Chapter 1

Renewable electricity generation scenarios

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

Introduction and key messages

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

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

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

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

The key messages in the chapter are:

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

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

- **A portfolio approach.** Given these uncertainties, a portfolio approach to development of low-carbon generation technologies is appropriate.
  - This should include market arrangements to encourage competitive investment in mature technologies such as nuclear and onshore wind generation.
  - It should also include additional support for less mature technologies including CCS, offshore wind and marine, where there is potential for the UK to drive these technologies down the cost curve. This is in contrast to solar photovoltaic (PV), where the pace and scale of development will be determined outside the UK.
- **Commitments for the 2020s.** As part of a portfolio approach, the Government should commit now to an approach for supporting offshore wind and marine in the 2020s. The approach should avoid stop-start investment cycles and provide confidence to supply chain investors of a long-term business opportunity beyond the next decade.
- **Firm commitments.** Given the need to provide investor confidence, support should be provided through firm commitments rather than vague aspirations. Such commitments should be implemented through the new electricity market arrangements. For example, within the Government's proposed Contracts for Differences for low-carbon generation, a proportion of these could be targeted at supporting less mature renewable technologies.
- **Illustrative 2030 scenario.** We set out an illustrative scenario in which commitments on support for offshore wind and marine through the 2020s are broadly in line with planned investment and supply chain capacity to 2020. Together with ongoing investment in onshore wind, this would result in a 2030 renewable generation share of around 40% (185 TWh). Sector decarbonisation would then require a nuclear share of around 40% (175 TWh) and a CCS share of 15%, along with up to 10% of generation from unabated gas.

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

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

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

The overall decarbonisation path

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

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

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

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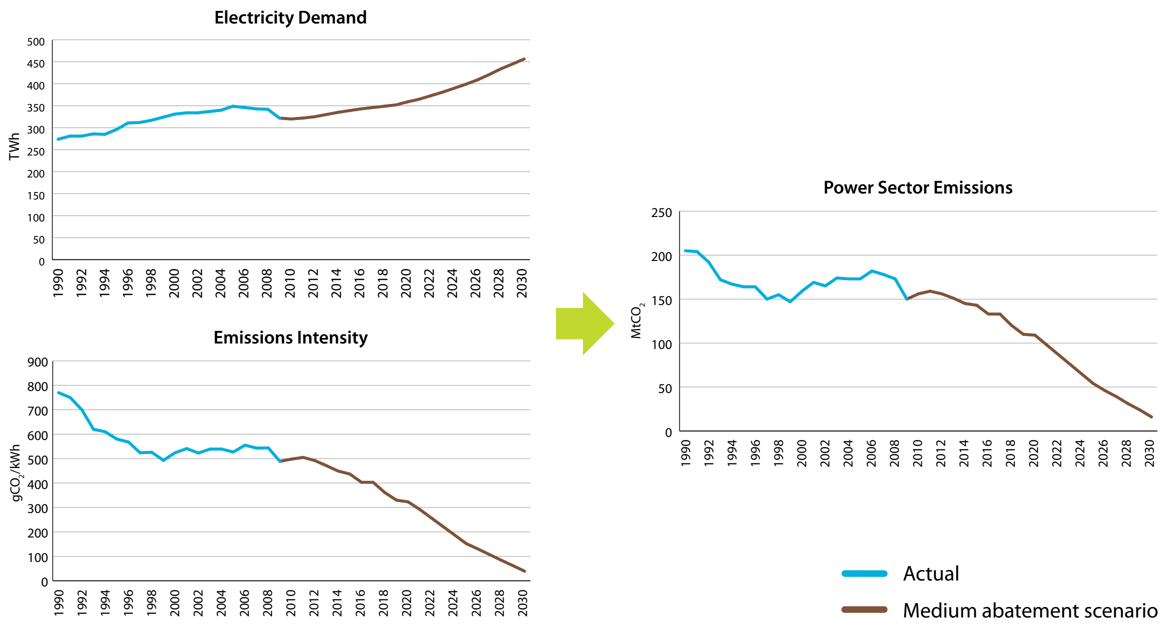
1 CCC (2010) *The Fourth Carbon Budget: Reducing emissions through the 2020s.*

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

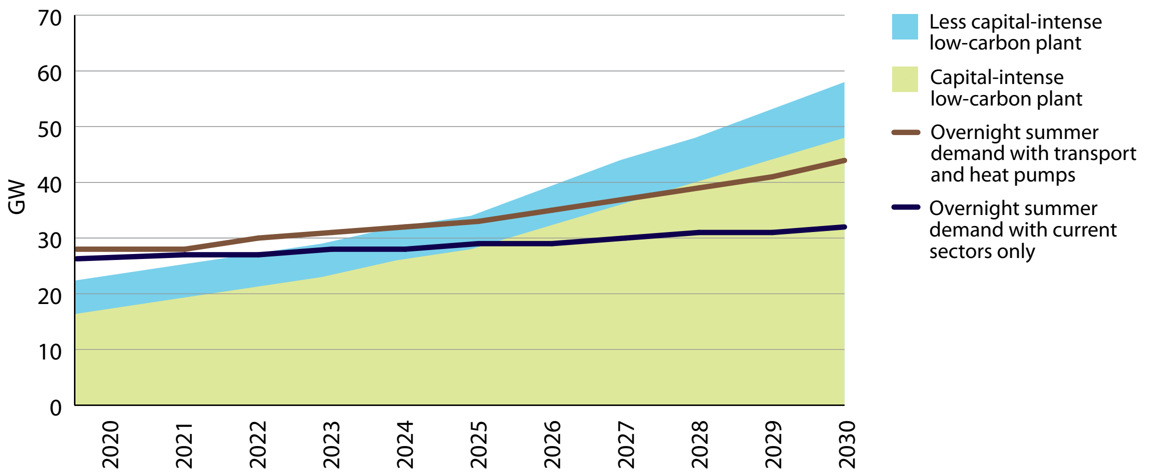
Figure 1.1: Electricity demand, emissions intensity and power sector emissions (1990-2030)



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

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

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



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

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

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

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

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

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

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

Technology mix to deliver decarbonisation

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

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

Box 1.2: Technology options for generating low-carbon electricity

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

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

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

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

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

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

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

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

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

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

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

(iii) Build constraints through the 2020s

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

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

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

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

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

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

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

- **Nuclear**. Notwithstanding potential for recent events in Japan to impact on public acceptability (Box 1.5), on the basis of resource potential alone, nuclear generation could make a significant contribution to sector decarbonisation:

  – Although there is a finite supply of uranium available, this will not be a limiting factor for investment in nuclear capacity for the next 50 years.

