# NET ZERO

## Opportunities for the power sector

NATIONAL INFRASTRUCTURE COMMISSION

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# Contents

# The Commission

## The Commission's remit

The Commission provides the government with impartial, expert advice on major long term infrastructure challenges. Its remit covers all sectors of economic infrastructure: energy, transport, water and wastewater (drainage and sewerage), waste, flood risk management and digital communications. While the Commission considers the potential interactions between its infrastructure recommendations and housing supply, housing itself is not in its remit. Also out of the scope of the Commission are social infrastructure, such as schools, hospitals or prisons, agriculture, and land use

The Commission's objectives are to support sustainable economic growth across all regions of the UK, improve competitiveness, and improve quality of life.

The Commission delivers the following core pieces of work:

- a National Infrastructure Assessment once in every Parliament, setting out the Commission's assessment of long term infrastructure needs with recommendations to the government
- specific studies on pressing infrastructure challenges as set by the government, taking into account the views of the Commission and stakeholders, including recommendations to government
- an Annual Monitoring Report, taking stock of the government's progress in areas where it has committed to taking forward recommendations of the Commission.

The Commission's binding fiscal remit requires it to demonstrate that all its recommendations for economic infrastructure are consistent with, and set out how they can be accommodated within, gross public investment in economic infrastructure of between 1.0% and 1.2% of GDP each year between 2020 and 2050. The Commission's reports must also include a transparent assessment of the impact on costs to businesses, consumers, government, public bodies and other end users of infrastructure that would arise from implementing the recommendations.

When making its recommendations, the Commission is required to take into account both the role of the economic regulators in regulating infrastructure providers, and the government's legal obligations, such as carbon reduction targets or making assessments of environmental impacts. The Commission's remit letter also states that the Commission must ensure its recommendations do not reopen decision making processes where programmes and work have been decided by the government or will be decided in the immediate future.

The Commission's remit extends to economic infrastructure within the UK government's competence and will evolve in line with devolution settlements. This means the Commission has a role in relation to non-devolved UK government infrastructure responsibilities in Scotland, Wales and Northern Ireland (and all sectors in England).

The Infrastructure and Projects Authority (IPA), a separate body, is responsible for ensuring the long term planning carried out by the Commission is translated into successful project delivery, once the plans have been endorsed by government.

# The Commission's members

**Sir John Armitt CBE (Chair)** published an independent review on long term infrastructure planning in the UK in September 2013, which resulted in the National Infrastructure Commission. Sir John is the Chair of National Express Group and the City & Guilds Group. He also sits on the boards of the Berkeley Group and Expo 2020.

**Dame Kate Barker** sits on the boards of Taylor Wimpey plc and Man Group plc. She also chairs the Jersey Fiscal Policy Panel, is the Chairman of Trustees at the British Coal Staff Superannuation Scheme, and a member of the Geospatial Commission. She was an external member of the Bank of England's Monetary Policy Committee from 2001 to 2010. In April 2020, she will become Chair-elect of the Universities Superannuation Scheme.

**Professor Sir Tim Besley CBE** is School Professor of Economics and Political Science and W. Arthur Lewis Professor of Development Economics at the LSE. He served as an external member of the Bank of England Monetary Policy Committee from 2006 to 2009.

**Professor David Fisk CB** is the Director of the Laing O'Rourke Centre for Systems Engineering and Innovation Research at Imperial College London. He has served as Chief Scientist across several government departments including those for environment and transport, and as a member of the Gas and Electricity Markets Authority.

**Andy Green CBE** holds several Chair, Non-Executive Director and advisory roles, linked by his passion for how technology transforms business and our daily lives. He chairs Lowell, a major European credit management company and has served as Chair of the Digital Catapult, an initiative to help grow the UK's digital economy.

**Bridget Rosewell CBE** is a director, policy maker and economist. She served as Chief Economic Adviser to the Greater London Authority from 2002 to 2012 and worked extensively on infrastructure business cases. She is a Non-executive Director at Network Rail, Chair of the Atom Bank and Non-executive Chair of the Driver and Vehicle Standards Agency.

**Professor Sadie Morgan OBE** is a founding director of the Stirling Prize winning architectural practice dRMM. She is also Chair of the Independent Design Panel for High Speed Two and one of the Mayor of London's Design Advocates. She sits on the boards of the Major Projects Association and Homes England.

**Julia Prescot** is a co-founder and Chief Strategy Officer of Meridiam and sits on the Executive Committee of Meridiam SAS. She has been involved in long term infrastructure development and investment in the UK, Europe, North America and Africa. Since 2019 she has sat on the board of the Port of Tyne.

# Executive summary

## Putting the UK on the pathway to a highly renewable electricity system is the best way to deliver low cost low carbon electricity for the UK.

**The net zero target makes this more urgent than ever.**

In June 2019 the government raised the UK's ambition on tackling climate change by legislating for a net zero greenhouse gas emissions target for the whole economy by 2050.[1] Decarbonising the power sector is integral to achieving this goal. Good progress has been made. Power sector emissions have fallen by around 53 per cent in the past decade,[2] and government has played a central role in supporting this reduction. The government's ambition to deploy 40 GW of offshore wind by 2030 is another welcome step. This positive progress must continue.

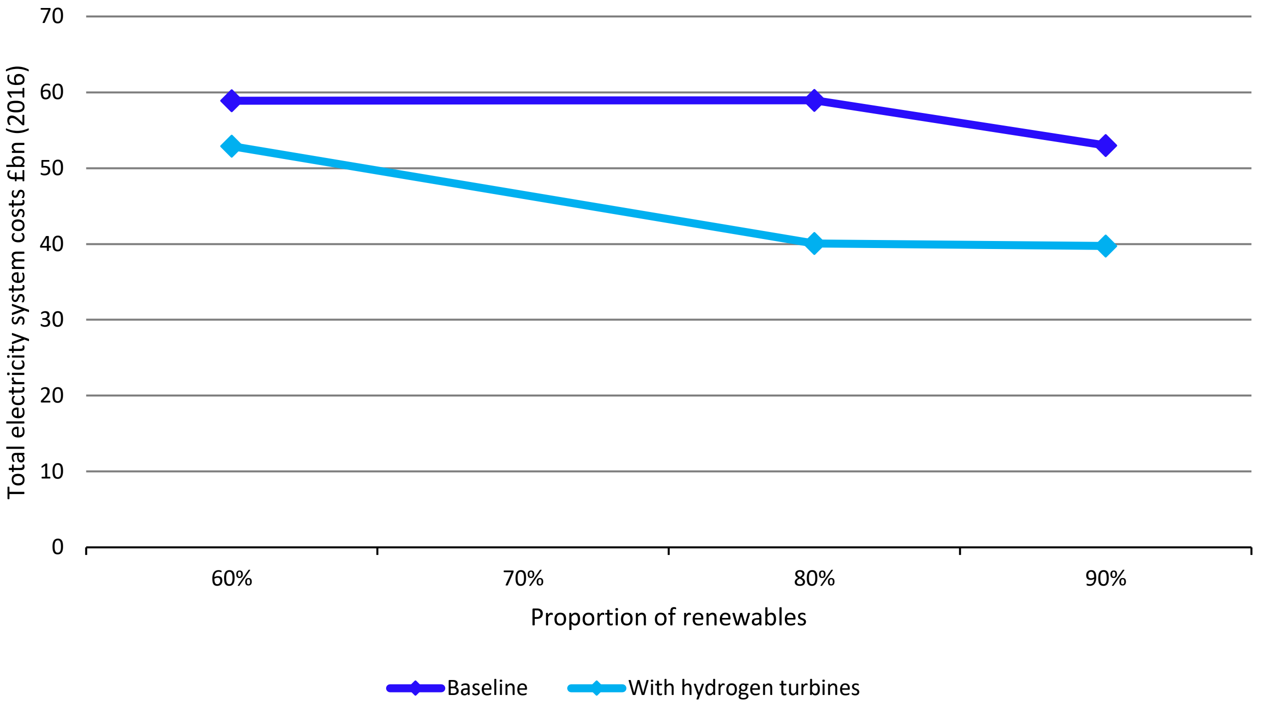
Delivering low carbon electricity while keeping costs affordable to consumers is key. Currently the average energy bill is around £1,200 per year[3], with electricity making up around £600 of this,[4] and energy bills make up on average 4 per cent of household expenditure.[5] For households in the bottom 10 per cent of the income distribution this increases to 8 per cent.[6]

Clearly, there is a lot of uncertainty when considering the UK in 2050. Accuratley knowing how people are going to heat their homes or move around cities and towns 30 years from now is an unachievable task. But uncertainty is not an excuse for inaction. It simply underlines the need to maintain optionality and flexibility in how the UK power system evolves.

That is why, in the *National Infrastructure Assessment*, the Commission set out clear, robust and achievable actions for government to take in the near term to support the decarbonisation of the power sector. These actions focused on setting the UK on the pathway to a highly renewable system. This is the best way to reduce emissions, keep costs low, and maintain optionality in a rapidly changing sector.

Modelling of the total cost of the power system in a net zero economy, carried out for the Commission by Aurora Energy Research,[7] demonstrates that increasing the proportion of renewables on the system does not materially impact the cost of the system. Future system costs may even be lower if action is taken to test the feasibility of deploying hydrogen turbines, an emerging technology for the power sector.

### Figure 1: Costs of net zero power systems (average annual costs from 2030 to 2050)




Note: the costs at 70% renewables have been estimated and not modelled.

### Table 1: Scenarios, cost and level of nuclear deployment

| Level of renewable penetration in 2050 | Total system costs (£2016) | Nuclear capacity deployed in addition to already contracted capacity |
|---|---|---|
| 60 per cent | £59bn | 24 GW, approximately 7 Hinkley Point C sized plants. |
| 80 per cent | £59bn | 7 GW, approximately 2 Hinkley Point C sized plants. |
| 90 per cent | £53bn | 3 GW, approximately, 1 Hinkley Point C sized plant. |

## Recommendations from the National Infrastructure Assessment

The analysis and insights summarised in this paper reaffirm the case for the Commission's recommendation to deliver at least 50 per cent renewable generation by 2030, as part of the transition to a highly renewable generation mix. Since the *National Infrastructure Assessment*, reductions in the cost of renewables have outstripped forecasts.

The latest modelling results also show that a highly renewable power system, combined with flexible technologies including hydrogen powered generation, could be substantially cheaper than alternatives that rely heavily on a fleet of nuclear power plants. There is considerable uncertainty around modelling over such a long time period and in a sector with so much technological change. It does not make sense to fully commit now to a system dominated by one technology, whether that is nuclear, offshore wind or another. Making such decisions now, for example by committing to a fleet of nuclear power plants, rules out a more diverse future generation mix and the potential this has to reduce costs to consumers.

That is why the Commission recommends that the government take action to ensure the UK is running on at least 50 per cent renewable generation by 2030, as part of the transition to a highly renewable system. A renewables based system looks like a safer bet at present than constructing multiple new nuclear plants. But a large amount of uncertainty does remain. Cancelling the nuclear programme entirely risks a 'stop start' approach which is likely to be highly inefficient. Agreeing support for no more than one more nuclear plant before 2025 allows the UK to pursue a highly renewable mix without closing off the nuclear alternative.

## Modelling approach

The work carried out for the Commission analyses the total electricity system costs of delivering a net zero compatible electricity system out to 2050. This involves modelling an electricity system that balances supply and demand for every half hour of the year. The costs presented include the costs of building, connecting and operating generation technology.

There are two different electricity demand scenarios assumed. One scenario assumes electrification of heating and the other assumes hydrogen for heating ('Greener Gas'). The modelling compares electricity systems with upwards of 50 per cent renewable generation beyond 2030 given current government commitments and the previous recommendation of the Commission.

Additionally, this work considers the impact that either hydrogen or bioenergy with carbon capture and storage could have if deployed in the power sector. Natural gas, which is used for producing hydrogen in some scenarios, is assumed to be available at current forecast prices.

## Net zero power systems with electrification of heat

Highly renewable systems are still a low cost option in a net zero world. The analysis once again finds that electricity system costs are broadly flat across a range of different levels of renewable penetrations. If hydrogen is deployed, providing low carbon and flexible generation, it could further reduce the costs of highly renewable systems, by up to 30 per cent in some scenarios modelled here.

If bioenergy with carbon capture and storage is deployed in the power sector, it is likely to be used to generate baseload. This leads to lower levels of nuclear, further highlighting the risks of committing to an extensive new nuclear fleet now.

## Net zero power systems with Greener Gas

The conclusions also hold in a lower demand scenario where heating has been decarbonised using hydrogen. This demonstrates that the Commission's analysis, and recommendations, are robust to uncertainty.

