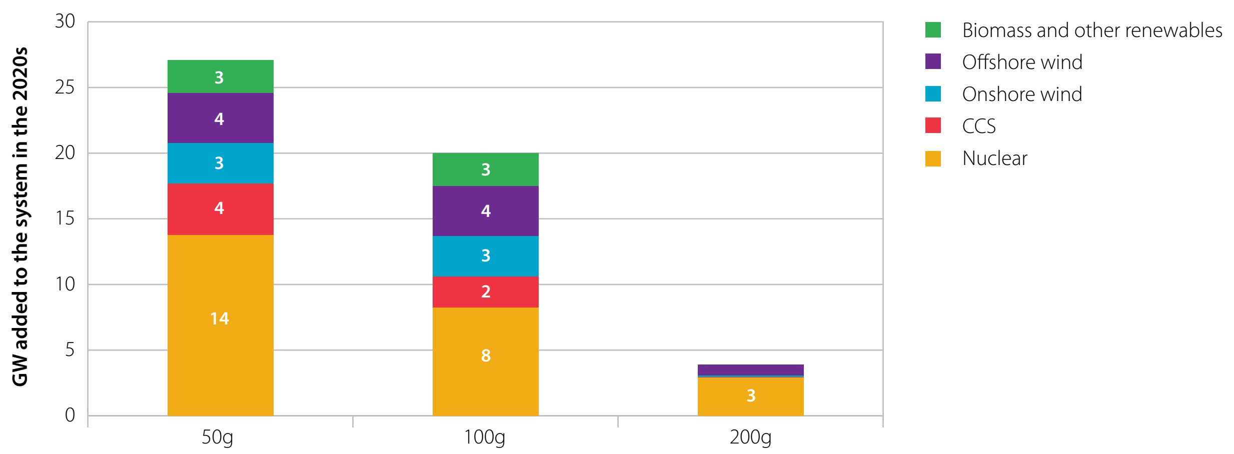
– The risks are that cost reductions will not be achieved, that the supply chain will be unable to meet UK and wider demand, and that overheating will again lead to cost premia in equipment contracts. The technology could therefore remain uncommercialised, with potential benefits not realised, and costs to consumers increased.

- Investments in low-carbon technologies have long lead times (e.g. around 10 years for nuclear, 10 years for CCS and 8 years for offshore wind), and very high development costs (e.g. £100s of millions prior to construction). In order that investments can come on the system in the early 2020s, project development should be underway or starting in the near future. However, the fact that the Government has signalled that there may not be a market for these projects in the 2020s makes it difficult for developers to justify incurring development costs. Therefore the risk is that there will not be a new pipeline of projects, resulting in reduced competition for contracts under EMR and an investment hiatus in the early 2020s, when investment in low-carbon technologies is economically desirable.

- There may also be an issue for larger offshore wind projects due to come onto the system before 2020, where these form the first phase of larger projects, and where development costs cannot be justified if there is a lack of confidence about whether subsequent phases will proceed.

The Crown Estate arrived at similar findings in their recent *Offshore Wind Market Study*.[6] Specifically, based on extensive consultation with industry stakeholders, they identified a significant lack of confidence stemming from concerns over the Government's commitment to the low-carbon transition (Box 2.1).

Figure 2.1: Implied low-carbon investment in the 2020s in the scenarios included in the Government's 2012 Gas Generation strategy



Source: CCC calculations based on DECC CfD Impact Assessment (February 2013). The levels of overall investment in these 50g and 100g scenarios are lower than in those we set out in Section 1 because of lower assumed demand (e.g. a lower level of electrification of heat and transport is assumed in these scenarios).

Box 2.1: The Crown Estate's Offshore Wind Market Study

The Crown Estate study assessed the current and future state of the UK offshore wind industry and identified key challenges that industry stakeholders perceive as potentially constraining offshore wind deployment in the short, medium and long term.

Political and regulatory uncertainty and the availability of financing were identified as major barriers to offshore wind development:

- **Policy and regulatory framework.** Industry stakeholders are concerned about political uncertainty created by the EMR as well as the Government's longer-term commitment to decarbonising the power sector. Stakeholders also identified the "chicken and egg" problem wherein future political commitment is contingent on cost reductions in offshore wind, but that these cost reductions cannot be delivered without significant political support in earlier stages.
- **Availability of finance.** The industry anticipates a funding shortfall for offshore wind development (estimated between £7-22 billion by 2020) and limited ability of utilities to take on additional debt to finance new projects. Alternative financing routes will be required, either via attracting new equity investors/project finance providers or through "equity recycling" (e.g. refinancing fully-built and operational wind farms and then recycling this capital back into additional projects). Key challenges include the perceived or actual risks associated with construction and concern as to how new joint venture structures would be treated by credit rating agencies.

Additional barriers to offshore wind deployment identified by industry include supply chain and skills, grid connections, technology risk and consenting.

The study concludes that it is crucial that the Government gives as much certainty as possible about its commitment to decarbonisation and supporting offshore wind to maturity. This could occur through consistent messaging from Government on its commitment to decarbonising the power sector (e.g. through specific 2030 targets) and timely developments of details of EMR proposals, in particular publication of strike prices in 2013.

As regarding financing new projects, the study recommended the Government should attract non-financial investors with the institutional capacity to manage construction in marine environments (e.g. oil and gas companies), de-risk construction through providing risk-sharing mechanisms, or provide liquidity or guarantees during construction via institutions such as the Green Investment Bank. Equity recycling could be supported through engaging with credit agencies and transferring risk away from utilities.

It is therefore essential to address this uncertainty in order that the EMR can be implemented in a way that gives value for money from the agreed levy control framework, supports commercialisation of low-carbon technologies, and encourages investments that offer potentially significant economic benefits.

(ii) Addressing uncertainty by setting a carbon-intensity target

A well designed target for carbon intensity in 2030 embodying investment in a portfolio of low-carbon technologies could provide certainty for investors that a market will be available if they can deliver projects to cost and on schedule, but without providing a blank cheque if they cannot. It would be a simple and direct way to reassure investors that the UK is a desirable market to invest in.

In particular, a target with periodic review based on transparent criteria could signal the Government's commitment to develop a portfolio of low-carbon technologies, and deliver an appropriate balance between certainty, incentives, and flexibility.