  – IEA analysis suggests that there is scope for investment in a new generation of nuclear plant globally within known sources of uranium, and potential to extend resources further (e.g. through better fuel production technology, closed cycle or fast breeder reactors).

- **CCS**. Abundant supplies of coal and gas suggest that if CCS technologies can be shown to be viable, these could make a significant contribution to sector decarbonisation, although there may be limits on available storage capacity.

  – Global reserves of coal will last around 150 years at current production rates[13].

  – Total global recoverable natural gas resources, including unconventional sources, will last for around 250 years at current rates of production.

  – CO_2 storage capacity, especially in saline aquifers, is considerably less certain and may imply a constraint over the long term (Box 1.6).

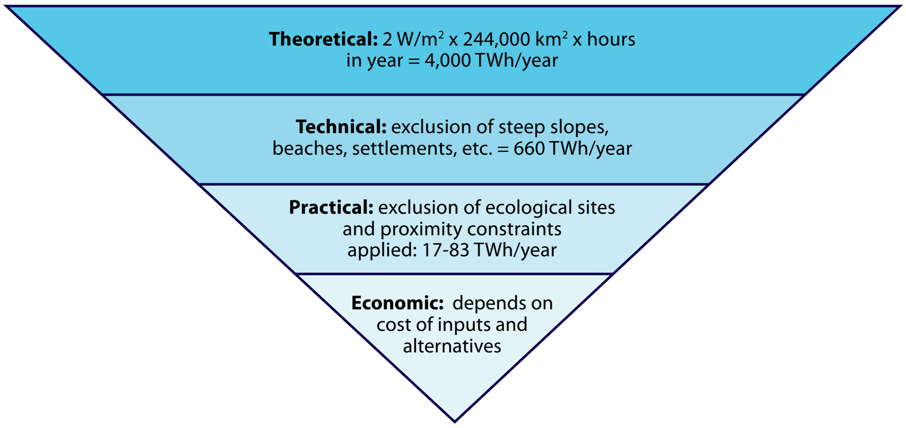
Box 1.3: Defining the UK's renewable resource – theoretical, technical, practical and economic

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

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

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

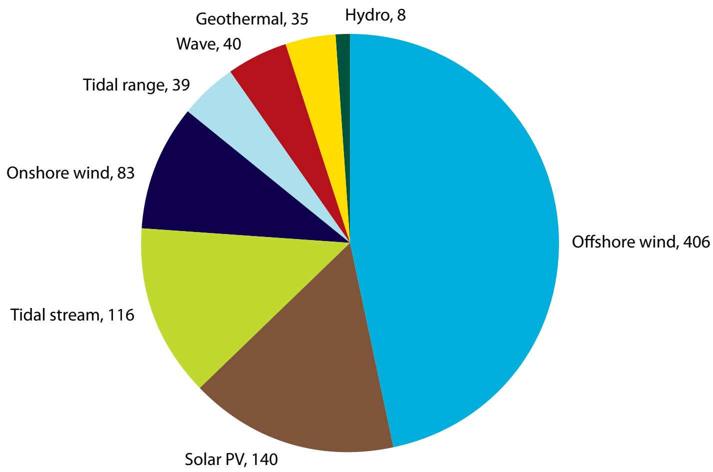
Figure B1.3a: Resource pyramid for onshore wind



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

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

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



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

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

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

Technology characteristics of solar CSP

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

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

Available solar CSP resource

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

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

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

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

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

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

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

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

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

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

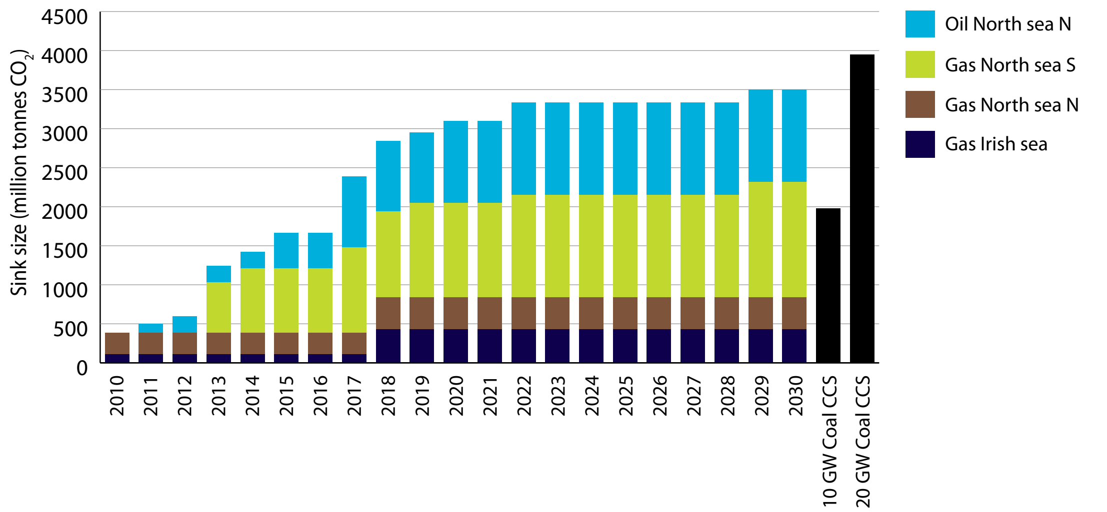
Should the review suggest limiting the role of nuclear generation in the UK in future, then a higher renewables contribution would be required. Alternatively if the review leads to a significant tightening of safety regulations, nuclear costs may be increased, which would improve the relative economics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

