Technical Annex: Integrating variable renewables into the UK electricity system

Introduction and summary

Variable renewable electricity - such as large scale onshore wind, offshore wind and solar PV - is now the cheapest form of electricity generation in the UK and can be deployed at scale to meet UK electricity demand. In 2018 these sources provided 22% of the UK's electricity. That proportion rises to 50-65% in our scenarios to 2030, and potentially higher towards 2050.

Variable (or 'intermittent') renewables - which are weather dependent - are different to other forms of electricity generation, and increased deployment of them could require additional system services. For example, renewables cannot be guaranteed to generate during winter peak demand periods, and renewable output is generally correlated across different sites. Similarly, wind and solar generation can change substantially over periods of just a few hours, requiring non-renewable plants to be held in reserve to meet any sudden shortfall in supply.

All technologies, including non-renewable technologies, have system costs which need to be taken into account. For example, a large power station or interconnector may require network upgrades, or for the system operator to hold reserves in place for if the plant or connection fails. This Annex focuses on the system costs of variable renewables only.

This Annex supports the Committee's advice on setting a target to reach net-zero greenhouse gas (GHG) emissions in the UK by 2050.[1] In that advice we set out scenarios, based on a 'Further Ambition' scenario, to show how the UK can reduce GHG emissions to net-zero across the economy by 2050.

A net-zero economy requires near-zero emissions from almost every sector. If intermittency in the power sector requires gas-based back-up or reserve, this could increase emissions. Similarly, a lack of deployment of system flexibility could restrict the deployment of renewables and increase costs. Our Further Ambition scenario for the power sector sees low-carbon sources providing 100% of power generation in 2050, through a mixture of variable renewables (57%), firm low-carbon power like nuclear or plants fitted with carbon capture and storage (38%) and decarbonised gas such as hydrogen (5%).

The drivers of the system impacts of renewables are well understood, but uncertainty remains about the additional costs weather-dependent renewables will impose on the system at high annual and instantaneous penetrations.[2] This Annex aims to summarise the evidence on the costs of intermittency, and the challenges that may arise with deep penetrations of variable renewables on the UK's electricity system.[3] A detailed description of a net-zero power system, and the steps necessary to achieve this can be found in Chapter 2 of *Net Zero - Technical report*.

[1] CCC (2019) *Net-Zero: The UK's contribution to stopping global warming* and CCC (2019) *Net-Zero - Technical report.*

[2] Variable renewables will have different impacts over different timeframes. Section 2 considers the evidence around high annual penetrations of renewable generation. Section 3 summarises impacts of high instantaneous penetrations of renewables.

[3] The CCC would like to thank UKERC, Imperial College and National Grid for their input into this technical annex.

Key messages:

- Intermittency of renewables does not prevent full decarbonisation of the power system. Deployment of variable renewables, alongside system flexibility, is a low-regrets and low cost means of decarbonising the UK's electricity system.
- Intermittency does imply a real, but likely high, economic and technical limit to shares of individual renewable technologies within the UK's generation mix. The precise limit is unknown, but in total is likely to be higher than the 57% penetration assumed in our Further Ambition scenario. Additional system flexibility can increase the share that can be accommodated, with higher shares generally associated with lower overall system costs.
- Power sector decarbonisation does not rely on variable renewables alone, but a portfolio of technologies including nuclear power, bioenergy with CCS and decarbonised gas via CCS or hydrogen. Other renewables, such as wave and tidal, could also play a role.
- The costs of intermittency can be estimated, and ideally reflected in policy and market design. Overall, the costs of intermittency represent a small proportion of overall system costs. Policy should support system flexibility.

This Technical Annex is set out in four sections:

1) Drivers of intermittency

2) Evidence on costs and the value of flexibility

3) Future integration challenges

4) Policy implications

1) Drivers of intermittency and system flexibility

Drivers of intermittency

An effective electricity system provides electricity where it is needed, when it is needed. Historically, power systems have relied largely on increasing or decreasing production from flexible thermal power plant – such as gas, coal or biomass generation – to ensure supply matches demand at all times.

Nuclear power plants are typically run to maximise output at all times (known as 'baseload' or 'firm' power). Variable renewables like wind and solar vary generation in line with wind patterns and solar irradiance. As more variable renewables come onto the UK's electricity system, matching supply with demand at all times becomes harder (Box 1).

A decarbonised power sector that is not properly managed could put security of supply at risk and/or prevent the system from accommodating renewables, with associated costs. However, with good management, these costs and risks can be avoided.

In 2018, with 22 GW of wind and 13 GW of solar capacity, wind and solar provided 22% of generation and there were no periods in the year where low-carbon generation exceeded demand.[4]

However as deployment increases (consistent with reducing carbon intensity to under 100 gCO_2/kWh in 2030 and 10 gCO_2/kWh by 2050) there would be challenges in using the available generation fully, in meeting peak demand at certain times, and in meeting other system balancing requirements such as reserve and response:

- **Meeting peak demand.** In particular there may be periods where demand is high, but intermittent renewables make a limited contribution to meeting it. To ensure the system is secure and reliable there needs to be enough firm capacity to meet peak demand with low contribution from intermittent sources.
- **Using available generation.** With high penetrations of intermittent renewables there are likely to be periods where output is in excess of demand. This output would effectively be wasted and have no value.
- **Balancing requirements (e.g. reserve and response).** There would also be challenges to balance the system and maintain grid frequency. That could require additional system flexibility, such as battery storage, or 'part-loading' of decarbonised gas plant, to be able to respond to rapid changes on the system.
- **Networks.** Renewables - such as wind in Scotland, or in the North Sea - may be located far from where electricity is needed. Additional investments in electricity networks could be required to transport this electricity.

