Chapter 2: Progress decarbonising the power sector

Introduction and key messages

In our last progress report we showed that the fall in power sector emissions of 7% in 2011 was largely due to transitory factors, including favourable weather conditions for generation of renewables and nuclear plant returning to operation after outages.[1]

In this report we consider the latest data on emissions along with progress investing in new low-carbon capacity. We also outline priorities for taking forward the Electricity Market Reform given its crucial role in driving future low-carbon investments.

Our key messages are:

- **Emissions.** In 2012, CO_2 emissions in the power sector increased by 8% to 156 $MtCO_2$, due to an increase of highly carbon-intensive coal generation at the expense of gas. This was driven by a low price of coal in the global market and a low carbon price, and is likely to be a temporary effect. The impact of increased coal generation on emissions was partially offset by the addition of renewable capacity to the system.
- **Carbon intensity.** While actual carbon intensity increased by 10% to 531 gCO_2/kWh in 2012, achievable carbon intensity fell by 6% to 315 gCO_2/kWh. In other words, if plant on the system were dispatched so as to minimise emissions by substituting coal for gas, carbon intensity would fall by 41% from 531 to 315 gCO_2/kWh. This is consistent with achieving 200 gCO_2/kWh intensity in 2020 and 50 gCO_2/kWh in 2030, which we have identified as being on the cost-effective path to meeting the 2050 target set out in the Climate Change Act. The gap between actual and achievable carbon intensity will be closed as coal plant is retired as the relative cost of coal increases under the rising carbon price floor and given tightening EU legislation on air quality.
- **Low-carbon technologies.** Although a record amount of capacity was added in 2012 and the pipeline is strong, major challenges and risks remain in delivering the investment required across the portfolio of low-carbon technologies.
  - **Wind.** The rate of wind new build, if sustained through the rest of the decade, would meet the required level of capacity by 2020 for both onshore and offshore. The future pipeline remains strong, with sufficient projects awaiting construction or in planning to meet our indicators to 2020. Delivering these projects will require that current policy uncertainties relating to the Electricity Market Reform are resolved and financial barriers are addressed (e.g. the Green Investment Bank mobilising project finance for offshore wind).

1 CCC (2012) *Meeting Carbon Budgets – 2012 Progress Report to Parliament*.

  - **Nuclear.** Important milestones were passed in the last year, with the approval of the Areva (EDF) reactor design and planning approval for EDF's new plant at Hinkley Point C. Hitachi completed the purchase of the Horizon venture, and submitted their reactor design for approval. Agreeing the contract for the first project at Hinkley Point C would allow focus on other contracts to be signed under the first EMR Delivery Plan period, with scope to sign for up to 6 GW by 2018/19, as part of a major nuclear programme through the 2020s, with significant economic benefits for the UK.

  - **Carbon Capture and Storage (CCS).** DECC's Commercialisation Programme has selected two projects to enter negotiations for Front-End Engineering and Design (FEED) studies, with a view to making final investment decisions in early 2015. It is essential that the momentum is maintained, so that these two plants can enter operation by 2018/19. The Government should set out its approach to supporting further projects to become operational in the early 2020s at the latest, including approaches to funding FEED studies and signing contracts. It will also be crucial to set out a longer-term commercialisation strategy, in order to maintain interest from the supply chain beyond the initial projects and to ensure that future cost reductions can be achieved.

- **Electricity Market Reform (EMR).** Following pre-legislative scrutiny by the Energy and Climate Change Select Committee, the Energy Bill was introduced to Parliament in November 2012 and is currently progressing through Parliament. Challenges remain in finalising the Bill, developing the EMR Delivery Plan, ensuring sufficient funding and providing long-term certainty.

  - **Contracts.** There are a number of detailed issues relating to contract design and payment mechanisms which should be resolved as the Bill is finalised.

  - **Delivery Plan.** The Delivery Plan (due to be published for consultation in July) should be designed to provide clarity for investors over the Government's intentions as market-maker. This should include setting out the quantity of capacity that the Government intends to contract over the period 2014/15-2018/19, and the prices that it intends to pay for wind generation.

  - **Funding.** Clarifications and possible adjustments on funding under the levy control framework to 2020 are needed in order to ensure that it is sufficient to support the required investment in low-carbon technologies.

  - **Longer-term certainty** should be provided through setting out commercialisation strategies for less mature technologies, setting a carbon-intensity target for 2030, and also extending funding under the levy control framework out to this date.

We set out the analysis underpinning these messages in six sections:

1. Power sector emissions
2. The Committee's power sector indicator framework
3. Investment in renewable generation
4. Deployment of new nuclear
5. Commercialisation of CCS
6. Progress on Electricity Market Reform

1. Power sector emissions

Emissions in 2012

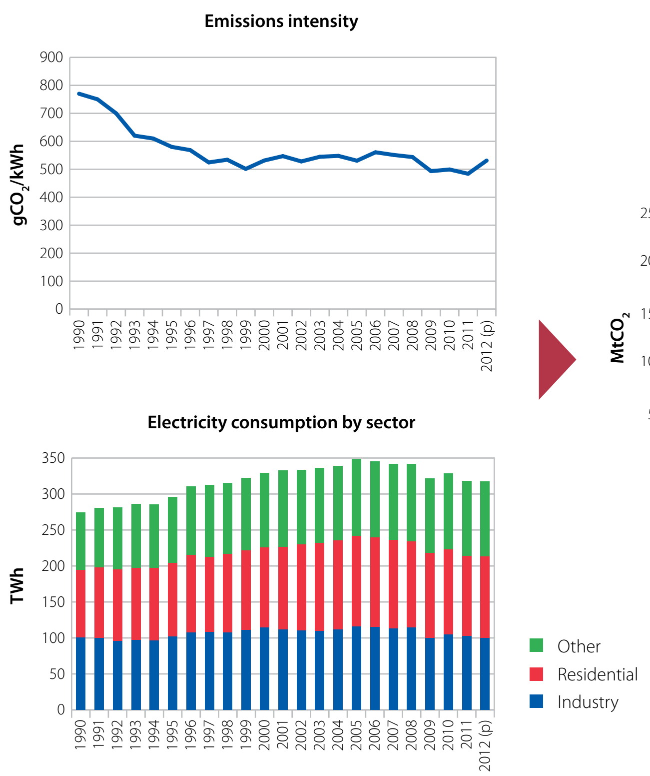
In 2012, power sector emissions accounted for 27% of total UK greenhouse gas emissions. Provisional data suggest power sector emissions increased by 8%, from 144 $MtCO_2$ in 2011 to 156 $MtCO_2$ in 2012. This was driven by an increase in the carbon intensity of power generation (Figure 2.1).

- **Consumption** remained broadly constant across all sectors at 317 TWh. A doubling of net imports of electricity led to a 4% reduction in the amount of electricity generated in the UK.[2]
- **Carbon intensity.** The carbon intensity of electricity consumed increased by 10% from 484 gCO_2/kWh in 2011 to 531 gCO_2/kWh in 2012. This reflects an increase in generation from carbon-intensive coal at the expense of gas, although this was partly offset by generation from new renewables capacity added to the system.
  - Coal generation increased by a third from 105 TWh to 140 TWh, while gas fell by a third from 133 TWh to 86 TWh. This reflects commodity prices that were favourable for coal relative to gas – the wholesale coal price and carbon price fell throughout the year and the wholesale gas price increased (Box 2.1).
  - Generation from renewables continued to increase, rising by 20% from 34 TWh in 2011 to 41 TWh in 2012 and now accounts for 12% of total generation. This increase was due to a record amount of wind capacity having been added to the system in 2012, slightly offset by less favourable weather conditions (average wind speed fell by 8% and rainfall decreased by 25% causing generation from hydro to fall by 8% compared to 2011).[3] If coal had not replaced gas in 2012, this increase in generation from renewables would have reduced emissions intensity by 2%.
  - Nuclear generation remained broadly constant at 70 TWh.

2 Imported power has no emissions in the UK. In calculating achievable emissions intensity (below) we assume no net imports.

3 Full year in 2012 compared with full year in 2011, DECC (March 2013) Energy Trends. Data are not yet published on load factors for 2012, although higher wind speeds usually imply higher load factors, for example in 2011 average wind speed increased by 16% and average load factor for onshore wind increased by 18% and for offshore wind increased by 27%.

Figure 2.1: Emissions intensity of electricity supply, electricity demand and CO_2 emissions from the power sector (1990-2012)



Source: DECC (March 2013) *Energy Trends*; DECC (2013) *UK Greenhouse Gas Emissions 1990-2012 (provisional)*, CCC calculations.
Notes: Emissions intensity is UK based useable generation, i.e. adjusted for losses. Electricity consumption includes imported power. 2012 data are provisional.

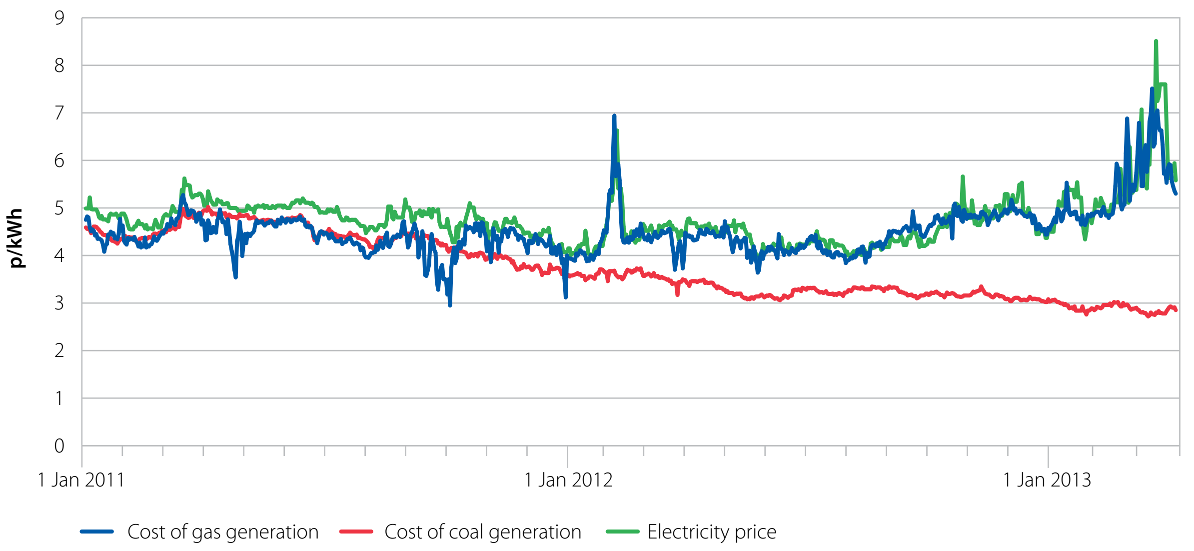
Box 2.1: Drivers of increased coal generation in 2012

The switch from gas to coal in 2012 was driven by a reduction in the cost of coal generation compared to gas. There were three key drivers for this:

- **The wholesale gas price increased** by 6% from 56 to 60 p/therm.[4] The price of gas in Europe rose, primarily as a result of increased demand from Japan, following the 2011 Fukushima nuclear disaster. This prompted closure of nuclear facilities, compensated with increased use of liquefied natural gas.
- **The wholesale coal price fell** by 11% from £89 to £79/tonne.[5] The exploitation of shale gas in North America pushed down US gas prices prompting a switch from coal to gas use in the US. Excess coal has therefore been supplied to European markets at low prices.
- **The carbon price in the EU Emissions Trading Scheme (EU ETS) remained at low levels** in 2012 following a dramatic fall of nearly 50% in 2011 from €14.1 to €7.4/tonne (£12 to £6.3/tonne).[6] It fell by a further 5% in 2012, averaging to €7.4 /tonne (£6/tonne) over the year. The carbon price drives a wedge between the cost of coal and gas generation as coal is more than twice as carbon-intensive as gas. As it has fallen, the relative cost of coal compared to gas generation has fallen.