# Recommendations from the National Infrastructure Assessment

**The Commission considers that the UK electricity system should be running on at least 50 per cent renewable generation by 2030, as part of the transition to a highly renewable electricity supply. To achieve this, the government should set out a pipeline of Contracts for Difference auctions to deliver the needed generation. Recent analysis for the Commission also highlights the potential for hydrogen technology in the power sector, which further supports the case for pursuing a highly renewable system.**

**The government's ambition to deploy 40 GW of offshore wind will go a long way to delivering at least 50 per cent renewable generation by 2030. This positive progress needs to continue. Delivering the Commission's recommendations would allow government to take the needed concrete action in the near term, whilst not closing down options for the future.**

## The Commission's recommendations deliver a 21st century power system

**In the National Infrastructure Assessment the Commission recommended that government:**

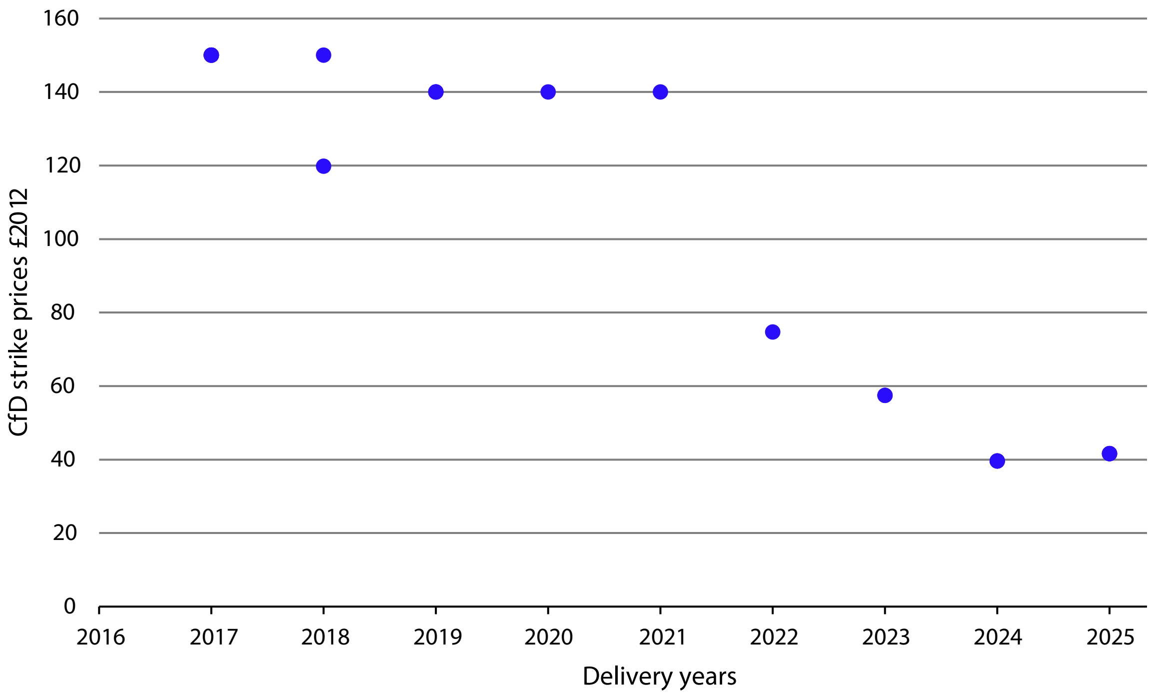
- set out a pipeline of pot 1 Contracts for Difference auctions, to deliver at least 50 per cent renewable generation by 2030, as part of the transition to a highly renewable generation mix
- move technologies that have recently become cost competitive, such as offshore wind, to pot 1 following the next Contracts for Difference auction in Spring 2019. Pot 1 should be used for the overwhelming majority of the increase in renewable capacity required
- publish indicative auction dates and budgets for the next decade by 2020
- over time take whole systems costs into account in Contracts for Difference auctions, as far as possible
- consider whether there is a case for a small-scale, pot 2 auction in the 2020s, if there are technologies which are serious contenders for future pot 1 auctions
- not agree support for more than one nuclear power station beyond Hinkley Point C, before 2025.

The considerations underpinning these recommendations are:

- **The analysis carried out for the Commission of future electricity system costs finds that systems with high penetrations of renewables are as cost effective as other systems** (Figure 1). This was true under the previous 2050 emissions target and it is still true with the new, more ambitious, net zero target. While there are uncertainties in any modelling, it is clear that ruling out the highest penetrations of renewables now would be counterproductive.
- **Renewable costs have consistently fallen faster than forecast.** The analysis summarised above uses informed and expert forecast of future technology costs, capturing a central view of how these costs could evolve. However, over the past decade renewables costs have consistently fallen faster than forecast. The latest Contracts for Difference auction once again demonstrated the rapid cost reductions in renewables (Figure 2), as the Commission suggested it might in its Assessment. Whilst this does not mean the Commission expects this to continue to happen, this presents an upside risk that renewables are even cheaper than currently expected. Other technologies that are key to low cost highly renewable systems, such as short term batteries, have also seen significant cost reductions over the past decade.[8]
- **In contrast, nuclear plants have not yet demonstrated consistent cost reduction.** Figure 3 shows the construction costs of nuclear power stations in various countries, by construction start date. With many decades of experience this data still shows no discernible trend in construction costs over time. This is true even for countries, such as France, that have built fleets of similarly designed reactors.
- **Emerging technologies, such as hydrogen, could further reduce the costs of highly renewable systems.** The Commission's latest analysis demonstrates that, if deployed, hydrogen, either generated from electrolysers using curtailed generation or gas reforming with carbon capture and storage (CCS), has the potential to materially reduce the cost of highly renewable electricity mixes. In some scenarios costs are reduced by up to 30 per cent.
- **If bioenergy with carbon capture and storage (BECCS) is deployed in the power sector, it will likely displace other baseload technologies such as nuclear.** The Committee on Climate Change have set out that BECCS will likely be needed to generate negative emissions. If deployed in the power sector the Commission's analysis finds it will likely generate baseload and therefore displaces some nuclear capacity.
- **Keeping options open in a rapidly evolving sector is important and putting the UK on the pathway to a highly renewable system does just this.** Costs and operability of different technologies will continue to change rapidly, and the UK must be responsive to this. Policy decisions that lock the UK consumer into paying for large scale programmes with long construction times risk missing opportunities that may emerge. In contrast to other technologies renewables have short construction timelines. Therefore, if action is taken to put the UK power system on a highly renewable pathway, and evidence emerges that makes the case for alternative technologies, it will be possible to change course. The potential cost savings from hydrogen in the power sector is one example that underlines the importance of this.

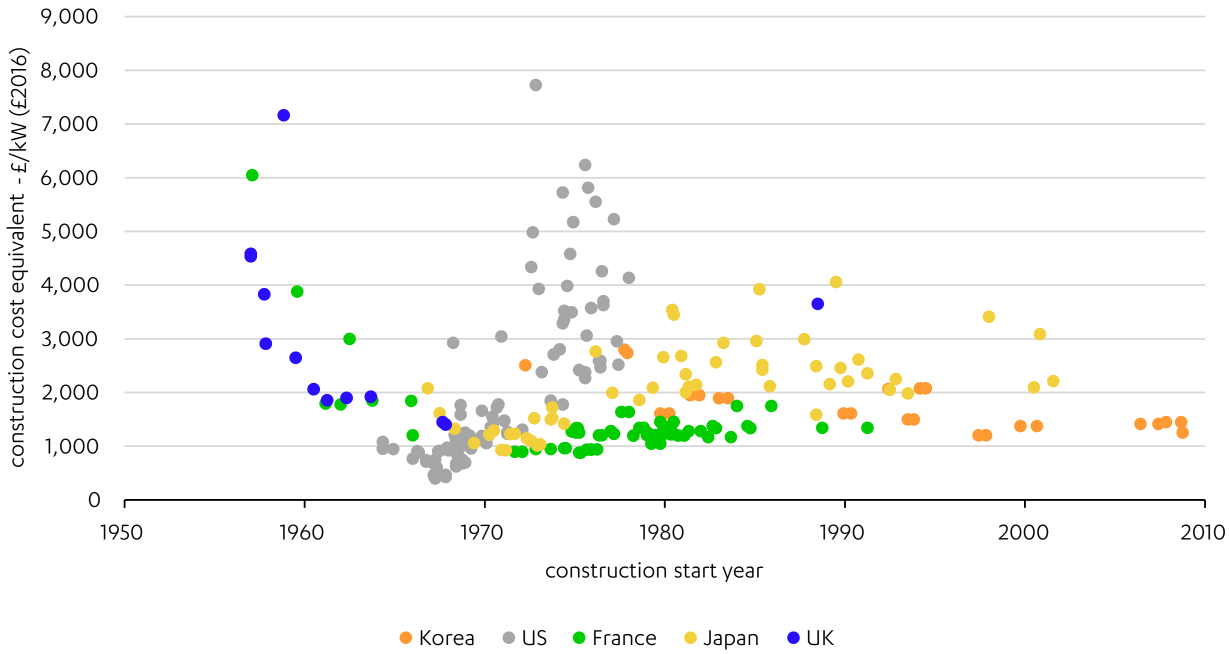
- **New low carbon capacity is needed over the next decade and renewables can deliver this.** As the Commission argued in the first Assessment, due to current plant retirements, in the 2020s there will be a gap in electricity generating capacity, that needs to be filled.[9] It must be the case that low carbon generation fills this gap. Given their short lead times, renewables are ideally placed to do this. With the exception of Hinkley Point C, nuclear power stations would likely only be able to deliver new capacity in the early 2030s. It therefore makes sense for government to take action to deploy renewables now.

**Figure 2: Price reductions in offshore wind in the UK[10]**




Note: Similar cost trajectories have been demonstrated for both onshore wind and solar. For example, *An analysis of the potential outcome of further 'Pot 1' CfD auction in GB estimated the price of onshore wind at around £45/MWh in £2012.*[11] However, this chart only covers prices agreed in signed Contracts for Difference in the UK. This trend is not just UK based, with cost reductions in onshore wind, offshore wind, and solar evidenced around the globe.[12]

**Figure 3: Construction costs of nuclear power stations over time[13]**




# The Commission's recommendations are robust to future change and uncertainty

The analysis presented in this paper makes estimates of the behavior of complex systems over long periods of time and in the context of rapid technological change. These estimates are inevitably uncertain. It is important to consider this uncertainty when drawing conclusions from any such modelling. Small differences in total costs in 2050 should not be used to justify the case for individual technologies, and significant policy decisions should not be taken on the basis of marginal differences in costs over the long term.

The Commission's recommendations are robust to this type of uncertainty. By focusing on high-level trends, and not on individual numbers or small cost differences, the Commission has accounted for the level of uncertainty to 2050. Moreover, the actions that the Commission recommends government take do maintain optionality and avoid excessive technological lock-in, allowing the UK to be reactive to future change.

### Box 1: A level playing field for onshore wind

The Commission recommended in the Assessment that cost competitive technologies such as offshore wind should be moved to pot 1 in the Contracts for Difference (CfD) auctions. A pipeline of pot 1 auctions should then be set out to deliver at least 50 per cent renewable generation by 2030, as part of the transition to a highly renewable generation mix. This would provide a genuine route to market for onshore wind and support the UK to deploy a low cost renewable generation mix.

Recently, the government has announced that it will once again run pot 1 auctions, giving onshore wind and solar a pathway to at scale deployment in the UK. This is positive progress towards meeting the Commission's recommendations on the power sector and is very welcome.

The additional challenge of a net zero target makes it even more crucial that government levels the playing field to enable all cost competitive renewable technologies to come forward. The modelling discussed in this paper shows that a significant increase in onshore capacity would support the least cost generation mix.

For each of the scenarios, there is a significant increase in onshore capacity by 2030 of between 2.8 – 4.3 GW, increasing from a 2020 baseline of 12.6 GW.

This is supported by a range of other analyses: Cornwall Insight's long-term power market model shows that the onshore wind capacity likely to be needed is between 16GW and 22GW by 2030 for net zero scenarios,[14] and the central scenario analysis commissioned for the Committee on Climate Change's net zero report from Vivid Economics shows 20GW onshore wind by 2025.[15]

With government support this is achievable. The government's Renewable Energy Planning Database, tracking renewable electricity projects, shows that there is 4.7 GW of onshore wind capacity awaiting construction having had planning permission granted.[16] The appropriate policy support would create a route to market for these projects that are ready to build in the 2020s.

# Modelling approach

## The electricity system modelling carried out for the National Infrastructure Assessment has been updated to account for the net zero emissions target. The Commission has also used this updated modelling to investigate the impact that some emerging technologies could have if deployed in the power sector.

**Aurora Energy Research was commissioned to carry out updated electricity system modelling. The approach taken is the same as was taken for the *National Infrastructure Assessmen*t. The modelling analyses the costs of delivering a net zero compatible electricity system with different levels of renewable generation.**

The net zero target requires emissions, after accounting for greenhouse gas (GHG) removals, to be zero by 2050. It does not require each sector in and of itself to produce zero emissions. In its indicative net zero consistent scenario the Committee on Climate Change (CCC) allowed for 2.9 MtCO2 (4.5gCO2/kWh) of emissions from the power sector.[17] This is used as a benchmark for the power sector in the analysis presented in this paper. Whilst there may be debate about the exact level of decarbonisation required in the power sector, the Commission considers that this accurately represents a very low emissions electricity system.

The Commission has investigated the cost of running an electricity system with different proportions of renewable generation. The modelling considered systems with 60, 80 and 90 per cent renewable penetrations in 2050. The least cost mix of renewables, between onshore wind, offshore wind and solar, is analysed in the modelling. The remaining generation is optimised economically based on profit maximisation, within the limits of emissions and operability constraints assumed. This modelling work involves analysing the electricity system for every half hour of the year and aggregating costs for meeting demand throughout.

The Commission has only considered renewable mixes above 50 per cent in this latest work. This approach is taken in light of recent government announcements on delivering 40 GW of offshore wind capacity and the Commission's recommendations to government that the UK should be running on at least 50 per cent renewable by 2030.

The modelling provides the following outputs for each scenario:

- total costs in £2016 of constructing and running the electricity systems, averaged over the years 2030 to 2050.
- capacity and generation for each type of technology.

The electricity system costs are further broken down into the following five categories:

- **Wholesale market costs:** The costs of electricity generation, including a carbon price. The carbon price is set at the value required to meet the emissions constraint under each scenario.

- **Capacity market costs:** Costs of procuring enough capacity to meet assumed security of supply constraints.
- **Balancing market costs:** These costs cover the actions required to ensure that the electricity system always balances supply and demand.
- **Network costs:** The cost of building new network cables to connect and support additional generation capacity.
- **Subsidy costs:** Any additional cost on top of the above four categories required to deploy the set amount of renewable capacity.

A more detailed overview of the modelling approach used by Aurora Energy Research is outlined in *Net zero electricity systems modelling* with the full data and assumptions from this analysis.[18] A table of key assumptions is set out in Annex 1.

## Demand scenarios

The future pathway for decarbonised heat in the UK is not yet set built it will have a significant impact on the demands on the power system. Uncertainties around cost, technology, and consumer behavior means that it is difficult to decide the cheapest way to replace natural gas to meet future climate targets now. But uncertainty is not an excuse for inaction in the near term. The Commission has previously made a number of recommendations for developing the evidence base on low carbon heating options. Doing so will give the government, industry, and others the confidence to invest in the best solution at the right time.

In the absence of a single pathway, the Commission's power sector analysis considers two heating pathways:

- **Electrification:** represents a future in which most of the heating sector has been decarbonised largely by using heat pumps.
- **Greener gas:** represents a future in which heat is primarily provided by low carbon hydrogen.

The approach used in this updated analysis is similar to the one used for the analysis underpinning the Assessment. The assumptions for the heating demand scenarios are based on *Cost analysis of future heat infrastructure options*.[19] The results for each scenario are presented separately in the following chapters.

## Emerging technologies for 21st century power systems

The net zero target will impact not just the electricity sector but the whole economy, changing which technologies are available and economic to use in the power sector. As the Committee on Climate Change set out in their report *Net zero: the UK's contribution to stopping global warming*,[20] action across all sectors is needed for the UK economy to fully decarbonise.