- It would signal to investors that, if they were able to bring forward cost-effective investment at pace, then contracts would be available under the EMR. Specifically, it would signal conditional support for investment in nuclear new build, carbon capture and storage (CCS) commercialisation, and continued investment in onshore and offshore wind after 2020.
- It would provide a challenge to industry, strengthening incentives by establishing a clear path for cost reduction, and limiting availability of contracts where cost reduction is not achieved. In effect this would be an extension of the principle in the Government's 2011 Renewable Energy Roadmap, where the ambition for offshore wind in 2020 is conditional on the extent of cost reduction that is achieved.
- It would provide flexibility to respond to new information about the feasible pace of delivery and costs, and therefore provide safeguards for electricity consumers (e.g. a failure to deliver cost reductions would result in a lowering of ambition, therefore mitigating price impacts for consumers).

The analysis in Section 1 shows that such a target and associated portfolio investment would offer significant economic benefits and would be low regrets compared to the alternative of investing in unabated gas-fired generation through the 2020s. Our analysis in Section 3 demonstrates that it would have limited incremental funding requirements and bill impacts during this period.

Given the fundamental economics, an appropriate approach could be to set in legislation either: a target to reduce carbon intensity to 50 gCO_2/kWh in 2030 with potential to adjust this, for example depending on cost reductions achieved for less-mature technologies and success in deploying new nuclear; or a target range (e.g. 50-100 gCO_2/kWh), with a clear statement of which end of the range will be the objective in different circumstances.

- The 50g target or the more ambitious end of the range would apply in a world where aggressive build rates for new nuclear capacity are achieved along with significant energy efficiency improvement and/or where costs of less-mature technologies are reduced.
- Adjustment of the target or the less ambitious end of the range would be relevant where these conditions are not met, but still consistent with what is required to meet the 2050 target.
- Alternative approaches could be considered in the extreme case of a failure to deliver on both nuclear deployment and cost reductions for less-mature technologies. Even in this case, some decarbonisation would be appropriate given the need to prepare for meeting the 2050 target.
- It would be appropriate to aim initially for 50 gCO_2/kWh, with periodic review prior to the drafting of each new EMR delivery plan (i.e. every five years), and possible modification depending on the pace of investment and cost reductions achieved.

This would then guide EMR implementation, in terms of technology commercialisation strategies, contracts to be signed, and funding under the levy control framework.

(iii) Committee recommendations and Government proposals

We recommended to the Government in summer 2012 that a carbon-intensity target aimed at reducing 2030 emissions to around 50 gCO_2/kWh should be set under the Energy Bill, which is currently progressing through Parliament.

In response, the Government has taken a power in the draft Bill which would allow it do this in 2016. It has argued that setting a target any earlier would be premature, given that the fifth carbon budget covering the period 2028-2032 – and setting the economy-wide emissions limit for 2030 – will not be legislated until 2016.

However, it is not necessary to wait for the setting of the fifth carbon budget to take a decision on the 2030 carbon intensity target, given clear evidence to show that investment in a portfolio of low-carbon technologies is a robust strategy with low regrets and significant potential benefits across a wide range of scenarios.

Neither is it necessary to wait for the fourth carbon budget review in 2014 to set a carbon-intensity target. Although the Government has linked its approach to EMR implementation with the review of the fourth carbon budget, it will remain economically desirable to invest in a portfolio of low-carbon technologies whatever the outcome of the review, given the 2050 target in the Climate Change Act.

Moreover, delay in setting the target will allow current uncertainties to be perpetuated, with adverse consequences for supply chain investment and project development, as outlined above.

We therefore continue to recommend to the Government and to Parliament that a carbon-intensity target aimed at reducing emissions to around 50 gCO_2/kWh should be set as a matter of urgency.

Given a carbon-intensity target, it is important that the Government sets out its approaches to commercialising less-mature technologies. Currently there is no detail around the approach to CCS beyond the first two demonstration projects, or to offshore wind beyond 2020. In particular, there is no signal to investors about what is expected of them in terms of cost reduction, and levels of investment prior to full commercial deployment if cost reductions are achieved.

To address this we recommend that the Government publishes commercialisation strategies for the less-mature technologies, including timelines for investment and conditions to be met (i.e. on cost reduction) in order that this proceeds.

The carbon-intensity target and technology commercialisation strategies should then guide EMR implementation, which should be such that the number of contracts to be signed during the first delivery plan period (2014/15-18/19) should be consistent with achieving this target.

It is also important that funding under the levy control framework covers a period sufficiently long to support current and future project development and supply chain investment, thereby buttressing the signal provided by the carbon-intensity target.

We therefore recommend that the levy control framework should now be extended to cover the period to 2030; this would be even more important if the Government cannot agree on the early setting of a carbon-intensity target.

We set out our assessment of contracts to be signed during the first EMR delivery plan period and required levy control funding in Section 3.

(iv) Addressing possible barriers to finance

Even if the investment climate can be improved, there remain questions about whether finance would be forthcoming for required investments. In particular, large amounts of finance are required, while balance sheet strength of energy companies may be limited, and appetite of banks and institutional investors for project finance is unclear:

- The total cost of investment in low-carbon power generation to 2020 is around £100 billion (comprising around half for onshore and offshore wind, and half for nuclear, CCS and other renewables), with around a further £90 billion through the 2020s. This is part of a wider set of significant investments, including those required in conventional power generation and the electricity grid over the next decade (e.g. Ofgem estimates total investment required of £200 million from 2010 to 2020).
- To date, investments in relatively high risk low-carbon technologies (i.e. offshore wind) have typically been financed using the balance sheets of energy companies to secure debt. However, it is questionable whether balance sheets are sufficiently strong to support the level of investment required going forward because: many energy company assets are largely depreciated; existing assets are of low capital intensity compared to low-carbon technologies; energy companies operate in many markets where investment requirements are often also high; the closure of German nuclear plant has adversely impacted the balance sheets of E.ON and RWE, two major players in the UK market.

- In the absence of finance backed by balance sheets, investment might proceed using project finance – where debt is secured against future project cash flows. However, appetite from banks and institutional investors to provide project finance during the early stages of projects where risks are high is unclear, and likely to be even harder to secure until new market arrangements are proven; it is at this early stage where project finance might be required, given balance sheet constraints. There are also questions about whether energy companies have sufficient funding to contribute levels of equity that would be required in a project finance structure.

The risk is that finance becomes a binding constraint on the level of investment in low-carbon technologies.

If this were the case, then the Government might help to mobilise finance through specific design of the EMR and use of financial instruments:

- Contracts in the EMR could be designed to provide a buffer against construction risks (e.g. through risk-sharing arrangements).
- The Green Investment Bank or Infrastructure UK could issue debt guarantees, and have some form of equity or quasi-equity participation.