Given these favourable conditions for coal compared with gas generation, the "clean dark spread" (i.e. the difference between the short-run cost of coal generation and the electricity price which is driven by the cost of gas generation) has been rising steadily since early 2012 (Figure B2.1).

Figure B2.1: Short-run cost of gas and coal generation and electricity price (January 2011 to March 2013)



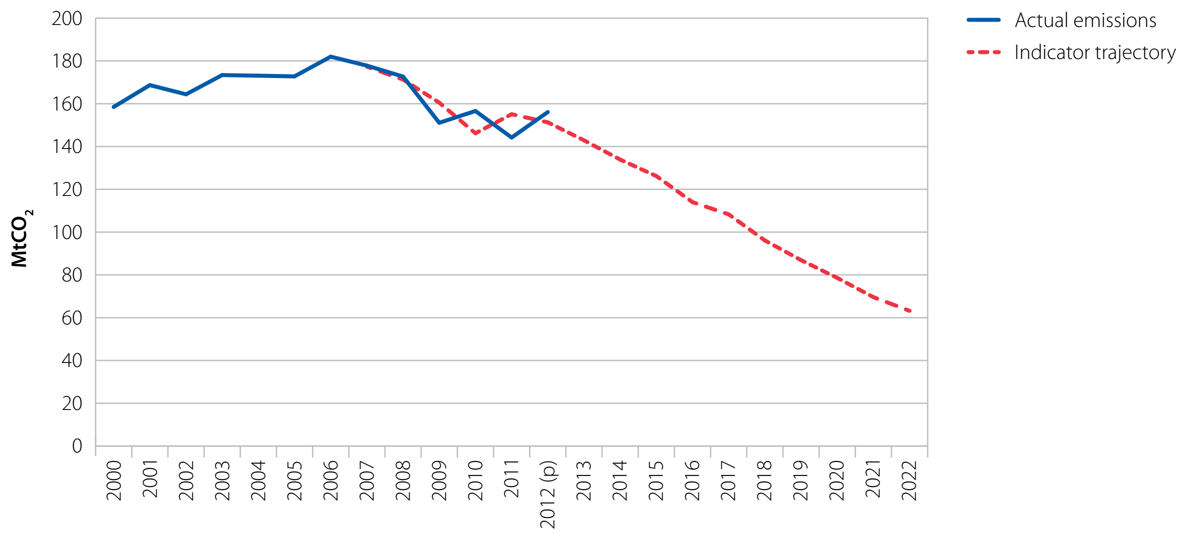
Source: *UK Power day-ahead data*, WMBA (accessed 9 May 2013); *System Average Price data*, National Grid (accessed 9 May 2013); *Coal ARA data*, ICIS, (accessed 12 May 2013); CCC calculations.
Notes: Assumes plant efficiency 49% for gas and 35% for coal (based on average for existing fleet). Carbon intensity 378 g/ CO_2kWh for gas and 1,000 g/ CO_2kWh for gas. Based on day-ahead electricity and gas prices, and coal monthly forward price.

4 Average gas wholesale price in 2012 compared to average price in 2011. Based on day-ahead gas price, National Grid (accessed 9 May 2013).

5 Average coal wholesale price in 2012 compared to average price in 2011. Based on month-ahead coal price, ICIS (accessed 12 May 2013). Conversion from $/tonne to £/tonne based on daily BID exchange rates, OANDA (accessed 27 May 2013).

6 Average December 2011 carbon price compared to average January 2011 price. Based on daily spot carbon price, ICE-ECX European Emissions (accessed 10 April 2013). Conversion based on daily BID exchange rates, OANDA (accessed 27 May 2013).

Figure 2.2: Actual power sector emissions compared with our indicator trajectory (2000-2022)



Source: DECC (March 2013) *Energy Trends*; DECC (March 2013) Provisional 2012 results for *UK greenhouse gas emissions and progress towards targets*; CCC calculations.

Emissions in 2012 were slightly above the trajectory set out in our indicators, despite the large fall during the recession (Figure 2.2). The large increase in 2012 driven by fuel switching from gas to coal raises a question as to whether the rise will persist in future. Our assessment is that it is unlikely that the increase in coal burn will be sustained in the medium-to-long term, due to the age of existing plants, existing environmental legislation and the UK's carbon price floor.

- **Age of coal plants.** The majority of coal plants in the UK were built in the 1960s and 1970s, and are now nearing the end of their typical lifetimes of 40-50 years. Therefore, most are expected to retire within the next decade, with little if any capacity on the system expected to remain in 2030 (the newest units at Drax power station started generating in the mid-1980s and will therefore be around 45 years old in 2030).
- **Environmental legislation.** European regulations relating to air quality will lead plants to retire or reduce their running hours earlier than suggested by expected retirement ages:
  - **Large Combustion Plant Directive (LCPD).** Around a quarter of UK coal-fired capacity (6 GW) faces restricted running hours between now and the end of 2015 under the LCPD,[7] and will have to close when these hours are used up. Many of these hours were used in 2012 (generating 35 TWh in 2012 compared with 4 TWh in 2011), with some plants subsequently shutting down. Only 15 TWh remain for 2013-2015.[8] This implies that most of the increase in generation in 2012 came from these plants (31 out of 35 TWh) and will necessarily fall again from 2012 to 2013 by at least 25 TWh (i.e. a reversal of two-thirds of the total increase in 2012). The favourable conditions for coal brought forward generation that is likely to have occurred at a later date, so the cumulative output and emissions from these plants is likely to be unaffected.

7 The LCPD regulates sulphur oxides, nitrogen oxides and particulate matter emissions. Plants were given a choice to opt in or out. Plants opting out were allocated 20,000 hours to run over the years 2008-2015. Plants opting in must comply with Emissions Limit Values for the three pollutants. This could involve undergoing full biomass conversion.

8 The coal plant at Kingsnorth (2 GW) closed in December 2012 having operated for 48 years, Cockenzie (1.2 GW) closed in March 2013 after 47 years and Didcot A (2 GW) closed March 2013 after 44 years.

- **Industrial Emissions Directive (IED).** The remainder of UK coal plants could also face restrictions from 2015 and be forced to close by the end of 2023 under the IED.[9] To comply with the IED, plants have to fit expensive NO_X abatement equipment to keep running at 2012 levels beyond 2015. Incentives to fit equipment could be limited given that many plants will be reaching the end of their operational lives and given increasing costs under the rising carbon price floor.

- **Economics of coal plant.** Even though the cost of coal generation has fallen over 2012, the profitability of coal plants is likely to decline in the future. This particularly reflects the UK's carbon price floor, which was introduced in April 2013 at £4.94/tCO_2 on top of the EU ETS price (intended to deliver a minimum price of around £16 per tonne),[10] adding just under 30% to the cost of coal generation. The price floor will rise to deliver an overall target of £32 per tonne in 2020, by which time it will add an additional 30% to the cost of coal generation.

More generally, progress in decarbonising the power sector should not be judged solely on reducing emissions. Emissions will tend to fluctuate with fuel prices, availability of existing nuclear plant and weather conditions for renewables generation. Progress can also be measured through the *achievable emissions intensity*, discussed in the next section, and through adding low-carbon capacity, which we consider in sections 3-5. An assessment from this perspective confirms that there has been underlying progress, despite the increase in emissions in 2012.

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 emission rather than least cost, while still maintaining security of supply to keep the lights on.

In practice this means meeting demand with nuclear and renewables first, followed by gas, and finally coal plant. Reductions in achievable emissions intensity therefore mainly reflect investment in low-carbon generating capacity, and are not affected by short-term fluctuations in fuel and carbon prices (which can determine whether coal generates before gas) or by load factors for nuclear and renewables varying between years (for example due to weather conditions).

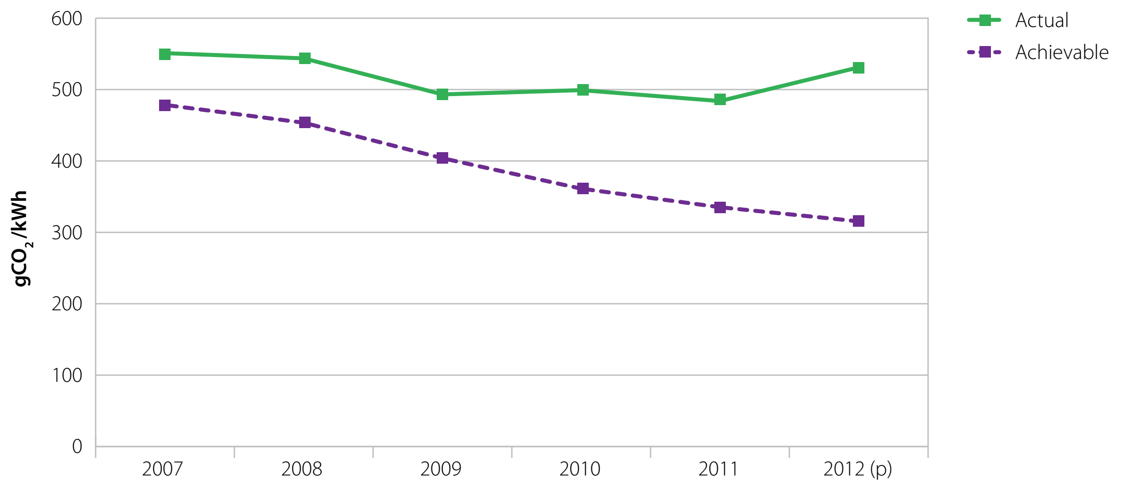
In 2012, achievable emissions intensity continued to improve, falling by 20 gCO_2/kWh (6%) compared to 2011, from 335 gCO_2/kWh to 315 gCO_2/kWh (Figure 2.3).[11] This reduction was due to renewables capacity added to the system in 2012, including 2.4 GW of wind and 0.7 GW of solar.

9 In 2010 the LCPD was combined with six other existing directives to form the IED. LCPD plants which opt in to the IED must agree to stricter emissions limits. Plants which opted in to the LCPD but choose not to opt in to the IED will have their hours capped at 17,500 for 2016-2023. Plants are required to give notice of intent to comply with IED at the end of 2013; the final decision has to be taken by the end of 2014.

10 The carbon price floor 'top up' was set in March 2011, on the expectation of an EU ETS price equivalent to around £11. HMT (2011) *Budget 2011*. However, so far in 2013, the price has turned out lower than expected (averaging under £5 so far in 2013), potentially reducing the actual floor price faced by generators to around £10.

11 Note that we have also recalculated previous year's figures based on revised outturn data for demand and capacity and a revised methodology.

Figure 2.3: Actual and achievable emissions intensity (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.

This indicator shows that there is scope to reduce current emissions intensity by over 200 gCO_2/kWh (41%) within existing capacity through fuel-switching, primarily from coal to gas. This is achievable while maintaining security of supply at minimal cost to the consumer, being available today without any requirement for new investment, and given that the market electricity price continues to be set largely by gas plant. It is likely to be achieved over time as old coal plant retires (as discussed above) and as relative economics change (for example as the carbon price rises).

2. The Committee's power sector indicator framework

The Committee's power sector indicator framework sets out a trajectory towards a largely decarbonised power sector by 2030, aimed at reducing emissions and developing a range of low-carbon options for future sector decarbonisation (Table 2.1).