Hydrogen, a zero carbon energy carrier, could be used to decarbonise areas of transport, heating, industry and potentially aviation and shipping. The CCC have stated that "By 2050, a new low carbon industry is needed with UK hydrogen production capacity of comparable size to the UK's current fleet of gas-fired power stations".[21]

Similarly, bioenergy with carbon capture and storage (BECCS), with its ability to generate negative emissions, will also be needed to meet the net zero target. The CCC have argued that BECCS will be needed "whether for power generation, hydrogen production or production of biofuels for areas that cannot move away from hydrocarbon fuels (e.g. aviation)".[22]

Given this, the Commission has now undertaken analysis of the impact that these two technologies could have if deployed in the power sector. This paper sets out that work. However, the paper does not consider the wider impact these technologies would have across the economy. Nor does it consider the case for using these technologies in the power sector compared to other sectors in the economy. It is only analysing the impact these technologies would have if deployed for electricity generation.

## Hydrogen technology in the power sector

The Commission has previously made recommendations on hydrogen for heating and use in fuel cells for heavy goods vehicles.[23][24] But the heightened ambition of moving to a net zero economy may mean that hydrogen is used in other sectors as well. The CCC included 270 TWh of low carbon hydrogen in its indicative net zero pathway.[25]

This paper uses two scenarios to analyse the impact that hydrogen could have if deployed in the power sector:

- **A flexible source of low carbon electricity to complement renewables:** hydrogen, generated from gas reforming with CCS, burning in hydrogen turbines where this lowers the costs of the electricity system.
- **Electrolysis in the power system:** hydrogen produced from electrolysers using curtailed generation, which is then burned for electricity at a later date.

This analysis has not considered the impacts or costs of the transmission or storage of hydrogen gas. More detail on the approach is set out in Annex 2.

## Bioenergy with carbon capture and storage

Burning biomass combined with CCS technology has the potential to generate both electricity and negative emissions (see box 5). But due to the high capital and fuel costs this technology is unlikely to be cost-effective in the power sector unless it receives revenue for the negative emissions it generates or provides value to the system by running flexibly.[26]

This analysis considers the impact of deploying BECCS in the power sector. This analysis is separate from the hydrogen scenarios described above. The quantity of BECCS assumed is based on estimates of the required amount of negative emissions in the economy by 2050.[27] In the scenarios presented here around 50 MtCO2 is captured by BECCS in power.* This is equivalent to around 135 TWh primary of biomass feedstock – well within current estimates for available supply.[28]

More detail on the approach is set out in Annex 2.

*This is not the full total of negative emissions that the CCC, and others, suggest the UK will need to generate. Additional negative emissions could be generated from other sources (see box 5).

# Net zero power systems with electrification of heat

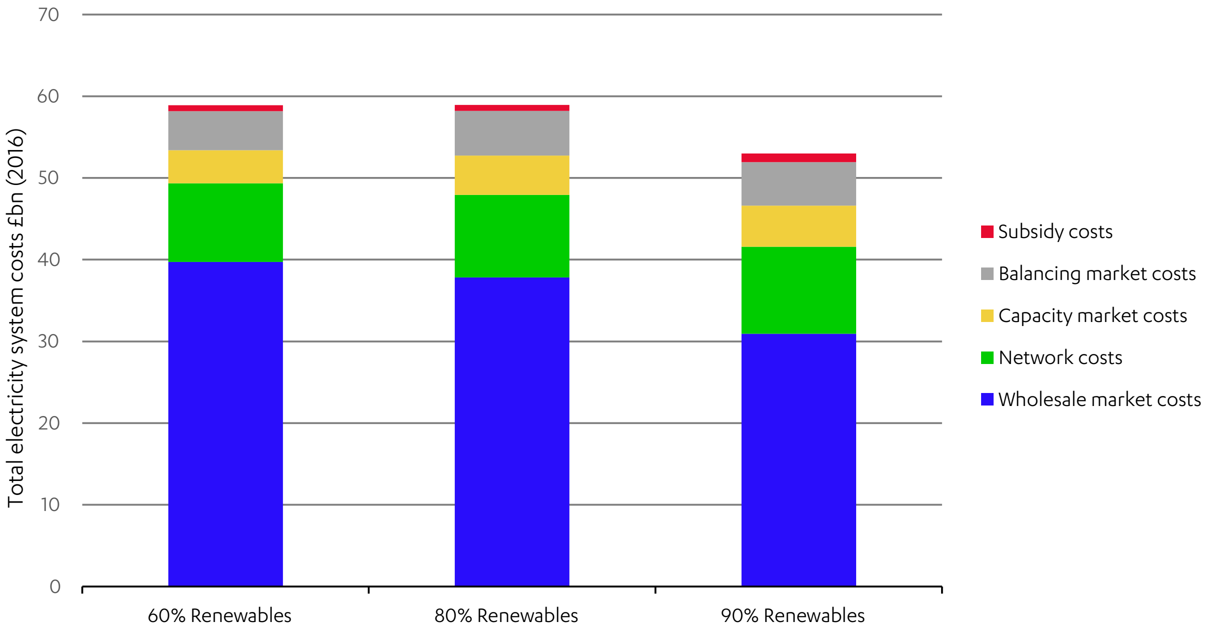
**This chapter presents the results of the power sector analysis with the electrification of heat demand scenario.**

## Highly renewable systems are still a low cost option in a net zero world

The modelled electricity system costs are lowest in the highest renewables scenarios (Figure 4). However, the cost difference is less than 10 per cent of total costs. This variability is well within reasonable tolerance levels given the uncertainty inherent in modelling out to 2050. The Commission has taken a prudent and sensible approach to uncertainty, not overly fixating on small 2050 cost differentials. Therefore the overall electricity system costs across the scenarios should be considered as broadly flat across the 60, 80 and 90 per cent scenarios. These estimates are similar to others in the literature.[29]

Scenarios with higher renewable deployment have lower wholesale market costs but this is largely offset through increases in other cost categories (Figure 4). As the renewables considered here are close to zero marginal cost, they significantly depress wholesale market prices, but some of this cost is shifted to increased subsidy levels. Higher balancing mechanism and network costs also occur. This is due to the inherent variability of renewables increasing the costs of balancing supply and demand, and the need for increased network capacity to connect more renewables.

### Figure 4: Costs of net zero power systems




## Box 2: Intermittency cost estimates

Variable renewables, specifically wind and solar, are a low-cost technology option for supplying electricity. Indeed, the Commission believes that a highly renewable mix could be the lowest cost electricity system for meeting consumers' needs from 2030 onwards. However, each of these technologies relies on variable weather patterns, driving up uncertainty and placing additional strain on the electricity system.

This cost has often been calculated as the "intermittency cost" in the literature.[30] This cost can be broken down into components in several different ways. For example, the Committee on Climate Change have suggested that it can be understood as the interaction of the following four, albeit overlapping, components:[31]

- **Meeting peak demand:** costs of procuring back-up capacity for periods of peak demand and low renewable output.
- **Balancing requirements:** costs of paying for flexible technologies to be on the system that can ramp quickly to meet short-term electricity shortfalls.
- **Additional network costs:** costs of constructing additional transmission and distribution networks to connect renewable generation to demand.
- **Curtailment:** costs of generation that must be constrained due to too much surplus electricity. This should be distinguished from curtailment due to network constraints, which is not considered here.

The full system cost of intermittent generation will vary depending on the penetration of renewables on the system. Estimates range between £5/MWh to £50/MWh for renewable penetration up to around 65 per cent.[32] From this latest analysis the Commission can estimate the cost of renewable integration at 90 per cent penetration levels. This is set out in table 2 below.

The Commission's analysis does not find that these costs increase substantially with higher levels of renewable penetration. This is in line with the conclusion that highly renewable systems are at least as cost effective as those with lower proportions of renewables for providing the UK's long term electricity supply. As with all estimates for 2050 electricity systems, these are uncertain. As more renewables are deployed on the electricity system these costs will become more certain.

It is also the case that inflexible technologies, such as nuclear, or particularly large assets, such as interconnectors, may impose separate costs on the electricity system. These should also be considered.

**Table 2: Intermittency cost calculations**

| Category | Methodology | Intermittency cost when moving from 60% to 90% renewables |
|---|---|---|
| Meeting peak demand | Calculated as the additional capacity market costs | £6/MWh |
| Balancing requirements | Calculated as the additional costs in the balancing mechanism | £3/MWh |
| Additional network costs | Calculated as the additional network costs | £6/MWh |
| Curtailment | Calculated as the total percentage of curtailed renewable generation. This should be applied as a cost uplift after other costs have been added to the baseline costs. | 17% cost uplift, £9/MWh using the example of an offshore wind farm at £40/MWh |
| **Total** | | £24/MWh |

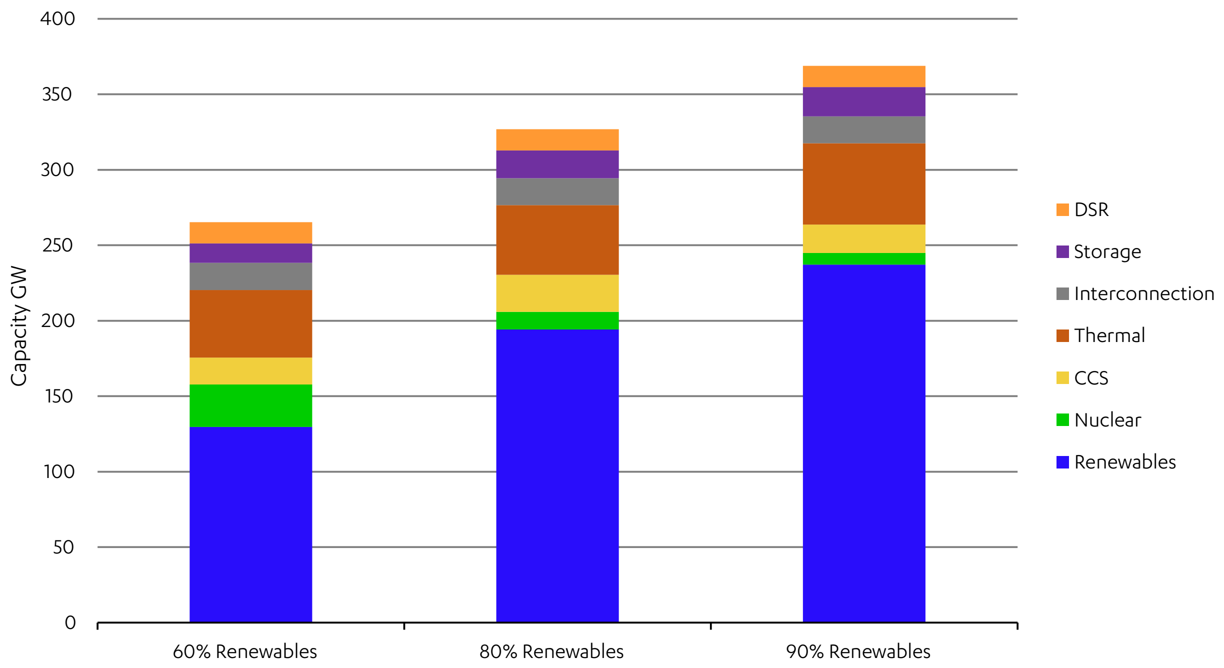
# Technology mixes in net zero power systems

The Commission's analysis of 2050 generation and capacity mixes has not significantly changed in light of the net zero target. The same technologies, in broadly similar quantities, are still likely to be needed in the long term (Figure 5, Figure 6). Across all scenarios, significant solar, onshore wind, and offshore wind capacity is needed:

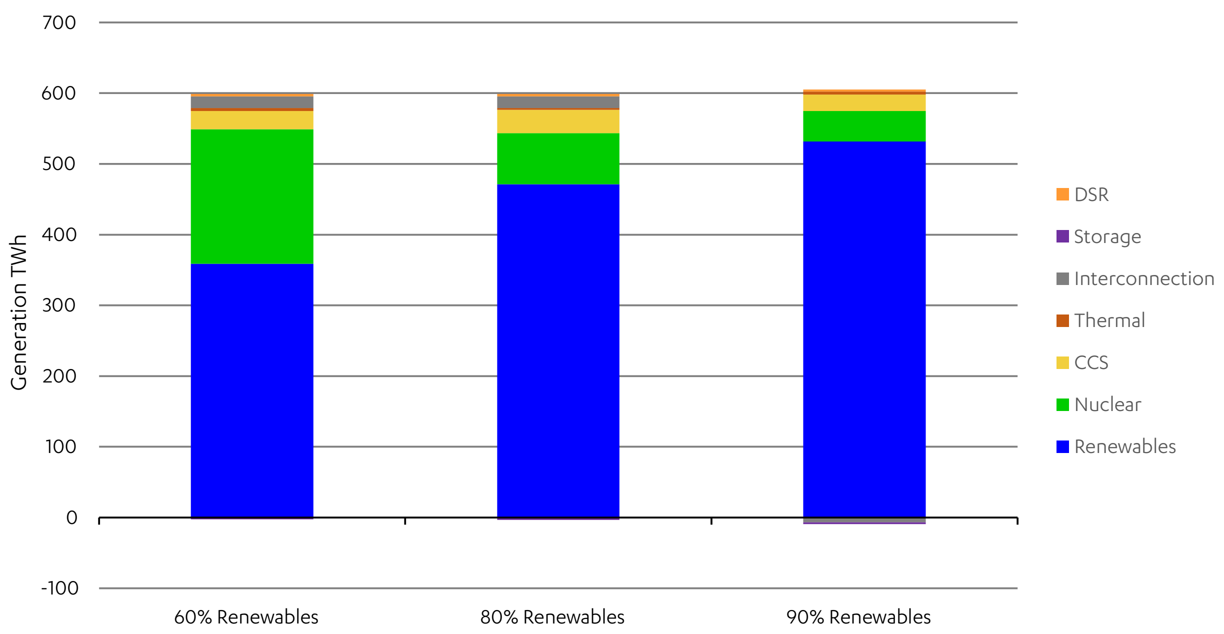
- Between 129 –237 GW of renewable capacity is in operation by 2050, generating between 360 – 530 TWh of electricity across the scenarios modelled. This includes 56 – 121 GW of solar, 18 –27 GW of onshore wind, and 54 – 86 GW of offshore wind.
- To ensure security of supply there is still a significant capacity of unabated thermal plant on the system by 2050 (between 45 - 54 GW). However, this only provides around 3 – 4 TWh of annual generation as it is primarily deployed as back up capacity.
- At least 18 GW of gas CCS capacity is needed by 2050 across all scenarios, generating upwards of 23 TWh of electricity. By 2050 it is primarily playing a peaking role in the electricity system, with annual load factors of between 14 – 16 per cent. The residual emissions from not capturing 100 per cent of the $CO_2$ is likely to limit its role in providing bulk baseload generation in a net zero power system, unless higher capture rates are achieved.

