Climate Change Committee

The Sixth Carbon Budget

Electricity generation

This document contains a summary of content for the electricity generation sector from the CCC's Sixth Carbon Budget Advice, Methodology and Policy reports.

Introduction

The Committee is advising that the UK set its Sixth Carbon Budget (i.e. the legal limit for UK net emissions of greenhouse gases over the years 2033-37) to require a reduction in UK emissions of 78% by 2035 relative to 1990, a 63% reduction from 2019. This will be a world-leading commitment, placing the UK decisively on the path to Net Zero by 2050 at the latest, with a trajectory that is consistent with the Paris Agreement.

Our advice on the Sixth Carbon Budget, including emissions pathways, details on our analytical approach, and policy recommendations for the electricity generation sector is presented across three CCC reports, an accompanying dataset, and supporting evidence.

- **An Advice report**: *The Sixth Carbon Budget – The UK's path to Net Zero*, setting out our recommendations on the Sixth Carbon Budget (2033-37) and the UK's Nationally Determined Contribution (NDC) under the Paris Agreement. This report also presents the overall emissions pathways for the UK and the Devolved Administrations and for each sector of emissions, as well as analysis of the costs, benefits and wider impacts of our recommended pathway, and considerations relating to climate science and international progress towards the Paris Agreement. Section 4 of Chapter 3 contains an overview of the emissions pathways for the electricity generation sector.
- **A Methodology Report:** *The Sixth Carbon Budget – Methodology Report*, setting out the approach and assumptions used to inform our advice. Chapter 5 of this report contains a detailed overview of how we conducted our analysis for the electricity generation sector.
- **A Policy Report:** *Policies for the Sixth Carbon Budget and Net zero*, setting out the changes to policy that could drive the changes necessary particularly over the 2020s. Chapter 5 of this report contains our policy recommendations for the electricity generation sector.
- **A dataset** for the Sixth Carbon Budget scenarios, which sets out more details and data on the pathways than can be included in this report.
- **Supporting evidence** including our public Call for Evidence, 10 new research projects, three expert advisory groups, and deep dives into the roles of local authorities and businesses.

All outputs are published on our website (www.theccc.org.uk).

For ease, the relevant sections from the three reports for each sector (covering pathways, method and policy advice) are collated into self-standing documents for each sector. A full dataset including key charts is also available alongside this document. This is the self-standing document for the electricity generation sector. It is set out in three sections:

1) The approach to the Sixth Carbon Budget analysis for the electricity generation sector
2) Emissions pathways for the electricity generation sector
3) Policy recommendations for the electricity generation sector

Chapter 1

The approach to the Sixth Carbon Budget analysis for the electricity generation sector

The following sections are taken directly from Chapter 5 of the CCC's Methodology Report for the Sixth Carbon Budget.[1]

Introduction and key messages

This chapter sets out the methodology applied for the electricity generation sector analysis that informs the Committee's advice on the Sixth Carbon Budget.

The scenario results of our costed pathways are set out in the accompanying Advice Report. Policy implications are set out in the accompanying Policy Report. For ease, sections covering pathways, method and policy advice for electricity generation are collated in the Sixth Carbon Budget – Electricity Generation. A full dataset including key charts is also available alongside this document.

The key messages for electricity generation are:

- **Emissions from electricity generation have already fallen by 68% since 1990.** The majority of these emissions reductions happened in the last decade. Emissions fell by 62% between 2008 and 2018, reflecting a move away from coal towards gas and low-carbon generation. The sector was responsible for 15% of UK emissions in 2018.
- **Options for reducing emissions.** Reducing power emissions further will entail increasing the role of renewables and possibly nuclear, and decarbonising dispatchable generation via carbon capture and storage (CCS) and/or hydrogen. In order to accommodate high levels of renewables, demand will also need to become increasingly flexible, which will require improvements in system flexibility from storage, interconnection, and demand-side response.
- **Analytical approach.** The analysis undertaken to develop scenarios for the Sixth Carbon Budget was based on power modelling that explored varying roles for generation technologies given electricity demand from other sectors. Finding least-cost systems that are optimal across hydrogen and electricity supply required complementary off-model analysis that informed the development of our scenarios. We find that it is possible to phase out unabated gas by 2035 and build a power system with 75% to 90% share of variable renewable generation by 2050.
- **Uncertainty.** Our scenarios to 2050 include uncertainties that will need to be resolved. This includes uncertainty over the achievable CO_2 capture rates of CCS; the level of flexibility that smart charging, pre-heating, and storage can provide; the carbon intensity of imported electricity; the ability to ensure security of supply as unabated gas-fired generation is phased out; the future costs of low-carbon technologies; and the implications of a growing electricity system for water use.

We set out our analysis in the following three sections:

1. Current and historical emissions in power
2. Options to reduce emissions and ensure security of supply
3. Approach to analysis for the Sixth Carbon Budget

1. Current and historical emissions in power

Burning of coal and gas are the contributions from electricity generation to the UK's greenhouse gas emissions.

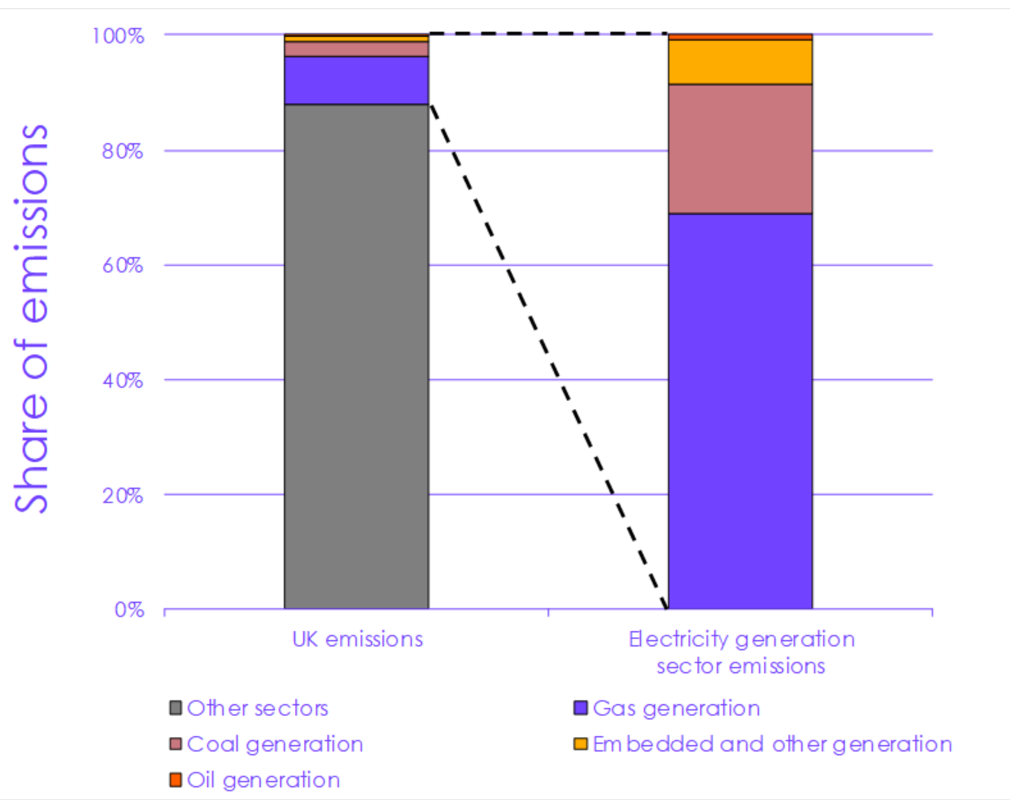
Greenhouse gas (GHG) emissions from the power sector were 65 $MtCO_2$ in 2018, which is 15% of the UK total (Figure M5.1).[1]

These emissions come from the burning of coal and gas for electricity, with a small proportion from oil and other small-scale embedded generation:

- Gas plants contribute to 70% of power emissions. They provide 40% of total electricity generation.
- Coal accounts for 23% of emissions but only 5% of generation.
- The remaining 7% of emissions come from oil and a variety of other small generation sources.

70% of emissions from electricity generation come from burning natural gas.

Figure M5.1 Breakdown of emissions from electricity generation (2019)



Source: BEIS (2019) *UK Greenhouse Gas Emissions 1990-2017*, and BEIS (2019) *Energy trends: Table 5.1*; CCC analysis.
Notes: Estimates of emissions from coal and gas generation are based on generation from major power producers. Embedded and other generation includes municipal solid waste plants.

Emissions from electricity generation have fallen by 70% since 1990, as the UK has switched from coal to gas and low-carbon generation.

Emissions from electricity generation in 2018 were 68% below 1990 levels (Figure M5.2). Most of these emissions reductions occurred between 2012 and 2018, when emissions fell by 58%.

[1] Biomass, municipal waste, and coal power emit nitrous oxide (N2O) and methane (CH4). However, these are less than 1% of power emissions, which is why this chapter will focus on CO_2.

This was driven by reductions in electricity demand and a reduction in carbon intensity of generation as coal was replaced by gas and renewables.

Electricity demand has fallen as lighting and appliances have become more energy-efficient (50% of all installed lightbulbs are now low-energy).

- **Lower electricity demand.** In 2018, electricity demand was around 300 TWh. This represents a decline of 12% compared to 2008 levels, and has led to lower generation and hence lower emissions. There was a reduction in both residential and industrial electricity consumption.
  - Residential electricity consumption fell by 12% between 2008 and 2018, even as the UK population grew by 7%. This is due to improvements in energy efficiency of lighting and appliances.
    - Households have seen efficiency improvements in lighting and appliances (e.g. low-energy lightbulbs now account for half of all installed lightbulbs, compared to around 15% in 2009).[2]
    - These trends should continue, as consumers continue to move towards more-efficient technologies. For example, the use of LEDs can contribute to energy savings as they are seven times more efficient than incandescent bulbs.
  - Industrial electricity consumption fell by 20% between 2008 and 2018, despite an increase in industrial output of 10% (see Chapter 4). This reflects structural changes in manufacturing and construction, away from more carbon-intensive sectors in addition to improvements in energy efficiency, particularly in the manufacturing of iron and steel, chemicals, and car manufacturing.[3]

Coal is the most polluting form of electricity generation. In 1990 coal generated 80% of UK electricity. Now it generates less than 5%.

- **Reduction in carbon intensity.** Carbon intensity of electricity generation decreased by 55% between 2008 and 2018, from 535 gCO_2/kWh to 245 gCO_2/kWh. That reflects a shift away from coal towards gas and renewable generation (Figure M5.3). Nuclear also contributes to low-carbon electricity generation.
  - In 1990, coal generated 80% of UK electricity. Following the 'dash-for-gas', that share dropped to 30% where it remained stable until the early 2010s. The introduction of the carbon price floor in 2013, alongside air quality legislation, initiated the phase-out of coal-fired generation. This has contributed to sustained emissions reductions in the sector of 14 $MtCO_2$ per year on average since 2013.
  - Carbon pricing also favoured the uptake of gas generation, which has provided around 40% of total generation since 2000. While emissions of gas-fired electricity are 60% lower than coal, this source of generation contributes to power emissions.
  - Deployment of variable renewables2 has also displaced coal generation.
    - Variable renewables now account for 22% of electricity generation, up from 3% in 2008.
    - This increase has been driven by Government commitments to support renewable deployment through Contracts for Difference (CfDs), of which 16 GW of capacity has been auctioned since 2015.

[2] Wind and solar generation.

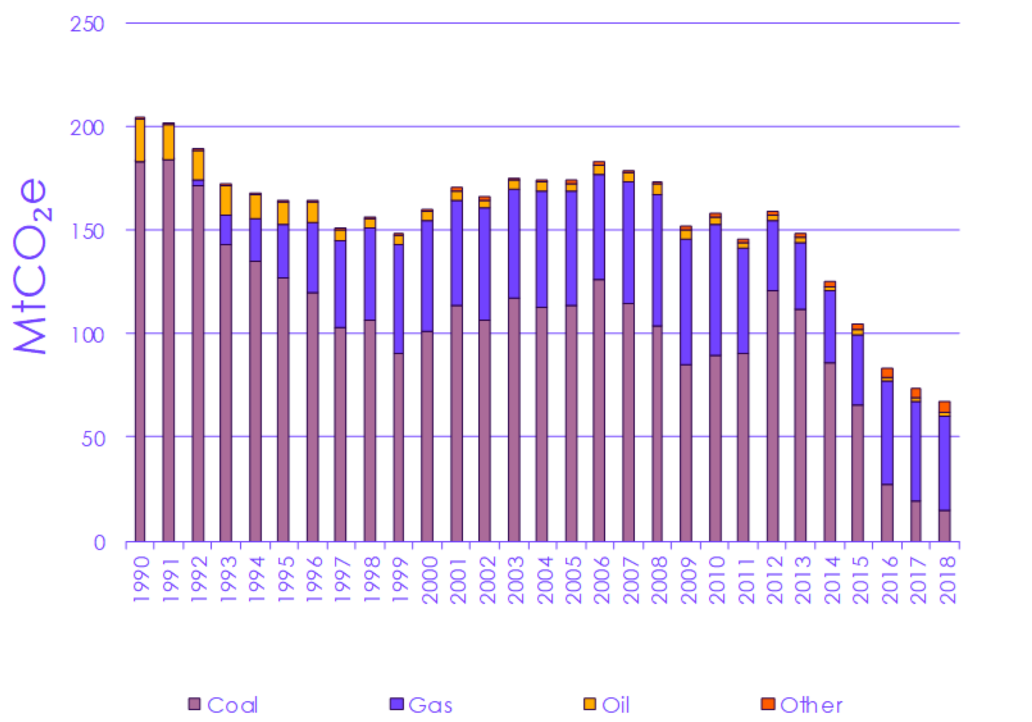
- Since the first contracts where allocated to projects, renewable costs have halved (see Variable Renewables section).

– Nuclear has consistently provided around 20% of UK electricity generation since 2000, with zero emissions.

UK emissions from electricity generation have fallen by 68% since 1990, reflecting a reduction in coal use.

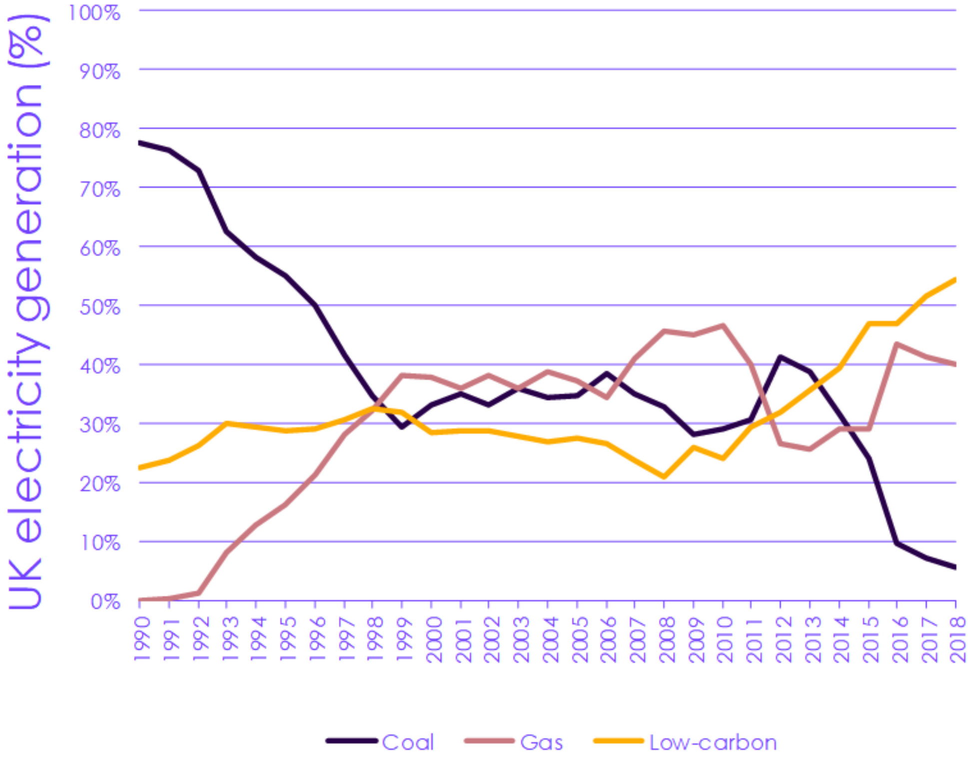
The success of phasing out coal means this now only accounts for less than 5% of electricity generation. The Government has committed to ending the use of coal by 2024. In future, this means efforts to decarbonise electricity generation will need to focus on displacing unabated gas, the remaining source of emissions to which we now turn.

Figure M5.2 Breakdown of emissions from electricity generation (1990-2018)



Source: BEIS (2019) *UK Greenhouse Gas Emissions 1990-2017*, and BEIS (2019) *Energy trends*; CCC analysis.
Notes: 'Other' includes emissions from municipal solid waste.

Figure M5.3 Share of electricity generation by Source (1990-2018)



Source: BEIS (2020) *Energy trends: table 5.1,* and BEIS (2020) *Energy trends: Table 6.1*; CCC analysis.
Notes: 'Other' includes emissions from municipal solid waste.

Continuing to reduce emissions from electricity generation while meeting new demands from the electrification of heat and transport will require a portfolio of generation technologies. That includes variable renewables and other low-carbon options (e.g. nuclear, gas CCS, hydrogen), as well as flexible demand and storage.

We set out the options for reducing emissions in the following five sections:

a) Demand and energy efficiency

b) Variable renewables

c) Firm power

d) Dispatchable generation

e) Flexibility and storage

a) Demand and energy efficiency

The overall strategic approach is to decarbonise electricity and then use low-carbon electricity to power as much of the economy as possible.

Electrification represents a key abatement option to reduce emissions in other sectors.

Given potential limits to the pace of deployment of low-carbon capacity, it will be important to focus on sectors which have the most efficient use of low-carbon electricity (Figure M5.4).

