Chapter 2: Reducing emissions from the power sector

Introduction and key messages

In 2012 power sector emissions were 156 $MtCO_2$ and accounted for 27% of UK emissions covered by carbon budgets.

In our original 2010 advice on the fourth carbon budget we proposed that deep cuts in power sector emissions through the 2020s are feasible, cost-effective and desirable in meeting the fourth carbon budget and preparing for meeting subsequent carbon budgets and the statutory 2050 target.

Our analysis suggested the need for investment in 30-40 GW of low-carbon capacity in the decade from 2020, to replace ageing capacity currently on the system and to meet demand growth. This investment in low-carbon power generation reflected an assessment of the economics and potential build constraints, as well as a range of possible growth scenarios for electric vehicles and heat demand. It would drive carbon intensity of power generation from current levels (around 500 gCO_2/kWh) down to around 50 gCO_2/kWh by 2030.

We revisited our analysis of scenarios to reduce power sector emissions in our May 2013 report *Next steps on Electricity Market Reform – securing the benefits of low-carbon investment*[1]. In that report, we concluded that decarbonising the power sector to an average grid intensity of around 50 gCO_2/kWh remained an appropriate objective for 2030. This reflected the latest evidence on costs and feasibility of deploying key low-carbon technologies as well as the importance of developing less-mature technologies and preparing for meeting the 2050 target to reduce economy-wide emissions by at least 80% relative to 1990.

In this chapter we update our scenario for power sector emissions in the 2020s to reflect that evidence as well as: latest projections of electricity demand, including our revised assessment of uptake of energy efficiency and heat pumps in buildings and industry and electric vehicles in transport (see chapters 3, 4, and 5); and the Government's latest views and analysis in its draft Delivery Plan for Electricity Market Reform (July 2013), including funding commitment in the Levy Control Framework for investment in low-carbon generation to 2020.

Our updated scenario still leads to a power sector that is decarbonised to an average grid intensity of around 50 gCO_2/kWh in 2030 but with lower emissions through the 2020s.

This reflects the specific conclusions from our new analysis:

- **Path to 2020.** Power sector emissions are projected to decrease much more rapidly to 2020 than assumed in our advice in 2010. This is due to revised demand projections and substantially revised projections for coal-fired and nuclear generation.

1 http://www.theccc.org.uk/publication/next-steps-on-electricity-market-reform-23-may-2013/

- **Demand.** Electricity demand after reflecting our updated assessment of uptake of abatement measures (e.g. energy efficiency in buildings) is now forecast to fall 9% from 2010 to around 300 TWh in 2020, which is 7% lower than projected in our 2010 advice.
- **Coal.** The assumed amount of unabated coal-fired generation in 2020 has been reduced by 72% to 21 TWh. This is because we now expect: some existing coal units to convert to biomass by 2020; that any coal CCS demonstrations would have CO_2 capture applied to all units rather than our previous assumption that just one unit would be fitted with capture equipment (and all others would burn coal unabated); more coal capacity to close or face limits on running hours in the face of the Industrial Emissions Directive; and that the impact of the carbon price underpin and a lower level of demand will limit market-pull towards coal generation. If coal generation does not fall significantly, power sector emissions will be much higher in 2020 than we have assumed in our updated assessment.
- **Nuclear.** The amount of assumed nuclear generation in 2020 has increased by 20% to 58 TWh, reflecting that several existing nuclear units that were scheduled to close before 2020 are now expected to receive lifetime extensions to operate into the 2020s. We assume that no new nuclear capacity begins generating until the early 2020s.
- **Renewables.** The amount of assumed generation from renewables remains similar to the previous estimate in our 2010 advice (i.e. around 120 TWh in 2020).
- **Emissions.** As a result, we have revised our estimate of power sector emissions to around 64 $MtCO_2$ in 2020 (compared to our previous estimate of 109 $MtCO_2$ in our 2010 advice). Average grid intensity is assumed to reduce 58% to 211 gCO_2/kWh in 2020 from current levels, compared to 323 gCO_2/kWh under our previous assumptions.

• **Path from 2020 to 2030.** Our scenario for power sector emissions in the 2020s reflects the latest evidence explored in scenarios developed for our May 2013 EMR report (*Next steps on Electricity Market Reform)* and new projections for electricity demand after uptake of abatement measures in the end-use sectors. Given new estimates of much lower power sector emissions in 2020, the pace of required emissions reductions during the 2020s to reach an average grid intensity of around 50 gCO_2/kWh in 2030 is less steep. This implies lower power sector emissions during the fourth carbon budget period (2023-27) than we previously assessed, but a similar 2030 end-point.

- **Demand.** Based on the latest energy projections from DECC and our updated assessment of abatement action in this report (i.e. uptake of energy efficiency, heat pumps and electric vehicles as set out in Chapters 3, 4 and 5), our scenario for electricity demand now has growth of 22% from 2020 to 2030, reaching 368 TWh, which is 13% lower than the estimate in our original 2010 advice.

- **Low-carbon capacity.** There are multiple possible scenarios to reach around 50 gCO_2/kWh in 2030 based on a portfolio of low-carbon technologies. These involve deployment through the 2020s of a significant nuclear programme (e.g. 8-16 GW of capacity), major commercialisation programmes for CCS and offshore wind and possibly significant contributions from other renewables (e.g. onshore wind, solar, marine technologies) depending on costs and deliverability.
- **Emissions.** If these scenarios for demand and capacity are delivered power sector emissions would be around 20 $MtCO_2$ in 2030.

- **The fourth budget period.** Our updated scenario has cumulative emissions during the fourth carbon budget period (2023-27) of 140 $MtCO_2$, roughly half the level we assumed in our original 2010 advice.
- **2030 objective.** Although our revised assessment implies that our scenario for the power sector now delivers emissions reductions well beyond what is required in the fourth budget period, it is still appropriate to deploy low-carbon capacity through the 2020s in preference to new fossil-fired plant. This is required to reach the same 2030 end-point, which will minimise costs in the face of expected rising carbon prices and develop technologies likely to be required in meeting the 2050 target.

We set out the analysis underpinning these conclusions in five sections:

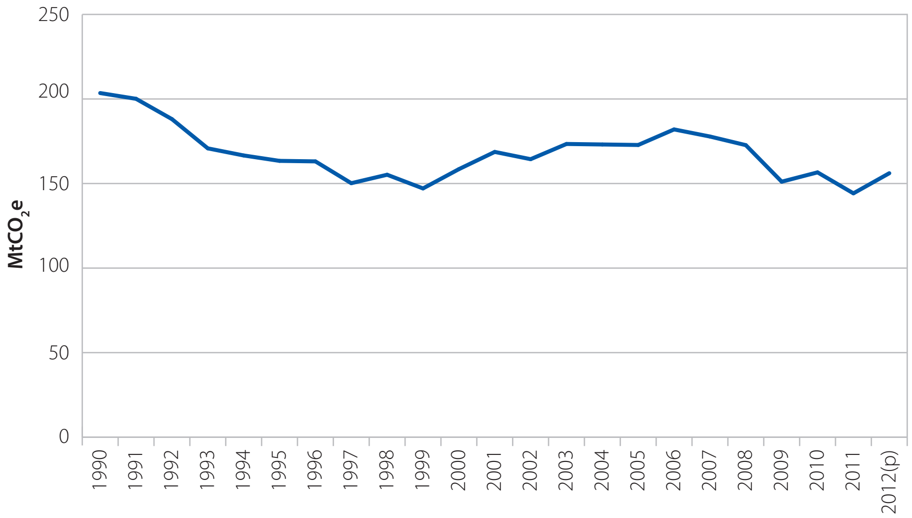
1. Current emissions from electricity generation
2. Latest projections for emissions before abatement action
3. Options for reducing emissions from electricity generation and associated costs
4. Projected emissions with abatement – an updated scenario for the 2020s
5. Benefits of early decarbonisation of the power sector

1. Current emissions from electricity generation

In 2012, power sector emissions in the UK were 156 $MtCO_2$, accounting for 27% of economy-wide emissions. Generation comprised 25% gas, 41% coal, 20% nuclear and 12% renewables. In 2011 (the latest year for which detailed data are available), gas and coal accounted for 35% and 63% of sector emissions respectively.

Emissions have fallen 23% overall since 1990, mainly as a result of the 'dash for gas' during the 1990s (Figure 2.1):

Figure 2.1: Power sector emissions (1990-2012)



Source: DECC (2013) *UK Greenhouse Gas Emissions 1990-2013*.
Notes: 2012 data are provisional.

