Imperial College London

# Value of baseload capacity in low-carbon GB electricity system

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# Executive Summary

## Introduction and objectives

The GB electricity system is expected to undergo a fundamental transformation over the coming decades in order to support delivering the ambitious energy sector decarbonisation targets in the 2050 horizon. Delivering on such a target will require significant investment in low-carbon generation technologies as well as an increase in the provision of flexibility services to enable the cost-effective system integration of low-carbon technologies.

Considering the recently seen reductions in the costs of variable renewable technologies (wind and solar PV) one of the key questions in the context of power sector decarbonisation is how to determine the most cost-efficient portfolio of low-carbon generation technologies. This also raises the question of the role and value of less flexible baseload low-carbon generation (such as nuclear power) and how its value changes depending on key system parameters. Several previous studies have shown that an efficient integration of large volumes of variable renewable generation will require considerable deployment of additional flexibility provided through energy storage, demand-side response (DSR), interconnectors and/or more flexible generation technologies.

The main objective of this study is to assess the need for baseload low-carbon technologies in the decarbonised UK power system over the coming decades. It therefore adopts the concept of *marginal value of baseload capacity* and quantifies how this value varies across a range of scenarios with different carbon constraints, system flexibility levels and other parameters. In the scope of the report baseload capacity was interpreted to primarily refer to nuclear generation, although the findings of the study could be extended to other low-carbon technologies with a similar cost structure (e.g. tidal power).

## Methodology and assumptions

The analytical approach in the report is based on the whole-system assessment methodology i.e. WeSIM model developed by Imperial. WeSIM determines the optimal decisions for investing into generation, network and/or storage capacity simultaneously with system operation decisions in order to satisfy real-time supply-demand balance in a least-cost way, while at the same time ensuring security of supply and imposing system-level carbon targets. This analytical framework is essentially used to perform two types of studies: a) determining least-cost low-carbon portfolios of generation technologies, and b) quantifying the marginal value of baseload generation.

This report adopts a *gross marginal benefit* approach to quantifying the value of nuclear generation in different power system scenarios. In this approach a relatively small volume of nuclear capacity is added to the counterfactual system, which is then re-optimised and the resulting difference in total system cost is interpreted as the gross marginal value of nuclear (expressed in £/MWh of added nuclear output). Comparing this value to the projected cost of nuclear provides an indication as to whether the system would benefit from having more nuclear (if its system value is greater than its cost) or less nuclear (if its cost exceeds the marginal system value) than in the counterfactual scenario.

The main power system scenarios used in this study have been constructed by varying three key system parameters: system carbon intensity (100 g/kWh and 25 g/kWh, also associated with a lower or higher level of demand electrification), system flexibility (High and Low availability of energy storage, DSR and interconnection) and baseline nuclear capacity (Low, Medium and High), resulting in the total of 12 main scenarios. The assumptions on the levelised costs of energy (LCOE) for variable renewables reflected the significant recent cost reductions seen in the UK and elsewhere in Europe and globally, while the costs of nuclear and CCS generation were based on the most recent BEIS estimates.

In addition to the 12 main scenarios, a range of sensitivity studies has been carried out to study the impact of additional drivers on the system value of nuclear generation and the cost-optimal portfolio of low-carbon generation: growth or reduction in electricity demand, relaxed deployment constraints for energy storage and interconnection, variation in the cost of energy storage and variation in the cost of variable renewables (wind and solar PV).

## Key findings

Key findings arising from the analysis are summarised as follows:

1. *Increasing system flexibility brings substantial savings in total system cost.*

   The value of system flexibility in low-carbon power system scenarios is found to be significant and increases with the level of carbon ambition, as shown in Figure E.1. In the 100 g/kWh scenarios High Flexibility results in net total system cost savings of up to £6.6bn per year, while in the 25 g/kWh scenarios the equivalent cost savings are considerably higher, up to £13.6bn per year. Net system benefits of flexibility include the additional investment in energy storage, interconnection and DSR resources that allow the system to integrate low-cost variable renewable generation more efficiently. Cost savings are achieved through replacing more expensive low-carbon technologies (nuclear and CCS) with renewables, while at the same time increasing the efficiency of using conventional generators and reducing the requirements for peaking generation and network capacity.

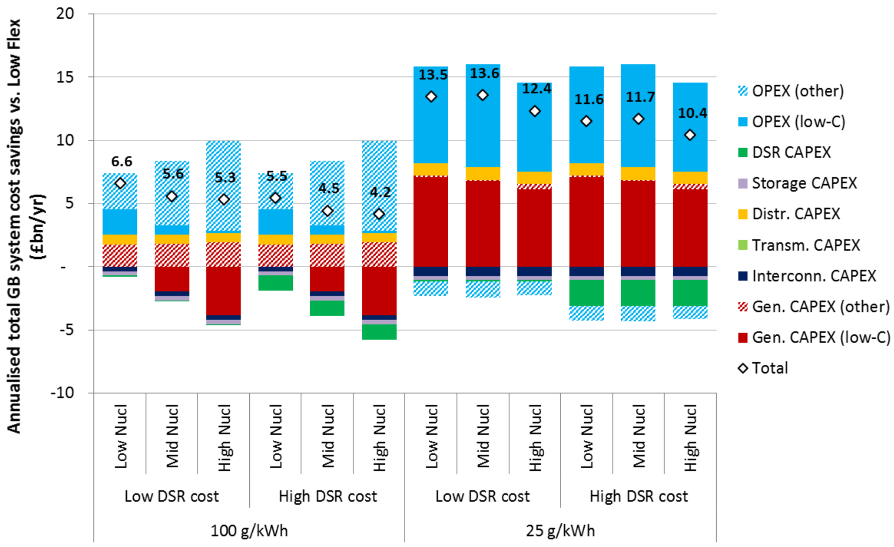


**Figure E.1. Benefits of flexibility (High vs. Low Flexibility)**

2. *Cost-optimal volumes of energy storage and interconnections represent a substantial increase from the current levels.*

   As shown in Figure E.2, The cost-optimal deployment of new battery storage in all scenarios was at the allowed upper limit regardless of its cost (5 GW in Low Flexibility scenario and 25 GW in High Flexibility scenarios), suggesting a very high system value of energy storage for supporting the integration of relatively inexpensive variable renewable generation. The optimal volume of interconnection was at its upper limit in all Low Flexibility scenarios (10 GW in total) and in High Flexibility scenarios with 25 g/kWh target

(25 GW). In High Flexibility scenarios with 100 g/kWh carbon intensity the optimal volume of interconnection was around 17.5 GW. Additional sensitivity studies showed that if the volumes of new battery storage and interconnection are not constrained, their cost-optimal deployment increases further to over 70 GW of battery storage and up to 30 GW of interconnection capacity, with more capacity required in more ambitious decarbonisation scenarios.

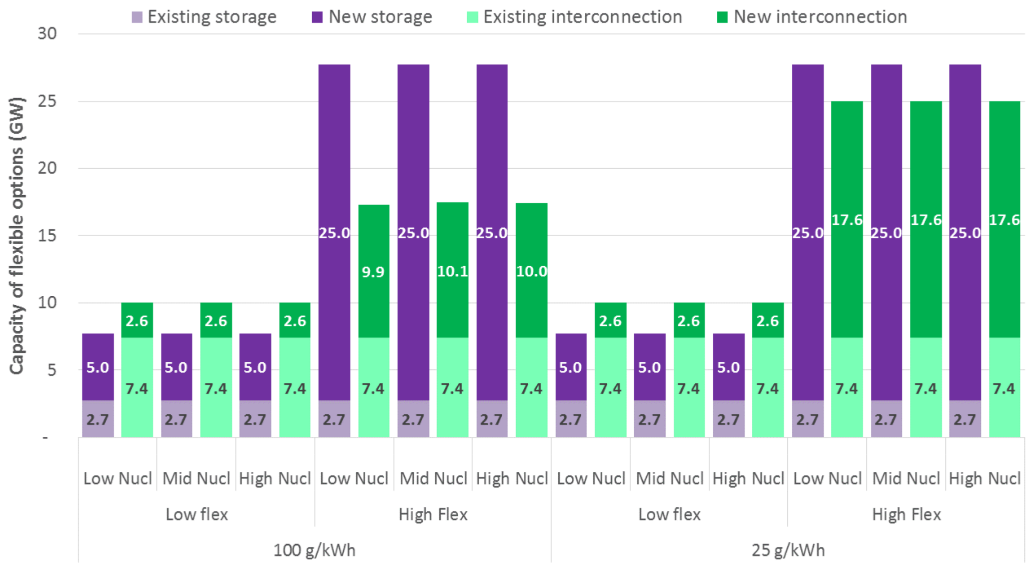


**Figure E.2. Deployment of energy storage and interconnection in main power system scenarios**

3. *Marginal system value of nuclear generation varies depending on the level of decarbonisation, system flexibility and the already present nuclear capacity.*

Gross marginal value of nuclear power was found to vary considerably across scenarios, as presented in Figure E.3, indicating that in some scenarios the system would benefit from increasing nuclear capacity, while in others it would be more efficient to reduce nuclear capacity. In 100 g/kWh scenarios with Low Flexibility, the marginal value at Low and Medium Nuclear deployment is around £95/MWh, while in the High Nuclear scenario it drops to around £75/MWh; with 100 g/kWh and High Flexibility the marginal value varies in the range of £70-78/MWh. In 25 g/kWh scenarios with Low Flexibility the system value of nuclear increase to £103-109/MWh, suggesting the system would benefit from additional nuclear capacity; with 25 g/kWh and High Flexibility the marginal value is high (£108/MWh) in the Low Nuclear scenario, but much lower in Medium and High Nuclear scenarios (£62-72/MWh).

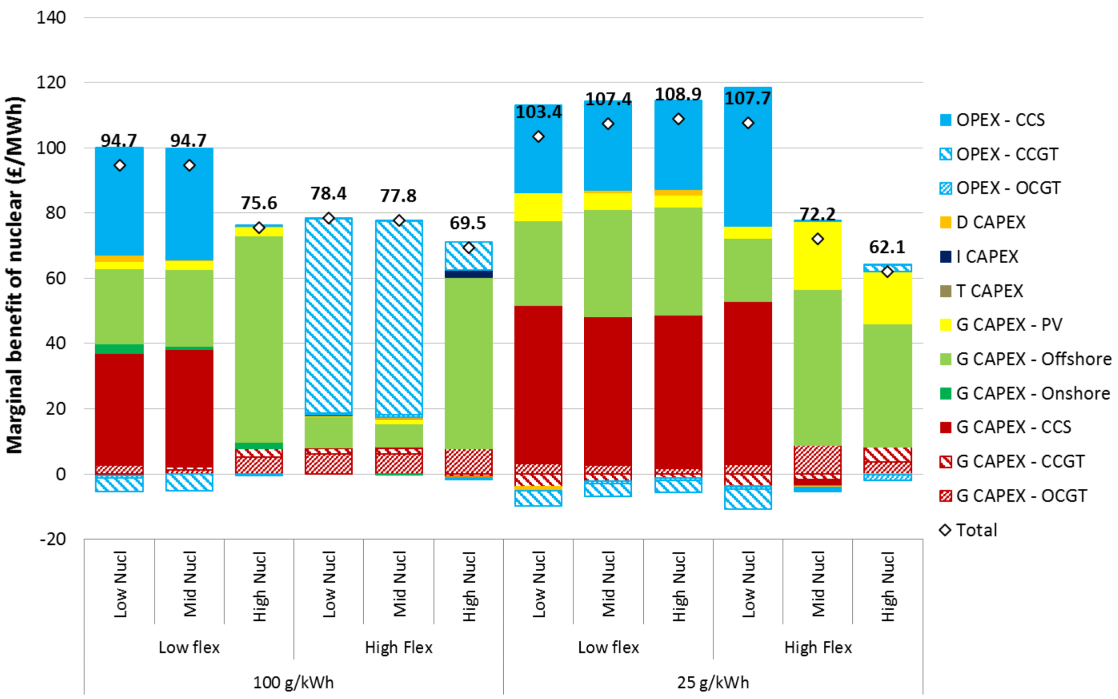


**Figure E.3. Gross marginal system benefit of nuclear generation**

4. *The cost-efficient volume of nuclear increases when moving towards more ambitious carbon reduction targets.*

   If the future system is characterised by a high level of flexibility, the cost-optimal volume of nuclear may be very small under moderately ambitious carbon targets (100 g/kWh) in the medium term, as shown in Figure E.4. This volume, however, becomes more significant (around 9 GW) with more ambitious carbon targets (25 g/kWh). The cost-optimal volume of nuclear in 25 g/kWh scenarios was found to be relatively robust to sensitivities on relaxed storage and interconnection capacity as well as reduced RES cost. This could justify maintaining some nuclear capacity to support the transition from 100 g/kWh towards 25 g/kWh and beyond.

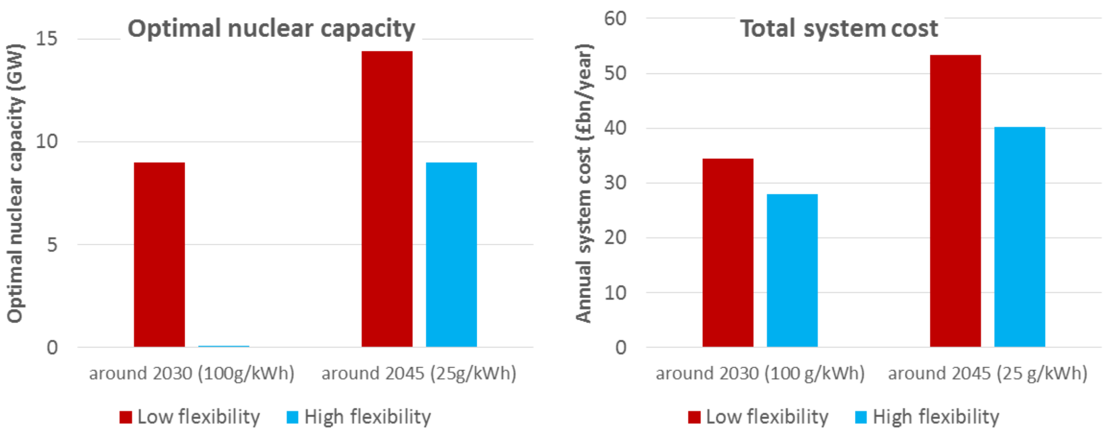


**Figure E.4. Optimal capacity of nuclear generation and total system cost as function of flexibility and carbon target**

5. *Future developments, which are still uncertain, may affect the optimal volume of nuclear: if alternative providers of inertia emerge, the optimal volume of nuclear could reduce even*

*as we approach ambitious carbon targets (25 g/kWh), while on the other hand coordinated de-loading of nuclear could reduce system cost and hence make nuclear more attractive.*

Relaxing the assumption that other technologies such as wind cannot provide sources of inertia – as well as the assumption that market arrangements are not reformed to incentivise or require its provision – could see the optimal volume of nuclear reduced in a very flexible system. This suggests that the finding of a need to maintain significant nuclear capacity in the system despite its higher cost can be at least partly attributed to nuclear's ability to provide inertia in a low-carbon system. There are, however, numerous uncertainties that increase when looking further into the future, including the possibility of provision of inertia from alternative providers and the associated cost implications and technical challenges. On the other hand, new operational approaches such as coordinated de-loading of nuclear generation in order to reduce the largest credible infeed loss could make nuclear relatively more attractive compared to other low-carbon technologies. Further research is needed to better understand the implications of both synthetic inertia as well as nuclear de-loading. It may therefore be beneficial to preserve optionality by holding off further nuclear procurement until generation technical capabilities as well as technology costs and economics of flexible options become more certain.

6. *In a system with low flexibility it may become necessary to build significant CCS capacity to meet the carbon emission target.*

   In a scenario with low nuclear capacity and low system flexibility it may be cost-efficient to add significant amount of CCS capacity to the low-carbon generation mix alongside nuclear, PV and wind, despite the higher cost of CCS. The cost-optimal capacity of CCS may even exceed 30 GW in 25 g/kWh scenarios with low flexibility.

# 1. Introduction

## 1.1. Background

The GB electricity system is expected to undergo a fundamental transformation over the next few decades in response to ambitious energy sector decarbonisation targets. The Committee on Climate Change (CCC) has emphasised the importance of decarbonising the power sector and recommended that the aim should be to reduce the carbon intensity of power generation from current levels of around 350 $gCO_2$/kWh to around 100 $gCO_2$/kWh in 2030. Even more ambitious targets are envisaged beyond 2030, reducing the carbon intensity of electricity generation to 10 to 25 g/kWh in the 2040-2050 horizon. Delivering on such a target will require significant investment in a portfolio of low-carbon technologies but also an increase in the provision of flexibility services to enable the cost-effective integration of low-carbon technologies in the new system.

The decarbonisation of the electricity supply is expected to be delivered through several key transformations:

- Increased penetration of low-carbon generation with a significant increase in variable renewable energy sources (wind and solar) and inflexible nuclear generation
- Demand growth driven by electrification of segments of heat and transport sectors
- Growth in the capacity of distribution-connected flexibility resource
- Increased ‘flexibility’ requirement to ensure the system can efficiently maintain secure and stable operation in a lower carbon system
- Opportunities to deploy energy storage facilities at both transmission and distribution levels
- Rapid uptake of demand-side response (DSR) across all sectors of the economy

In light of the significant recent reductions in the costs of variable renewable technologies (in particular wind and solar PV) one of the key questions in the context of low-carbon transition of the power sector is how to determine the least-cost portfolio of low-carbon generation technologies given their costs. More specifically, it is critically important to establish the role and value of baseload low-carbon generation such as nuclear within the portfolio, and how this value changes as function of the specific carbon target, system flexibility and other drivers.

The traditional power system is dominated by relatively flexible and controllable plants that follow a moderately fluctuating and largely predictable demand. However, low-carbon electricity system would be characterised by a generation mix including significant amounts of low capacity value, variable and difficult to predict intermittent RES (e.g. wind and solar) in combination with less flexible nuclear and thermal plant, which requires a fundamental review of the current approach to the system control, operation and planning.

Due to the variability, uncertainty and limited inertia capability, integration of significant amount of renewable power generation in the electricity system will impose a considerable demand for additional flexibility, particularly for services associated with system balancing and this will lead to the higher value of flexibility in future. In addition to renewables, meeting the future electricity demand will require the use of non-renewable low-carbon generation technologies such as nuclear and/or Carbon Capture and Storage (CCS) plants. It is expected that both of these technologies will have lower operation flexibility compared to the existing Combined Cycle Gas Turbine (CCGT) units, i.e. that they will strongly favour operating with a flat output close to their maximum capacity, for both technical and economic reasons. The increased flexibility requirement and reduced flexibility from traditional sources will increase the cost of balancing services in future.

As it is becoming clear that meeting the future needs for flexibility solely with conventional generators might become very costly while also potentially worsening the environmental performance of the system, increasing attention has been directed towards the alternative sources of flexibility. Emerging flexible technologies including flexible generation, energy storage, demand-side response and flexible network technologies (including interconnection) will play an important role in supporting the cost-effective transition toward the low-carbon energy system.

## 1.2. Challenges of integrating low-carbon generation and role of flexibility

System flexibility, referring to the ability to adjust generation or consumption in the presence of constraints or contingencies in order to maintain a secure system operation, will be the key enabler of this transformation to a cost-effective low-carbon electricity system. There are several flexibility resource options available including highly flexible thermal generation, energy storage, DSR and cross-border interconnection to other systems. A recent study[1] undertaken by Imperial College to inform the development of the roadmap for flexible resources demonstrated that the system wide benefits of integrating new sources of flexibility relative to the use of conventional thermal generation-based sources of flexibility are potentially very significant – between £3.2bn and £4.7bn per year in a system meeting a carbon emissions target of 100 $gCO_2$/kWh in 2030. Key categories of system cost savings achievable by accessing these new sources of flexibility include:

- Reduced *investment in low-carbon generation*, as the available renewable resource and nuclear generation can be utilised more efficiently enabling the system to reach the carbon target with less low carbon generation capacity;

- Reduced *system operation cost*, as various reserve services are provided by new, cheaper, flexibility sources rather than by conventional generation; and

- Reduced requirement for *distribution network reinforcement* and *backup capacity*.

The National Infrastructure Commission's "Smart Power" report[2] estimated the potential cost savings from deploying flexibility in the future GB power system at up to £8bn per year. Estimated benefits of flexibility in the NIC report were based on the analytical study of the value of flexibility carried out by Imperial College London for the Committee on Climate Change[3]. A 2016 BEIS study on the role of flexibility in the context of GB power system decarbonisation until 2050 estimated the NPV of cumulative benefits of flexibility to be between £17bn and

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[1] Pöyry Management Consulting and Imperial College London, "Roadmap for flexibility services to 2030", report for the Committee on Climate Change, May 2017. Available: https://www.theccc.org.uk/publication/roadmap-for-flexibility-services-to-2030-poyry-and-imperial-college-london/

[2] National Infrastructure Commission, "Smart Power", March 2016. Available: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/505218/IC_Energy_Report_web.pdf

[3] Imperial College London, "Value of flexibility in a decarbonised grid and system externalities of low-carbon generation technologies", report for the Committee on Climate Change, October 2015. Available: https://www.theccc.org.uk/publication/value-of-flexibility-in-a-decarbonised-grid-and-system-externalities-of-low-carbon-generation-technologies/

£40bn[4]. Finally, a concurrent study on the heat decarbonisation options in the UK until 2050[5] has shown that cross-energy system flexibility would be required in order to maximise the utilisation of renewable energy. The same study has also demonstrated that to achieve a deep decarbonisation i.e. a zero-carbon energy system in the UK it will be required to deploy firm low-carbon capacity either in the form of nuclear or hydrogen generation.

Figure 1.1 illustrates the annualised cost savings for the UK system associated with moving from low to medium and high flexibility in three example scenarios meeting the 100 or 50 g/kWh emission intensity targets.