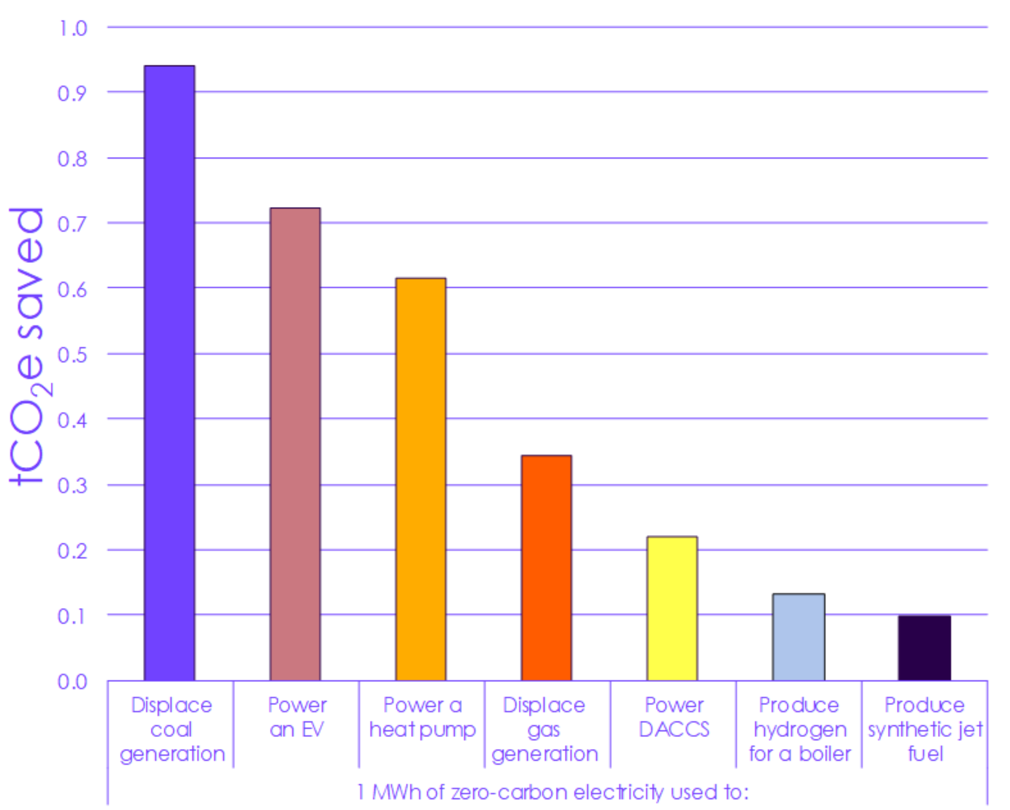
Electrification should be targeted where it has the most impact (e.g. electric vehicles, heat pumps rather than hydrogen production).

Across our scenarios new demands therefore come primarily from the electrification of transport, heat, and industry. Hydrogen production, Direct Air Capture, and synthetic fuels are relatively inefficient uses of electricity and should be lower priority than direct use of electricity for decarbonisation.

The range for demand across our scenarios is 550-680 TWh in 2050, compared to around 300 TWh in 2018. Demand in the Balanced Pathway is 610 TWh.

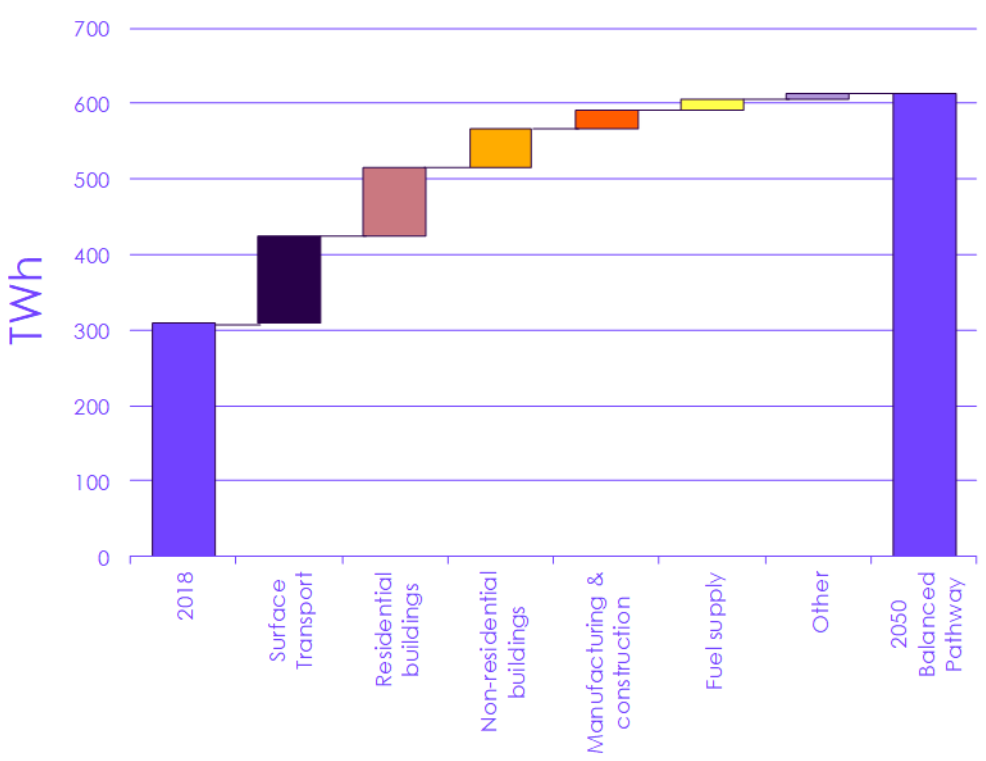
Figure M5.5 shows how each sector contributes to the increase in demand out to 2050. This shows that the majority (85%) of the increase in electricity demand is a result of the electrification of surface transport and buildings.

Figure M5.4 Emissions saved with 1 MWh of zero-carbon electricity across sectors



Source: CCC analysis.

Figure M5.5 Contribution by sectors to increased Electricity demand in the Balanced Pathway (2018-50)



Source: CCC analysis.
Notes: 'Other' category includes agriculture, aviation, direct air capture, shipping and F-gases.

Energy efficiency improvements will limit the increase in demand.

These demand scenarios incorporate efficiency measures that limit the increase in electricity demand:

- **Lighting and appliances.** Energy efficiency in households has already led to lower demand in recent years. Low-energy lightbulbs now account for half of all lightbulbs in use (compared to around 15% in 2009). Lighting and appliances could continue to improve their efficiency and reduce electricity demand. However, the scope for further improvements will decrease over time as the stock becomes increasingly converted to energy-efficient options (Figure M5.6).

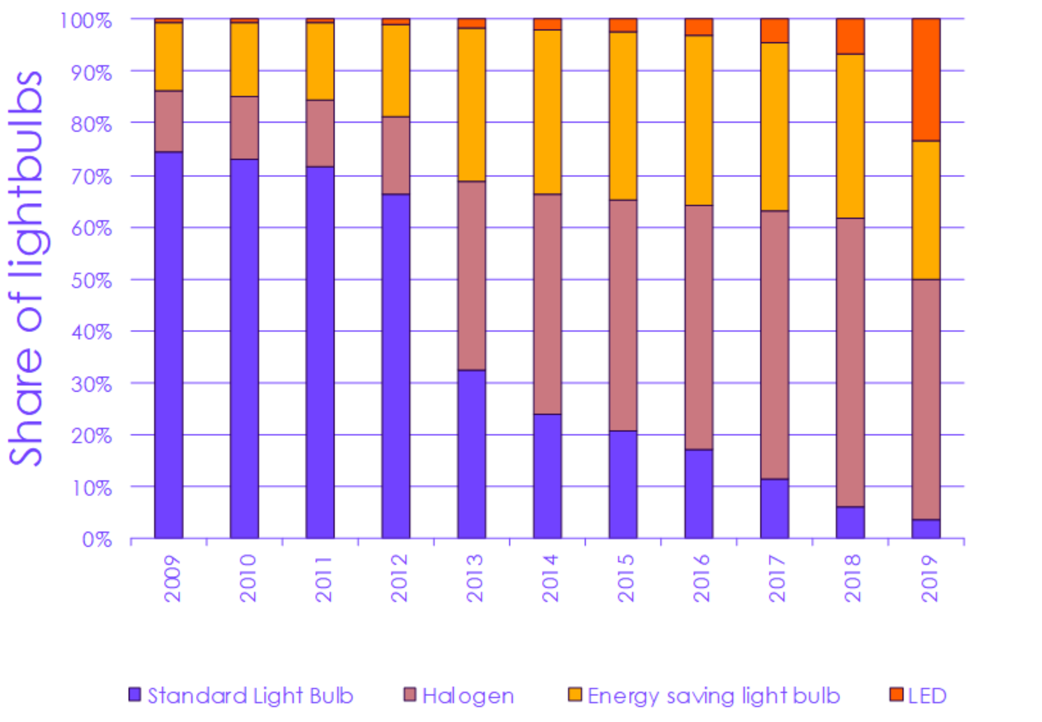
- **Heating.** Although deployment of heat pumps will lead to an increase in electricity demand, their use requires energy-efficient buildings in order to optimise performance. Heat pumps are also much more efficient than boilers, by a factor of three to four. These factors naturally help limit the increase in electricity demand from heating.

- **Manufacturing.** The uptake of energy efficiency (e.g. heat recovery) across a wide range of manufacturing sectors coupled with resource efficiency (e.g. lower demand for manufacturing products) could have a significant effect on electricity demand.

- **Transport.** Structural changes such as a transition away from car use towards public transportation and/or active travel could reduce electricity demand from transport. In addition, electric vehicles are around three times more energy efficient than internal combustion engine vehicles.

Low energy lightbulbs now make up 50% of all installed lightbulbs, compared to around 15% in 2009.

Figure M5.6 Share of energy-efficient light bulbs in UK homes (2009-2019)



Source: BEIS (2020) *Energy Consumption in the UK.*
Notes: Standard light bulb is an incandescent type. Energy saving lightbulb is a CFL type.

b) Variable renewables

The UK has extensive renewables resources which can generate electricity at low cost.

Variable renewables (i.e. wind and solar) have a key role to play in the decarbonisation of electricity generation, as they can provide zero-carbon electricity generation at low cost.

- **The UK benefits from extensive wind and solar resources.**
  - Previous analysis undertaken for the Committee suggests the UK has the potential to deploy capacity to generate 415-1075 TWh (95-245 GW) of offshore wind, 100-335 TWh (29-96 GW) of onshore wind, and 130-540 TWh (145-615 GW) of solar power.[4]
  - In 2018, 65 TWh came from variable renewable generation, which provided 22% of total UK generation. That represents an increase of 6 TWh every year since 2012.

Costs of renewables have fallen significantly over the last decade, and offshore wind is now among the cheapest forms of electricity generation.

- **Variable renewables are a low-cost source of generation.**
  - Costs of renewables have fallen significantly, with offshore wind costs falling from £150/MWh to £45/MWh over the last decade.
  - That compares to £50/MWh for gas generation, meaning renewables are now the cheapest generation technology on a levelised cost basis.

- Variable renewables will need to be accompanied by changes to the electricity system to accommodate intermittency (Section 2.e).
- Our modelling considers both the levelised costs and the wider system changes required to accommodate generation from different sources (Section 3).

There is enough space for offshore wind, but it will need to co-exist with other uses of the sea.

- **Maximising the potential of variable renewables in the UK will have wider implications for the land and seabed (Box M5.1).**
  - Offshore wind deployment must take into account a range of constraints, including seabed availability, wildlife and radar interference.
  - The Crown Estate for England and Wales has already leased seabed rights for 45 GW of offshore wind. Crown Estate Scotland could lease an additional 10 GW.
  - Existing leasing is sufficient to meet the Government target of reaching 40 GW of offshore wind by 2030. This would require around 4,000 turbines of 10 MW, which would cover 5,700 to 8000 km^2 of the seabed. Less than 1% of the seabed should therefore be used by offshore wind to meet the target.
  - In addition, we expect some offshore wind to be floating rather than fixed to the seabed. This means turbines could be deployed in deeper waters where there are likely to be fewer constraints.
  - We are therefore confident that offshore wind, planned strategically, should be deployable at significant levels.
  - With 14 GW, onshore wind currently takes up 2,700 km^2 of land.[3] To deploy 30 GW of onshore wind could need an additional 3,300 km^2 of land.
  - Large-scale solar currently has 13 GW installed capacity in the UK, which requires 290 km^2.[4] Maximising the potential of solar generation might entail using an additional 1,500 km^2.

Box M5.1
Challenges to deploying offshore wind

In less than a decade, the UK has been able to increase offshore wind capacity to 10 GW in 2019. Around a third of that capacity was deployed between 2017 and 2020, doubling build rates to 1.7 GW of offshore wind per year. Another 10 GW has already been contracted and will start generating in the 2020s. In order to achieve the Government target of 40 GW by 2030, an additional 20 GW of capacity will need to be delivered, which are likely to be commissioned from the mid-2020s (Figure MB5.1).

- As a result, deployment rates could increase to about 4 GW/year. Our analysis suggests that the UK would need to maintain this pace of deployment past 2030 to reach 95 GW of offshore wind, as in our Balanced Pathway scenario.
- An additional 2 GW/year might be needed in the 2030s and 2040s to repower the existing fleet at the end of its lifetime. This will create an opportunity to replace existing turbines with better-performing ones, thus limiting the need for new capacity. This

[3] Assuming 5 MW/km^2.

[4] Assuming 45 MW/km^2.

would increase offshore wind capacity at lower costs, as development and transmission costs would not need to be incurred again.

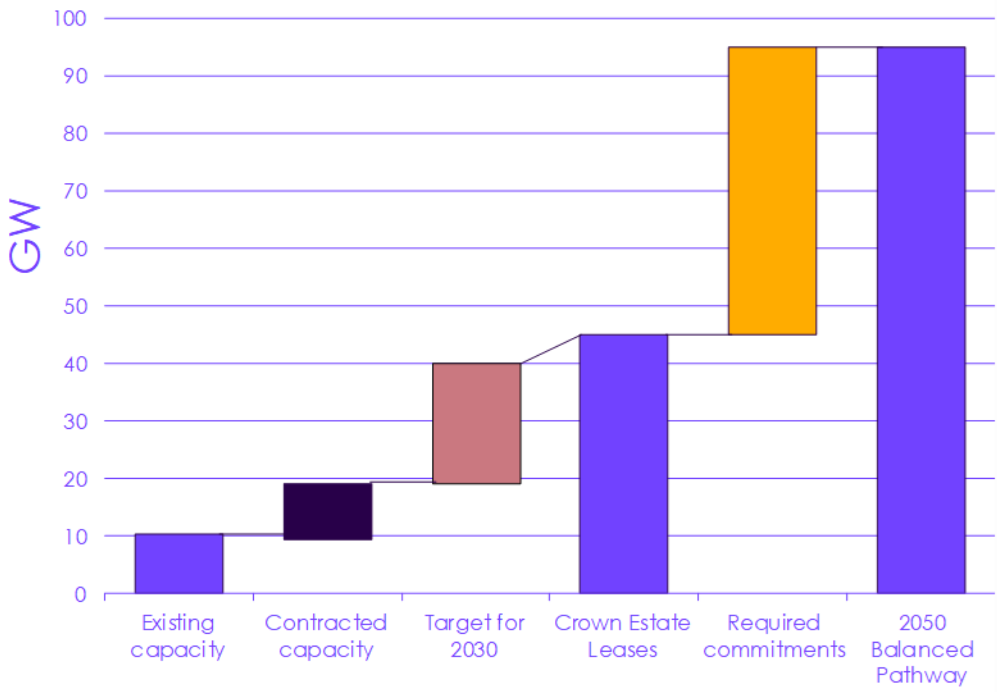
These levels of deployment will bring about different challenges:

- **Supply chains.** Maximising the potential of offshore wind to meet the 2030 Government target already represents a challenge for supply chains, as they will have to increase the pace of deployment. That level of ambition might need to be sustained and possibly increased past 2030 to help meet Net Zero by 2050.
  - Supply chains will require long-term signals over capacity needs to provide a predictable environment to investors and developers. This includes certainty on offshore wind consenting and support mechanisms in order to avoid stop/start of supply chain investment.
  - However, there could also be opportunities for UK supply chains to meet new demand for offshore wind capacity. A recent study suggests that 3,500 jobs could be created across the supply chain in the North East alone, if offshore wind were to be developed further.[5]
- **Leasing.** Crown Estate England and Wales has unlocked a total of 45 GW of offshore wind in the seabed. In addition, the first round of ScotWind leasing could lead to leasing seabed in Scottish waters for an additional 10 GW. This is more than sufficient for the 2030 Government target. Nonetheless, securing new seabed leases requires several years as projects need to do pre-development planning, consenting applications, and construction. Accordingly, the UK will need to hold new leasing rounds to provide clarity to developers.

An expansion of offshore wind beyond the 2030 commitment for 40 GW will be required by 2050 for Net Zero.

- **Networks.** With high renewable deployment, the governance of networks for offshore wind will need to be increasingly coordinated.
  - To date, Offshore Transmission Owners (OFTOs), offshore wind developers and operators have taken responsibility for developing connections between offshore wind farms and the onshore network. This reduced reliance on third parties and the possibility of delays.
  - The result has been a lack of coordination, as offshore wind farms planned connection routes independently. This represents a lost opportunity to optimise the existing network design, but it is also affecting coastal communities.
  - Better governance will ensure we can maximise the potential of offshore wind, minimise total costs and reduce the possibility of delays.
- **Cumulative impacts.** Deploying offshore wind at very high levels could entail putting pressure on areas sensitive to wildlife.
  - Activities in the seabed, including existing offshore wind farms could lead to cumulative environmental impacts on birdlife and marine mammals. In addition to the environmental cost, this could lead to direct costs for developers, as compensation might be required.
  - Nevertheless, these impacts can be avoided with a planning and consenting regime that allocates seabed locations with low risks for wildlife. Wider coordination between the Crown Estates, Government, industry, and conservation bodies could ensure wider monitoring of these impacts beyond that of project operators.
  - In addition, floating wind turbines could be deployed in deeper waters, which is less sensitive to wildlife.

Figure MB5.1 Delivering offshore wind to 2050 in the Balanced Pathway



Source: BEIS (2019) Energy trends: Table 5.1, The Crown Estate (2019) *Offshore wind operational report*, Low Carbon Contracts Company (2020) *CfD Register*; CCC analysis.

Further detail on the policy implications of these challenges is set out in Chapter 5 of the accompanying Policy Report.

c) Firm power

'Firm power' refers to sources of predictable electricity generation. In this report, this mainly refers to nuclear generation, which is designed to run continuously.

Nuclear provides a source of zero-carbon generation.

- **Nuclear has consistently provided 20% of generation in the UK. As nuclear plants retire, there is potential for new projects to maintain or possibly increase that contribution.**
  - There is currently 9 GW of nuclear capacity in the UK, which provides around 60 TWh (20%) of UK electricity generation. However, 8 GW is set to retire in the 2020s. Without new nuclear projects, nuclear generation would therefore fall to 2-3% of total electricity generation by 2030.
  - Analysis undertaken by the Energy Technologies Institute (ETI) suggests that the UK could deploy up to 35 GW of nuclear capacity. That could provide 275 TWh of generation, which is 90% of current electricity demand. Nonetheless, maximising nuclear capacity is contingent on costs.[6]

– Three projects are underway to replace retiring nuclear plants. One is under construction and two are awaiting approval for their reactor designs.

– Hinkley Point C (HPC) should provide 3 GW of capacity in the second half of the 2020s, backed by a 35-year Contract for Difference with a £105/MWh strike price.[5]

– Plants at Sizewell C and Bradwell could provide an additional 5 GW of nuclear capacity. That would lead to a total 10 GW of nuclear capacity in the UK, despite planned retirements. The nuclear sector deal has committed to bringing costs down by 20-30% (at £85-75/MWh) by replicating the design of Hinkley Point C.[7]

– Small Modular Reactors (SMR) could further increase the potential for nuclear in the UK, given that they could be deployed on a wider range of sites. However, they may face similar barriers to large nuclear plants regarding costs in addition to new challenges around public acceptability.