- Emissions fell by 28% between 1990 and 1999 due to investment in new-gas fired capacity in the early 1990s which substituted for coal-fired generation (the 'dash for gas').
- Emissions increased by 24% between 1999 and 2006 due to an increase in demand and a slowdown in the substitution of coal-fired capacity with gas-fired capacity.
- Emissions decreased 21% between 2006 and 2011 due to the economic slowdown.
- In 2012 CO_2 emissions in the power sector increased 8% due to an increase of coal generation at the expensive of gas, driven by low coal and carbon prices.

We noted in our 2013 Parliament report[2] that there is scope to significantly reduce power sector emissions within the existing stock of power stations based on analysis of achievable emissions intensity. Achievable emissions intensity is the carbon intensity of electricity supply that would be achievable if power plants were dispatched in order of least emissions rather than least cost, while still delivering security of supply. In practice this means meeting demand with nuclear and renewables first, followed by gas, and finally coal plant.

In 2012, achievable emission intensity continued to improve, falling by 28 gCO_2/kWh (9%) compared to 2011, from 311 gCO_2/kWh to 283 gCO_2/kWh (Figure 2.2). This reduction was due to renewables capacity added to the system in 2012, including 2.4 GW of wind and 0.7 GW of solar.

Over time as more low-carbon capacity is added to the system and old coal plant is retired or reduces its running hours, we expect the gap between actual and achievable emissions intensity to close, while the achievable emissions intensity should continue to fall.

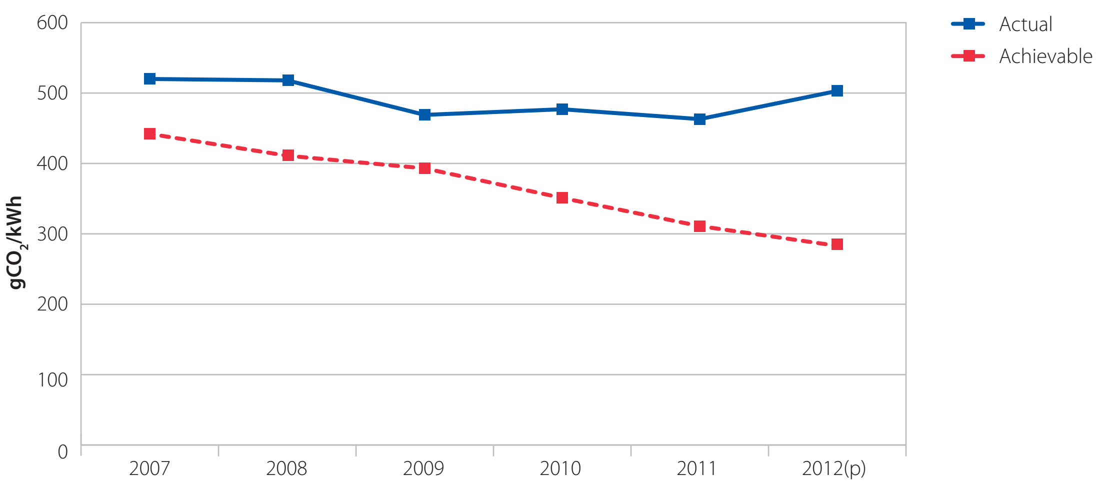
2 CCC (June 2013) *Meeting Carbon Budgets – 2013 Progress Report to Parliament*.

We concluded in our original fourth carbon budget advice that decarbonising the power sector is key to economy-wide decarbonisation given that:

- Power is a major source of UK emissions.
- Low-carbon technologies are available for power generation which are or are likely to become cost-effective (i.e. cheaper than fossil fuel generation facing a rising carbon price – see Chapter 1 for our assumptions on carbon prices).
- Over the next two decades there will be significant capital stock turnover in the UK's power system as assets retire, creating an opportunity for early investment in low-carbon generation.
- Power can be used as a route to decarbonisation in other sectors (buildings, transport and industry).

We now consider the latest evidence on projected emissions and options to reduce power sector emissions, and then set out an updated scenario to 2030 in section 4.

Figure 2.2: Actual and achievable emissions intensity of UK electricity production (2007-2012)



Source: CCC calculations based on various sources including Defra GHG conversion factors; DECC (March 2013) *Energy Trends*; DECC (June 2012) *DUKES*.
Notes: Achievable emissions intensity is the minimum average emissions intensity that could be achieved in a year, given the installed capacity, demand and the demand profile of that demand. Emissions intensity is UK-based useable generation, i.e. adjusted for losses.

2. Latest projections for emissions before abatement action

Our starting point when building scenarios is to develop demand and emissions projections without any action to reduce emissions. To develop this 'baseline' for the power sector, we use baseline electricity demand and generation projections from DECC's energy model[3]. DECC electricity demand projections are based on assumptions of future economic growth, fossil fuel prices, electricity generation costs, population, and other key variables. Inevitably they also involve some judgement over how these will be reflected in new build of capacity and how capacity is run.

3 DECC (17 September 2013) *Updated energy and emissions projections*.

The baseline projections assume that requirements for new-build capacity are met by a mix of unabated coal- and gas-fired generation. They include some deployment of renewable technologies (e.g. wind, solar) through the 2010s and 2020s, but in insufficient levels to meet the UK's 2020 renewable energy target.

Since our original advice, projections for baseline electricity demand have been revised downwards, given slower expected growth in GDP. Electricity demand (excluding demand for autogeneration, which is met by on-site generation, rather than generation from the grid), before abatement measures to improve efficiency is now projected to increase 5% from 2010 to around 345 TWh in 2020 and to around 400 TWh in 2030 (both 3% lower than previously expected in our 2010 advice).

Our baseline scenario suggests that even with limited efforts to incentivise new low-carbon generation, power sector emissions could fall 16% between 2012 and 2030 to around 130 $MtCO_2e$. This largely reflects an assumed continuing shift from coal to gas-fired generation in the longer term.

However policies to which the Government have already committed will support investment in low-carbon generation to 2020 and therefore further reduce power sector emissions. These include the Renewables Obligation and contracts for difference offered under Electricity Market Reform, which to 2020 are aiming to deliver investment in new renewable capacity consistent with meeting the UK's target under the EU Renewable Energy Directive (i.e. to meet 15% of all energy through renewable sources). Furthermore, options exist to continue to decarbonise power generation through the 2020s. We now turn to these options.

3. Options for reducing emissions from electricity generation and associated costs

Options for reducing power sector emissions

As we have set out previously, there is scope for significant reduction in power sector emissions over the next two decades and beyond, through investment in a portfolio of low-carbon technologies which are or are likely to become cost-effective (i.e. cheaper than fossil fuel generation facing a carbon price). These technologies include nuclear energy, renewables (including onshore and offshore wind, solar and marine and biomass conversion), and carbon capture and storage (CCS).

In our advice on the fourth carbon budget (2010) we set out detailed technical and economic assessments of these low-carbon technologies. Since 2010, we have reassessed the costs and potential of deploying these technologies on a regular basis.[4] These assessments have reinforced our previous conclusions that there are plausible scenarios where nuclear, renewables and CCS will be feasible and cost-effective within the next two decades provided effective policy is in place.

4 See for example CCC (May 2011) *The renewable energy review*; CCC (April 2012) *The 2050 target – achieving an 80% reduction including emissions from international aviation and shipping*; CCC (May 2013) *Next steps on Electricity Market Reform – securing the benefits of low-carbon investment.*

Previous and updated estimates of costs of abatement options

We recently commissioned Pöyry to assess the latest information on costs of low-carbon technologies for our May 2013 report *Next Steps on Electricity Market Reform – securing the benefits of low-carbon investment*.[5] DECC has also reassessed electricity generation costs[6] in developing its draft EMR Delivery Plan. Our new assessment of costs is largely consistent with the latest DECC views of generation costs. We summarise analysis of these technology costs and compare to previous assessments below (Figures 2.3, 2.4 and 2.5).

