An analysis of electricity system flexibility for Great Britain

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David Sanders, Alex Hart, Manu Ravishankar and Joshua Brunert from the Carbon Trust wrote this report based on independent research and analysis. It has engaged expert stakeholders and project partners from government, industry and academia for this work. The Carbon Trust's mission is to accelerate the move to a sustainable low carbon economy. It is a world leading expert on carbon reduction and clean technology. As a not-for-dividend group, it advises governments and leading companies around the world, reinvesting profits into its low carbon mission.

Goran Strbac, Marko Aunedi and Danny Pudjianto from Imperial College London conducted dedicated modelling of the UK's electricity system for this report. This team has led the development of novel advanced analytical approaches and methodologies that have been extensively used to inform industry, governments and regulatory bodies about the role and value of new technologies and systems in supporting the cost effective evolution to a smart low carbon future. The Imperial team is grateful for the support obtained from the Engineering and Physical Sciences Research Council through the "Whole Systems Energy Modelling Consortium" and "Energy Storage for Low Carbon Grids" grants, which enabled the fundamental research that led to the development of the methodology applied in this study.

We are grateful for the support of the many experts in industry, government, and academia who agreed to be interviewed for this report.

Contents

Executive Summary

Technologies that provide flexibility will be critical for solving the future challenges of a low carbon electricity system at least cost and lowest risk

The UK electricity system is undergoing significant changes to provide electricity that is secure, affordable and low carbon. To achieve decarbonisation, the electricity system will integrate increasing amounts of variable renewable and inflexible nuclear generation, whilst enabling the electrification of the heat and transport sectors. These changes will increase the need for system flexibility. At the same time traditional sources of flexibility, such as conventional coal and gas generation, will reduce in capacity. Therefore new sources of flexibility will be needed to adequately meet demand and ensure system stability.

The greater variability in electricity supply, due to increased renewable generation, and exacerbated peaks in electrical demand, due to the electrification of heat and transport, will result in reduced utilisation of generation, transmission and distribution assets. This reduction in utilisation increases the capacity required to achieve the same performance, leading to higher system costs. Technology options such as demand side response, energy storage, flexible power generation and electricity interconnectors, can mitigate the negative impacts on asset utilisation.

However, quantifying these benefits is very complex due to uncertainties in how the future energy system will evolve, and the projected cost and availability of different flexibility options. Yet, despite these uncertainties, key investment decisions need to be made in the short-term, which will have a lasting impact on Great Britain's future energy system. This is primarily because generation and network assets have long lead times between the investment decisions and the start of operation, in addition to even longer lifetimes once installed, so choices made now will affect the design and cost of the electricity system for decades ahead.

The need to invest despite uncertainty creates the possibility for regret, where decisions turn out to be suboptimal and have long-lasting negative consequences. A 'least-worst regret' approach is about quantifying the worst possible outcomes for a set of strategic choices, and then identifying the choice with the 'least-worst' outcome. In other words, a 'least-worst regrets' solution finds the safest path that avoids the worst possible outcomes.

Additional flexibility can also provide 'option value', whereby small investments in flexibility can postpone decision-making on larger investments until there is better information, hence reducing the need to make potentially high regret decisions.

This report assesses the benefits of different flexibility solutions for a future UK electricity system. It first uses a systems analysis to determine the optimal deployment of additional flexibility technologies given their uncertain future costs. It further determines the level of deployment of these technologies that avoids the worst possible regret.