Nuclear is higher-cost than renewables, but provides predictable generation.

- **In a system driven by variable renewables, nuclear can play an important role to provide predictable low-carbon power.**

– Despite higher levelised costs than renewables, the predictability of nuclear power and its high capacity factor can make it an important part of the generation mix.

– However, the relative inflexibility of nuclear power production can lead to excess generation when demand is low. This surplus of electricity could be used to produce hydrogen via electrolysis, albeit at a higher energy cost than from renewables.

d) Dispatchable low-carbon generation

Dispatchable low-carbon generation is needed to complement variable renewables generation.

To complement variable renewable generation, other low-carbon sources are able to provide dispatchable low-carbon electricity generation. This generation can be planned with a high degree of confidence for hours, days and, normally, weeks ahead and relied on to be able to run continuously if required. These include gas with carbon capture and storage (CCS), bioenergy with carbon capture and storage (BECCS), and hydrogen plants.

i) Gas CCS and BECCS

Gas CCS and BECCS are two main sources of flexible dispatchable generation.

Gas CCS and BECCS plants are expected to be able to deliver relatively flexible low-carbon output, at medium cost. BECCS plants also offer the additional benefit of removing carbon emissions from the atmosphere.

- **The UK is well placed to deploy gas CCS and BECCS plants, given the CO_2 storage potential in the North Sea and other areas.**

– The UK has vast resources in CO_2 storage. Indeed, studies suggest that the UK has 78 Gt of CO_2 storage available.[8] This would be the equivalent to storing over 150 $MtCO_2$ per year, which could support 50 GW of gas CCS plant running all year, for 500 years.

– In addition, the cost of storage and transport should be limited to £15-19/tCO_2.

[5] £2019 prices.

- CO_2 storage should not therefore be a limiting factor to developing gas CCS and BECCS.

Although more expensive than renewables, gas CCS and BECCS provide valuable flexibility.

- **Gas CCS and BECCS are projected to be more expensive than renewables, but could bring value to a system dominated by variable generation.**
  - Gas CCS costs are expected to be higher than renewables, but competitive with nuclear at £85/MWh if running baseload.[9]
  - BECCS could play a similar role to gas CCS, albeit at higher costs that we estimate would be closer to £130/MWh based on analysis by the Wood Group.[10]
  - Despite higher costs than renewables, this form of dispatchable generation would be bring value to a generation mix driven by renewables, helping meet demand when renewable output is low.
- **The value of gas CCS and BECCS is dependent on the ability to efficiently capture CO_2.** Our analysis assumes capture rates ranging from 90% to 95%. If those rates were to be lower, the value of gas CCS as an abatement option would decrease.
  - A system based on renewables might require gas CCS and BECCS plants to run fewer hours in the year, making them more flexible. This could result in lower capture rates at start-up and shut-down, which would increase residual emissions.
  - A recent study by AECOM suggests capture rates of 95% could be maintained at low additional costs (Box M5.2).
- **By removing carbon from the atmosphere,[6] BECCS offers significant benefits as an abatement option.** However, the development of BECCS is contingent on sourcing sustainable biomass, given concerns over the associated lifecycle emissions.[11]

ii) Hydrogen plants

Hydrogen can also play a role as dispatchable low-carbon generation.

Hydrogen or ammonia[7] in electricity generation could play a crucial role in delivering flexible generation. By adjusting their output in a short period of time, hydrogen plants can ensure security of supply with low-carbon generation. These could be burnt in dedicated plants, or in retrofitted natural gas plants.

- Our 2018 *Hydrogen Review* suggested that hydrogen burned in gas turbines or engines was technically possible for electricity generation.[12] Further research and testing will nonetheless be required to better understand the performance of hydrogen plants.
- Existing and new gas turbines could run on hydrogen without significant increases in capital costs.[13] The cost of hydrogen as a fuel will be the main driver of total costs, which will depend on how this is produced.
  - Hydrogen burned in gas plants can be produced via electrolysis, which uses electricity as an energy input, or methane reformation that relies on CCS. Electrolysis supplies hydrogen without producing direct emissions, however electricity costs

[6] We refer to negative emissions to indicate the sequestering of avoided carbon.

[7] In this report, references to hydrogen include hydrogen carriers such as ammonia.

tend to be higher than those of gas, which is used for methane reformation.

- In the 2020s, methane reformers with CCS are more likely to play a role in providing hydrogen. That is because the cost of electricity would need to be as low as £10/MWh to be cost competitive with methane reformers that could cost £40/MWh of hydrogen. In this case, a hydrogen plant burning blue hydrogen to produce electricity could be £80/MWh.
- However, as renewables become a larger share of the generation mix, there could be surplus generation when demand is low but renewable output is high. This surplus electricity could be used to produce hydrogen at costs competitive with methane reformation with CCS, albeit at volumes constrained by availability of these surpluses.
- We therefore expect to see a transition towards green hydrogen as the share of renewables on the electricity system grows (see Chapter 6).

To fully utilise the potential for hydrogen a transportation and storage network will be required.

- The development of hydrogen plants will be contingent on development of transportation and storage for low-carbon fuels such as ammonia or hydrogen.
- To maximise the potential of hydrogen, gas networks would need to be converted to hydrogen. Alternatively, gas plants could be located in conjunction with hydrogen production sites, thereby facilitating the transport of the fuel.

Box M5.2
New evidence informing our analysis

A number of new publications have supplemented the evidence base used for this report:

- A report published by AECOM[14] explored potential solutions to improve capture rates of gas CCS plants at start-up and shut-down periods. This analysis suggests gas CCS could run more flexibly to accommodate more renewables without increasing residual emissions. However, this would lead to additional costs that could make gas CCS less competitive than generation technologies with flexible outputs such as hydrogen plants.
- A study by Jacobs investigated the costs of long-term storage technologies.[15] The analysis shows that pumped hydro could provide the cheapest form of one-week duration storage at £70/MWh. Other forms of storage such as Compressed Air Energy Storage (CAES) could have higher costs at £160/MWh for the same storage duration. In comparison, hydrogen storage could cost £100/MWh. Nevertheless, this analysis does not consider seasonal storage that could offer months of storage. Our analysis relies more heavily on this form of hydrogen storage, given that medium-term storage technologies could not be modelled directly within our analysis using the Dynamic Dispatch Model (see section 3). However, a combination of these technologies might be required to meet storage requirements in a renewable-driven generation mix.

e) Managing the system

i) Integration of variable renewables

Variable renewables are weather dependent and therefore generate intermittently.

The increase in renewable generation in the electricity system will come hand-in-hand with higher intermittency. This will lead to additional system requirements, particularly to ensure security of supply.

- **Historically, coal and gas generation have been able to increase or decrease their output rapidly, which has been essential to meet periods of peak demand.**
  - Peaking plants currently run on gas or oil. Despite low levels of fuel efficiency, their contributions to emissions are relatively low given that they run 10% of hours in the year, on average.
  - However, these emissions could increase substantially in a year when wind is scarce, even after flexibility of demand and storage have been fully utilised. Decarbonising peak generation will therefore be an important part of running a Net Zero electricity system.
- **Variable renewables are different to conventional generation technologies as they are dependent on the weather to generate and therefore cannot vary their output on demand.**
  - The output of wind farms varies according to wind patterns, while solar plants are dependent on solar irradiance.
  - These weather patterns can change within hours on the same day, and can vary seasonally or even year-by-year for wind. As a result, renewable generation cannot be relied on to meet demand at all times, even if it can provide a very high proportion of generation on average across the year.

Costs of additional services to address intermittency are likely to be low.

- **As a result, the electricity system as a whole needs to provide additional system services to ensure security of supply.** These services incur additional costs to integrate a larger share of renewables into the system.
  - The Committee's Net Zero Technical Annex on integrating variable renewables into the UK electricity system reviewed the evidence on integration costs.[16] These range from £10/MWh to £25/MWh for generation mixes with 50% to 65% of renewables.
  - As the deployment of renewables increases, integration costs will increase. Modelling undertaken for this report shows that these integration costs could be £25-30/MWh for a system with 75% to 90% of variable renewables.
  - Increases in integration costs would be partly offset by reductions in the cost of renewable generation. With sufficient flexibility, a system based on renewables could be cheaper than one running on fossil fuels (see Chapter 3 in the accompanying Advice Report).

Surplus generation could be stored or used to make hydrogen.

- **Surplus generation (i.e. when renewable output is greater than electricity demand) would reduce the marginal value of renewables and nuclear, but this could be captured through storage.**
  - Surplus electricity could be used for short to medium-term storage, exports, or hydrogen production.

- In turn these services could help support security of supply in a daily or seasonal capacity when renewable output is low.

- **As electricity generation is increasingly decarbonised and demand grows, network requirements will also rise.**
  - Investments in transmissions networks will be key to accommodate higher levels of generation that are located far from demand, like offshore wind.
  - The uptake of electric vehicles and heat pumps will also lead to an increase in electricity demand in most areas. As a result, upgrades in distribution networks might be necessary.

ii) Flexibility

In addition to low-carbon dispatchable generation, demand flexibility can help address the intermittency of renewable generation.

An increasingly flexible electricity system could help offset the intermittency impacts, and associated system costs, of variable renewables generation,

That flexibility could be provided by a range of options, including demand, storage, and interconnection.

- **Consumers that use electric vehicles and/or heat pumps could provide flexibility by allowing their demand to be shifted.**
  - That would require incentives to consume electricity outside periods of peak demand, for example through lower prices in those periods. That would reduce energy bills.
  - That will require some degree of behavioural change, as consumers will need to engage with their own demand, but it will also require the deployment of smart technology to send and manage price signals (see Section 3).

There are a range of storage options, able to cover a variety of duration lengths from daily to seasonal.

- **In an electricity system based on renewables, storage will be important to manage variable output.**
  - Battery storage can provide within-day flexibility when renewable output falls rapidly.
  - Hydrogen could be used as a form of medium-term storage as electricity is converted into this energy vector.
  - Other forms of medium-term storage such as pumped hydro, Compressed Air Energy Storage (CAES), could play a similar role to hydrogen. A study by Jacobs suggests pumped hydro and hydrogen could be used at similar costs of £70-100/kWh.[17]
- **Interconnectors**. Interconnections between the UK and neighbouring countries have a total current capacity of 6 GW.[18] These allow the sale of surplus energy to neighbouring markets and provide access to resources in other countries. Planned projects with 5 GW of capacity are expected to be delivered in the early 2020s. However, until the power systems in the rest of Europe become fully decarbonised, there is uncertainty around the carbon intensity of imported electricity.

a) Analytical methodology

i) Modelling and analytical processes

In this section, we set out the approach used to develop the emission scenarios for electricity generation that informed the level of the Sixth Carbon Budget. This covers the modelling approach and the approach taken for selecting scenarios.

We undertook detailed modelling of the electricity system out to 2050.

For the analysis underpinning this report we used the Department of Business, Energy, and Industrial Strategy's (BEIS) Dynamic Dispatch Model (DDM). We supplemented this with additional analysis to reflect the use of evidence and analyses that were not supported by the model.

BEIS Dynamic Dispatch Model

The DDM is an electricity market model that considers electricity demand and supply in Great Britain on a half-hourly basis. The model estimates the merit order of plants, which is then matched to demand.

The DDM does not have perfect foresight. Hundreds of possible generation mixes were modelled for each year and scenario.

- The model takes into account demand profiles of different end users as well as weather patterns for sample days. The model does not have perfect foresight in order to reflect investor decision-making, but rather generates many different capacity mixes and resulting mixes of generation.
- We used the model to identify a range of optimal pathways for emissions reflecting different input factor combinations, each of which had to meet security of supply constraints. That range of solutions included capacity deployment of different technologies and associated costs, provided by the CCC. This resulted in hundreds of possible generation mixes for each year modelled and each scenario.
- The modelling provided us with results on generation, capacity, costs, security of supply, and emissions.[19]

The CCC provided external inputs that covered demand, flexibility assumptions, capacity ranges, costs, and carbon values. As a result, our analysis does not share the same assumptions - or results - as other analyses undertaken by BEIS.

Scenario modelling

For each year, we provided inputs on demand levels and demand-side flexibility, ranges of possible capacity levels for different generation technologies, costs, and carbon prices.

- For each scenario, we provided assumptions on electricity demand (Figure M5.7). These inputs reflect the use of electrification to decarbonise other sectors. This, in turn, was predominantly determined by the modelling carried out in those sectors, including surface transport, manufacturing, buildings, fuel supply, greenhouse gas removals, aviation and shipping.

Flexible demand will be important for managing the future electricity system.

– Demand inputs included assumptions on flexibility provided by heat and transport (Box 1.11 in Chapter 1). We assumed that pre-heating and hot water tanks enable certain homes to shift their electricity demand four hours away from peak, while homes with storage heaters can shift their demand at all times. In transport, we assume that 80% of charging demand can be shifted up to eight hours outside of peak.

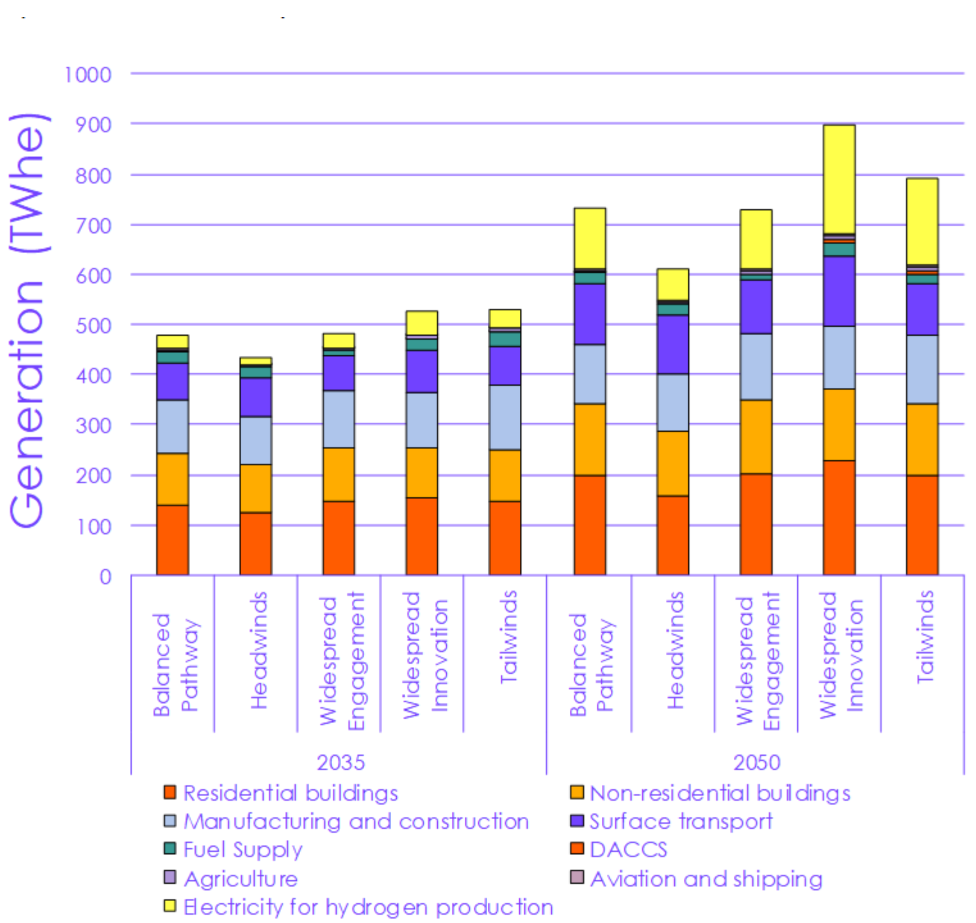
– These demands already consider energy efficiency measures in buildings and industry, thus avoiding 40 TWh of new demand and helping to limit total demand to 610 TWh (Figure M5.8).

- Capacity ranges were another key modelling input. For each scenario and each year, the model could select from a range of possible capacity levels of different generation technologies, including wind, solar, gas CCS and nuclear. This range was informed by existing capacity that represented a lower bound while historical build rates provided the basis to estimate an upper limit.

- We provided estimates for cost assumptions, including costs associated with capital, operation and maintenance as well as fuel. We assumed costs remained the same across scenarios, except in the Widespread Innovation and Tailwinds scenarios where variable renewables experience further cost reductions. Cost assumptions are set out in further detail in Table M5.1.

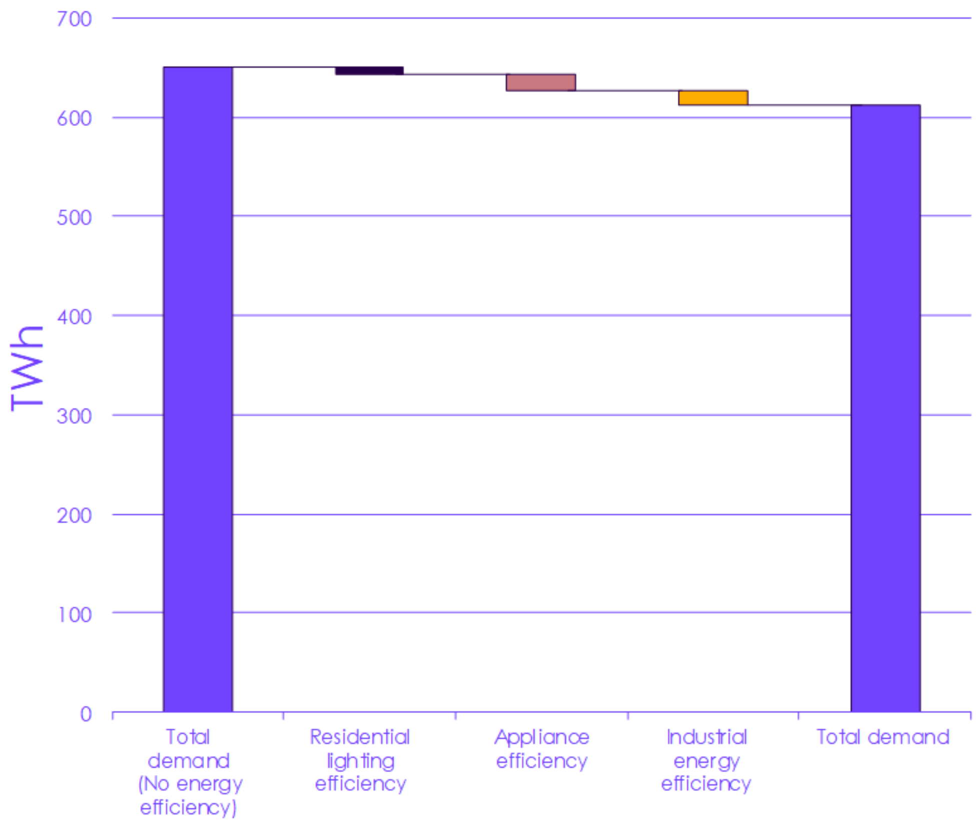
Electricity demand doubles in our scenarios out to 2050, compared to current levels of around 300 TWh.