The indicators set out timelines for key stages of investment, including policy milestones:

- **Renewables.** Our indicators cover capacity on the system and progression through the project cycle (i.e. in and entering construction, in planning, etc), generation, planning approval rates and progress in developing the transmission network (required reinforcements, access to the network, investment in the onshore and offshore grid) – see section 3.
- **Nuclear.** We monitor progress towards building a new generation of plants, including indicators on planning and regulation – see section 4.
- **CCS.** Our indicators for the first three budget periods focus on progress with the UK's programme of demonstration projects – see section 5.

- **Electricity Market Reform.** We have previously proposed that new market arrangements are required to support low-carbon investment and we monitor Government's progress in implementing these – see section 6.

The indicators therefore enable us to track not just the impact of investments on emissions in the latest year, but also the expected impacts in future years. They are designed to provide early warning of problems in the pipeline and to identify areas where action is required.

3. Investment in renewable generation

Progress adding new wind capacity

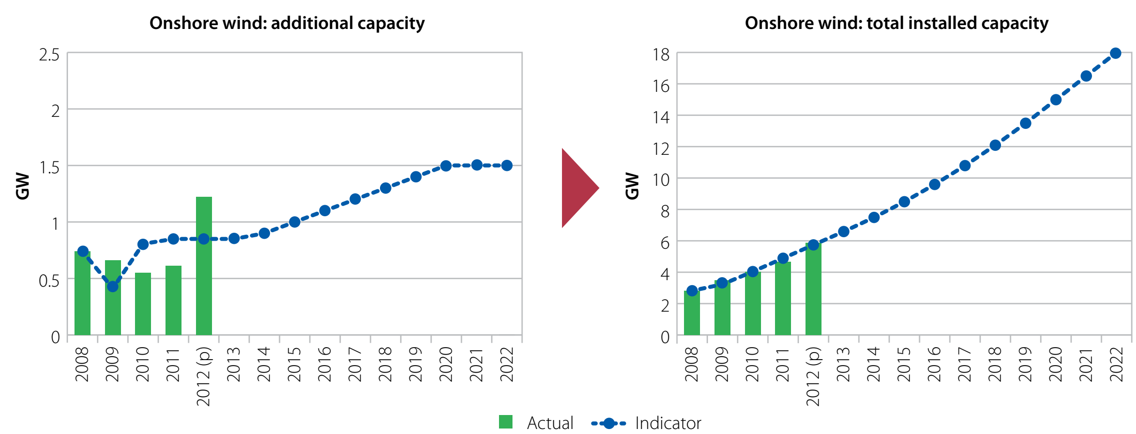
Our approach to monitoring progress in reducing underlying emissions focuses on how much wind capacity has been added to the system, and how much is likely to be added based on forward indicators (i.e. capacity entering construction, capacity moving through the planning system, supply chain investment and investment in transmission infrastructure to support the required increase in wind generation).

The overall picture for wind capacity is one of a significant ramp-up in the level of capacity deployed in 2012, a strong pipeline of potential projects, but questions over whether investment levels will be sustained.

Capacity added to the system

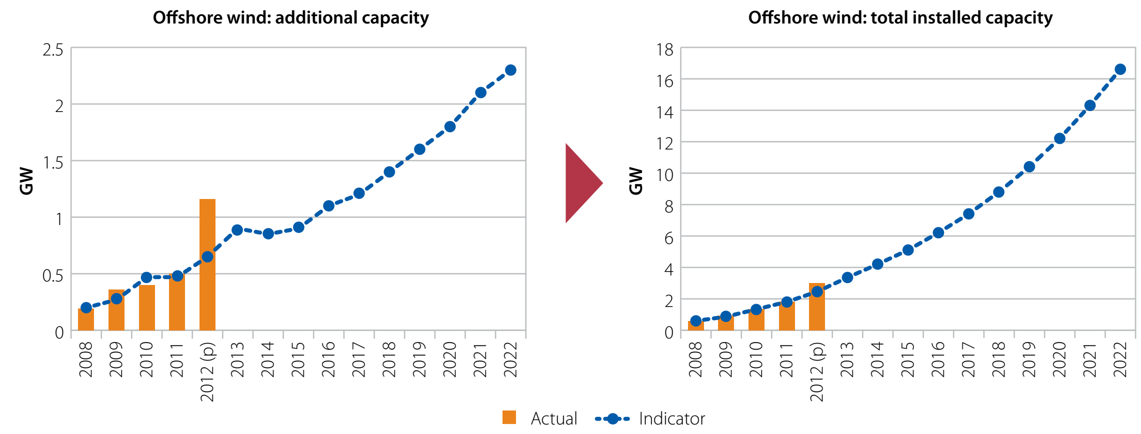
A record level of onshore and offshore capacity was added to the system in 2012 (1.2 GW of each), substantially exceeding our indicator for additional capacity (Figure 2.4 and Figure 2.5). If these deployment levels can be sustained this would be enough to meet our 2020 indicators for both onshore and offshore wind (i.e. 15 GW and 12 GW respectively).

Figure 2.4: Onshore wind: annual additional and cumulative capacity against our indicators (2008-2022)



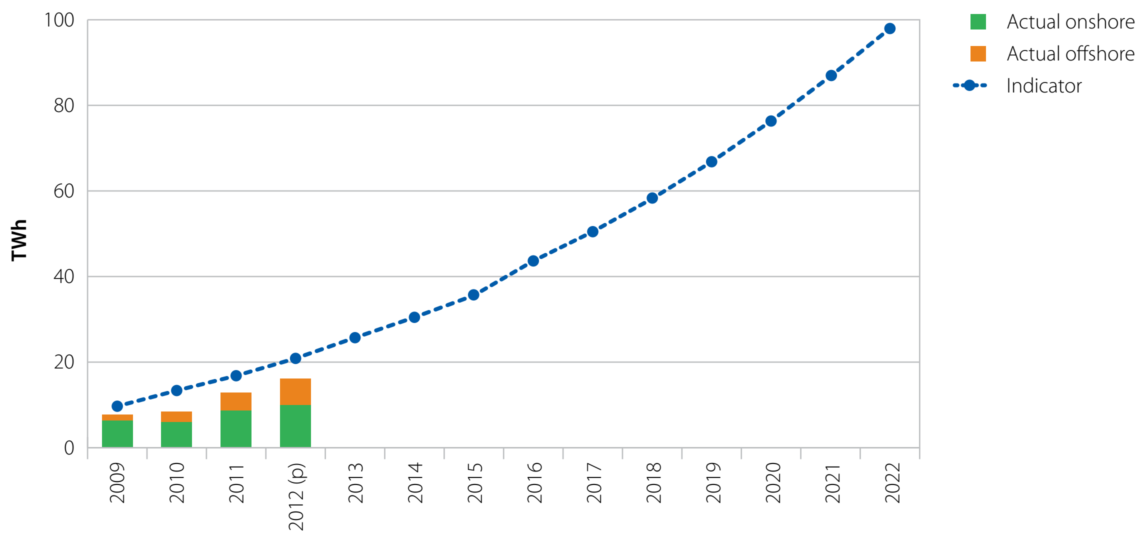
Source: DECC (March 2013) *Energy Trends.*
Notes: 2012 data are provisional.

Figure 2.5: Offshore wind: annual additional and cumulative capacity against our indicators (2008-2022)



Source: DECC (March 2013) *Energy Trends*.
Notes: 2012 data are provisional.

Figure 2.6: Onshore and offshore wind generation against our indicator (2008-2022)



Source: DECC (March 2013) *Energy Trends*.
Notes: 2012 data are provisional.

Wind performance in 2011 was in line with our assumed load factor (26% onshore and 37% offshore) when wind speed was at the long-term average (9 knots).[12] Load factors in 2012 are likely to have fallen (although data are not yet available), reflecting wind speeds that were 8% lower than average. Generation in 2012 is below the level envisaged in our indicators; this is not itself an indication of low load factors, but rather reflects that our indicators are based on an assumption that capacity is all available at the start of the year, whereas in reality it is commissioned throughout the year (Figure 2.6).

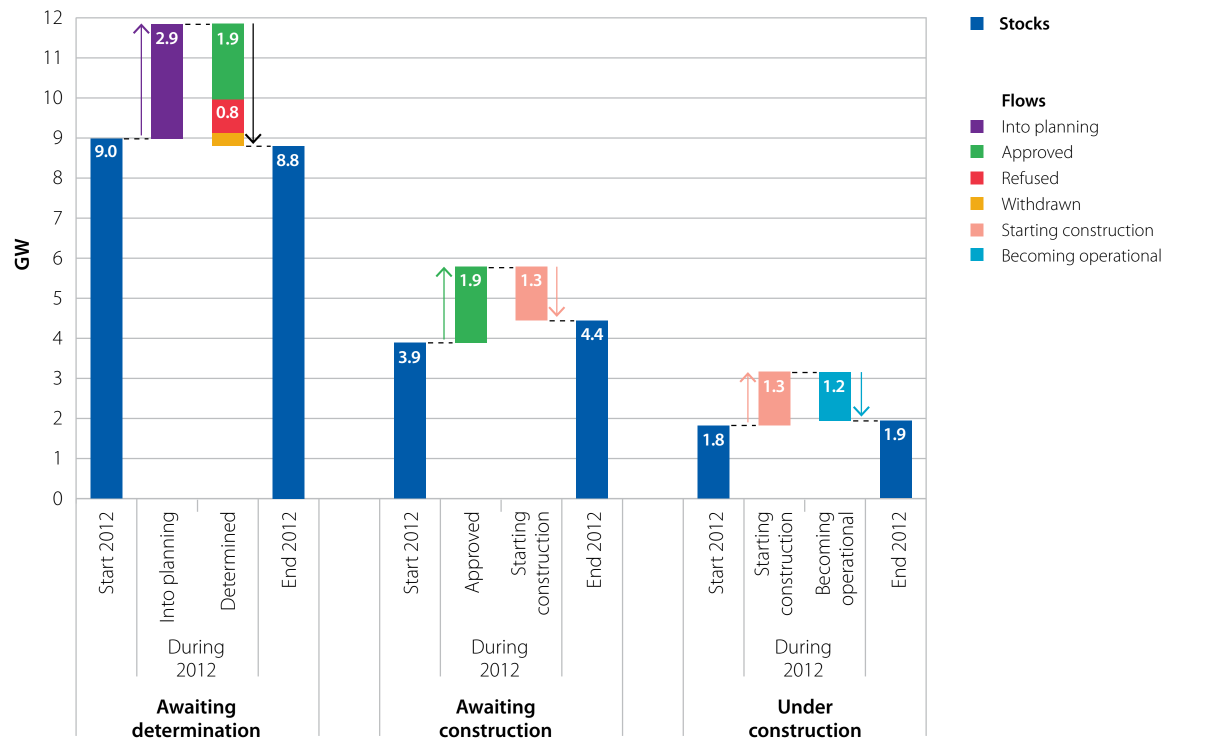
12 2011 is the most recent data available for load factors on an unchanged configuration basis (i.e. only including projects that had been on the system for the whole year). DECC (2012) *Regional load factors on an unchanged configuration basis, 2011*.

Wind project pipeline

There is a large amount of potential capacity in the project pipeline for both onshore and offshore wind, but offshore projects are moving slowly into construction (Figure 2.7 and 2.8).