- As little as 8 GW of nuclear capacity has been deployed in some scenarios, suggesting that it is possible to meet demand in electricity systems without significant capacity of inflexible baseload generation in the long-term. This is broadly equivalent to one additional nuclear plant beyond Hinkley Point C, in line with the Commission's recommendation.
- All technologies deployed here fall within the maximum potential capacity deployable in the UK. This is further discussed in Annex 3.

## Figure 5: Capacity mix of modelled scenarios in 2050




## Figure 6: Generation mix of modelled scenarios in 2050

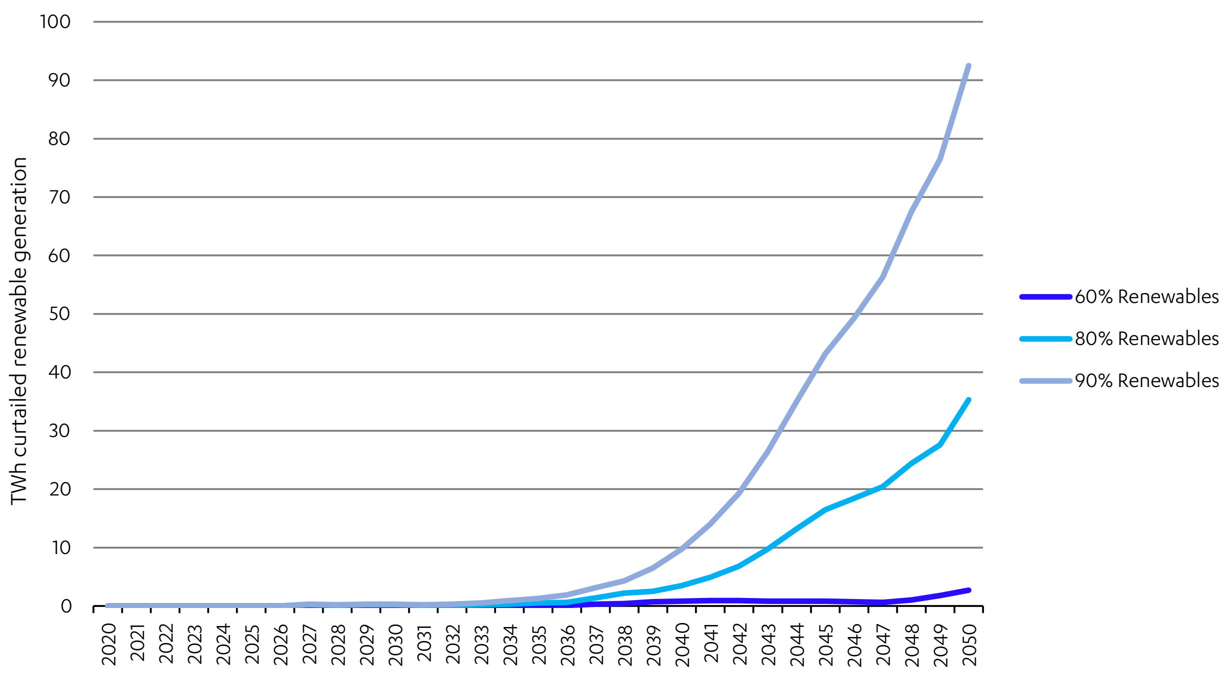


# Curtailment in highly renewable power systems

Increasing deployment of renewables is likely to result in more curtailment, but this does not stop highly renewable systems from being a low cost option. Due to their reliance on weather patterns renewables may generate at times when the electricity system already has enough electricity to meet demand. When this happens, the excess generation may need to be curtailed. This curtailment is different from curtailment in the current system which happens largely due to constraints on the transmission or distribution grid. The maximum level of curtailment in the scenarios modelled here is around 90 TWh (Figure 7). However, whilst this does increase the unit costs of renewables, capital and operating cost estimates are now low enough that highly renewable systems are still low cost.

It is unlikely that significant volumes of curtailed generation would go unused in the long run. New technologies or business models that will be able to make economic use of this curtailment are likely to be deployed. Therefore, it is better to see this curtailment not as a cost to the system but an opportunity. One technology that could take advantage of this opportunity is hydrogen production.

**Figure 7: Curtailment of renewables across modelled scenarios**




## Box 3: The role of system flexibility

Flexible technologies, those that can help balance supply and demand, will be integral to providing the UK with a power system fit for the 21st Century and securing low cost, low carbon electricity for UK consumers. The Commission recognised this in *Smart Power* published in 2016.[33] *Smart Power* set out a range of actions for government and regulators to take to position the UK as a world leader in electricity system flexibility. Analysis carried out for the Commission estimated that achieving a highly flexible electricity system could save UK consumers up to £8bn by 2030.[34] Subsequent analysis has reinforced this and argued that this saving is likely to be even higher by 2050.[35] The analysis presented in this paper further bolsters this case.

Specifically, the Smart Power report called for the UK to become a world leader in electricity storage systems, interconnection and demand side response. A significant capacity of these three technologies are deployed in the analysis presented here, highlighting their importance to the system:[36]

- Across all scenarios 17.9 GW of interconnection comes online, performing a key role in balancing the system, especially in periods of low renewable output. This is in line with the pipeline of interconnectors that are either in operation, under construction, or have been given regulatory approval from Ofgem.[37]
- Large volumes of storage, primarily lithium-ion batteries, and demand side response are included in the mix based on being able to make sufficient economic returns.

One key challenge for future electricity systems is the ability to meet peak demands, especially through the winter months. In the 60 per cent renewables scenario the higher capacity of baseload generation, in the form of nuclear and gas CCS, make these peaks relatively straightforward to meet (Figure 8). But a very highly renewables system can also meet these peaks. Figure 9 demonstrates how the peaks are met during the modelled 2050 January. With 90 per cent of annual generation coming from renewables they contribute the majority of this. However, when renewable output is low, nuclear, gas CCS, storage, interconnection and demand side response all stack up to meet the majority of these peaks. Some small amount of gas CCGT generation is still occasionally required but this only makes up around 4TWh of annual generation using 2Mt$CO_2$[38] of 2.9Mt$CO_2$ emissions constraint.

All future electricity systems need to be robust to extreme weather conditions, especially in a changing climate. The Commission recognised the importance of fully understanding weather impacts on electricity systems and has commissioned the Met Office to undertake research on this. An initial literature review conducted by the Met Office suggested that there are four key areas of uncertainty:[39]

**Peak winter residual demand:** a combination of low temperatures in winter driving high energy demands, combined with low windspeeds leading to low renewable wind energy, and potential limits on solar generation.

**Summer wind drought:** high pressure heatwaves in summer which could lead to a drought of wind supply, exacerbated by possible very low wind speeds, increasing the reliance on solar generation.

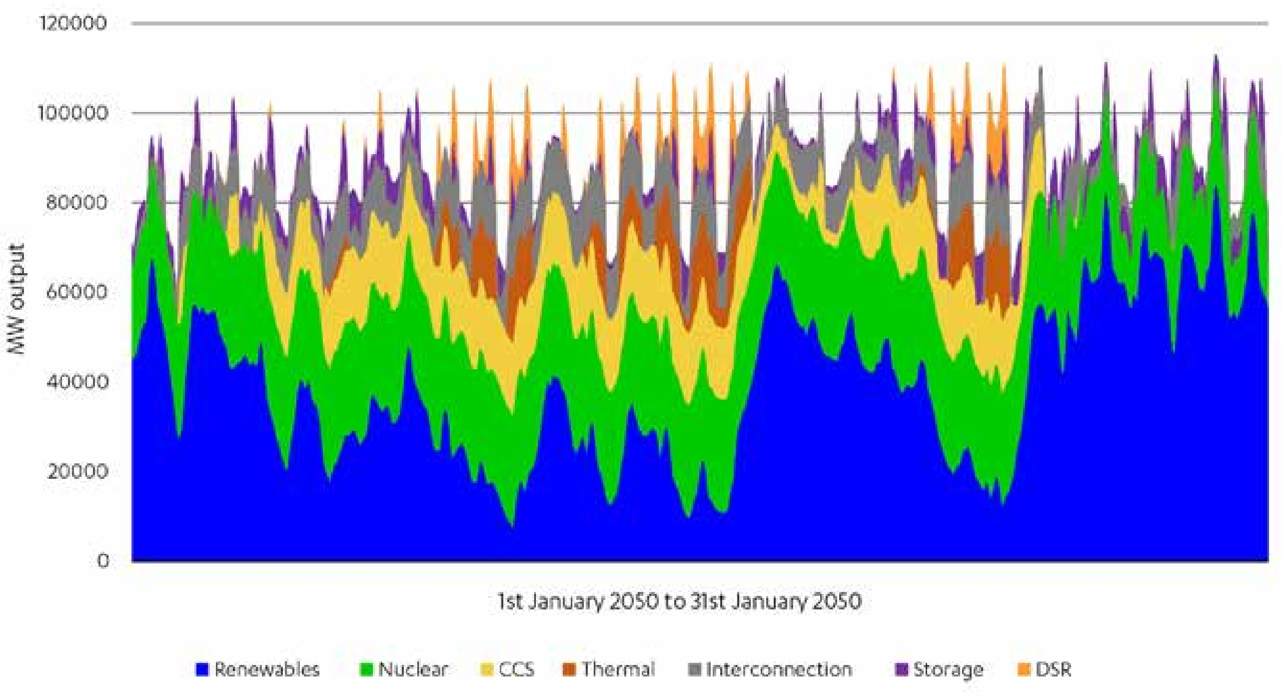
**Surplus solar:** combination of low demand and high solar generation output, leading to residual demand frequently dropping below zero and leading to surplus generating supply.

**Wind and solar ramping:** major changes in wind speed or solar irradiance over short time periods, both of which could lead to short term surplus and a requirement to curtail supply.

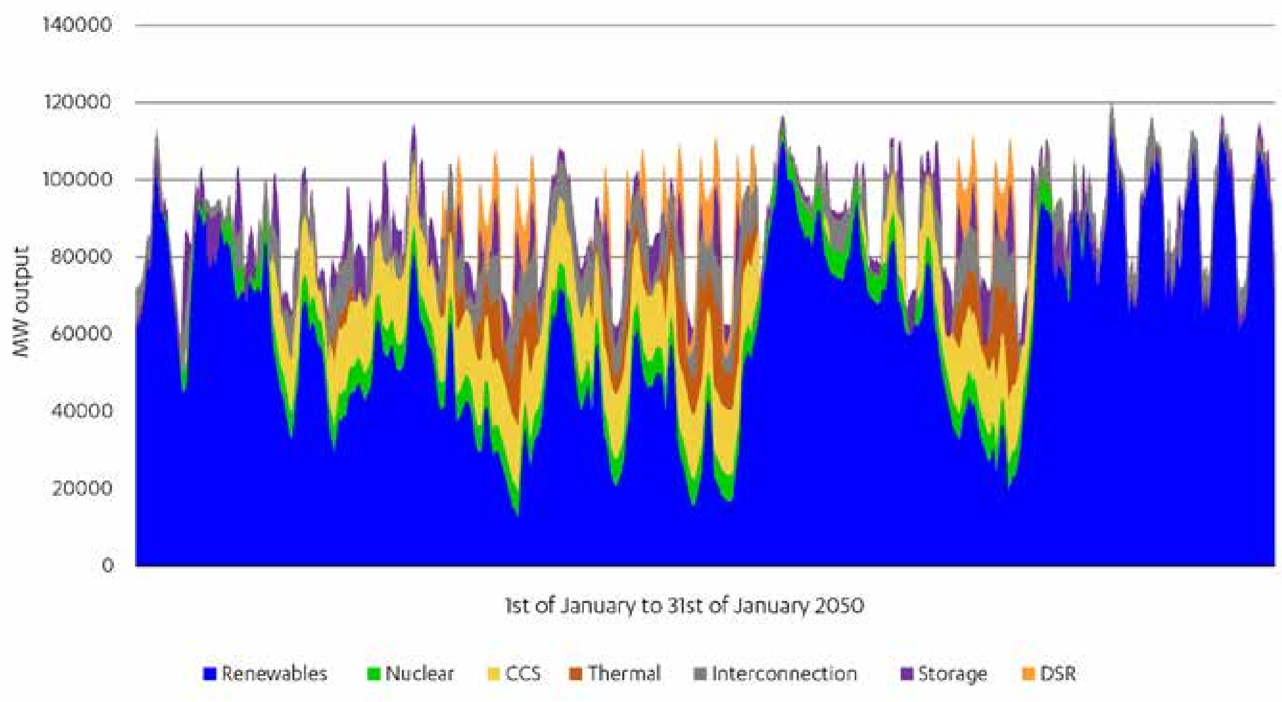
The review also highlighted the benefits of the UK having a diverse mix of renewables to help manage variable meteorological conditions. Additionally, ensuring that the UK's renewable generators are spread across the country to take advantage of complementary weather patterns could also be key.

The Commission will look to work with the Met Office, and others, to further build this evidence base in the coming years.

## Figure 8: Model outputs for generation mix of January 2050 in 60% renewables electrification scenarios




## Figure 9: Model outputs for generation mix of January 2050 in 90% renewables electrification scenarios

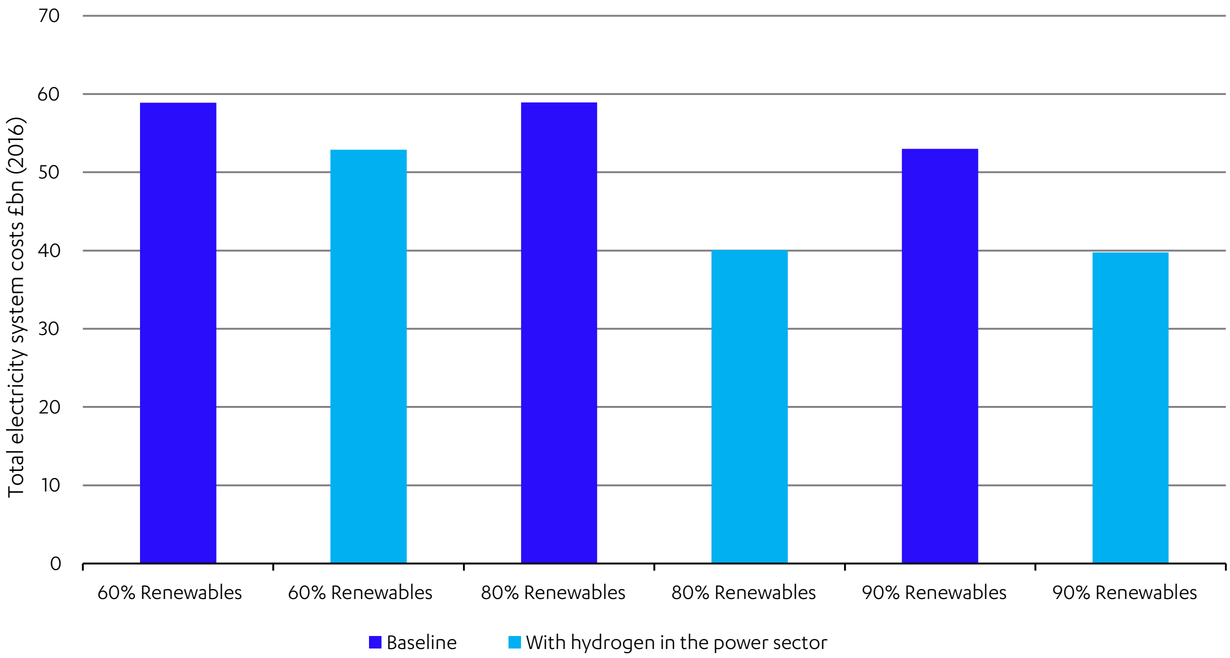



Note: the demand profiles differ across Figure 8 and Figure 9 due to when storage, interconnection and DSR are importing electricity from the system alongside different electric vehicle charging profiles.