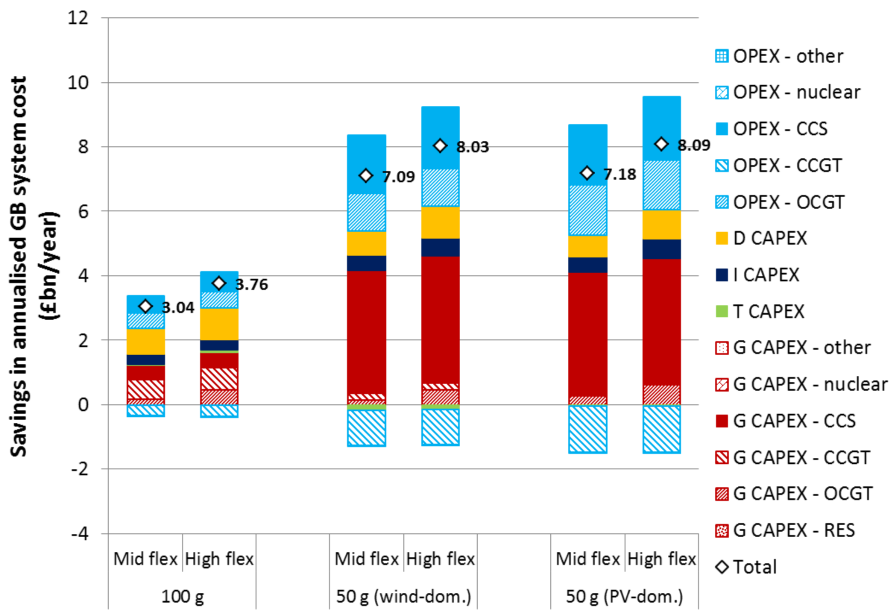


**Figure 1.1. Impact of increasing system flexibility on system cost savings in three core scenarios in 2030**

For the 100 g/kWh scenario the value of flexibility is between £3bn and £3.8/bn per year for 100 g/kWh system, while for the 50 g/kWh system the value of flexibility increases to £7.1bn to £8.1bn. Key categories of system cost savings include reduced investment and operation cost of CCS, as the available renewable resources can be utilised more efficiently helping to reach the carbon target, reduced operating cost of OCGT plant (which face high running costs due to lower efficiency and increasing fuel and carbon prices), and to a smaller extent reduced requirement for distribution network reinforcement.

Ignoring flexibility may result in undesired system outcomes, as illustrated in Figure 1.2, where a future scenario that was notionally capable of achieving a carbon intensity of 50 $gCO_2$/kWh based on annually available energy actually turned out to have emissions of almost 200 $gCO_2$/kWh when analysed in the high-resolution power system model (WeSIM) and assuming there were no improvements to flexibility and efficiency compared to today's system.[6]

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4 Carbon Trust and Imperial College London, "An analysis of electricity system flexibility for Great Britain", report for BEIS, November 2016. Available: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/568982/An_analysis_of_electricity_flexibility_for_Great_Britain.pdf

5 Imperial College London, "Analysis of alternative UK heat decarbonisation pathways", report for the Committee on Climate Change, June 2018. https://www.theccc.org.uk/publication/analysis-of-alternative-uk-heat-decarbonisation-pathways/

6 The figure is taken from Imperial's 2015 CCC study "Value of Flexibility in a Decarbonised Grid and System Externalities of Low-Carbon Generation Technologies".

Only by deploying a range of measures such as additional storage capacity, DSR, expanding interconnection capacity etc. was it possible to reduce the system emissions to around 50 $gCO_2$/kWh.

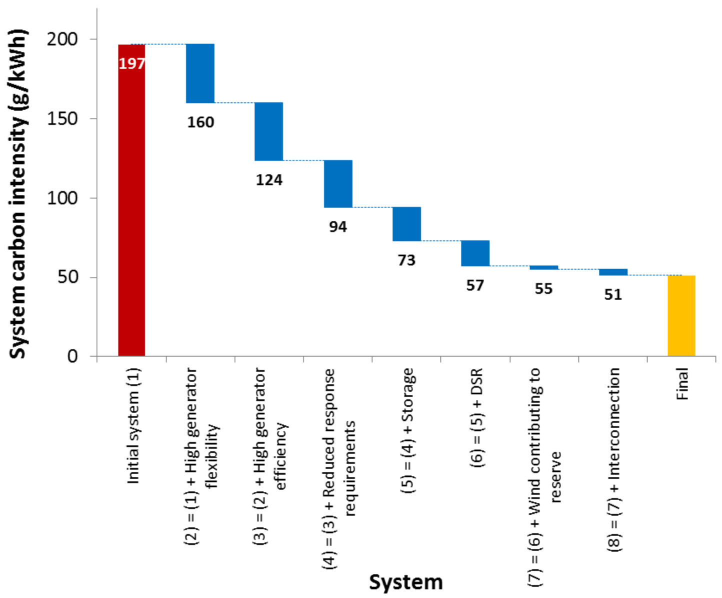


**Figure 1.2. Impact of increasing system flexibility on carbon emissions in 50 g/kWh scenario**

Another key aspect of flexibility in low-carbon systems is that it would *affect the cost-optimal low-carbon generation mix*. This is illustrated in Figure 1.3, where cost-optimised scenarios reveal markedly different generation mixes depending on the level of flexibility that may be available despite the same assumptions on generation technology cost. For instance, base-load low-carbon technologies such as CCS and nuclear are preferred in a less flexible system while variable renewables are predominant in a more flexible system. This follows from the fact that flexibility critically affects the system integration cost of variable renewables.

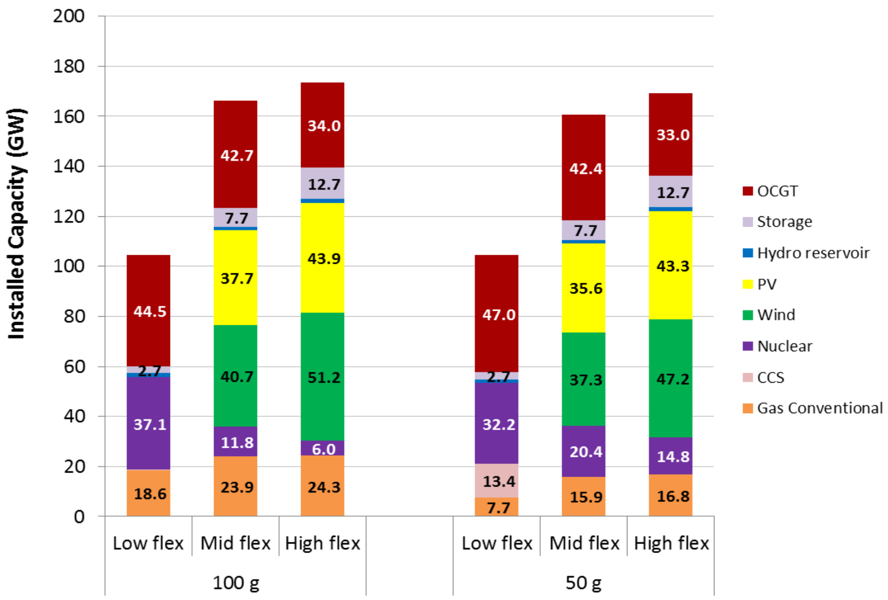


**Figure 1.3. Impact of system flexibility on optimal generation mix in 2030**

This example shows that in order to inform the energy policy regarding the most cost-efficient mix of low-carbon generation technologies, including baseload generation such as nuclear and/or CCS, as well as variable renewables such as wind and PV generation, it is necessary to consider not only their levelised costs but also the availability and cost of various flexible options in the system, including energy storage, DSR, interconnectors and flexible generation technologies.

On the other hand, this example also shows that even in very flexible scenarios there may still be a need for firm (baseload) low-carbon generation, especially when aiming for more ambitious carbon targets. For instance, in a system reaching 50 g/kWh the modelling suggests that 15 GW of nuclear capacity should be added despite a higher LCOE than wind or PV.

## 1.3. Key objectives

In the context of the above, the main objective of this study is to address the following key questions:

- Which role will baseload technologies play in the decarbonised UK power system over the coming decades?
- How much baseload capacity would be part of a cost-optimal generation mix that delivers a given carbon intensity target?
- What is the marginal value of additional baseload capacity in scenarios with carbon constraints?
- How does the variation in level of energy system flexibility affect the answers above?
- What is the impact of different future scenarios on the value of baseload capacity?
- How sensitive are these answers to other assumptions (fuel and carbon prices, technology costs, demand electrification etc.)?

According to the standard definition, baseload capacity refers to resources that act as price takers in electricity markets, reflecting low variable costs and high start-up and shut-down costs. In the decarbonisation context this category primarily refers to nuclear generation, and therefore the valuation carried out in the study is applied to nuclear capacity. Nevertheless, the findings of the study could be interpreted to apply more widely to any low-carbon technology with high investment cost and very low to zero variable operating cost such as for instance tidal power generation.

The remainder of the report is organised as follows:

- Chapter 2 presents the methodology for whole-system assessment of electricity systems and the adopted modelling approach to quantifying marginal system value of low-carbon baseload generation.
- Chapter 3 provides an overview of the scenarios and key assumptions used in the study.
- Chapter 4 discusses the modelling results of main power system scenarios, including the quantified marginal value of nuclear power across different scenarios.
- Chapter 5 presents additional case studies with the aim of establishing the sensitivity of results to variation in key input parameters.

- Chapter 6 draws the main conclusions and recommendations of the analysis carried out.

## 2. Methodology for assessing the value of baseload generation

This chapter presents the key feature of the whole-system assessment methodology developed by Imperial, and how this methodology is used to: a) determine least-cost low-carbon portfolios of generation technologies, and b) quantify the marginal value of baseload generation.

### 2.1. Whole-system assessment of electricity systems

Capturing the interactions across different time scales and across different asset types is essential for the analysis of future low-carbon electricity systems that includes flexible technologies such as energy storage and demand side response. Clearly, the application of those technologies may improve not only the economics of real-time system operation, but they can also reduce the investment into generation and network capacity in the long run.

In order to capture these effects and in particular trade-offs between different flexible technologies, it is critical that they are all modelled in a single integrated modelling framework. In order to meet this requirement Imperial has developed *Whole-electricity System Investment Model (WeSIM)*, a comprehensive system analysis model that is able to simultaneously balance long-term investment decisions against short-term operation decisions, across generation, transmission and distribution systems, in an integrated fashion.

WeSIM determines optimal decisions for investing into generation, network and/or storage capacity (both in terms of volume and location), in order to satisfy the real-time supply-demand balance in an economically optimal way, while at the same time ensuring efficient levels of security of supply. An advantage of WeSIM over most traditional models is that it is able to simultaneously consider system operation decisions and capacity additions to the system, with the ability to quantify trade-offs of using alternative mitigation measures, such as DSR and storage, for real-time balancing and transmission and distribution network and/or generation reinforcement management. A prominent feature of the model is the ability to capture and quantify the necessary investments in distribution networks in order to meet demand growth and/or distributed generation uptake, based on the concept of statistically representative distribution networks.

Analysing future electricity energy at sufficient temporal and spatial granularity is essential for assessing the cost-effectiveness of alternative decarbonisation pathways. In this context, WeSIM based modelling has clearly demonstrated that in order to quantify system operation and investment cost and the carbon performance, quantitative models need to simultaneously consider second-by-second supply-demand balancing issues as well as multi-year investment (e.g. reduced system inertia may trigger investment in flexible technologies). Furthermore, electricity system decarbonisation will also need to adequately consider the synergies and conflicts between local/district level and national (or trans-national) level infrastructure requirements, which is another key feature of WeSIM.

WeSIM carries out an integrated optimisation of electricity system investment and operation and considers two different time horizons: (i) short-term operation with a typical resolution of one hour or half an hour (while also taking into account frequency regulation and short term reserve requirements), which is coupled with (ii) long-term investment i.e. planning decisions with the time horizon of typically one year (the time horizons can be adjusted if needed). All annual investment decisions and 8,760 hourly operation decisions are determined simultaneously in order to achieve an overall optimality of the solution. Key features and constraints considered in WeSIM include: a) power balance, b) reserve and response requirements, c) generator operating limits, d) demand-side response capability; e) distribution network investment, f) carbon emission constraints, g) constraints on electricity imports and exports, and h) security constraints.

A more detailed description of the modelling framework can be found in Appendix A.

## 2.2. Determining cost-optimal low-carbon portfolios

One of the key strengths of WeSIM is that it can determine the least-cost portfolio of generation (and storage) technologies that is needed in the power system to meet a given target level of $CO_2$ intensity. The composition of the portfolio will be determined by a number of factors, such as the costs (LCOEs) of low-carbon technologies[7], their output variability as well as the level of system flexibility.

As illustrated in Figure 1.3, varying the level of flexibility in the system (e.g. through different uptake levels of DSR and energy storage) could results in markedly different least-cost generation mixes even with identical assumptions on technology costs. This outcome is closely related to the concept of *system integration cost* of low-carbon technologies, which includes various additional costs incurred by the system when integrating these generation technologies, but which are not included in the capital or operating cost estimates of these technologies. Examples of SIC components include: a) increased balancing cost, b) network reinforcement cost[8], c) increased backup capacity cost, and d) cost of maintaining system carbon emissions. In our previous studies[9] we have shown that this integration cost fundamentally depends on the level of flexibility in the system.

Depending on the scenario definition and setup, when optimising the generation portfolio in WeSIM it is possible to either optimise each technology from zero or from a predefined level (reflecting e.g. legacy capacity or capacity additions already in the pipeline), or maintain its capacity as fixed. Similar options apply for transmission, interconnection and energy storage capacity. The exact setup for system optimisation will be specified in the section on scenario definition.

Key caveats of the modelling approach used in the study include:

- In order to have a tractable model that considers long-term investment decisions simultaneously with short-term operating decisions, the model assumes *perfect foresight* for the variations in electricity demand and variable renewable output. Nevertheless, the constraints in the model ensure that sufficient volumes of ancillary services (reserve and response) as well as back-up capacity are available in the system to deal with any foreseeable deviation of demand and supply from originally forecasted values.

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7 Note that in the model the LCOE is not treated as a single input parameter per technology, but is rather decomposed into investment cost (per kW of capacity) and operating cost (in £/MWh of output), so that the total cost of deploying and using a technology will depend on how it is used over the course of the year. Note that the operating cost of variable renewables (wind and PV) was assumed to be zero. The operating cost of thermal generators is further represented as the function of the cost of fuel, cost of carbon (where applicable) and the level of output (by considering the so-called “no-load” cost parameter), to capture the fact that it is normally more efficient to operate these generators closer to their maximum rather than minimum output.

8 Network reinforcement cost includes the investment in upgrading transmission and distribution networks. The cost of distribution network reinforcement is determined based on the representative network analysis (see Appendix A for more details) and the peak demand after accounting for the use of distributed generation, DSR and energy storage. Although the model uses a simplified representation of the GB transmission grid (see Section A.3), it accounts for the effect of transmission network constraints (e.g. having to use more expensive generators due to network constraints) and where allowed makes cost-optimal investment decisions in increasing transmission capacity.

9 Imperial College London, “Value of Flexibility in a Decarbonised Grid and System Externalities of Low-Carbon Generation Technologies”, report for the CCC, 2015.

- The model is set up to carry out *annual studies* of the power system. All the results presented in the report therefore represent snapshots for a given year and scenario, and do not seek to characterise the dynamic evolution of the system over a large number of years (e.g. between 2020 and 2050).

- Given that the model's objective function is cost minimisation, the model follows the *least-cost paradigm*, implicitly assuming that a single entity is responsible for designing and operating the power system rather than simulating complex market interactions between different actors in the system (generation companies, system and network operators and flexibility providers).

## 2.3. Quantifying marginal system value of low-carbon generation

To quantify the whole-system value of nuclear generation in different power system scenarios, we adopt a *gross marginal benefit* approach, where a relatively small volume of nuclear capacity is added to the counterfactual system (which may already contain some nuclear capacity), which is then re-optimised and the resulting difference in total system cost (ignoring the cost of incremental nuclear capacity) is interpreted as the gross marginal system value. This value can be expressed per MWh of added nuclear output, and then compared to the estimated LCOE of nuclear power to establish whether the system would benefit from having more nuclear (if its value is greater than its cost) or from having less nuclear (if its LCOE exceeds the marginal system value).

A particularly useful feature of this approach is that it not only provides the estimate of the whole-system value in £/MWh of nuclear output, but also establishes the breakdown of whole-system value into components: generation CAPEX by technology, operating cost, network CAPEX and storage CAPEX. This breakdown allows for identifying the key cost categories being displaced by incremental nuclear capacity that also act as key drivers for its whole-system value.

The high-level algorithm for calculating the marginal system value of nuclear generation consists of the following steps:

1. Select a scenario defined by its generation and demand background, cost and availability of flexible options, carbon target etc.

2. Optimise the system in the counterfactual scenario i.e. minimise total system cost while meeting the carbon target as well as security and other constraints. Record the total system cost associated with the scenario.

3. Adjust the counterfactual scenario by adding a relatively small amount[10] (1 GW) of nuclear capacity and optimise the system again, this time ignoring the cost of additional 1 GW of nuclear when quantifying total system cost.

4. Use the total system cost from the counterfactual (#2) and marginal value study (#3) and find the difference to obtain the gross marginal system benefit of nuclear broken into components (generation, transmission and distribution CAPEX and OPEX).

[10] Although it can be argued that 1 GW of nuclear is a relatively significant volume, reducing this amount could potentially cause numerical difficulties in running the model given that its objective function includes not only GB but also the entire European power system in which 1 GW is a relatively small amount. We have run test studies with nuclear capacity increments of 0.5 GW and have confirmed there are only minor differences in results compared to the 1 GW increments.

5. Compare the marginal benefit of nuclear with its LCOE: if it is higher than LCOE, this implies the system would benefit from increasing nuclear capacity, and vice versa.

# 3. Scenarios and assumptions

This section describes the construction of scenarios used in this study and specifies key input assumptions into whole-system modelling.

## 3.1. Description of scenarios

In agreement with Ofgem, the main power system scenarios used in this study have been constructed by varying three key system parameters as follows:

1. **Level of decarbonisation**
    - 100 g/kWh with moderate heat/transport electrification, broadly reflecting system evolution in the 2030 time horizon
    - 25 g/kWh with high heat/transport electrification, broadly reflecting system evolution in the 2040 time horizon and beyond
2. **System flexibility**
    - Low Flexibility: high cost and limited availability of storage; no DSR; low volume of new interconnection
    - High Flexibility: low cost and high availability of storage; high DSR uptake; high volume of new interconnection
3. **Nuclear generation capacity**[11]
    - Low (4.5 GW)
    - Medium (9 GW)
    - High (14.4 GW)

Combining the above system parameters resulted in twelve system scenarios, which are characterised in Table 3.1.

[11] *Low nuclear* scenario is consistent with the capacity of Hinkley Point C (3.3 GW) plus Sizewell B (1.2 GW), assuming all other nuclear power stations will retire by 2030. *Medium nuclear* scenario is based on the nuclear capacity in BEIS 2017 Updated Energy and Emissions Projections (Reference scenario) around 2030; the 9 GW is broadly equivalent to the *Low nuclear* scenario plus the capacity of the proposed Wylfa (2.7 GW) and Moorside projects (one unit with 1.8 GW). *High nuclear* scenario with 14.4 GW is consistent with the 2035 nuclear capacity in UEEP projections, which would broadly correspond to the realisation of several new nuclear projects: Hinkley Point C, Wylfa, Moorside and Sizewell C.

**Table 3.1. Key elements of main power system scenarios**

| Scenario # | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Carbon target (g/kWh) | 100 | | | | | | 25 | | | | | |
| Demand (TWh)<br>*(of which heat / transport)* | 379<br>*(27 / 19)* | | | | | | 507<br>*(61 / 61)* | | | | | |
| Flexibility | Low | | | High | | | Low | | | High | | |
| Nuclear capacity (GW) | 4.5 | 9.0 | 14.4 | 4.5 | 9.0 | 14.4 | 4.5 | 9.0 | 14.4 | 4.5 | 9.0 | 14.4 |
| Storage cost (£/kW) | 1,280 | | | 395 | | | 1,280 | | | 395 | | |
| Max volume of new storage (GW) | 5 | | | 25 | | | 5 | | | 25 | | |
| DSR uptake | 0% | | | 50% | | | 0% | | | 50% | | |
| Max total interconnection (GW) | 10 | | | 25 | | | 10 | | | 25 | | |

Nuclear capacity in all scenarios has been kept fixed as specified in Table 3.1. Build rate limits on energy storage and interconnection capacity have been implemented as explicit constraints in the model. Carbon emissions constraints have been implemented by explicitly limiting the annual carbon intensity of the power system, expressed as the ratio of total annual $CO_2$ emissions and total annual electricity demand.

As mentioned in Section 2.2, the scenarios analysed in the study represent snapshots of the power system in a single year, and therefore do not explicitly consider how the system might evolve over a continuous number of years such as for instance between today and 2050. An equivalent interpretation is that the modelling implicitly assumes that the circumstances corresponding to each scenario would remain largely unchanged over a longer time period.

It is also worth mentioning that the results of the analysis are subject to more uncertainties as the analysis looks further into the future. Therefore the findings for the 25 g/kWh scenario will be subject to greater uncertainty than the conclusions made for the 100 g/kWh scenario.

## 3.2. Assumptions on generation technologies

The assumptions on the levelised costs of energy (LCOE) for low-carbon generation technologies used in the study are specified in the second column of Table 3.2. For the three renewable technologies (offshore wind, onshore wind and solar PV) the LCOEs were based on recent evidence provided by Aurora Energy Research[12] and Bloomberg New Energy Finance[13], and were also informed by discussions with the CCC and BEIS. For nuclear and CCS generators the costs were taken from the most recent BEIS Electricity Generation Costs estimate[14]. The costs of variable renewables were assumed so as to reflect the significant recent cost reductions seen in the CfD auctions in the UK and in the costs of renewable projects in continental Europe and internationally.

12 Aurora Energy Research, "Prospects for subsidy-free wind and solar in GB", March 2018. https://www.auroraer.com/insight/prospects-subsidy-free-wind-solar-gb/

13 Bloomberg New Energy Finance, "Flexibility gaps in future high-renewable energy systems in the UK, Germany and Nordics", report for Eaton and Renewable Energy Association, November 2017. https://uk.eaton.com/content/content-beacon/RE-study/GB/home.html

14 BEIS Electricity Generation Costs (November 2016), https://www.gov.uk/government/publications/beis-electricity-generation-costs-november-2016.

**Table 3.2. Assumptions on LCOEs and build rates for low-carbon generation technologies**

| Technology | LCOE (£/MWh) | Capacity factor | Min. cap. (GW) | Max. cap. (GW) |
|---|---|---|---|---|
| Offshore wind | 57.5 | 41.9% | 9.7 | 100 |
| Onshore wind | 45 | 27.2% | 12.1 | 30 |
| Solar PV | 40 | 11.9% | 20.0 | 150 |
| Nuclear | 94 | 90.0% | N/A | N/A |
| CCS | 102 | 90.0% | - | N/A |

The maximum capacity factors for different low-carbon technologies assumed in the study are specified in the third column of Table 3.2, and reflect typical UK utilisation factors for wind and PV generation, as well as 90% annual availability for nuclear and CCS generation to account for planned maintenance.