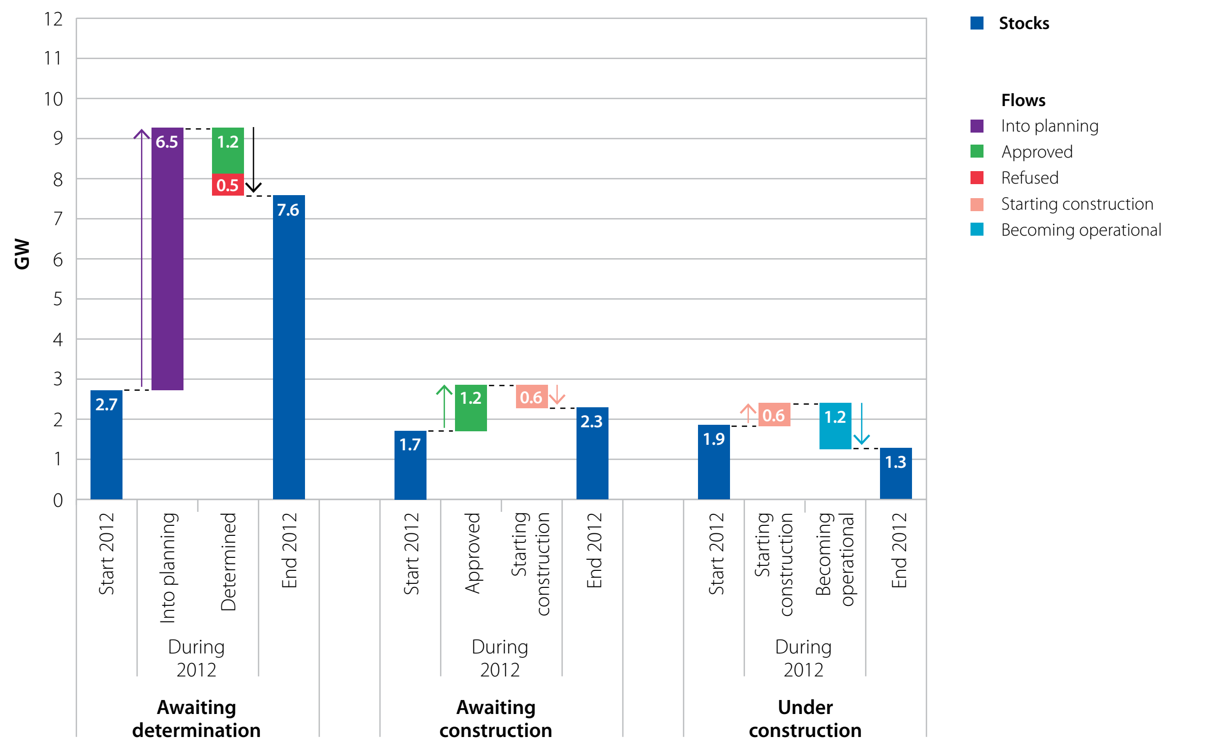
- **Capacity under construction.** At the end of 2012, 1.9 GW of onshore wind and 1.3 GW of offshore wind were under construction. This could potentially sustain the high level of added capacity from 2012 for onshore, given a construction time of 1-2 years, but is unlikely to do so for offshore, where construction periods are 2-3 years. This reflects that in 2012 far less offshore capacity started construction than completed it (0.6 GW compared with 1.2 GW), while a large amount of onshore capacity began construction (1.3 GW).
- **Capacity awaiting construction.** There was a further 4.4 GW onshore wind and 2.3 GW offshore wind with planning approval and awaiting construction at the end of 2012. If these projects move smoothly into construction and operation then, together with those projects already under construction, this would be enough to deliver required capacity additions for the next six years for onshore and four years for offshore. However, particularly for offshore, these projects do not appear to be progressing rapidly to construction. That may reflect the various uncertainties currently facing offshore wind developers (see below).
- **Capacity entering and moving through planning.** There was a substantial number of new wind planning applications in 2012 (particularly offshore) and the number of determinations was in line with our indicator. The average approval rate for onshore projects was strong overall, but fell for small-scale projects, whilst determination periods showed a slight improvement. However for offshore wind, the first large-scale planning refusal was seen and there was an increase in determination times.
  - **Onshore.** There was a continued flow of projects into the planning system, with 2.9 GW of new projects submitted for approval in 2012. Of the capacity awaiting approval, 3.0 GW were determined, with 1.9 GW approved, 0.8 GW refused and 0.3 GW withdrawn, leaving around 9 GW still awaiting approval at the end of 2012. The majority of this capacity is in Scotland (63%). This pipeline of onshore projects awaiting determination along with those already deployed or in the construction pipeline would be sufficient to deliver 2020 capacity in our indicator trajectory (i.e. 15 GW) assuming historic approval rates continue (Figure 2.9).
  - **Offshore.** In 2012, applications submitted for planning approval reached a record 6.5 GW for new offshore capacity with significant applications from the Round 3 and Scottish Territorial Waters leasing rounds. Of the capacity awaiting approval, 1.7 GW were determined. As a result there was a large amount of capacity (7.6 GW) awaiting determination at the end of 2012. Of this, 4.0 GW is in Scottish waters and the remaining 3.6 GW is in English waters. As with onshore wind, the offshore pipeline, if added to that already deployed or in the construction pipeline, would be sufficient to deliver our 2020 indicator (i.e. 12 GW) if approved and constructed (Figure 2.9). However as we note below, significant challenges remain.

Figure 2.7: Capacity moving through planning and construction – onshore wind (2012)



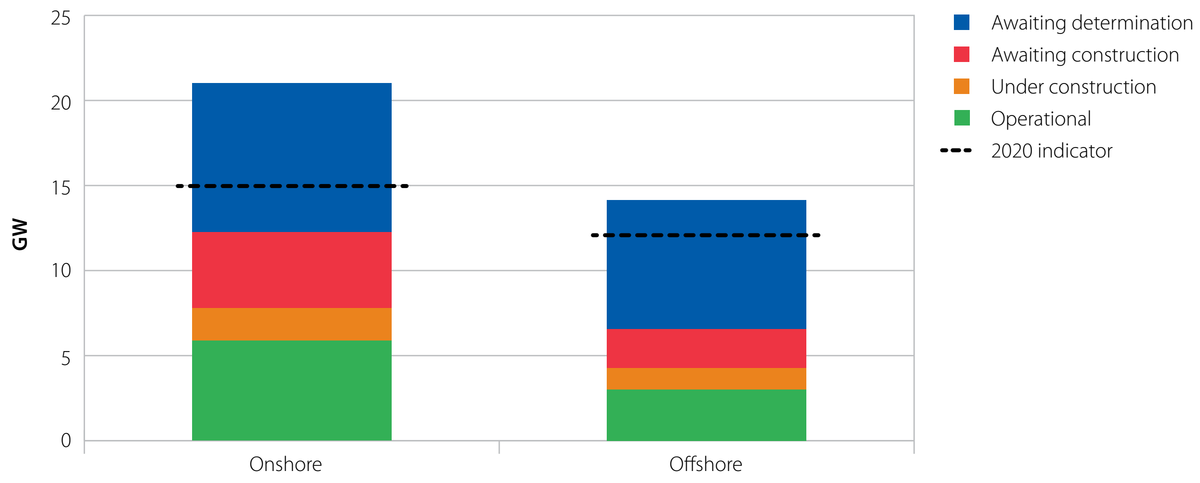
Source: DECC (March 2013) *Renewable Energy Planning Database*.
Notes: Numbers may not sum due to rounding. For the three pre-operational stages (awaiting determination; awaiting construction; and under construction), chart shows capacity at the beginning of 2012; capacity moving through each stage; and capacity at the end of 2012.

Figure 2.8: Capacity moving through planning and construction – offshore wind (2012)



Source: DECC (March 2013) *Renewable Energy Planning Database*.
Notes: Numbers may not sum due to rounding. For the three pre-operational stages (awaiting determination; awaiting construction; and under construction), chart shows capacity at the beginning of 2012; capacity moving through each stage; and capacity at the end of 2012.

Figure 2.9: Stock in planning and construction (end-2012) compared with the CCC's 2020 capacity indicator



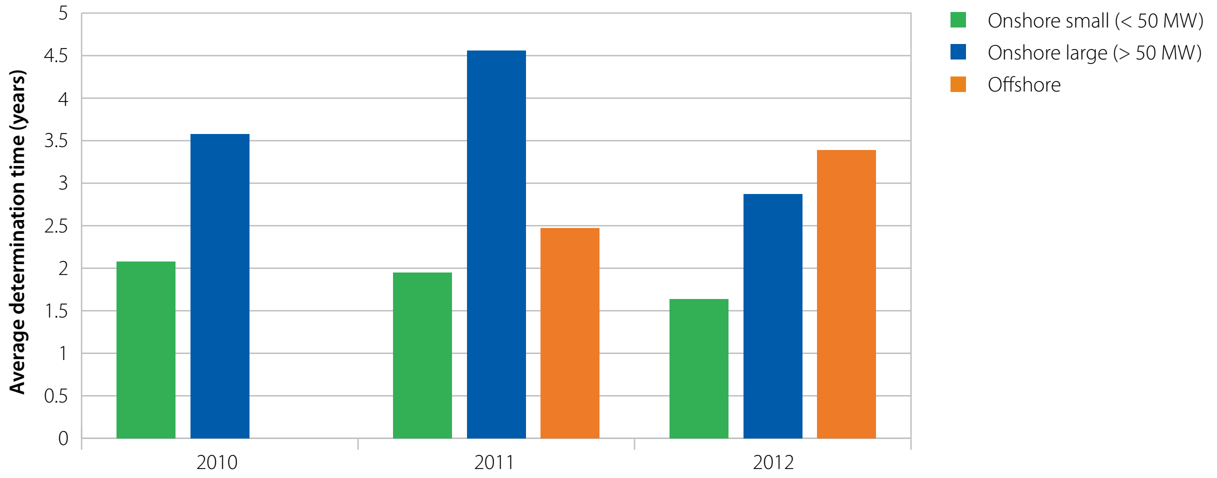
Source: DECC (March 2012) *Renewable Energy Planning Database* and DECC (March 2013) *Energy Trends*.

- **Planning approval rates.** The UK-wide approval rate for onshore projects was 70% in 2012, comparable to recent levels, which have fluctuated between 50% and 80%. This reflects a high approval rate for large projects (i.e. >50 MW) but falling approval rates for small projects, especially in Wales and Scotland (Box 2.3). Decisions regarding offshore wind applications are infrequent and lumpy; one 0.5 GW project was refused in 2012 in England over wildlife concerns. This pushed the overall approval rate down to 70% in 2012 whereas historically 100% of projects have been approved.
- **Determination periods.** This is the time taken from entering planning to approval or refusal, excluding projects that go to appeal. Determination periods fell for onshore wind; however they still remain substantially greater than our indicator of 12 months. For small-scale onshore projects, the average time fell from 19 to 16 months and for larger-scale projects (determined by the Secretary of State) the average time fell from 46 to 29 months. Offshore wind determination periods increased to 41 months in 2012 from 34 months in 2011 (Figure 2.10). Long determination periods reduce the amount of capacity ready to enter construction and could limit competition for contracts under the Electricity Market Reform.

The slow movement of projects into construction could be a result of uncertainties over returns of current and future projects and a tight supply chain resulting from a lack of clarity over direction for the power sector beyond 2020. Although the Government has set funding for 2020 in the levy control framework and made some progress with the design of contracts, there is still a lack of clarity over these contracts and objectives beyond 2020.

- **Support mechanisms and finance constraints.** Uncertainties over project returns may have held back projects from proceeding.

Figure 2.10: Determination time for wind capacity determined in 2012



Source: DECC (March 2013) *Renewable Energy Planning Database.*
Notes: Chart shows average determination time weighted by capacity. Determination time refers to the period between an application being submitted to the relevant planning body and an initial planning decision. It includes projects that later went to appeal, but excludes the time taken during the appeal process.