Box 1.6: Availability of CO_2 storage capacity

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

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

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



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

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

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

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

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

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

The intermittency challenge

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

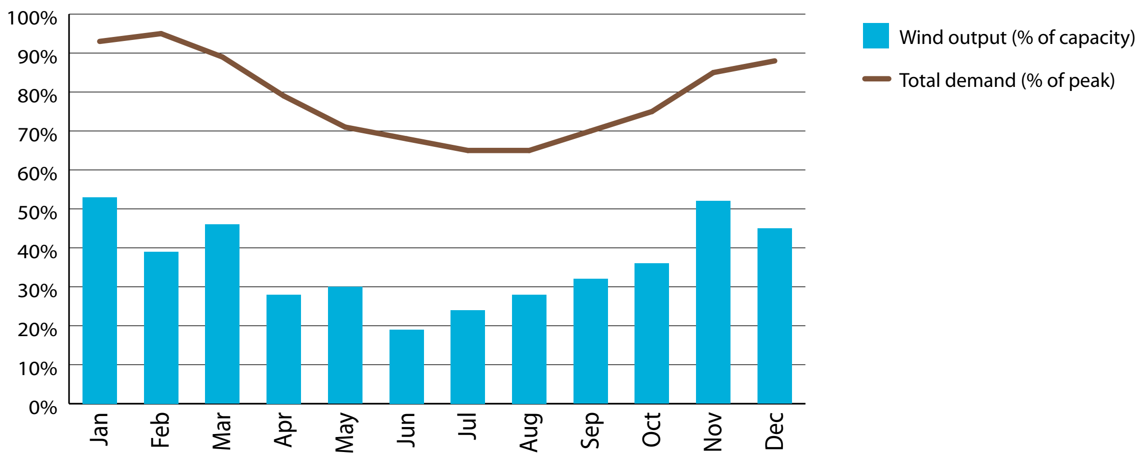
In answering this question, the challenges presented by intermittency should not be overstated:

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

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

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

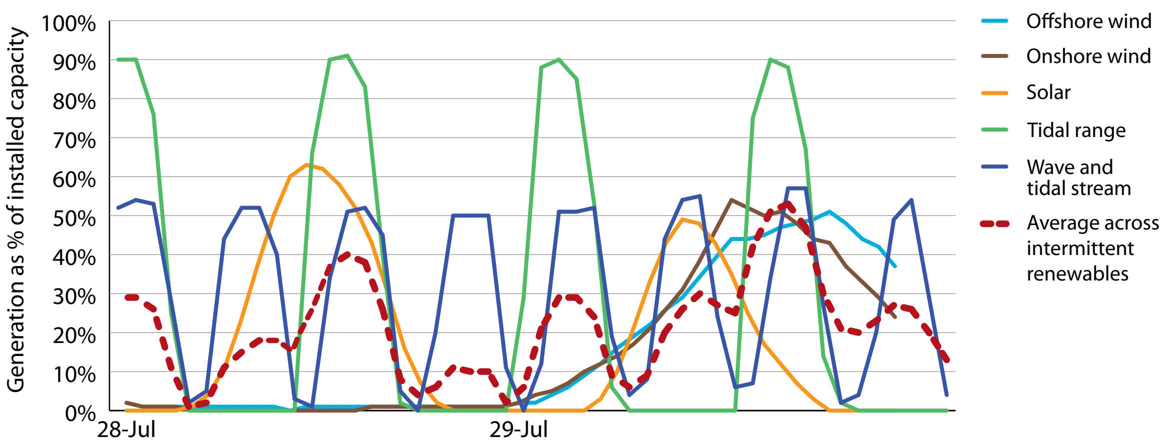
Figure 1.3: Seasonality of wind generation versus seasonality of demand



Source: CCC calculations based on modelling by Pöyry.

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

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



Source: CCC analysis based on modelling by Pöyry.

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

Options for managing intermittency

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

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

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

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

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

Pöyry modelling for the CCC

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

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

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

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

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

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

Sensitivities

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

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

Other studies

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

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

Box 1.8: Government smart meter proposals

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

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

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

[21] www.roadmap2050.eu.

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

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

Costs of managing intermittency

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

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

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

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

(iii) Build constraints through the 2020s

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

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

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

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

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

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

3. Renewable and other electricity generation costs

Uncertainty in underlying cost drivers

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

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

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

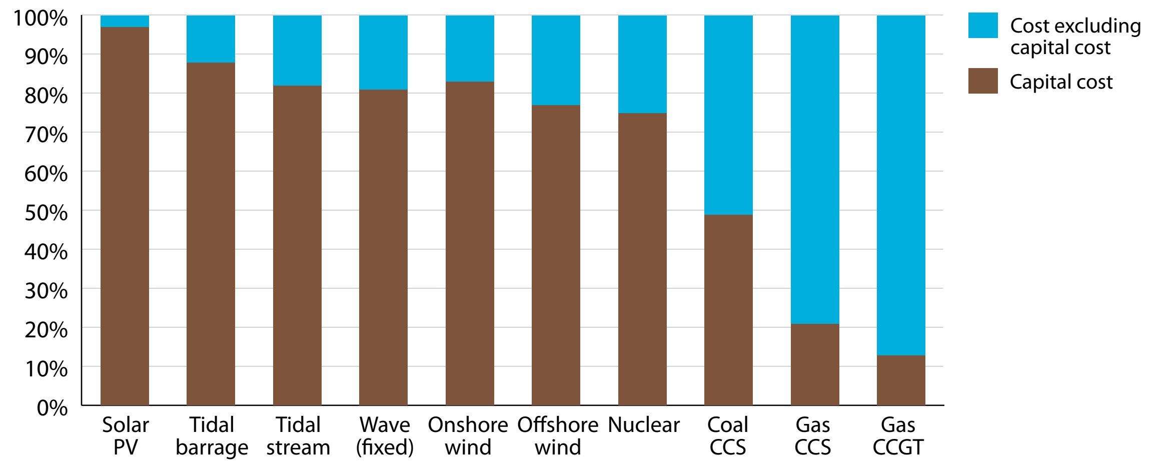
– There is uncertainty over what load factors will be achievable in future, particularly as regards relatively untested offshore wind and marine generation. Given sensitivity of costs to load factors, this could have a significant impact on the economics of these technologies (Figure 1.7).