Improving system flexibility can help to meet these challenges. Even with high flexibility, challenges and costs will remain - our net-zero scenarios include all relevant costs to meet the four challenges above and ensure security of supply is maintained.

[4] CCC analysis of Drax (2018) *Electric Insights*.

Box 1. Variable renewables

Variable renewables such as wind and solar only produce power when the wind blows and the sun shines, whereas traditional power stations can generate electricity constantly over the year, and moderate their output flexibly in order to match electricity demand.

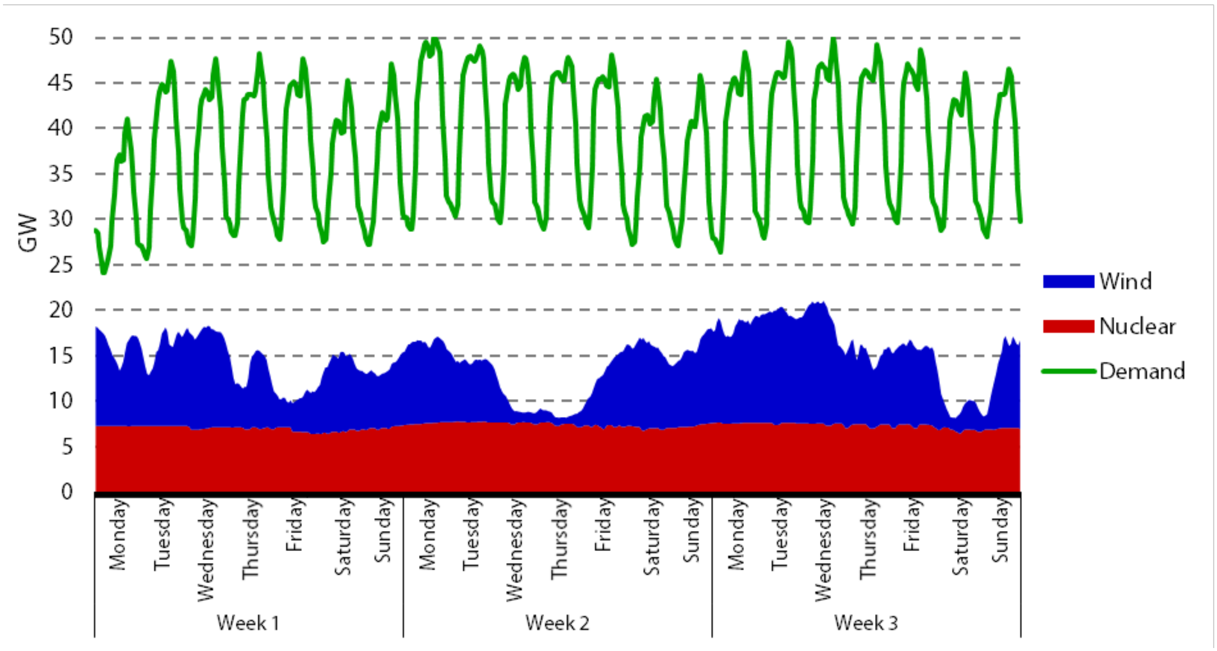
Weather patterns in the UK fluctuate over the year, from small changes in cloud cover and wind speeds within a period of just a few hours, to seasonal swings in solar output (higher in summer) and wind generation (higher in winter). In 2018, wind power provided 18% of total electricity generation (and solar PV another 4%), but generation within any single half hour of the year can vary significantly: on average the wind fleet produced around 40% of its potential power generation over the year, though this varied between close to 0% and near 100%. The CCC's scenarios for 2030 and 2050 include penetrations of wind and solar PV of up to 65%.

Figure B1.1 shows generation from wind and nuclear power output in the first three weeks of January 2018, compared to electricity demand. Whilst nuclear power was fairly constant over this period, wind output ranged from 90% of potential output to just 5%. Additionally, wind output changed by up to 12% from hour to hour, and 26% over a three hour period.

Other forms of capacity may be needed, to compensate for this variability. Paying for these 'reserve' plants to be available when the wind doesn't blow (capacity) and to be able to vary their output over short periods of time (reserve and response) makes up the majority of the 'system integration costs' discussed in this annex.

Similarly, solar will have lower output during winter periods (requiring capacity), though short-term variations in its output will be more predictable and its higher generation during the daytime generally will be advantageous.

Figure B1.1. Generation from wind and nuclear; electricity demand (first three weeks, Jan 2018)



Source: CCC Analysis based on Drax (2019) *Electric Insights*.

Options for system flexibility

Improving electricity system flexibility is key to keeping the costs of integrating variable renewables into energy systems low. In particular, improvements in flexibility can provide low-carbon sources of system reserve and response to minimise the need for part-loaded unabated gas plant, with associated emissions savings. Flexible systems also allow renewables and nuclear output to match demand better by shifting demand (demand-side response), supply (storage), or both (interconnection).