– **Renewables Obligation (RO).** The RO Banding Review was published in July 2012, setting out support levels for projects commissioning between 2013/2014 and 2016/2017. It is likely that projects were delayed from proceeding into construction until this announcement. Resolution of uncertainty about the RO, however, would only provide a temporary reprieve, given that projects entering construction next year are likely to commission under the Electricity Market Reform (assuming a three-year lead time).

– **Electricity Market Reform (EMR).** After March 2017, projects will be supported under the EMR rather than the RO. Projects may also choose to receive support under the EMR from 2014 onwards. However, the final arrangements for contracts and the levels of support under the EMR are not yet known (see section 6). This could be especially problematic for new projects that might not complete construction in time to be eligible for support under the RO. For offshore projects, further complications may arise for investments where the first phase of a larger project commissions under the RO, but where later phases proceed under the EMR.

– **Electricity price uncertainty.** Revenue under the RO is dependent on the wholesale electricity price at which generators can sell their electricity. Uncertainty over support under the RO is compounded by concerns over the availability of Power Purchase Agreements for independent renewable generators and uncertainty of the electricity price that will ensue under the EMR.

– **Finance.** There may be limited appetite to finance projects, given revenue uncertainties and the further uncertainties over details of support under the EMR, limited balance sheet strength of vertically integrated companies and conditions in capital markets. This would prevent projects moving into construction, given that projects need to secure finance before construction commences.

– **Onshore transmission charging.** After a lengthy review process, the preferred option for charging arrangements for onshore generators was published by Ofgem in May 2012 ('Project TransmiT'). This may have affected projects considering moving into construction early in 2012. Onshore wind developers now have some clarity over transmission charging (up to around 10% of costs for onshore wind), although the detailed methodology for calculating transmission charges is currently being developed by industry.

- **Supply chain.** Offshore installation vessels do not appear to be causing problems, with six delivered in 2012 and two already entering into service so far this year (enough to install several GWs per year). However, there could be issues with other parts of the supply chain – although we have noted significant developer interest in constructing UK manufacturing facilities in our previous progress reports, these have not progressed into construction and operation. Given the limited pre-existing supply chain for offshore wind, the importance of the UK market in the wider European market, the need for specialist parts (e.g. high voltage undersea cables) and the benefits of local sourcing given high transport costs, this could be preventing developers contracting required parts. Supply firms have indicated that the current lack of visibility for the UK market beyond 2020 is preventing them from investing in the UK supply chain.[13]

- **Radar.** Last year we acknowledged that radar interference posed a significant barrier for capacity seeking planning approval. The Government is making good progress with respect to radar in some areas, for example £2 million has been committed for a technology demonstration intended to release a large amount of offshore capacity facing refusal due to radar interference with air traffic control. Further research and development is being carried out looking for solutions for other radar interferences. Despite these steps, radar still presents an important potential barrier for both onshore and offshore wind projects.

The risk is that projects currently developed do not proceed to construction, that new projects are not developed, and that supply chain investments are not made. These risks should be mitigated through urgent resolution of the various uncertainties associated with the Electricity Market Reform (see section 6).

13 See for example, letter to The Times (October 2012) *'Go green or we quit'*.

Box 2.2: Onshore wind: trend in approval rate by UK country

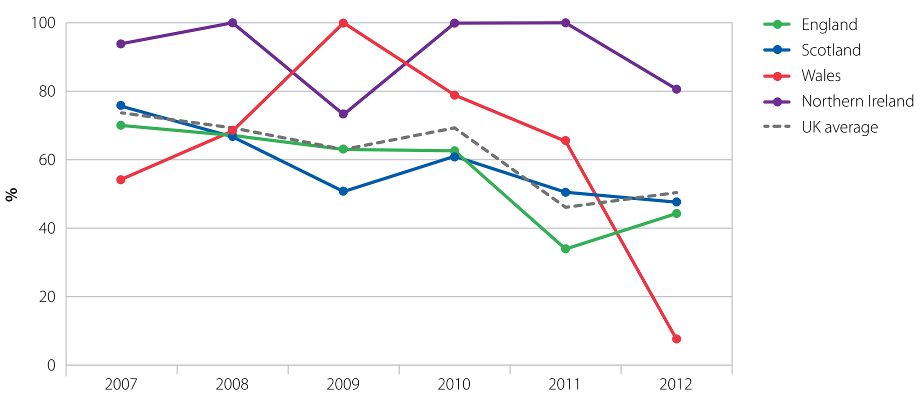
Just under half of the 8.8 GW of onshore capacity awaiting planning approval at the end of 2012 is considered 'large scale' (larger than 50 MW), with the remainder being 'small scale' (less than 50 MW). In 2012, approval rates were high for large projects, and relatively low for small projects.

- **Large projects.** Large onshore wind projects are determined at the national level by the Secretary of State, with advice from the Ministerial Infrastructure Planning Unit (MIPU). There are relatively few large-scale projects and determinations; therefore approval rates can vary markedly. In 2012, 100% of large-scale projects determined in England and Wales were approved (based on two projects), 92% of capacity of the six large Scottish projects were approved, and there were no large-scale determinations in Northern Ireland.[14]
- **Small projects.** Small onshore wind projects are determined at the local authority level. The UK-wide approval rate for these small projects has fallen from 69% in 2010 to 50% in 2012, with only England seeing an increase in the approval rate from 2011 to 2012 (Figure B.2.2).
  - **England.** 1.2 GW (25%) of UK small-scale capacity awaiting approval at the end of 2012 are projects in England. There has been a downward trend in the approval rate since 2007, with a substantial drop in 2011 only partly offset in 2012 (just 34% of capacity of projects determined received approval in 2011 and 44% in 2012, compared with 63% in 2010).
  - **Scotland.** 2.2 GW (48%) of small-scale capacity awaiting determination at the end of 2012 is in Scotland. The approval rates for Scotland fell slightly in 2012, from 51% in 2011 to 48% in 2012.
  - **Wales.** 0.6 GW (13%) of small-scale capacity awaiting determination is in Wales. The approval rate fell from 65% in 2011 to 8% in 2012. In 2012, Wales had the lowest approval rate for small-scale projects out of the devolved administrations and England.
  - **Northern Ireland.** 0.7 GW (14%) of capacity awaiting determination is in Northern Ireland. In contrast to the other devolved administrations, Northern Ireland has had relatively high approval rates for the period since 2007, with 100% of small scale projects approved in 2008, 2010 and 2011, although this fell to 81% in 2012.

The approval rate remains higher in Scotland than England where the Scottish Government has created a more explicit guidance for developers. The fall in small-scale approval rates throughout the UK could be due to a number of factors. It could be indicative of more appropriate sites being used up, local opposition, an increase in the number of applications (the *number* of onshore applications doubled in 2012 compared to 2011 although remained broadly unchanged in *capacity* terms), and/or reductions in planning board capacity at the local level.

The National Planning Policy Framework was published in March 2012, aimed at making the planning system less complex for England. This was followed in June this year by new guidance on local community engagement and benefit funds which increases the recommended community benefit package (from £1,000 to £5,000 per MW per year). There will also be an update to planning guidance in July 2013, which could affect future approval rates and development choices.

Figure B2.2: Approval rate for small-scale wind capacity by UK country



Source: CCC calculations using DECC (March 2013) *Renewable Energy Planning Database.*
Notes: Chart shows average approval rate weighted by capacity for projects determined in that year. Excludes projects that were withdrawn before determination.

Progress with other renewables

Biomass generation

Our indicator trajectory includes around 4 GW of solid biomass power generation, largely from converted coal plant, by 2020, in line with the Government's 2010 National Renewable Energy Action Plan, and within the Government's range in the 2011 Renewable Energy Roadmap.

In 2012, only 30 MW (0.03 GW) of solid biomass was added to the system compared with 830 MW (0.83 GW) in 2011 (largely due to the conversion of Tilbury coal power station). However, a further 0.5 GW has converted so far in 2013 (Ironbridge) and another 5.5 GW is publicly investigating converting.

While there has been progress adding biomass capacity it is important to put in place safeguards to ensure that the use of biomass results in genuine reductions in emissions. We therefore repeat our recommendation that the threshold for the use of biomass under the RO should be tightened to 200 gCO_2/kWh from the current threshold of 285 gCO_2/kWh, and should be progressively tightened over time. In achieving this, it is important that forest biomass comes from sustainably managed forests, meaning that carbon stocks should be maintained and possibly increased over time.

We will continue to monitor the addition of all types of biomass capacity and the development of sustainability criteria as part of our annual progress reporting.

Solar

Last year we highlighted a large increase in installed solar capacity driven by declining solar costs and over-generous support under the Feed-in Tariff (FiT) where 0.9 GW was added in 2011 compared with 0.1 GW in 2010. However, tariffs were cut by 40-70% for large-scale solar (over 50 kW) in August 2011 and further cuts for all new solar installations were introduced in April 2012 with ongoing reviews scheduled thereafter. Tariffs are now at a level that provides support similar to the subsidy for offshore wind under the RO.

Solar installations continued at a high level in 2012 (0.7 GW installed) although this was slightly down on 2011. Of this, over half (0.4 GW) came on line since the further tariff cuts came into force in April 2012, suggesting that solar generation is still profitable at these lower tariffs. This level of deployment is capable of generating around 0.6 TWh, equivalent to the output of around 0.25 GW of onshore wind, or 0.2 GW of offshore wind.

Last year we identified a risk that higher than intended deployment of solar could divert resources from more cost-effective low-carbon technologies under the levy control framework. This is less of a risk as tariffs fall, and if costs continue to decline there could be a greater role for solar PV than envisaged in our scenarios.

14 Approval rates refer to capacity-weighted average approval rates (as opposed to a simple average based on the number of projects).

Marine generation

Wave and tidal stream technologies remain at a very early stage, despite reaching record levels of deployment in 2012. 3 MW was added to the system, taking the total figure for installed capacity to 6 MW (0.006 GW).

The Government has increased support under the RO from 2 to 5 ROCs from April 2012 to March 2017 in line with that in Scotland and Wales, albeit subject to a 0.03 GW size limit.[15] However, so far this appears to be insufficient to bring forward new capacity without additional capital funding.

To date in 2013, two tidal stream projects, MeyGen Ltd in Scotland (0.4 GW) and Sea Generation Wales Ltd (0.01 GW), have won funding under the government's Marine Energy Array Demonstrator scheme (MEAD). MEAD was launched in April last year to support the development and testing of pre-commercial marine devices in array formations out at sea. These projects plan to become operational by 2015 (Sea Generation) and 2020 (MeyGen).

Looking forward, Siemens have opened a large testing and assembly facility for tidal installations in Bristol. Falmouth-based engineers Mojo have secured £3 million from the Technology Strategy Board for research into the HiFlo-4 project.

Transmission investment

Our indicator framework includes development of the UK's transmission network to support increased low-carbon capacity. These are based on the reinforcements identified by the Electricity Networks Strategy Group (ENSG).

In line with our indicator, the Allowed Revenue, the regulatory agreement of investment in new onshore transmission infrastructure, was announced in December 2012.[16] There has also been some progress with both onshore and offshore transmission investment, although in some cases this has been slower than we envisaged.

- **Onshore.** In December 2012, Ofgem provided final regulatory approval for up to £14.5 billion capital expenditure for transmission lines in England and Wales.[17] There has been some progress in the planning approval of new investments; the Western HVDC link (bootstrap, 2 GW) and Beauly-Denny (0.9 GW) lines are now under construction and on track to begin transmitting power respectively by 2016.[18] However, major delays of 2 to 4 years were announced late in 2012 for many projects in Northern Scotland and the reinforcements required in mid and north Wales remain behind schedule.[19] Our indicators envisaged that construction would begin in 2012 (mid-Wales) and this year (north Wales), but there have been continued delays in planning, largely due to local public opposition.