We have not undertaken our own detailed analysis of all possible sources of finance or of current capital market conditions. However, it is clear that a significant increase in finance is required, and that a challenge exists in delivering this.

We recommend that the Government should undertake and publish an assessment of current capital market conditions focusing on whether and how investments in low-carbon power generation might be financed. To the extent that this assessment suggests a risk that finance will be constrained, options to address this through design of the EMR and use of financial instruments should be considered.

3. Implications for the first delivery plan

The Government is due to publish its first draft Delivery Plan for the Electricity Market Reform in July 2013 for consultation, to be finalised by the end of the year. The Delivery Plan should cover the contracts to be signed and proposed strike prices for the years 2013/14 to 2018/19.

Given long project lead times, these contracts will largely determine investments coming onto the system until the mid-2020s, and therefore whether 2030 objectives are achieved.

In this section we draw out the implications of our analysis for contracts to be signed in order to keep open the multiple options for achieving 2030 objectives (e.g. as in our 50g and 100g scenarios in Section 1); we build on the cost analysis in Section 1 to assess strike prices that may be required to bring forward the key technologies; and we estimate required funding under the levy control framework to 2020 and 2030.

(i) Contracts to be signed during the first delivery plan period

Investment scenarios underpinning the Delivery Plan

The scenarios in Section 1 reflect investment in cost-effective technologies (i.e. nuclear, onshore wind generation), and commercialisation of less mature technologies (i.e. offshore wind and carbon capture and storage, CCS), with the aim that these become cost-effective during the 2020s.

Scenarios to achieve carbon intensity of 50 gCO_2/kWh in 2030 should be *Plan A*, but there should be some flexibility to adjust the level of ambition dependent on the feasible pace of investment and the pace of cost reduction achieved. For example, a *Plan B* that reaches up to 100 gCO_2/kWh while still deploying a portfolio of low-carbon technologies might become appropriate if costs fall less quickly than currently envisaged, or if achievable build rates are lower than expected.

However, flexibility should be limited given clear evidence that significant decarbonisation in the 2020s is feasible and desirable in terms of managing costs and risks of meeting the 2050 target for an economy-wide emissions reduction of 80% versus 1990.

In particular, we recommend that the Delivery Plan does not include a 200g scenario; this scenario offers no economic benefit in a carbon-constrained world, and its inclusion would perpetuate uncertainty which would further damage conditions for investment in the sector.

From investment scenarios to contracting strategy

Translating investment scenarios to a contracting strategy requires assumptions on project lead times and the point within the project cycle at which contracts are signed.

- We assume that contracts are signed prior to plants entering construction, in line with developers' final investment decisions.
- We assume project lead times from commencing construction to commissioning of 2 years for onshore wind, 3 years for offshore wind, 6 years for early nuclear projects, falling to 5 years for later projects, and 4-6 years for CCS projects, with coal plants at the top of this range and gas plants at the bottom.
- There may be a case for signing contracts earlier given high development costs, in which case more contracts would need to be signed in the first delivery plan. This is something for further consideration and should form part of the consultation.

Combining our assumptions on investment and project lead times suggests a set of contracts to be signed during the first delivery plan period which is similar across our 2030 scenarios, with a possible acceleration in offshore wind if costs are clearly coming down more quickly than expected.

The appropriate contracting strategy would vary between scenarios during the second delivery plan period (i.e. 2019/20 to 2023/24), with the appropriate strategy to be determined in light of new information on costs and the feasible pace of investment.

Contracts to be signed during the first delivery plan period

Our analysis suggests that the aim should be to sign contracts for around 25 GW of low-carbon capacity during the first delivery plan period from 2014/15-2018/19 (Table 3.1). This should include: contracts for renewables projects as required to meet the EU 2020 renewable energy target and to continue deployment into the early 2020s; CCS demonstration projects which go beyond the two which were recently announced; and up to four new nuclear projects.

- **Renewables.** In our annual progress monitoring we assume that the renewables target is met with 15 GW onshore wind, 12 GW offshore wind and 4 GW of solid biomass capacity in 2020.[1] Given existing capacity (i.e. 6 GW onshore wind, 3 GW offshore wind) and development times set out above, this illustrative split would require annual contracting of around 1-1.5 GW per year on average for each of onshore and offshore wind. This contracting level should continue to the end of the period, for projects to come on line in the early 2020s. Contracts for up to 4 GW of biomass conversion may also be needed over the period, although much of this probably will be brought forward under the RO regime instead.

1 See for example, CCC (2012) *Meeting Carbon Budgets – 2012 Progress report to Parliament*.

- **CCS.** The first two demonstration projects should be contracted in 2014/15, following completion of FEED studies (Front-End Engineering and Design) and ahead of commissioning in the period 2016-2020. Further projects should be contracted later in the period, consistent with commercialisation in the 2020s. For example, this could include two further projects to sign contracts in 2016 to allow FEED studies to go ahead. Final decisions on these contracts could be made in 2018, reflecting any learning from the FEED studies. These plants could then come on the system in the early 2020s. Any further delay to these projects would hold back commercialisation and limit the contribution that CCS can make to sector decarbonisation.
- **Nuclear.** The Government is currently negotiating with EDF over the first nuclear project at Hinkley, under the 'FID-enabling' arrangements (to enable Final Investment Decision). The contract for the second project at the same site should follow shortly after. By the end of the first delivery plan the Government should also look to contract at least one plant from the second developer (Horizon), following completion of the Generic Design Assessment of their proposed reactor. A second EDF project could also be contracted around this time, and the first project from NuGen may be ready to contract at the end of the period or soon after. With further contracts to follow in the second delivery plan, this would enable an extensive nuclear programme by 2030, with related cost savings for consumers.

Table 3.1: Illustrative levels of capacity to sign contracts in the first Delivery Plan (2014/15 to 2018/19)

	GW Capacity
Onshore	1-1.5 GW per year on average
Offshore	1-1.5 GW per year on average
Biomass conversion	Up to 4 GW by the end of the period, depending on capacity commissioned under the Renewables Obligation
Nuclear	First plant (1.6 GW) contracting in 2013 (under FID-enabling arrangements), followed by 1.6 GW in 2014/15 and a further two plants (around 3 GW) by the end of the period
CCS	Two demonstrations (each c. 0.3 GW) to contract in 2014/15. More to follow (e.g. two projects signing contracts in 2016, to be finalised in 2018 after completion of FEED studies).

Source: CCC calculations
Note: 'FID' = Final Investment Decision.