The fourth and fifth columns of Table 3.2 specify the minimum and maximum capacities for low-carbon generators, to reflect the capacity of current projects and those in the pipeline, as well as estimated resource limits in the UK context.

The cost of conventional generation was assumed in line with 2016 BEIS Electricity Generation Costs. For CCGT and OCGT, the two key technologies, the investment costs used in the study were £500/kW and £400/kW, respectively. Also, to account for the significant present CCGT capacity that is likely to be operating in the next 15-20 years, we assume a minimum CCGT capacity of 20 GW across all scenarios.

In all scenarios the system optimisation in WeSIM was set up so that, with the exception of nuclear capacity that was kept fixed, the model could add both conventional (CCGT and OCGT) as well as low-carbon (CCS and variable renewables) capacity in order to meet the demand at the lowest cost, subject to security, carbon and other constraints. The capacity additions were determined subject to minimum and maximum capacity limits specified in Table 3.2.

## 3.3. Electricity demand assumptions

The electricity demand levels in 100 g/kWh and 25 g/kWh scenarios were assumed to reflect increasing levels of ambition with respect to decarbonising heat and transport. A moderate level of heat and transport electrification is assumed in the 100 g/kWh scenarios, with heat and transport accounting for 27 and 19 TWh annually, respectively. In the 25 g/kWh a higher electrification rate was assumed, with both heat and transport electricity demand equalling 61 TWh annually.

The source of demand information for the 100 g/kWh scenario was the 2015 CCC study on the value of flexibility[15], while in the 25 g/kWh scenarios the demand assumptions were taken from the 2016 BEIS study analysing least-worst regret options for future system flexibility[16].

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[15] Imperial College London, "Value of flexibility in a decarbonised grid and system externalities of low-carbon generation technologies", report for the CCC, 2015. https://www.theccc.org.uk/publication/value-of-flexibility-in-a-decarbonised-grid-and-system-externalities-of-low-carbon-generation-technologies/

[16] Carbon Trust and Imperial College London, "An analysis of electricity system flexibility for Great Britain", report for BEIS, November 2016. Note that the 25 g/kWh scenario demand was based on the Reference demand scenario used in that study, although only High and Low scenarios are reported in that study.

## 3.4. Cost and availability of flexible options

System flexibility has recently been identified as one of the key drivers for the cost-efficient integration of renewables and other low-carbon generation. Therefore, the main scenarios distinguished between high and low system flexibility, assuming different levels of cost and availability for the three key flexible options:

1. *Energy storage*: in the High Flexibility scenarios the model was allowed to add up to 25 GW of new energy storage at a low cost, while in the Low Flexibility scenarios it was only allowed to add up to 5 GW of energy storage at a high cost. New storage capacity was assumed to be distributed, battery-type storage, and its high and low costs were based on the 2016 Carbon Trust study[17]. Any new energy storage was additional to the already existing 2.7 GW of pumped-hydro storage in the UK.

2. *Demand-side response (DSR)*: WeSIM considers the following categories of flexible electricity demand: electric vehicles, smart appliances, flexible heating demand and flexible industrial and commercial (I&C) demand. The theoretical potential of each one of these categories to provide flexibility has been quantified using specific bottom-up demand models informed by a number of relevant UK trials.[18] In these studies we vary the assumptions as to how much of the theoretical potential has been implemented; in the Low Flexibility scenario there is no DSR uptake, while in the High Flexibility ones the assumed uptake is 50% of the maximum potential.[19]

3. *Interconnection*: The minimum GB interconnection capacity was set at 7.4 GW (of which 1 GW with Ireland and the rest with continental Europe) to reflect current capacity and projects that are under construction or have been approved. In the Low Flexibility scenarios the total GB interconnection capacity was allowed to increase to only 10 GW in total (i.e. including both fixed and additional capacity). The High Flexibility scenarios allowed the GB interconnection capacity to increase to 25 GW in total. In line with our previous studies, the assumed cost of new interconnection capacity was £96/MW/km/yr.

## 3.5. Fuel and carbon cost

The most relevant fuel price in the context of modelling the future UK power system is that of natural gas (any generation using oil or coal is assumed to be phased out by 2030). In line with the most recent BEIS fossil fuel price projections[20] the assumed price of gas was 67 p/therm (or £22.9/MWh).

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17 Carbon Trust, "Can storage help reduce the cost of a future UK electricity system?", 2016. https://www.carbontrust.com/resources/reports/technology/energy-storage-report/

18 For more details on flexible demand modelling, see e.g. Appendix C of our 2015 CCC study "Value of flexibility in a decarbonised grid and system externalities of low-carbon generation technologies".

19 Note that the deployment of DSR was not optimised in the model, but was rather assumed to follow directly from the assumed DSR uptake level. Nevertheless, the cost of DSR has been included in total system cost calculation (see Section 4.5). Due to significant uncertainty in DSR cost, both low and high values of DSR cost were used to quantify total system cost.

20 BEIS 2017 Fossil Fuel Price Assumptions (Central projection), https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/663101/BEIS_2017_Fossil_Fuel_Price_Assumptions.pdf

The cost of carbon was also assumed in accordance with the most recent BEIS projections[21], which foresee a price of £79.4/t$CO_2$.

In addition to the upper bounds on the overall carbon emissions from the power system (25 or 100 g/kWh), all model runs also imposed the criteria of: a) self-sufficiency (i.e. that sufficient capacity margin exists within GB to meet peak demand), and b) energy neutrality (i.e. that the total net annual electricity import is zero). The latter constraint is introduced in order to maintain the relevance of GB-level carbon targets, i.e. to ensure the carbon neutrality of power exchanges with the neighbouring systems.

[21] BEIS, “Updated short-term traded carbon values used for UK public policy appraisal”, January 2018. https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/671194/Updated_short-term_traded_carbon_values_for_appraisal_purposes.pdf

# 4. Quantitative results for main power system scenarios

This chapter presents the key quantitative outputs from WeSIM model runs across all main power system scenarios. The presentation of model outputs will focus on two key sets of results: a) system performance in 12 counterfactual scenarios, including the least-cost generation mix, annual electricity output, carbon emissions, renewable curtailment and total system cost; and b) marginal system values of baseload low-carbon (i.e. nuclear) generation across the 12 scenarios, calculated as described in Section 2.3.

## 4.1. Generation technology portfolio and annual output

After conducting the analysis of the 12 main counterfactual scenarios in WeSIM, the cost-optimal generation mixes were obtained as shown in Figure 4.1. As a reminder, the nuclear capacity in all 12 scenarios has been fixed in advance, while the capacities of other low-carbon and conventional generation were optimised subject to minimum and maximum capacity limits as specified in Section 3.2. The chart also shows the cost-optimal deployment of energy storage, subject to deployment limits defined in the scenario description (Sections 3.1 and 3.4).

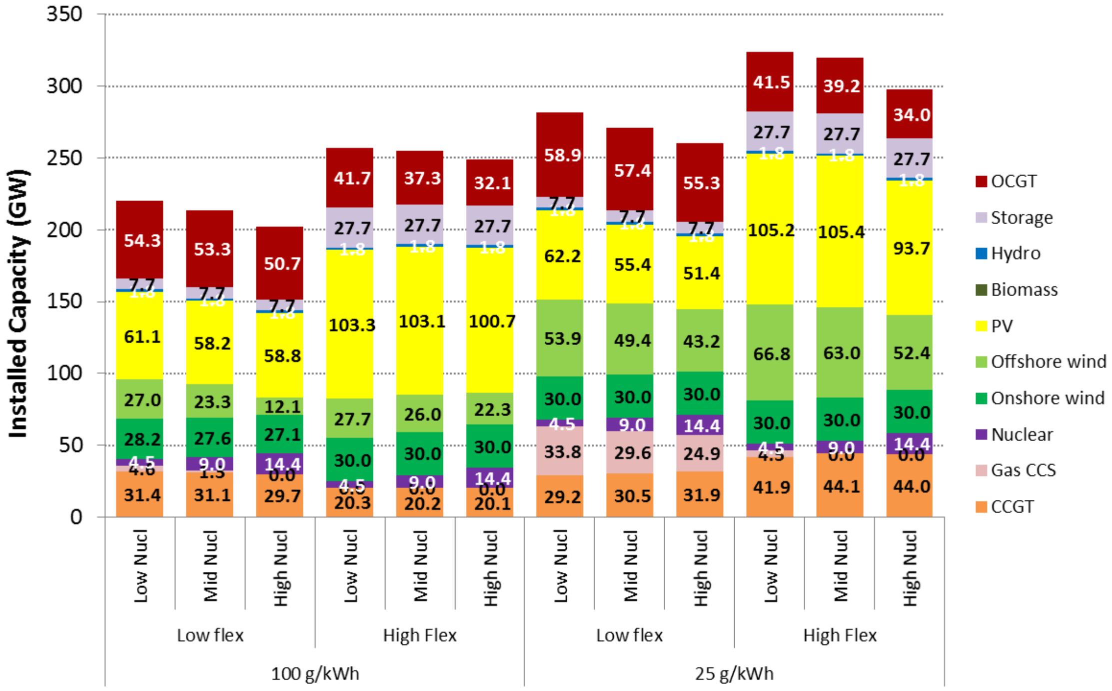


**Figure 4.1. Generation capacity mix in 12 main scenarios**

Unsurprisingly, all future scenarios driven by ambitious decarbonisation targets require a significant deployment of low-carbon generation. The exact proportion of their deployment is a function of system flexibility and the carbon target, however all of the scenarios represent a considerable shift in electricity generation portfolio from the current setting.

All of the main scenarios feature a significantly expanded renewable generation capacity, in particular solar PV (although its share in the actual output will be significantly lower due to low capacity factors). It is well understood that variable renewable sources such as wind and solar PV have a *very low capacity value* in terms of their contribution to system security, given that during system peak demand conditions, which in the UK typically occur on a cold winter evening, there will be no output from PV generation, and wind generation will also generally be very low given that peak demand conditions may coincide with low wind conditions. At the same time, the peak demand levels are expected to increase compared to today's levels as the results of heat and transport electrification (which have been shown to have a greater impact on peak demand than on annual energy requirements). In order to meet the system security criteria i.e. to ensure sufficient margin of firm capacity above the peak demand, the solution in all scenarios includes a significant amount (in tens of GW) of peaking (OCGT) capacity.

Another clear finding is that new energy storage capacity is always added up to the maximum allowed level regardless of the assumed cost of storage. This is an indication of the high system value of energy storage, and of flexibility in general, in any scenario with an ambitious decarbonisation target and variable renewable energy available at low cost.

The cost-optimal generation mix required to reach the carbon target varies across scenarios. In 100 g/kWh scenarios with low flexibility the carbon target is met by deploying a mix of CCS capacity (which appears complementary to nuclear as CCS capacity is higher when nuclear is lower and vice versa), variable renewables and 10-11 GW of additional CCGT capacity. Despite low system flexibility the low cost of renewables is sufficiently attractive to ensure around 60 GW of PV capacity in the cost-optimal mix as well as a considerable amount of wind (of which onshore wind is close to its maximum deployment of 30 GW). It can also be observed that with increasing nuclear capacity the volume of variable renewables in the optimal portfolio reduces, mostly at the expense of offshore wind, which is assumed to have the highest LCOE among the three main renewable technologies (see Table 3.2).

In 100 g/kWh scenarios characterised by high flexibility the integration of variable renewable generation is very efficient and therefore it is possible to take full advantage of their low LCOEs. None of the three scenarios requires any CCS or new CCGT capacity, and the volumes of wind and PV generation added are considerably higher than in the low-flexible cases. Higher level of flexibility, including the 25 GW of new energy storage, support the deployment of renewables even beyond the 100 g/kWh carbon target (discussed further in Section 4.2).

In more ambitious decarbonisation scenarios targeting the carbon intensity of 25 g/kWh, low levels of system flexibility require a very high deployment of firm low-carbon generation in the form of CCS capacity (given that nuclear capacity is fixed in all main scenarios), with between 25 and 34 GW of CCS being installed in addition to 9-12 GW of CCGT and a high amount of peaking OCGT capacity. This is combined with a relatively high renewable deployment, with onshore wind being deployed at the maximum allowed level (30 GW), 43-54 GW of offshore wing and 51-62 GW of PV. Note that the contribution of CCS to the system targeting 25 g/kWh is limited due to the non-zero emissions from CCS plants.[22] If on the other hand the 25 g/kWh target is delivered while maintaining high system flexibility, the requirements for CCS capacity are massively reduced, to the level similar to low-flexible 100 g/kWh scenarios. At the same time, very high volumes of renewable generation would be required to meet the demand, with 52-67 GW of offshore wind and 94-105 GW of solar PV added to the system. Clearly, without flexible options (storage, DSR and interconnection) present in the system to facilitate the management of renewable output fluctuations, the installation of such high volumes of technologies such as PV would be rather inefficient given its highly variable output profile that peaks in the summer during periods of relatively low demand.[23]

Figure 4.2 shows the annual energy output of different generation technologies for all 12 main scenarios. Due to the difference in capacity factors, the contribution of nuclear plant in terms of annual output is more pronounced compared to wind and solar than its share of the capacity

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[22] In the modelling carried out in this study the emission factor of CCS at maximum efficiency point was about 40 g/kWh, assuming a 90% carbon capture rate.

[23] For illustration, the average electricity demand during June and July in 100 g/kWh scenarios is around 37 GW.

mix. The annual output of storage is presented as net total of charging and discharging, resulting in a negative value (or net demand) due to cycle efficiency losses.

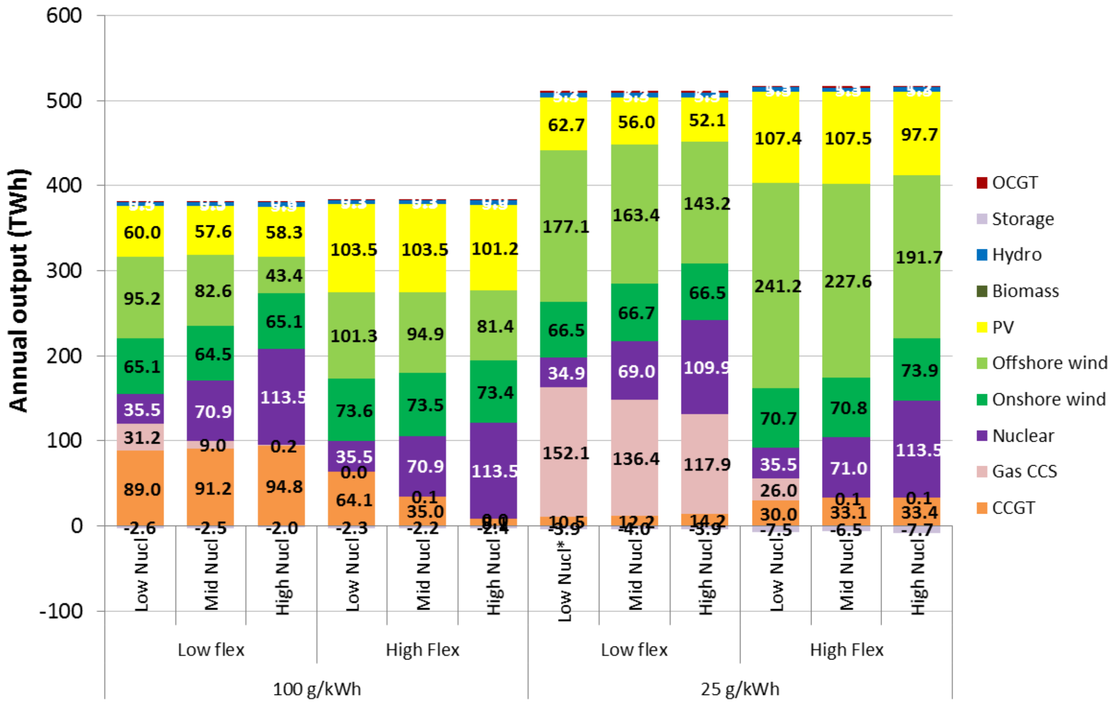


**Figure 4.2. Annual generation output in 12 main scenarios**

In the 100 g/kWh scenarios the nuclear generators contribute around 9%, 19% and 30% of annual output in Low, Medium and High Nuclear scenarios, respectively. Due to the higher electricity demand in 25 g/kWh scenarios the respective shares of power output from nuclear are 7%, 14% and 22%. The annual utilisation of nuclear capacity is at or very close to 90% given its very low operating cost.

In 100 g/kWh scenarios with low system flexibility the share of CCGT is quite stable at around 25%, while the share of wind and PV reduces from 58% to 44% as the nuclear capacity increases from Low to High. In the Low Nuclear scenario there is also around 8% of output being provided by CCS generation. For High Flexibility scenarios the share of renewable energy increases to 67-73%, while the contribution of CCGT reduces considerably and is also negatively correlated with the level of nuclear capacity.

In 25 g/kWh scenarios there is a significant contribution from CCS in Low Flexibility cases, varying between 23% (High Nuclear) and 30% (Low Nuclear). The share of variable RES in the same cases varies between 52% and 60%. Increasing system flexibility greatly reduces the CCS output (5% in Low Nuclear and zero in other cases) and correspondingly increases the share of renewables to between 71% and 82%. Wind generation is the dominant technology in these high-flexible scenarios, with its share varying between 52% and 61%.

## 4.2. Carbon emissions

As explained in the scenario definition, the carbon emission constraints in the modelling were implemented at upper limits on annual system $CO_2$ emissions. Figure 4.3 shows the actual emissions resulting from system optimisation. It is evident that in all cases except for 100 g/kWh with High Flexibility the imposed emission targets (100 or 25 g/kWh) are binding. In highly flexible 100 g/kWh scenarios the system integration of relatively low-cost renewable generation is very efficient, making them the lowest-cost source of electricity (after factoring in the cost of carbon). As a consequence, renewables are deployed at such a high level that the overall system emissions fall below the 100 g/kWh target.

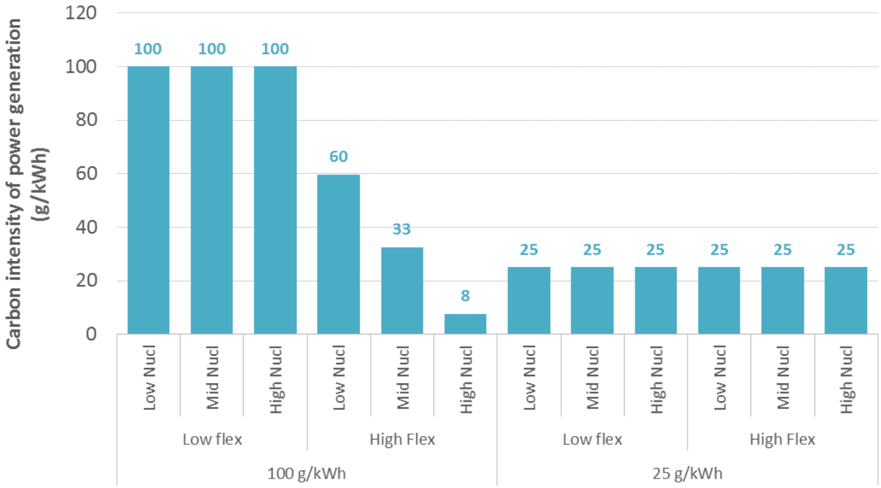


**Figure 4.3. Carbon emission intensity in 12 main scenarios**

## 4.3. Renewable curtailment

With very high deployment levels of variable renewables, such as those featuring in the scenarios investigated in this study, it may become inevitable to occasionally curtail renewable generation output, due to the inability to absorb the entire renewable output at times of e.g. high wind and PV output and low system demand. Presence of high volumes of flexible solutions such as DSR or energy storage can reduce the necessary curtailment of variable renewables and hence reduce the cost of their integration into the power system.

Figure 4.4 presents the annual output curtailment levels across main scenarios for the three key renewable technologies (offshore wind, onshore wind and solar PV) as well as for their combined total. In the low-flexible 100 g/kWh scenarios the curtailed output varies between about 4% and 6%, while with high flexibility this reduces to around 2% despite higher volumes of renewable generation, demonstrating the key role of flexibility for efficient system integration of variable renewables.

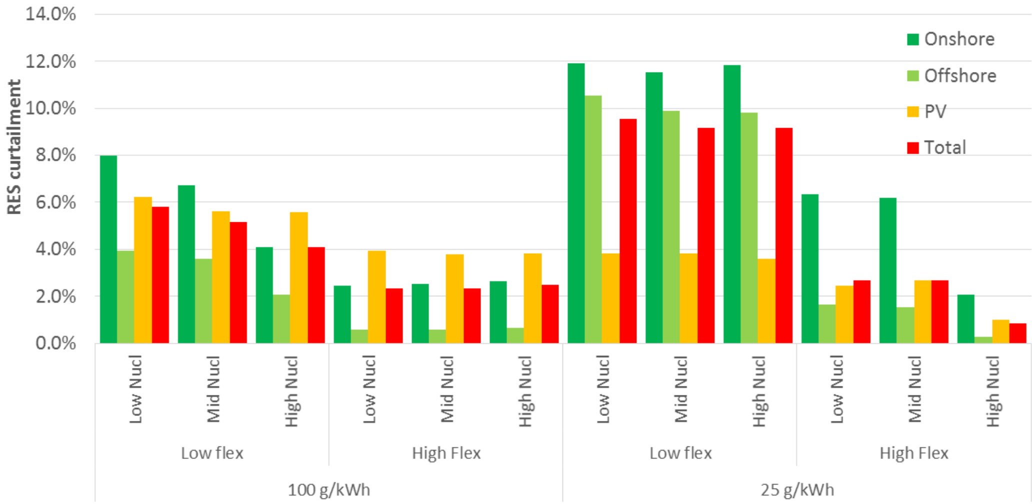


**Figure 4.4. Renewable output curtailment in 12 main scenarios**

In 25 g/kWh scenarios with low flexibility the aggregate renewable curtailment increases to almost 10%, which is still acceptable in these cases given the relatively low cost of renewables compared to CCS generation as well as the non-zero emissions of CCS plant. With flexibility available at a high level, renewable curtailment drops significantly to between 0.8% and 2.7% while at the same time the capacity of variable renewables is significantly increased compared to the low-flexible scenarios.

## 4.4. Deployment of flexible options

In all scenarios the model was allowed to add energy storage and interconnection capacity above the minimum amount assumed across all scenarios, and up to the maximum level that varied across scenarios as described in Section 3.4 (note that the DSR uptake was assumed as an input parameter and was not optimised by the model). Figure 4.5 shows the cost-optimal deployment of energy storage and interconnection across the twelve main scenarios, which is presented relative to the assumed minimum existing volume of the two flexible options.