15 For larger projects, support remains at 2 ROCs for additional capacity in excess of 0.03 GW. This is designed to prevent unexpectedly large projects putting pressure on the RO budget, not to incentivise smaller projects.
16 This was under a new regime of price controls (RIIO T1). Ofgem (2012) *RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas*
17 Ofgem (2012) *Final Proposals for National Grid Electricity Transmission and National Grid Gas*. Figures are from accompanying press release, £ 2009/10 prices.
18 The 'bootstraps' are planned to connect onshore generation in Scotland with end-use in England.
19 National Grid (2012) *Summary of the Impact of the SHE Transmission programme changes – 20 December 2012.*

- **Offshore.** There is now 1 GW of capacity fully operational under the 'transitional' OFTO regime, with a further 3 GW in the process of competitive tendering. Although not yet operational, Ofgem expects a number of projects to qualify under the 'enduring' regime, delivering up to 30 GW of additional capacity over the next decade (Box 2.3). Although implementation of the new regulatory regime governing the offshore network has progressed more slowly than envisaged in our indicators, this does not appear to have affected the deployment of offshore wind to date.

Despite progress in transmission investment continuing to be slower than envisaged in our indicators, delivery of infrastructure when required remains feasible.

Box 2.3: Offshore transmission – progress implementing the transitional and enduring regimes

Ofgem estimate that up to £15 billion of investment in offshore transmission will be needed to connect new offshore wind to mainland substations over the next decade.[20] This will be brought forward under a new regulatory regime involving 'OFTOs' (Offshore Transmission Owners), whereby there will be competitive tendering (managed by Ofgem) for the right to build, own and operate offshore transmission networks. National Grid (as System Operator) will provide strategic oversight to ensure these networks are developed in a coherent manner. These will be tendered in two phases:

- **Transitional regime.** In earlier rounds (July 2009 – March 2012), offshore developers built the transmission assets but are then required to sell these assets to an OFTO under a competitive tendering process. To date, around £0.5 billion has been attracted through this round and Ofgem expect a further £2 billion of investment once all transitional projects reach financial close.[21]
- **Enduring regime.** Later projects (from March 2012) have the choice over whether to follow the OFTO model (where OFTOs design and build transmission assets), or whether to undertake construction themselves and transfer responsibility to an OFTO once construction is complete. Tendering for projects under this phase is expected to commence in the second half of 2013, but Ofgem have not published any expectations of when the first projects are likely to be operational.

There has been a slight delay in implementation of the OFTO regime, as our indicators envisaged that the first offshore connections under the enduring regime would become operational in 2012. However, this does not appear to have been a barrier to the deployment of offshore wind to date, as the level of total installed capacity in 2012 slightly exceeded our indicators (Figure 2.5).

4. Deployment of new nuclear

Nuclear generation accounted for one fifth of all generation in the UK in 2012; however 9.3 out of 10.6 GW will retire by the end of the next decade. Nuclear power can play an important role in the decarbonisation of the power sector providing sufficient capacity comes on line throughout the 2020s.

There are currently eight sites in the UK approved for new nuclear plants with a combined capacity potential of around 23 GW. EDF, Horizon and the NuGen consortium are at various stages of development in projects on a number of these sites. Last year we reported that the Horizon venture was up for sale; this has now been bought by Hitachi, continuing the intention to build around 6 GW of new nuclear capacity.

20 Ofgem website (accessed 20 May 2013). http://www.ofgem.gov.uk/
21 Ofgem website (accessed 20 May 2013). http://www.ofgem.gov.uk/

Our indicators track progress against development and deployment of the new nuclear power stations, based on a number of policy and project milestones. Two important milestones were passed in the last year with generic design approval of the Areva reactor design (for use by EDF) and planning permission granted for the Hinkley site, while a third key step of agreeing contract terms for the first plant is underway.

- **Approval of reactor designs.** Progress was delayed following the Fukushima incident and awaiting the outcome of the Weightman report (2011), which concluded that the UK displayed a strong safety culture with adequate existing procedures. The pressurised water reactor designed by Areva, which will be used by EDF and NuGen, received generic design approval by the regulator in December 2012. Horizon's planned boiling water reactor design was submitted for approval in January 2013, with a final decision expected by 2017/18.
- **Planning.** The EDF project at Hinkley Point C was also delayed and gained planning permission in March 2013, two years later than we initially expected.
- **Contracting.** The Government is currently negotiating with EDF over the level and terms of support for a new nuclear plant at Hinkley. Following agreement the project can reach final investment decision and potentially begin construction this year.

In March 2013, the Government published a strategy to support the development of the nuclear industry in the long term. The strategy sets out the key actions and approach needed to provide industry with the confidence to invest in new nuclear in the UK and to ensure the UK's role as a centre of excellence in the international market.[22]

In addition to the progress with new nuclear, EDF announced in December 2012 that it will extend the operating life of two of its existing plants by seven years (equivalent to around 1.7 GW), allowing them to generate until 2023. This will help manage the transition to new nuclear and will mean existing plants continue to play an important role in the UK generation mix.

The priorities now are to finalise the Electricity Market Reform, ensuring that contracts provide revenue certainty for investors and to agree an effective contract for the first new nuclear project. Agreement on the first project is needed in order for future projects to proceed and to unlock the benefits of a major nuclear programme for the UK.

5. Commercialisation of CCS

Carbon capture and storage (CCS) is a crucial set of technological options for reducing emissions in the medium to long term, as it can perform several key roles.

- It is a relatively flexible form of low-carbon electricity generation (when used with fossil fuels).
- It is an essential option to reduce emissions from carbon-intensive industry.
- It can maximise the emissions reduction potential of scarce bioenergy, generating negative emissions.

22 HMG (March 2013) *The UK's Nuclear Future.*

The near-term priority is to move ahead quickly with projects that demonstrate the viability of CCS at scale. DECC launched its CCS Commercialisation Programme in Spring 2012, which has since made progress towards funding two initial projects that could be operational in 2018/19 if they proceed as planned.

Two projects are being taken forward, with the intention to take final investment decisions (FIDs) in early 2015:

- Eight bids for support were received by the July 2012 deadline. In October 2012, DECC announced that four of these projects had been shortlisted: one gas post-combustion, one coal oxy-fuel and two pre-combustion coal projects.
- In March 2013, DECC announced that two of the four projects (the 340 MW gas post-combustion project at Peterhead and the White Rose 304 MW oxy-fuel coal project at Drax) had been selected as preferred bidders to negotiate Front-End Engineering and Design (FEED) contracts, with a view to taking FIDs in early 2015. This would allow them to complete construction and begin operation by 2018/19.
- The two other shortlisted projects, Captain Clean and Teesside (both pre-combustion coal), remain in reserve in case agreement cannot be reached with the preferred bidders.
- It will be important that the Government continues to learn the lessons of the earlier failed CCS Competition, including the need for rapid progress and avoiding traditional procurement processes unsuited to a complex first-of-a-kind project. If the FID date can be brought forward to the second half of 2014, this would be highly desirable.
- Scope for leveraging UK funding with that from the EU should be fully explored, particularly given the failure to access this funding in the context of the first phase of the NER300 (Box 2.4).

Given the slow progress to date, it is now questionable whether four CCS projects can be delivered by 2020, as set out in the Coalition Agreement in 2010. This could still be possible in principle, but would require the Government to proceed more quickly with other projects than currently planned.

- If the new timeline is kept to then the first two projects (either the preferred bidders or the reserve projects) should be operational by 2018/19.
- However, given that no further funding for FEED studies has been announced, it is not clear that further projects could follow soon afterwards, before 2020.
- Given the urgency to develop CCS and the benefits of keeping supply chain interest following the selection of the two preferred bidders, the Government should set out its approach to supporting a further two projects. This should include approaches to funding FEED studies and signing contracts, such that these further projects become operational in the early 2020s at the latest, noting the Coalition Agreement commitment to support four CCS demonstration projects.

– Should the two preferred bidder projects proceed, the two pre-combustion coal reserve projects would be candidates for subsequent support. It will be important to signal the next steps sufficiently early to avoid these potential projects disappearing due to a lack of clarity over future opportunities.

– The Don Valley project (also pre-combustion coal), which was top-ranked within the European NER300 process, was not shortlisted in the UK competition. However, it has previously undertaken a FEED study and has declared an intention to compete for a Contract for Difference, with FID possible in 2015.

Despite progress being slower than planned, the UK remains one of the leading countries in developing and demonstrating CCS given limited progress elsewhere (Box 2.4). Therefore, UK action towards CCS commercialisation is expected to make an important contribution to its development as a crucial option to reduce emissions globally.

Box 2.4: International progress in CCS demonstration

CCS has not been demonstrated on power generation at scale to date anywhere in the world. There remain only two large-scale CCS power generation projects under construction globally, although several smaller non-power projects using high-CO_2 gas streams have also emerged:

- The two power projects under construction are both driven by enhanced oil recovery opportunities in North America, and are both due to enter operation in 2014. The Saskpower project in Canada is a post-combustion retrofit to an existing coal plant, while the Kemper County project is a new-build pre-combustion coal plant.
- There are several other projects in North America outside the power sector, either now operational or due to be later in 2013, based on carbon capture from plants producing ethanol, hydrogen and fertiliser, as well as natural gas processing (all sources of flue gas with high CO_2 concentrations).

Within Europe, the first phase of the 'NER300', the mechanism to disperse funds from the sales of 300 million EU ETS permits from the New Entrant Reserve, awarded €1.2 billion for renewables but did not fund any CCS projects, although it remains possible that it may do so in the second phase.

- The only CCS project for which its national government was able to provide the necessary financial guarantees was at the Florange steelworks in France. However, this project failed to go ahead after the company withdrew.
- A second phase of the NER300 was launched in April 2013. This phase will disperse funds from the sale of the remaining 100 million permits, plus the €288 million funds remaining from the first phase (i.e. those allocated to the Florange CCS project).

The lack of progress on CCS demonstration within Europe was acknowledged in a communication in March 2013 from the European Commission[23], which described the extent of the shortfall in policy and funding to date, as well as the challenges still to be overcome. One of the policy options outlined to accelerate matters was for a Europe-wide 'CCS Obligation', requiring large emitters to deploy a certain quantity of CCS, or to buy certificates from those that have done so. Such a mechanism could raise considerable funds for the deployment of CCS, much of which could occur in the UK, given the UK's high proportion (around 50%) of candidate projects within the NER300 process.

We conclude that the UK remains one of the leading countries in developing CCS and that it will be important to ensure that the UK programme interfaces effectively with international action.