Although our focus is on contracting low-carbon capacity, our modelling also identifies the need for new gas capacity. We estimate that around 5 GW of new CCGT capacity would be needed by 2020 to keep system security at current levels.[2] This plant would need to begin construction during the first Delivery Plan period, and could be secured through the proposed Capacity Market.[3]

2 This is an illustrative estimate; the precise level will depend on the reliability standard chosen, the success of efforts to improve energy efficiency, the exact amount and type of low-carbon capacity built, and any improvements to system flexibility (e.g. due to smart meter roll-out).

3 The Capacity Market is the Government's proposed mechanism to incentivise investors to deliver adequate reliable capacity to ensure overall system security. It will take the form of an auction, where successful bidders will commit to meeting capacity requirements in return for payment. It will aim to optimise across all types of capacity (new generation, demand, storage and interconnection).

Given the need to provide a signal to investors a number of years ahead in order to support project development, we recommend that the Delivery Plan should clearly state the quantity of contracts that the Government intends to enter into over the period 2014/15-2018/19. This should be subject to cost considerations being met and should allow some flexibility in the balance of renewable technologies deployed to meet the renewable energy target (e.g. if more can be delivered onshore, this could substitute for some offshore wind and reduce costs overall).

This is preferable to simply announcing capacity to be commissioned (i.e. to come on the system) by 2018/19, which would provide only very limited visibility (e.g. this would signal contracts to be entered for offshore wind only in 2014 and 2015, and onshore wind in 2014, 2015 and 2016).

(ii) Contract strike prices to bring forward required investment

Approach to contract prices in the Delivery Plan

The Delivery Plan will include proposed contract strike prices for wind generation, but not for nuclear and CCS, which will be negotiated on a project-by-project basis.

The argument above about providing visibility across the delivery plan period also applies to contract prices. Unless announced for the whole period in advance, investors would have to develop projects with no information on future prices. The need for certainty should be balanced with the need for flexibility to respond to new information while maintaining the overall direction of travel.

We therefore recommend that the Government announce in advance strike prices for wind projects to be contracted over the whole delivery plan period (i.e. out to 2018/19). This should be subject to review as part of the process for updating the delivery plan, based on relevant new information about key cost drivers.

In this section we set out the implications of our cost analysis for contract strike prices, to illustrate what might be paid for wind generation, nuclear and CCS. We also include illustrative prices for biomass conversion, although much of this capacity is likely to be brought forward under the Renewables Obligation.

Considerations in setting contract prices

In order to bring forward required investments, contract strike prices will have to cover the levelised cost of generation plus discounts applied to the wholesale market price:

- We set out our levelised cost estimates in Section 1 above.
- Developers will require a higher strike price under the contract than their levelised cost. This is due to the fact that wholesale market prices are discounted to reflect "basis risk".
  - Developers will sell their generation output into the electricity wholesale market and additionally receive a return under EMR equal to the difference between the agreed strike price and the market wholesale price (with the specific price index, e.g. day-ahead, set in the contract). If developers could achieve a return from the wholesale market equal to the market price then the required contract price would match their levelised cost.
  - However, in reality developers do not receive the full wholesale price. This is due to a range of factors, including the costs associated with managing the intermittency of wind output or risks of unplanned nuclear outages, along with more general transaction costs between power purchasers and generators.
  - Based on discounts currently observed in Power Purchase Agreements for intermittent and baseload generation, Pöyry estimate that developers' returns will be around 10% less than the wholesale price for wind generators and up to 7% less for nuclear, biomass and CCS. Therefore, strike prices will need to be higher than levelised costs to compensate for these discounts.

Required strike prices will also depend on contract length: the shorter the contract length, the higher the price that would have to be paid under the contract, since expected returns outside the contract period are likely to be lower than those during the contract. Whereas our cost analysis assumes depreciation over the technical life of assets, the Government has proposed shorter contract lengths (Box 3.1).

In what follows, we present our estimates of contract costs for different lengths of contract, and we show the implications of different contract lengths for support under the levy control framework in Section 3(iii) below.

In determining appropriate contract length, we recommend that the Government should undertake a full assessment of impacts for consumers under different contract lengths, and proceed with shorter contracts only if this is shown to offer a clear consumer benefit.

Box 3.1: Considerations in setting the length of contracts under EMR

The Government has proposed 15-year contracts for wind projects. These are significantly shorter than project lifetimes (i.e. 24 years onshore, and 22 years offshore) and shorter than the qualifying period for subsidies under the Renewables Obligation (i.e. 20 years).

Shorter contracts will require higher prices. They could still offer better value in principle, but there is a risk that in practice costs to consumers will be higher over project lifetimes.

- Clearly where developers are paid subsidies over fewer years these will need to be paid at a higher level.
- In principle, there could be an advantage to front-loading subsidies into early years. This follows from the fact that developers have higher discount rates than consumers (i.e. developers' required returns are typically around 10%, whereas the social discount rate is 3.5%). The implication is that consumers will value the reduction in subsidy in later years by more than they feel the cost of the increase required to compensate developers in early years.
- However, as well as front-loading subsidies, shorter contracts expose developers to uncertainties over their non-subsidised returns (i.e. the wholesale market price) outside the contract period. These are the same risks (e.g. uncertainties over the future gas and carbon prices and how these will translate to electricity prices) that EMR seeks to remove from investors and could lead developers to assume a very low residual value for their asset beyond the contract.
- For example, faced with unclear market rules in the long term developers could anticipate a world where low marginal cost generation drives the wholesale price to very low levels. An expectation of a very low wholesale price beyond the contract period would lead them to require a higher price during the shortened contract period.
- Consumers could end up paying for these high returns during the contract *and* also paying a high price beyond the contract period, particularly if high carbon prices do transpire, if gas prices rise or if wholesale prices prove robust to increasing penetrations of plants with low marginal costs.
- There is a further risk that shorter contracts reduce incentives for developers to spend on maintenance and hard-wearing parts to ensure that their projects maintain good performance throughout their potential lifetimes. If project lives are curtailed then consumers will not be able to benefit from potentially lower costs outside the contract period.

We conclude that the case for shorter contracts is uncertain. If it is to proceed with shorter contracts, the Government should first demonstrate that these offer the best value for consumers given uncertainties for developers over residual asset value.

Estimated contract prices

Our analysis shows that required strike prices are uncertain but likely to fall through the delivery plan period (Table 3.2)

- **Onshore wind.** The cost and performance of different types of wind project are reasonably well understood, with significant variation across project types. However, there is uncertainty over what will be the marginal project in a particular year, and therefore the strike price required to bring forward this project. Based on an assessment of the project pipeline (Box 3.2), we estimate a strike price in a central case broadly comparable with current returns under the Renewables Obligation (RO), which we estimate to be around £105/MWh. We identify scope for a lower strike price of around £95/MWh for later projects contracting in 2018, with a range of £85-105, with the cost reduction between 2014 and 2018 reflecting a slightly reduced cost of capital as developers/investors gain comfort with the new arrangements, and a small amount of learning.