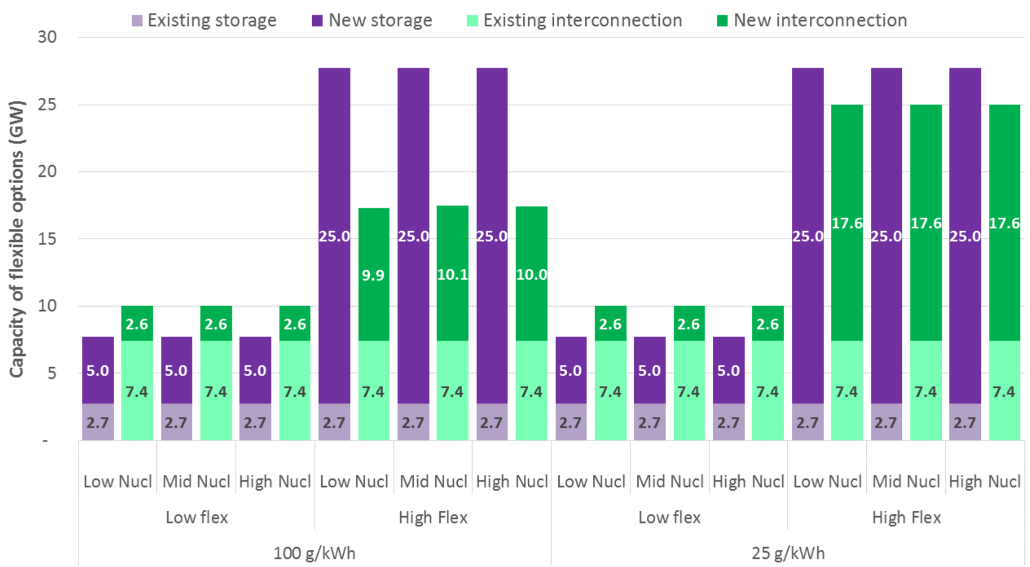


**Figure 4.5. Deployment of energy storage and interconnection in 12 main scenarios**

Deployment of new energy storage is at the maximum allowed level across all scenarios (regardless of whether the cost of storage is low or high), i.e. at 5 GW in all Low Flexibility scenarios and 25 GW in all High Flexibility scenarios. This result suggests that energy storage would be vital for enabling a cost-efficient decarbonisation of the power system based on a rapid expansion of variable renewable generation.

New interconnection capacity is also added across all scenarios. Scenarios with Low Flexibility (both 25 and 100 g/kWh) all have 2.6 GW of new interconnection added, bringing it to the allowed maximum total of 10 GW. In the High Flexibility scenarios the model chooses to add about 10 GW of new interconnectors in the 100 g/kWh cases, reaching the total of about 17.5 GW and therefore not utilising the entire allowed volume of 25 GW. In these cases the 10 GW of new capacity appears to be sufficient for the level of renewable generation installed in the system, and also because other flexible options (energy storage and DSR) are present in the system in relatively high volumes. In highly flexible 25 g/kWh scenarios however, the interconnection capacity is added up to the maximum level of 25 GW, which is driven by significantly higher capacity of renewables needed to meet the more ambitious carbon target.

## 4.5. Total system cost

The final set of outputs for the 12 counterfactual scenarios is related to total system cost. Due to the model set up and assumptions the following remarks apply to the presentation of total system cost in this section:

- Total system cost consists of investment cost (CAPEX) of generation, storage, interconnection, transmission and distribution infrastructure plus the operating cost (OPEX) for power generation.

- Total system cost refers to the annual CAPEX and OPEX required to deliver electricity at the lowest cost, where all investment costs are annualised using appropriate lifetime and discount rate assumptions.[24]

- Within the total annual system cost the CAPEX values for generation, storage and interconnection assets apply to their *entire* capacities (i.e. both existing and those added by the model), while transmission and distribution CAPEX only include *incremental* or *reinforcement* cost above the current situation. In other words, the total system cost does not include the investment costs associated with the existing transmission and distribution infrastructure.[25]

- Generation CAPEX and OPEX is separated into low-carbon technologies (wind, PV, nuclear and CCS) and conventional or other technologies (CCGT and OCGT).

- The CAPEX of DSR is included in total system cost (although DSR deployment is not optimised but rather assumed fixed as an input parameter), however due to significant uncertainty in DSR cost estimates the results for High Flexibility scenarios are shown for both low and high DSR cost assumptions.[26]

Based on the above the total system cost across the main power system scenarios is presented in Figure 4.7. In general, we note that the cost associated with Low Flexibility scenarios is substantially higher than the cost observed in High Flexibility scenarios. The cost in 25 g/kWh scenarios is clearly higher than in corresponding 100 g/kWh cases, due to both higher demand as well as more ambitious carbon target.

The bulk of the cost is associated with the CAPEX of low-carbon generation, following from the high capital cost and low operating cost of technologies such as nuclear, wind and PV, which are required to meet the carbon emission target. In scenarios with significant CCS capacity there is also a visible contribution from low-carbon OPEX associated with CCS operation. The share of CAPEX and OPEX associated with low-carbon generation is expectedly higher in 25 g/kWh scenarios. CAPEX of conventional generation also represents a significant proportion of total system cost across all scenarios, as conventional capacity is used to provide peaking capacity i.e. meet the capacity margin requirements. The cost components associated

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24 The approach with minimising the annualised system cost is equivalent to assuming the year in question will repeat itself in perpetuity.

25 Although this slightly diminishes the completeness of reported total system cost figures, it allows for an identification of key drivers for changes in total system cost across scenarios, also enabling the quantification of system benefits of flexibility by looking at differences between scenarios, where the cost associated with fixed (i.e. existing) infrastructure is not relevant.

26 The cost assumptions for DSR have been taken from Carbon Trust and Imperial College study carried out for BEIS in 2016, “An analysis of electricity system flexibility for Great Britain”. DSR cost was assumed at the 2050 level reported in Tables 24 and 25 of that study (page 74), i.e. at £805/kW for residential and £400/kW for I&C in the high cost scenario, and £23/kW for residential and £200/kW for I&C in the low cost scenario.

with interconnection CAPEX and transmission and distribution reinforcements are relatively small compared to the total. CAPEX of DSR is almost negligibly small with low DSR cost, while in the case of high DSR cost it accounts to between £1.2bn/yr (100 g/kWh scenarios) and £2bn/yr (25 g/kWh scenarios).

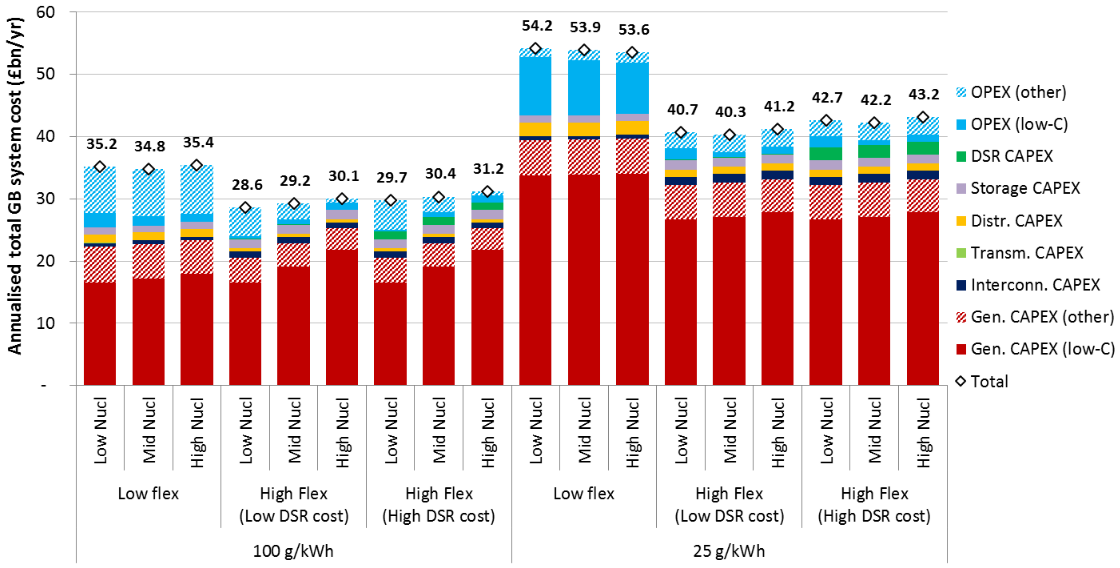


**Figure 4.6. Total system cost in 12 main scenarios**

For the reasons mentioned earlier, total system cost figures are particularly useful to make comparisons across scenarios, as this provides the basis for quantification of the system value of flexibility by contrasting relevant High and Low Flexibility scenarios. Differences in total system cost between Low Flexibility scenarios and the corresponding High Flexibility scenarios are presented in Figure 4.7. Note that the reported system cost savings represent *net system benefits*, i.e. account for the cost associated with increasing flexibility through investing in more energy storage, interconnection and DSR, which are shown as negative values in total net cost savings.

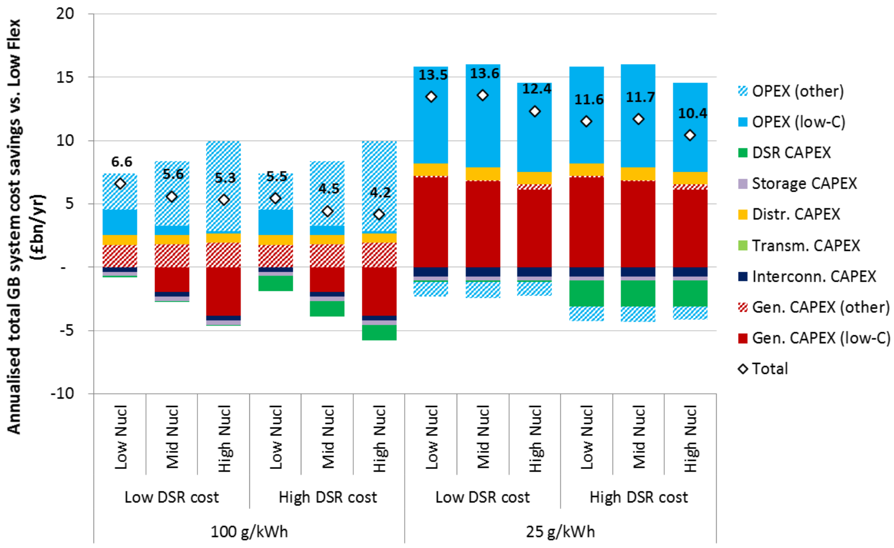


**Figure 4.7. Benefits of flexibility (High vs. Low Flexibility)**

The value of flexibility is found to be significant, and increases with the level of carbon ambition. In the 100 g/kWh scenarios higher flexibility brings a net reduction in total system cost of £5.3-

6.6bn per year in case of low DSR cost, or £4.2-5.5bn per year with high DSR cost. The corresponding figures are considerably higher for 25 g/kWh scenarios: £12.4-13.6bn per year with low DSR cost and £10.4-11.7bn per year with high DSR cost.

The analysis also demonstrates that the system value of flexibility generally decreases with higher nuclear capacity in the system (as this is also linked with lower renewable capacity), although this trend is less pronounced than the impact of reducing carbon target from 100 to 25 g/kWh. These results confirm the findings of our earlier studies indicating that the value of flexibility increases dramatically when moving towards more ambitious carbon targets, particularly when these targets are delivered by significant deployment of variable renewable generation.

## 4.6. Marginal value of baseload generation

In this section we present the results of marginal system benefit calculations for nuclear capacity, following the steps outlined in Section 2.3. Marginal value calculations have been carried out by running additional studies for the 12 main system scenarios, in which the GB capacity of nuclear in each scenario was increased by 1 GW that was assumed to be available at zero cost, and the resulting change in total system cost attributed to additional nuclear power and expressed in monetary units per MWh of additional nuclear output.

The results of marginal value calculations for all main scenarios are presented in Figure 4.8. In each of the main scenarios the chart also specifies the detailed breakdown of the marginal system value into components: generation CAPEX (G CAPEX) for each technology, OPEX for each generation technology, as well as the CAPEX of interconnection, transmission and distribution (although these three categories have a very limited impact on the overall marginal system value). Note that some of these components can also be negative i.e. the addition of nuclear displaces certain types of generation capacity and output, but may trigger an increase in the capacity and output of other types.

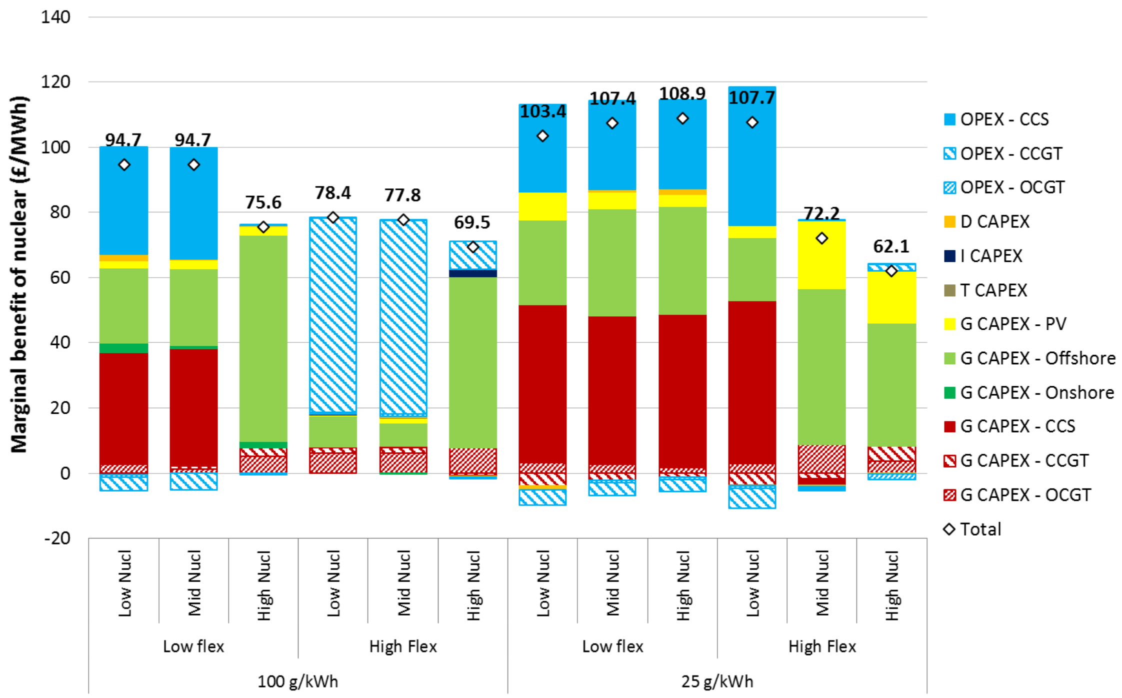


**Figure 4.8. Gross marginal system benefit of nuclear generation**

Taking 100 g/kWh, Low Flexibility, Mid Nuclear scenario as an example, we note that the total marginal system benefit of nuclear is around £95/MWh, which results from the following adjustments in the system triggered by the addition of 1 GW of nuclear capacity:

- CAPEX savings from reduced CCS capacity (0.72 GW)
- CAPEX savings from reduced wind (0.95 GW) and PV (0.51 GW) capacity
- CAPEX savings from reduced CCGT and OCGT capacity (0.28 GW)
- OPEX savings from reduced CCS output (4.9 TWh)
- Slight OPEX increase from increased CCGT output (0.5 TWh)

All of these changes combined together result in system cost reduction of £95 per MWh of added nuclear output, ignoring the cost of the additional MWh of nuclear output (i.e. this value represents gross system savings). As indicated in Section 2.3, comparing the marginal system value of nuclear (or any other technology for that matter) with its LCOE can provide an indication as to how close the volume of nuclear generation in the system is to its optimal level:

- If the *marginal value* of nuclear is *higher than its LCOE*, the system would benefit (i.e. the total system cost would reduce) from *increasing* nuclear capacity.
- If the *marginal value* of nuclear is *lower than its LCOE*, the system would benefit from *decreasing* nuclear capacity.
- If the *marginal value* of nuclear is *close to its LCOE*, the system would be *indifferent* to moderate changes in nuclear capacity, implying that this capacity is near its optimal level.

The following observations can be made regarding the results of marginal value of nuclear across scenarios:

- In 100 g/kWh scenarios with Low Flexibility, the marginal value of nuclear in Low and Medium Nuclear scenarios is very close to the assumed LCOE of nuclear (£94/MWh, see Table 3.2), suggesting that these levels of nuclear capacity are close to the overall optimal capacity mix for the system. In the High Nuclear scenario the marginal value drops to around £75/MWh as in this scenario nuclear no longer displaces CCS generation, but rather displaces the capacity and output of offshore wind as well as relatively inexpensive conventional (CCGT and OCGT) capacity.
- In 100 g/kWh scenarios with High Flexibility and Low/Medium Nuclear, the additional nuclear output effectively displaces CCGT generation as there is no CCS generation to displace and the LCOE of offshore wind is lower than the cost of operating CCGT. The resulting marginal value is around £78/MWh, significantly lower than when displacing CCS generation. In the High Nuclear scenario the CCGT output is already so low that the additional nuclear generation effectively displaces offshore wind, which given the low LCOE of offshore wind (£57.5/MWh) combined with a low integration cost of wind in a highly flexible system, results in an even lower marginal value of nuclear of around £70/MWh.
- In 25 g/kWh scenarios with Low Flexibility, the incremental nuclear capacity always displaces a significant amount of CCS capacity and output as well as some wind and PV capacity, resulting in a relatively high system value of nuclear of £103-109/MWh. In

these scenarios the system would clearly benefit from having more nuclear in the generation portfolio.

- In 25 g/kWh scenarios with High Flexibility, the additional 1 GW of nuclear generation in Low Nuclear scenario still displaces CCS generation, and its marginal value (£108/MWh) is hence very similar to the values observed in Low Flexibility scenarios. On the other hand, in Medium and High Nuclear scenarios there is no more CCS to displace, so the incremental nuclear capacity would replace a mix of wind and PV generation, which due to the lower LCOEs of these two technologies yields a lower marginal value of nuclear (£62-72/MWh).

It is also interesting to correlate the results for the marginal system value of nuclear with observed trends in total system cost (Figure 4.6) when nuclear capacity increases from Low to Medium and High. The two 100 g/kWh scenarios with marginal value of nuclear close to its LCOE (Low Flexibility, Low and Medium Nuclear) also have the same levels of total system cost, which confirms the conclusion that in these scenarios the system would be broadly indifferent to moderate changes in nuclear capacity. In other 100 g/kWh scenarios the total system cost clearly increases with increasing nuclear capacity, which is consistent with its marginal value being below the LCOE, as also suggested by the results in Figure 4.8. Similarly, in all 25 g/kWh scenarios with Low Flexibility, as well as the Low Nuclear scenario with High Flexibility we observe that the total system cost reduces with the increase in nuclear capacity, which also follows from the marginal values in those scenarios being above the LCOE of nuclear. This trend reverses when moving from Medium to High Nuclear at High Flexibility, which is again in line with the marginal benefit of nuclear falling below its LCOE in these scenarios.

# 5. Sensitivity studies

The objective of sensitivity studies is to extend the analysis of the main power system scenarios defined in Section 3.1 to study the impact of additional drivers on the system value of nuclear generation and the cost-optimal portfolio of low-carbon generation. The sensitivity analysis discussed in this chapter focuses on the following system drivers:

- Growth in electricity demand
- Decrease in electricity demand
- Relaxed constraints on deployment of energy storage and interconnection
- Variation in the cost of energy storage
- Variation in the cost of variable renewable technologies (wind and solar)

As explained later in this chapter, some sensitivities were only run for a subset of scenarios i.e. carbon targets. In addition to the drivers listed above, some sensitivity studies determined the cost-optimal level of nuclear capacity by optimising it from zero, while others assumed fixed nuclear capacity as specified in the main scenarios. Table 5.1 provides a complete list of sensitivity studies included in this report, including the variations of key input parameters.

**Table 5.1. List of sensitivity studies**

| Sensitivity | Varied parameter | Value(s) | Carbon target (g/kWh) | Flex. level | Nuclear capacity |
|---|---|---|---|---|---|
| Demand increase | System demand | Original, +25%, +50%, +75% | 100, 25 | High | Optimised |
| Demand reduction | System demand | Original, -15%, -30%, -50% | 100, 25 | Low | Optimised |
| Relaxed constraints on flexible options | Storage and IC limits | Unconstrained | 100, 25 | High | Optimised |
| Variation in storage cost | Storage cost | High cost, -20%, -40%, -60%, -80% | 25 | Low | Optimised |
| Variation in RES cost: Marginal value of nuclear | RES cost | -25%, -50% | 25 | Low, High | Low, Mid, High |
| Variation in RES cost: Cost-optimal portfolio | RES cost | -25%, -50% | 25 | Low, High | Optimised |

## 5.1. Impact of increased electricity demand

The impact of increased electricity demand is investigated by increasing the annual demand in 100 and 25 g/kWh scenarios by 25%, 50% and 75% above the original demand in these scenarios (as specified in Section 3.3). Demand increase was implemented as proportional scaling of main scenario demand levels across all demand categories.

These sensitivity studies were run only for the High Flexibility 100 and 25 g/kWh scenarios, in order to determine how the increased electricity demand affects the amount of nuclear capacity in the least-cost low-carbon mix. In all sensitivities, including the ones with the original system demand level, the nuclear capacity was optimised from zero rather than fixed as in the main scenarios. Other generation technologies were optimised according to the same minimum and maximum levels as in the main scenarios.

The impact of increasing demand on installed capacity mix is shown in Figure 5.1. For completeness, the chart also includes the total interconnection capacity alongside generation and energy storage.

Firstly, it is interesting to compare the optimised generation portfolios with original demand levels with the portfolios from the main scenarios and the corresponding marginal system values of nuclear generation. In the highly flexible system with 100 g/kWh target the cost-optimal portfolio does not include any nuclear capacity under the assumption for the LCOE of nuclear as in Table 3.2; decarbonisation is instead delivered exclusively through variable renewables supported by a high uptake of flexible options (energy storage, DSR and interconnection).[27] This also confirms the quantitative findings on the marginal value of nuclear generation, which in the High Flexibility scenarios with 100 g/kWh was consistently below the assumed LCOE of nuclear (see Figure 4.8). Other than the absence of nuclear, the generation portfolio is similar to that with Low Nuclear capacity, including the interconnection capacity. Also, in this case, same as in main 100 g/kWh scenarios with High Flexibility, the system is so efficient in integrating renewables that it reduces carbon emissions below the target, to 85 g/kWh.