# A flexible source of low carbon electricity to complement renewables

Deploying hydrogen turbines at scale, as a complement to renewable technologies, significantly reduces overall systems costs. Across the three different levels of renewable penetration, savings of between 10 –30 per cent are seen (Figure 10). It is still the case that the higher penetration renewable scenarios are the cheapest, suggesting that a highly renewable mix is still likely to be at least as cost effective as those with higher baseload capacity. But deploying hydrogen turbines at scale could further lower costs.

**Figure 10: Electricity system costs with hydrogen from gas reforming in the power sector**




**The hydrogen turbines displace many other non-renewable forms of generation and flexibility, reducing the capacity of these technologies needed, and hence system costs** (Figure 11 and Figure 12). Specifically, hydrogen gas turbines:

- Displace nuclear by providing cheaper baseload generation. Nuclear capacity decreases by up to 11 GW with a low of around 5 GW across the scenarios.
- Completely displace all gas CCS from the scenarios. Hydrogen turbines provide both baseload generation and flexible supply at lower cost than gas CCS, completely replacing it in the modelling.
- Significantly decrease the amount of thermal back up capacity needed. As outlined earlier, the scenarios have a large capacity of traditional thermal generation which is needed for security of supply but very rarely runs. As hydrogen turbines also provide firm power, they replace much of this thermal plant. Capacity of thermal plant falls by between 13 – 16 GW across the scenarios.
- Decrease the amount of electricity that is imported from connected EU markets during high price periods. Net imported generation falls by up to 20 TWh across all scenarios.

- The hydrogen turbines provide low carbon baseload generation, low carbon flexibility and firm power, which are normally provided in the modelling by a range of different technologies. By combining all of these services in one technology, this significantly lowers the amount of capacity needed and therefore the capital investments required. This lowers overall system costs.

**Figure 11: Capacity mix with hydrogen from gas reforming in the power sector in 2050**

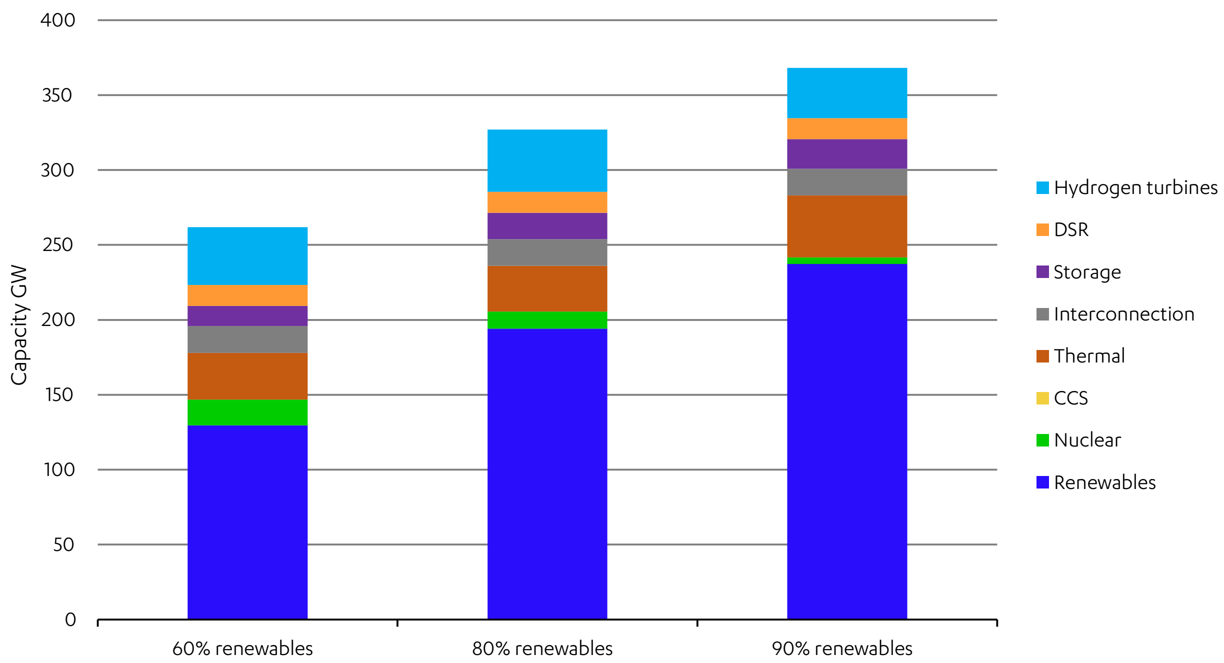
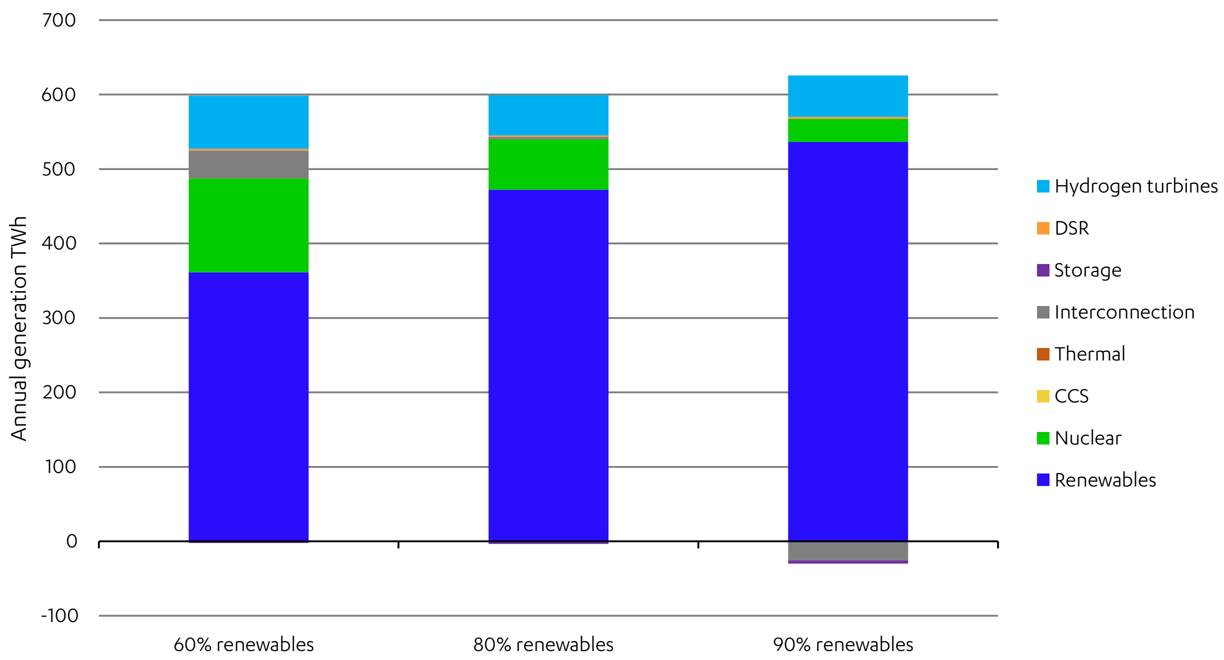



**Figure 12: Generation mix with hydrogen from gas reforming in the power sector in 2050**

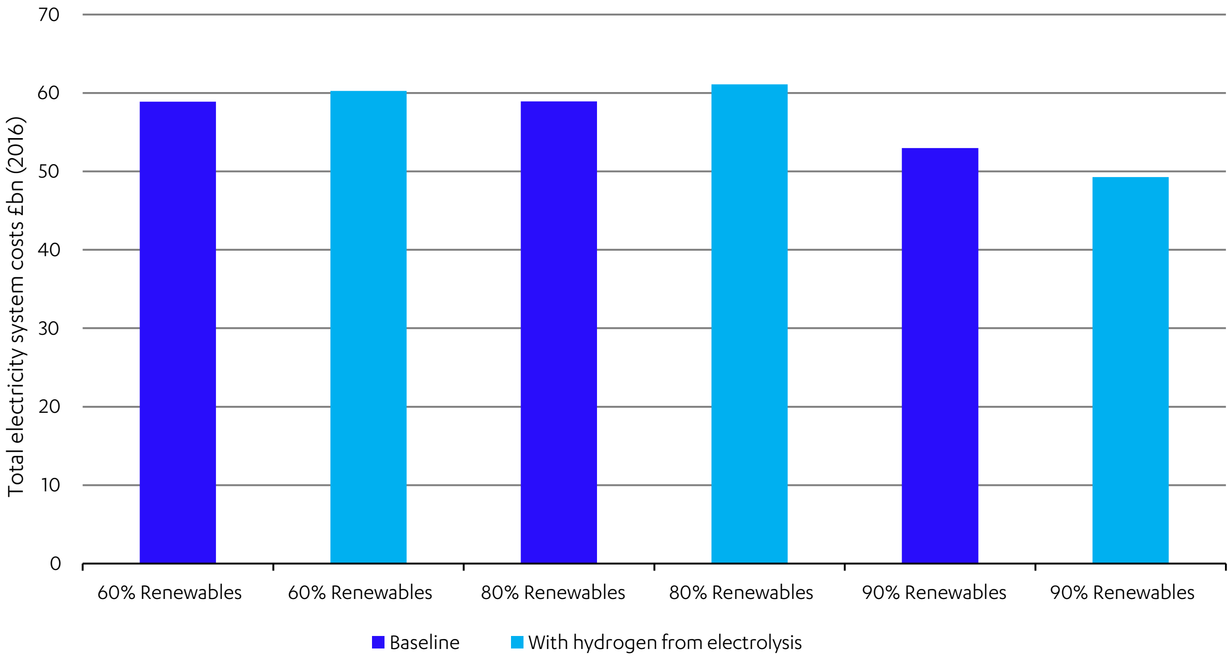



Note: If the UK is net exporting electricity this appears on the chart as a negative figure below the x-axis.

# Electrolysis in the power sector

The Commission's analysis finds that some electrolyser capacity does have the potential to reduce system cost, by up to 7 per cent (Figure 13), through using curtailed renewable generation. This is most likely in systems with higher renewables deployment and hence higher levels of curtailment, as this allows the electrolysers to achieve higher load factors.

**Figure 13: Electricity system costs with electrolysis in the power sector**



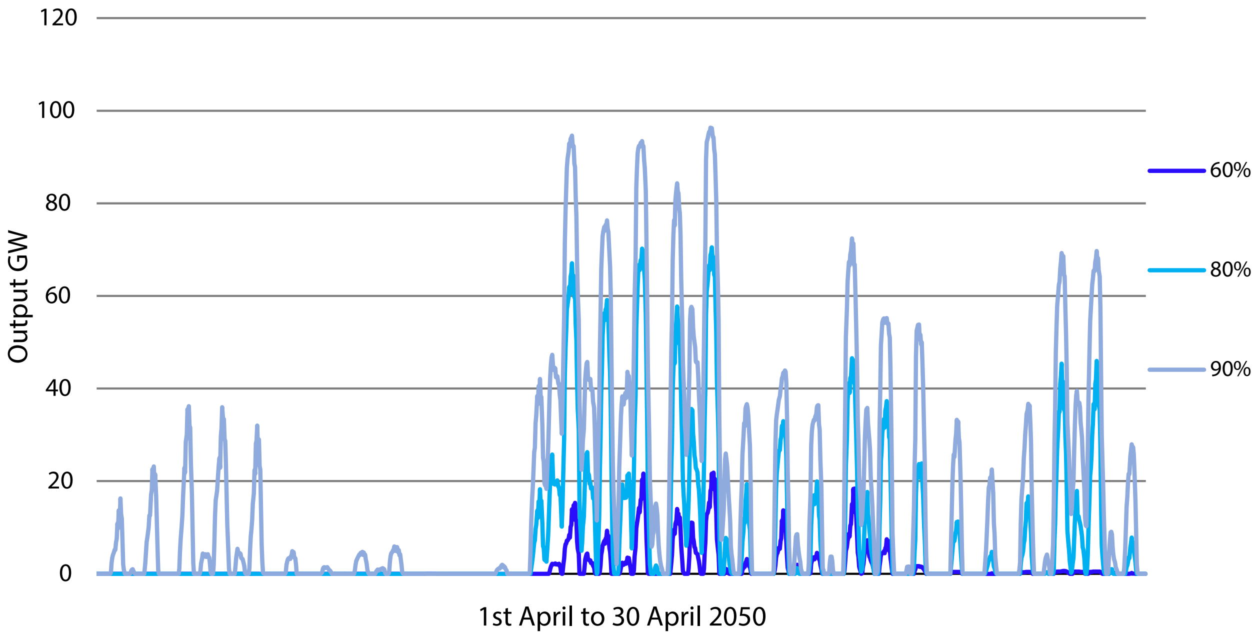

Electrolysers in this analysis capture 90 per cent of the curtailed renewable generation. In lower renewable penetration scenarios deployment of electrolysers is found to marginally increase costs as there is not enough curtailed generation to cover the capital investment required to build the electrolysers.