23 Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions on the Future of Carbon Capture and Storage in Europe. Available at http://ec.europa.eu/energy/coal/doc/com_2013_0180_ccs_en.pdf

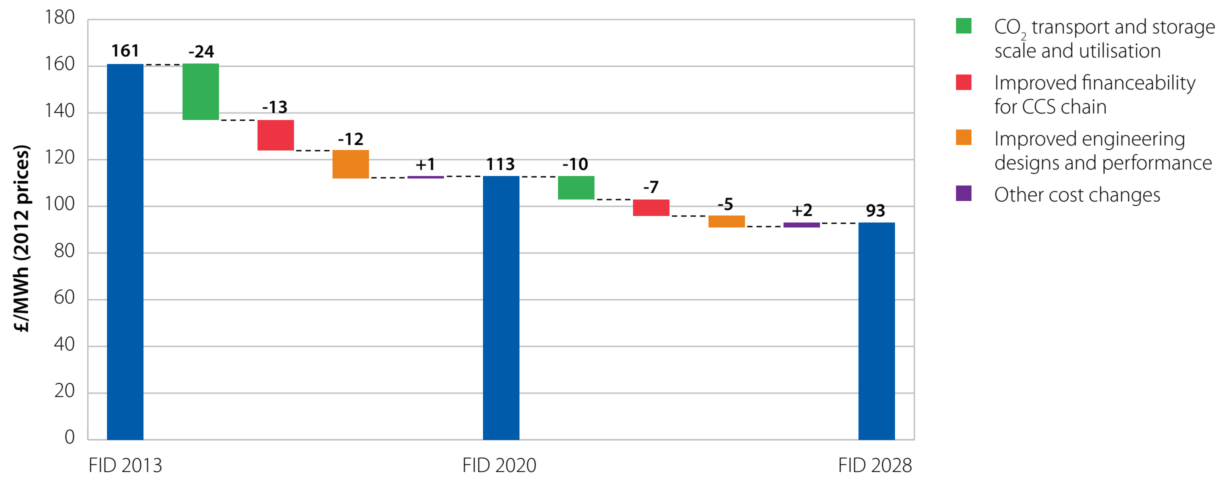
Another important development was the report by the CCS Cost Reduction Task Force, which set out the steps necessary for CCS to become a cost-competitive form of low-carbon generation. This analysis highlighted that only around 25% of the reduction in levelised cost of CCS power generation over the next 15 years will derive from reductions in the cost of component technologies. The remaining 75% would result from reducing the cost of capital by reducing the riskiness of investments and from increasing the scale and utilisation of CO_2 transport and storage infrastructure (Box 2.5).

Box 2.5: Findings of the CCS Cost Reduction Taskforce

The CCS Cost Reduction Taskforce was set up by DECC to advise Government and industry on the potential for reducing costs so that CCS generation projects are financeable and competitive with other low-carbon technologies in the early 2020s. The Taskforce's interim report was published in November 2012, focusing on the quantitative analysis, with the final report following in May 2013.

The report sets out the steps that would take the levelised cost of CCS power generation from around £160/MWh for projects with a final investment decision (FID) in 2013, to below £100/MWh for FID in 2028. These steps can be separated into three broad categories: improvements in the cost/performance of component technologies (around 25% of the cost reduction); increasing the scale/utilisation of CO_2 infrastructure (50%) and reductions in projects' cost of capital (25%) (Figure B2.5).

Figure B2.5: CCS cost reduction trajectory



Source: CCS Cost Reduction Taskforce (2013).
Notes: Chart shows average costs across technologies. Calculations assume DECC's central fossil fuel prices and carbon values (applied to residual CO_2 emissions). FID = Final Investment Decision.

Box 2.5: Findings of the CCS Cost Reduction Taskforce

The report sets out key next steps to support the large-scale development of power and industrial CCS in the UK, including:

- **Ensure optimal UK CCS transport and storage network configuration:** Conduct industry-led but government supported studies to identify options for developing configurations for the UK CCS transport and storage system for both early CCS projects and future CCS projects, in order to minimise long-run costs.
- **Create a vision for development of CCS Projects in the UK from follow-on projects through to widespread adoption:** Create an industry-led and government-supported vision of how subsequent phases of CCS projects in the UK can be developed and financed.
- **Promote characterisation of CO_2 storage locations to create maximum benefit from the UK storage resource:** Examine the options for characterisation of both storage areas and also specific sites for CO_2 storage in the UK Continental Shelf, and recommend a way forward to Government and industry.
- **Create policy and financing regimes for CCS from industrial CO_2:** Create proposed policy and financing regimes for the CCS of industrial CO_2.

The Taskforce's assessment highlighted the need – as we set out in last year's report, and reinforced in our recent report on Electricity Market Reform (see section 6) – for a longer-term Government strategy to commercialise CCS, beyond the initial plants being funded by the Commercialisation Programme.

Having begun moving forward with the first demonstration projects, it is important now that the Government has a clear strategy for moving beyond these to full commercialisation of the technology. Such a strategy should include:

- Scenarios for future investment in CCS, including minimum levels of investment and associated expectations of cost reductions. This would reduce the perceived riskiness (and therefore cost of capital) in this sector while enabling supply-chain investment and appropriate investment strategies (e.g. in CO_2 infrastructure).
- A strategy for the development of CO_2 infrastructure. This would encompass not only DECC's storage strategy, currently under development, but also what to build, how this would be funded and implications for locating new fossil and biomass power plants.
- How bioenergy and industry CCS projects will be brought into future phases of deployment, in a manner consistent with meeting our long-term emissions targets.

With a sense of urgency in taking forward the Commercialisation Programme, together with the development of a longer-term strategy beyond these initial projects, the Government would be well placed to deliver on its stated goal to make CCS competitive with other low-carbon technologies in the 2020s.

6. Progress on Electricity Market Reform

Electricity Market Reform (EMR) introduces long-term contracts for low-carbon generators to support power sector decarbonisation. Our report published in May this year, *Next Steps on Electricity Market Reform – securing the benefits of low-carbon investment,* showed this offers significant economic benefits.[24]

Decarbonisation involves paying a relatively small premium on energy bills in the near to medium-term, which we estimate to be around £100 on the typical annual household bill by 2020. Our estimate is broadly comparable with DECC's recent estimate (Box 2.6).

There has been important progress in EMR during the last year. Specifically the enabling legislation in the draft Energy Bill was introduced to Parliament on 29 November 2012. The Bill completed the Report stage in the House of Commons on 4 June before passing to the House of Lords the following day.

There are a number of outstanding technical issues which should be addressed as a matter of urgency, relating to contract design and the payment mechanism. These must be resolved as the Bill is finalised and in negotiations of specific contracts if investments that are currently being held up are to proceed.

Although the Energy Bill sets the right framework for EMR by introducing long-term contracts, it does not sufficiently resolve uncertainties to allow investments to proceed at lowest cost. That requires clarity in the Delivery Plan and allocation of sufficient funding under the levy control framework:

- **Delivery Plan.** The Government will publish its first draft Delivery Plan for EMR in July for consultation, to be finalised by the end of 2013. In order to support project development, the Delivery Plan should set out the quantity of capacity to be contracted (rather than commissioned) during the delivery plan period of 2014/15 to 2018/19, and the prices that will be offered for onshore and offshore wind generation. These prices, and possibly the quantities, should be subject to periodic review of new evidence based on transparent criteria, with a move to auctioning if practical.
- **Levy control framework.**[25] The level of funding confirmed for 2020 (£7.6 billion) is broadly sufficient to support required investments in renewables, nuclear and CCS, provided that it is calculated on an appropriate basis and that contracts can be signed at prices in line with costs over project lifetimes. These provisions should be clarified, otherwise there is a risk that there will be a funding shortfall of around £1.2 billion under our central assumptions:

24 In that report we set out analysis showing savings £25-45 billion, in present value terms under central case assumptions about gas and carbon prices, rising to over £100 billion with high gas and carbon prices.

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

- **How spending is calculated.** The cost to consumers is best represented by the cost of low-carbon generation calculated against the full cost of gas-fired generation rather than the wholesale price of electricity. This reflects that investments in low-carbon generation with low marginal costs will tend to reduce the wholesale price (the so-called "merit order effect") to the advantage of consumers, as may the introduction of the capacity market. This will also give investors more certainty over what can be funded given uncertainties in predicting the wholesale price. If spending is instead calculated based on the wholesale price, then we estimate a funding shortfall of around £0.7 billion.

- **How contracts are defined.** The final details of the contracts under EMR could require accelerated depreciation of assets. Specifically, required prices could be higher if shortened contract lengths are offered, particularly for offshore wind.[26] It is not clear that these would offer better long-term value for consumers than the alternative of contracts which are commensurate with asset life. Full-length contracts should be seriously considered, but if shorter contracts are preferred, we estimate a further £0.5 billion of funding would be needed in 2020 under the levy control framework, with the expectation that the identified future benefits would more than offset this in later years.

There is also currently a significant risk that supply chain investment, which has long payback periods, and project development, which has long lead times, will not proceed due to uncertainty over the path for the power sector beyond 2020, with potentially serious adverse consequences:

- The Government has not yet set out its intentions for the direction for the power sector beyond 2020. There is therefore a high degree of uncertainty for low-carbon projects commissioning after this date. This uncertainty was compounded by the publication of the Gas Generation Strategy (and later in the CfD Impact Assessment published earlier this year) which included a scenario with almost no low-carbon investment in the 2020s such that carbon intensity remains at 200 gCO_2/kWh throughout the 2020s.[27]

- This uncertainty is problematic as regards supply chain investment required to drive innovation and cost reduction, and project development for investments to come on the system after 2020 (and possibly before). If not addressed it would risk failing to prepare sufficiently for meeting the 2050 target in the Climate Change Act to reduce economy-wide emissions by 80% relative to 1990 levels.

It is therefore essential to address this uncertainty in order that the EMR can be implemented in a way that gives value for money for consumers.

26 Some of the detailed technical issues to be resolved as the Bill is finalised (e.g. relating to change in law protection) could also increase required prices and therefore funding.
27 DECC (2012) *Gas Generation Strategy*; DECC (2013) *Electricity Market Reform – ensuring electricity security of supply and promoting investment in low-carbon generation [update: January 2013].*

In our May 2013 report, we identified a number of actions by which the Government could address the issue of uncertainty over the long-term direction:

- **Carbon-intensity target.** Set a target in legislation during this Parliament to reduce the carbon intensity of power generation to 50g CO_2/kWh by 2030. There should be some flexibility to adjust this in light of new information – for example, if costs fall less quickly than currently envisaged, or if achievable build rates are lower than expected.
- **Commercialisation strategies.** Publish strategies for the further development of offshore wind and commercialisation of carbon capture and storage, setting out the amount of intended investment to 2030 and cost reductions required to sustain this ambition.
- **Funding after 2020.** Extend the levy control framework beyond 2020 to 2030 with flexibility to adjust this in light of new information, for example about gas prices and technology costs. Our analysis suggests it would need to be £1-2 billion higher in 2030 than in 2020, with the range depending on the size of the CCS commercialisation programme in terms of deployment and scope of technologies supported.

The Government has recognised the value of setting a carbon-intensity target by including a provision to do so in the draft Bill. However, it does not intend to do this until 2016, by which time this will be a key priority.[28] For the interim period, the other measures above would help to improve the investment climate, and should be implemented in order to unlock the full economic benefit of the EMR and the move to a low-carbon economy.

28 A target has been set in Scotland at 50 gCO_2/kWh under Scotland's revised Offshore Wind Route Map, and the Scottish Government's draft second report on proposals and polices (RPP2).