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

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

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

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



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

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

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

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

Current costs of capital

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

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

Future costs of capital

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

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

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

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

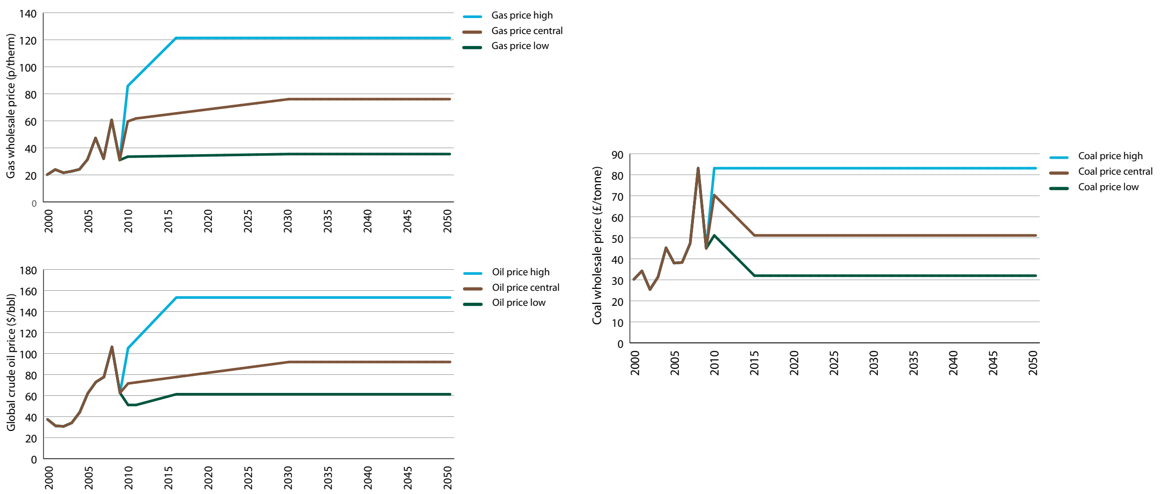
Given the above, and for transparency, we use a 10% discount rate across technologies and time periods and report sensitivities on 7.5% (current central estimate for unabated gas) and 3.5% (risk-free social discount rate).

Importance of cost of capital on relative costs of generation technologies

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

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

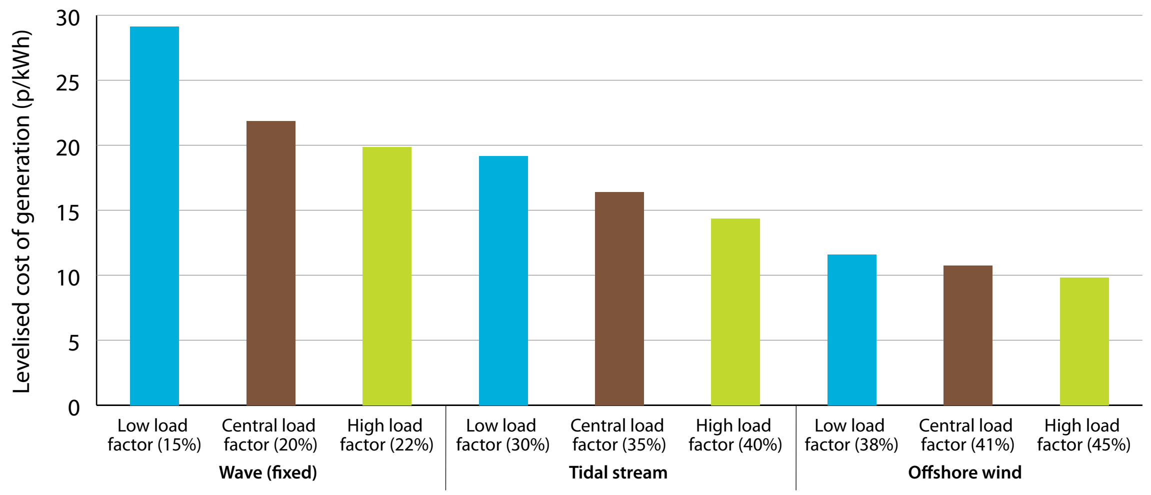
Figure1.6: Fossil fuel price assumptions to 2050



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

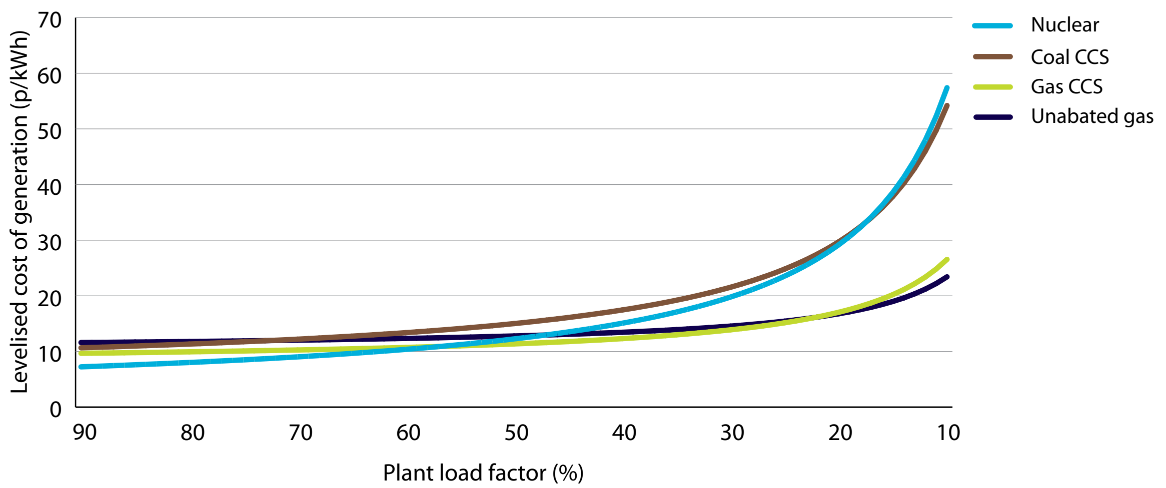
Note(s): 2009 prices. Fossil fuel prices are highly uncertain and highly volatile – none of these individual projections reflect a likely future world (e.g. in reality prices will fluctuate widely from year to year) but the range across scenarios aims to capture the range of uncertainty involved.