- The utilisation rate of the electrolysers has a significant impact on how cost-effective they are. Curtailment of renewables varies dramatically throughout the year (Figure 14). To capture all curtailed generation, including the largest of these peaks, would require around 95 GW capacity of electrolysers. But these would be achieving a utilisation rate of less than 1 per cent and would therefore be uneconomic. In this analysis, electrolysers are sized to capture 90 per cent of curtailed generation, leading to annual utilsation rates of around 15 per cent.

- The hydrogen produced from these electrolysers is burned in hydrogen compatible gas turbines. These hydrogen gas turbines then primarly displace nuclear and gas CCS generation.

This work only highlights one potential use of curtailed generation. Other technologies, for example inter-seasonal storage such as compressed air storage,[40] may find an economic use for curtailed generation. The value proposition for electrolytic hydrogen outside the power sector, such as for use in heavy goods vehicles, also needs to be fully understood. But this analysis highlights that curtailed generation should not be considered as a cost in isolation as it is highly likely that economic uses of it will emerge.

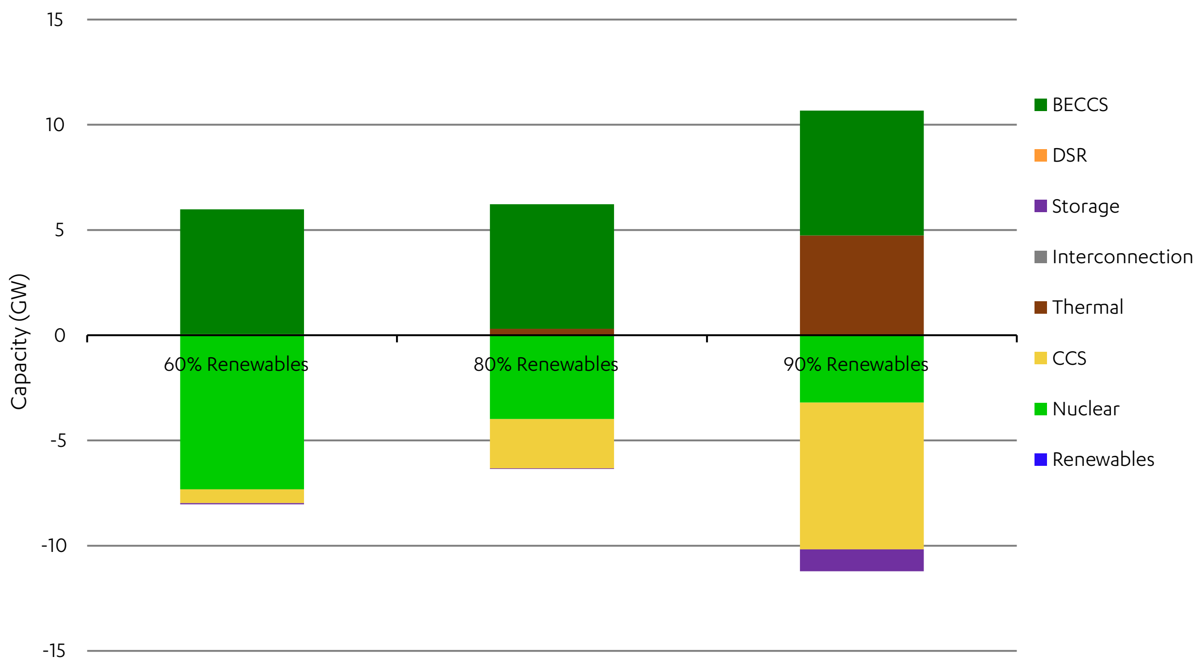
**Figure 14: Profile of curtailed renewable generation in modelled April 2050**




# Bioenergy with carbon capture and storage in power

The analysis concludes that deploying bioenergy with carbon capture and storage in the power sector has little impact on total electricity system costs, but that it would likely weaken the case for a large nuclear fleet in the long term.(Figure 15).

**Figure 15: Change in capacity in 2050 when introducing BECCS into the electricity system**



The modelling finds that BECCS will likely run baseload – meaning it would aim to generate constant output rather than flex to meet demand. As a result, it displaces other inflexible technologies such as nuclear that compete for baseload. Whilst BECCS has the technical capability of providing some system flexibility, the costs of building additional capacity outweigh the potential revenue from capturing peak prices. The Commission has not considered whether BECCS should be deployed in the power sector but sought to understand the impacts if it was:

- The BECCS deployed runs baseload in all scenarios. The analysis finds that the cost of building extra BECCS capacity to allow a plant to run flexibly, by ramping up and down to meet demand, exceeds any revenue gained from capturing peak prices. This is compounded as BECCS is unlikely to be as flexible as other technologies such as traditional CCS plants.[41]
- As a result, introducing BECCS into the generation mix reduces the capacity of nuclear by 3 – 7 GW across all scenarios, and reduces the capacity of gas CCS by up to 7 GW across all scenarios.
- There could be other sectors that BECCS may have more value in. Similar in depth analysis needs to be conducted on a sector by sector basis to provide insight into where BECCS has the highest value across the whole economy.

# Conclusions

**Highly renewable electricity systems are at least as cost effective as those with lower proportions of renewables.** This conclusion is unchanged from the analysis conducted for the Assessment. As is expected when carrying out modelling exercises there have been some changes at the margins, with capacity mixes and deployment timelines of various technologies changing slightly. But these have not affected the overall conclusion used to inform the Commission’s recommendations.

**The modelling also finds that there could be a role for either hydrogen or BECCS in the power system, with hydrogen offering the potential to lower electricity system costs:**

- Hydrogen gas turbines, with a plentiful supply of cheap low carbon hydrogen could play a major role in future power systems. They can act as a natural complement to renewables, helping to reduce whole system costs, but further action is required to demonstrate the technology at scale.
- Electrolysis, producing hydrogen from curtailed electricity, could help to reduce system costs in highly renewable mixes. However, it will be challenging to absorb all curtailed renewable generation at low cost due to the volatility of its production.
- Deploying BECCS in the power sector has little impact on costs, but it would likely displace other baseload generation such as nuclear.

# Net power systems with decartbonised gas heating

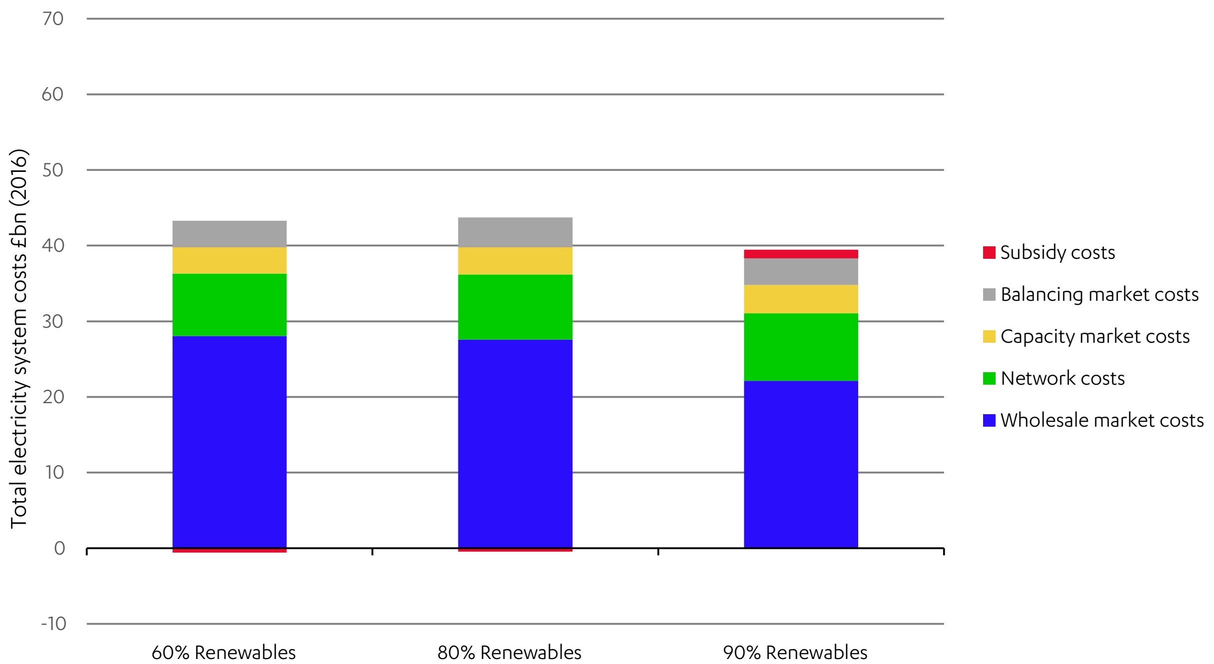
**This chapter summarises the results from the power sector analysis with the Greener Gas demand scenario. As set out in table 1, the two primary changes are lower demand, at around 465 TWh, and a corresponding tighter emissions constraint of 1 MtCO2. All other assumptions, including technology costs, are held the same. The results in this section are similar to the results for the electrification of heat demand scenarios and therefore only the key results are presented.**

## Power system in the Greener Gas scenario

The modelling finds that the costs of low carbon electricity systems, averaged between 2030 and 2050, are again broadly flat across the 60, 80 and 90 per cent renewables penetration scenarios (Figure 16).

- The overall system costs of the electrification of heat and greener gas scenarios should not be directly compared. The costs of providing low carbon electricity for heat are included in the electrification of heat analysis (Figure 4) but the costs of generating low carbon hydrogen for heating are not included in the greener gas scenario (Figure 16).

**Figure 16: Costs of net zero power systems**

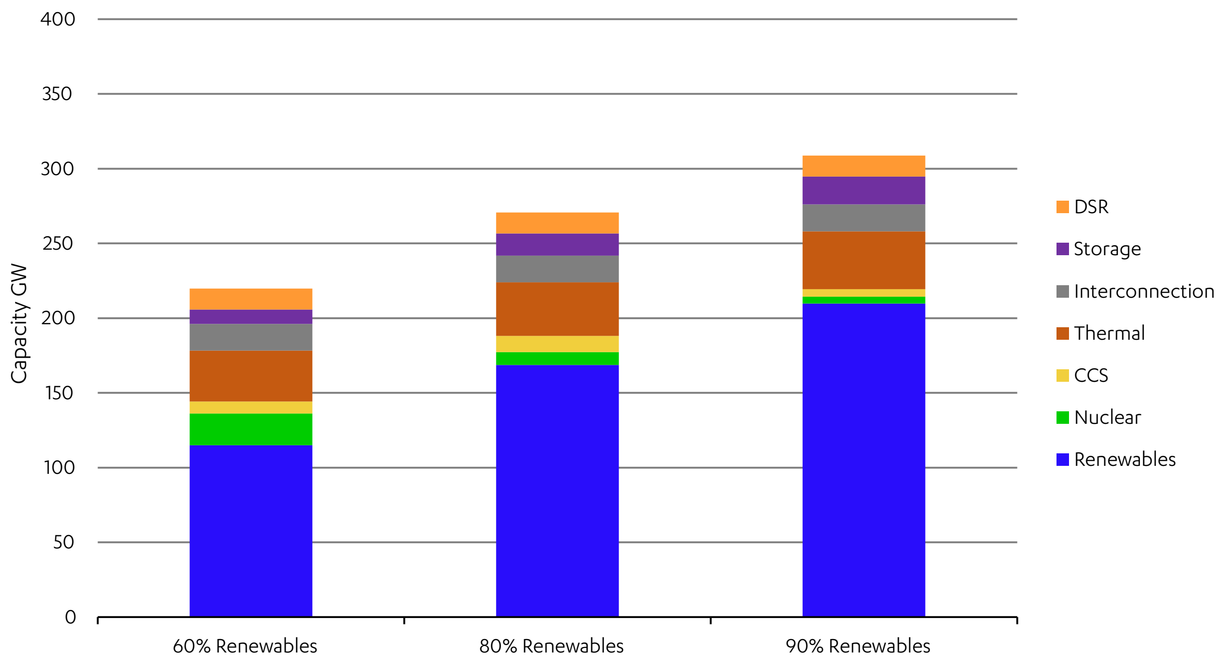


The generation (Figure 18) and capacity (Figure 17) mixes in the Greener Gas scenario have similar proportions of technologies to the electrification of heat scenarios but lower overall levels. As the demand for electricity in these scenarios is lower, less capacity is built out to meet it:

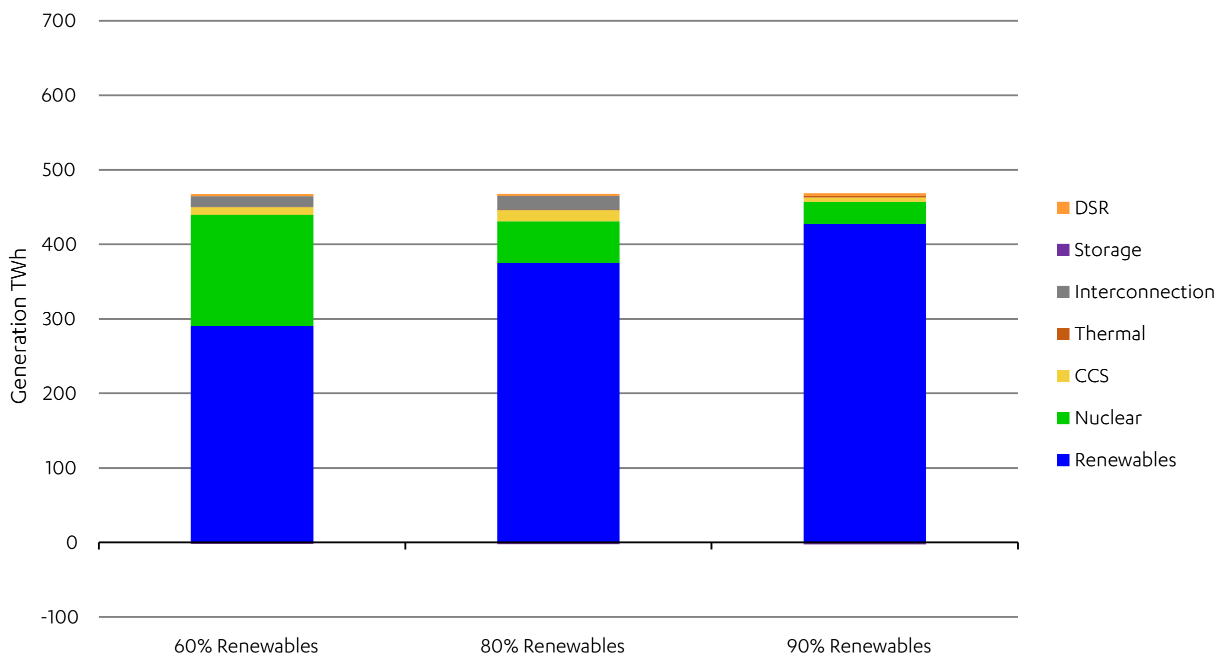
- Across the three scenarios 57 – 124 GW of solar, 15 – 22 GW of onshore wind, and 41 –62 GW of offshore wind are deployed by 2050.
- To ensure security of supply there is still a significant capacity of unabated thermal plants on the system by 2050. However, this only provides up to 2 TWh of annual generation as it is primarily deployed as back up capacity.
- At least 5 GW of gas CCS capacity is needed by 2050 across all scenarios. Similarly to the electrification scenarios this is primarily playing a peaking role by 2050 due to the residual emissions of generating baseload.
- Between 5 – 21 GW of nuclear capacity is deployed by 2050 across the three scenarios.
- The capacity of all technologies is lower in the Greener Gas scenarios than in the electrification of heat. The capacities therefore fall within the resource constraints discussed in Annex 3.