There are five main options for system flexibility:

- **Flexible gas plant.** There is currently 32 GW of unabated gas on the UK's system. More efficient and flexible generation technologies are available that can operate stably at lower levels of output, provide faster frequency response than at current levels, and consume less fuel when part-loaded to provide system reserve. Greater use of these would require less overall thermal plant to be built to stabilise the system, be less likely to curtail renewables output, and reduce overall emissions (until decarbonised gas is used).
- **Interconnection.** Interconnection already provides a valuable source of flexibility to the UK with 5 GW of capacity linked from GB to Ireland, France, the Netherlands and Belgium. Increased interconnection to these or other electricity markets (e.g. Norway) can improve security of supply and operating efficiency through sharing of backup capacity as well as ancillary services, and better accommodate intermittent generation by taking advantage of different weather patterns and/or electricity demand profiles.
- **Demand-side response.** Shifting electricity demand away from 'peak' time periods, such as on a winter evening and towards periods when demand is lower, is known as Demand-Side Response (DSR) or Demand-Side Management (DSM). DSR can help to manage large volumes of intermittent renewable generation and can significantly reduce the overall cost of a decarbonised system by shifting demand to off-peak periods with higher renewable output or by reducing the requirements for capacity during peak periods. DSR is also expected to be able to provide ancillary services such as frequency response.
- **Energy storage technologies.** There is currently around 3 GW of pumped hydro storage in the UK (equivalent to around 30 GWh). Further deployment of bulk and distributed energy storage (e.g. battery technologies) can reduce the need for additional backup capacity, generation and infrastructure, by storing electricity when demand is low and discharging when demand is high. Deployment of storage solutions is in the early stage, with around 0.4 GW of battery devices currently being used across the UK.[5]
- **Power-to-gas.** Converting power to hydrogen via electrolysis, could act as a form of energy storage, with the gas being stored (e.g. via salt caverns) and later being used for energy production. Electrolysers could also act as a flexible form of energy demand, and provide electricity system services.

Value of system flexibility

Improvements in system flexibility have the potential to bring electricity system costs down by £3-8 billion/year by 2030 (to a total system cost of around £30 billion/year) and £16 billion/year by 2050 (to around £50 billion/year), by making better use of low-carbon

[5] BEIS (2019) *Renewable Energy Planning Database*.

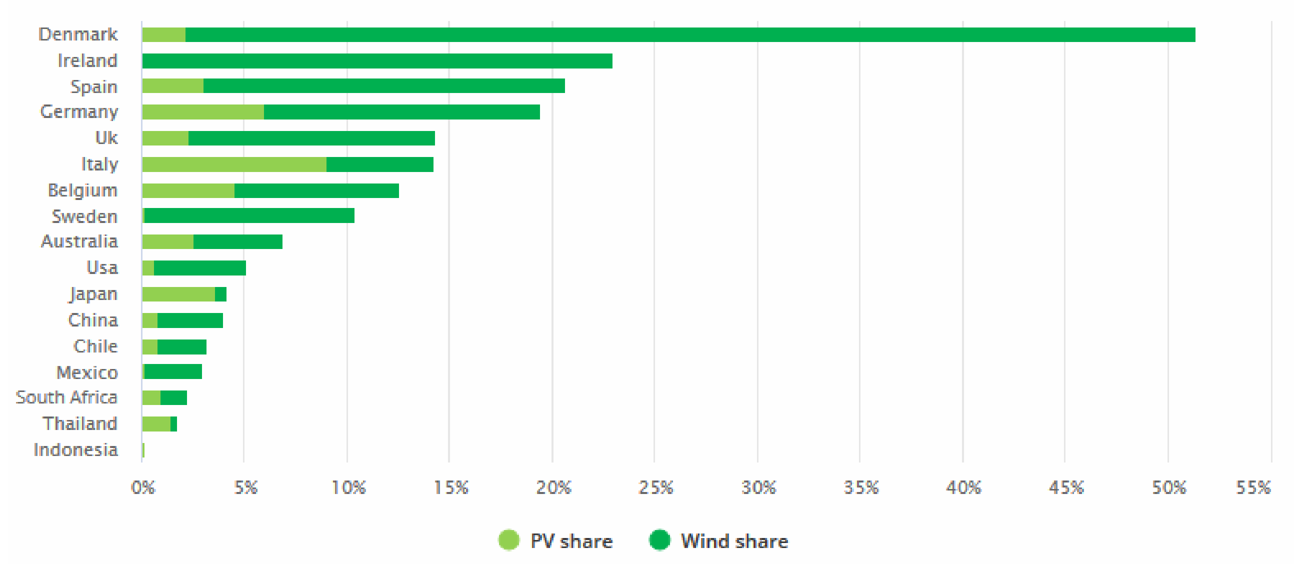
generation and avoiding the need for reserve and back-up plant. [6] With increased flexibility, the UK's power system would be better able to cope under periods of stress or unexpected circumstances, and better able to accommodate a much larger share of intermittent generation:

- During periods of high demand and low output of wind and/or solar, demand-side response can be activated to shift demand to periods when demand is lower, interconnectors can import and storage devices can discharge fully into the grid.
- During periods of low demand and high renewables output, demand can be increased (e.g. electric vehicles can be charged, and heat pumps can be switched on to either provide or store heat), storage devices can charge, and interconnectors can export. Rolling out these options for flexibility is important to decarbonise the power system at lowest cost while maintaining security of supply.