The high-flexible case with 25 g/kWh target and optimised generation portfolio on the other hand does include about 9 GW of nuclear generation with the same LCOE assumptions. This is the same volume as the one assumed in the main scenarios with Medium Nuclear capacity. Consequently, the remainder of the generation mix (including energy storage and interconnection) is almost identical to the Medium Nuclear scenario with 25 g/kWh and High Flexibility. This is again in agreement with the findings on marginal value of nuclear, which suggested the system would benefit from increasing nuclear capacity beyond the Low Nuclear level, but not further than the volume in Medium Nuclear. It is interesting to note that, unlike in the 100 g/kWh scenario, the system still adds a considerable volume of nuclear capacity (broadly similar to the UK nuclear capacity in operation today) despite a high level of system flexibility, suggesting that a deeper decarbonisation of the power system would be difficult to achieve without at least some nuclear in the generation portfolio.

27 These findings draw on the assumption that the LCOE of nuclear is £94/MWh and are therefore contingent on that parameter. If the assumed cost of nuclear was lower, the cost-optimal low-carbon portfolio in this and other sensitivity studies with optimised generation capacities would likely include more nuclear capacity.

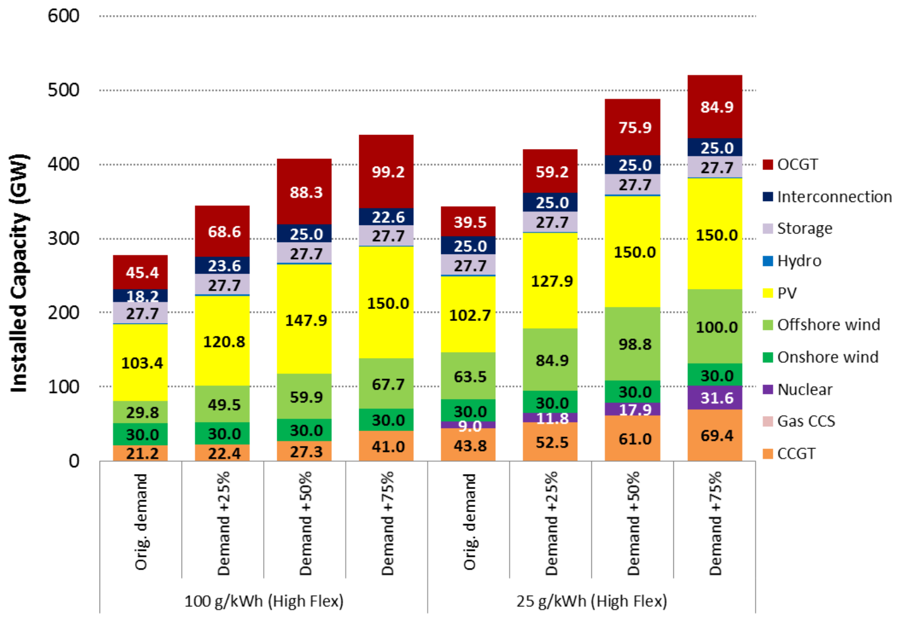


**Figure 5.1. Generation capacity mix for sensitivity studies with increased electricity demand (High Flexibility scenarios only)**

Furthermore, it can be observed that increasing the electricity demand in the 100 g/kWh system does not require any nuclear generation to be added to the cost-optimal low-carbon portfolio, as the carbon targets can still be met by expanding renewable capacity (subject to maximum deployment limits) in combination with flexible conventional generation (CCGT and OCGT). In the 25 g/kWh scenario, however, the system does include more nuclear as electricity demand increases, so that for instance at 75% increase from the original demand level (which was already significantly higher than in the 100 g/kWh scenarios) more than 30 GW is included in the generation mix. This occurs because the system benefits from having a year-round low-carbon baseload electricity supply but also because the deployment of renewables reaches the limits specified in Section 3.2.

## 5.2. Impact of reduced electricity demand

The effects of reduced electricity demand were investigated on both 100 and 25 g/kWh scenarios, by analysing the Low Flexibility cases only. Annual electricity demand was proportionally reduced in three steps: by 15%, 30% and 50%. Similar as in the sensitivities with increased demand, the cases with original demand levels were also optimised including nuclear capacity starting from zero.

The impact on demand reduction on the portfolio of generation, storage and interconnection capacity is shown in Figure 5.2. An immediately obvious difference to the optimised High Flexibility cases with original demand is that the cost-optimal portfolios now include significantly less renewable capacity. In the 100 g/kWh scenario the model now adds nuclear generation (about 8 GW) as well as some CCS capacity, while in the 25 g/kWh case very high volumes of both nuclear (26 GW) and CCS (16 GW) capacities are included in the portfolio. These results are again consistent with quantified marginal values of nuclear, which in the 25 g/kWh were consistently higher than the nuclear LCOE, and in the 100 g/kWh scenario were close to the LCOE in Low and Medium Nuclear cases.

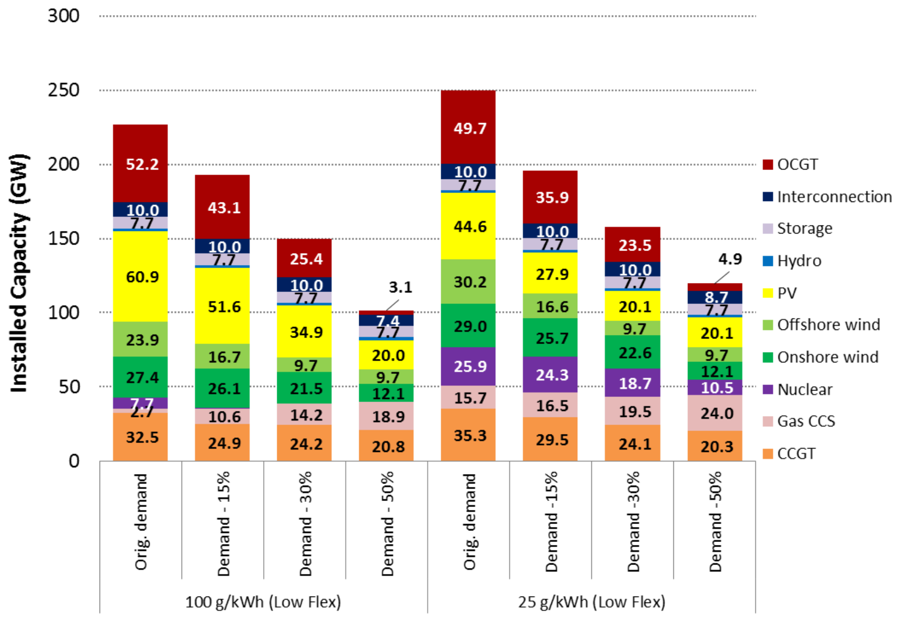


**Figure 5.2. Generation capacity mix for sensitivity studies with reduced electricity demand (Low Flexibility scenarios only)**

As system demand decreases, we note that capacities of both nuclear and renewable generation diminish while the capacity of CCS increases. In Low Flexibility systems CCS represents a more flexible low-carbon alternative to nuclear, which is particularly relevant for reduced demand cases where the scope to operate must-run baseload nuclear generation progressively shrinks. On the other hand, CCS plants can be switched on and off to follow demand fluctuations.

## 5.3. Impact of relaxed deployment limits for energy storage and interconnection

This set of sensitivity studies aimed at investigating the cost-optimal deployment of energy storage and interconnection in the decarbonised UK power system if the upper limits for deployment of these two options were relaxed. The sensitivities were run for High Flexibility scenarios only, and with optimised nuclear capacity. In the 100 g/kWh scenario the sensitivity was only run for the original demand level, while in the 25 g/kWh the sensitivities studies also included cases with increased demand levels with 25%, 50% and 75% increments. The optimised generation portfolios (including storage and interconnection capacity) are shown in Figure 5.3.

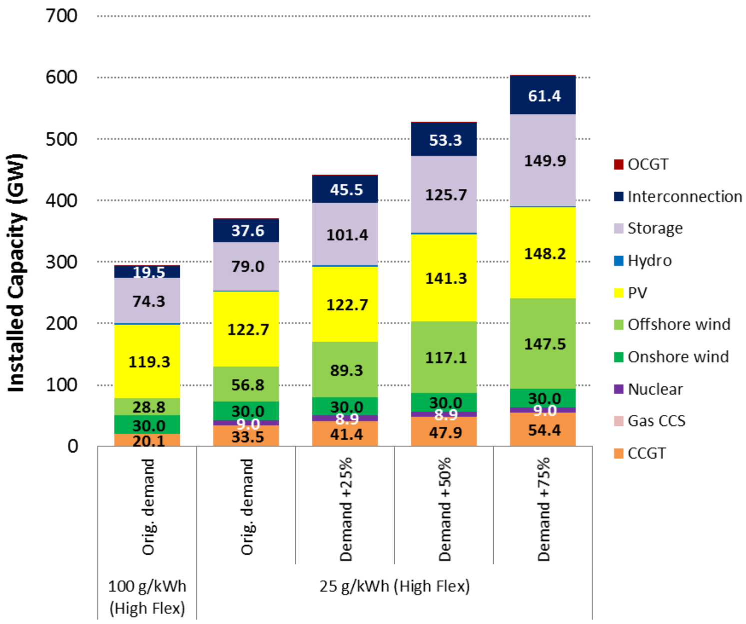


**Figure 5.3. Generation capacity mix for sensitivity studies with relaxed constraints on interconnection and energy storage (High Flexibility scenarios only)**

In the 100 g/kWh scenario with relaxed storage and interconnection limits the cost-optimal volume of energy storage (if available at the low cost specified in Table 3.1) increases substantially to almost 75 GW. Given that in these cases the cost of energy storage per kW of installed capacity is lower than the cost of OCGT generation, storage completely replaces OCGT as provider of firm capacity margin. Also, the very high volume of battery storage makes the integration of PV output more efficient, and therefore the generation mix includes more PV and less offshore wind than in the scenarios with constrained storage capacity. Deployment of interconnectors in this case is slightly higher than in the constrained case (see Figure 5.1) but still does not reach the maximum allowed level specified in constrained studies (25 GW in total).

Cost-efficient storage and interconnection capacity increases further in the unconstrained 25 g/kWh scenario run with original demand, to 79 GW of storage and 30 GW of interconnection. As in the 100 g/kWh scenario the cost-optimal generation portfolio now includes more PV and less offshore wind than in the constrained case. The cost-efficient level of nuclear capacity, however, does not change, remaining at 9 GW. This implies that the system should include a certain volume of nuclear generation even in case of very high flexibility i.e. unlimited availability of low-cost battery storage and interconnection capacity.

With the demand increasing in the 25 g/kWh scenario we note that the volume of storage increases broadly in proportion with demand, as do the volumes of offshore wind, CCGT and interconnection (note that in these studies the upper limit on offshore wind was relaxed). Interestingly, the cost-optimal volume of nuclear does not increase beyond the 9 GW (corresponding to the Medium Nuclear scenario) at the assumed level of nuclear LCOE (£94/MWh).

## 5.4. Impact of reduced cost of energy storage

The final set of sensitivity studies examined the impact of the assumed cost of energy storage on the generation capacity mix. These sensitivities were carried out only for 25 g/kWh scenarios with Low Flexibility. The cost of storage was varied starting from the high cost level (Table 3.1) and then progressively reduced by 20%, 40%, 60% and 80% below that level. Given that in all Low Flexibility scenarios studied so far the deployment of battery storage was always at the upper limit (5 GW), the deployment limit in these sensitivity studies was relaxed.

The composition of the cost-optimal capacity mix across the sensitivities on battery storage cost is presented in Figure 5.4.

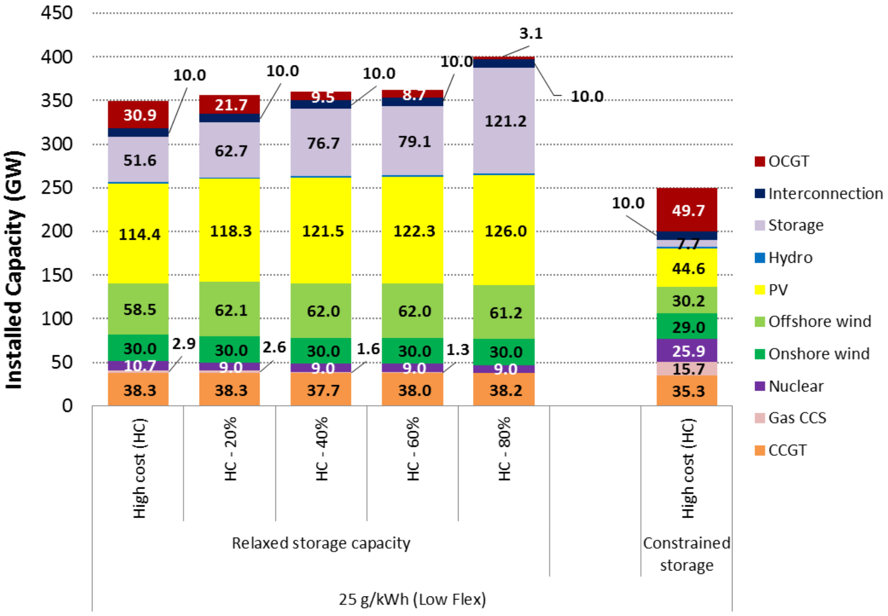


**Figure 5.4. Generation capacity mix for variations in cost of energy storage (25 g/kWh, Low Flexibility scenarios only)**

Lifting the constraint on deployment of battery storage, although it is available at a relatively high cost, causes profound changes in the optimal capacity mix when contrasted to the comparable constrained scenario from Figure 5.2 (25 g/kWh, Low Flexibility with original demand), which is also reproduced at the right-hand side of Figure 5.4. The cost-optimal volume of storage in this case is more than 50 GW i.e. an order of magnitude higher than the upper limit in Low Flexibility scenarios of 7.7 GW. Higher storage capacity provides additional flexibility that makes renewables relatively more attractive for the system than nuclear, so for instance PV capacity increases from 45 GW to 114 GW and offshore wind from 30 to 58 GW, while the capacity of nuclear decreases from 26 to 11 GW and that of CCS from 16 to 3 GW. At this cost level the battery storage is still more expensive than OCGT capacity when used purely as backup capacity in meeting the security criteria; therefore the model still chooses a significant volume of OCGT capacity (31 GW) as part of the optimal mix.

With gradual reduction in battery storage cost[28] and all other parameters kept equal, the cost-optimal volume of storage expectedly increases as well. Increase in storage capacity gradually displaces peaking (OCGT) capacity and also slightly increases the PV capacity in the generation portfolio while reducing the contribution from CCS generation. Similar to the relaxed sensitivity studies (Figure 5.3), cost-optimal nuclear capacity stabilises at the level of 9 GW and remains there even as battery storage capacity increases.

## 5.5. Impact of reduced cost of variable renewable generation

The results so far have shown that despite significant differences in the assumed LCOE values between nuclear and variable renewable technologies (wind and solar), the cost-optimal solu-

[28] Note that the lowest cost point for battery storage in these sensitivity studies, representing 80% cost reduction, would be lower than the storage cost assumption in the High Flexibility scenarios (which is about 69% lower than the Low Flexibility cost assumption – see Table 3.1).

tion can still include a considerable volume of nuclear generation, even in highly flexible scenarios with ambitious carbon targets. It is therefore of interest to investigate to which extent a further increase in LCOE differentials (i.e. a further reduction in the cost of renewables) would affect the marginal value of nuclear as well as the share of nuclear generation in a cost-optimal portfolio of low-carbon generation.

As specified in Table 5.1, two further levels of RES cost were assumed in this sensitivity study, one that is 25% lower than the baseline cost assumptions (Table 3.2), and the other that is 50% lower than baseline. For each of the two alternative RES cost levels we carried out two sets of modelling runs: one to determine the impact on the *marginal value of nuclear*, and the other to establish the impact on the *cost-optimal portfolio* of low-carbon generation technologies. The sensitivity studies with reduced cost of variable renewables were only carried out for the 25 g/kWh scenarios.

### 5.5.1. Impact on marginal value of nuclear generation

Quantitative studies on the marginal value of nuclear were set up and run using the approach described in Section 2.3. The cost-optimised generation portfolios (including interconnection and energy storage) for the 6 main 25 g/kWh scenarios with pre-defined nuclear capacity are shown in Figure 5.5 for both 25% and 50% lower renewable cost. Unsurprisingly, the reduction in the cost of renewable generation results in more wind and solar and less CCS being added to the generation portfolio in Low Flexibility scenarios, when compared to the main scenarios with baseline renewable cost assumptions (25 g/kWh scenarios in Figure 4.1).

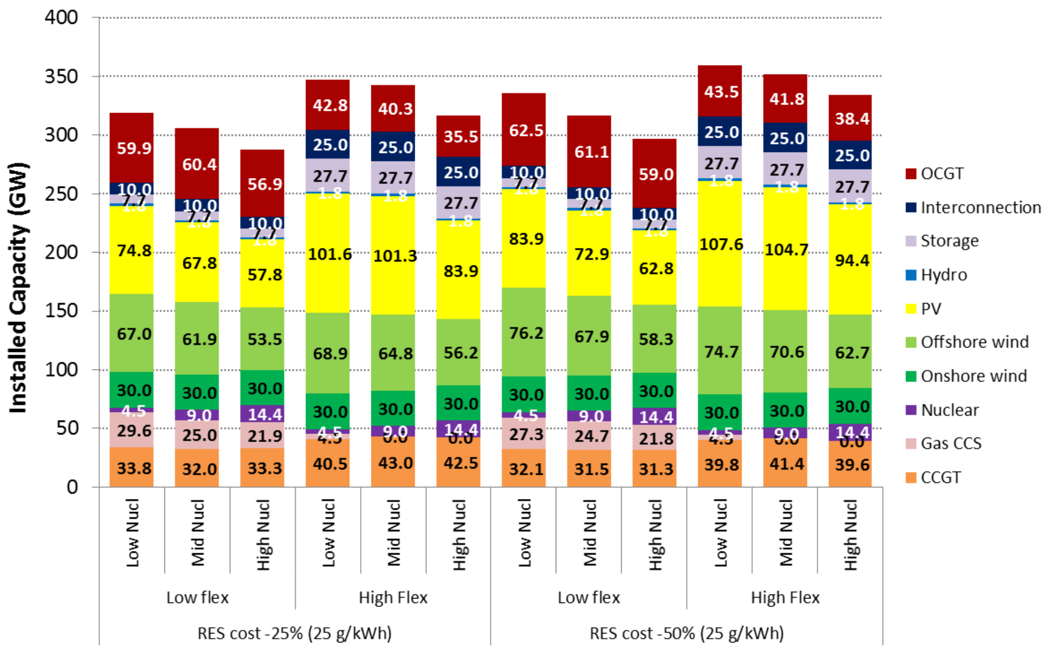


**Figure 5.5. Generation portfolios for main 25 g/kWh scenarios with reduced cost of renewables**

Taking the Low Nuclear scenario as an example: in the baseline scenario (the first 25 g/kWh scenario in Figure 4.1) there was 34 GW of CCS installed along with 54 GW of offshore wind and 62 GW of solar PV. With lower RES cost the CCS capacity reduces to 30 GW and 27 GW with 25% and 50% RES cost reduction, respectively, while the offshore wind capacity in these two cases increases to 67 GW and 76 GW, and solar PV capacity to 75 GW and 84 GW. Onshore wind capacity remains the same as in the main scenarios given that it is always built up to its deployment limit. Despite high renewable curtailment levels in the Low Flexibility scenario (around 20% annually), lower RES cost makes it cost-efficient to further increase wind and solar capacity and displace CCS.

On the other hand, in the High Flexibility scenarios the capacity of CCS remains broadly unaffected compared to the main scenarios in Figure 4.1; there is about 4.5 GW added in the Low Nuclear scenario and none in Medium and High Nuclear scenarios. RES curtailment levels in High Flexibility scenarios are much lower than for Low Flexibility scenarios (around a few percentage points) and therefore the system is already able to take full advantage of RES even before further cost reductions of 25% and 50% are assumed. It can however be observed that the composition of the renewable generation portfolio changes slightly compared to the portfolios determined in the main scenarios (Figure 4.1), with more wind and less solar PV generation. This can be explained by the fact that the integration cost of renewables plays a more significant role in relative terms as their LCOE reduces; it is known from previous studies that the integration cost of PV tends to be higher than for wind due to higher seasonal and diurnal output variability.

Figure 5.6 summarises the results obtained for the marginal value of nuclear across the sensitivity studies with reduced cost of variable renewables. The marginal system benefit of nuclear increases in Low Flexibility, Low Nuclear scenarios, which now feature more renewable generation in counterfactual scenarios (see Figure 5.5). When low system flexibility is combined with Medium or High Nuclear capacity, the marginal value decreases compared to the main scenarios as it becomes more driven by the lower cost of renewables (although the majority of the value still comes from displacing CCS). For instance, as illustrated in Figure 5.6, in the 25% RES cost reduction sensitivity the observed marginal values of nuclear for those two nuclear scenarios are £95-101/MWh, and with 50% RES cost reduction the marginal values are £80-83/MWh.