With a significantly smaller power sector there is less overall curtailed generation (Figure 19). However, there is little difference in the percentage levels of curtailed renewables. In the electrification of heat scenarios between 1 – 17 per cent of renewable generation is curtailed. In the Greener Gas scenario this is around 0 – 14 per cent.

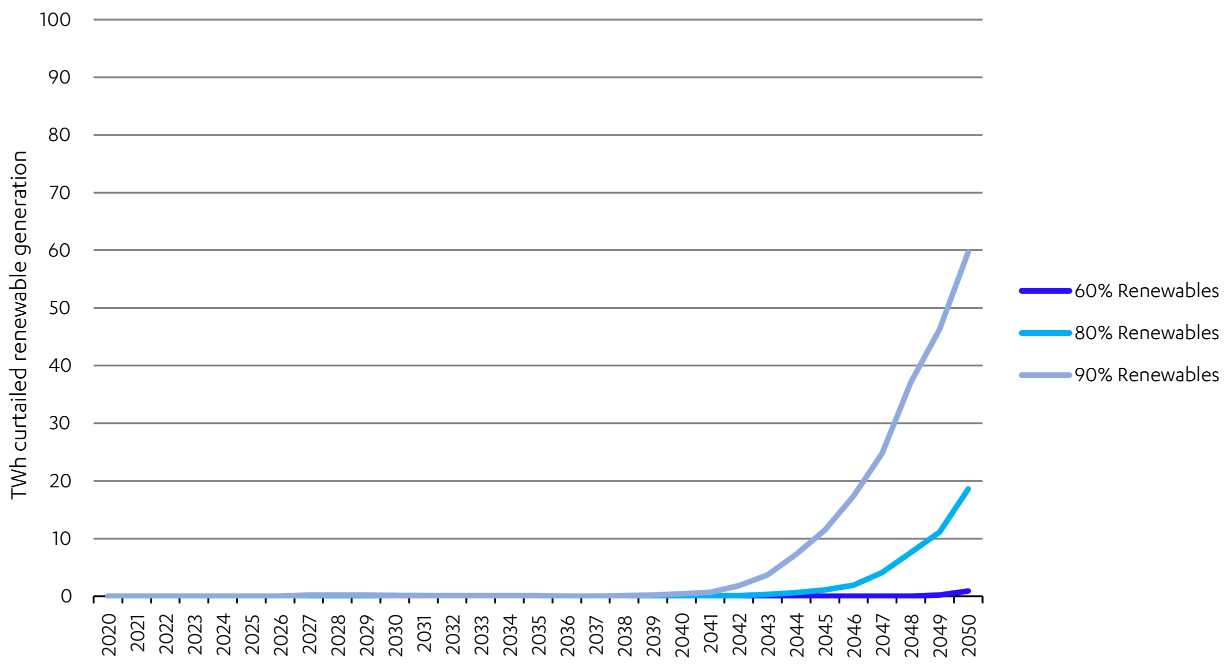
### Figure 17: Capacity mix in 2050 of modelled scenarios



## Figure 18: Generation mix in 2050 of modelled scenarios




## Figure 19: Curtailment of renewables across modelled scenarios

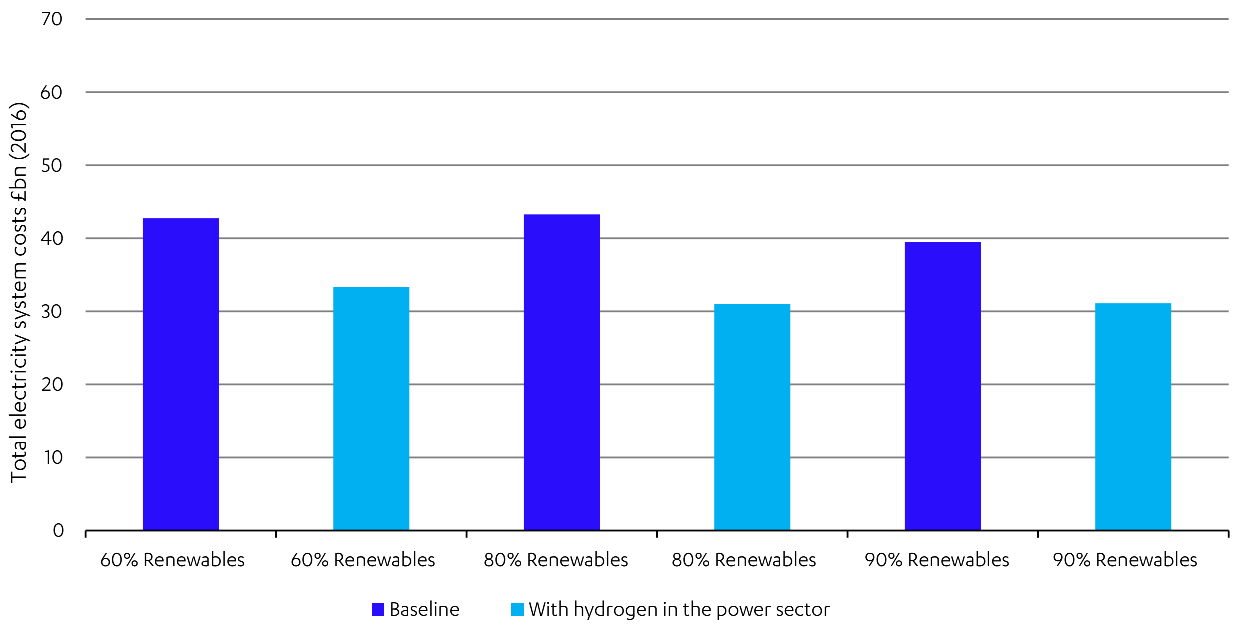


# Hydrogen technology in the power sector

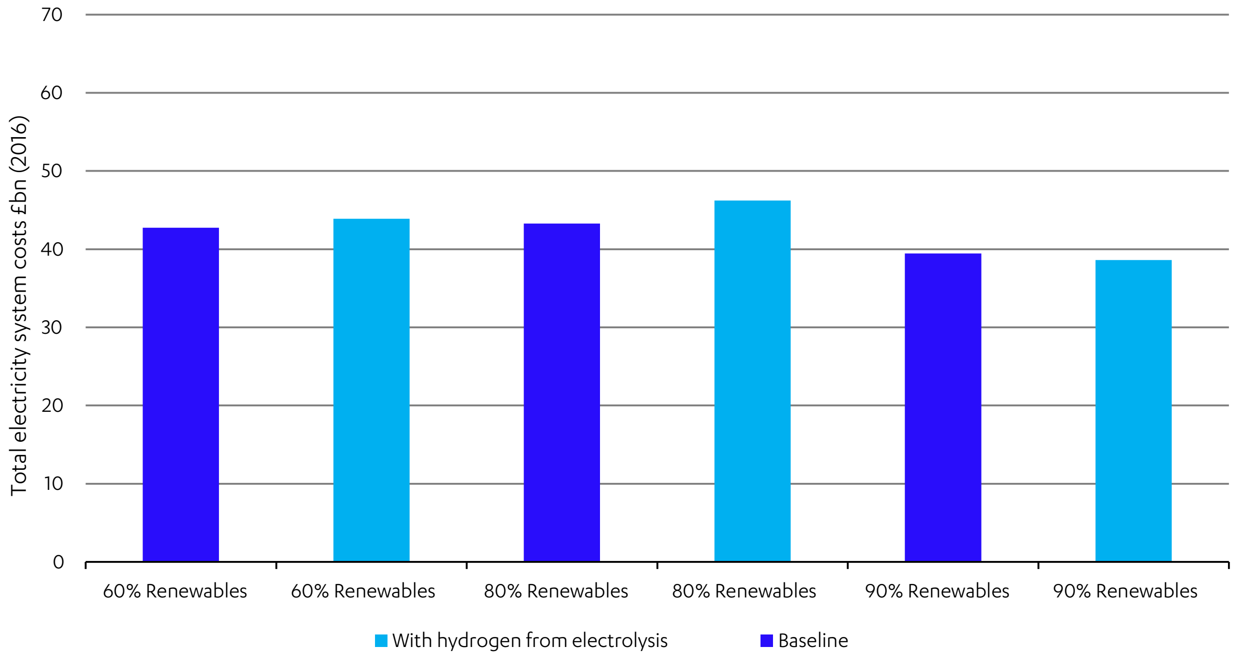
Hydrogen technologies are once again found to have the potential to materially reduce overall electricity system costs:

- Gas reforming can significantly reduce costs by 21 – 28 per cent (Figure 20). However, costs still reduce with higher levels of renewables suggesting that at scale hydrogen is a complement to rather than replacement for renewables.
- Electrolysis reduces costs marginally at the highest levels of renewable deployment, by around 2 per cent, but at lower penetrations there is not enough curtailment to make it economic (Figure 21).
- The hydrogen generation displaces many other forms of non renewable generation and capacity (Figure 22, Figure 23). Up to 8 GW of nuclear capacity is displaced and all gas CCS capacity is replaced by hydrogen gas turbines.

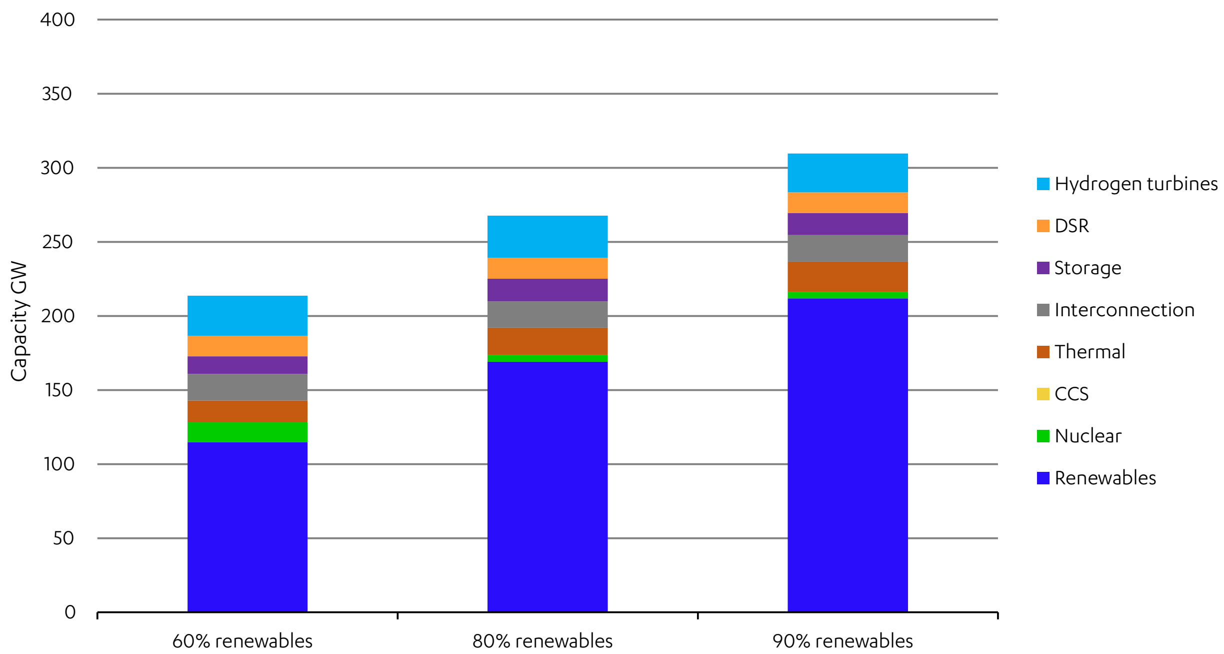
**Figure 20: Electricity system costs with hydrogen from gas reforming in the power sector**



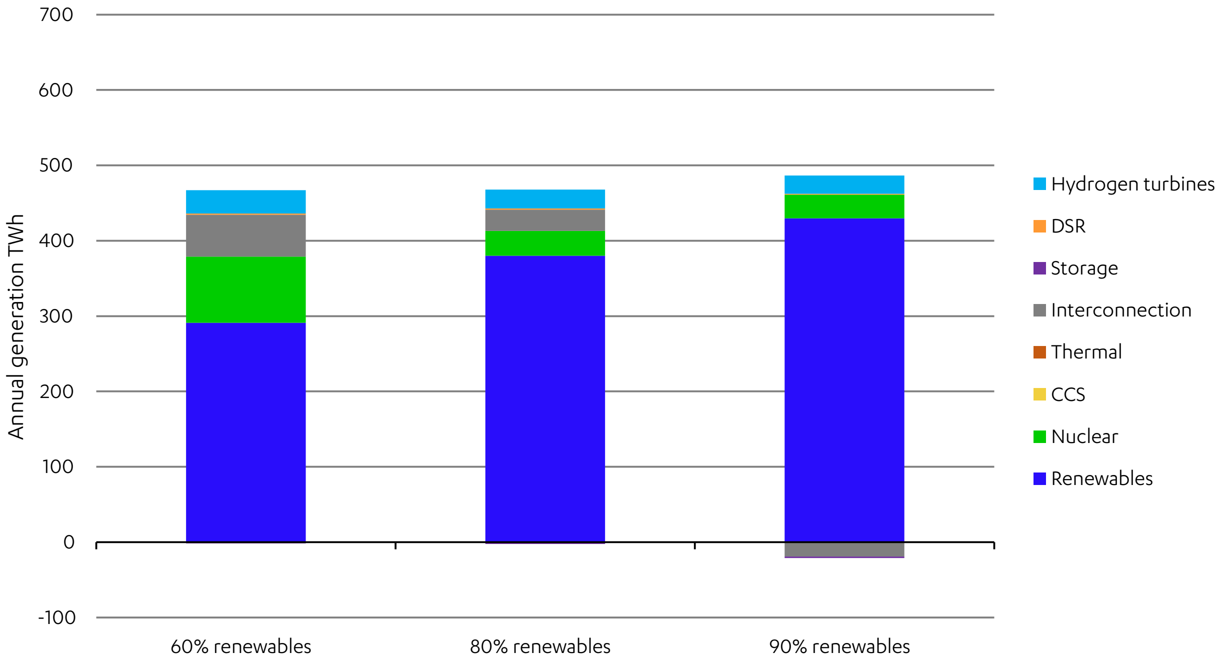
### Figure 21: Electricity system costs with electrolysis in the power sector