Improved system flexibility is a key consideration in studies of system integration costs, with even modest improvements in system flexibility significantly reducing the costs of managing intermittency (Box 2).

The UK is not alone in facing these challenges – Denmark and Ireland already have higher shares of variable renewables on the system (Figure 1). However, some characteristics of the UK's electricity system – such as increased electricity demand in winter, and relatively low interconnection (as a proportion of the total system) – may make renewable integration in the UK more challenging.

Figure 1. Share of variable renewables in electricity generation in 2015 (selected countries)



Source: IEA (2018) *System integration of renewables*.
Notes: Wind and solar power provided 22% of UK generation in 2018 (an increase from the 2015 share shown in this Figure). The CCC's scenarios for 2030 and 2050 include penetrations of wind and solar PV of up to 65%.

[6] See Ofgem (2015) *Making the electricity system more flexible and delivering the benefits for consumers*; Imperial College (2015) *Value of Flexibility in a Decarbonised Grid and System Externalities of Low-Carbon Generation Technologies*.

2) Evidence on integration costs

Multiple studies have used detailed models to look at deep penetrations of variable renewables in electricity systems around the world, and in the UK. Therefore the implications of a high share of renewables are increasingly well understood.

Estimating system integration costs is analytically challenging and it is important to understand underlying assumptions. Studies are required to make extensive assumptions around the system being modelled, system flexibility and a counterfactual technology (often compared to a non-renewable technology like nuclear power). Allocating costs to specific categories is even more difficult, as there is significant scope for 'double-counting'. For example, a gas plant providing back-up capacity for renewables in winter can also provide system reserve and response services. For ease of comparison, studies often attempt to quantify the integration cost per unit of variable renewable generation.

Several studies demonstrate that annual penetrations of over 80% of variable renewables in the UK's electricity system are technically achievable (i.e. electricity demand can be met at all times, whilst meeting the standards expected of a modern electricity system). However evidence on the explicit costs of integrating these renewables into the UK electricity system is more limited. The available evidence suggests integration costs could be around £10-25/MWh for annual penetrations of up to 50-65% renewables, but could increase further at higher penetrations.[7] This is in addition to a levelised cost for wind and solar of around £50/MWh.[8]

- Multiple studies demonstrate that penetrations of over 60-80% renewables can be integrated into the UK's electricity system, though these do not explicitly estimate the integration costs of renewables.[9]
- Detailed studies of system integration costs are largely reliant on modelling (Table 1, Box 2), and provide useful insights on how costs might change as more renewables enter the system. Reviews of integration costs by the UK Energy Research Centre (UKERC) and the International Energy Agency (IEA) estimate system integration costs for renewables, and highlight the importance of system flexibility.
  - A recent IEA/NEA study suggested that penetrations of 75% variable renewables could impose average integration costs of $50/MWh (£40/MWh), but did not consider significant deployment of battery storage or demand-side flexibility in the study, which could reduce costs significantly.[10]
  - A 2006 UKERC study estimated the costs of managing intermittent renewable output and building back-up capacity to be up to around £8/MWh, at 20% penetration. An update to this review, in 2016, noted that the costs depend significantly on the definition of system costs and levels of flexibility, but broadly the average costs of integrating renewables into the system are up to £25/MWh at penetrations of 50%.[11]

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[7] It should be noted that evidence on system integration costs above annual penetrations of variable renewables of 35% or more in the UK is limited.
[8] Levelised cost estimates for a gas CCGT plant are around £70/MWh, and £70-80/MWh for nuclear and CCS.
[9] See, for example, Aurora (2018) *System cost impact of renewables*, Imperial College (2018) *Analysis of alternative heat decarbonisation pathways*.
[10] OECD & NEA (2019) *The costs of decarbonisation: System Costs with High Shares of Nuclear and Renewables.*
[11] This was the median value in the study.

This is alongside costs of £5-15/MWh for building back-up capacity at the same penetration, although these costs are not additive. UKERC note the importance of system flexibility in studies of integration costs, and note that studies with lower costs typically have more system flexibility (see below).

- As penetrations of renewables increase, the underlying assumptions in the studies become increasingly important, particularly around the level of flexibility. Improved system flexibility reduces the integration costs of renewables, and allow more renewables to be brought into the system. Studies for the CCC have considered improved system flexibility and estimate that integration costs could be around £10-25/MWh - even at penetrations of renewables of 50-65%:
  - The CCC's 2011 Renewable Energy Review, based on analysis we commissioned from Pöyry Management Consulting[12], concluded that high shares of intermittent renewable capacity (e.g. 50% or more) could be managed, provided options for flexibility are appropriately deployed. We estimated a cost of integrating intermittent renewables of around £10/MWh.
  - A study by Imperial College for the Committee in 2015[13] suggests that for a system with an emissions intensity of 100 gCO_2/kWh and with 35-40% variable renewables penetration, wind and solar intermittency can be managed at a cost of around £10 per MWh of those technologies. However, in a more decarbonised power system reaching 50 gCO_2/kWh in 2030, with higher levels of intermittent renewables penetration (50%), the marginal integration costs could be £20/MWh or above.[14]
  - The same study also considered scenarios that reach an emissions intensity of around 10 gCO_2/kWh, with 60% penetration of variable renewables - consistent with the Further Ambition scenario presented in our *Net-Zero Technical Report*. These suggested system integration costs for variable renewables in a 10 gCO_2/kWh system could be around £25/MWh, with improvements in system flexibility (Box 2).