Box 2.6: Impact of support for low-carbon generation on household energy bills – CCC and DECC analysis

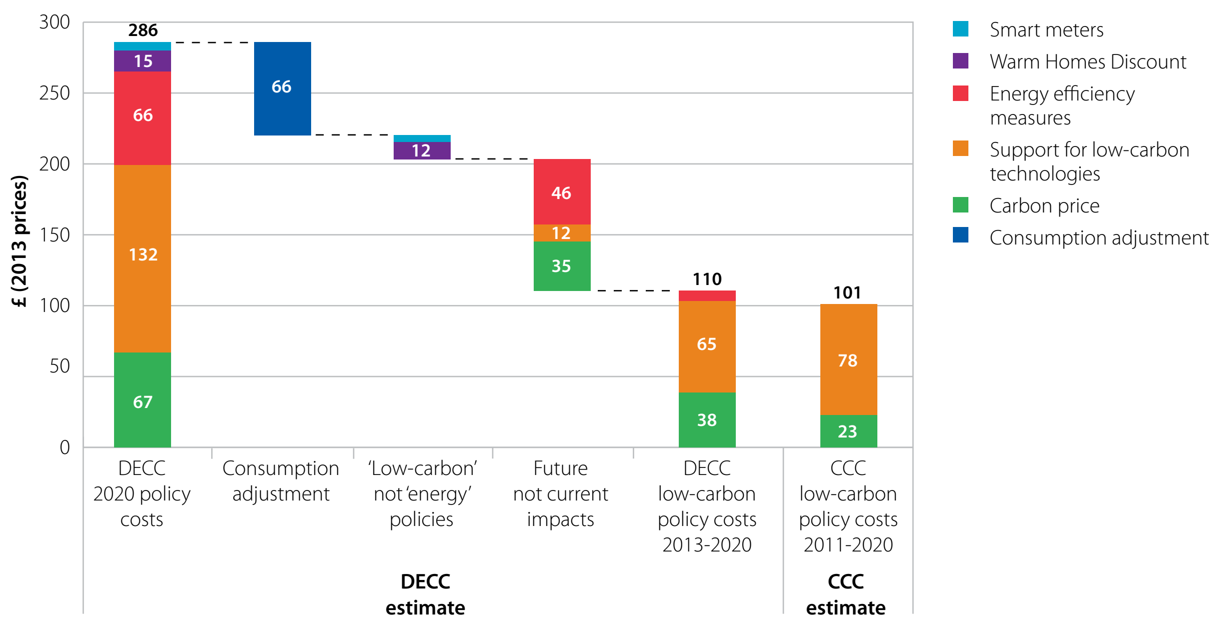
In our December 2012 report *Energy Prices and Bills – Impacts of meeting carbon budgets* we concluded that the impact of support for low-carbon generation would add around £100 to the typical annual household energy bill in 2020.

In March 2013, DECC published their assessment of the impact of energy policy on prices and bills, and also found that household bills will be higher in 2020 due to policy. To compare our analysis with DECC's, some adjustments are required (Figure B2.7):

- **Consumption adjustment.**
  - **Average versus 'dual-fuel' bill.** DECC considers the impact on the 'average' energy bill, based on electricity consumption including electrically-heated households. We focus on the dual-fuel bill (around 85% of households) and assess the impact on electrically heated households separately. As electrically heated households have very high annual electricity consumption (i.e. around 12,000 kWh compared to 4,000 kWh for a dual fuel household) our level of consumption (and therefore bill) for a household is lower than DECC's.
  - **Consumption baseline.** DECC also calculate costs against a hypothetical consumption baseline which reflects a world 'if there had been no past energy efficiency'. In contrast, we compare consumption against what it was in 2011.
- **Policy.** DECC include a wider set of policies that do not directly support the reduction of CO_2 emissions, such as the Warm Homes Discount (which provides a rebate for the fuel poor), and smart meters (which help customers monitor their energy use and bring down their bill).
- **Current versus future impacts.** DECC include the 'current' impact of policies in their headline figure, while our figure is an estimate the future cost and so does not include this.

After adjusting for these factors, we estimate that the comparable figure in DECC's analysis is an increase of around £110 (Figure B2.6). Furthermore, both we and DECC conclude that there is scope to more than offset the impact of higher prices due to support for low-carbon technologies with further energy efficiency measures.

Figure B2.7: DECC and CCC estimates of the cost of climate change policies on the household energy bill



Source: DECC (2013) *Policy impacts on prices and bills*; CCC (2012) *Energy prices and bills – impacts of meeting carbon budgets*; CCC calculations.
Notes: The first adjustment compares DECC's consumption on a consistent basis to CCC – i.e. reflects consumption based on a 'typical' dual-fuel household bill (using gas for heating and electricity for lights and appliances) rather than an 'average bill' (including electrically heated). It also reflects using today's consumption as a baseline rather than DECC's hypothetical consumption baseline of no past energy efficiency. The second adjustment reflects the impact of only assessing low-carbon policies rather than all energy policies e.g. removing Warm Homes Discount which assists low-income households. Finally we remove the costs of these policies to date; and only present the future impacts on the bill out to 2020.

Source: DECC (2013) *Policy impacts on prices and bills*; CCC (2012) *Energy prices and bills – impacts of meeting carbon budgets*; CCC calculations.

Key findings

- Power sector **emissions increased by 8%** to 156 $MtCO_2$ in 2012, driven by an increase in carbon intensity of electricity, as demand stayed constant.

- **Carbon intensity increased** by 10% to 531 gCO_2/kWh, reflecting the increase in highly carbon-intensive **coal generation** at the expense of gas. We expect this to be **temporary**, as EU legislation, end-of-life retirements and the carbon price floor, force coal off the system.

- **Achievable emissions intensity**, which measures underlying progress, **improved by 6%** to 315 gCO_2/kWh as more renewables were added to the system.

- A **record level of wind** capacity was added to the system in 2012 (2.4 GW), which if continued would be sufficient to reach our 2020 indicator. This is challenging given an apparent **bottleneck** for offshore wind projects moving into construction.

- Some key **milestones** were achieved for **nuclear**. The first site gained **planning approval** and **Generic Design Assessment** (GDA) approval and a further design was submitted for GDA. Agreeing the contract for the first project would open up the option of a larger nuclear programme.

- The second **CCS commercialisation programme** has selected two projects to enter Front-End Engineering Design studies. It is vital now to maintain **momentum**, with the Government setting out the approach for further demonstration projects and a longer-term **commercialisation strategy**.

- The **Energy Bill** introducing **long-term contracts** for low-carbon capacity is progressing through Parliament. Details of EMR are still to be **finalised** which are crucial to bringing forward **investment** in low-carbon power generation.

- The **Delivery Plan** should set out **capacity** to be contracted over 2014/15-18/19 and **prices** to be paid for wind. Funding under the levy control framework (LCF) should be clarified and adjusted if necessary. **Longer-term clarity** should be provided beyond 2020 through a 2030 target for carbon intensity, **commercialisation strategies** for less mature technologies, and **extending funding** under the LCF to 2030.

Table 2.1: The Committee's Power sector indicators

POWER		Budget 1	Budget 2	Budget 3	2012 trajectory	2012 outturn
Headline indicators						
Emissions intensity (g/kWh)		509	390	236	509	531
Total emissions (% change from 2007)		-15%	-39%	-64%	-15%	-12%
Generation (TWh/year)	Wind	21	50	98	20.9	19.4
	Nuclear	58	30	48	58.2	70.4
	CCS	0	5	11	0	0
Supporting indicators						
Transmission						
Agreement on incentives for anticipatory investment for Stage 1 reinforcements		2010			In place	Scottish TO's business plans agreed, National Grid (NGET) revenue controls finalised Dec 2012
Implementation of enduring regime for accessing grid		2010			In place	In place
Transitional OFTO regime in place		2009			In place	In place
Enduring OFTO regime in place		2010			In place	In place, but yet to be implemented
Grid reinforcement planning approval		2011: Scotland Stage 1, Wales Stage 1 (Central), South East	2013: Wales Stage 1 (North), English East Coast Stage 1, South West 2014: Scotland Stage 2		Major delays of 2-4 years for many SHE projects, Wales Stage 1 (Central) a serious concern	
Grid reinforcement construction begins		2012: Scotland Stage 1, Wales Stage 1 (Central), South East	2014: Wales Stage 1 (North), English East Coast Stage 1, South West 2015: Scotland Stage 2		Scotland Stage 1 in construction, but delays in planning for Wales Stage 1 (Central) and London	

Table 2.1: The Committee's Power sector indicators

POWER		Budget 1	Budget 2	Budget 3	2012 trajectory	2012 outturn
Grid reinforcements operational			2015: Scotland Stage 1, Wales Stage 1 (Central), South East 2017: Wales Stage 1 (North), English East Coast Stage 1, South West	2018: Scotland Stage 2	n/a in 2012	
Tendering for first offshore connections under enduring OFTO regime		2010	2017: Wales Stage 1 (North), English East Coast Stage 1,		In place	Continuing to tender under transitional regime. Enduring regime tenders now expected later in 2013.
Construction of first offshore connections under enduring OFTO regime begins		2011	South West	2018: Scotland Stage 2	Still under transitional regime	
First offshore connections under enduring OFTO regime operational		2012			Delayed	
Planning						
IPC set up and ready to receive applications		2010				Replaced by MIPU in April 2012
Market						
Review of current market arrangements and interventions that will help deliver low-cost, low-carbon generation investment		To begin in first budget period				Energy Bill introduced long-term contracts, technical details need to be resolved and clarity needed for investors after 2020
Wind						
Generation (TWh/year)	Onshore	13	26	44	12.9	11.9
	Offshore	8	24	54	8.0	7.5
Total capacity (GW)	Onshore	5.7	10.8	18.0	5.7	5.9
	Offshore	2.5	7.4	16.6	2.5	3.0

Table 2.1: The Committee's Power sector indicators

POWER		Budget 1	Budget 2	Budget 3	2012 trajectory	2012 outturn
Wind (continued)						
Capacity entering construction (GW)	Onshore	0.9	1.3	1.5	0.9	1.3
	Offshore	0.9	1.6	2.6	0.9	0.6
Capacity entering planning	Onshore	New planning applications will be required from the end of the second budget period at the latest to maintain flow into construction			No trajectory	2.9
	Offshore	New planning applications will be expected in line with site leasing			No trajectory	6.5
Average planning period (months)		<12	<12	<12	<12	33
Nuclear						
Regulatory Justification process		2010			In place	In place
Generic Design Assessment		2011			In place	Final approval December 2012
National Policy Statement for nuclear (including Strategic Siting Assessment)		2010			In place	Approved July 2011
Regulations for a Funded Decommissioning Programme in place		2010			In place	In place
Entering planning		First planning application in 2010	Subsequent applications at 18 month intervals		In place	In place
Planning approval; site development and preliminary works begin		First approval and site development and preliminary works begin in 2011	Subsequent application approvals, site development and preliminary works at 18 month intervals		In place	Approved March 2013
Construction begins			First plant in 2013, subsequent plants at 18 month intervals		n/a for 2012	
Plant begins operation				First plant in 2018, with subsequent plants at 18 month intervals*	n/a for 2012	

Table 2.1: The Committee's Power sector indicators

POWER	Budget 1	Budget 2	Budget 3	2012 trajectory	2012 outturn
CCS					
Front-End Engineering and Design (FEED) studies for competition contenders initiated	End 2009			Initiated	Initiated early 2010
FEED studies for competition contenders completed	2010			Completed 2010	Completed 2011
Announce competition winner	2010			Announced 2010	Funding not awarded, 2011
Second demonstration competition	Launch 2010, announce winners 2011			Initiated 2010	Initiated 2012
Quantification of saline aquifer CO2 storage potential		No later than 2015		Research initiated/ongoing	
Review of technology and decision on framework for future support		No later than 2016**		n/a for 2012	
Strategic plan for infrastructure development		No later than 2016		n/a for 2012	
Planning and authorisation approval, land acquisition, and storage site testing completed, construction commences	First demo in 2011	Subsequent demos 2012/13		First demo not yet commissioned	
Demonstrations operational		First demo in 2014, subsequent demos 2015/16***		n/a for 2012	
First new full CCS plants supported via the post-demonstration mechanism			2022	n/a for 2012	
Other drivers/wider monitoring					
Total demand (TWh), coal and gas prices, nuclear outages.					
Average wind load factors, availability of offshore installation vessels, access to turbines.					
Nuclear supply chain, availability of skilled staff.					
International progress on CCS demonstration and deployment.					

Notes: Budget numbers indicate the number in the last year of budget period e.g. 2012, 2017, 2022

* Up to 3 nuclear plants by 2022.
** The Energy Act 2010 requires a rolling review of CCS progress, to report on the appropriate regulatory and financial framework by 2018.
*** Total of 4 CCS demonstration plants by 2020.

Key: Headline indicators · Implementation indicators · Forward Indicators · Milestones · Other drivers