- **Offshore wind.** As for onshore wind, there is variation across offshore projects, with uncertainty around what will be the marginal project, albeit the project pipeline is more straightforward to characterise given the larger scale of projects (Box 3.2). There is also uncertainty around project cost and performance, given that there is less experience investing in offshore wind. Our analysis of the project pipeline suggests a central case strike price of around £160/MWh in 2014, with a range £145-175. We note that the central case is slightly higher than implied revenue under the RO, suggesting either that the RO would not support the marginal project, or that cost is lower than our central estimate; further assessment is required here. The key point from our analysis is that the required strike price falls to around £130/MWh in a central case by 2018, with a range of £110-145. The change in cost between 2014 and 2018 is due to a reduction in the cost of capital from over 12% to closer to 10% as developers gain comfort with the new arrangements and the technology is shown to work effectively, with some learning and innovation.
- **Nuclear.** There is a high degree of cost uncertainty around nuclear generation particularly relating to construction cost. The first project is currently the subject of detailed negotiations between the Government and EDF, and is likely to involve some premium over future plants. The Pöyry analysis therefore suggests scope for reduction in costs for contracts to be signed further out in the delivery plan period (e.g. to £70-95/MWh) as adjustments for the UK regulatory regime are made and associated risks are reduced.
- **CCS.** There is a high degree of uncertainty around costs of CCS, relating both to construction costs and costs of capital. Costs also differ significantly between the types of CCS technology (e.g. gas or coal, pre- or post-combustion). The Pöyry analysis of costs suggests scope for reduction of strike prices for CCS projects between the first and second demonstration phases (e.g. to around £100 per MWh in a central case for gas post-combustion), subject to there being learning between these phases (e.g. about project costs and performance, and viability of contract structures).

This suggests scope to announce in advance *falling* prices for onshore and offshore wind for the delivery plan period. However, these estimates are uncertain, and further work is required (and underway/planned by DECC) before final contract prices are announced. In particular, other evidence on construction costs and plant performance, required rates of return and basis risk discounts, should be fully considered.

Box 3.2: Project supply curves for wind

The pipeline of wind projects is diverse, both geographically and by project size, leading to variation in the project costs. As part of their review of costs and feasible build rates, we asked Pöyry to undertake a detailed assessment of specific cost drivers such as location and project size in order to derive a cost distribution or 'supply curve'. From this, we can estimate the potential capacity that is likely to come forward at a given strike price in a given year.

- **Key cost drivers.** The key cost drivers are summarised in Table B3.2. Whilst wind conditions are a key driver of the cost (and therefore required strike price), it is difficult to pick out a specific pattern. For example, a wind project with a relatively low load factor could be comparable in cost to a project with a higher load factor if it benefits from economies of scale and low transmission costs.
- **Wind conditions.** These will vary by location and by turbine size. Onshore projects in Scotland generally benefit from higher load factors than those in England but can face higher transmission costs (see below).
- **Size.** Larger projects (e.g. greater than 50 MW onshore) are able to spread fixed costs across greater output thereby benefiting from economies of scale. For offshore projects, Pöyry assume all projects except those commissioning in the near term benefit from the next generation of larger turbines (6-7 MW).
- **Transmission costs.** These costs include the cost of connecting to the nearest onshore substation and the transmission charging zone. Projects located further away from substations, and in more remote areas (such as Scotland) face higher costs than those in the South East.

Table B3.2: Project-specific factors affecting costs – onshore and offshore wind

Onshore	Offshore
Wind conditions and load factor	Wind conditions and load factor
Size	Size
Distance to onshore sub-station	Distance to shore, offshore transmission owner (OFTO) charge, onshore connection point & charge
Transmission charging zone (TNUoS) and charge	Depth
	Wave and seabed conditions

Box 3.2: Project supply curves for wind

The supply curve

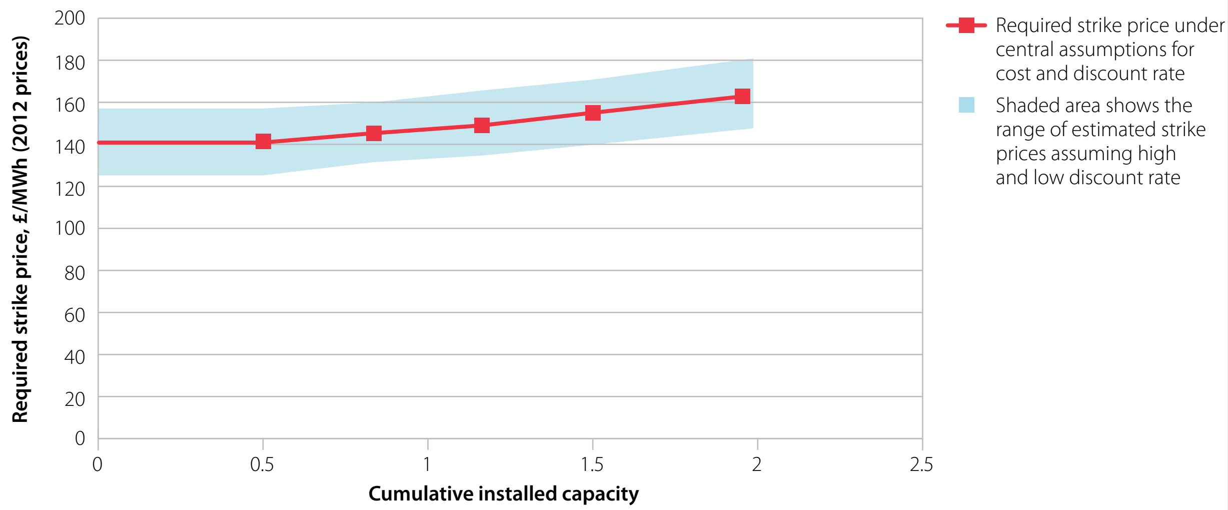
Having identified the key cost drivers across projects and characterised the projects in the pipeline, Pöyry constructed supply curves for potential projects currently, and in future, in line with the cost assumptions set out in Section 1.