Common findings of these studies are that flexibility is vital, that up to a point the main integration cost is for provision of back-up capacity at £5-15/MWh and that diversification of the renewables portfolio tends to allow a higher overall share. Higher integration costs tend to be associated with 'lost' renewable generation when output is in excess of demand.

We note that current trends in technology will tend to support larger renewable shares and lower system integration costs. Offshore wind farms are achieving considerably higher load factors (up from around 40% to closer to 60%); levelised costs of renewables are falling (so the effective cost of 'lost' generation will be lower); and costs of batteries and other storage options are falling. Development of a low-carbon hydrogen industry in future would ensure that where back-up generation is needed it is associated only with extra costs, not extra CO_2 emissions.

[12] Pöyry (2011) *Analysing Technical Constraints on Renewable Generation to 2050.*
[13] Imperial College (2015) *Value of flexibility in a decarbonised grid and system externalities of low-carbon generation technologies*
[14] Studies also vary in their presentation of average or marginal system integration costs. Average integration costs are the costs of intermittency spread over the entire fleet of variable renewables. Marginal integration costs are the costs of the additional system requirements for an additional unit of variable renewable generation.

Table 1. System integration costs by driver of cost			
Cost driver	**Estimated cost (£/MWh)**	**Cost associated with**	**Impact at high penetrations**
Meeting peak demand	5-10	Back-up capacity for periods of peak demand.	Unlikely to increase significantly.
Using available generation	0-25	Wasted generation when renewables exceed electricity demand.	Increases with more deployment of the same technology.
Balancing requirements (e.g. reserve and response)		Paying for part-loaded plant to remain on the system.	Unlikely to increase significantly.
Networks	0-5	Building new transmission networks to bring renewables to centres of demand.	Dependent on location.

Source: CCC analysis based on Imperial College (2015) *Value of flexibility in a decarbonised grid and system externalities of low-carbon generation technologies* and UKERC (2016) *The costs and impacts of intermittency (2016 update).*
Notes: There is likely to be overlap and double counting of costs, especially at higher penetrations. The costs of 'using available generation' and 'balancing requirements' are grouped to reflect this, though there will also be overlap with capacity costs. For example, back-up capacity can also provide generation for balancing and reserve. 'Impact' refers to per unit costs not aggregate costs. Aggregate costs will increase with renewable penetration, but are likely to remain a small overall proportion of total electricity system costs (see Section 4).

Box 2. System integration cost estimates at high penetrations of renewables

Studies by Imperial College in 2015 and 2016 looked at the marginal cost of integrating renewable electricity into the UK's electricity system, against a given set of assumptions on system flexibility. In these studies a unit of renewable electricity (i.e. a MWh) is either added (or removed) in the UK's electricity system, replacing (or replaced by) a non-renewable technology such as nuclear power. The total system costs before and after the change are estimated, and used to calculate the marginal system integration cost for renewables.

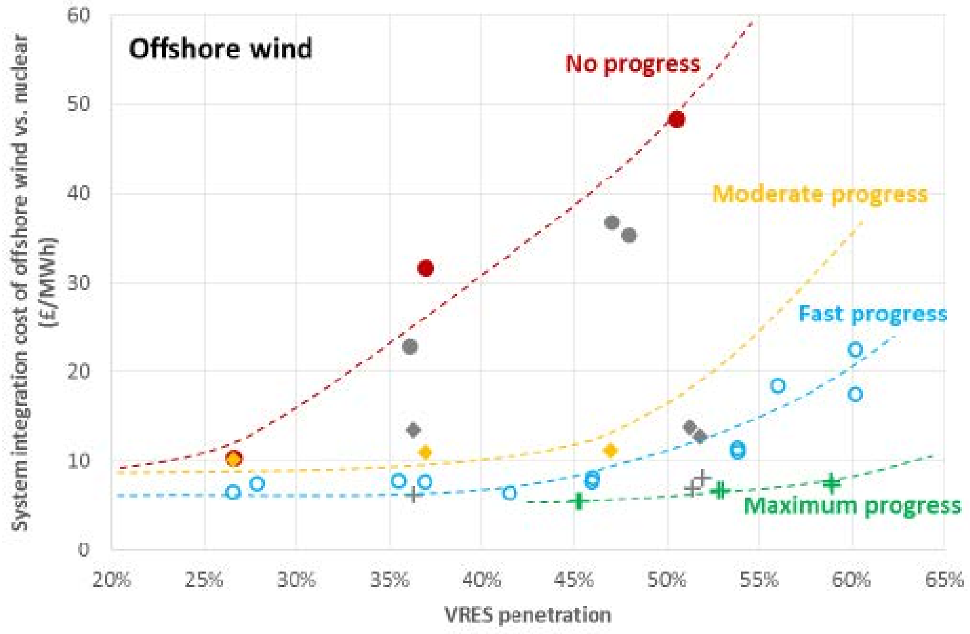
Imperial College concluded that integration costs of variable renewables could range from £10-50/MWh depending on system flexibility (Figure B2.1). System flexibility could limit this to £20/MWh or below. At higher penetrations of renewables, low system integration costs are contingent on the level of system flexibility, and carbon intensity of the system:

- Costs associated with back-up capacity and networks are likely to remain fairly constant.
- Making use of generation is likely to become more difficult, thus increasing costs. As adding more wind to a wind-driven system increases the likelihood of wind generation exceeding electricity demand at any point in time, additional units of wind generation have increasingly limited value.