- **Nuclear.** We assumed a cost of around £85-100/MWh for delivering the first UK project, slightly higher than our 2010 assumptions, reflecting further delays in delivering European projects (Flamanville and Olkiluoto), although projects outside Europe have progressed to time and budget. We identified significant scope for costs to fall after the first plant (e.g. to £60-70/MWh by 2030), capturing domestic and international learning effects. The recently announced 'strike price' for the first nuclear project of £92.50/MWh is consistent with these assumptions, and the contract terms explicitly recognise the scope for costs to fall for future projects.
- **Onshore wind.** Our new estimates of the current and future costs of onshore wind remain unchanged from our 2010 assessment. Current costs are estimated up to around £100/MWh although there are significant differences in costs between individual projects due to different load factors, project size and connection costs. Potential cost reductions for onshore wind are limited as the technology is already mature, although there may be small gains in the cost of capital once new market arrangements are tested and proven to work.
- **Offshore wind.** Current costs for the majority of projects in the pipeline are estimated around £140-165/MWh. Offshore wind is at an earlier stage of development to onshore wind but offers significant scope for cost reduction. We assume costs fall close to £100/MWh by 2030, although others have suggested faster reductions are possible subject to certain conditions such as confidence about long-term development of the market, steady deployment over 2015-2025, and supply-chain competition to spur innovation.[7]
- **Carbon capture and storage (CCS).** Pöyry estimate costs for the first CCS projects of up to £180/MWh under central fuel prices, with gas projects estimated to be significantly cheaper than coal. These costs reflect the risky nature of successfully deploying a new technology at scale for the first time (i.e. high cost of capital and high capital expenditures). Our estimates of future costs of CCS are similar to our previous 2010 assessment, where costs could be reduced to around £100/MWh by the late 2020s assuming successful commercialisation of the technology, including measures to de-risk transport and storage infrastructure.
- **Biomass conversion.** We estimated the levelised costs of converting existing coal plants and running them with solid biomass fuels at around £80-90/MWh under central fuel price assumptions. However recent DECC estimates reflect more up-to-date data on biomass fuel prices, and estimate a higher cost of between £105-115/MWh for projects commissioning in 2014.

5 Pöyry (June 2013) *Technology Supply Curves for Low-Carbon Power Generation*, a report to the CCC.
6 DECC (July 2013) *Electricity Generation Costs*, https://www.gov.uk/government/publications/decc-electricity-generation-costs-2013
7 The Crown Estate (May 2012) *Offshore wind cost reduction pathways study*; Offshore Wind Cost Reduction Task Force Report (June 2012).

- **Solar.** Solar generation costs have fallen substantially since our 2010 advice reflecting reductions in the cost of solar panels (which have fallen by 50%[8]), with further cost reductions expected between now and 2020 reflecting further technological and supply-chain development. DECC estimates current costs for large-scale solar PV projects to range between £115-130/MWh with costs falling to £65-75/MWh by 2030.
- **Marine.** Both wave and tidal technologies are yet to be demonstrated commercially and currently operate on a very small scale (e.g. total capacity in 2012 was 6 MW). Given its early stage, it is unlikely to be cost-effective within the next two decades, but with commercialisation and rapid cost reductions it could play a significant role as part of a diverse mix in the longer term.

Since publishing our May 2013 EMR report, the Government announced the strike prices that will be offered for long-term contracts for renewable energy projects under the Electricity Market Reform.[9]

It is important to note that strike prices are not the same as levelised costs of generation.

- Contract strike prices need to cover generation costs as well as 'basis risk' discounts applied to the wholesale market price. For example, generators do not receive the full wholesale price when selling electricity to the market due to costs associated with managing the intermittency of wind output or risks of unplanned nuclear outages, along with more general transaction costs between power purchasers and generators. Strike prices therefore need to be higher than levelised costs in order to compensate for these discounts.
- Required strike prices will also depend on contract length: the shorter the contract length, the higher the price that would have to be paid under the contract, since expected returns outside the contract period are likely to be lower than those during the contract. The Government has taken a decision to offer shorter contract lengths (e.g. 15-year contracts for offshore wind projects when the technical lifetime of an offshore wind farm can be around 24 years).

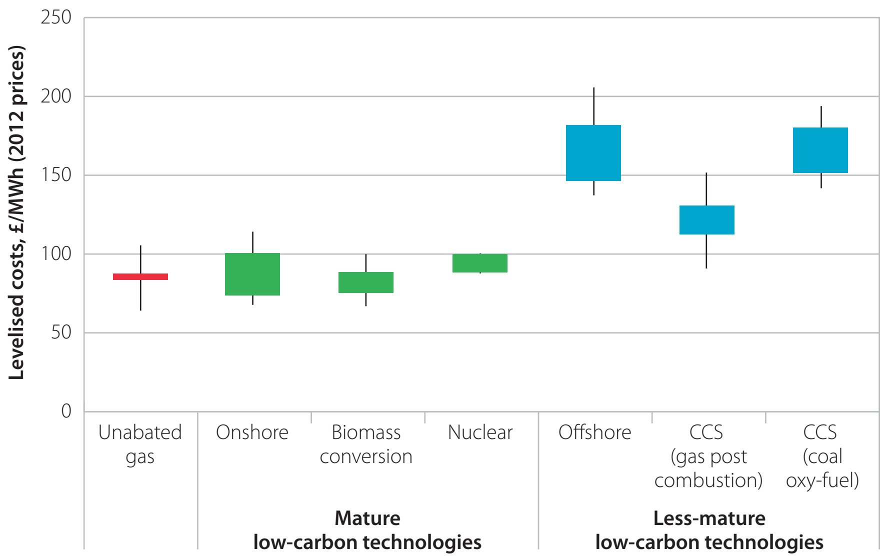
Setting strike prices at the right level is important to ensure projects continue to come forward. In general, the Government's strike prices are broadly in line with our levelised cost estimates after making the necessary adjustments:

- Final strike prices for onshore wind are £95/MWh for projects commissioning in 2014/15 and reduce to £90/MWh for projects commissioning in 2018/19.
- Final strike prices for offshore wind begin at £155/MWh for projects commissioning in 2014/15 then fall to £140/MWh in 2018/19. These have been revised up from draft prices published in June, following advice from the Committee that the proposed degression was faster than implied by the evidence, albeit the revision was smaller than we suggested may be needed.

8 DECC (October 2013) *UK Solar PV Strategy Part 1: Roadmap to a Brighter Future.*
9 National Grid (July 2013), *EMR Analytical report*; DECC (December 2013) *Investing in renewable technologies – CfD contract terms and strike prices.*

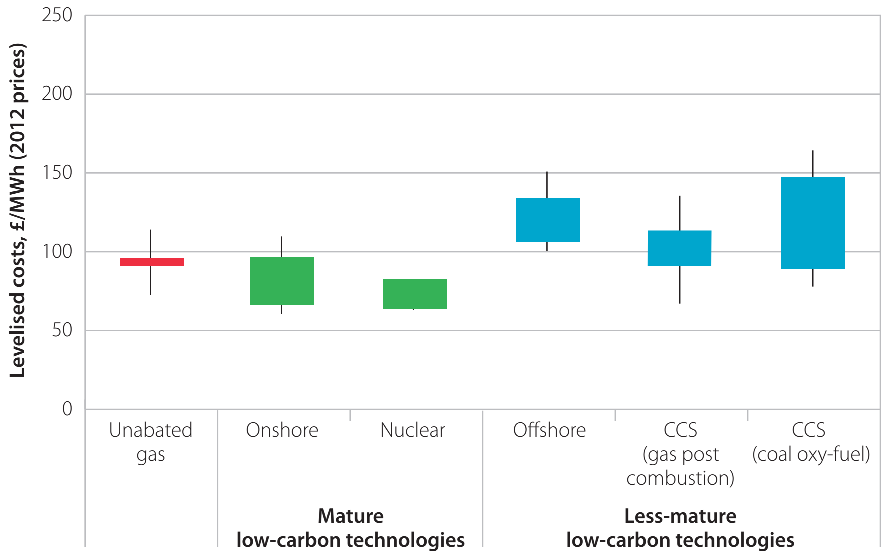
The implication of our cost estimates is that nuclear and onshore wind are likely to have broadly comparable costs to new unabated gas-fired generation under projected carbon prices (which at around £50/tonne in 2025 implies a cost of gas generation of £80/MWh in that year, and an average of £100/MWh over a 15-year lifetime, given rising carbon prices). Investing in these technologies in preference to unabated gas can therefore offer a cost saving over plant lifetimes. Investment in other low-carbon technologies (e.g. offshore wind, CCS) is also desirable in preparing for the 2050 target where this can drive cost reduction and increase deployment potential for later years.