Figure B3.2 illustrates the cost of offshore wind projects estimated as available to sign contracts in 2016 and commission in 2019 under central discount rate assumptions (11.4%), with sensitivities at a high-low range (9.9%-12.9%). It highlights the uncertainty and difficulty in determining appropriate strike prices:

- Even under central assumptions on key cost components (e.g. capital and operating costs), the range for strike prices for projects signing contracts in 2016 ranges from £140/MWh up to 160/MWh, depending on the marginal project. Given that the precise set of projects available to contract and the precise level of capacity to be contracted are uncertain, the marginal project and therefore the required strike price is uncertain.
- Adding in uncertainty over the required rate of return (which will also vary between developers and projects) this range extends to £125-180/MWh.

We use these supply curves to inform our strike price modelling, whilst concluding that project heterogeneity contributes a significant level of uncertainty when setting strike prices.

Figure B3.2: Estimated required strike price for offshore wind projects ready to sign contracts in 2016 for commissioning in 2019



Source: CCC calculations based on Pöyry.
Notes: Assumes contract length is equal to full project lifetime (22 years). Central scenario assumes a pre-tax real rate of return of 11.4%. High scenario = 12.9%. Low scenario = 9.9%.

Table 3.2: Illustrative strike prices (£/MWh) for the first Delivery Plan period

Year contract signed:	2014		2018	
	Full project lifetime	**Shorter contract**	**Full project lifetime**	**Shorter contract**
Onshore	Broadly comparable with current support under the RO (i.e. c. £105/MWh)	+ c.£5	c.£95	+ c.£5
Offshore	c.£160	+c.£10	c.£130	+c.£10
Biomass conversion	£80-95 (at central fuel prices)			
Nuclear	Individually negotiated, for example: Falling to £70-95 for projects signing later in period, with the first project likely to be more expensive.			
CCS	To be individually negotiated, in light of information from FEED studies. Falling for later projects (e.g. to £90-120) for projects in the second pre-commercial phase.			

Source: CCC calculations.
Note: These are illustrative prices only, based on the evidence, approach and assumptions as set out in this report. Shorter contracts for wind assume 15 year contracts, compared with full lifetime of 22 years for offshore and 24 years onshore. Figures for CCS are for a post-combustion gas plant under central fuel price assumptions. FEED: Front-End Engineering and Design

Dealing with uncertainty in costs

Even with further consideration, information for setting prices will always remain imperfect and asymmetric (i.e. developers will have better information about their required rates of return, plant performance and construction costs), suggesting that there will always be problems with administrative price setting. If prices are set too high then consumers would bear unnecessary costs, and if set too low then investment may not come forward as required to develop a low-carbon portfolio.

Given this difficulty, alternative mechanisms for price discovery such as auctions are attractive. Auctions are particularly effective where the counterparty (the Government in this case) is not well informed of the participants' costs/valuations, where bidders are offering a product with uniform well-defined characteristics, and where there is a strong pipeline with many bidders and low bidding costs. In these circumstances auctions should ensure a strike price that reflects actual project costs.

Wind generation, particularly onshore, is well suited to auction of contracts, whereas this may not be the case for nuclear and CCS in the near term.

- **Wind generation.** There is a strong pipeline of wind projects with uncertain costs and potential for competitive bidding.

- Onshore wind projects are typically small-scale (e.g. around a third of projects in the pipeline are under 50 MW), and many different players are engaged in deployment. There are also significantly more projects ready for deployment than need to be contracted each year (e.g. at the end of 2012 over 6 GW of projects had planning consent but had not yet commissioned, compared to the 1-1.5 GW annual capacity to be contracted).
- Although offshore projects tend to be larger (e.g. the largest projects can be over 1 GW), there are also several players involved in development, suggesting competition for contracts could be strong. Over 10 GW of projects were in the pipeline at the end of 2012, and whilst many of these still require planning consent this is less of a barrier offshore.
- Taken together with the cost uncertainty identified above, this suggests both onshore and offshore wind are well suited to auctions. In the specific case of large offshore projects with significantly different cost structures and high development costs there could be a case for individual negotiations.
- In auctioning for a specific level of capacity there would remain a risk of very high prices being paid if there is a shortage of bidders in any one year. This could be managed by setting contract reserve prices, for example based on a cost assessment such as we have set out above.

- **Nuclear.** Currently there is only one developer (EDF) ready to proceed with new nuclear investment. Even in the long run only three developers are in play, suggesting scope for competitive bidding is limited. In principle nuclear developers could bid against other technologies, although our cost estimates suggest this is unlikely to increase competitive pressure (i.e. since other technologies' costs appear to be higher than for nuclear); this would also raise questions such as the relative value of baseload versus intermittent generation. Furthermore, site-specific considerations (e.g. different reactor types, different developers) suggest scope for overall cost saving from setting individual prices (e.g. through negotiation) rather than having a single clearing price.
- **CCS.** A commercialisation strategy for CCS will require consideration of factors beyond price, while potential for a competitive bidding process is likely to be limited.
  - The first two CCS projects have been selected and will negotiate strike prices individually.
  - Beyond this auctioning may remain difficult prior to commercialisation, given that the relative merits of different projects will involve considerations beyond price. For example, although several projects came forward to the Government's competition, only one of these involved application of CCS to a gas-fired plant, which we have identified as a key priority for the commercialisation programme. If contracts are indexed against fuel prices, this could also make comparisons difficult insofar as there are different risks attached to the prices of different fuels.

– Development costs for CCS projects are also high (e.g. FEED studies can cost around £20 million[4] and are required to understand project costs), restricting potential for a competitive bidding process.

In considering when to move to auctions, there are a number of practical challenges, which should be considered:

- If auctions are introduced too quickly (e.g. before the market players are comfortable with the new system of CfDs) then achievable prices will be higher.
- Time will be required to design an effective auctioning system which keeps transaction costs to a minimum, including consultation with industry and time to educate potential bidders.
- Auctions will only be effective where there are sufficient players able to bid in. For example, for offshore wind our analysis of supply curves suggests a significant amount of capacity is likely to be consented by the start of 2016.
- Auctions should occur within the project cycle such that there are limited costs involved in preparing bids, or consideration should be given to possible reimbursement of bidding/development costs.

However, the fact that auctions place a limit on the number of contracts that will be awarded, and therefore imply a risk for developers that their project will not be taken forward, is not an argument against them, as the amount of capacity contracted will have to be controlled whatever price discovery mechanism is employed. To the extent that this creates a problem, some flexibility could be built in, for example with more contracts awarded if achieved prices are lower than expected – consistent with our recommended approach to scenarios.