Box 2. System integration cost estimates at high penetrations of renewables

- As the carbon intensity of the power system reduces, there is less scope for unabated gas generation to back up renewable electricity, increasing integration costs. Though decarbonised gas - and to some extent other system flexibility options - can help fill this role, it is more expensive than unabated gas.

Figure B2.1. Offshore wind integration costs as a function of renewable penetration and system flexibility



Notes: Integration costs are expected to be similar for onshore wind, but will differ for solar as it has a different seasonal generation profile. Estimates of system integration costs are compared to nuclear power, which will have system integration costs of its own, and are for a system with a carbon intensity of 100 gCO_2/kWh. 'No progress' has no added system flexibility. 'Moderate progress' includes 5 GW of new storage, 25% DSR uptake and 10 GW of interconnection. 'Maximum progress' includes 15 GW of new electricity storage, 15 GW of interconnection capacity (15 GW) and 100% uptake of DSR.

Source: Imperial College (2015) *Value of Flexibility in a Decarbonised Grid and System Externalities of Low-Carbon Generation Technologies* & Imperial College (2016) *Whole-system cost of variable renewables in future GB electricity system.*

3) Intermittency in a net-zero world

Our Further Ambition scenario for 2050 sees a doubling of electricity demand compared to today's levels, with increased electricity demand primarily from electric vehicles (EVs), electrified heat via heat pumps and electrolytic hydrogen production.[15] These create potential for demand-side flexibility to be provided by EV and heat pump users, which match well with variable renewables, as well as opportunities to use decarbonised gas in the power system.

The transition to a low-carbon power system presents both challenges in integrating renewables and opportunities to increase system flexibility, particularly from new electricity demands. Importantly, electricity system flexibility is already improving and adapting to these new circumstances.

Current progress

Progress is already being made in integrating renewables into the UK's electricity system, and making the system more flexible:

- Studies suggest that there may be more existing flexibility within the grid than previously expected.[16]
- Experience to date suggests that some system integration costs could be lower than previously envisaged. For example, the costs of procuring capacity in the Capacity Market have been lower than expected. Similarly, cost reductions in battery storage and renewables have exceeded expectations.[17]
- The System Operator is already planning to manage the grid to operate 'safely and securely at zero carbon' for parts of the year as early as 2025.[18]
- BEIS and Ofgem recently set out a list of 29 actions which are likely to significantly improve deployment of system flexibility. Progress on some of these actions has already been achieved. [19]
- The UK's balancing mechanism - which is used to meet short-term changes in supply and demand - has been amended to reflect better the costs of managing the system, and to make it easier for demand-side management providers to participate.[20]
- Smart meters are being offered to UK households and small businesses, which, alongside Ofgem's progress on half-hourly metering, should allow for greater participation of demand-side management in UK electricity markets.
- The Energy Networks Association has created a working group to identify the appropriate long-term roles for transmission and distribution system operators.

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[15] New demands from EVs and heat pumps are likely to cause network upgrades at the distribution levels. This is covered in more detail in Box 2.2 of *Net-Zero Technical Report*.
[16] Joos and Staffell (2018) *Short-term integration costs of variable renewable energy: Wind curtailment and balancing in Britain and Germany*.
[17] See Chapter 7 of CCC (2019) *Net-Zero - Technical Report*.
[18] National Grid (2019) *Zero Carbon Operation 2025*.
[19] BEIS & Ofgem (2018) *Smart Systems and Flexibility Plan: Progress Update*.
[20] National Grid (2019) *Future of balancing services*.

- The system operator, National Grid, through its Power Responsive programme, is working on improving information on system requirements, reducing complexity in its contracting system and reforming its energy services markets. This has been reflecting in its work on System Needs and Product Strategy.

Progress will need to continue from all parties, to manage the transition to a smart, flexible electricity system and to ensure that the future electricity system delivers power at the lowest possible cost. We monitor progress in developing system flexibility in our annual progress reports to Parliament.[21]

Future challenges and opportunities

Increased variable renewable generation will reduce the role of thermal power plant on the system, which currently provides important system services. New means of providing these services will be needed to maintain power system quality, including provision of these services by variable renewables. Some of these are already being adopted. Planning and operating the networks on a whole system basis and optimising across the full suite of energy and demand sources present an opportunity to help integrate renewables into the electricity system.