### Figure 22: Capacity mix with hydrogen from gas reforming in the power sector in 2050



## Figure 23: Generation mix with hydrogen from gas reforming in the power sector in 2050

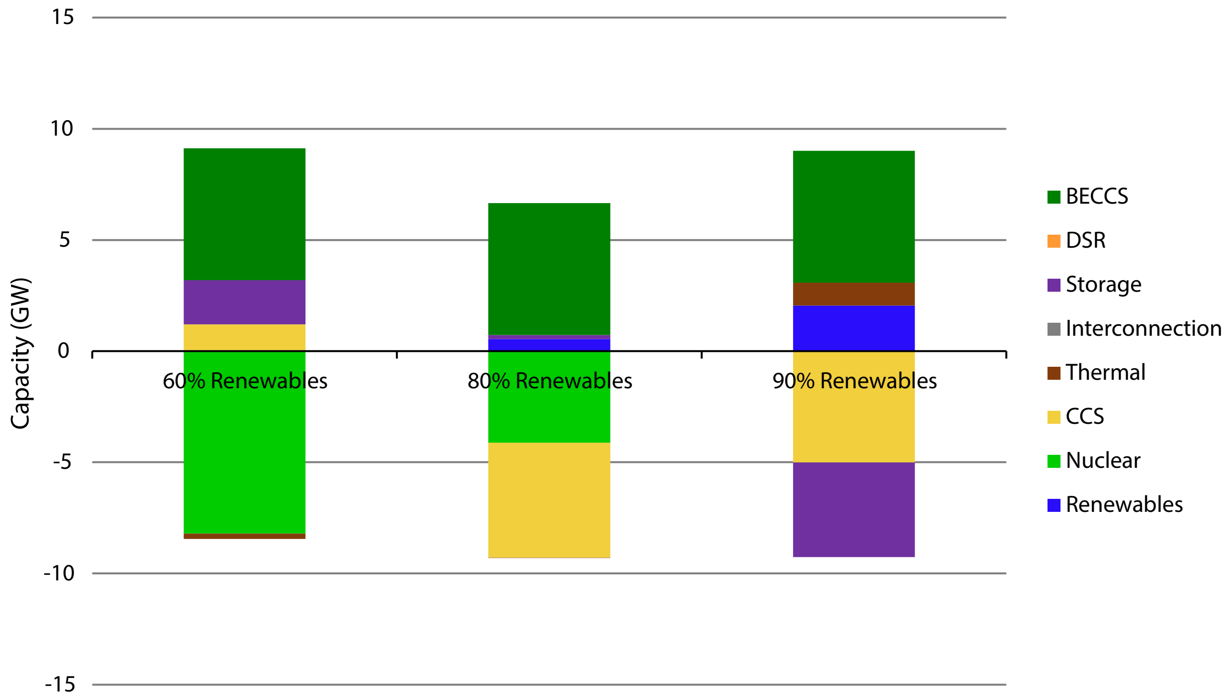



Note: If the UK is net exporting electricity this appears on the chart as a negative figure below the x-axis.

# Bioenergy with Carbon Capture and Storage in the Power Sector

The analysis finds that deploying BECCS in power will marginally increase overall power systems cost due to the relatively higher capital costs and again displaces nuclear capacity (Figure 24). Similarly to the electrification of heat scenarios, the BECCS capacity runs baseload in all scenarios.

**Figure 24: Change in capacity in 2050 when introducing BECCS into the electricity system**



# Annex 1: Key assumptions

## Table 1: Key assumptions for the electrification scenario

<table>
<tr><th>Parameter/Scenario</th><th>Assumptions for electrification</th><th>Assumptions for Greener Gas</th><th>Comments</th></tr>
<tr><td>Annual generation (TWh)</td><td>595</td><td>465</td><td>These total demand scenarios are comparable to the demand in the CCC indicative net zero scenario (650 TWh)[42] and the National Grid ESO Future Energy Scenarios 2019 (400 – 450 TWh)[43]</td></tr>
<tr><td>Emissions constraint (MtCO2)</td><td>2.9</td><td>1</td><td>In the electrification scenarios as demand is similar to that in the CCC indicative net zero pathway a 2.9 $MtCO_2$ constraint is used, as the Greener Gas scenario has a smaller power sector a lower emissions constraint of 1 $MtCO_2$ is used.</td></tr>
<tr><td>Electric vehicle deployment</td><td>Assumed 100% new sales are EVs by 2030</td><td>Assumed 100% new sales are EVs by 2030</td><td>In line with recommendations made in the Assessment by 2030 100 per cent of new car sales are electric vehicles.</td></tr>
<tr><td>Number of heatpumps</td><td>33 million 4kW heatpumps are installed in homes</td><td>N/A</td><td>These assumptions are based on Cost analysis of future heat infrastructure option[44]</td></tr>
<tr><td>Energy efficiency measures</td><td colspan="2">Heat demand is lowered by around 100 TWh against the counterfactual from energy efficiency measures.</td><td>These assumptions are based on Cost analysis of future heat infrastructure options[45]</td></tr>
<tr><td>Gas prices</td><td colspan="2">BEIS central gas prices are assumed, reaching 63p/therm by 2050.</td><td>BEIS fossil fuel price assumptions[46]</td></tr>
<tr><td>Interconnector capacity assumed</td><td>17.9 GW</td><td>17.9 GW</td><td>This is based on the capacity of interconnectors either already in operation, under construction or with regulatory approval from Ofgem[47]</td></tr>
<tr><td>Baseline level of nuclear to 2050</td><td>4.6 GW</td><td>4.6 GW</td><td>Assuming Sizewell B and Hinkley Point C are both online in 2050</td></tr>
</table>

# Annex 2: Hydrogen and BECCS

## Hydrogen assumptions and methodology

In each of the two scenarios modelled the hydrogen generated is burned in a 100 per cent hydrogen compatible gas turbine to generate electricity. Gas turbines, specifically combined cycle gas turbines (CCGT), are a mature technology which generate a significant amount of the UK's electricity.[48] These plants burn natural gas to generate electricity. However, engineering assessments have suggested that natural gas could be replaced with up to 100 per cent hydrogen at little additional cost.[49] Whilst this may result in high NOx emissions, which have significant air quality impacts, NOx capture facilities or diluted fuels could likely be used to mitigate this impact.[50] A number of organisations have made public commitments to developing hydrogen turbines in the 2020s.[51] Siemens have already developed a prototype turbine capable of running on 100 per cent hydrogen.[52]

Given the lack of technical maturity of this technology similar costs and running parameters to a traditional CCGT plant are assumed in this analysis (Table 4). Further research, development and deployment is needed to increase confidence and certainty in the technical capability of this technology. The UK has the opportunity to be at the leading edge of this.

### Table 4: H2 CCGT running parameters in 2050

| Parameter | Value |
|---|---|
| Capital costs | £700/kW |
| Fixed operating costs | £25/kW |
| Variable operating costs | £1/MWh |
| Efficiency | 50% |

The costs and running parameters of low carbon hydrogen technology are highly uncertain. There is currently little hydrogen produced from gas reforming with CCS globally (see Box 4),[53] and no at scale deployment of 100 per cent hydrogen combusting gas turbines.[54] To fully assess the viability of a future power system with a significant role for hydrogen, and the cost savings it can bring, this must change. With near-term action the UK can be at the leading edge of proving the viability of this technology.

In the Assessment the Commission recommended that government support the development of a hydrogen production plant using gas reforming with carbon capture and storage by 2023, as part of a large scale trial to supply hydrogen for heating to at least 10,000 homes. Successful delivery of such a plant would significantly reduce levels of uncertainty and build confidence that future systems with hydrogen used at scale are realisable.

## A flexible source of low carbon electricity to complement renewables

Flexible low carbon generation is the ideal complement to renewable generation as it can respond to changing weather and demand patterns – hydrogen burning gas turbines could play this role. Baseload technologies, those that run at a near constant output throughout the year, are not as flexible.

The Commission has modelled a power sector which has both low carbon hydrogen available and hydrogen compatible gas turbines to burn this hydrogen. The work assumes that hydrogen is produced from gas reforming with CCS, as this is currently likely to be the cheapest source of hydrogen. To ensure this is consistent with economy wide decarbonisation, the emissions from producing the hydrogen used to generate electricity are accounted for in the power sector while maintaining net zero compliant emissions in the power sector.

## Electrolysis in the power system

Curtailed renewable generation could be used by electrolysers to generate zero carbon hydrogen. At periods where generation significantly exceeds demand the surplus electricity can be absorbed by electrolysers and turned into hydrogen for combustion in the power sector at a later date. Not only could this help to reduce wasted electricity, and hence costs, but it may also provide an effective long-term storage option for the power sector.

### Box 4: Producing low carbon hydrogen

Hydrogen is a zero carbon gas capable of replacing natural gas, and other energy carriers, in a range of different processes. There is currently around 2000 TWh of hydrogen produced globally,[55] but this is largely made through high carbon emissions processes. There are two primary routes through which low carbon hydrogen can be produced:

- **Gas Reformation with CCS:** combines natural gas and water and converts these to hydrogen and carbon dioxide. Gas reformation is currently significantly cheaper than any other method of hydrogen production and is the most widely used method today. This production method needs to be paired with carbon capture and storage, otherwise it still emits significant amounts of carbon dioxide. Additionally, if the future costs assumptions used in this analysis are to be realised it is likely that novel reforming methods, such as Auto Thermal Reforming, would need to be developed and deployed at scale.[56]
- **Electrolysis:** uses an electric current to split water into hydrogen and oxygen. Provided that the electricity is from a low carbon source electrolysis has the potential to produce hydrogen with minimal carbon emissions. However, this is a more expensive and energy intensive method of hydrogen production than gas reformation.[57]

These assumptions for hydrogen production technologies are based on *Hydrogen Supply Chain Evidence Base*[58] and are similar to those used in other analysis.[59] Throughout, this analysis has, in order to better demonstrate the potential benefits of hydrogen in the power sector at scale, used ambitious cost assumptions for hydrogen technologies.

The overall cost of hydrogen production will also depend on gas prices, a globally traded commodity. If prices significant diverge from those assumed here, this could materially impact the conclusions of the analysis.

#### Table 5: Assumptions for advanced gas reforming with CCS in 2050

| Parameter | Value |
|---|---|
| Capital costs | £455/kW |
| Fixed operating costs | £49/kW |
| Variable operating costs | £0/MWh, excluding the electricity price |
| Efficiency | 74% |

#### Table 6: Assumptions for electrolysis in 2050

| Parameter | Value |
|---|---|
| Capital costs | £455/kW |
| Fixed operating costs | £49/kW |
| Variable operating costs | £0/MWh, excluding the electricity price |
| Efficiency | 74% |

## Bioenergy with carbon capture and storage methodology

Double counting negative emissions generated from biomass is a risk in a sector specific approach. It is likely that, if there is a limited supply of negative emissions, these will be needed to offset emissions in sectors other than power – some of which are outside the Commission's remit. Therefore, the same net zero compliant emissions target for the power sector, used elsewhere in this analysis, is assumed. The negative emissions and any associated revenue streams are not included in this work. The implicit assumption is that the negative emissions are accounted for, and remunerated, elsewhere in the economy. Based on this, the modelling captures the lowest cost way to capture 50 $MtCO_2$ emission from BECCS used in the power system in 2050

### Box 5: Biomass with carbon capture and storage technology

Biomass, when considered in the context of generating energy, primarily refers to: crops grown specifically for energy, forest and agricultural residues, and organic wastes.[60] It can be used to generate electricity through combusting in a power plant. In 2018 biomass plants generated around 35 TWh of electricity in the UK.[61]

Carbon capture and storage is the process of capturing carbon from high carbon processes and storing it underground, instead of allowing it to be released into the atmosphere.

When combined with biomass, CCS technology can produce negative emissions, drawing down carbon from the atmosphere and storing it underground. Detailed consideration and lifecycle assessments would need to be made to ensure that this is creating a genuine carbon reduction – this is not the topic of this paper.

A key parameter when considering CCS technology is the capture rate, the amount of carbon dioxide that would have otherwise been released that is captured. This has a significant impact on the role that various CCS technologies could play in a net zero economy. For this analysis a 90 per cent capture rate is assumed – this is consistent with the range of current estimates.[62]

There are many other sources of generating negative emissions, including afforestation and reforestation, soil carbon sequestration, enhanced terrestrial weathering, and direct air capture.[63] However, these do not directly relate to the power sector and are therefore not the subject of this paper.

# Annex 3: Resource constraints

There will be an upper limit on the amount of each technology that can be deployed in the UK. For example, land or seabed availability will limit the amount of capacity of some technologies in the UK. The modelled levels of capacity fall within the current theoretical estimates of the total capacity of each technology that can be deployed in the UK. However, barriers may emerge in practice that need to be better understood going forward:

- A range of factors must be accounted for when considering resource constraints for renewables, these include land and seabed availability, solar irradiance, wind speeds, and water depths. The capacity of onshore wind, offshore wind and solar built across the full range of scenarios considered here fall well within current resource estimates.[64] However, in practice, more granular constraints may emerge. A better understanding of competing uses of the seabed and visual impacts of renewables will be needed to reach the upper end of capacity deployed in these scenarios.
- There are a range of different factors and constraints that need to be considered when assessing whether a specific location is viable and safe for a large scale nuclear plant to be deployed.[65] This limits the number of plants that could theoretically be constructed in the UK. Estimates suggest that currently identified nuclear sites could support up to 35 GW of nuclear capacity by 2050.[66] Nuclear capacity in all scenarios presented here falls within this limit.
- The primary resource constraint on deploying CCS in the UK is likely to be the capacity of $CO_2$ storage. $CO_2$ is likely to be stored offshore in depleted oil and gas fields or saline aquifers. Current estimates suggest the UK has between 1.5 – 78 Gt$CO_2$ storage capacity[67] – significantly more than the upper limit of 7 Mt$CO_2$ annually captured in any scenarios presented here.

# Endnotes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