Figure M5.7 Electricity demand from sectors (2035 and 2050)



Source: CCC analysis.

Figure M5.8 Energy saved in the Balanced Pathway from efficiency measures (2050)



Source: CCC analysis.

Scenario selection

Our analysis favoured scenarios that were optimal across electricity and hydrogen supply.

The outputs provided us with over 4,000 possible generation mixes across years. We therefore proceeded to select an illustrative generation mix for each of our scenarios based on three criteria:

- **Hydrogen and power optimum.** The outputs of the DDM informed us of the level of curtailment in each run. In addition, the DDM was able to model how much of that curtailment could be captured by different levels of electrolyser capacity. For each run, we estimated the value of producing hydrogen with surplus electricity, which we factored in as a negative cost to the electricity system.[8] This placed a value on the curtailed electricity that could be used for hydrogen production, thus reflecting the value of inflexible generation to the system once a system perspective is taken into account.
- **Path-dependency.** Selected generation mixes had to be consistent with capacity developed to meet demand in 2050. In other words, the capacity in scenarios for 2030 and 2035 could not be higher than those in 2050, to ensure no plant was built and decommissioned before the end of their lifetime.
- **Cost-effectiveness.** Thereafter, we selected the least-cost scenario.

[8] The value of electrolytic hydrogen production was estimated by calculating cost avoided by running an electrolyser on free electricity and hydrogen production from fossil gas reforming with CCS.

Additional analysis

We supplemented the DDM modelling with additional analysis to take into account a wider range of technologies and more detailed estimates of distribution costs.

- Some generation technologies, such as BECCS and hydrogen plants, are not included within the scope of the DDM. However, other technologies in the model could play a similar role, albeit at different costs and emission factors. We used gas CCS as a proxy for BECCS and unabated CCGT as a proxy for hydrogen plants, adjusting for changes in costs and emissions accordingly.
- We assume hydrogen plants start displacing unabated gas in the 2020s, assuming that the policy framework incentives its dispatch ahead of unabated gas, contributing to the phase-out of unabated gas (Box M5.3).
- Distribution costs are not estimated within the DDM. We used the BEIS electricity Distribution Network Model to estimate distribution costs, using the same assumptions from the DDM modelling. However, these models are not able to futureproof investment in networks, which could help limit costs. As a result, investment in networks tends to increase in proportion to generation. However, in practice front-loading one-off investment in 'future-proofing' network upgrades is likely to be the lowest-cost solution, given that the majority of the costs are in the civil works rather than the equipment. The cost estimates for electricity networks are therefore likely to be overestimated.

Anticipatory investment in network upgrades is likely to be a low-regrets solution.

Box M5.3
Phasing out unabated gas generation

Our analysis shows that unabated gas could be phased out by 2035, provided alternative technologies are deployed at pace to deliver security of supply.

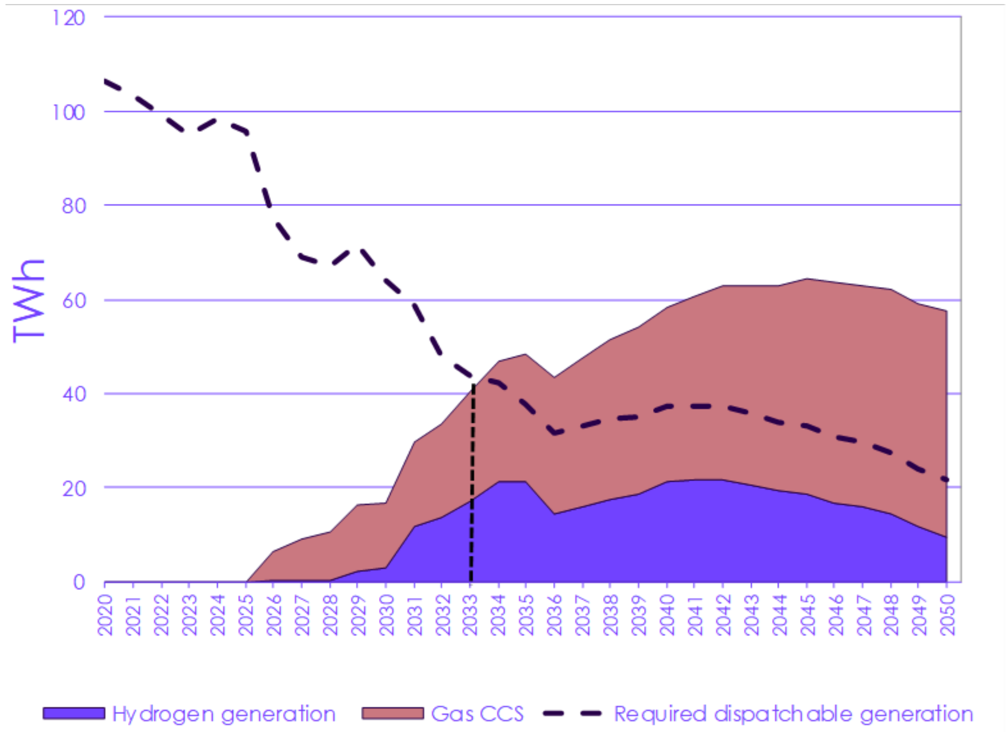
– **Retirement of unabated gas capacity.** There are currently 33 GW of Combined Cycle Gas Turbines (CCGT) and Open Cycle Gas Turbines (OCGT) in the UK.
  - Most of these plants were built in the 1990s during the 'dash-for-gas' period. The last plant was built in 2016. This means that existing plants are likely to retire by 2041, assuming an average operating life of 25 years.
  - These retirements represent an opportunity to phase out unabated gas generation, as new plants should prepare to retrofit with CCS or hydrogen. For that, new gas plants will need to demonstrate their ability to store hydrogen on-site and show their preparedness for using hydrogen-blending or their ability to retrofit CCS. Proximity to planned hydrogen or CCS infrastructure should also be a key criterion applied to all new gas plants.

– **Carbon price**. Our analysis suggests that a strong carbon price could move unabated gas down the merit order, thus reducing its role in the generation mix.
  - CCGTs currently cost £50/MWh, excluding the cost of carbon. In comparison, a gas CCS plant is expected to cost around £85/MWh in 2025.[20] Based on our hydrogen analysis, we assume costs for a hydrogen plant would range from £85/MWh to £130/MWh in the same year. Based on these costs, unabated gas would continue to play a significant role in the system without a carbon price.
  - However, a carbon price of £125/tCO_2 in 2030 - or equivalent policy - would be sufficient to bring the cost of a CCGT to £130/MWh, making it more expensive than the alternatives. As a result, a carbon price could push gas generation down the merit order such that it would play a more marginal role, particularly in meeting security of supply.

- **Security of supply**. Although a carbon price could displace gas generation, the phase-out of unabated gas is contingent on the deployment of low-carbon alternatives that can provide relatively flexible dispatchable generation. Our analysis suggests that hydrogen and gas CCS generation could be deployed at scale by 2035 to ensure security of supply.
  - In the Balanced Pathway, demand for electricity increases to 460 TWh in 2035 of which 335 TWh are met by renewables. The deployment of cheap renewables contributes to reducing the need for unabated gas. By 2035, 50 TWh of dispatchable generation would be needed to ensure security of supply (Figure MB5.3). This could be provided by low-carbon generation.
  - Deploying less than 1 GW/year of hydrogen capacity in the second half of the 2020s could contribute to understanding the performance of hydrogen burning in gas turbines. Further deployment could take place in the 2030s, when the technology has been proven. Thereafter, deploying 3.5 GW/year between 2030 and 2035 could help deliver 15 TWh/year of hydrogen on average. These build rates are consistent with historical build rates achieved by CCGT deployment in the 'dash-for-gas' period.
  - In addition, deploying around 1 GW a year of gas CCS between 2025 and 2035 would enable it to provide 5 TWh of generation in 2026 increasing to 27 TWh by 2035.
  - Together, hydrogen and gas CCS generation could therefore displace unabated gas before 2035.
- **Phasing out unabated gas by 2035**. With sufficient deployment of low-carbon alternatives and the support of a carbon price and/or other policy mechanisms, unabated gas could be phased out by 2035, subject to ensuring security of supply.
  - This date is contingent on the development of CCS and hydrogen infrastructures, and appropriate incentives across the energy system.
  - It may also be necessary to maintain some unabated gas capacity for periods where renewable output could be particularly low (e.g. wind droughts). This would require the development of business plans or policy that could support these marginal plants which would run at very low load factors.

Further detail on the policy implications for phasing out unabated gas is set out in Chapter 5 of the accompanying Policy Report.

Figure MB5.3 Deployment of dispatchable low-carbon generation in the Balanced Pathway (2020-50)



Source: CCC analysis.

Source: CCC analysis

ii) Scenarios

Offshore wind is the backbone of all our scenarios, providing 65-70% of total generation by 2050.

We have developed four exploratory scenarios for emissions to 2050, and a Balanced Pathway which keeps open the option to 2035 of achieving any of these by 2050. These scenarios are based around significant deployment of low-cost renewables, which meet 75% to 90% of electricity demand in 2050.

- **Offshore wind is the backbone of electricity generation across all scenarios.**
  - Offshore wind is able to meet a substantial share of demand with wind patterns correlated to seasonal demand, which supports the uptake of heat electrification. As a result, our scenarios include at least 65 GW of offshore wind in Headwinds and up to 140 GW in Widespread Innovation by 2050. The Balanced Pathway has 95 GW.
  - The high share of offshore wind is made possible by its low costs. Despite higher system costs, technology costs of £25/MWh-£40/MWh in 2050 contribute to running a system at lower costs than one based on fossil fuels.
  - An increase in interconnection could limit the need for new offshore wind capacity. Our analysis suggests that an additional 9 GW of interconnectors in our scenarios would reduce the need for 4-7 GW of offshore wind capacity.

- **All scenarios see new onshore wind generation being deployed by 2050**.
  - Onshore wind has similar benefits to offshore wind, albeit with lower capacity factors.
  - Our modelling reflects this by almost doubling onshore wind capacity to 25-30 GW in all scenarios by 2050.

Solar generation could produce hydrogen during summer that could be used in periods of higher demand in winter.

- **Solar contributes to decarbonising power at low costs, providing 10% to 15% of generation in 2050.**
  - Solar generates mostly during the summer when solar radiance is strongest. As a result, solar generation is less suitable to meet the seasonal pattern of demand, which is higher in winter periods due to heating demands. However, our modelling suggests high levels of solar generation in the summer could be stored (e.g. as hydrogen) to be used when demand is higher.
  - If solar deployment were to be lower than considered in the Balanced Pathway, an extra GW of offshore wind could replace the generation of 3 GW of solar capacity.

Pumped hydro could play a role in providing medium-term storage.

- **Other renewables could provide predictable generation, which would complement variable generation.**
  - Technologies such as tidal and wave that have not been commercialised at large scale could provide predictable power to a variable renewables-driven system. However, costs would need to decrease substantially to be competitive against other technologies.
  - Pumped hydro could be further developed in the UK (Box M5.2), which would be beneficial as a source of storage.

In a generation mix driven by renewables, other technologies will need to play a role in balancing the system. In addition, they provide optionality if renewable deployment were to encounter significant bottlenecks.

- **The role of nuclear is dependent on its cost and the share of renewable output in the system.**
  - In scenarios with a high share of renewables (i.e. more than 75% of generation), continuous power from nuclear might be curtailed in periods of low demand. This surplus could be used to produce hydrogen, albeit at higher costs than renewables, depending on electrolyser capacity factors.
  - However, nuclear offers a zero-carbon alternative to renewables, which could help meet new demands if renewable deployment were to slow down. This would increase overall generation costs, given nuclear is more expensive than offshore wind.

Gas CCS and BECCS can offer valuable dispatchable generation.

- **All our scenarios benefit from having gas CCS and BECCS on the system, which provide 7% to 15% of generation in 2050.**
  - These technologies offer a flexible dispatchable source of low-carbon generation, which can supplement variable weather-dependent renewables.
  - The role of these technologies varies across scenarios, as they are dispatched 40% to 45% of hours in the year.

– If gas CCS and BECCS were to be run more flexibility to help meet security of supply, costs and emissions would increase. Alternatively, gas turbines burning hydrogen could displace these technologies.

Table M5.1 summarises the role of different technologies across our scenarios.

Table M5.1
Role of technologies in the scenarios

	Capacity 2050	Average build rates 2030-50	Levelised cost 2050
Balanced Pathway	**GW**	**GW/year**	**£/MWh**
Offshore wind	95	3	40
Solar	85	3	40
Gas CCS	15	1	80
Nuclear	10	<1	85
BECCS	5	<1	125-185
Headwinds	**GW**	**GW/year**	**£/MWh**
Offshore wind	65	1	40
Solar	85	3	40
Gas CCS	15	1	80
Nuclear	10	<1	85
BECCS	10	<1	125-185
Widespread Engagement	**GW**	**GW/year**	**£/MWh**
Offshore wind	100	3	40
Solar	80	2	40
Gas CCS	5	<1	80
Nuclear	5	<1	105
BECCS	10	<1	125-185
Widespread Innovation	**GW**	**GW/year**	**£/MWh**
Offshore wind	140	5	25
Solar	90	3	25
Gas CCS	15	1	80
Nuclear	5	<1	105
BECCS	5	<1	125-185
Tailwinds	**GW**	**GW/year**	**£/MWh**
Offshore wind	125	4	25
Solar	75	2	25
Gas CCS	5	<1	80
Nuclear	5	<1	105
BECCS	10	<1	125-185

Source: CCC analysis based on BEIS (2020) Electricity Generation Costs and Wood Group (2018) Assessing the Cost Reduction Potential and Competitiveness of Novel (Next Generation) UK Carbon Capture Technology.
Notes: Costs in 2019 prices. Capacities and costs rounded to the nearest 5.

b) Deriving the paths for emissions in the devolved administrations

Our approach to developing emission pathways for Scotland, Wales, and Northern Ireland is based on the UK-wide approach and takes into account the specific circumstances of each devolved administration.

In common with the UK-wide approach, pathways for the devolved administrations reflect an increasing demand for electricity to 2050. That is decarbonised through a significant expansion of low-carbon generation, in particular low-cost renewables and decarbonised back-up generation, in conjunction with more flexible demand and use of storage.

Electricity demand across the devolved administrations doubles by 2050.

- **Demand.** The pattern for electricity demand across the scenarios reflects the same drivers as for the UK-wide analysis, with demand broadly doubling out to 2050. That includes an increasing switch towards electrification in transport, heating, and manufacturing and construction. Further detail on the drivers of this increase is set out in the relevant sector chapters of this Methodology Report.
  - **Scotland.** Demand broadly doubles by 2050, reaching 55-65 TWh. The fastest growth comes in the Widespread Innovation scenario, and the slowest growth is in the Headwinds scenario. The Balanced Pathway reaches 60 TWh in 2050.
  - **Wales.** Demand increases to 30-35 TWh in 2050, with the Balanced Pathway in the middle of this range.
  - **Northern Ireland.** Demand in Northern Ireland is relatively low, at around half of Welsh and a fifth of Scottish levels. It increases from less than 10 TWh in 2019 to 15-20 TWh in 2050, with the Balanced Pathway towards the lower end of the range.

Scenarios phase out unabated gas in electricity generation by 2035 in Scotland and Wales, in line with the UK-wide scenarios.

- **Carbon intensity.** Our approach to decarbonisation pathways for Scotland and Wales follows the methodology developed for our previous advice on devolved administration targets.[21] For Northern Ireland we use the pathways for carbon intensity published by the System Operator for Northern Ireland.[22]
  - **Scotland and Wales.** After the phase out of coal by 2024, remaining emissions will come from use of unabated gas and any residual emissions from the small proportion of CO_2 emissions not captured at fossil CCS plants.
    - For unabated gas plant we make a bottom-up assessment of the profile for retirements of existing capacity over time, based on an assumed 25-year lifetime. Onto this we overlay the change in load factors by scenario from the UK-wide analysis. The scenarios phase out use of unabated gas in electricity generation by 2035, except Headwinds in which it happens by 2040.
    - For gas CCS, we distribute UK-wide generation proportionately to the DAs based on their share of industrial CCS in our scenarios. In the Balanced Pathway that is 15% and 25% for Scotland and Wales respectively in 2050.
  - **Northern Ireland.** We use the pathways for carbon intensity published by the System Operator for Northern Ireland. These imply an intensity of less than 10 gCO_2/kWh in 2050.

    We have aligned the Balanced Pathway and the Headwinds scenario to the ‘Addressing Climate Change’ scenario, and the remaining scenarios to the ‘Accelerated Ambition’ scenario.

Our scenarios show near-zero emissions from electricity generation from the devolved administrations by 2050.

- **Emissions.** Figure M5.9 shows emissions under the Balanced Pathway for the devolved administrations. Emissions fall to near-zero by 2050.
  - **Scotland** has no remaining coal plants, and one remaining large gas plant. Once this closes, emissions are only from gas CCS, which is deployed through the 2030s and 2040s, but remain at very low levels to 2050.

- **Wales** has a higher share of existing gas capacity than it does of demand. Unabated gas capacity is phased out by 2035 in line with the UK-wide scenarios. Emissions stabilise at very low levels thereafter, reflecting the small proportion of CO_2 emissions not captured at gas CCS plants.
- **Northern Ireland.** The reduction in emissions plateaus somewhat in the 2030s, reflecting that the scale up in demand increases at a faster rate than carbon intensity declines. Emissions fall faster in the 2040s, reaching near-zero by 2050.

Overall, our scenarios show it is possible to reduce emissions from electricity generation to near-zero in the devolved administrations by 2050, while still meeting a doubling of demand and ensuring security of supply.

Figure M5.9 Devolved administration emissions under the Balanced Pathway (2020-50)

Source: CCC analysis.

c) Approach to uncertainty

Our scenarios are designed to reflect a wide range of uncertainty about future development of electricity demand, availability of generating technologies, and costs. Nonetheless, significant uncertainties remain, particularly on a 2050 timescale. These include:

- **Technologies.**
  - **Capture rates, especially with flexibility.** We assume that capture rates for CCS plants improve from 90% in 2030 to 95% in 2050. If capture rates were lower, the value of gas CCS as an abatement option would decrease and other technologies would need to play a more significant role.
  - **Storage.** Our scenarios maximise the role of hydrogen as a form of storage in power by producing hydrogen with surplus generation and burning hydrogen in gas plants to meet security of supply. However, other medium to long-term storage solutions could play a similar role, although it is unclear which mix of storage technologies could bring the most value to a renewable-driven generation mix.

There are significant uncertainties on future costs, particularly for renewables that could continue experiencing cost reductions.

  - **Costs.** There is significant uncertainty around generation technology costs in the future, as well as the impact of renewables on total system costs. While offshore wind has experienced significant cost reductions, it is unclear whether they will be sustained in the 2020s and beyond. This uncertainty applies to all generation technology costs that could experience capital cost reductions or support from policy that could decrease levelised costs.
  - **Carbon intensity of interconnector imports.** There is uncertainty around the carbon intensity of electricity imported from other countries. Our scenarios suggest the UK could become a net exporter of electricity, thus limiting residual emissions from interconnection.
- **Demand flexibility.** Consumers could be incentivised to provide flexibility services to the grid. However, the extent to which consumers would be willing to participate in these services is unclear. If cost incentives are not enough to prompt behavioural change, power would decarbonise at higher costs.