- **Other challenges.** Today's renewables do not currently offer some system properties that thermal power plants do, such as providing system inertia, voltage and frequency management services, and other contributions to system operation. As thermal power plants come off the system, alternative ways to provide these services will need to be developed. Work is being done to address these challenges, and the electricity system operator (National Grid, the ESO) expects to be able to operate a zero-carbon power system by 2025:
  - **System inertia.** An increased share of renewables in the capacity mix reduces the system inertia which is provided by the stored kinetic energy of the rotating mass of the power generator's turbines (known as 'synchronous generation'). With this reduction in system inertia, any imbalance between supply and demand will change system frequency more rapidly making the system unstable. Technologies such as batteries, which provide rapid frequency response can help, and are being installed. Other solutions include flywheels, synchronous condensers and 'grid-forming inverters'.[22] Levels of regional inertia are likely to become increasingly important.
  - **Rapid changes in frequency** can damage electrical equipment. This equipment is often designed to shut off beyond a certain 'Rate of Change of Frequency' (RoCoF). RoCoF standards are changing so that power equipment can handle more rapid frequency changes, without being damaged.
  - **Black start** is the ability of the power system to restart itself after a complete or partial system loss of electrical power. Typically large generators would be contracted to provide this service. A recent open Black Start tender process has brought in a range of new technologies and innovative ways of using existing equipment in combination to provide an alternative method of black start service provision. The

[21] See, for example, CCC (2018) *Progress Report to Parliament*.
[22] Ackermann et al. (2017) *Paving the Way: A Future Without Inertia Is Closer Than You Think*.

ESO also suggests groups of smaller generators would be able to provide the same service.[23]

  - **Grid constraints**. Renewables in some locations are unable to get their power to users due to grid constraints. Depending on the location of new renewables, new transmission infrastructure may need to be built to accommodate this.
  - Thermal power stations are currently able to provide **frequency and voltage recovery services** (including reactive power), when frequency and voltage deviates from the system optimum. The ESO suggests that additional dynamic voltage support will be required to replace that which is currently provided by synchronous generation, and is exploring the most cost-effective way to deliver these services, with industry and market participants.[24]

- **Opportunities.** New electricity demands from electric vehicles and heat pumps offer an opportunity to integrate the electricity, transport, heat and gas systems. Co-ordinated planning and operation of these systems can reduce costs. It is likely that renewables can also provide some of the system services that thermal plant offer.
  - **Whole system integration** - planning and operating heat, transport and electricity systems together - can unlock flexible demand, complementing variable renewable output.
    - A recent report for the Committee suggested that both EV and heat pump demands are inherently flexible, and can reduce the cost of integrating renewables into the electricity system.[25]
    - Electricity demand in winter is already one third higher than electricity demand in summer, which correlates well with output from the UK's wind fleet. Electrified heat demand will make demand more seasonal.
    - Electrifying transport can also offer potential for smart charging, as well as so called 'vehicle-to-grid' services whereby vehicles could not only charge flexibly, but also put energy back into the grid at certain periods.
    - Studies suggest integrating electricity, heat and transport systems can allow more renewable energy to be brought into the system.[26]
  - Our Further Ambition scenario sees **hydrogen** being used across the economy, with a potential role as a low-carbon fuel in the power sector. Separately, power could be used to produce hydrogen via electrolysis, which could act as a flexible demand, and contribute to system services.
  - **Renewables can provide some of the system services** that thermal plant currently provide, reducing the need for alternatives.
    - Renewables can provide some ancillary services, such as fast frequency response (sometimes called 'synthetic inertia'), reserve, reactive power and inertia control. For example, wind farms in Canada must be able to provide frequency response

[23] National Grid (2017) *Black Start from Distributed Sources*.
[24] National Grid (2018) *Voltage and Frequency Dependency*.
[25] Vivid Economics & Imperial College (2019) *Accelerated electrification and the GB electricity system*.
[26] Zhang et al. (2018) *Whole-System Assessment of the Benefits of Integrated Electricity and Heat System*.

as a condition of their connection. Analysis for the UK suggests that renewables could earn up to £5/MWh from ancillary services.[27]

- Load factors for offshore wind farms have improved significantly over the past few years, from 38% to over 58%.[28] This suggests a higher probability of generating during all periods across the year, which may mean that less backup capacity could be required for a given amount of wind generation. This also implies a more even profile of output, potentially reducing reserve and response costs.
- Other renewable technologies, such as wave and tidal, could offer a more predictable output that is less correlated with wind and solar output, increasing the diversity of the UK's renewable portfolio.

Our analysis presents a non-exhaustive list of the changes likely to occur with higher penetrations of variable renewables on the system. There will undoubtedly be other issues that arise that need to be addressed, and the CCC will continue to monitor these issues as they arise.

How these costs fit in the overall system cost picture

Analysis for our net-zero report suggests the costs of a building and running a high-carbon system, based on unabated gas, to meet (increased) projected electricity demand in our Further Ambition scenario in 2050 would be around £46 billion/year.

Building and running a very low-carbon power system instead - while still meeting today's electricity system standards for security of supply - would cost £4 billion more per year. The majority of intermittency costs are captured within this, such as the costs of building back-up generation, and the costs of building and running reserve and response plant.

Overall, system intermittency costs make up a small percentage of overall system costs (less than 10%) and are likely to more than be offset by cheaper wholesale prices from low-carbon generation.

- Most of the costs of the system are from building and running low-carbon capacity (73%). Within this, the average 'levelised' cost of renewables is around £54/MWh, compared to £56/MWh for an unabated gas plant (without a carbon price, with a range of £38-66/MWh, depending on gas prices).
- The costs of building and running back-up and reserve capacity are 7% of the scenario costs. This includes paying for back-up capacity and reserve and response plant for renewables, which are likely to be the bulk of the system integration costs (though only some of the costs in the scenario would be directly associated with renewables)
- The remainder of costs of running the system are from building and maintaining electricity networks (20%). Upgrades to networks are likely to be required to accommodate electric vehicles and heat pumps.