Given the particular characteristics of wind generation, both as regards cost uncertainty and suitability for auction, we recommend that the Government should transition to auctioning for onshore and offshore wind contracts as soon as is practical. Auctions should be designed to ensure a minimum amount of offshore wind is contracted, consistent with technology development.

Further out in time it may be possible to hold auctions that are technology neutral, once currently less mature technologies have been commercialised and costs have converged across technologies. Our analysis suggests that this is unlikely to be before the second half of the 2020s, although earlier convergence and possible competition between low-carbon technologies should not be ruled out. This is broadly in line with the four stages the Government has set out for EMR, which involve technology neutral auctions in 'Stage 4', estimated to be in the late 2020s and beyond.

4 NAO (2012) *Carbon capture and storage: lessons from the competition for the first UK demonstration.*

(iii) Required funding under the levy control framework to 2020 and 2030

Levy control framework to 2020

It is essential that the intention to sign contracts is underpinned by funding, and that this is announced in advance in order to provide a credible signal to investors.

The mechanism for providing this signal is the levy control framework, which limits the amount of subsidy that can be paid under the Renewables Obligation and the Electricity Market Reform[5].

In our 2012 Parliament report we suggested that the levy control framework should be set at a level of around £8 billion in 2020 to support required investments in renewables, nuclear and CCS coming onto the system by this time.

We now update this estimate to allow for:

- **Latest costs.** Our new estimate builds in the analysis set out in this report on levelised costs of low-carbon technologies.
- **Basis risk.** Our previous analysis was based on levelised costs, whereas our new estimate is based on required strike prices, which include basis risk discounts for generators (see section 3(ii) above).
- **CCS projects.** As discussed in Section 1, there are questions over whether it will be possible to deliver four CCS projects by 2020. We therefore include only two projects by 2020 in our updated calculations, while noting that the need to commercialise CCS remains an urgent priority.
- **Marine energy.** We previously included 4 TWh of marine generation in 2020, but latest evidence suggests that deployment of marine technologies is unlikely to achieve generation much above 1 TWh, the centre of the range in the Government's 2011 Renewable Energy Roadmap. This reduces costs as marine generation is expected to be relatively expensive (e.g. receiving up to 5 ROCs per MWh, compared to less than 1 ROC for onshore wind).

These effects are roughly offsetting, and our revised estimate remains at around £8 billion required funding in 2020 (Table 3.3). This is comparable to the £7.6 billion announced by the Government in November 2012,[6] (e.g. noting uncertainties over current offshore wind costs assumed in our analysis).

5 More specifically, the levy control framework (LCF) sets a limit on the funding for support for certain DECC policies to be paid by consumers via energy bills. In this report, it refers to the support for low-carbon generation under the Renewables Obligation, Feed-in Tariffs and Contracts for Differences under the EMR. It does not include required funding for other policies e.g. Warm Homes or ECO.

6 DECC statement: http://tools.decc.gov.uk/en/content/cms/news/pn12_0146/pn12_0146.aspx.

Our estimate has been calculated against the cost of new unabated gas-fired generation, which is a more appropriate metric for the levy control framework than the projected wholesale price.

- The levy control framework aims to limit costs to consumers.
- The cost to consumers is best measured by the price paid compared to the price required by the alternative investment. This alternative is to build new unabated gas-fired generation (i.e. a combined cycle gas turbine – CCGT), which would require a price equal to its long-run marginal cost (LRMC, i.e. including the full cost of operation and payments to cover the investment cost).
- The projected wholesale price is lower than the cost of CCGT, because EMR results both in generation with low marginal costs (which will reduce the wholesale price – the so-called "merit order effect"), and possibly in excess capacity under the capacity mechanism. The wholesale price could also be lower if coal is at the margin, but that is not an alternative for investment given that the Government has placed a moratorium on new coal investments.
- Therefore projected wholesale price does not measure subsidy. Using it would introduce additional uncertainty, given that the wholesale price is more uncertain than the cost of new gas generation. This would adversely impact the sector investment climate.

Based on our assumptions on the difference between wholesale prices and the cost of new gas-fired generation, using projections of the baseload wholesale price consistent with the latest DECC publication[7], would suggest a £0.7 billion shortfall relative to funding required to support investment in 2020 (Table 3.3).

- The lower the metric against which low-carbon costs are compared, the more funding will appear to be needed.
- The projected wholesale price is around 15% lower than the cost of CCGT in 2020 (i.e. wholesale price projections are around £60/MWh, compared with £70/MWh for the cost of gas generation)[8].
- This implies a funding shortfall of around £0.7 billion if the wholesale price were to be used as the comparator metric rather than gas CCGT.

7 GB baseload wholesale price series consistent with the Updated Energy Projections (October 2012):https://www.gov.uk/government/publications/2012-energy-and-emissions-projections
8 In 2012 prices.

Given the importance of ensuring that sufficient funding is committed for required investments, the Government should clarify that the levy control framework will be calculated against the cost of new CCGT generation rather than the wholesale price.

It is also important to note that our estimates of required funding assume contract lengths commensurate with asset life rather than shorter contracts which have been suggested by the Government (see Section 3(ii) above). If contracts are to be shorter, then these will require higher levels of funding in 2020, reflecting higher strike prices in shorter contracts.

Our analysis suggests that additional funding of around £0.5 billion would be required in 2020 based on shorter contracts (Table 3.3). If the Government makes the case and moves forward on the basis of shorter contracts, we recommend that the levy control framework should be adjusted upwards accordingly in order that required investments are fully funded and can proceed.

Table 3.3: Estimated funding required under the Levy Control Framework in 2020

		Comparator metric	
		Cost of gas generation	**Wholesale electricity price**
Contract length	**Full lifetime**	c.£7.9 billion	c.£8.6 billion
	Shorter contracts	c.£8.4 billion	c. £9.1 billion

Source: CCC calculations. *Shorter contracts for assume 15 year contracts for wind and CCS, compared with full lifetime of 22 years for offshore wind, 24 years onshore wind and 30 years for CCS.

Levy control framework to 2030

Although setting funding to 2020 is helpful, visibility further out in time is required given long lead times for projects and long pay-back periods for supply chain investments. This is the rationale for setting the 2030 carbon-intensity target, and setting out the funding with which this should be backed if it is to be credible, and to provide a strong signal to investors.

It is possible to set a broad funding envelop now notwithstanding uncertainty relating to the period between 2020 and 2030:

- **Costs to 2020.** Our analysis above shows that costs are uncertain in the near term, and are likely to remain so. As a consequence, and in the event that costs are higher than expected, ambition to 2020 would have to be scaled within the existing levy control framework, or this would have to be adjusted upwards. In either case, this could be carried through to the 2030 levy control framework, which would then be no more uncertain than the framework in 2020. For lower than expected costs, the levy control framework could be adjusted downwards without any detrimental impact for investors.