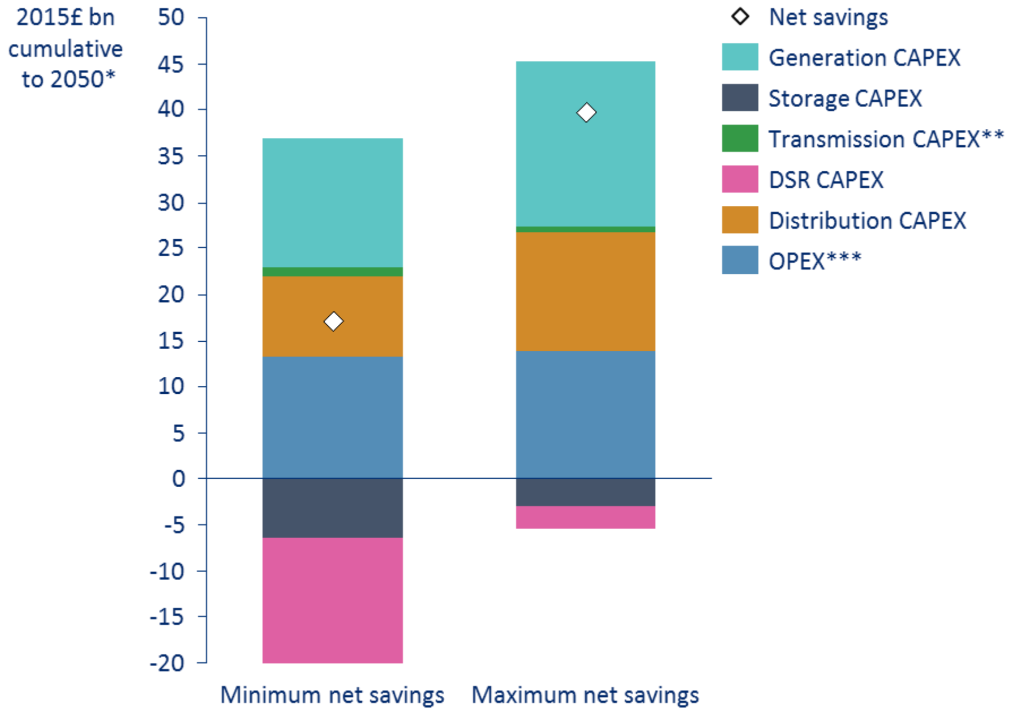
The UK could save £17-40 bn across the electricity system from now to 2050 by deploying flexibility technologies[1]

Flexibility in the energy system, from technologies such as demand side response (DSR), storage and interconnectors, provide three key sources of value:

1. They reduce the capacity of low carbon generation needed to achieve carbon reduction targets by improving the utilisation of intermittent low carbon generation;
2. They enable system balancing at a lower cost by displacing more expensive flexibility options such as peaking plants; and
3. They improve the utilisation of existing conventional generation, and defer investments in transmission and distribution network reinforcement.

As highlighted in Chart 1 below, having sources of flexibility reduces the net cost of the UK energy system to 2050 across a range of scenarios considered in this study. Flexibility enables the UK to meet its carbon targets at lower cost whilst contributing to maintain a robust and stable electricity system. The key sources of flexibility are interconnectors, demand side response (DSR), electricity storage and gas generators, with each playing an important role to 2050.

Chart 1 A breakdown of the minimum and maximum cost differences in scenarios with and without flexibility, cumulative to 2050



*Discounted back to 2015 using HM Treasury's Green Book social discount rate.
**Includes interconnector and onshore transmission CAPEX.
***Refers to variable OPEX (fuel and carbon costs). Fixed OPEX is included in CAPEX figures.

The above range of savings, as well as the ranges of deployment volumes for flexibility technologies discussed later, represent conservative estimates. They are driven by the shares of variable wind and PV deployment, and inflexible nuclear generation, assumed in the scenarios used. Scenarios with

[1] When compared against electricity systems that do not deploy additional flexibility technologies.

higher shares[2] could have been used, which would have led to higher optimal deployments of flexibility technologies, and consequently higher savings from these deployments.

The quantitative benefits of deploying flexibility technologies in this analysis are broadly consistent with the results of other recent studies. To illustrate, this study found that the net benefits of deploying flexibility technologies, inclusive of their costs, are in the range of £1.4-2.4 bn/year in 2030, assuming an electricity carbon emissions intensity target of 100 g/kWh in 2030. For comparison, a recent Committee on Climate Change study[3] found a gross benefit from deploying flexibility technologies of £3-3.8 bn/year in 2030, the additional benefit being largely explained by this being a gross saving, i.e. not including the cost of the additional flexibility technologies deployed. Similarly a report by the National Infrastructure Commission[4] states that gross benefits could range from £2.9-8.1 bn/year in 2030. In this case the difference is largely explained by these again being gross not net benefits and by this analysis assuming an emissions intensity target of 50 g/kWh in 2030 for the high end of the range. These methodological differences explain most of the differences in the results, and given the large uncertainties inherent in this sort of analysis, the studies are all largely in agreement that new sources of flexibility could reduce the cost of the UK energy system by billions of pounds cumulatively by 2030.