[27] Aurora (2017) *The new economics of offshore wind*.
[28] See BEIS (2019) *Draft Allocation Framework for the Third Allocation Round*, which estimated load factors for offshore wind at 58.4%.

- This modelling assumes that generation from renewables can be used in the UK or exported to other countries, reducing curtailment. Without this system flexibility, renewables could exceed generation 3-8% of the time (20-50 TWh). At average costs of renewables of £50/MWh this implies wasted generation of £1.5-4/MWh, or £1-2.5 billion per year (an increase of 2-5% of overall system costs).

Therefore, though important, the costs of integrating renewables into the UK's energy system are likely to represent a small proportion of overall system costs (less than 10%), and do not detract from the conclusion that a near zero-carbon power system by 2050 is a cost-effective means of meeting the UK's emissions reduction targets.

4) Policy implications

A shift away from thermal power to variable renewable power has implications for market design, flexibility services and how costs are allocated across the system. The Government, regulator and system operator are developing reforms to address this. These reforms should encourage the roll-out of variable renewables and system flexibility, which are 'low-regrets' options for a low-carbon power system.

- **All technologies impose system costs, though these are likely to be higher for renewables.** Policies and electricity markets should be designed so that market participants face the costs and benefits of their capabilities and actions.
  - In principle, all market participants should face the costs and benefits of their actions. For example, technologies that contribute to security of supply should be rewarded for their capacity. Similarly, projects that require or provide system flexibility should face penalties or rewards that recognise the value they provide to the system.
  - It is likely that renewables already face many of the costs of the externalities they impose on the system, although steps can be taken to transfer some of the risks currently borne by consumers onto market participants.[29] Similarly, the ongoing evolution of ancillary service markets and network pricing will likely improve the cost-reflectiveness of the current system.
- **Installing more renewables is low-regrets**, as they are significantly cheaper than the alternatives.
  - It is already cheaper to build and run new wind and solar farms in the UK than to build and run new gas-fired capacity.[30] Between 2020 and 2050 building new renewables may become cheaper than operating existing gas plant. System integration costs delay the date of cost parity but do not change this overall conclusion.
  - Our scenarios for 2050 assume a penetration of 57% of variable renewables. Adding renewables above this level could increase the proportion of their output that is unable to be used, reducing value. But this could still be economic. For example, if wind costs £40/MWh and spills 33% of the time then the overall cost of this would be £60/MWh. This suggests two things:

[29] See NERA & Imperial College (2015) *System Integration Costs for Alternative Low Carbon Generation Technologies –Policy Implications*, and UKERC (2018) *Response to Helm Review*.
[30] We set out our assumptions on gas prices and costs of generation for different options in section 2.

- There is a real, but likely high, economic limit to the penetration of certain renewables, which will depend in large part on the cost of building renewables. It is worth installing wind up to the cost of alternative forms of generation (e.g. nuclear or CCS at £70-80/MWh). Analyses disagree as to what this limit is, although some studies have shown that overall system costs continue to decline until penetrations reach over 80%.[31]
- Potential demands (and storage options) that can make use of the 'excess' generation may be able to access it at very low cost.

– This is supported by recent modelling for the Committee, which concluded that adding more renewable electricity to the UK's electricity system in the 2020s and 2030s - to meet new demand from electric vehicles and heat pumps - reduces overall system costs.[32]

- **Improving system flexibility** will allow more renewables to be integrated into the UK's electricity system, at lower cost. Several studies have suggested the value that this can provide, and BEIS and Ofgem's Smart Systems and Flexibility Plan intends to unlock this value, in line with the principles the Committee has previously set out:
  – **Markets should be designed to reflect the full system value of flexibility options.** The market design must effectively price and reward energy, capacity and flexibility. For example, this requires removal of double-charging for storage, completing the shift to half-hourly settlement and allowing flexibility providers to receive multiple revenue streams across different services.
  – **Market rules should seek to reduce complexity, but system operators will need to manage greater complexity (across multiple sources/boundaries).** Increasing flexibility implies a shift in system control from the transmission to the distribution level and ability of the system to deal with more interactions between distribution and transmission networks, and to promote and utilise more active demand management.
  – **Support should be available for innovation in technology, services and operating models.** It will be important that, as the institutional and market framework evolves, the drive for innovation across the value chain is not dampened. Where innovation offers significant system benefit that cannot be captured by the innovators, it may require public support.
  – **Intervention may be needed to encourage greater consumer participation.** In addition to establishing the technical infrastructure for demand-side response, legal and regulatory frameworks around consumer protection and data protection will be necessary to achieve widespread consumer acceptance. Standards may be required to ensure widespread uptake of smart appliances.

There are also implications for other technologies, such as nuclear and CCS. If these remain more expensive than variable renewables they should provide a supporting role. That is likely to mean operating at reduced load factors (e.g. when wind output is low) rather than at baseload, and contracts should be designed accordingly.

[31] Aurora (2018) *System cost impact of renewables.*
[32] Vivid Economics & Imperial College (2018) *Accelerated electrification and the GB electricity system*.