Unabated gas should be phased out by 2035, however this is contingent on meeting security of supply.

- **Phase-out of unabated gas.** Our analysis suggests that unabated gas-fired generation could be phased out earlier than other sectors, during the period of the Sixth Carbon Budget. However, in our scenarios, security of supply is contingent on its replacement with hydrogen and on the ability to build a CO_2 and hydrogen infrastructure for electricity generation and industry. Without these technologies, the electricity system would require further reductions in demand, higher flexibility, and/or extensive storage. In addition, nuclear would likely play a role in providing baseload generation to ensure security of supply.

Our scenarios could lead to water savings, provided sea water is used for cooling of nuclear plants.

- **Water use for electricity generation.** Freshwater could become scarcer in the future, depending on the level of climate change that takes place. Our scenarios suggest that water could be saved as we transition from a generation mix reliant on nuclear and fossil generation that require water for cooling. Nonetheless, the uptake of electrolysers could increase overall demand for water.

- Our scenarios indicate a 10% decrease in water use by 2050, including water use for electrolysis. This is contingent on new nuclear capacity using sea water over freshwater. If this were not the case, water use could increase by 20%.
- In a recent report commissioned for the Third Climate Change Risk Assessment,[23] future projections of water availability were modelled for a range of socio-economic and climate adaptation scenarios. While this analysis did not directly evaluate the impact of changing water availability on energy generation, the projected changes in naturally available resource under different climate scenarios show the potential exposure of energy generation to risks from reduced water availability.
- This risk can be mitigated by using seawater or desalinating seawater.

Our scenarios show that it is possible to run a low-carbon electricity system from the mid-2030s, and a near-zero emission system by 2050. The success of delivering that will depend on the policy framework that is put in place. We discuss the implications of our scenarios for policy in Chapter 5 of the accompanying Policy Report.

Endnotes

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Chapter 2

Emissions pathways for the electricity generation sector

The following sections are taken directly from Chapter 3 of the CCC's Advice Report for the Sixth Carbon Budget.[24]

Introduction and key messages

In this section we set out how to reduce emissions from electricity generation to near-zero. This will require a significant expansion of low-carbon generation, in particular low-cost renewables and decarbonised back-up generation, in conjunction with more flexible demand and use of storage.

Our Balanced Net Zero Pathway decarbonises electricity generation by 2035, with action thereafter focused on meeting new demands in a low-carbon way. We set out the analysis underpinning these conclusions in the following three sub-sections:

a) The Balanced Net Zero Pathway for electricity generation

b) Alternative routes to delivering abatement in the mid-2030s

c) Impacts of the scenarios: costs, investment, and co-impacts

Further detail on the approach to developing the scenarios is set out in Chapter 5 of the accompanying Methodology Report.

a) The Balanced Net Zero Pathway for electricity generation

Our Balanced Net Zero Pathway very largely decarbonises electricity generation by 2030, and decarbonises it completely by 2035, with action thereafter focused on meeting rising demand with low-carbon generation.

The key features of the scenario are an increasing demand for electricity, decreasing carbon intensity of generation, and a more flexible system:

The Balanced Pathway has a doubling in demand by 2050 compared to 2019 levels.

- **Increasing demand for electricity.** This reflects increasing electrification of the economy (e.g. use of electric vehicles in transport). There is a doubling of demand, from around 300 TWh today to 360 TWh in 2030, 460 TWh in 2035, and 610 TWh in 2050 (Figure A3.4.a). That excludes the production of hydrogen using surplus generation, which accounts for an additional 30 TWh of electricity generation in 2035 and 120 TWh in 2050.

Electricity generation is entirely low-carbon by 2035.

- **Decreasing carbon intensity of electricity generation.** Carbon intensity of generation falls from 220 gCO_2/kWh in 2019 to around 50 gCO_2/kWh in 2030, 10 gCO_2/kWh in 2035, and 2 gCO_2/kWh in 2050 (Figure A3.4.b).
  - **Phasing out unabated fossil fuel generation by 2035.** Electricity generation will be completely low-carbon once unabated coal and gas plants are no longer generating. Following the coal phase-out by 2024, almost all remaining emissions will come from unabated gas. The Balanced Pathway phases out use of unabated gas by 2035, meaning electricity generation is completely low-carbon from that date. That is achievable with the cost-effective deployment of renewables, gas CCS, and hydrogen at scale. Chapter 5 in the Methodology Report sets out further detail on why this is an achievable date, and Chapter 5 in the Policy Report sets out the policy implications.

Renewables form the backbone of the electricity system, representing 80% of generation in 2050.

- **Increasing variable renewables to 80% of generation by 2050.** Under the Balanced Pathway variable renewables reach 60% of generation by 2030, 70% by 2035, and 80% by 2050. This generation allows new electricity demands to be met with minimal emissions and at low cost.
  - Wind, particularly offshore, is the backbone of the system, providing 265 TWh of generation in 2035 and 430 TWh in 2050. That requires deploying 3 GW per year of new wind capacity, plus repowering of older sites as they reach the end of their (25-30 year) operating lives.
  - Solar generation increases from 10 TWh in 2019 to 60 TWh in 2035 and 85 TWh in 2050. On average, 3 GW per year will need to be installed to reach this level of solar generation.

Dispatchable low-carbon generation is needed to balance variable renewables.

- **Dispatchable low-carbon generation.** Some flexible low-carbon generation (e.g. gas or bioenergy with carbon capture and storage (CCS), or hydrogen) will be required, in particular during periods of low production from variable weather-dependent renewables.
  - **Gas with CCS.** From the second half of the 2020s, the Balanced Pathway sees the development of CCS infrastructure, which enables the deployment of gas CCS. By 2035, 30 TWh of generation comes from gas CCS, meeting 6% of demand.
  - **Bioenergy with carbon capture and storage (BECCS).** Development of CCS infrastructure also enables deployment of BECCS plants. These could provide 3% of generation by 2035. Although they have higher costs than other ways of generating electricity, these plants provide an additional benefit of removing carbon from the atmosphere (see Section 3.11).
  - **Hydrogen** can provide a flexible form of dispatchable generation similar to unabated gas. In the Balanced Pathway, some gas plants start to switch to hydrogen in the 2020s. By 2035, hydrogen gas plants provide 20 TWh of generation, meeting 5% of demand.
- **Nuclear.** Despite retirements of existing nuclear plants in the 2020s, this scenario sees new nuclear projects restore generation to current levels by 2035. The Balanced Pathway reaches 10 GW of total nuclear capacity by 2035, with 8 GW of new-build capacity.

Flexible demand is also important for managing the system.

- **A more flexible electricity system** will help balance out the variability in renewable generation. Increasing flexibility comes from both demand (e.g. demand-side response, and use of surplus renewable generation to produce hydrogen) and supply (e.g. use of electricity storage).
  - **Storage.** With an increasing share of variable renewables, storage can capture surplus energy when demand is low and provide backup generation when demand is particularly high.
    - The Balanced Pathway uses hydrogen as the primary source of storage. However, a similar role could also be performed by other medium-term storage technologies.
    - Pumped hydro storage offers dispatchable flexibility. Our analysis assumes capacity at similar levels to the currently installed 3 GW. However, there are already plans to develop new schemes and new sites have been identified which could provide an additional 7 GW.[25]

- Batteries can provide within-day flexibility. The Balanced Pathway assumes 18 GW of battery storage capacity by 2035.

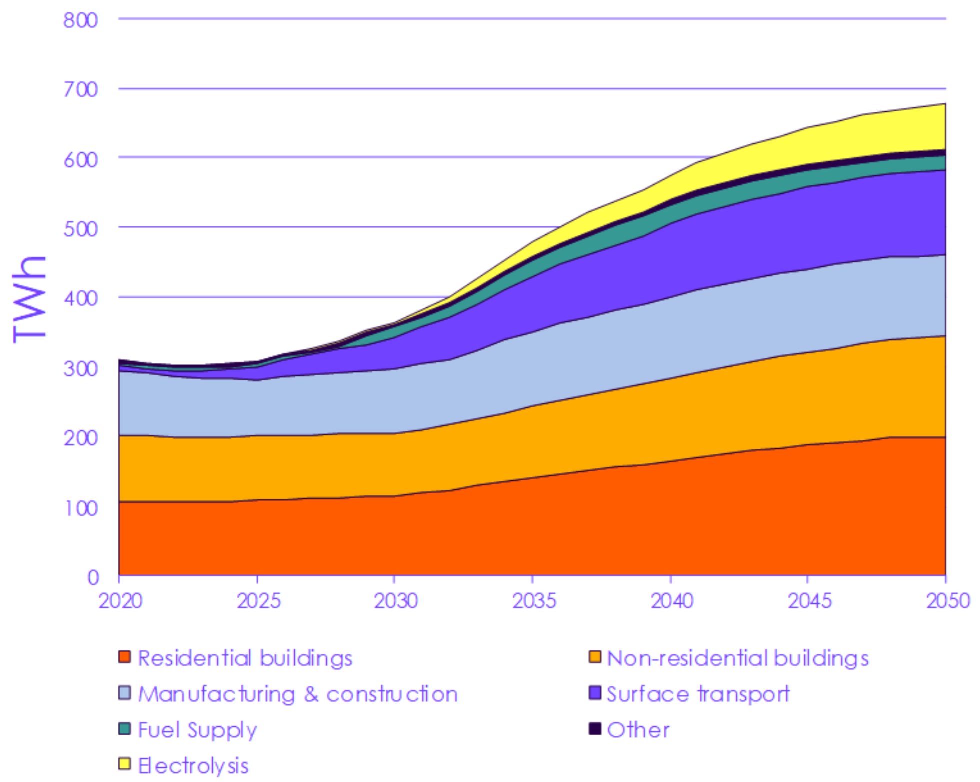
– **Flexible demand.** Our analysis assumes that pre-heating and storage in buildings, and smart charging in transport can provide flexibility to the power system, by shifting electricity demand away from peak hours. The Methodology Report chapters on surface transport and buildings set out further detail on this.

– **Use of surplus electricity.** The Balanced Pathway has an important role for electrolysers to produce hydrogen at low cost from surplus generation. In the Balanced Pathway 25% of hydrogen supply comes from electrolysis in 2035, increasing to 45% by 2050 (see Section 3.5 on Fuel Supply).

– **Interconnectors**. Interconnections between the UK and neighbouring countries have a total current capacity of 6 GW.[26] These allow the sale of surplus energy to neighbouring markets and provide access to resources in other countries. Under the Balanced Pathway interconnector capacity increases to 18 GW by 2050. However, until the power systems in the rest of Europe become fully decarbonised, there is uncertainty around the carbon intensity of imported electricity.

Electricity demand doubles to 2050, reflecting electrification of sectors across the economy.

Figure A3.4.a Electricity demand by sector in the Balanced Net Zero Pathway (2020-50)



Source: CCC analysis.
Notes: Other category includes agriculture, aviation, direct air capture, shipping and F-gases.

There are clearly defined phases to the Net Zero transition.

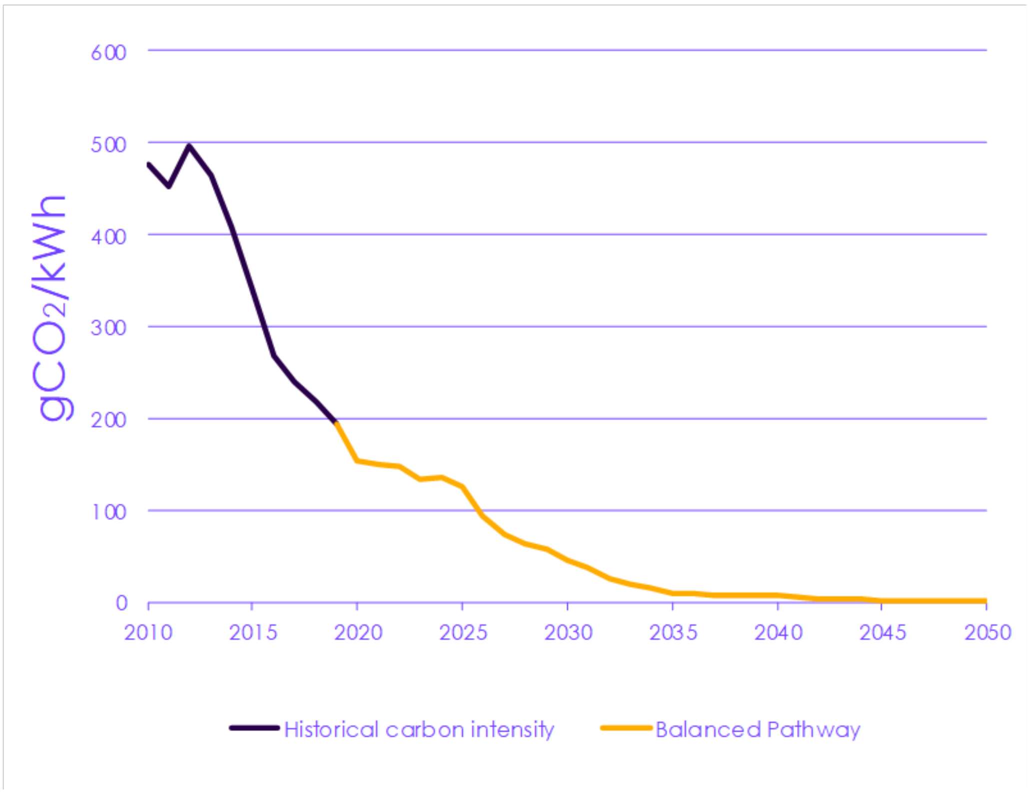
The transition to a near-zero emission electricity system will have several phases:

- **2020s –** Deploying low-cost renewables at scale and developing the markets for gas CCS and hydrogen, with some new build nuclear.
- **2030s –** Transitioning to a completely low-carbon system by displacing unabated gas with low-carbon alternatives by 2035, alongside ramping up deployment of zero-carbon generation to keep pace with electrification of end-use sectors and increasing potential for demand-side flexibility via electric vehicles, heat pumps, and hydrogen production.
- **2040s –** Running a near-zero emission electricity system, with variability in renewable generation managed through flexible demand, medium- and long-term storage, and use of dispatchable low-carbon generation.

The result is that generation under the Balanced Pathway is completely low-carbon by 2035 (Figure A3.4.c) and close to zero emission before 2050.

Carbon intensity in the Balanced Pathway falls rapidly in the 2020s, reflecting the transition to a full low-carbon system by 2035.

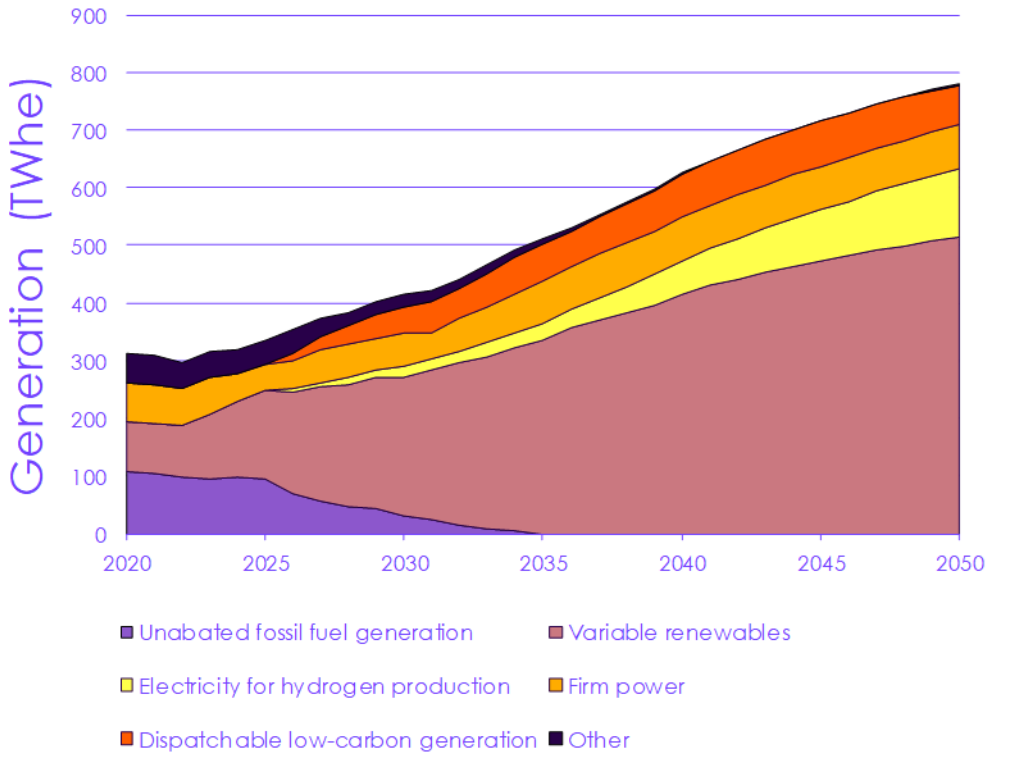
Figure A3.4.b Carbon intensity in the Balanced Net Zero Pathway (2010-50)



Source: BEIS (2020) *2018 UK greenhouse gas emissions: final figures*. BEIS (2020) 2019 *UK greenhouse gas emissions: provisional figures*; CCC analysis.
Notes: Rate of reduction in carbon intensity accelerates from 2025, reflecting a rapid expansion of low-carbon generating capacity.

Variable renewables form the backbone of the future electricity system, with no unabated fossil fuel use after 2035.