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



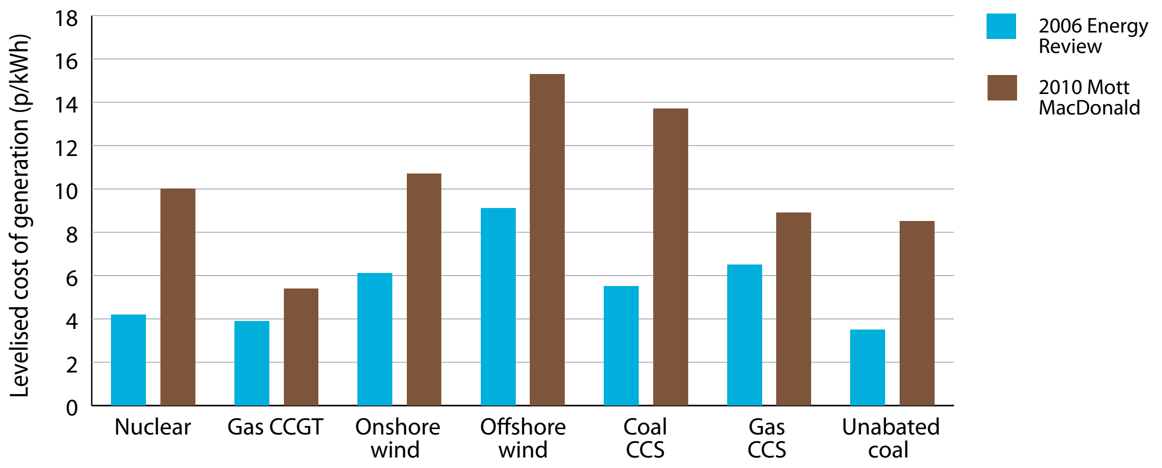
Source: CCC calculations, based on Mott MacDonald model (2010) *UK Electricity Costs Update* and (2011) *Costs of low-carbon technologies*.
Notes: 2010 prices. Costs are for projects starting construction in 2030, and are based on central capital cost assumptions and a 10% discount rate.

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



Source: CCC calculations, based on Mott MacDonald model (2010) *UK Electricity Costs Update* and (2011) *Costs of low-carbon technologies*.
Note(s): 2010 prices. Costs are for projects starting construction in 2030, and are based on central capital, fuel and carbon prices and a 10% discount rate.

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



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

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

Estimating future generation costs

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

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

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

Across technologies Mott MacDonald found three key themes:

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

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

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

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

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

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

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

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

– **Marine.** Marine technologies (tidal stream, wave) are at an early stage of development, with uncertainty over what costs will be for demonstration projects and what subsequent cost reductions are achievable through learning. Our estimates start high and fall considerably, but are likely to remain above offshore wind costs to 2040.

– **Solar PV.** Solar PV costs have fallen rapidly in recent years, with studies suggesting scope for further reductions of between 50-60% over the next decade, and 70-80% by 2040 (Box 1.12). These large reductions (which are likely to be largest for the costs of the module and of installation) could make solar PV economically viable in the UK by 2030 (e.g. at around 11 p/kWh costs could be comparable to offshore wind).

– **Biomass.** Anaerobic Digestion (AD) is commercially proven but relatively small scale (i.e. below 5 MW) with current cost estimates ranging from 13.5-17.5 p/kWh for food waste AD. Dedicated biomass plants are typically larger (e.g. 150 MW units) with current costs in the order of 8-17.5 p/kWh, falling to 7-15 p/kWh by 2040. Approximately 40% of the costs are fuel costs.

– **Geothermal.** Geothermal power generation is not currently deployed in the UK and its costs are therefore highly uncertain. Potentially it could be competitive with new gas and with other low-carbon options, depending on success demonstrating this technology in the UK.

- **Nuclear:** Nuclear generation is a mature technology, with investments envisaged in the next decade and beyond based on an evolution of existing models. However, there is a high degree of uncertainty over how much nuclear costs will be for the first new plant in the UK, and how much this will fall as a result of location-specific learning and scale economies in moving towards a programme of roll-out (e.g. the 2010 Mott MacDonald study[25] for DECC suggests a 40% cost differential between the first nuclear plant and a programme in the UK).
- **CCS.** Carbon capture and storage technologies are also still at the demonstration stage, implying current costs and potential learning are highly uncertain. This is reflected in wide ranges for future costs.
- **Unabated fossil fuels.** Costs of unabated fossil-fired generation will increase as the carbon price increases, but are highly uncertain given uncertainties over fuel prices. Costs will also rise if load factors or lifetimes are reduced to accommodate low-carbon generation.
- **Discount rate sensitivities.** The above costs are estimated using a 10% real discount rate. In sensitivities using discount rates of 3.5% and 7.5%, the economics of renewables improve relative to less capital-intense technologies, suggesting that solar PV and tidal stream technologies could be more competitive and at an earlier stage (Figure 1.11).

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

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

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

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

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

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

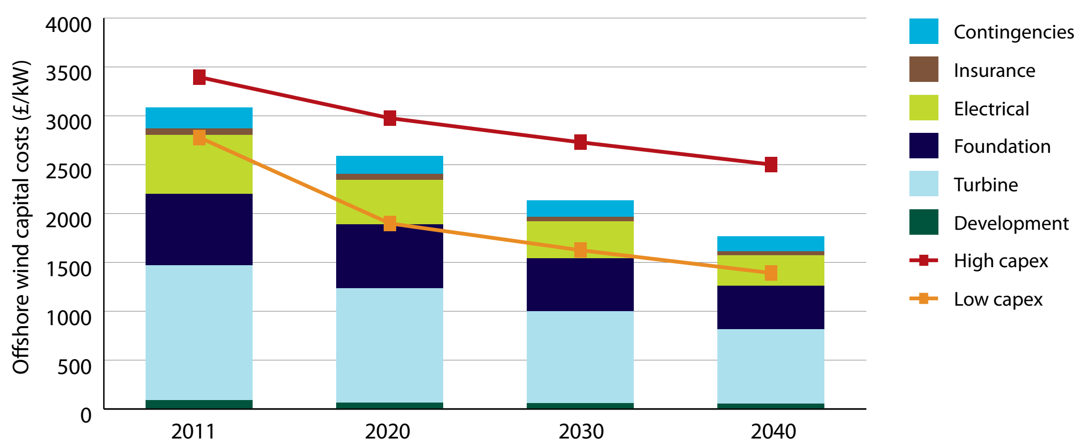
Box 1.11: Learning potential for offshore wind