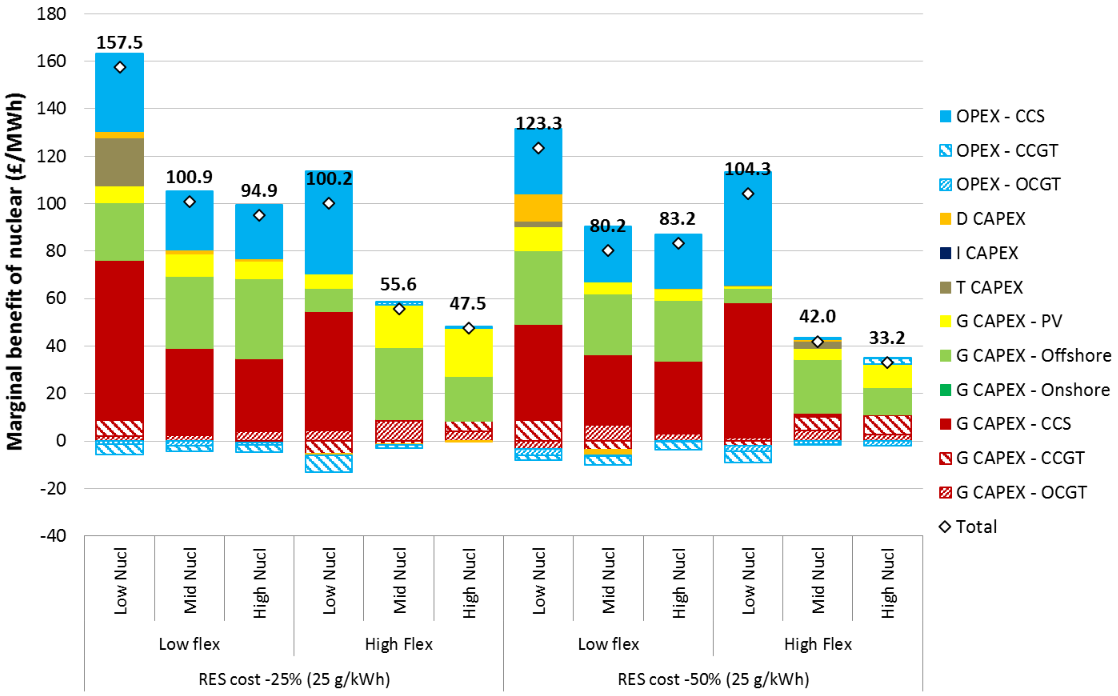


**Figure 5.6. Marginal value of nuclear in sensitivity studies with reduced cost of renewables**

In the High Flexibility scenarios the marginal value with Low Nuclear capacity is still above £100/MWh as it is dominated by the cost of displaced CCS. However, as the nuclear capacity increases to Medium and High levels, there is a significant drop in the marginal benefit of nuclear, which becomes dictated by the cost of wind and PV generation it displaces when nuclear is added to the system. With 25% lower RES cost the marginal benefit of nuclear in these two scenarios is between £48/MWh and £56/MWh, while with 50% lower RES cost the marginal value further reduces to £33-42/MWh. Overall, it is evident that the marginal system benefit of nuclear will be determined by the costs of other low-carbon technologies it is displacing when added into the system in a given scenario.

It should be noted that the results obtained for the marginal value of nuclear by adding a discrete amount of 1 GW in the Medium Nuclear scenario, High Flexibility, would likely increase if the marginal value was quantified by subtracting rather than adding nuclear capacity. This is because the Medium Nuclear capacity of 9 GW is the cost-optimal level of nuclear capacity for the High Flexibility scenario (see next section) and therefore represents a tipping point for the system value of nuclear.

### 5.5.2. Impact on cost-optimal portfolio of low-carbon technologies

In order to evaluate the impact of lower wind and PV cost on the composition of the cost-optimal low-carbon generation portfolio a further set of sensitivity studies was run where the capacity of nuclear generation was optimised along with other low-carbon technologies. Cost-optimised sensitivity studies were run for the 25 g/kWh scenario, for Low and High Flexibility levels, as well as the scenario with relaxed storage and interconnection constraints (effectively representing a very high level of system flexibility). Figure 5.7 shows the cost-optimal capacity portfolios with reduced LCOEs of wind and PV generation. To enable comparison, the results are shown alongside the results of model runs with original RES cost assumptions.

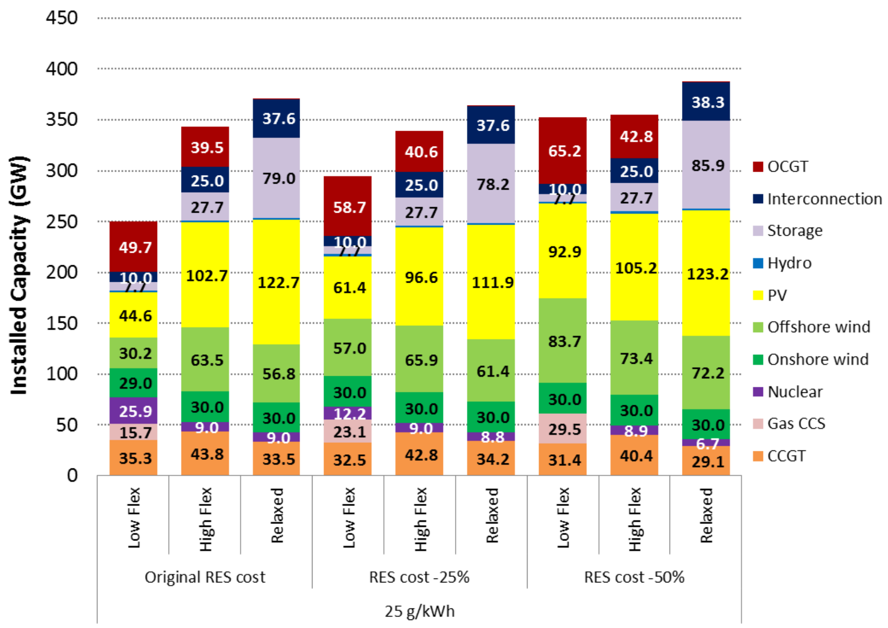


**Figure 5.7. Cost-optimised capacity mix in sensitivity studies with reduced cost of renewables**

Reducing the cost of RES generation expectedly results in more wind and PV capacity being added to the system to meet the carbon target. The difference is most prominent in Low Flexibility scenarios, where the combined wind and PV capacity increases from 104 GW in the main scenario to 148 GW and 207 GW in 25% and 50% RES cost reduction scenarios, respectively. High Flexibility scenarios were already dominated by wind and PV in the main scenarios, given that the system preferred renewables due to lower cost and was able to integrate them cost-efficiently thanks to high flexibility. Nevertheless, there is a slight increase in RES capacity even in those scenarios, mainly with respect to offshore wind.

Unlike the results of marginal system benefits of nuclear presented in the previous section, the cost-optimal generation portfolios will depend on the assumed cost of nuclear generation (Table 3.2), alongside other input parameters. Had a lower nuclear cost been assumed and other parameters remained the same, the results would likely include more nuclear capacity.

It is also interesting to note that in the High Flexibility scenarios, despite the significantly reduced cost of RES generation, the model still adds around 9 GW of nuclear capacity into the generation mix. The extent to which this is driven by technical constraints associated with maintaining the stability of system frequency, and in particular the system inertia, is explored in the next subsection (5.5.3).

The capacities of baseload low-carbon generators, nuclear and CCS, change considerably in Low Flexibility scenarios. With baseline RES cost assumptions nuclear was the dominant baseload technology with about 26 GW, supported by 16 GW of CCS. As RES cost gradually decreases, the cost-optimal capacities change in the favour of CCS, so that the 25% RES cost reduction scenario has only 12 GW of nuclear and 23 GW of CCS, while the 50% RES cost reduction scenario requires about 30 GW of CCS and does not include any nuclear capacity.

To explain this trend, it is useful to quantify how the LCOEs of nuclear and CCS depend on the annual capacity factor.[29] This is demonstrated in Figure 5.8, which shows that for annual utilisation levels below 73% it is better to install CCS rather than nuclear, despite the higher operating cost of CCS, and take advantage of the lower investment cost of CCS. In lower RES cost scenarios with Low Flexibility it becomes efficient to install more wind and PV despite high curtailment levels. Higher fluctuations in aggregate renewable output require other generators in the system to operate more flexibly i.e. with a lower capacity factor. This also means that the requirements for system balancing (i.e. reserve and response services) increase, and they can be more efficiently provided by CCS than by nuclear generation. Hence, the model tends to add relatively more CCS and less nuclear in scenarios with lower RES cost.

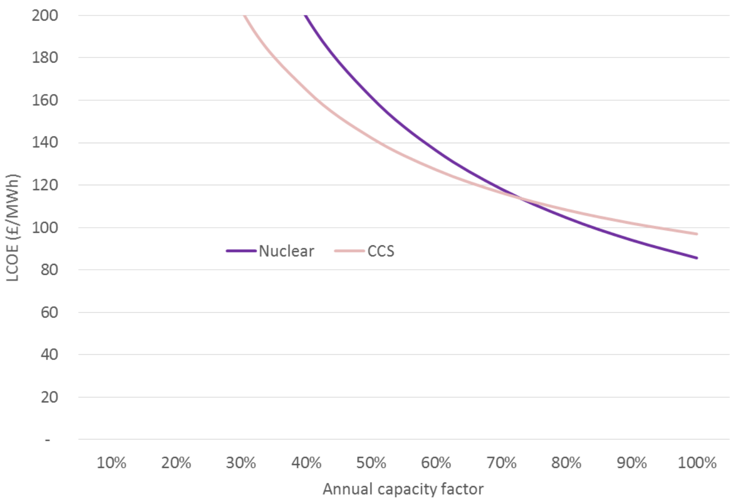


**Figure 5.8. Levelised cost of electricity for nuclear and CCS generation as function of annual capacity factor**

29 Note that this simplified analysis does not consider certain specific aspects of operating electricity generators, such as start-up costs or part-loaded efficiency, but is sufficient to illustrate the point. Also, note that the LCOE assumptions for nuclear and CCS included in Table 3.2 were based on an annual load factor of 90%, which was assumed to be the maximum achievable load factor for these technologies. However, the model could choose to operate these technologies at lower load factors if cost-efficient.

### 5.5.3. Impact of system inertia requirements

Sensitivity studies on the cost-optimal portfolio of low-carbon generators (Section 5.5.2) have shown that despite very high cost differentials between nuclear and renewable technologies, the model still builds about 9 GW of nuclear capacity even when there is a high level of flexibility in the system. It is reasonable to assume that this is at least partly driven by the system requirements for the provision of inertia[30] by synchronous generators in the system, given that nuclear generators are the only zero-carbon option considered in the study that can provide mechanical inertia (note that CCS generators will have non-zero carbon emissions, in the order of 40 g/kWh, due to less than 100% $CO_2$ capture rate, and neither wind nor PV generators involve synchronous machines).

A recent study[31] by the authors has studied in detail the future system flexibility requirements and has in that context argued the case for developing market mechanisms to incentivise the provision of flexible system services, including system inertia:

> *"One of the key challenges associated with integration of renewable generation is the reduction of system inertia. This may be provided through conventional generators manufactured with a higher inertia constant or from wind generators providing "synthetic inertia" (SI). However, the current flexibility market does not reward the provision of inertia and this has contributed to a lack of interest by investors to develop alternative ways for enhanced inertia provision. Without a remuneration mechanism for inertia, there will be higher cost to the system." (page 28)*

This study has not considered the provision of *synthetic inertia* (SI) by wind generators, which some studies and demonstration projects suggest may become a viable option at high wind penetrations.[32] Recent research, including the analysis carried out by the authors[33], has shown that implementing a suitable control mechanism for wind turbines to provide SI is a complex issue. Unlike conventional plants, the inertia provided by wind generators will depend on the choice of controller design parameters (especially the time constant), which should generally aim to maximise system benefits and should ideally be modified dynamically according to system needs. The key factor determining the volume of available SI by wind generators will be the number of wind turbines being online, which even for a given level of aggregate wind output is a variable and uncertain quantity, and therefore raises the issue of reliability of delivering SI. Another complicating factor is that the delivery of SI is followed by a *recovery period*, causing a temporary reduction in power output of wind turbines below the original operating point. This recovery could delay the system frequency reaching the steady-state level, and may lead to an increased demand for secondary frequency regulation to maintain system security, also

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30 Inertia in a power system refers to the inertial kinetic energy of synchronous generators, which is essential for stabilising system frequency in case of a sudden mismatch between supply and demand (e.g. following a large generator or interconnector outage). Inertia determines how fast the system frequency changes in case of e.g. a sudden loss of generation (this is often quantified as the Rate of Change of Frequency or ROCOF, expressed in Hz/s). Without inertia, a fast-dropping frequency could send power systems into cascading failures given that generator protection systems would detect a high level of ROCOF as a loss-of-mains event and therefore disconnect from the grid.

31 Pöyry Management Consulting and Imperial College London, "Roadmap for flexibility services to 2030", report for the Committee on Climate Change, May 2017. Available: https://www.theccc.org.uk/publication/roadmap-for-flexibility-services-to-2030-poyry-and-imperial-college-london/

32 A system with synthetic inertia would need to digitally control the rotational speed of asynchronous wind generators to achieve the effect similar to mechanical inertia currently provided by synchronous generation. See e.g. https://www.nrel.gov/news/program/2018/when-the-gears-stop-turning.html.

33 F. Teng, G. Strbac, "Assessment of the Role and Value of Frequency Response Support from Wind Plants", IEEE Transactions on Sustainable Energy, Vol: 7, April 2016.

associated with additional cost of delivering frequency regulation and diminishing the benefits of SI.

A key factor that influences inertia requirements in power systems is the size of the largest credible infeed loss, which effectively refers to the size of the largest generator in the system. Most scenarios envisage that the largest generating unit in the future power system will be one of the new nuclear units (such as those to be built at Hinkley Point C), with the corresponding size of the largest loss of 1.8 GW. Reducing the level of largest infeed loss, during periods when low demand condition coincide with high RES outputs, would also reduce the system requirements for frequency regulation services and system inertia to be maintained during those periods. One approach to achieve this would be to reduce the output of nuclear units i.e. *de-load* them in a coordinated fashion during low demand and high RES output periods, so that the size of the largest credible infeed loss decreases accordingly. Although this option was not modelled in this study, recent (and as yet unpublished) research by the authors has shown that although nuclear units provide low-cost, zero-carbon output, under certain system conditions it may be cost-effective to reduce their scheduled output in order to reduce the need for frequency services and system inertia. Furthermore, the same research has shown that de-loading nuclear units can also reduce carbon emissions despite a lower load factor of nuclear, as it reduces the need for frequency services delivered by part-loaded conventional generators, which in turn results in the system being able to accommodate more RES output and reduce RES curtailment.

Notwithstanding the issues associated with SI provision by wind generators as well as the option to de-load nuclear units to meet the inertia and frequency response requirements more cost-effectively, several indicative WeSIM model runs were additionally carried out where the *system inertia requirement was reduced by 50%*, in order to simulate the conditions where system inertia would no longer need to be delivered by synchronous generators only. The purpose of these indicative studies was to establish whether the inertia requirements were a driver for the model keeping about 9 GW of nuclear capacity in the system even when the LCOE of nuclear was several times higher than the cost of wind and PV. Note that these results should be interpreted as illustrative only given the caveats and modelling limitations with respect to SI and de-loading of nuclear units discussed above.

The results of model runs with reduced inertia requirements are presented in Figure 5.9 alongside the corresponding results of the studies with conventional inertia requirements. The studies only included 25 g/kWh scenarios with a) High Flexibility and b) relaxed storage and interconnection constraints (referred to as Very High Flexibility in the chart), while the assumed RES cost levels included the original assumptions, 25% lower and 50% lower RES cost.

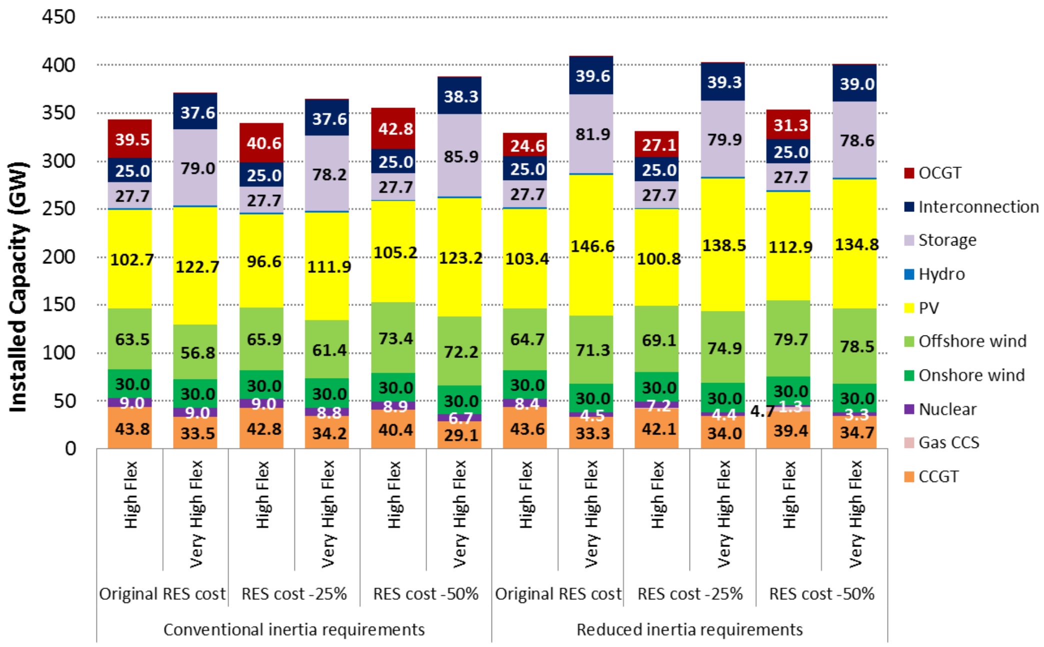


**Figure 5.9. Cost-optimised capacity mix with relaxed inertia constraints**

The results suggest that in a highly flexible system, and in particular in a system with relaxed constraints on energy storage and interconnection, it would be possible to achieve the carbon target of 25 g/kWh with less than 9 GW of nuclear. In an extremely flexible system with low-cost renewables the provision of inertia appears to be a driver that determines the volume of nuclear in the cost-optimal low-carbon portfolio. It should be noted that this conclusion comes with a caveat that synthetic inertia would need to be widely available and well understood and that all of the associated technical and economic challenges have been resolved. Further research is needed to provide a more robust assessment of the system-level cost and benefit associated with the provision of synthetic inertia, as well as to further explore the option of de-loading nuclear units to improve the efficiency of meeting frequency response and inertia requirements.

## 5.6. Changes in total system cost

Variations in assumptions and parameters using in sensitivity studies also result in different levels of total system cost than in the main scenarios. This section discusses the key drivers behind changes in total system cost associated with the sensitivity studies presented in Sections 5.1 to 5.5 and contrasts them to the findings from the main scenario analysis. Total system cost results are shown separately for 100 g/kWh sensitivities and 25 g/kWh sensitivities, as well as separately for the sensitivities on RES cost.

### 5.6.1. 100 g/kWh sensitivities

Total system cost across the sensitivity studies carried out for the 100 g/kWh scenarios is shown in Figure 5.10.[34]

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34 For simplicity all cost figures in this section assume a low DSR cost. The same remarks apply to the presentation of total system cost numbers as in Section 4.5.

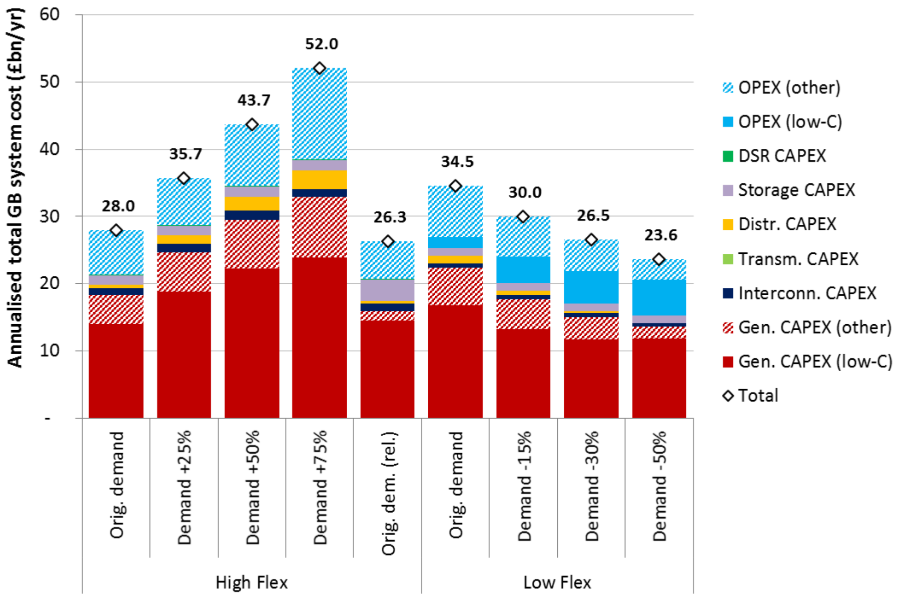


**Figure 5.10. Total system cost for 100 g/kWh sensitivity studies**

In the 100 g/kWh scenarios the total system cost with the original demand level is £28bn and £34.5bn per year in High and Low Flexibility cases, respectively. The implied value of flexibility is the difference between the two cost figures, or £6.5bn per annum. Given that the generation portfolios were fully optimised rather than involving a fixed amount of nuclear capacity, this represents a reduction from the corresponding lowest cost figures in the main scenarios (£28.6bn and £35.2bn, respectively – see Figure 4.6). Relaxing the constraint on storage and interconnection deployment reduces total system cost by further £1.7bn per year (i.e. to £26.3bn/yr), as the increased cost of investing into storage is more than offset by reduced investment in peaking generation capacity. Finally, as expected, increasing or decreasing electricity demand gives rise to higher or lower total system cost, respectively.

### 5.6.2. 25 g/kWh sensitivities

Similar trends can be observed in the total system cost numbers across 25 g/kWh sensitivities (Figure 5.11). With original demand assumptions, the benefits of high flexibility are £13.1bn/yr, given that it reduces total system cost from £53.4bn to £40.3bn per year. Relaxing storage and interconnection constraints provides a further £1.4bn per year in system cost savings, bringing the total cost to £38.9bn per year. When comparing the fully optimised case with the results from main scenarios (Figure 4.6) we note that the cost in the optimised High Flexibility case is the same as in Medium Nuclear main scenario, which is expected given that the optimised system contains the same amount of nuclear (9 GW) as the Medium Nuclear scenario. The optimised Low Flexibility case on the other hand is £0.2bn per year less expensive than the lowest-cost main scenario with Low Flexibility (High Nuclear) given that the cost-optimal volume of nuclear capacity (26 GW) is higher than the capacity assumption in the High Nuclear case (14.4 GW).