Figure A3.4.c Illustrative generation mix for the Balanced Net Zero Pathway (2020-50)



Source: CCC analysis.
Notes: Chart reflects UK electricity generation. Additional capacity is available through interconnection. Unabated fossil fuel generation includes coal and gas. Variable renewables include wind and solar. Firm power includes nuclear. Dispatchable low-carbon generation includes gas CCS, BECCS and hydrogen.

b) Alternative routes to delivering abatement in the mid-2030s

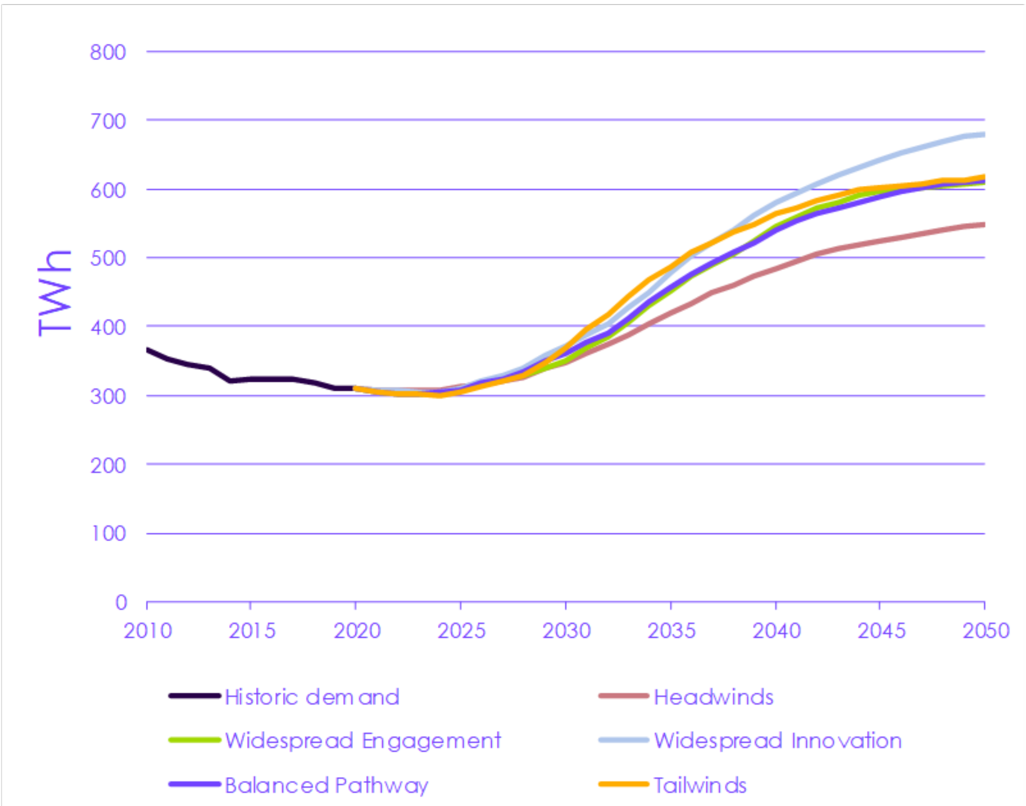
In addition to the Balanced Pathway, we have developed four exploratory scenarios. The overall approach to these is set out in Chapter 1.

These scenarios explore alternative ways of reaching near-zero emissions from electricity generation over the period to 2050. They have a similar pathway for emissions but reflect different levels of electrification across the economy, as well as different technology mixes to generate that electricity.

Demand increases across all scenarios to 2050.

Across the exploratory scenarios, electricity demand ranges from 350 to 370 TWh in 2030, 420 to 490 TWh in 2035, and 550 to 680 TWh in 2050 (Figure A3.4.d), compared to around 300 TWh today.

Figure A3.4.d Electricity demand across the exploratory scenarios (2010-50)



Source: BEIS (2020) *Digest of UK Energy Statistics*; CCC analysis.
Notes: Excludes demand from electrolysis using surplus electricity generation. That accounts for an additional 65-290 TWh in 2050, depending on the scenario.

These ranges for electricity demand reflect different patterns and levels of electrification in other sectors:

- **Headwinds.** This scenario has the least amount of electrification across the economy, and therefore the lowest demand level. Cars and vans are electrified, as in all the scenarios, and in this scenario heat and industrial processes in manufacturing are partially electrified, in total adding 245 TWh of electricity demand by 2050.
- **Widespread Engagement.** In this scenario Heavy Goods Vehicles (HGVs) are also electrified, but a switch towards active travel and public transport moderates transport demand. A greater proportion of manufacturing and most heat energy demand is electrified. Together this leads to 310 TWh of new electricity demands by 2050.
- **Widespread Innovation.** This is a scenario with widespread electrification, as a result of low electricity costs. Heating, surface transport (including HGVs), and manufacturing and construction electrify extensively. In addition, there are new demands from Direct Air Capture and to a lesser extent from agriculture and aviation. Overall, these sectors add 375 TWh of electricity demand by 2050.

The Widespread Innovation scenario has the most extensive electrification, reflecting the low-cost of renewables in this scenario.

- **Tailwinds.** This scenario is similar to Widespread Innovation, but with a lower degree of electrification of heating and surface transport. There is an additional 315 TWh of new demand by 2050.

Onto these different demand levels, we overlay scenarios for future low-carbon technologies. The range for carbon intensity under these scenarios is less than 50 gCO_2/kWh in 2030, 10-15 gCO_2/kWh in 2035, and 1-2 gCO_2/kWh in 2050. These compare to a carbon intensity of 220 gCO_2/kWh in 2019.

Decarbonisation is similar across our scenarios over the 2020s, with variable renewables reaching 65-70% of electricity generation in 2030. However, the pace of low-carbon deployment and the mix of generation technologies in the scenarios start to diverge after 2030 (Figure A3.4.e). Table A3.4.a sets out the key differences across scenarios.

The Headwinds scenario has the lowest demand and the lowest share of renewables in 2050.

- **Headwinds.** This scenario has the lowest share of variable renewables in 2050, with a greater role for dispatchable low-carbon generation and nuclear.
  - Past 2030, the share of renewable generation increases to around 75%. Nuclear also meets some of the growth in the 2030s, while dispatchable low-carbon generation plays an increasingly important role, meeting 20% of demand by 2050. Unabated gas generation is phased out by 2040, later than in the Balanced Pathway.
  - At this level of variable renewable generation, there could be 70 TWh of surplus electricity production. Most of that could be used to produce green hydrogen, with installed electrolyser capacity of 10 GW in 2030 and 50 GW in 2050.
- **Widespread Engagement.** In this scenario there is a greater emphasis on variable renewables and dispatchable low-carbon generation.
  - Despite higher levels of demand, this scenario sees the renewable share of generation grow to 85% by 2050. Dispatchable low-carbon generation and nuclear play a consistent role in providing about 15% of generation in total. In this scenario, hydrogen plants or storage solutions are particularly important to ensure security of supply.
  - The surplus electricity that stems from variable generation can help produce 95 TWh of green hydrogen in 2050. In order to capture that there is 10 GW of installed electroyser capacity in 2030 and 100 GW in 2050.

The Widespread Innovation scenario has the highest demand and the highest share of renewables in 2050.

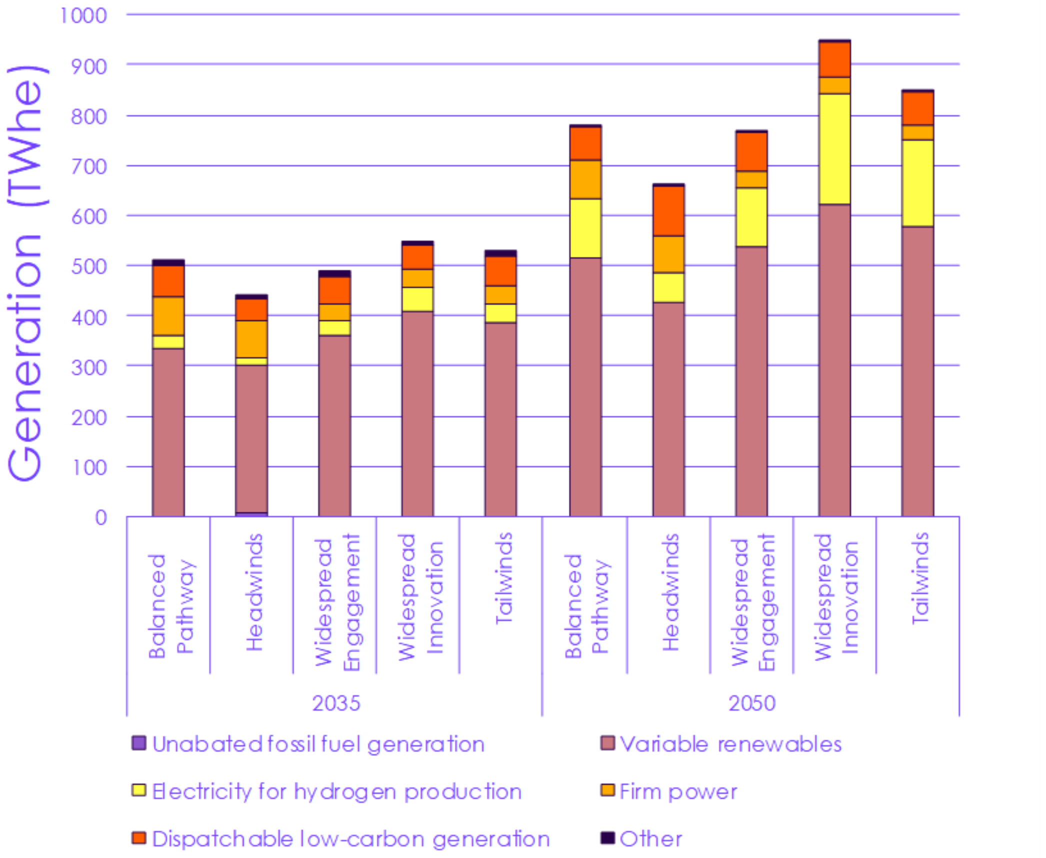
- **Widespread Innovation.** This scenario has the highest share of variable renewable generation, reaching 90% in 2050.
  - With 90% of generation being met by variable renewables in 2050, the remaining 10% of generation is delivered by a mix of nuclear, gas CCS, BECCS, and hydrogen.
  - The high level of demand in this scenario requires high and rapid deployment rates for low-carbon capacity, including an average of 6 GW per year of wind and 2 GW per year of hydrogen plant between 2030 and 2050.
  - The high level of renewables also provides more opportunity for use of energy that could produce up to 180 TWh of green hydrogen in 2050. This would require 10 GW of electrolysers by 2030 and 95 GW by 2050.

- **Tailwinds.** This scenario is very similar to Widespread Innovation, with variable renewables making up 90% of generation in 2050, with a mix of low-carbon generation to balance the system.

For the Sixth Carbon Budget period (2033-37), emissions from electricity generation across the exploratory scenarios are very low (Figure A3.4.f) and range from 23 to 35 $MtCO_2e$ over the five years. The range largely reflects the differing dates for phasing out unabated gas generation. Once this happens, all electricity is from decarbonised sources, with any residual emissions only coming from the small proportion of CO_2 emissions not captured at fossil CCS plants. This occurs by 2035 across all scenarios except for Headwinds, in which it happens by 2040.

Scenarios with higher deployment of renewables have greater potential for use of surplus generation.

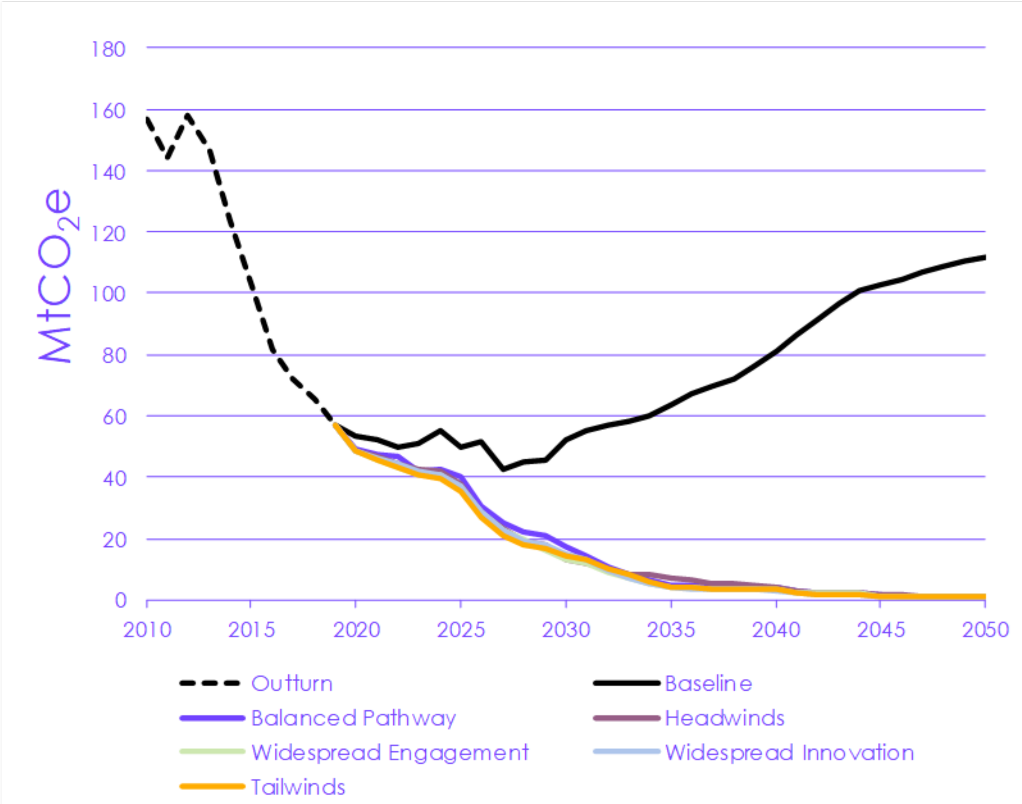
Figure A3.4.e Illustrative generation mix for the exploratory scenarios (2035 and 2050)



Source: CCC analysis.
Notes: Chart reflects UK electricity generation. Additional capacity is available through interconnection. Unabated fossil fuel generation includes coal and gas. Variable renewables includes wind and solar. Firm power includes nuclear. Dispatchable low-carbon generation includes gas CCS, BECCS and hydrogen.

Emissions over the Sixth Carbon Budget Period (2033-37) from electricity generation are very low, because the system is entirely low-carbon by 2035.

Figure A3.4.f Emissions pathways for electricity generation (2010-50)



Source: BEIS (2020) *2018 UK greenhouse gas emissions: final figures*, BEIS (2020) *2019 UK greenhouse gas emissions: provisional figures;* CCC analysis.

Table A3.4.a
Summary of key differences in the electricity generation scenarios (2050)

	Balanced Net Zero Pathway	Headwinds	Widespread Engagement	Widespread Innovation	Tailwinds
Demand (TWh)	**610**	550	610	680	620
Extent of electrification	**Cars & vans Partial heating Partial manufacturing**	Cars & vans Partial heating Partial manufacturing	Cars & vans* HGVs Heating Partial manufacturing	Cars & vans HGVs Partial heating Partial manufacturing DACCS	Cars & vans* Partial heating Partial manufacturing DACCS
Renewable generation & capacity**	**80% of total Wind: 125 GW Solar: 85 GW**	75% of total Wind: 90 GW Solar: 85 GW	85% of total Wind: 130 GW Solar: 80 GW	90% of total Wind: 175 GW Solar: 90 GW	90% of total Wind: 160 GW Solar: 75 GW
Dispatchable generation & capacity***	**10% of total 65 GW**	15% of total 50 GW	10% of total 55 GW	8% of total 65 GW	7% of total 65 GW
Nuclear capacity	**Multiple projects 10 GW**	Multiple projects 10 GW	Contracted capacity 5 GW	Contracted capacity 5 GW	Contracted capacity 5 GW
Phase out of unabated gas	**2035**	2040	2035	2035	2035

Source: CCC analysis
Notes: *Although cars and vans electrify, these scenarios see a wider use of public transportation and active travel, thus reducing overall demand. **Variable renewables include wind and solar, including generation for electrolysis. ***Dispatchable low-carbon generation includes gas CCS, BECCS and hydrogen. These numbers do not include demand for producing hydrogen with electricity. Our scenarios produce electrolytic hydrogen using surplus electricity only, and with methane reformation if surplus electricity is not available. It does not therefore necessarily reflect an additional demand for electricity.

c) Impacts of the scenarios: costs, investment, and co-impacts

Our overall approach to assessing costs and benefits is set out in Chapter 5 of this report. This section sets out the implications for electricity generation, covering costs, investment requirements, and co-benefits.

i) Costs

We compare the costs of running the low-carbon electricity systems in our scenarios to the cost of running a high-carbon system (i.e. one based on unabated gas in the long-run). Although each scenario follows a broadly similar pathway for emissions, they do so with different levels of demand and different mixes of technologies. Both of these influence total costs:

- Scenarios with higher levels of demand tend to have higher total costs, because more generating capacity and network investment is required.
- Scenarios with more deployment of relatively expensive technologies have higher total costs. Table A3.4.b sets out the cost of different technologies.

Table A3.4.b Costs of generation technologies			
	2020 £/MWh	**2035 £/MWh**	**2050 £/MWh**
Unabated gas plant (excluding carbon price)	50	60	60
Variable renewables	65	40-45	25-40
Firm power	-	85-105	85-105
Dispatchable low-carbon power	-	100-205	110-220

Source: CCC analysis based on BEIS (2020) *Electricity Generation Costs*, CCC (2018) *Hydrogen Review*, Wood Group (2018) *Assessing the Cost Reduction Potential and Competitiveness of Novel (Next Generation) UK Carbon Capture Technology.*
Notes: Costs in 2019 prices. Costs based on a central gas price scenario. Variable renewables include wind and solar. Firm power includes nuclear. Dispatchable low-carbon generation includes gas CCS, BECCS, and hydrogen.

There are limited additional costs of decarbonisation by 2035, and the Balanced Pathway is cost-saving by 2050.

Our analysis shows that a near-zero electricity system has limited additional costs in 2035 compared to a high-carbon system (e.g. up to £3 billion). By 2050 the annual additional cost ranges between -£5 billion and £9 billion across the scenarios.

- **Balanced Pathway.** In this scenario, there is an additional cost in 2035 of £3 billion compared to a high-carbon system. By 2050, costs decrease with the uptake of relatively cheap renewables, resulting in cost savings of £5 billion.
- **Headwinds.** The additional cost in this scenario is £2 billion in 2050. With the lowest level of demand (550 TWh) and the highest share of the most expensive technologies, that implies a relatively high average cost of generation compared to the other scenarios.
- **Widespread Engagement.** In 2050 there is no additional cost for delivering this scenario. Despite a higher level of demand (610 TWh), this is achieved through a greater use of relatively cheap renewables compared to the Headwinds scenario.
- **Widespread Innovation.** This scenario has an additional cost of £2 billion in 2050, but with the lowest average cost of generation. Compared to the Headwinds scenario it meets 25% more electricity demand for the same total cost.
- **Tailwinds.** This scenario has an additional cost of £9 billion in 2050, which is the highest across all of the scenarios. That reflects the higher share of more expensive technologies in the generation mix (e.g. BECCS), combined with relatively high demand.

Costs of decarbonisation have reduced since our 2019 advice on Net Zero, reflecting a reduction in cost of renewable generation.

These estimates compare to an additional annual cost of £4 billion in our 2019 Net Zero advice for moving to a low-carbon system in 2050. Since then renewables costs have fallen (e.g. offshore wind costs in the Government's latest auction were £45/MWh for 2025 (in 2019 prices), compared to our previous assumption of £50/MWh in 2050), helping to reduce overall costs and increase the share of renewables in the scenario generation mixes.

ii) Investment

The additional investment required to decarbonise electricity generation peaks in the 2030s at around £15 billion per year.

Delivering our scenarios will require significant investment in deploying the low-carbon technologies needed to reduce emissions and meet new electricity demands.

Figure A3.4.g shows the additional capital expenditure, and operational cost savings, for the Balanced Pathway compared to a high-carbon baseline.