[2] The scenarios in this report are based largely on recent BEIS scenarios detailed later in this report. As one example of alternative scenarios, a recent Committee on Climate Change report (see following footnote for reference) has scenarios meeting 100 g CO_2/kWh and 50 g CO_2/kWh by 2030, which have renewable penetrations in 2030 that are 41% and 84% higher respectively. As another example the National Grid report Future Energy Scenarios 2015 contains 4 scenarios, one of which has a renewable penetration in 2030 that is 3% lower, while the other three are 45%, 56% and 80% higher.

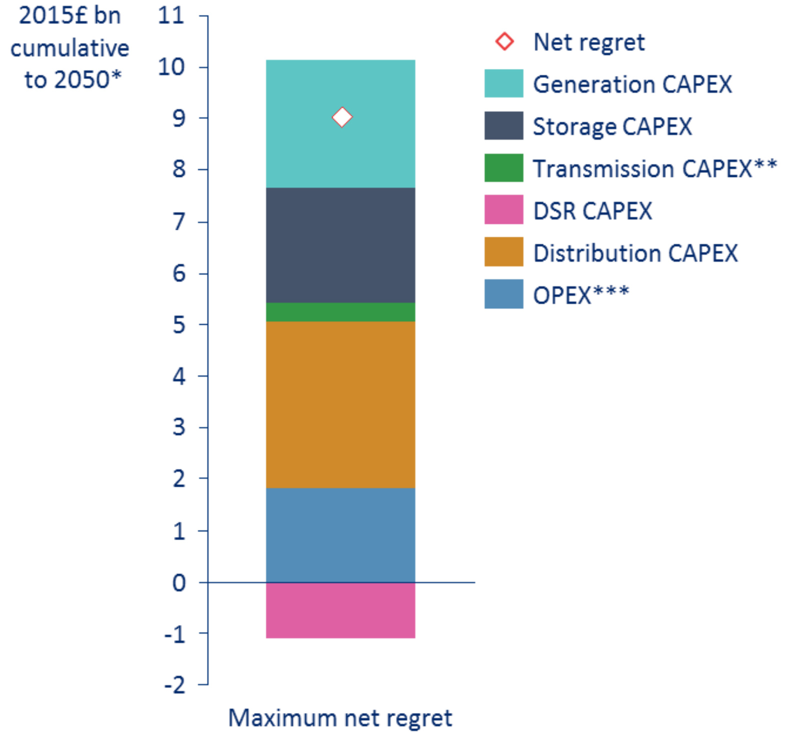
[3] Imperial College and NERA Consulting, *Value of flexibility in a decarbonised grid and system externalities of low-carbon generation technologies*, report for the Committee on Climate Change (CCC), 2015.

[4] National Infrastructure Commission, *Smart Power*, 2016.

Not deploying any additional sources of flexibility ('do nothing') by 2020 is the Pathway that delivers the greatest overall regret for the UK energy system

A pathway where no additional flexibility technologies are deployed by 2020, and deployment between 2020 and 2025 is constrained by this slow start, leads to the highest regret of all the pathways considered in this analysis. The additional cost of the UK electricity system due to this 'do nothing' pathway could reach £9 bn by 2050, as shown by Chart 2 below.

Chart 2 A breakdown of the maximum additional cost ('regret') caused by a 'do nothing' pathway across all the core scenarios, cumulative to 2050



*Discounted back to 2015 using HM Treasury's Green Book social discount rate.
**Includes interconnector and onshore transmission CAPEX.
***Refers to variable OPEX (fuel and carbon costs). Fixed OPEX is included in CAPEX figures.

This highest regret occurs in scenarios where there is high demand across the system, both DSR and storage see large cost reductions by 2025, and the pipeline of scheduled interconnector deployment[5] is delayed. The very low deployments of flexibility technologies caused by this pathway lead to the highest levels of regret seen across all of the analysis, because of the missed opportunity to reduce the cost of the electricity system. The avoided costs of not deploying DSR and storage are overwhelmed by the extra costs in generation, transmission and distribution.