Figure 2.3: Current costs of low-carbon technologies, relative to unabated gas



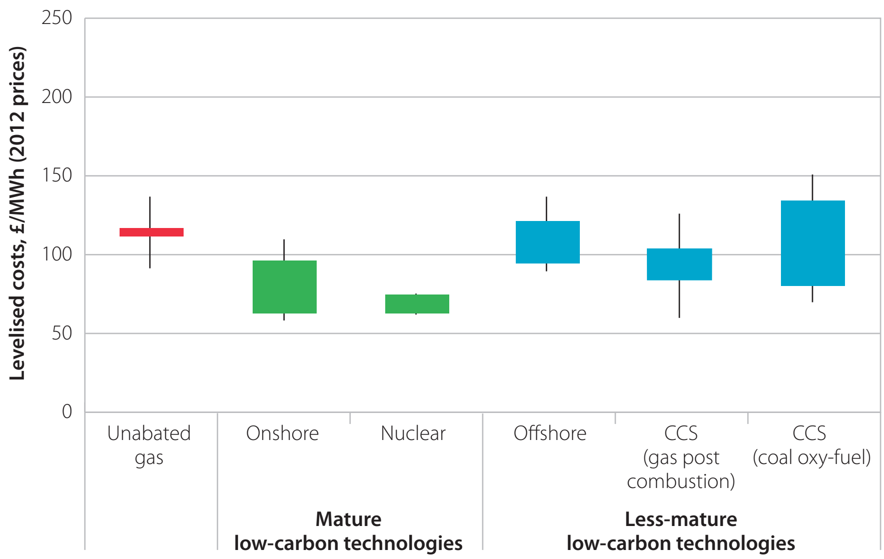
Source: CCC calculations based on Pöyry, Parsons Brinckerhoff.
Notes: Costs for projects starting in 2013 and coming online towards the end of this decade (i.e. 2015 for onshore wind and biomass conversion, 2016 for offshore wind, 2020 for nuclear, 2018/19 for CCS demonstrations. Fuel price assumptions consistent with latest DECC Projections (October 2012). Carbon price rises in line with Carbon Price Floor, to £32/t in 2020 and £76/t in 2030. Cost over project lifetime assuming pre-tax real rate of return of 9% for unabated gas, 9.6% onshore, 12.4% offshore, 11% nuclear, 15% CCS demo, 10% biomass conversion. Solid boxes represent range for high/low capex and central fuel prices (central load factor for wind); thin extending lines show sensitivity to combined high/low capex and high/low fuel prices (high/low load factor for wind).

Figure 2.4: Projected costs of low-carbon technologies (2020), relative to unabated gas



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

Figure 2.5: Projected costs of low-carbon technologies (2030), relative to unabated gas



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

Previous and updated estimates of potential uptake of abatement options

In our original 2010 advice on the fourth carbon budget we suggested the need for investment in 30-40 GW of low-carbon capacity (in baseload-equivalent terms)[10] in the decade from 2020 to replace ageing capacity currently on the system and to meet demand growth.

Our updated analysis in our May 2013 EMR report suggests that there is potential to add up to 60 GW of low-carbon capacity in total over the next two decades, on a baseload-equivalent basis, compared to around 45 GW required to reduce carbon intensity to around 50 gCO_2/kWh. This suggests scope to achieve carbon-intensity of around 50 gCO_2/kWh through different combinations of nuclear, renewables and CCS.

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

- **Onshore wind.** Deployment is slightly ahead of the indicators against which we monitor when reporting to Parliament, and which reach 15 GW of installed capacity by 2020. New project proposals continue to be brought forward and planning approval rates have remained fairly steady. Given the 8 GW capacity already commissioned or in construction, the 4.4 GW already consented and the 8.8 GW awaiting planning consent and the continuing stream of new projects, Pöyry consider deployment of 25 GW total installed capacity to be achievable by 2030 (capable of generating around 60 TWh in an average year). However, in its draft EMR Delivery Plan the Government assume only 11 GW of capacity is deployed by 2020.
- **Offshore wind.** At the end of 2012, there were 3 GW of offshore wind installed and operating in UK waters. The Crown Estate has granted leases for a total of around 47 GW of capacity. Availability of sites is therefore unlikely to be a constraint on deployment for the foreseeable future, although supply chain capacity and availability of finance could limit roll-out, as could developer interest more generally. Based on an assessment of existing and potential future projects, Pöyry estimate that 25 GW total installed capacity could be delivered by 2030, and 40 GW or more would be possible with sufficient funding to incentivise a further ramp-up of the supply chain.
- **Biomass conversion.** Several existing coal plants could potentially convert to run on woody biomass instead of coal. We estimated in our 2011 Bioenergy Review that potential generation from converted coal plants could be more than enough to meet the Government's ambition for biomass power generation (i.e. at that time 32-50 TWh/year in 2020, equivalent to 4-6 GW capacity, and further revised down in the scenarios in the draft Delivery Plan). As we have previously recommended, investment should be subject to stringent sustainability standards, otherwise emissions reductions may not follow.

10 We adjust the capacity of intermittent technologies to a baseload-equivalent basis to account for the fact that they do not generate at their full rated capacity throughout the year. For example, assuming a non-intermittent plant is available to generate for 90% of the year, and offshore wind generates the equivalent of 42% of its full-rated capacity over the year, 1 GW of offshore wind is equivalent to (42%/90%) * 1 GW = 0.47 GW of baseload-equivalent capacity.

- **Nuclear.** The Government has announced strike prices for EDF to develop the first new nuclear plant at Hinkley. The Horizon venture was acquired by Hitachi in November 2012, and has announced plans to build four to five 1.3 GW advanced boiling water reactors by 2030. The NuGen consortium also maintains an interest in nuclear development. The existing sites owned by these three consortia and approved for new nuclear development under the National Policy Statement of July 2011 could accommodate 21-25 GW of new nuclear projects. Pöyry identified existing plans for 16 GW as being more realistic by 2030, with potential to reach deployment of over 20 GW if new developers enter the market (e.g. once the CfD regime has been established).
- **Carbon capture and storage (CCS).** The Government announced in March 2013 that it had selected two preferred bidders to be supported under its CCS Commercialisation Programme: a gas post-combustion project at Peterhead and a coal oxy-fuel project at Drax. The next step for these projects is to proceed with detailed Front End Engineering Design studies, with a view to take final investment decisions by early 2015. Two projects remain in reserve and several other projects have been put forward for the DECC programme and/or EU funding, some of which may be viable in future, while new projects may also emerge. Pöyry suggest the need for a second phase of pre-commercial deployment before commercial plants can be rolled out in the late 2020s. This could give a total of around 10 GW of capacity by 2030.

Given the above assessments, we have recommended that a portfolio approach be adopted under which each of the technologies above is developed possibly supplemented by other technologies like solar and marine. This is appropriate given the scale of challenge in decarbonising the power sector, cost uncertainties, scope for reducing costs of less-mature technologies, and the potential constraints or risks around the deployment of individual technologies. It is reflected in the Government's approach, under which tailored support is or will be available for less-mature low-carbon technologies under the Electricity Market Reform.

Barriers to deploying low-carbon generation in the 2020s

Key barriers to deploying low-carbon generation include regulatory and political uncertainty impacting the investment conditions and the availability of finance.

Investor uncertainties

In our original fourth carbon budget assessment we advised that current market arrangements were unlikely to deliver required investments in low-carbon generation and that tendering long-term contracts would reduce risks which energy companies are not well placed to manage and would provide confidence that required investments will be forthcoming at least cost to consumer.

Since then, the Government has introduced Electricity Market Reform (EMR) to support the transition to a low-carbon power sector, which includes provision of long-term contracts to developers/generators to provide revenue certainty for low-carbon projects. The Government has recently published final strike prices for various low-carbon technologies as well as contract terms, and has established a Levy Control Framework to control subsidy costs.

The EMR should work to support portfolio investment in low-carbon technologies and supply-chain investment, thereby ensuring early decarbonisation of the power sector. Remaining challenges include ensuring that strike prices have been set at the right level and providing confidence to investors that there will be sufficient and ongoing volume to 2020 and beyond.

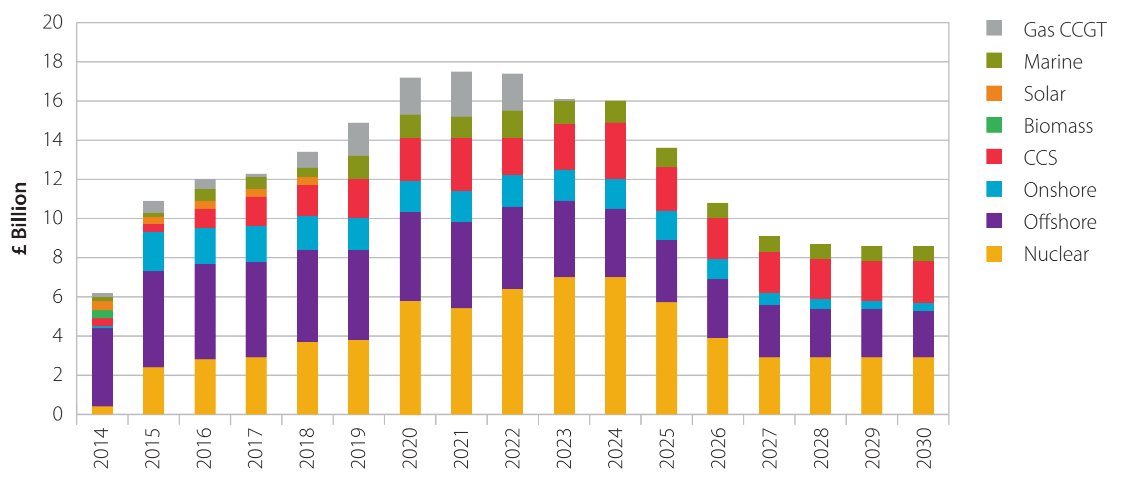
Possible barriers to finance

We have also looked further into the infrastructure and financing challenge to deploying low-carbon generation over the next two decades.