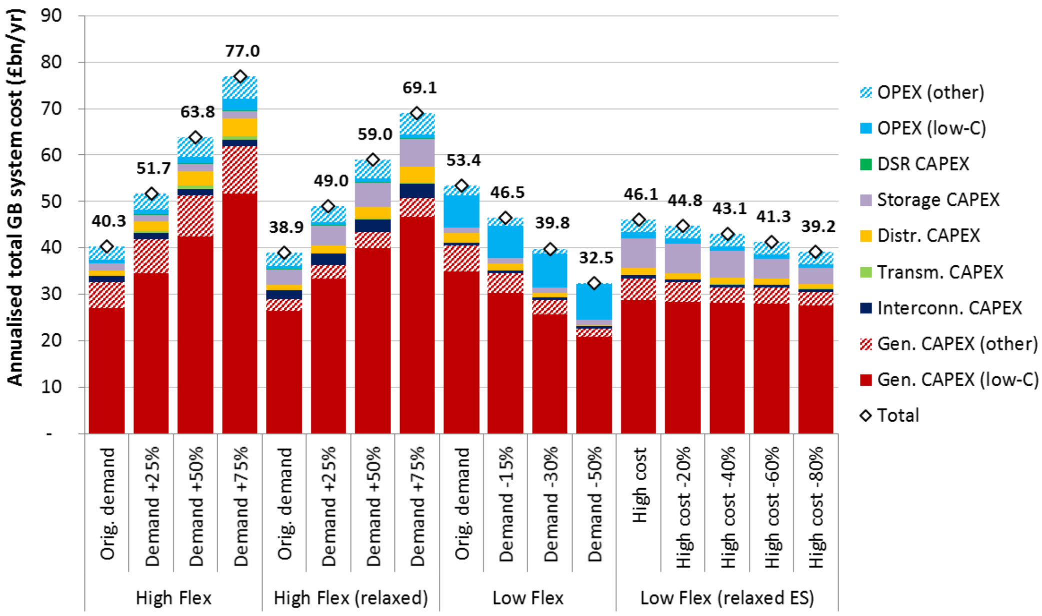


**Figure 5.11. Total system cost for 25 g/kWh sensitivity studies**

Relaxing the storage and interconnection constraints (the “High Flex (relaxed)” group of studies in Figure 5.11) provides additional benefits compared to the High Flexibility cases that increase depending on the assumed demand level: from £1.4bn/yr at the original demand level to £7.9bn/yr for 75% higher demand.

If the storage constraint is relaxed in the Low Flexibility case while still assuming a high cost of battery storage (the “Low Flex (relaxed ES)” group of studies), the total system cost reduces substantially to £46.1bn per year, which is £7.3bn per year lower than in the original Low Flexibility scenario. Gradually reducing the cost of battery storage (while maintaining the same low or zero levels of interconnection and DSR) provides further cost benefits, so that at storage cost that is 80% lower than the assumed high cost the annual system cost would reduce to £39.2bn per year, which represents further £6.9bn per year in savings compared to the relaxed high storage cost case.

### 5.6.3. Reduced renewable cost sensitivities

Finally, the impact on total system cost of wind and PV generation being available at a lower cost is presented in Figure 5.12 alongside the results from the main scenarios, for cost-optimised generation portfolios described in Section 5.5.2. Regardless of the flexibility level, lowering the cost of renewables results in a significant reduction in system cost. In the 25% RES cost reduction studies, the total system cost reduces by £3.5bn per year in a less flexible system and by £5.1bn per year in a more flexible system. In the 50% RES cost reduction scenarios the system cost savings more than double, ranging from £8.8bn per year in the Low Flexibility scenario to £9.5-10.3bn per year in High Flexibility and Relaxed scenarios.

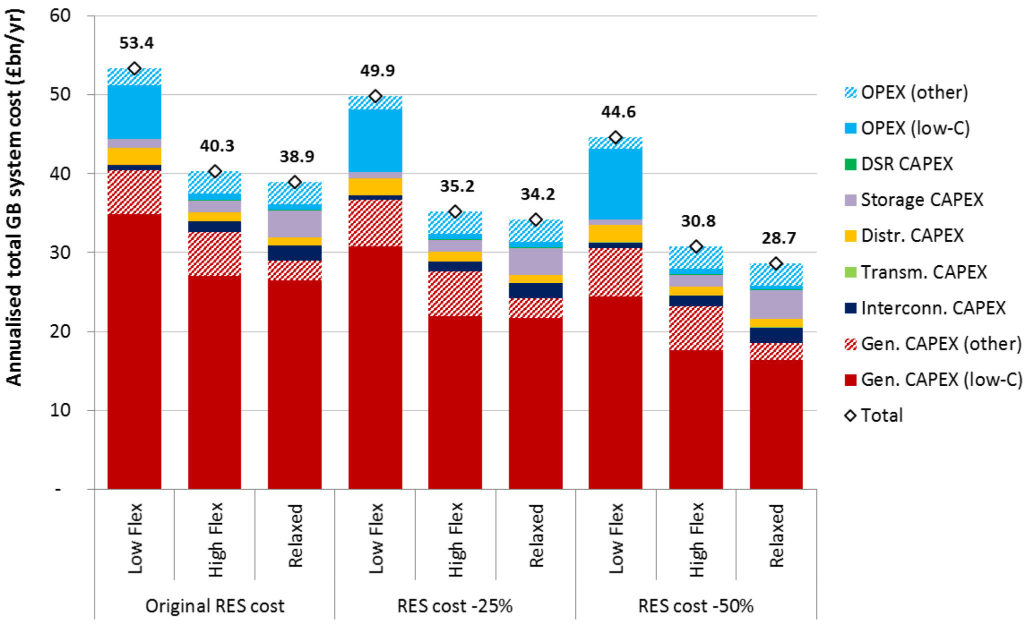


**Figure 5.12. Total system cost for lower RES cost sensitivity studies**

The main driver for cost changes are differences in the portfolios of low-carbon generation. In the High flexibility and relaxed scenarios wind and PV dominate the electricity supply, and therefore the cost reduction mainly results from costing the RES generation at a lower cost. In the Low Flexibility scenarios on the other hand, there is an increase in RES capacity as its costs decreases, but this is also coupled with replacing nuclear generation with CCS and high RES curtailment; therefore the cost reductions in low-flexible scenarios are somewhat lower.

# 6. Conclusions

The analysis presented in this report focused on quantifying the value and cost-optimal volume of nuclear power in the context of ongoing UK power system decarbonisation across a number of scenarios and sensitivity studies. Key findings from the analysis are summarised below:

1. **Increasing system flexibility brings substantial savings in total system cost.**
   The value of system flexibility in low-carbon power system scenarios analysed in the study is found to be significant and increases with the level of carbon ambition. In the 100 g/kWh scenarios higher flexibility brings net total system cost savings of up to £6.6bn per year, while in the 25 g/kWh scenarios the equivalent cost savings are considerably higher, up to £13.6bn per year. These net savings are the result of investment in energy storage, interconnection and DSR resources that allow the system to integrate low-cost variable renewable generation more efficiently. Cost savings are achieved through replacing more expensive low-carbon technologies (nuclear and CCS) with renewables while at the same time increasing the efficiency of using conventional generators and reducing the requirements for peaking generation and network capacity.

2. **Cost-optimal volumes of energy storage and interconnections represent a substantial increase from the current levels.**
   The optimal deployment of new battery storage in all scenarios was at the allowed upper limit, regardless of its cost (this limit was 5 GW in Low Flexibility scenario and 25 GW in High Flexibility scenarios), suggesting a very high system value of energy storage in supporting the integration of relatively inexpensive variable renewable generation (i.e. wind and solar PV). Similarly, the optimal volume of interconnection was at its upper limit in all Low Flexibility scenarios (10 GW in total) and in High Flexibility scenarios with 25 g/kWh target (25 GW). In High Flexibility scenarios with 100 g/kWh carbon intensity the optimal volume was around 17.5 GW. Moreover, the sensitivity analysis showed that if the volumes of new battery storage and interconnection are not constrained, their cost-optimal deployment increases further to over 70 GW of battery storage and up to 30 GW of interconnection capacity, with more capacity required in more ambitious decarbonisation scenarios.

3. **Marginal system value of nuclear generation varies depending on the level of decarbonisation, system flexibility and the already present nuclear capacity.**
   Gross marginal value of nuclear power was found to vary considerably across scenarios, indicating that in some scenarios the system would benefit from increasing nuclear capacity, while in others it would be more efficient to reduce nuclear capacity. In 100 g/kWh scenarios with Low Flexibility, the marginal value at Low and Medium Nuclear deployment is around £95/MWh, while in the High Nuclear scenario it drops to around £75/MWh; with High Flexibility the marginal value varies in the range of £70-78/MWh. In 25 g/kWh scenarios with Low Flexibility the system value of nuclear is high, around £103-109/MWh, suggesting the system would benefit from additional nuclear capacity; with High Flexibility the marginal value is high (£108/MWh) in the Low Nuclear scenario, but much lower in Medium and High Nuclear scenarios (£62-72/MWh).

4. **The cost-efficient volume of nuclear increases when moving towards more ambitious carbon reduction targets.**
   If the future system is characterised by a high level of flexibility, the cost-optimal volume of nuclear may be very small under moderately ambitious carbon targets (100 g/kWh) in the medium term. This volume, however, becomes more significant (around 9 GW) with more ambitious carbon targets (25 g/kWh). The cost-optimal volume of nuclear in 25 g/kWh scenarios was found to be relatively robust to sensitivities on relaxed storage and interconnection capacity as well as reduced RES cost. This could justify maintaining

some nuclear capacity to support the transition from 100 g/kWh towards 25 g/kWh and beyond.

5. **Future developments, which are still uncertain, may affect the optimal volume of nuclear: if alternative providers of inertia emerge, the optimal volume of nuclear could reduce even as we approach ambitious carbon targets (25 g/kWh), while on the other hand coordinated de-loading of nuclear could reduce system cost and hence make nuclear more attractive.**
   Relaxing the assumption that other technologies such as wind cannot provide sources of inertia – as well as the assumption that market arrangements are not reformed to incentivise or require its provision – could see the optimal volume of nuclear reduced in a very flexible system. This suggests that the finding of a need to maintain significant nuclear capacity in the system despite its higher cost can be at least partly attributed to nuclear's ability to provide inertia in a low-carbon system. There are, however, numerous uncertainties that increase when looking further into the future, including the possibility of provision of inertia from alternative providers and the associated cost implications and technical challenges. On the other hand, new operational approaches such as coordinated de-loading of nuclear generation in order to reduce the largest credible infeed loss could make nuclear relatively more attractive compared to other low-carbon technologies. Further research is needed to better understand the implications of both synthetic inertia as well as nuclear de-loading. It may therefore be beneficial to preserve optionality by holding off further nuclear procurement until generation technical capabilities as well as technology costs and economics of flexible options become more certain.

6. **In a system with low flexibility level it may become necessary to build significant CCS capacity to meet the carbon emission target.**
   In a scenario with low nuclear capacity and low system flexibility it may be cost-efficient to add significant amount of CCS capacity to the low-carbon generation mix alongside nuclear, PV and wind. The cost-optimal capacity of CCS may even exceed 30 GW in 25 g/kWh scenarios with low flexibility.

# Appendix A: Description of Whole-electricity System Investment Model (WeSIM)

In this Appendix we describe the modelling approach used to assess the marginal value of baseload low-carbon generation and determine cost-optimal portfolios of low-carbon technologies required to meet a given carbon emission target. We highlight the key capabilities of our modelling framework that enables a holistic economic assessment of low-carbon electricity systems that include flexible balancing technologies. This framework makes optimal operation and investment decisions aimed at minimising the total system cost, by trading off short-term operating decisions against those related to long-term investment into new generation, transmission and distribution networks or storage capacity.

We first highlight the necessity to adopt a whole-systems approach when assessing the value of flexible balancing technologies in future low-carbon electricity systems, and describe Imperial's *Whole-electricity System Investment Model* (WeSIM), which is specifically designed to perform this type of analysis. We also present our approach to estimating the distribution reinforcement cost at the national scale, using the concept of statistically representative networks. The description of our modelling approach concludes with the overview of flexible demand technologies considered in studying the impact of demand-side response. This involves a number of different demand technologies, each of which is studied in detail using dedicated bottom-up models that enable us to quantify the flexibility potentially provided by these technologies, while maintaining the level and quality of service provided to end consumers.

Our approach to quantifying the value of flexible balancing technologies considers total system cost (including both investment and operation) for a given generation and demand scenario, and compares the case when the model is allowed to add new capacity of alternative balancing technologies (such as interconnection, flexible generation, storage or DSR) in a cost-optimal manner, with the case where no such addition is allowed in the system. The reduction in total system cost as a result of deploying flexible balancing technologies is interpreted as the value generated by these technologies, which also takes into account the investment needed to build the new capacity of flexible technologies.

## A.1. Whole-system modelling of electricity sector

When considering system benefits of enabling technologies such as storage, Demand-Side Response (DSR), interconnection and flexible generation, it is important to consider two key aspects:

- **Different time horizons**: from long-term investment-related time horizon to real-time balancing on a second-by-second scale (Figure A.1); this is important as the alternative balancing technologies can both contribute to savings in generation and network investment as well as increasing the efficiency of system operation.

- **Different assets in the electricity system**: generation assets (from large-scale to distributed small-scale), transmission network (national and interconnections), and local distribution network operating at various voltage levels. This is important as alternative balancing technologies may be placed at different locations in the system and at different scales. For example, bulk storage is normally connected to the national transmission network, while highly distributed technologies may be connected to local low-voltage distribution networks.

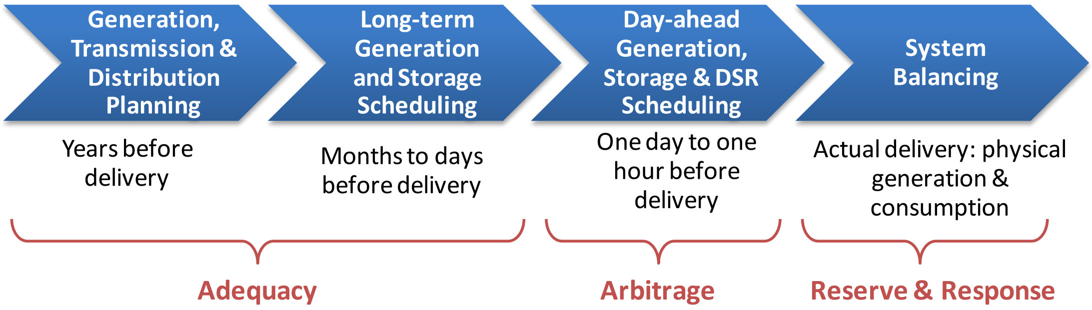


**Figure A.1. Balancing electricity supply and demand across different time horizons**

Capturing the interactions across different time scales and across different asset types is essential for the analysis of future low-carbon electricity systems that includes alternative balancing technologies such as storage and demand side response. Clearly, applications of those technologies may improve not only the economics of real time system operation, but they can also reduce the investment into generation and network capacity in the long-run.

In order to capture these effects and in particular trade-offs between different flexible technologies, it is critical that they are all modelled in a single integrated modelling framework. In order to meet this requirement we have developed *WeSIM*, a comprehensive system analysis model that is able to simultaneously balance long-term investment decisions against short-term operation decisions, across generation, transmission and distribution systems, in an integrated fashion.

This holistic model provides optimal decisions for investing into generation, network and/or storage capacity (both in terms of volume and location), in order to satisfy the real-time supply-demand balance in an economically optimal way, while at the same time ensuring efficient levels of security of supply. The WeSIM has been extensively tested in previous projects studying the interconnected electricity systems of the UK and the rest of Europe.[35] An advantage of WeSIM over most traditional models is that it is able to simultaneously consider system operation decisions and capacity additions to the system, with the ability to quantify trade-offs of using alternative mitigation measures, such as DSR and storage, for real-time balancing and transmission and distribution network and/or generation reinforcement management. For example, the model captures potential conflicts and synergies between different applications of distributed storage in supporting intermittency management at the national level and reducing necessary reinforcements in the local distribution network.

## A.2. WeSIM problem formulation

WeSIM carries out an integrated optimisation of electricity system investment and operation and considers two different time horizons: (i) short-term operation with a typical resolution of one hour or half an hour (while also taking into account frequency regulation requirements), which is coupled with (ii) long-term investment i.e. planning decisions with the time horizon of typically one year (the time horizons can be adjusted if needed). All annual investment decisions and 8,760 hourly operation decisions are determined simultaneously in order to achieve

[35] WeSIM model, in various forms, has been used in a number of recent European projects to quantify the system infrastructure requirements and operation cost of integrating large amounts of renewable electricity in Europe. The projects include: (i) “Roadmap 2050: A Practical Guide to a Prosperous, Low Carbon Europe” and (ii)“Power Perspective 2030: On the Road to a Decarbonised Power Sector”, both funded by European Climate Foundation (ECF); (iii) “The revision of the Trans-European Energy Network Policy (TEN-E)” funded by the European Commission; and (iv) “Infrastructure Roadmap for Energy Networks in Europe (IRENE-40)” funded by the European Commission within the FP7 programme.

an overall optimality of the solution. An overview of the WeSIM model structure is given in Figure A.2.

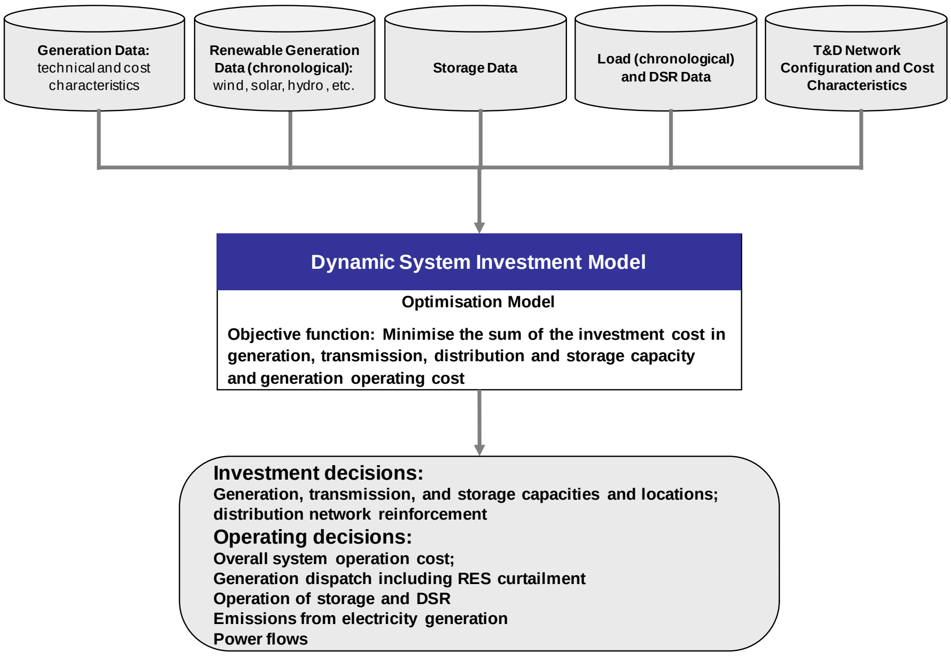


**Figure A.2. Structure of the Whole-electricity System Investment Model (WeSIM)**

The objective function of WeSIM is to minimise the overall system cost, which consists of investment and operating cost:

- The investment cost includes (annualised) capital cost of new generating and storage units, capital cost of new interconnection capacity, and the reinforcement cost of transmission and distribution networks. In the case of storage, the capital cost can also include the capital cost of storage energy capacity, which determines the amount of energy that can be stored in the storage. Various types of investment costs are annualised by using the appropriate Weighted-Average Cost of Capital (WACC) and the estimated economic life of the asset. Both of these parameters are provided as inputs to the model, and their values can vary significantly between different technologies.

- System operating cost consists of the annual generation operating cost and the cost of energy not served (load-shedding). Generation operating cost consists of: (i) variable cost which is a function of electricity output, (ii) no-load cost (driven by efficiency), and (iii) start-up cost. Generation operating cost is determined by two input parameters: fuel prices and carbon prices (for technologies which are carbon emitters).

There are a number of equality and inequality constraints that need to be respected by the model while minimising the overall cost. These include:

- *Power balance constraints*, which ensure that supply and demand are balanced at all times.

- *Operating reserve constraints* include various forms of fast and slow reserve constraints. The amount of operating reserve requirement is calculated as a function of uncertainty in generation and demand across various time horizons. The model distinguishes between two key types of balancing services: (i) frequency regulation (response), which is delivered in the timeframe of a few seconds to 30 minutes; and (ii) reserves, typically split between spinning and standing reserve, with delivery occurring within the timeframe of tens of minutes to several hours after the request (this is also linked with need to re-establish frequency regulation services following outage of a generating plant). The need for these services is also driven by wind output forecasting errors and this will significantly affect the ability of the system to absorb wind energy. It is expected that the 4 hour ahead[36] forecasting error of wind, being at present at about 15% of installed wind capacity, may reduce to 10% post-2020 and then further to less than 6%, may have a material impact of the value of flexibility options. Calculation of reserve and response requirements for a given level of variable renewable generation is carried out exogenously and provided as an input into the model. WeSIM then schedules the optimal provision of reserve and response services, taking into account the capabilities and costs of potential providers of these services (response slopes, efficiency losses of part loaded plant etc.) and finding the optimal trade-off between the cost of generating electricity to supply a given demand profile, and the cost of procuring sufficient levels of reserve and response (this also includes alternative balancing technologies such as storage and DSR as appropriate).

In order to take into account the impact of having less inertia during low demand and high renewable output conditions, the WeSIM's formulation has been enhanced by including additional constraints that dictate the minimum response requirements to meet the RoCOF specification, the minimum frequency at the nadir point, and the steady state frequency deviation from the nominal frequency as illustrated in Figure A.3.

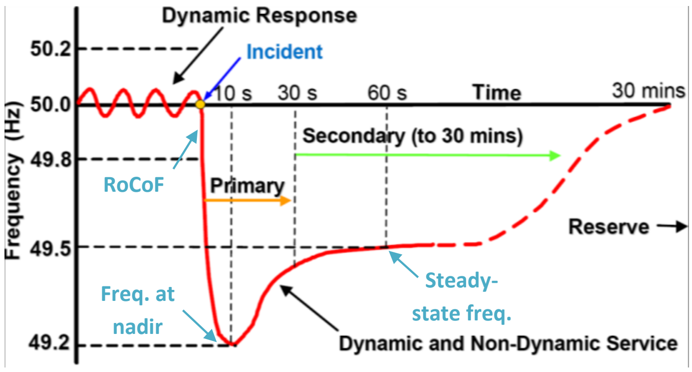


**Figure A.3. System frequency evolution after a contingency (source: National Grid)**

In WeSIM, frequency response can be provided by:

- Synchronised part-loaded generating units.
- Interruptible charging of electric vehicles.
- A proportion of wind power being curtailed.
- A proportion of electricity storage when charging
- Smart refrigeration.

While reserve services can be provided by:

- Synchronised generators
- Wind power or solar power being curtailed
- Stand-by fast generating units (OCGT)
- Electricity storage

36 4 hours is generally the maximum time needed to synchronize a large CCGT plant.

- I&C flexible demand
- Interruptible heat storage when charging

The amount of spinning and standing reserve and response is optimized ex-ante to minimise the expected cost of providing these services, and we use our advanced stochastic generation scheduling models to calibrate the amount of reserve and response scheduled in WeSIM.[37,38] These models find the cost-optimal levels of reserve and response by performing a probabilistic simulation of the actual utilisation of these services. Stochastic scheduling is particularly important when allocating storage resources between energy arbitrage and reserve as this may vary dynamically depending on the system conditions.