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

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

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

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



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

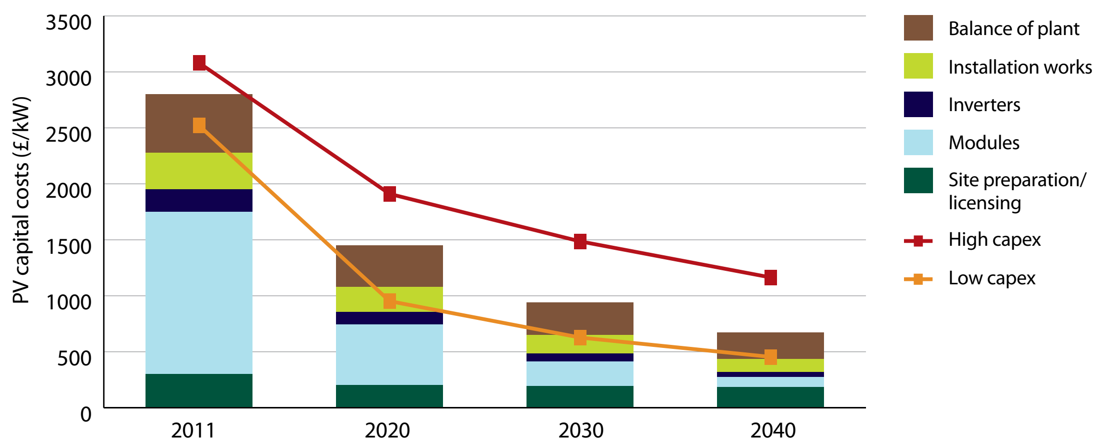
These estimates assume major advances in wind turbine technology, but do not assume a shift to floating foundations or new vertical-axis machines. Sourcing components from lower-cost jurisdictions (e.g. China) than at present could also bring savings. Such impacts are difficult to quantify, making future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

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

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

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

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



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

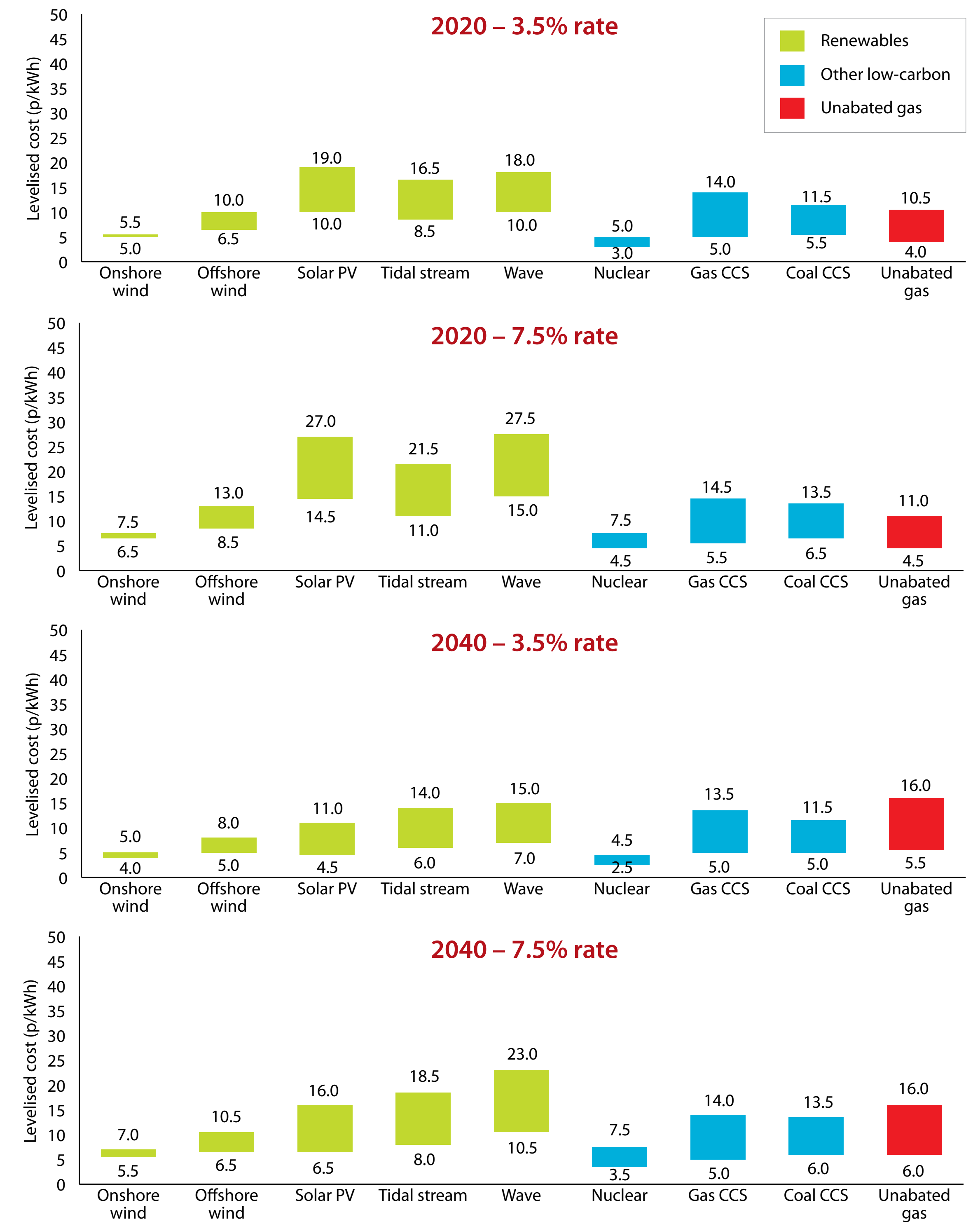
Note(s): 2010 prices. Based on a ground-mounted crystalline system (10MW). Balance of plant includes costs of mounting structure, cables, junction boxes, monitoring equipment and other electrical equipment such as grid interconnection panels and meters.