While over the past years capacity has ramped up quickly under support from the Renewables Obligation (renewables capacity has doubled from around 6 to 12 GW over the past 5 years)[11], there is the question as to whether these deployment rates can be sustained. Renewables deployment will need to continue, while at the same time significant capital expenditures on nuclear and CCS projects will be required.

We estimate that the total capital costs of scenarios reaching around 50gCO_2/kWh by 2030 could be up to £200 billion between 2014 and 2030 (Figure 2.6).

Figure 2.6: Capital expenditure on low-carbon technologies in CCC 'Higher Energy Efficiency' scenario reaching 50gCO_2/kWh by 2030



Source: CCC calculations based on Poyry (2013) and Redpoint (2013) modelling.
Notes: One of several scenarios developed for CCC May 2013 EMR report. Figures are in £2012 prices.

11 DUKES (2013) *Chapter 6 – Renewables sources of energy.*

We have not undertaken a detailed analysis of all possible sources of finance or of current capital market conditions. However, it is clear that a substantial increase in finance is required, and that a challenge exists in delivering this, particularly around risky projects (e.g. offshore wind and CCS). The Government can and has started to address this challenge (e.g. through establishment of the Green Investment Bank) and will have to keep this under review (Box 2.1).

Box 2.1: Building low-carbon power capacity – potential sources of finance

Low-carbon technologies require a very large amount of up-front investment and the balance sheet strength of energy companies to finance new projects may be limited. Furthermore, many projects are perceived as risky (e.g. offshore wind and CCS) and therefore the appetite from banks and institutional investors for project finance is unclear. Traditional and potential new sources of finance for low-carbon deployment are summarised below:

- **Balance sheet capital.** To date, investments in relatively high-risk low-carbon technologies (i.e. offshore wind) have typically been financed using the balance sheets of energy companies to secure debt. However this current source of finance available to developers may be insufficient to deliver the increased levels of investment required for these technologies:
  - Balance sheets may not be sufficiently strong to support the level of investment required going forward because: many energy company assets are largely depreciated, existing assets are of low capital intensity compared to low-carbon technologies, energy companies operate in many markets where investment requirements are often also high, over-exposure could negatively affect credit ratings.
  - Banks have become less willing to provide long-term capital and have moved to shorter-term lending.
- **Project finance.** Investment might proceed using project finance – where debt is secured against future project cash flows. However appetite from banks to provide project finance during the early stages of projects where risks are high is unclear, and likely to be harder to secure until new market arrangements are proven.
- **Institutional investors.** These include non-commercial banks, pension funds, insurance companies and asset management funds that are willing to provide long-term loans where commercial banks are not. Currently the share of institutional investors in the UK offshore wind market is less than 5%, suggesting that these investors do not necessarily have the skills to assess project risk or are unwilling to fund projects based on an assessment of risk/reward. The introduction of EMR may encourage further investment from institutional investors.

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

Since publishing our 2010 advice, the Government has set up the Green Investment Bank (GIB) to provide financial solutions to accelerating private sector investment in the green economy, including bridging the gap left by the financial crisis, to drive innovation and to advise Government on the finance impacts of their policy. One of the GIB's key areas of focus is offshore wind and it is working towards addressing bottlenecks in financing initial construction and refinancing projects once operational:

- **Leveraging finance.** The GIB has been capitalised with £3.8 billion and since inception, has committed more than £700 million and mobilised a further £2 billion for construction through the backing of 21 projects.
- **Capital recycling.** Initial investment in the risky construction phase of a project is difficult for developers to secure from elsewhere and so this is usually funded on balance sheet by the utility companies. When the project is operational, the risk falls substantially and utilities are able to sell parts of their assets to commercial banks and institutional investors, freeing up cash to invest in new projects. If this cycle continues, capital can be recycled through many projects. Without the perceived option to refinance once operational, developers may not take on new projects. The GIB is aiming to help develop secondary markets for buying shares in operational projects.

4. Projected emissions with abatement – an updated scenario for the 2020s

In our advice on the fourth carbon budget we developed an emissions scenario involving measures that were likely to be economically sensible in a carbon-constrained world – measures that are important on the path to the 2050 target and that are cost-effective compared to expected carbon prices over investment lifetimes. This was our best estimate of the cost-effective path to the 2050 target and formed the basis for the fourth carbon budget.

This scenario included investment in around 20 GW of (baseload-equivalent) low-carbon capacity to 2020, with an additional 35 GW to 2030, which we identified as feasible based on an assessment of build constraints. We expected this scenario to reduce sector emissions to around 16 $MtCO_2$ in 2030 with an average grid intensity of around 50 gCO_2/kWh in 2030.

We now develop a new power sector scenario based on the latest evidence as set out above.

Outlook to 2020

The starting point for our scenario is a projection for emissions in 2020. We have projected emissions in 2020 on the basis of the Government's latest view in its draft EMR Delivery Plan, which reflects latest projections for electricity demand and funding commitment in the Levy Control Framework for investment in low-carbon generation to 2020.

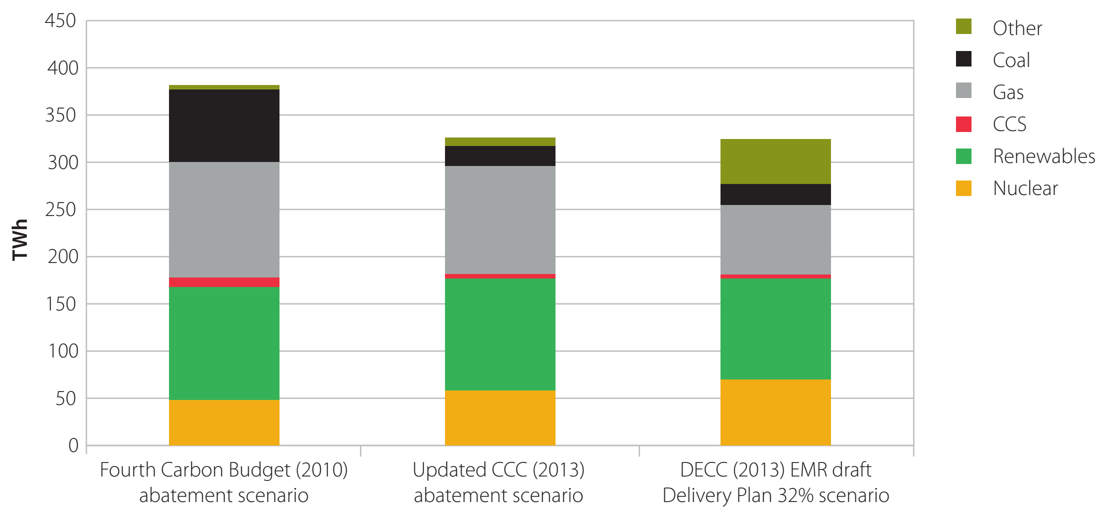
Power sector emissions are now projected to decrease substantially more rapidly to 2020 compared to assumptions in our advice in 2010. This is partly due to revised demand projections but mainly due to new assumptions for coal-fired and nuclear generation (Figure 2.7):

- Electricity demand after reflecting our updated assessment of uptake of abatement measures (e.g. energy efficiency in buildings) is now forecast to fall by around 10% relative to 2010, to be around 300 TWh in 2020, or 7% lower than projected in our 2010 advice.
- The assumed amount of unabated coal-fired generation in 2020 has been reduced by 72% to 21 TWh. This reflects new assumptions regarding: the conversion of existing coal units to biomass, that any coal CCS demonstrations would have CO_2 capture applied to all units rather than our previous assumption that just one unit would be fitted with capture equipment (and all others would burn coal unabated), the impact of the Industrial Emissions Directive, and the impact of the carbon price underpin. We note that projections for power sector emissions reduction to 2020 are highly sensitive to these new coal assumptions. If coal generation does not fall significantly, then power sector emissions will be much higher in 2020 than we have assumed in our updated assessment.
- The amount of nuclear on the system to 2020 has been revised upwards due to plant lifetime extensions. Whereas previously we assumed closure of around 3.5 GW of nuclear capacity by 2020 we now assume that these plants will receive an average lifetime extension of at least five years in line with public announcements. We assume that no new nuclear capacity is built until the early 2020s. Given lifetime extensions, the assumed amount of nuclear generation in 2020 has increased by 20% to 58 TWh from our 2010 assessment.