- The total additional capital investment required (compared to a high-carbon system) rises to around £15 billion in 2035 and £5 billion in 2050.
  - Investment requirements peak in the 2030s, and are lower in the following period as costs of low-carbon technologies fall.
  - These investment costs include the additional cost of strengthening the electricity network to accommodate higher levels of demand. These costs make up around 30% of the total on average.
  - Capital investment in electricity generation helps avoid operational costs in other sectors, as those sectors electrify.

This capital investment is more than offset by the operational cost savings it enables.

- Total costs are lower than investment costs, given the significantly lower operational costs of running low-carbon technologies (i.e. renewables have no fuel input costs). The Balanced Pathway saves £10 billion in operational costs in 2050 compared to the high-carbon baseline.

Overall, by 2050 the operational cost savings under the Balanced Pathway more than offset the additional investment required in electricity generation.

Capital investment peaks in the 2030s and by 2050 is more than offset by operational cost savings.

Figure A3.4.g Additional investment requirements For electricity generation in the Balanced Net Zero Pathway (2020-50)

Source: CCC analysis.
Notes: Chart shows additional capital and operational expenditure in the Balanced Net Zero Pathway compared to a high-carbon baseline.

iii) Co-impacts

There could be significant co-benefits from decarbonising power, including for air quality, electricity prices, exports, and jobs

Reducing emissions in line with our scenarios will bring a range of co-benefits:

- **Air quality.** Switching from use of unabated fossil fuel for electricity generation to zero-carbon generation (i.e. variable renewables, nuclear) will help improve air quality, given these have no emissions. In addition, there will be wider improvements in air quality through the electrification of buildings, transport, and industry.[27]
- **Electricity prices.** Policy should ensure that electricity prices are cost-reflective (i.e. they reflect the low cost of adding low-carbon capacity and account for any system costs they impose), so that barriers to electrification are reduced and electricity consumers benefit from cost reductions in these technologies. That could include moving some costs away from electricity bill payers and onto general taxation, including for legacy costs of early renewables deployment. Chapter 6 sets out our analysis on energy bills.
- **Industrial opportunities and Just Transition.** The investment required to expand renewable generation, and to develop new markets in CCS and hydrogen, will help create new opportunities for firms, exports, and jobs. A

strong signal from Government on the long-term pathway for these new sectors will help give industry and investors confidence to undertake the long-term investments required to unlock these benefits.

- **Exports.** There is a significant opportunity for the UK to export engineering expertise, components, and services to the rapidly growing EU and global market for offshore wind. Similar opportunities would exist for CCS, where the UK is well placed to develop this industry, and hydrogen.
- **Just Transition and employment.** New offshore wind, hydrogen and CCS industries could help support the Government's 'levelling up' agenda through investment in regional economies, and by providing new jobs. A recent Policy Exchange study[28] estimated these could lead to a net gain of 40,000 direct jobs, plus more across the wider supply chain.

Further detail on the economy-wide co-benefits of the transition to Net Zero is set out in Chapter 5.

Endnotes

[24] CCC(2020) *The Sixth Carbon Budget – The Path to Net Zero.* Available at: www.theccc.org.uk
[25] Jacobs (2020) *Strategy for Long-Term Energy Storage in the UK*
[26] Ofgem https://www.ofgem.gov.uk/electricity/transmission-networks/electricity-interconnectors
[27] Air Quality Expert Group (2020) *Impacts of Net Zero pathways on future air quality in the UK*
[28] Policy Exchange (2020) *The Future of the North Sea*

Chapter 3

Policy recommendations for the electricity generation sector

Introduction

The following sections are taken directly from Chapter 5 of the CCC's Policy Report for the Sixth Carbon Budget.[29]

This chapter sets out the policy implications of the Committee's scenarios for decarbonising electricity generation that underpin the Sixth Carbon Budget.

The scenario results of our costed pathways are set out in the accompanying Advice and Methodology Reports. For ease, sections covering pathways, method and policy advice for electricity generation are collated in the Sixth Carbon Budget – Electricity Generation. A full dataset including key charts is also available alongside this document.

The key messages for electricity generation are (Table P5.1):

Electricity generation should be fully decarbonised by 2035. This will require phasing-out the use of unabated gas, and has implications for market design.

- **Electricity generation should be fully decarbonised by 2035.** That will need to happen while meeting a 50% increase in demand, and will require:
  - **Deployment of 400 TWh of new low-carbon generation,** including 50 TWh of dispatchable low-carbon generation to ensure security of supply.
  - **An increasingly flexible electricity system,** including from demand-side response (with 20% of demand being flexible in 2035), storage, hydrogen production, and interconnection.
  - **A coordinated strategic approach** to ensure all elements of the 2035 low-carbon transition are developed as a coherent package.
- **Phasing-out unabated gas by 2035.** The Government should commit to phasing-out unabated gas generation by 2035, subject to ensuring security of supply. This will require developing the markets for dispatchable low-carbon generation in the 2020s, to be in a position to regulate for a phase-out from 2030. No new unabated gas plant should be built from 2030, and those built prior to this should be suitable for retrofit.

Given lead-times for policy development and investment, Government should begin immediately planning market design for Net Zero.

- **Market design for Net Zero.** Renewables are likely to play a dominant role in the future electricity system (e.g. 70% of generation in 2035, and up to 90% in 2050). This will bring new challenges for the electricity market.
  - An evolutionary approach is appropriate over the short-to-medium term. But planning for running a fully decarbonised system should begin immediately, given lead-times for policy development and investment.
  - The Government should develop a clear long-term strategy as soon as possible, and certainly before 2025, on market design for a fully decarbonised electricity system.

We set out our assessment in two sections:

1. Current policy and gaps to be addressed
2. A policy framework for the Sixth Carbon Budget & Net Zero

Table P5.1
Summary of policy recommendations for electricity generation

Deploying low-carbon capacity	**Fully decarbonise electricity generation by 2035, while meeting a 50% increase in demand, through:** • Delivering 485 TWh of generation by 2035, which should all be low-carbon. That will require 400 TWh of new low-carbon generation. • Deploying variable renewables at scale, including 40 GW of installed offshore wind capacity by 2030 and sustaining that build rate to support deployment of up to 140 GW by 2050. • Deploying at least 50 TWh of dispatchable and flexible generation (e.g. gas CCS, hydrogen) by 2035 that can balance a system driven by renewables at low emissions. • An increasingly flexible system, including from demand-side response (with 20% of demand being flexible in 2035), storage, hydrogen production, and interconnection. **Develop and implement plans to overcome barriers to deployment, including through:** • Developing a holistic deployment strategy and planning and consenting regime for offshore wind as soon as possible to improve coordination, taking into account wildlife concerns, commercial activities, and radar interference. • Contracting models for nuclear, gas CCS, and BECCS that provide predictable revenue streams. • Demonstrating the viability of burning low-carbon fuels such as hydrogen or ammonia in gas turbines and then incentivising their deployment at commercial scale in the 2020s. **Ensure networks are ready to accommodate new generation technologies and new demands, by:** • Delivering plans to ensure investment in networks can accommodate future demand levels in coordination with Ofgem. • Developing a strategy to coordinate interconnectors and offshore networks for wind farms and their connections to the onshore network, bringing forward legislation necessary to enable that.
Phasing-out use of unabated gas	**By the end of 2021 the Government should:** • Commit to phasing-out unabated gas generation by 2035, subject to ensuring security of supply. • Publish a comprehensive long-term strategy for unabated gas phase-out. • Ensure new gas plant are properly CCS- and/or hydrogen-ready as soon as possible and by 2025 at the latest. **In the 2020s the Government should ensure unabated gas generation faces a carbon price consistent with it being phased-out by 2035, and incentivise initial deployment of low-carbon alternatives.** **From 2030, once further progress has been made and more information is available on the relative economics of different options, the Government should:** • Regulate for a firm pathway to zero unabated gas by 2035, subject to ensuring security of supply. • Not allow new unabated gas capacity to be built.
Electricity market design	**The Government should develop a coherent vision for a Net Zero electricity system by:** • Developing a clear long-term strategy as soon as possible, and certainly before 2025, on market design for a fully decarbonised electricity system. • Continuing the use of long-term contracts as an appropriate investment mechanism. • Focusing on developing the market for gas CCS and hydrogen, strongly deploying low-carbon generation, and phasing-out unabated gas.

1. Current policy and gaps to be addressed

This section sets out the existing policies that have contributed to reducing emissions by 64% since 2012, in addition to the policy gaps that need to be addressed to deliver new low-carbon generation in the 2020s.

Policies for reducing emissions from electricity generation have been built up incrementally over the last several decades. They reflect a range of different regulatory and market-driven approaches:

- **Long-term contracts for electricity generation.** Contracts for Difference (CfDs) are long-term contracts which provide an investment mechanism that lowers risks and therefore costs. Offshore wind costs have fallen from £140-150/MWh for projects contracted in 2015 to around £40/MWh – below the cost of new gas-fired generation – for projects coming online in the mid-2020s.
- **Carbon pricing.** A price on carbon helps incentivise lower-carbon generation to be dispatched ahead of higher-carbon generation. UK generators currently face a carbon price through the EU Emissions Trading System (EU ETS), and an additional top-up through the UK Carbon Price Support. The Government will introduce a UK ETS or carbon tax after leaving the EU.
- **Coal phase-out.** Use of coal in electricity generation decreased by nearly 95% between 2012 and 2019, driven by a combination of factors, including EU-wide regulations on air quality, carbon pricing, and retirement of old coal power stations (Box P5.1). The UK Government has committed to ending the use of coal for electricity generation by 2024.
- **Energy efficiency.** Energy efficiency policies and standards agreed by EU Member States have helped reduce electricity consumption. For example, the installed share of efficient (A-rated or better) home appliances has increased from 9% in 2012 to 34% in 2019, and the installed share of low-energy lightbulbs from 20% in 2012 to 50% in 2019.
- **Flexibility and security of supply.** The Capacity Market (CM) has ensured security of supply by creating a predictable revenue stream for backup capacity, demand-side response (DSR), and storage. This now includes 15-year CM agreements for DSR, which contribute to securing more flexibility in the electricity system.
- **Networks.** Ofgem has published new guidance that requires network companies to propose and present new evidence on Business Plans that are consistent with the Net Zero target.

This combination of policies has helped emissions fall 72% below 1990 levels.

This set of policies has been effective so far in helping reduce emissions, which have fallen by 64% since 2010 and are now 72% below 1990 levels. This is the fastest rate of any sector of the economy. In doing so, variable renewable capacity has increased from 5.5 GW in 2010 to 37.5 GW in 2019, increasing the share of generation from 3% to 25% over the same period.

The key challenge for the sector is to ensure this progress continues. A number of changes are required:

Reaching Net Zero will need a rapid expansion of low-carbon generation, a move away from unabated gas, and policies to incentivise this.

- **Deploying low-carbon generation,** including variable renewables and dispatchable low-carbon generation.
  - Under our Balanced Net Zero Pathway, demand for electricity increases by 50% by 2035 and 100% by 2050, reflecting increasing electrification of the economy (e.g. use of electric vehicles in transport).
  - With offshore wind as the backbone of the energy system, renewables could contribute up to 90% of generation by 2050.[9] The aim should be for 75-140 GW of offshore wind capacity by 2050, up from 40 GW in 2030.
  - No single technology can deliver all the generation that is needed to meet new electricity demands, meaning that a portfolio of zero-carbon generation technologies will be needed, also including onshore wind, solar and nuclear. Bioenergy with carbon capture and storage (BECCS) could provide capacity and generation, while also delivering greenhouse gas removals (see section 2a).
  - To manage a system based largely on variable generation, there will need to be greater flexibility. That includes from demand (including demand-side response, and use of surplus generation for hydrogen production), from storage and interconnection, and from use of dispatchable low-carbon generation (e.g. hydrogen, fossil gas with CCS).
- **Moving completely away from unabated fossil fuel generation.** After the end of coal generation by 2024, this will require phasing out the use of unabated gas for electricity generation. The Government should commit to achieving this by 2035, subject to ensuring security of supply.
- **Market design.** A well-functioning market structure will be needed to deliver these changes and provide the right incentives for investors, generators, and consumers. The Government is planning to publish an Energy White Paper in 2020, which is expected to set out their view on the changes needed in the energy system to meet Net Zero.

New policies will be needed to meet the challenge of a Net Zero electricity sector.

Existing policies have helped reduce emissions in the power sector. However, new policies will need to be put in place and others will need to be scaled up to meet the Sixth Carbon Budget and Net Zero, to which we now turn.

[9] Including generation for hydrogen production.

A strategic approach will be needed to ensure electricity generation decarbonises coherently in a way which minimises costs.

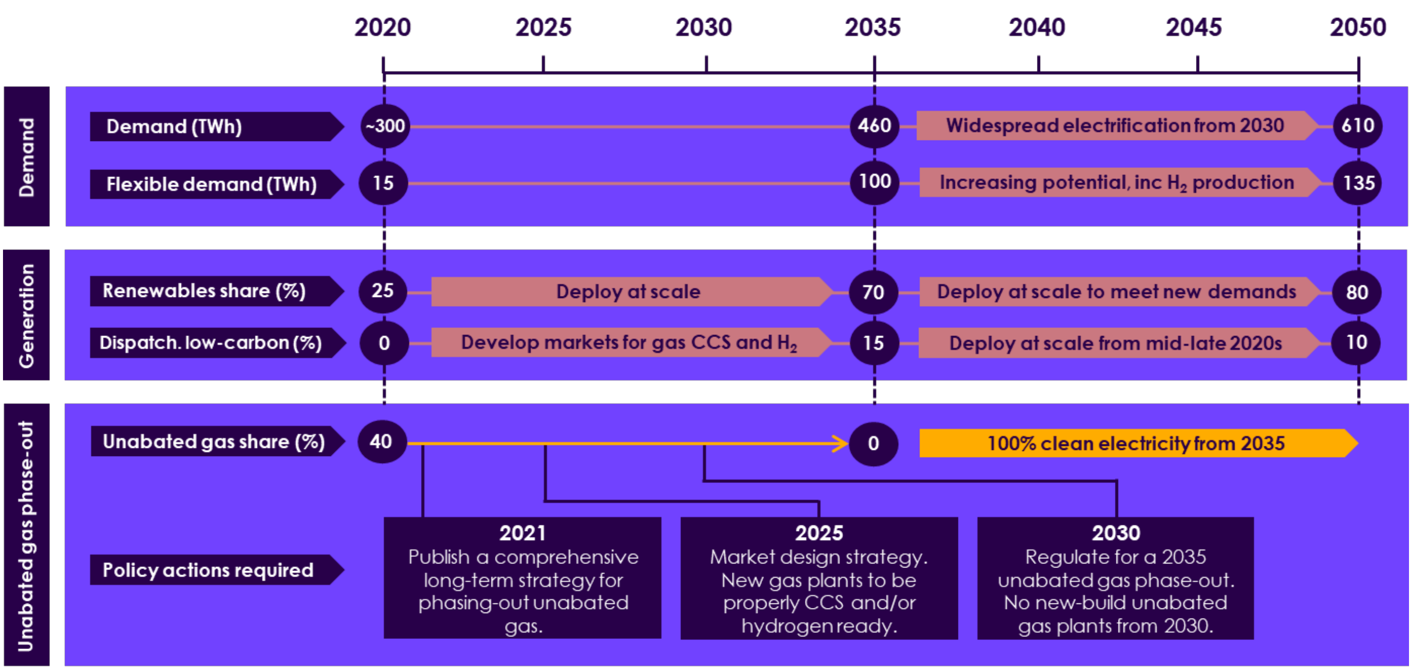
The Sixth Carbon Budget pathways set out the transition to Net Zero, including fully decarbonising electricity generation by 2035. The Government should take a strategic approach to ensure all elements of the transition for electricity generation are developed as a coherent package. In this section we discuss those elements in the following three sections and summarised in Figure P5.1:

a) Deploying low-carbon electricity at scale

b) Phasing-out unabated gas generation

c) Market design to deliver Net Zero

Figure P5.1 Timeline of key outcomes and policy requirements under the Balanced Pathway (2020-50)



Source: CCC analysis.
Notes: Renewables share includes wind and solar. Dispatchable low-carbon generation includes gas CCS, BECCS, and hydrogen plants. Demand is lower than generation, accounting for losses, flexibility services, and interconnection.

Low-carbon generation will need to scale up to meet a 50% increase in electricity demand by 2035.

a) Deploying low-carbon electricity at scale

Our Balanced Pathway involves a reduction in the emissions intensity of electricity generation from around 200 gCO_2/kWh today to 10 gCO_2/kWh in 2035, and 1-2 gCO_2/kWh in 2050.[10]

Achieving this while meeting a 50% increase in demand by 2035 will require a very significant increase in low-carbon generation.

- Under the Balanced Pathway 485 TWh of generation will be required in 2035, which must all be low-carbon.
  - Currently around half (i.e. 130 TWh) of all generation is low-carbon. However, given expected nuclear plant retirements, that number is likely to fall to around 90 TWh by 2030 without new projects.
  - By 2035 the Balanced Pathway therefore requires around an additional 400 TWh of new low-carbon generation in order to meet demand.
  - Close to 50 TWh of renewables, BECCS, and nuclear have already been committed, meaning around an additional 350 TWh of new low-carbon generation is required beyond that.
- This additional low-carbon generation will need to be met through a scaling up of variable renewables and decarbonised dispatchable generation.
  - Variable renewables (i.e. wind and solar) form the majority - 70% - of electricity generation in 2035.[11]
  - To balance the system and ensure security of supply there will be a need for dispatchable low-carbon generation. Our scenarios suggest that we would need at least 50 TWh of dispatchable and flexible generation from gas CCS (4-7 GW), BECCS (3-4 GW) and hydrogen (10-20 GW).

There are a range of barriers that will need to be overcome to enable the levels of deployment required under our scenarios:

Potential barriers to offshore wind deployment include supply chains, the consenting regime, and issues of the wider marine environment.

- **Offshore wind.** The pace of offshore wind deployment will need to accelerate in the 2020s in order to meet the 40 GW target and be sustained, if not increased, to meet Net Zero which could require up to 140 GW of capacity by 2050.
  - Supply chains will require long-term signals over capacity needs to provide a predictable environment to investors and developers. This includes certainty on offshore wind consenting and support mechanisms in order to avoid stop/start supply-chain investment.
  - Crown Estate England and Wales has unlocked a total of 45 GW of offshore wind in the seabed. In addition, the first round of ScotWind leasing could lead to leasing seabed in Scottish waters for an additional 10 GW. This is more than sufficient for the Government's 2030 target. Nonetheless, securing new seabed leases requires several years as projects require pre-development planning, consenting

[10] Covers direct emissions from electricity generation (i.e. the non-captured CO_2 from gas CCS), but excludes upstream emissions from natural gas used in CCS and/or hydrogen production, and negative emissions from BECCS.

[11] This includes surplus generation used to produce hydrogen.

applications, and construction. Accordingly, the UK will need to hold new leasing rounds to provide clarity to developers.

  - There may be constraints to offshore wind deployment from wider factors in the marine environment including wildlife concerns, commercial activities, and radar interference. The Government should develop a deployment strategy and planning and consenting regime that takes these issues into account. Coordination between the Crown Estates, Government, industry, and key stakeholders could ensure wider monitoring of these impacts beyond that of project operators.