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

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

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

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



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

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

4. Renewable generation scenarios from 2020

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

We develop the scenarios in four steps:

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

Renewable electricity generation in the period to 2020

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

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

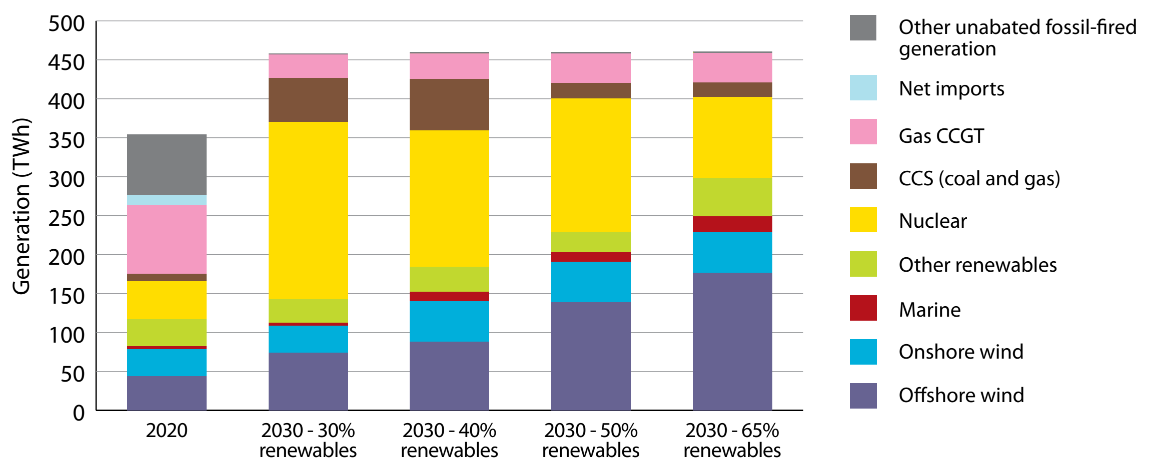
Although there are currently delivery risks associated with this scenario – for example, as regards planning approval for projects, financing, supply chain expansion, see Chapter 2 – we assume that these risks are addressed and that we enter the 2020s with around 38 GW of renewable capacity on the system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

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

Scenarios for investment in renewables from 2020

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

Figure 1.12: Range of renewable electricity penetration scenarios to 2030



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

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

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

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

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

Box 1.13: The Severn barrage

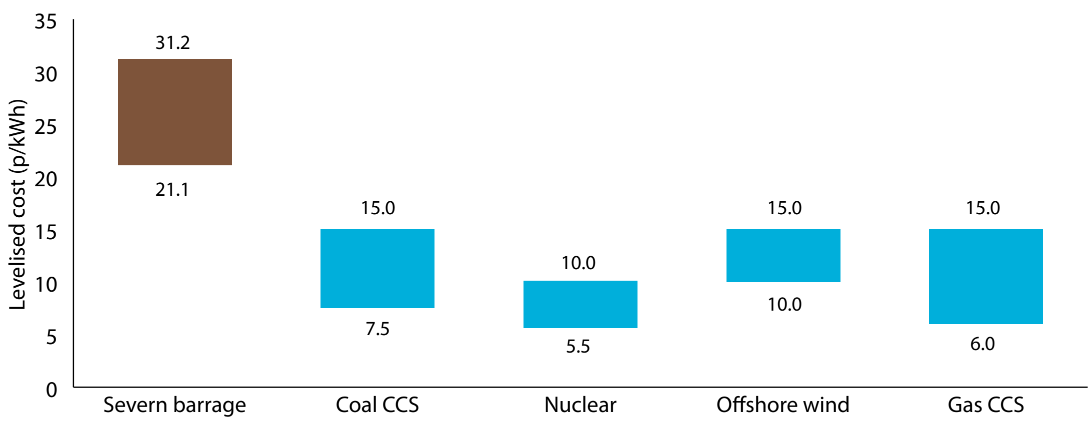
We have previously set out that a Severn barrage could play a useful role in power sector decarbonisation if it can be shown to be economically viable from a societal perspective, and that environmental concerns can be mitigated. The recent DECC Severn Feasibility Study ruled out the construction of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

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

Economics of Severn barrage

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

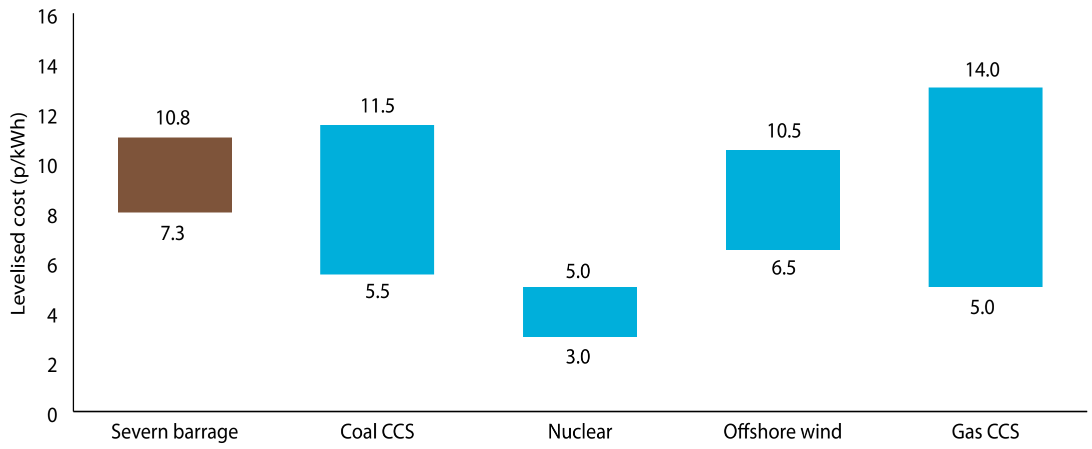
Figure B1.13a: Severn barrage relative to alternatives at 10% discount rate



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

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

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



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

Note(s): See notes to figure above.