- The amount of renewables generation in 2020 is assumed to be similar to our previous assessment in our 2010 advice (around 120 TWh).
- Our new scenario for power sector emissions in 2020 includes 13 GW of onshore wind, 11 GW of offshore wind, 9.5 GW of existing nuclear capacity, 0.6 GW of demonstration CCS (gas and coal), and 33 GW and 13.5 GW respectively of unabated gas- and coal-fired capacity. This reflects the Government's latest views on 2020 investment in its draft EMR Delivery Plan. We have adjusted the deployment of nuclear capacity to reflect the delayed timeline for Hinkley (announced in October 2013) and adjusted investment upwards in onshore and offshore wind within the limits of the Levy Control Framework[12] to be closer to the feasible deployment set out in our progress report indicators.
- Total generation in 2020 is projected to be 326 TWh, or 14% lower than the level we assumed in our 2010 advice. This reflects lower demand projections, with nuclear generating 58 TWh, renewables 119 TWh, coal 21 TWh and gas 114 TWh (Figure 2.7).

As a result, we have revised our estimate of power sector emissions to around 64 $MtCO_2$ in 2020 (compared to our previous estimate of 109 $MtCO_2$ in our 2010 advice), with average grid intensity falling rapidly between now (around 500 gCO_2/kWh) and 2020 to around 210 gCO_2/kWh, compared to 323 gCO_2/kWh in 2020 under our previous assumptions. Our new estimate of power sector emissions implies a 60% reduction on current emissions.

Figure 2.7: Scenarios for UK power generation in 2020



Source: CCC (December 2010); DECC (July 2013); National Grid (2013) *EMR Analytical Report*; CCC calculations based on Redpoint (2012) and (2013) modelling.
Notes: Generation from major power producers only; renewable generation from all generators. DECC scenario reflects generation mix in 32% scenario in draft EMR Delivery Plan (July 2013). Other category includes pumped storage, gas CHP, oil, and in DECC scenario, imports. CCC updated abatement scenario assumes no imports in 2020 (instead generation is supplied by gas CCGT). Renewables includes onshore and offshore wind, solar PV, marine. biomass and hydro as well as other renewables identified in DECC's 2013 draft EMR Delivery Plan. Nuclear generation in updated CCC (2013) abatement scenario is lower than DECC (2013) EMR draft Delivery Plan to reflect recently announced (October 2013) delay in Hinkley Point C timeline.

12 The levy control framework put a limit on the total spending to cover the following policies: the Renewables obligation (RO), Feed-in Tariffs (FiTs) Warm Home Discount, and Contracts for Difference (CfDs).

The path from 2020 to 2030

Scenarios developed for advice on Electricity Market Reform (May 2013)

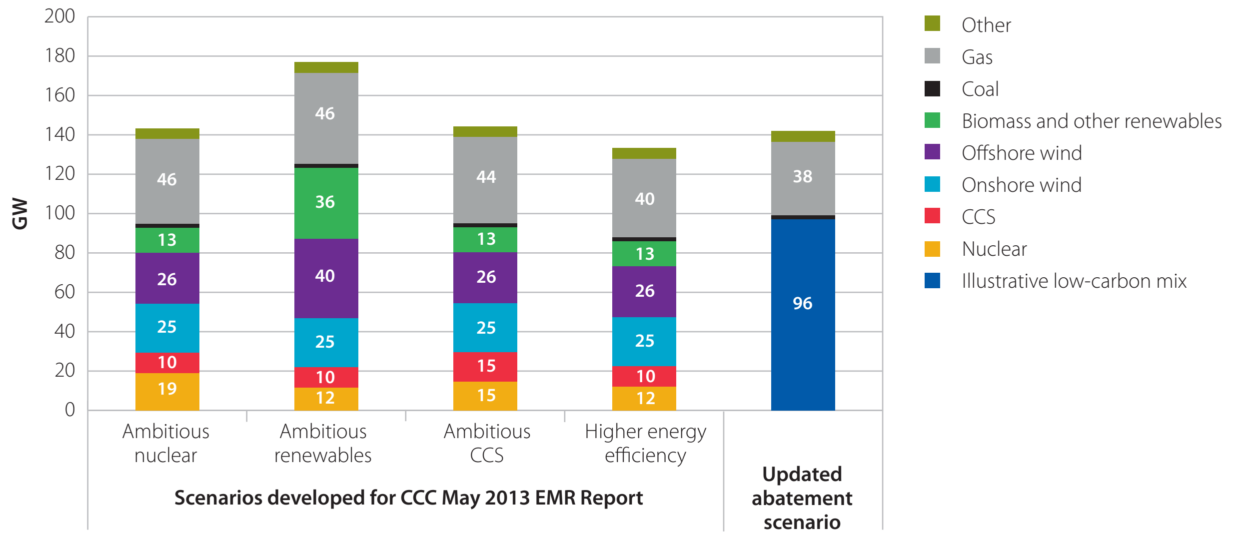
Since our original 2010 advice, we have looked further into technology mixes that could allow the power sector to largely decarbonise to an average grid intensity of around 50 gCO_2/kWh by 2030 in the most economically efficient path. Specifically, in our May 2013 report, *Next steps on Electricity Market Reform*, we developed four scenarios with differing emphasis on the four key options for decarbonisation (i.e. nuclear, renewables, CCS and energy efficiency). These scenarios:

- Allow for flexibility for one technology to substitute for another. For example while the scenario in our advice on the fourth carbon budget was more nuclear-focused, these scenarios explore the potential of going further with CCS if the technology develops more quickly and favourably; with renewables if offshore wind costs fall towards the lower end of our range; with nuclear if sufficient capital and developer interest is available; or demand reduction if cost-effective opportunities can be found and delivered.
- Include a minimum roll-out of less-mature technologies – with around 25 GW offshore wind and 10 GW of CCS installed by 2030 (Figure 2.8). This is intended to develop a portfolio of options for ongoing provision of low-carbon electricity after 2030 and create flexibility to response to changing costs.
- Involve limited roll-out of other renewables (e.g. marine technologies, solar) given currently high costs. However these options may be viable and could provide alternatives should the others deliver less.
- Involve a significant increase in deployment of flexibility options in order to limit costs and maintain system security. Sources of flexibility include:
  - **Demand-side response.** Active management of demand (e.g. charging electric vehicles or running washing machines overnight when other demand is low) can help smooth the profile of demand and reduce the requirement for capacity during peak periods. Widespread deployment and use of smart technologies (such as smart meters) will facilitate increases in demand-side response given sufficient consumer engagement.
  - **Interconnection.** Interconnection already provides a valuable source of flexibility to the UK, with around 4 GW of capacity with Ireland, France and the Netherlands. Flows are price-driven according to relative demand and supply, and to the extent that these differ across countries, will continue to be an important source of flexibility.
  - **Storage.** Bulk storage, such as pumped storage, can be used both to provide fast response and to help provide flexibility over several days (providing supply at times of peak daily demand rather than continuously over the whole period). Other storage options could emerge in the future.

- **Flexible generation.** Gas-fired capacity offers the potential to meet demand when output from intermittent technologies is low, and can be operated reasonably flexibly. There may also be some scope for using low-carbon capacity flexibly – for example scheduling maintenance outages for summer when demand is low, or running CCS at slightly reduced load factors.

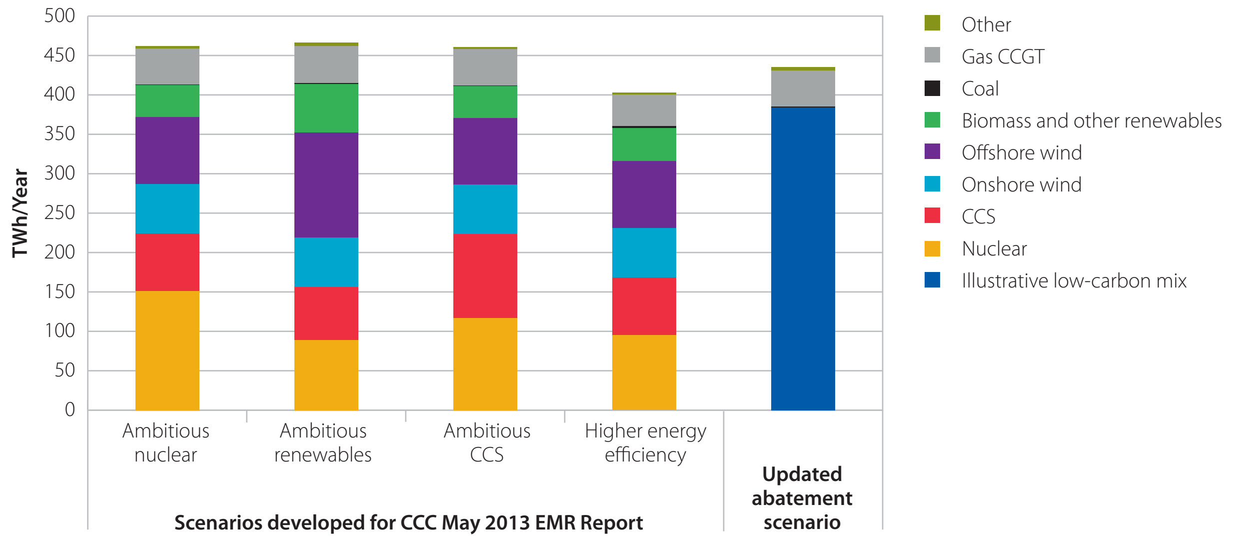
The scenarios therefore reduce CO_2 emissions and generation costs while maintaining system security.