Policy will also need to deliver deployment of hydrogen, new nuclear, and CCS.

- **Hydrogen.** Hydrogen plays a key role in our scenarios to ensure security of supply in a low-carbon manner. Policy will need to support the uptake of hydrogen in the 2020s and the accelerated deployment in the 2030s (Chapter 6).
  - In the 2020s, hydrogen blending should be tested with gas before moving on to 100% hydrogen. This will help demonstrate the viability of burning hydrogen in gas turbines in the next decade before accelerating the pace of hydrogen plant deployment in the 2030s.
  - All new-build gas plant should be ready to retrofit hydrogen or CCS from 2025. For hydrogen, this will entail building plants near hydrogen production infrastructure and designing plants that can accommodate the burning and storage of hydrogen.
- **Nuclear.** The Government should consider contracting models which help make new nuclear projects commercially viable for private developers.
- **Carbon capture and storage (CCS).** The development of CCS will be essential across the economy, including for electricity generation where it could help provide dispatchable low-carbon generation (in conjunction with fossil gas) and help remove emissions from the atmosphere (in conjunction with bioenergy, see Chapter 12). The development of this technology could require the support of a long-term contract, which may need to be adjusted for dispatchable generation.

The electricity network will also need to be in a position to manage the expected higher levels of demand and generation out to 2050. That will require additional investment and a more strategic coordination of connections from the offshore to onshore network.

Electricity networks will need to be future-proofed to enable rapid electrification of the economy.

- **Electricity networks.** Many networks will need to be upgraded in a timely manner and future-proofed to limit costs and enable rapid uptake of electric vehicles and heat pumps:
  - The cost of upgrading distribution network capacity is relatively insensitive to the size of the capacity increase, as most of the cost is in the civil works rather than the equipment (e.g. larger cables).
    - It is essential, therefore, that when grid capacity is increased, this is to a sufficient level to avoid having to upgrade the capacity again prior to 2050.
    - A relatively large expansion in capacity is likely to have low regrets, 'future-proofing' the network to enable greater electrification if necessary and/or enabling demand to respond more readily to variations in low-carbon electricity supply.

- It is important that grid capacity constraints do not impede growth of electric vehicle deployment in the 2020s, given the emissions savings and cost savings they will bring. It will therefore be important either to make anticipatory investments to upgrade electricity networks and/or to re-open the allowed investment partway through the 2023-2028 regulation period (i.e. RIIO-ED2) to ensure timely upgrades.
- Transmission network capacity will need to keep pace with developments on generation (e.g. large-scale offshore wind) and interconnections, and with the need to ensure that peak demand can be met reliably in all areas on still days as well as on windy days.

Expansion of offshore wind will require a more coordinated approach to offshore networks and their onshore connections.

- **Offshore network connection.** Under current arrangements project developers are responsible for building the networks and connections required to bring offshore energy onshore. While this has helped de-risk project delivery to-date, in future it may be more efficient to coordinate these connections, given the high level of deployment required and the significant local impacts of the onshore infrastructure.
  - The Government has recognised this issue, and in July 2020 announced an *Offshore Transmission Network Review*. This aims to set out an enduring approach in 2021.
  - That approach should include a strategy to coordinate interconnectors and offshore networks for wind farms and their connections to the onshore network and should bring forward any legislation necessary to enable coordination.

b) Phasing-out unabated gas generation

The UK will need to move away from burning unabated gas in order to fully decarbonise electricity generation.

The Government has committed to ending the use of coal for electricity generation by 2024. After this the only significant remaining source of emissions in the power sector will be from unabated gas generation.

It is therefore important to set out a pathway for phasing-out the use of unabated gas generation, after which electricity generation will be entirely low-carbon.

Such a pathway will need to:

Phasing-out unabated gas will require dispatchable low-carbon alternatives, providing the right incentives, and preventing lock-in.

- **Develop markets for dispatchable low-carbon alternatives to unabated gas generation.** These will be needed to complement variable renewable generation, and includes gas with carbon capture and storage (CCS) and hydrogen. These technologies exist but need to be commercialised and deployed at scale.
- **Provide the right incentives for low-carbon generation,** so that these technologies are dispatched ahead of unabated gas in the merit order once they are commercially available.
- **Prevent lock-in of unabated gas technology.** That includes ensuring that any new-build unabated gas plant are properly able to retrofit for CCS or hydrogen and, subsequently, ensuring they are no longer built.

This transition is likely to be more challenging than the move away from coal, given that low-carbon alternatives that could play the same role as gas (e.g. gas CCS, hydrogen) still need to be fully commercialised and deployed at scale. Box P5.1 sets out the key transferable lessons from the coal transition.

Box P5.1

How the UK phased-out coal generation

In 1990, coal provided 80% of UK electricity generation. By 2019 it provided 2% (Figure PB5.1), and the Government has committed to phasing it out completely by 2024.

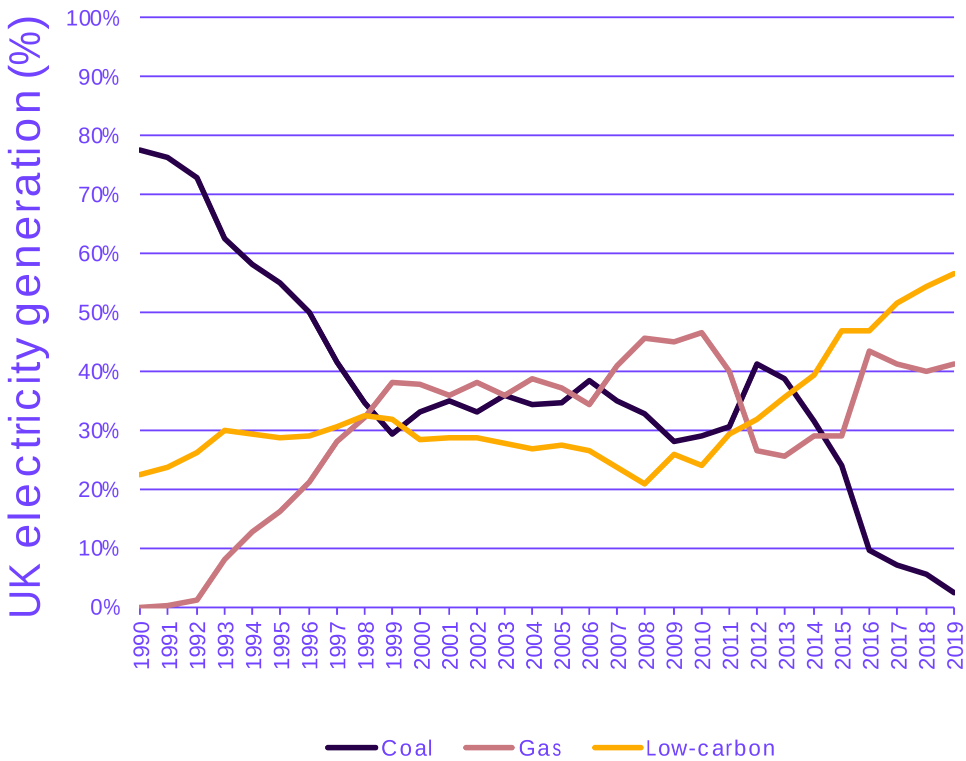
This transition has been the result of a number of factors across three distinct phases, including market forces, air quality legislation, and climate policy:

- **Market forces.** Coal use fell from 80% of generation in 1990 to 30% in 1999 as a result of the 'dash-for-gas' in the 1990s. That was driven by liberalisation of the energy markets and economic forces which favoured gas investment over coal and nuclear.
- **Air quality legislation.** The 2001 Large Combustion Plant Directive (LCPD, superseded by the Industrial Emissions Directive) was a policy agreed by EU Member States to limit air quality emissions. Large plants had a choice to comply with the emissions limits or opt-out. Plants which opted-out were limited to a maximum of 20,000 hours of further operation, and had to close completely by the end of 2015. In the UK nine plants, totalling 12 GW of capacity, decided to opt-out and therefore close.[30] That reflected the age of those plants, meaning retrofit to meet the emissions standards would not be cost-effective.
- **Climate policy.**
  - The introduction of the EU Emissions Trading System (EU ETS) in 2005, and in the UK the Carbon Price Support in 2013, combined to put a price on carbon emissions which has made coal generation less economic compared to unabated gas and low-carbon generation.
  - Support for low-carbon generation (e.g. through long-term contracts) has helped expand supply, creating the potential for alternative sources to substitute for coal while still meeting demand.
  - In addition, the UK Government has committed to ending the use of coal by 2024. While not a legislated target, this has provided a strong signal to investors that new coal is not viable.
  - Combined with LCPD compliance, these policies have helped reduce the share of coal in generation from 40% in 2013 to 2% in 2019.

The lessons from the phase-out of coal are that a range of policy approaches - both regulatory and market-driven - are required in order to influence investment and dispatch decisions. With the right policies in place and sufficient alternative low-carbon generation, the transition away from coal in the UK has ultimately been a smooth one.

Coal fell in the 1990s from 80% to 30% of generation due to the 'dash-for-gas'. In the 2010s it fell to 2%, with a rise in low-carbon and gas generation.

Figure PB5.1 Share of electricity generation by source (1990-2019)



Source: CCC analysis based on BEIS (2020) *Energy Trends: Table 5.1* and BEIS (2020) *Energy Trends: Table 6.1*

The Government should commit to phasing-out use of unabated gas in electricity generation by 2035 (subject to ensuring security of supply). Box 5.3 in Chapter 5 of the accompanying Methodology Report sets out why 2035 is an achievable date.

Ensuring unabated gas is phased-out by 2035 will require a range of policy approaches. That includes innovation and market development for gas CCS and hydrogen, and a firmer regulatory approach once these are commercially deployable at scale (Figure P5.1).

In 2021 the Government should commit to a 2035 phase-out date, publish a long-term strategy to achieve that, and address new build.

By the end of 2021 the Government should:

- Commit to phasing-out unabated gas generation by 2035, subject to ensuring security of supply.
- Publish a comprehensive long-term strategy for unabated gas phase-out.
- Ensure new gas plant are properly CCS-ready and/or hydrogen-ready as soon as possible and certainly by 2025.
  - Properly ready means located in areas that will be supported by CO_2 and/or hydrogen infrastructure.
  - The Government should review the current 300 MW threshold for CCS-readiness in light of a 2035 gas phase-out, to avoid risk of new capacity being stranded while ensuring security of supply.

The current 300 MW threshold for CCS-readiness has distorted incentives and should be reviewed.

- Demonstrating that CCS retrofit is technically and economically feasible for new plant has been a requirement of planning consent since 2009.[31]
- A key weakness of those requirements is that they only apply to plant above 300 MW capacity. This has given incentives to developers to build below the threshold (e.g. at 299 MW) in order to avoid those obligations, and has created risk of stranded plant that are not future-proofed.
- Nevertheless, owners of new plants above the 300 MW threshold have known for over a decade that phase-out of unabated operation could be required during their lifetimes.

An effective long-term strategy should set out the actions and timings needed to be in a position to regulate for a phase-out from 2030:

A long-term strategy should develop the markets for gas CCS and hydrogen, and ensure these dispatch ahead of unabated gas.

- In the 2020s the Government should put in place policies to:
  - Deliver decarbonised dispatchable capacity (e.g. gas CCS and hydrogen) and deploy low-carbon generation at scale.
    - That should include developing low-carbon hydrogen supply chains, CCS infrastructure and networks, and identifying the locations where plants can be classed as 'ready'.
  - Ensure operation of low-carbon generation ahead of unabated gas plant, reducing unabated gas solely to a back-up/peaking role.
    - That includes ensuring unabated gas generation faces a carbon price consistent with phasing-out by 2035.

The Government should regulate for a firm pathway to zero unabated gas from 2030.

- From 2030, once further progress has been made and more information is available on the relative economics of different options, the Government should:
  - Regulate for a firm pathway to zero unabated gas by 2035, subject to ensuring security of supply. Policy options include:
    - An emission intensity standard for generation that declines to zero in 2035.
    - An 'hour limit' on generation, which could be spread over several years or decline to zero in 2035.[12]
  - Not allow new unabated gas capacity to be built, so that all additional capacity built from 2030 onwards is low-carbon.

c) Market design to deliver Net Zero

Current market arrangements have been successful at delivering low-carbon generation, but Net Zero will bring new challenges.

The current policy framework has succeeded in bringing forward additional low-carbon capacity at low cost. Low-carbon sources are now responsible for over half of electricity generation.

Delivering a fully decarbonised electricity system will bring a range of new challenges which current market arrangements are not fully designed for (Table P5.2).

[12] This could potentially be a very low but non-zero allowance to allow for some ultra-peaking unabated gas use, depending on security of supply constraints.

High uptake of variable renewables is likely to lead to increasing periods of zero or negative prices, which could lead to a hiatus in investment.

- **High proportion of variable renewables.** Our scenarios have variable renewables providing 70% of generation in 2035 and up to 90% in 2050, compared to around 20% in 2019.
  - These technologies have high upfront capital costs, but zero marginal costs of generation.
  - With increasing deployment of zero-marginal-cost renewables, and a market structure designed around marginal cost pricing, there are likely to be an increasing number of periods where the wholesale price is close to zero or negative.
  - This creates a risk that generators may not be able to cover their fixed costs, and hence that investment in low-carbon generation is not delivered at the required levels.

The future electricity system will need to reward flexibility, in order to accommodate high levels of variable renewables.

- **Need for more a more flexible system.** With higher levels of variable renewables comes the need for a more flexible system, including through demand-side response, use of surplus generation to make hydrogen, storage, and interconnection. The market structure will need to provide signals to ensure the system rewards these services and provides the required levels of investment.

Table P5.2
Future structure of the electricity system

	Current system	Net Zero system
Demand	300 TWh	Up to 1,000 TWh
Emissions	~200 gCO_2/kWh	1-2 gCO_2/kWh
Variable renewables	20% of generation	Up to 90% of generation
System structure	Meets demand by flexing supply	Matches supply by flexing demand and/or supply
Role of demand	Passive	Flexible, including for hydrogen production
Cost structure	Mainly marginal	Mainly capital

Source: Adapted from Robinson and Keay (2020) *Glimpses of the future electricity system? Demand flexibility and a proposal for a special auction.*

Current market arrangements have been incrementally developed over several decades.

The current market design has been developed incrementally over the last several decades and includes:[32]

- **Wholesale market.** This provides generators with the price signals to help decide whether they should run their capacity, whether they should invest in new capacity, and whether they should close existing capacity.
- **Capacity market.** This pays generators for the availability of capacity, in order to ensure there is adequate generation at times of high demand.
- **Balancing market.** This is used to reconcile market decisions about plant dispatch with what can actually be delivered through the physical network.
- **Network charges.** These cover the cost of running the electricity transmission and distribution network.
- **Carbon policy.** Various policies are used to reward and incentivise low-carbon generation, including a carbon price (e.g. through the EU ETS, and UK Carbon Price Support), and long-term contracts for generators.

Future market arrangements will need to evolve to meet the Net Zero challenge.

In future the market will need to incentivise:

- Investment in very high levels of variable and low-marginal cost low-carbon capacity.
- Investment in sufficient decarbonised dispatchable low-carbon capacity (including storage) to ensure security of supply.
- Flexible demand, including for hydrogen production.
- Phase-out of unabated gas generation.

Future market arrangements should provide predictable signals across both demand and supply, and should ensure security of supply.

A range of options have been suggested for future market arrangements.[33] Future reform should be guided by three principles:

- **The need for certain and predictable signals.** Clearly signalled in advance, these will reduce costs and give market participants confidence that the regulatory regime will support the levels of investment required. That includes the role for Government in developing new technologies as well as supporting mature ones.
- **The need for a whole-market approach.** This should reflect the importance of both flexible demand and supply of low-carbon electricity, so that both are rewarded in competitive markets to deliver the lowest-cost overall system.
- **The need to ensure security of supply.** Alongside variables renewables, there will be a need for dispatchable low-carbon capacity to ensure security of supply. Business models will be required to support this, even though they may only run at very low load factors.

There are clearly defined phases to the Net Zero transition, which will require different policy approaches.

Figure P5.1 shows that the transition to a near-zero emission electricity system will have several phases, which are likely to require different policy approaches:

- **2020s:** Deploying low-cost renewables at scale and developing the markets for gas CCS and hydrogen.
- **2030s:** Transitioning to a completely low-carbon system by displacing unabated gas with low-carbon alternatives by 2035, alongside ramping up deployment of zero-carbon generation to keep pace with electrification of end-use sectors and increasing potential for demand-side flexibility via electric vehicles, heat pumps, and hydrogen production.
- **2040s:** Running a fully decarbonised electricity system, with variability in renewable generation managed through flexible demand, medium- and long-term storage, and use of dispatchable low-carbon generation.

An evolutionary approach is appropriate in the short-to-medium term.

This suggests an evolutionary approach is likely to be appropriate over the short-to-medium-term, but planning should begin immediately for the more fundamental challenges of running a completely decarbonised system:

- **Long-term contracts remain appropriate.**
  - CfDs have been successful at procuring low-cost, low-carbon capacity.
  - They remain appropriate given the capital-intensive nature of low-carbon technologies, and the need for bankable revenue streams.

In the 2020s the Government should focus on developing the markets for gas CCS and hydrogen.

- **In the 2020s, Government policy should focus on developing the market for gas CCS and hydrogen.**

- In order to phase out unabated gas by 2035, the Government will need to put in place policy to develop the markets for dispatchable alternatives.
- Without further intervention, markets are unlikely to pull through these technologies at the scale and on the timeframes required.

The Government should develop an approach for market design under a fully decarbonised electricity system as soon as possible.

- **The Government should develop a clear long-term strategy as soon as possible, and certainly before 2025, on market design for a fully decarbonised electricity system.**
  - Under our scenarios renewables uptake reaches 65-70% of generation by 2030, suggesting the impact of zero marginal cost production on the system will become increasingly apparent during this decade. The system is then entirely low-carbon by 2035.
  - Given lead times for policy development, investment decisions, and construction, and the high and sustained build rates required, it will be important to start planning for a fully decarbonised system soon in order to avoid a hiatus in investment.
  - Government should develop a clear long-term strategy as soon as possible, and certainly before 2025, on the future changes required to deliver a fully decarbonised electricity system.

These recommendations will help ensure the Net Zero transition for electricity generation is delivered smoothly, avoids hiatus in investment, and minimises costs to consumers.

Endnotes

[29] CCC(2020) *Policies for the Sixth Carbon Budget and Net Zero*. Available at: www.theccc.org.uk

[30] National Grid ESO (2007) *Large Combustion Plant Directive, GCRP 07/32.*

[31] DECC (2009) *Carbon Capture Readiness (CCR). A guidance note for Section 36 Electricity Act 1989 consent applications.*

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[33] Blyth, W, Gross, R, and Rhodes, A (2020) *Electricity markets with a high share of variable renewables. A review of issues and design options.*

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