Contribution to renewable deployment scenarios:

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

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

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

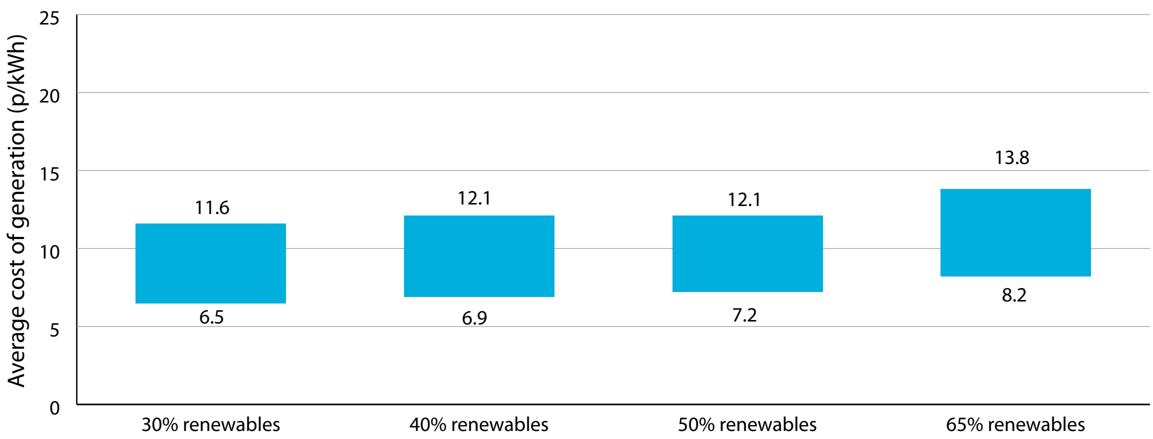
[30] Pöyry (2011) *Analysing Technical Constraints on Renewable Generation.*

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

Scenario costs and investment requirements

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

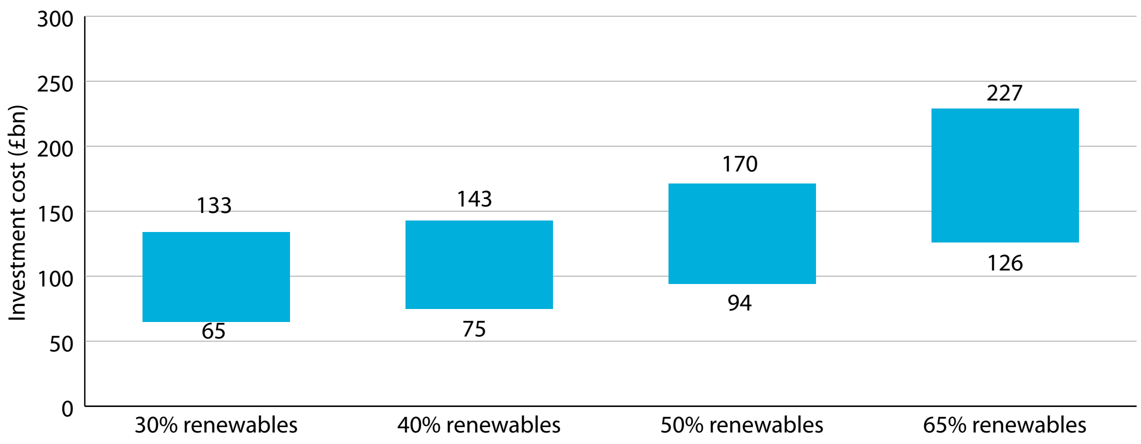
Figure 1.13: Range for average electricity generation costs in renewable generation scenarios (2030)



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

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

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



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

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

5. Recommendations on ambition for renewable generation

Developing renewable generation options as part of a portfolio approach

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

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

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

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

[31] Costs are for a project starting construction in that year. Estimates take into account capital, fuel and carbon price uncertainty. Additional system costs due to intermittency (e.g. back up, interconnection) are not included.

[32] CCC calculations based on Mott MacDonald's assessment of 2 GW site.

[33] Cost estimates for Severn barrage (Cardiff -Weston scheme) from DECC (2010) *Severn Tidal Power Feasibility study*. High end of costs is represented by the Feasibility Study estimate including Optimism Bias (OB), Risk Assessment (RA) and Compensatory Habitat payments. Low end includes Compensatory Habitat payments but not RA and OB.

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

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

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

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

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

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

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

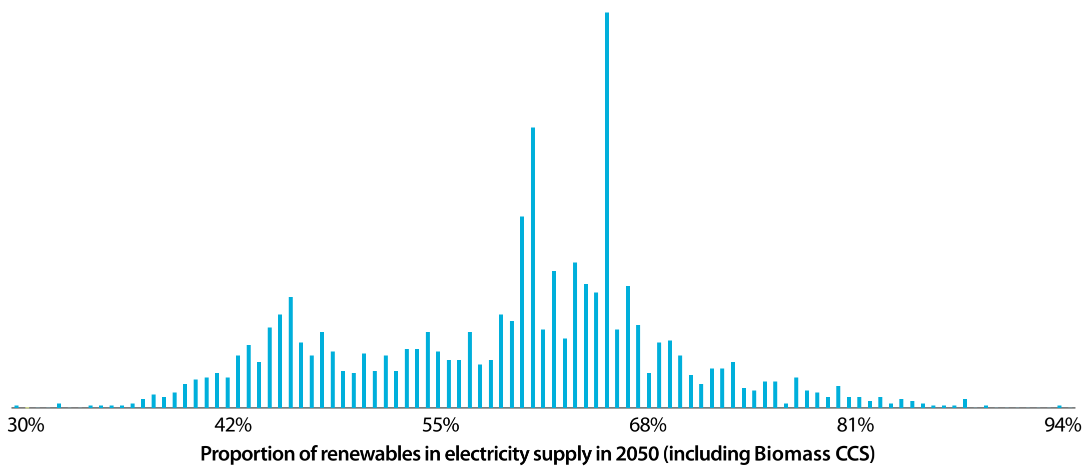
We undertook runs for 2050, and in each of these years variants were also modelled in which nuclear and/or CCS were made unavailable. The key parameters on which we placed uncertainty within these simulations – each of which contained 2,000 runs – are:

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

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

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

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



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

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

Committing now to technology support in the 2020s

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

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

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

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

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

An illustrative scenario for technology support

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

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

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

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