Figure 2.8: Power sector scenarios reaching 50gCO_2/kWh by 2030 – capacity (GW)



Source: CCC (April 2013) *Next steps on Electricity Market Reform*; CCC calculations based on Redpoint modelling (2012 and 2013).
Notes: Other includes Pumped Storage and Gas CHP. Other renewables includes solar PV, marine and hydro. Excludes autogeneration consumed onsite. CCGT: Combined Cycle Gas Turbine. All the scenario data are presented at UK level, including an adjustment to add Northern Ireland to the GB-level outputs of the Redpoint modelling.

Figure 2.9: Power sector scenarios reaching 50gCO_2/kWh by 2030 – generation (TWh/year)



Source: CCC (May 2013) *Next steps on Electricity Market Reform*; CCC calculations based on Redpoint modelling (2012 and 2013).
Notes: Other includes Pumped Storage and Gas CHP. Other renewables includes solar PV, marine and hydro. Excludes autogeneration consumed onsite. CCGT: Combined Cycle Gas Turbine. All the scenario data are presented at UK level, including an adjustment to add Northern Ireland to the GB-level outputs of the Redpoint modelling.

Updated scenario for fourth carbon budget review advice

We have revisited our scenario for the 2020s based on the analysis in our May 2013 EMR report, the Government's latest views on the entry point for power sector emissions in 2020, and our latest views of electricity demand after abatement in other sectors or uptake of energy efficiency measures, heat pumps and electric vehicles (see chapters 3, 4, and 5). We have assumed, as before, that the power sector reaches an average grid intensity of around 50 gCO_2/kWh by 2030. This reflects that our reassessment of the latest evidence on costs and feasibility of deploying key low-carbon technologies implies that this continues to be an achievable and desirable goal, offering significant cost saving relative to delayed decarbonisation.

- **Demand projections from existing sectors.** The DECC energy model projects electricity demand (excluding autogeneration) of 398 TWh in 2030, or 3% lower than we assumed in our 2010 advice.
- **Demand projections from new sectors.** We have reassessed uptake of abatement measures in other key emitting sectors (buildings, heat and transport) and the impact on electricity demand. The combination of energy efficiency improvements in lights and appliances, heat pumps in buildings and industry, and electric vehicles in transport (see Chapters 3-5), reduces electricity demand in 2030 by 8% versus the DECC projection, to 368 TWh. Overall, our projection for demand after abatement is 13% lower than the level we assumed in our original 2010 advice.
- **2020 entry point.** Given the new lower projection for power sector emissions in 2020 (see above), the pace of emission reductions required to reach a 50 gCO_2/kWh grid intensity by 2030 is less steep than in our original 2010 advice.
- **2030 capacity.** It is not possible or necessary to predict the precise mix of low-carbon technologies, with different mixes potentially appropriate depending on how costs and deliverability develop. It is important however that any mix involves a portfolio of low-carbon technologies, including not just those with the lowest cost (e.g. nuclear and onshore wind in our central assumptions), but also emerging technologies with scope to drive down costs through deployment and with large potential beyond 2030 (e.g. offshore wind and CCS). For our updated abatement scenario we assume an illustrative mix in line with our May 2013 scenarios: up to 17 GW of nuclear (of which 8-16 GW is new capacity added during the 2020s), 15-25 GW of onshore wind, at least 25 GW of offshore wind and 5-15 GW of CCS in 2030 (Figure 2.8 and 2.9). This appears to be feasible based on current project pipelines and developer plans, assumptions for cost reduction and technological development, and the scenarios in the Government's draft EMR Delivery Plan.
- **Security of supply requirements.** Our new power sector scenario has been designed to meet DECC's recently proposed reliability standard for the Great Britain electricity market, which targets a loss-of-load expectation of no more than three hours per year.[13] This represents the number of hours per year in which, over the long term, it is statistically expected that supply will not meet demand.

13 DECC (July 2013) *Draft EMR Delivery Plan – Annex C: Reliability Standard Methodology.*

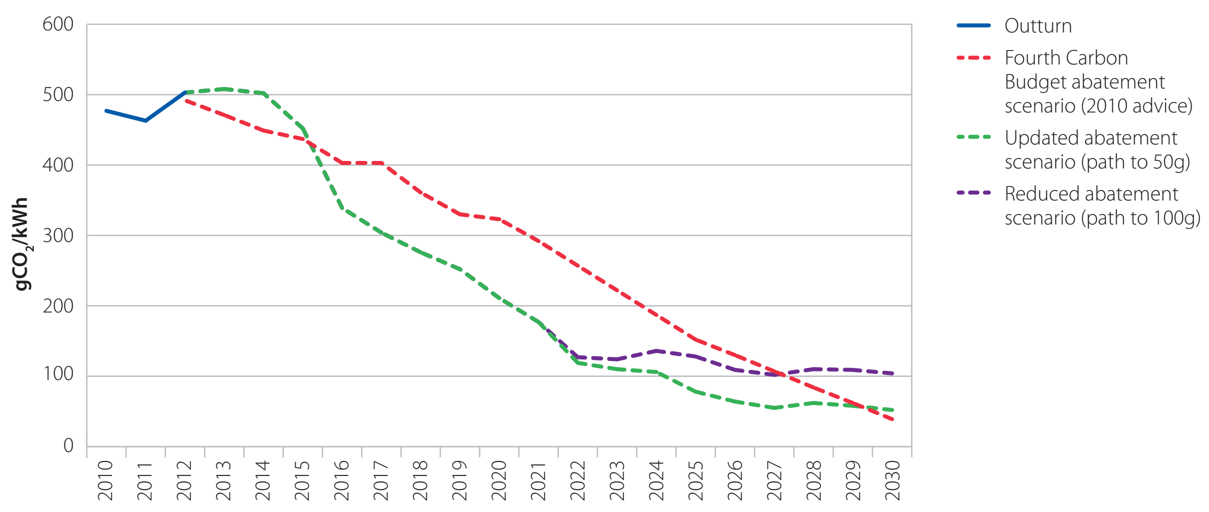
This updated abatement scenario results in emissions intensity in 2030 of 50 gCO_2/kWh and emissions of 21 $MtCO_2$, an 87% reduction on 2012 and similar to our previous estimate (Figure 2.10 and 2.11).

Cumulative power sector emissions over the fourth carbon budget are estimated to be 140 $MtCO_2$, or half the level we estimated in our original 2010 fourth carbon budget advice (280 $MtCO_2$) (Figure 2.11).

Although our revised assessment implies that our scenario for the power sector now delivers emissions reductions well beyond that required in the fourth budget period, it is still appropriate to deploy low-carbon capacity through the 2020s in preference to new fossil-fired plant. This is required to reach the same 2030 end-point and will minimise costs in the face of expected rising carbon prices (e.g. as in the Government's carbon price underpin) and develop technologies likely to be required in meeting the 2050 target at least cost.