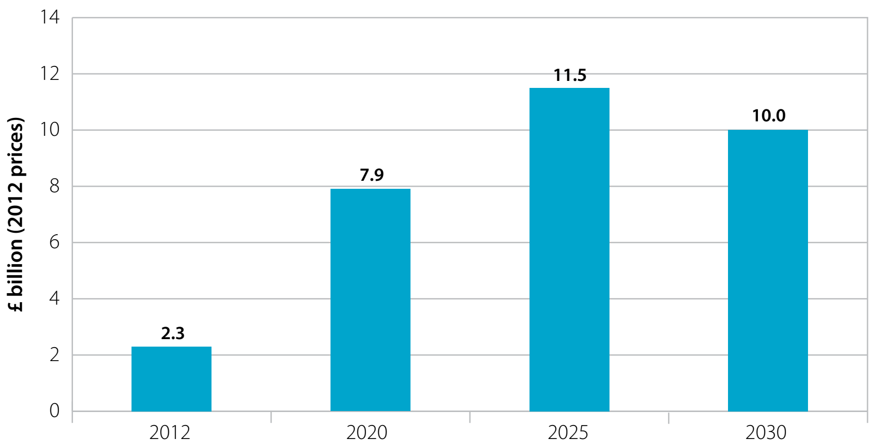
- **Cost reductions in the 2020s.** Going beyond 2020, there are additional uncertainties around the pace of cost reduction due to learning and innovation. However, if this were not to ensue, funding commitments premised on cost reduction should not be adjusted upwards – rather the rate of deployment should be slowed, which could possibly reduce the funding required. Cost reductions beyond those currently envisaged would allow a downward revision in the level of funding.
- **Carbon prices.** While carbon prices are relevant in determining required support for investment in low-carbon technologies, carbon price uncertainty is limited given the Government's carbon price underpin. Given the difficulties in committing to the carbon price underpin trajectory, Government should clearly indicate that funding would be increased if out-turn carbon prices are lower than planned (and decreased if carbon prices are higher).
- **Gas prices** are important in determining required support for low-carbon technologies given that they influence the metric against which strike prices are compared (e.g. a higher than projected gas price would lower the level of required support). Agreement on a 2030 levy control framework would have to allow for this by adjusting support for differences between projected and outturn prices.
- **Demand** uncertainty would not change the appropriate pace of investment in less mature technologies, which should be determined by what is required to drive cost reduction. Rather, if it were the case that there is a significant departure from projected demand, this should, if anything, result in a changed pace of investment in cost-effective technologies. These technologies require limited if any support under the levy control framework in 2030. Therefore changing the pace of investment in these technologies would not change required funding.
- **Feasible deployment of mature technologies.** Similarly, uncertainty over the achievable deployments of nuclear and onshore wind by 2030 does not significantly affect the funding requirement, since support for these technologies will be limited in 2030.

Under central estimates of projected technology costs and gas prices, and the Government's carbon values to 2030, we estimate that levy control funding required in 2030 would be in the range of around £9-10 billion (Figure 3.1).

This would add around £20 to the typical household's annual energy bill, compared to 2020. Required funding would be falling at this time and would be lower in later years.

The range reflects different assumptions on the nature of the CCS commercialisation programme, with the higher end of the range corresponding to a programme with greater deployment and wider scope in terms of technologies supported (Box 3.3).

Figure 3.1: Estimated funding required for low-carbon generation under the Levy Control Framework to 2030



Source: CCC calculations.
Notes: Includes funding for Renewables Obligation, Feed-in Tariffs and support under CfDs. Excludes funding for Warm Homes and ECO.

Box 3.3: CCS commercialisation programme and implications for LCF funding

Our scenarios assume a CCS programme deploying 10 GW of capacity by 2030, to achieve commercialisation by the late-2020s. This could include:

- At least two projects from the Government's ongoing Commercial Programme (at the 300-500 MW scale) by 2020, demonstrating multiple technology options (e.g. the gas post-combustion and coal oxy-fuel projects that have been selected) and including CO_2 transportation and storage infrastructure that can benefit later projects. Including further projects (i.e. up to the four that the Government have committed to delivering) in this first phase could increase the chance of success and learning opportunities and cover a wider set of technologies.
- A second phase of pre-commercial projects in the early 2020s at a greater scale (e.g. 800 MW) to benefit from learning generated by the earlier projects and by international experience, again deploying a range of technologies.
- Commercial deployment from the mid-to-late 2020s initially at around 1 GW per year, rising to around 2 GW per year by the late 2020s, potentially focusing on one or two technological options following the evidence on the performance and costs of earlier plants. Our 10 GW scenarios require that investors commit to these commercial projects prior to the second phase projects becoming operational – they may therefore still involve a significant cost premium.

It is plausible that less UK effort might be consistent with full commercialisation, particularly if other countries drive forward CCS development more aggressively than currently appears likely. For example, two UK projects in the 2010s could be part of a string of projects internationally that help to develop a range of technologies, with fewer projects being required in the UK second phase in the early-to-mid 2020s.

However, it would still be necessary to have some projects in order to reduce later risks, both by showing that CCS works within the specific UK context and by developing an initial CO_2 infrastructure that enables new projects to connect, implying a minimum required deployment in the UK by 2030 (e.g. of at least 5 GW). This would reduce the cost of the CCS commercialisation programme and therefore reduce required support under the Levy Control Framework by around £1 billion in 2030, from £10 billion to £9 billion.

It is not for the Committee to set out a detailed commercialisation strategy for CCS. The Government should do this, including the potential to leverage learning from international projects, and balancing the costs involved with early UK deployment to develop the technology against the benefits of early commercialisation of CCS.

These estimates could be adjusted if out-turn gas prices were to be different to those assumed (e.g. funding could be reduced by around £3 billion per year in 2030 if the IEA's 'Low unconventional' scenario were to ensue rather than DECC's central case projection).

Given the need to send a credible signal to investors about the future direction of travel for the UK power sector, we recommend that the levy control framework should be extended to 2030, rising to around £10 billion at this time, with flexibility to adjust to differences in projected and outturn gas prices.

The combination of a carbon-intensity target, committed funding, and the offer of contracts during the first delivery plan period, would provide a high degree of confidence that required investments will proceed, which will keep in play an option which insures customers against the risks of dangerous climate change and rising energy bills.

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