- *Generator operating constraints* include: (i) Minimum Stable Generation (MSG) and maximum output constraints; (ii) ramp-up and ramp-down constraints; (ii) minimum up and down time constraints; and (iv) available frequency response and reserve constraints. In order to keep the size of the problem manageable, we group generators according to technologies, and assume a generic size of a thermal unit of 500 MW (the model can however commit response services to deal with larger losses, e.g. 1,800 MW as used in the model). The model captures the fact that the provision of frequency response is more demanding than providing operating reserve. Only a proportion of the headroom created by part-loaded operation, as indicated in Figure A.4.

- Given that the functional relationship between the available response and the reduced generation output has a slope with an absolute value considerably lower than 1, the maximum amount of frequency regulation that a generator can provide ($R_{max}$) is generally lower than the headroom created from part-loaded operation ($P_{max}$ – $MSG$).

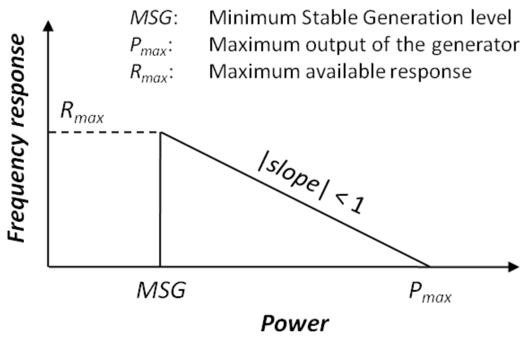


**Figure A.4. Provision of frequency regulation from conventional generation**

- *Generation:* WeSIM optimises the investment in new generation capacity while considering the generators' operation costs and $CO_2$ emission constraints, and maintaining the required levels of security of supply. WeSIM optimises both the quantity and the location of new generation capacity as a part of the overall cost minimisation. If required, the model can limit the investment in particular generation technologies at given locations.

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[37] A. Sturt, G. Strbac, "Efficient Stochastic Scheduling for Simulation of Wind-Integrated Power Systems", *IEEE Transactions on Power Systems*, Vol: 27, pp. 323-334, Feb 2012.

[38] A. Sturt, G. Strbac, "Value of stochastic reserve policies in low-carbon power systems", *Proceedings of the Institution of Mechanical Engineers: Part O-Journal of Risk and Reliability*, Vol: 226, pp. 51-64, Feb 2012.

- *Annual load factor constraints* can be used to limit the utilisation level of thermal generating units, e.g. to account for the effect of planned annual maintenance on plant utilisation.

- For *wind, solar, marine, and hydro run-of-river* generators, the maximum electricity production is limited by the available energy profile, which is specified as part of the input data. The model will maximise the utilisation of these units (given zero or low marginal cost). In certain conditions when there is oversupply of electricity in the system or reserve/response requirements limit the amount of renewable generation that can be accommodated, it might become necessary to curtail their electricity output in order to balance the system, and the model accounts for this.

- For *hydro generators with reservoirs and pumped-storage units*, the electricity production is limited not only by their maximum power output, but also by the energy available in the reservoir at a particular time (while optimising the operation of storage). The amount of energy in the reservoir at any given time is limited by the size of the reservoir. It is also possible to apply minimum energy constraints in WeSIM to ensure that a minimum amount of energy is maintained in the reservoir, for example to ensure the stability of the plant. For storage technologies, WeSIM takes into account efficiency losses.

- *Demand-side response constraints* include constraints for various specific types of loads. WeSIM broadly distinguishes between the following electricity demand categories: (i) weather-independent demand, such as lighting and industrial demand, (ii) heat-driven electricity demand (space heating / cooling and hot water), (iii) demand for charging electric vehicles, and (iv) smart appliances' demand. Different demand categories are associated with different levels of flexibility. Losses due to temporal shifting of demand are modelled as appropriate. Flexibility parameters associated with various forms of DSR are obtained using detailed bottom-up modelling of different types of flexible demand, as described in the "Demand modelling" section.

- *Power flow constraints* limit the energy flowing through the lines between the areas in the system, respecting the installed capacity of network as the upper bound (WeSIM can handle different flow constraints in each flow direction). The model can also invest in enhancing network capacity if this is cost efficient. Expanding transmission and interconnection capacity is generally found to be vital for facilitating efficient integration of large amounts of variable renewable resources, given their location. Interconnectors provide access to renewable energy and improve the diversity of demand and renewable output on both sides of the interconnector, thus reducing the short-term reserve requirement. Interconnection also allows for sharing of reserves, which reduces the long-term capacity requirements.

- *Distribution network constraints* are devised to determine the level of distribution network reinforcement cost, as informed by detailed modelling of representative UK networks. WeSIM can model different types of distribution networks, e.g. urban, rural, etc. with their respective reinforcement cost (more details on the modelling of distribution networks are provided in the section "Distribution network investment modelling").

- *Emission constraints* limit the amount of carbon emissions within one year. Depending on the severity of these constraints, they will have an effect of reducing the electricity production of plants with high emission factors such as oil or coal-fired power plants. Emission constraints may also result in additional investment into low-carbon technologies such as renewables (wind and PV), nuclear or CCS in order to meet the constraints.

- *Security constraints* ensure that there is sufficient generating capacity in the system to supply the demand with a given level of security.[39] If there is storage in the system, WeSIM may make use its capacity for security purposes if it can contribute to reducing peak demand, given the energy constraints.

  WeSIM allows for the security-related benefits of interconnection to be adequately quantified.[40] Conversely, it is possible to specify in WeSIM that no contribution to security is allowed from other regions, which will clearly increase the system cost, but will also provide an estimate of the value of allowing the interconnection to be used for sharing security between regions.

Specific constraints implemented in WeSIM for the purpose of studying balancing technologies are:

- UK is *self-sufficient* in terms of capacity, i.e. there is no contribution from other regions to the capacity margin in the UK and vice versa. However, sensitivity studies are carried out to understand the impact of relaxing the self-sufficient constraint on the cost of making the system secure and the value of alternative balancing technologies in supporting the system.

- UK is *energy-neutral*. This means that the net annual energy import / export is zero. This allows UK to import power from and export to Europe / Ireland as long as the annual net balance is zero. In other words, the UK is still able to export power when there is excess in energy available, for example when high wind conditions coincide with low demand, and import energy from Europe when economically efficient e.g. during low-wind conditions in UK. Imposing energy neutrality also ensures that any system-level carbon constraints are meaningful, given that it implies carbon neutrality of energy imports versus exports.

## A.3. System topology

The configuration of the interconnected GB electricity system used in this study is presented in Figure A.5. Given that the GB transmission network is characterised by North-South power flows, it was considered appropriate to represent the GB system using the four key regions and their boundaries, while considering London as a separate zone.

The two neighbouring systems, Ireland and Continental Europe (CE), are considered (CE is an equivalent representation of the entire interconnected European system). Several generation and demand backgrounds in CE and Ireland are considered (for example, WeSIM optimises the operation of the entire European system, including seasonal optimisation hydro in Scandinavia, pump storage schemes across CE and DSR across CE).

Lengths of the network in Figure A.5 do not reflect the actual physical distances between different areas, but rather the equivalent distances which are chosen to reflect the additional investment associated with local connection and reinforcements. Network capacities indicated in the figure refer to capacities expected to be in place by 2020.

[39] Historical level of security supply are achieved by setting VOLL at around 10,000£/MWh.
[40] M. Castro, D. Pudjianto, P. Djapic, G. Strbac, "Reliability-driven transmission investment in systems with wind generation", *IET Generation Transmission & Distribution*, Vol: 5, pp. 850-859, Aug 2011.

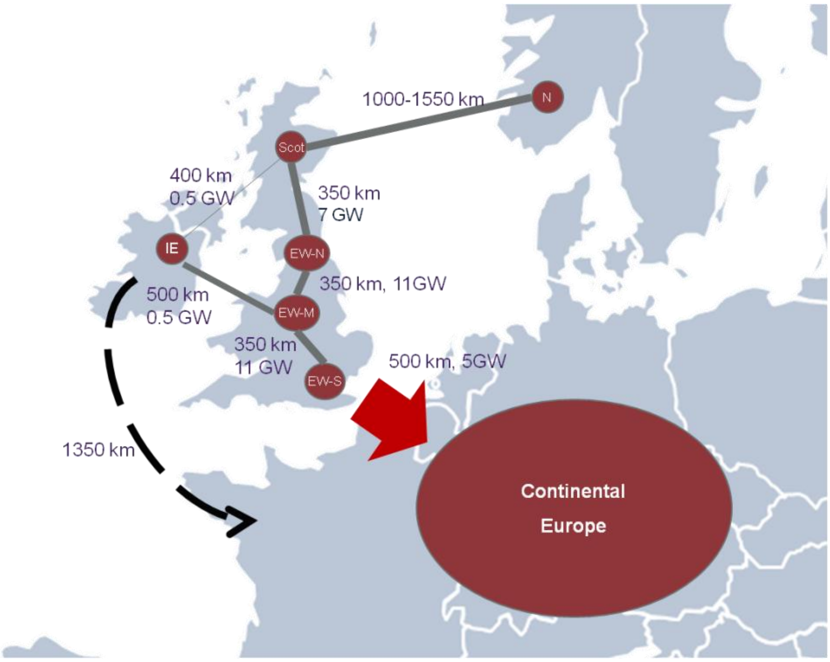


**Figure A.5. System topology used for studying the value of flexible balancing technologies**

## A.4. Distribution network investment modelling

In line with the general modelling approach, Great Britain (GB) is split into five regions for the purpose of evaluating the distribution network investment in various scenarios: Scotland, North England and Wales, Midlands, London, and South England and Wales. The total GB distribution network reinforcement cost, which is a component of the overall system cost, is obtained as the sum of reinforcement costs in individual regions. Regional loading of an entire region is split into ten *representative networks* according to the characteristics of different network types. Reinforcement cost of each representative network is estimated as a function of peak demand, and this information is provided as input into WeSIM to perform an overall system cost assessment.

Examples of different consumer patterns / layouts that can be created by specifying the desired layout parameters[41] are shown in Figure A.6 for different urban, rural and intermediate layouts. Parameters of representative networks are calibrated against the actual GB distribution systems.[42] [43]

[41] J.P. Green, S.A. Smith, G. Strbac, "Evaluation of electricity distribution system design strategies", *IEE Proceedings-Generation, Transmission and Distribution*, Vol: 146, pp. 53-60, Jan 1999.

[42] C.K. Gan, N. Silva, D. Pudjianto, G. Strbac, R. Ferris, I. Foster, M. Aten, "Evaluation of alternative distribution network design strategies", 20th International Conference on Electricity Distribution (CIRED), 8-11 June 2009, Prague, Czech Republic.

[43] ENA and Imperial College, "Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks", April 2010.

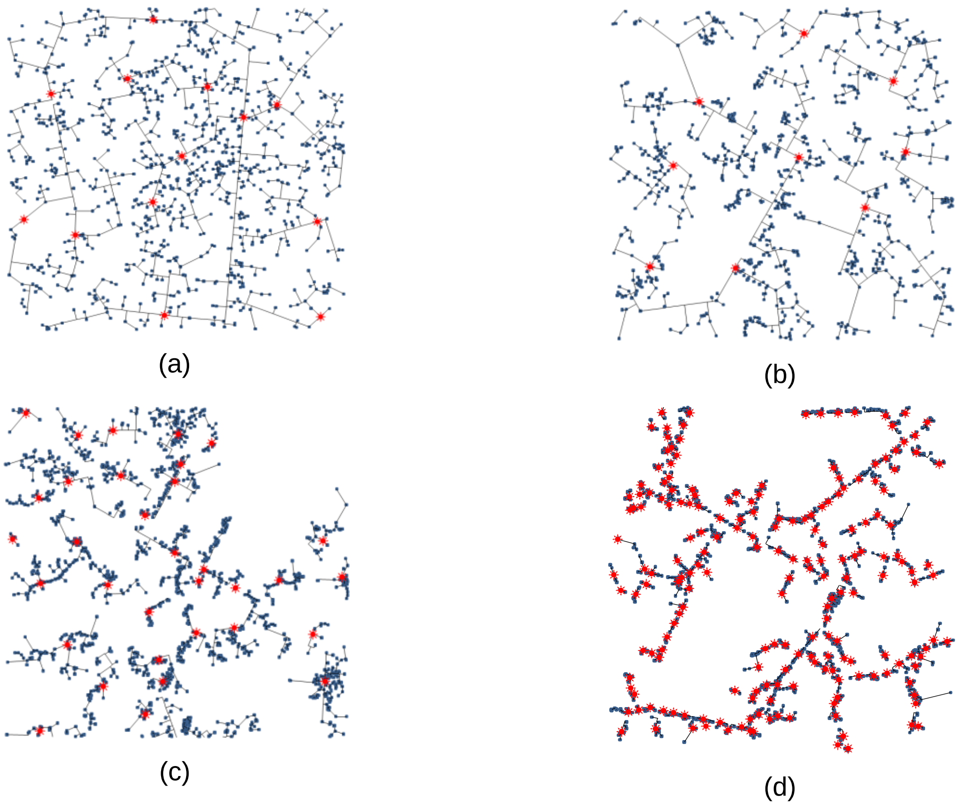


**Figure A.6. Examples of generated consumer layouts: a) urban area; b) semi-urban area; c) semi-rural area; and d) rural area. (Blue dots represent consumers, while red stars represent distribution substations.)**

Many statistically similar consumer layouts can be generated with this approach and the corresponding distribution networks will have statistically similar characteristics. Any conclusions reached are then applicable to areas with similar characteristics. Based on the geographical representation of GB in this study through the five regions, and the allocation of different DNO areas to these regions, we first determine the actual number of connected consumers, length of LV overhead and underground network and the number of pole-mounted and ground-mounted distribution transformers for the GB regions, as shown in Table A.1.

**Table A.1. Regional distribution network parameters**

| Parameter | | Scotland | N England & N Wales | Midlands | London | S England & S Wales | GB |
|---|---|---|---|---|---|---|---|
| Consumers | | 2,996,192 | 7,656,576 | 5,047,743 | 2,311,841 | 11,403,761 | 29,416,113 |
| LV | Overhead (km) | 8,552 | 12,160 | 10,896 | 0 | 33,321 | 64,929 |
| | Underground (km) | 36,192 | 89,863 | 59,570 | 22,556 | 119,428 | 327,609 |
| DT | PMT | 67,823 | 68,388 | 57,706 | 0 | 149,940 | 343,857 |
| | GMT | 26,175 | 50,448 | 35,058 | 17,145 | 101,639 | 230,465 |

Abbreviations: LV = Low Voltage, DT = Distribution Transformers, PMT = Pole-Mounted Transformer, GMT = Ground-Mounted Transformer

Allocation of consumers in each representative network per region is presented in Table A.2. We use ten representative networks in this study, each containing a specific consumer mix that reflects the actual numbers of consumers of different types across regions.

**Table A.2. Number of connected consumers per each representative network per region**

| Representative network | Scotland | N England & N Wales | Midlands | London | S England & S Wales | GB |
|---|---|---|---|---|---|---|
| Rural 1 | 45 | 183,202 | 220,042 | 0 | 830,048 | 1,233,337 |
| Rural 2 | 47,599 | 184,144 | 131,151 | 0 | 535,248 | 898,143 |
| Rural 3 | 353,533 | 154,569 | 110,331 | 0 | 167 | 618,600 |
| Semi-rural 1 | 1,608,899 | 1,302,743 | 1,025,507 | 722,388 | 3,053,402 | 7,712,940 |
| Semi-rural 2 | 395 | 33,503 | 56,452 | 114,368 | 2,036,067 | 2,240,786 |
| Semi-rural 3 | 1,544 | 2,216,451 | 1,334,728 | 2,019 | 884 | 3,555,626 |
| Semi-urban 1 | 898,249 | 3,581,960 | 1,891,938 | 826,475 | 3,194,184 | 10,392,805 |
| Semi-urban 2 | 3,285 | 0 | 277,587 | 143,988 | 56,093 | 480,954 |
| Urban 1 | 6,359 | 0 | 1 | 67,043 | 1,696,171 | 1,769,574 |
| Urban 2 | 76,286 | 1 | 2 | 434,196 | 1,496 | 511,979 |
| **Total** | **2,996,194** | **7,656,574** | **5,047,738** | **2,310,478** | **11,403,759** | **29,414,744** |

We then generate representative networks that are calibrated to match the actual distribution systems. The mismatches in control parameters between the actual and representative networks characterised using this process, are less than 0.1%, as illustrated in Table A.3 (which closely matches the data presented in Table A.1).

**Table A.3. Regional representative networks parameters**

| Parameter | | Scotland | N England & N Wales | Midlands | London | S England & S Wales | GB |
|---|---|---|---|---|---|---|---|
| Consumers | | 2,996,194 | 7,656,574 | 5,047,738 | 2,310,478 | 11,403,759 | 29,416,238 |
| LV | Overhead (km) | 8,552 | 12,160 | 10,896 | 0 | 33,321 | 64,929 |
| | Underground (km) | 36,192 | 89,863 | 59,570 | 22,558 | 119,428 | 327,598 |
| DT | PMT | 67,823 | 68,388 | 57,706 | 0 | 149,940 | 343,857 |
| | GMT | 26,175 | 50,448 | 35,058 | 17,143 | 101,639 | 230,474 |

Abbreviations: LV = Low Voltage, DT = Distribution Transformers, PMT = Pole-Mounted Transformer, GMT = Ground-Mounted Transformer

Designed representative networks satisfy the network design (security) standard ER P2/6.[44] The unit cost data used in our study are based on cost figures approved by Ofgem (2008) used in the recent distribution price control review. Table A.4 shows an excerpt from the list of cost items.

[44] C.K. Gan, P. Mancarella, D. Pudjianto, G. Strbac, "Statistical appraisal of economic design strategies of LV distribution networks", *Electric Power Systems Research*, Vol: 81, pp. 1363-1372, Jul 2011.

**Table A.4. Network equipment cost**

| Asset | Units | Cost (£k) |
|---|---|---|
| LV overhead line | km | 30.0 |
| LV underground cable | km | 98.4 |
| 11/0.4 kV ground mounted transformer | # | 13.2 |
| 11/0.4 kV pole mounted transformer | # | 2.9 |
| HV overhead line | km | 35.0 |
| HV underground cable | km | 82.9 |
| EHV/11 kV ground mounted transformer | # | 377.9 |

## A.5. Demand modelling

It is expected that new electricity demand categories such as electrified heating or transport will play an increasingly important role in decarbonising the electricity sector. We have gained understanding of specific features of these demand sectors, and have developed detailed bottom-up models which enabled us to produce hourly demand profiles based on large databases of transport behaviour and building stock data. This allows us to develop detailed hourly profiles for different demand categories contained in long-term development pathways, which typically only specify annual energy consumption figures.

Understanding the characteristics of flexible demand and quantifying the flexibility they can potentially offer to the system is vital to establishing its economic value.[45] In our analysis we consider various forms of domestic and commercial types of flexible demand.[46,47,48,49,50,51,52,53]

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45 G. Strbac, "Demand side management: Benefits and challenges", *Energy Policy*, Vol: 36, pp. 4419-4426, Dec 2008.

46 M. Aunedi, G. Strbac, "Efficient System Integration of Wind Generation through Smart Charging of Electric Vehicles", *8th International Conference and Exhibition on Ecological Vehicles and Renewable Energies (EVER)*, Monte Carlo, March 2013.

47 ENA, SEDG, Imperial College, "Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks", April 2010. Available at: http://www.energynetworks.org/modx/assets/files/electricity/futures/smart_meters/Smart_Metering_Benerfits_Summary_ENASEDGImperial_100409.pdf.

48 C.K. Gan, M. Aunedi, V. Stanojevic, G. Strbac and D. Openshaw: "Investigation of the Impact of Electrifying Transport and Heat Sectors on the UK Distribution Networks", *21st International Conference on Electricity Distribution (CIRED)*, 6-9 June 2011, Frankfurt, Germany.

49 D. Pudjianto, P. Djapic, M. Aunedi, C. K. Gan, G. Strbac, S. Huang, D. Infield, "Smart control for minimizing distribution network reinforcement cost due to electrification", *Energy Policy*, Vol. 52, pp. 76-84, January 2013.

50 Imperial College London, "Value of Smart Appliances in System Balancing", Part I of Deliverable 4.4 of Smart-A project (No. EIE/06/185//SI2.447477), September 2009.

51 M. Aunedi, P. A. Kountouriotis, J. E. Ortega Calderon, D. Angeli, G. Strbac, "Economic and Environmental Benefits of Dynamic Demand in Providing Frequency Regulation", *IEEE Transactions on Smart Grid*, vol. 4, pp. 2036-2048, December 2013.

52 M. Woolf, T. Ustinova, E. Ortega, H. O'Brien, P. Djapic, G. Strbac, "Distributed generation and demand response services for the smart distribution network", Report A7 for the "Low Carbon London" LCNF project: Imperial College London, 2014.

53 Imperial College and NERA Consulting, 2012, "Understanding the Balancing Challenge", analysis commissioned by DECC to support this publication. Please see https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48553/5767-understanding-the-balancing-challenge.pdf

In order to offer flexibility, controlled devices (or appliances) must have access to some form of storage when rescheduling their operation (e.g. thermal, chemical or mechanical energy, or storage of intermediate products). Load reduction periods are followed or preceded by load recovery, which is a function of the type of interrupted process and the type of storage. This in turn requires bottom-up modelling of each individual demand side technology (appliance) understanding how it performs its actual function, while exploiting the flexibility that may exist without compromising the service that it delivers.

The following assumptions of *full DSR flexibility* are made in system integration cost studies:[54]

- Electric vehicles: up to 80% of EV demand could be shifted away from a given hour to other times of day;

- Heat pumps: heat storage enables that the 35% of HP demand can be shifted from a given hour to other times of day;

- Smart appliances: demand attributed to white appliances (washing machines, dishwashers, tumble dryers) participating in smart operation can be fully shifted away from peak;

- Industrial and commercial demand: 10% of the demand of I&C customers participating in DSR schemes can be redistributed.

- Note that in our analysis any demand shifting only occurs within the timeframe of one day i.e. no demand shifting over longer time horizons was considered.

In addition to improving energy management and potentially reducing capacity adequacy requirements due to lower peak demand, these flexible sources are assumed to also be capable of providing frequency response (maintain grid frequency). It is important to stress that the magnitude of demand (and therefore the absolute volume of demand that can be shifted) in each of the above categories changes in time (it is time-specific).

[54] An overview of the rationale and evidence behind these assumptions is provided in:
M. Aunedi, F. Teng, G. Strbac, "Carbon impact of smart distribution networks", Report D6 for the "Low Carbon London" LCNF project, December 2014.