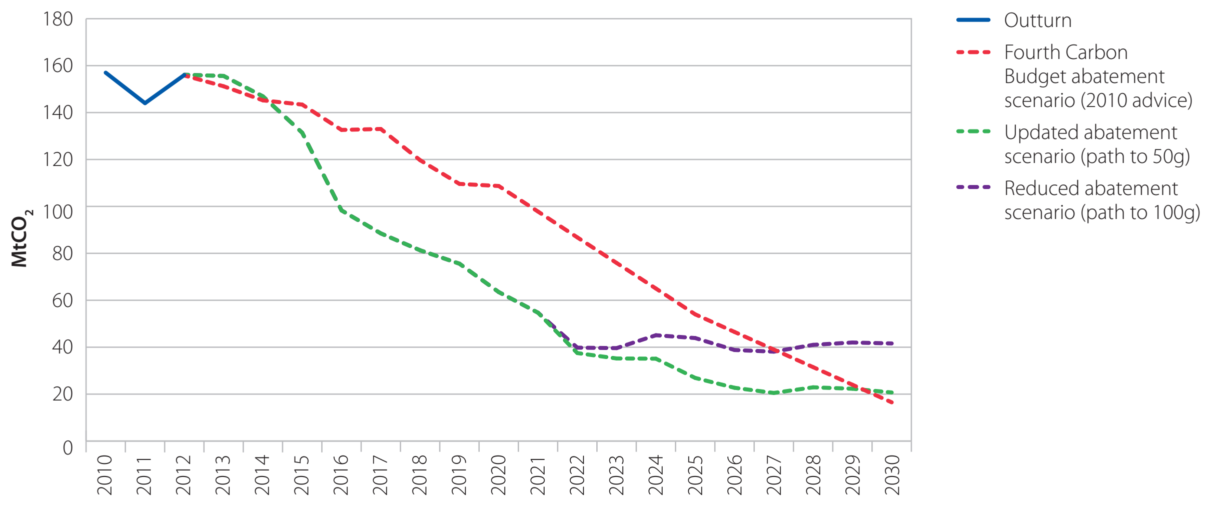
Foregoing cost-effective investment in the 2020s could increase costs and require unachievable build requirements after 2030 in order to meet the 2050 target, particularly given the limited range of low-carbon options implied under such an approach.

Figure 2.10: Emissions intensity of electricity (2010-2030)



Source: CCC calculations (2010 Fourth Carbon Budget advice); CCC calculations based on Redpoint (2012 & 2013) modelling.
Notes: Intensity is based on energy supplied from major power producers and all renewable generators and is net of transmission and distribution losses.

Figure 2.11: Scenarios for UK power sector emissions (2010-2030)



Source: CCC calculations (2010 Fourth Carbon Budget advice); CCC calculations based on Redpoint (2012 & 2013) modelling.
Notes: Redpoint modelling adjusted to assume no imports into UK between 2014-2023 and instead demand is assumed to be met with additional gas CCGT generation; modelling suggests UK will be a net exporter of power generation between 2024 and 2030.

Sensitivities and flexibilities

The scenarios above are an appropriate basis for policy under the current best evidence regarding costs and feasible investment rates. However, conditions for decarbonisation could be less favourable, making a 50g scenario undesirable or unachievable. This could be because, for example: nuclear costs do not come down, or developers are not able to finance projects; CCS does not progress as an effective decarbonisation technology; costs of offshore wind do not fall with deployment; and/or further demand reduction cannot be delivered. In the nearer term, there is a risk that coal-fired capacity stays on the system longer than our current assumption. Finally, low gas and/or carbon prices could make unabated gas generation relatively more attractive.

We have captured some of these uncertainties by modelling scenarios that results in an average carbon intensity of around 100 gCO_2/kWh in 2030, with emissions of around 42 $MtCO_2$ (Figures 2.10 and 2.11). A 100g scenario could still prepare sufficiently for the 2050 target, provided it sufficiently develops emerging options, and would still enable meeting of the fourth carbon budget through UK emissions reductions:

- A 100g scenario would need faster roll-out after 2030 to achieve the same levels of decarbonisation by 2050 (e.g. an extra 0.5 GW each year on average compared to a 50g scenario). This is likely to be achievable provided that the full set of options is available, and specifically provided that the programme in the 2020s has sufficiently developed the less-mature technologies (e.g. CCS and offshore wind). For example, a 100g scenario with high nuclear deployment but low investment in CCS and offshore wind during the 2020s would leave the UK overly reliant on a single low-carbon technology. This would imply unacceptable costs and risks of achieving the 2050 target and/or of very high electricity prices required to deploy uncommercialised low-carbon options at scale after 2030.

- Power sector emissions during the fourth carbon budget would be higher by on average around 13 $MtCO_2$ per year in these scenarios compared to the 50g scenarios. At 205 $MtCO_2$ across the fourth budget period, power sector emissions would still be lower than in our original fourth budget scenario, given the lower emissions from coal that we now expect through the 2020s.

It will therefore be important to monitor the relevant factors (e.g. costs and deliverability) and retain flexibility in policy to respond. For example, it will be important that the 2030 target for power sector decarbonisation due to be set in 2016 under the EMR sufficiently recognises these uncertainties.

5. Benefits of early decarbonisation of the power sector

In our May 2013 EMR report[14], we compared the costs of UK portfolio investment in low-carbon technologies through the 2020s with the alternative of a strategy focused on gas investment in the 2020s followed by a ramping up of investment in low-carbon technologies in the 2030s, as required to meet the 2050 target. This delayed strategy could result in an average emissions intensity of close to 200 gCO_2/kWh in 2030. Our analysis has suggested that earlier investment – through the 2020s – is cheaper or is required to prepare for meeting the 2050 target. A delay in investment would therefore increase costs.

We quantified the cost for such a delay:

- **Early versus delayed investment in mature low-carbon technologies.**
  - Investment in nuclear rather than gas-fired power generation through the 2020s would result in a present value benefit of £23 billion across project lifetimes under DECC central case assumptions for fossil fuel and carbon prices[15]. This is due to the rising carbon price through the 2020s and beyond. The analysis suggested significantly higher benefits under high gas and/or carbon prices (£40 billon in DECC's 'high' gas price scenario, rising by a further £20 billion if carbon prices are also high). Costs of investment in nuclear and gas-fired generation would be broadly comparable (i.e. the net present value would be close to zero) under DECC's extreme scenario for low gas prices, or if carbon prices were at half the current levels (i.e. well below the planned floor price, at £38/tCO_2 in 2030).
  - Investment in 10 GW of onshore wind capacity – generating equivalent to around 3 GW of baseload capacity – could result in benefits of the order £2-3 billion under central case assumptions.
- **Early versus delayed investment in less-mature low-carbon technologies (offshore wind and CCS).**

14 CCC (May 2013), *Next steps on electricity market reform – securing the benefits of low-carbon investment*, available at www.theccc.org.uk.
15 DECC's carbon appraisal values have central levels of £216/tonne in 2050 (2012 prices) with low and high values 50% below and above the central levels; DECC's central gas prices scenario anticipates an increase in gas prices to 74p/therm in 2020 and then remains constant to that level in 2030 (with a range between 42-105p/therm); see Chapter 1.

- We calculate a net present value of up to £40 billion under central cost assumptions of investment in offshore wind and CCS. The benefit would be small (i.e. net present value close to zero) if the long-term requirement for less-mature technologies is low, but would reach £40 billion where there is a high need for less-mature technologies, reflecting limits to deployment of mature technologies and/or a very high level of electricity demand in 2050. In a case where nuclear is available but limited to existing sites the net present value would be around £20 billion under central assumptions.
- There would be significantly higher savings (e.g. up to £70 billion) if gas and carbon prices are high. Under low gas or carbon price assumptions, net costs of investment in offshore wind and CCS (i.e. a negative net present value) could be at most £15 billion, and only where the long-term need for these technologies turns out to be low.

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

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

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

- **Spillovers.** CCS is a crucial technology for broader decarbonisation; developing CCS therefore has major spillovers for other sectors (e.g. use of CCS in industry and as a route to negative emissions in combination with bioenergy are key options for meeting the 2050 target; see Box 1.7 in Chapter 1). CCS is also likely to be a key abatement option globally, with significant spillovers to international action to reduce emissions from the UK contribution to commercialisation.
- **Flexibility.** Earlier deployment of low-carbon power technologies gives more time to respond to difficulties and develop other decarbonisation options should they be needed (e.g. if CCS is unsuccessful, then more focus can be put on developing offshore wind and electrifying processes in industry).
- **Economics benefits.** Preparing to invest in a low-carbon portfolio in the 2020s will put the UK amongst the early movers on decarbonisation and continue investment programmes currently underway. That may allow the UK to gain an industrial advantage in supply chains for low-carbon technologies, which may bring economic benefits given expected ongoing domestic and international markets for these technologies, and could contribute to objectives to increase employment in manufacturing industries.

- **Import dependency.** Investing in a portfolio of low-carbon technologies would enhance the UK's energy sovereignty. It would also reduce exposure to volatility in fossil fuel prices, and the associated risk of damaging economic impacts.

Given potentially significant benefits and low regrets, investment in a portfolio of low-carbon technologies is a sensible strategy to commit to in a carbon-constrained world. Such a commitment would help to improve conditions for investment and bring forward investments in low-carbon technologies and associated benefits.

Delivering this investment and the associated benefits will require strong policies. The Government has recognised this in introducing long-term contracts for low-carbon capacity under EMR. Ensuring success in this will require sufficient visibility for investors (e.g. through setting a carbon-intensity target in 2016 for 2030 and developing commercialisation strategies for offshore wind and CCS). It will also require that barriers to delivery, such as finance and infrastructure, are tackled.

We will return to consider policy success through the first budget period in our 2014 progress report to Parliament and draw out any lessons for the future.