In scenarios where the level of system demand is low, both DSR and storage fail to significantly reduce their costs from their present day levels by 2025, and all of interconnector pipeline to 2025 is deployed, the regret from this 'do nothing pathway' is much lower. In these scenarios, the very low deployments of flexibility technologies caused by this pathway are not as far below optimal[6] levels,

[5] Ofgem, *Electricity interconnectors*. Available at: https://www.ofgem.gov.uk/electricity/transmission-networks/electricity-interconnectors [last accessed 14 April 2016], and expert input.

[6] Throughout this report 'optimal' is used to mean 'least cost' at the level of the whole electricity system.

and the avoided costs of not deploying DSR, storage and additional interconnectors net off a larger proportion of the extra costs from additional generation CAPEX and OPEX.

This ‘do nothing’ pathway is hypothetical, because there are already policies and market mechanisms in place that will deliver some additional flexibility by 2020. However, the existing capacity and pipeline of DSR and storage is very small when compared to the levels that would be optimal by 2020.

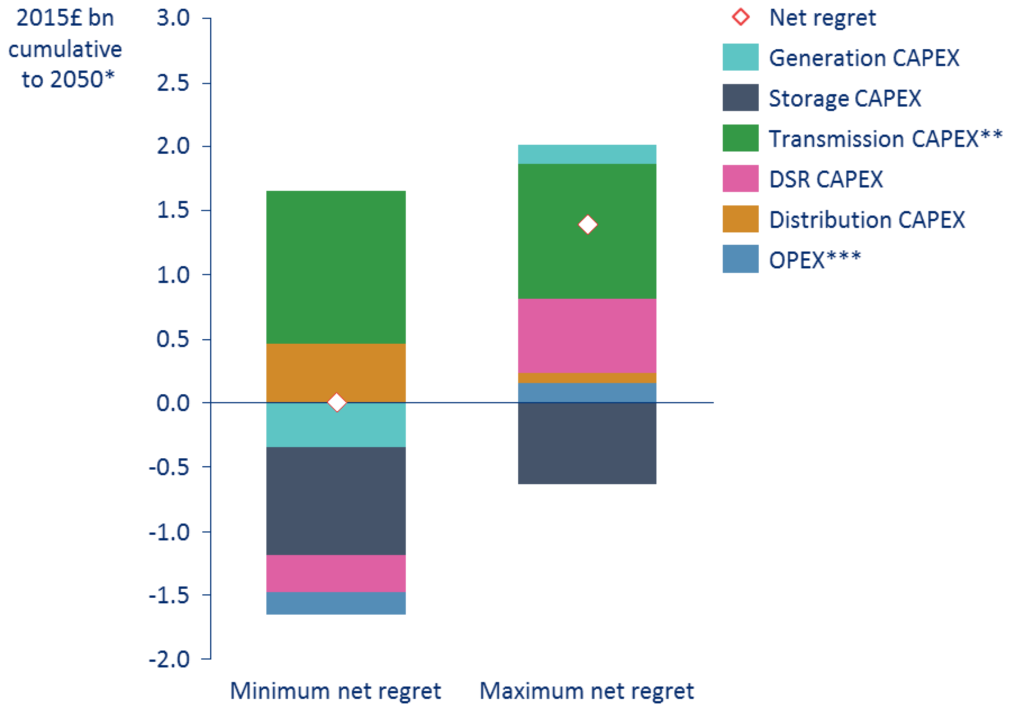
A 'balanced' strategy of deployment across different sources of flexibility is the 'least worst regret' pathway for the UK energy system

Key decisions need to be made soon that will have a lasting impact on the UK's future energy system. This is primarily because energy generation assets and network configurations have long lifetimes, and so choices made about what is deployed imminently will have impacts on the cost of the system for decades. However, greater flexibility in the electricity system provides option value: small investments in flexibility enable room to delay decision making until there is better information, reducing the need to make potentially high regret decisions.

Choosing a 'balanced' deployment pathway, with some deployment of DSR, storage and flexible CCGT by 2020, and deployment of the current interconnector pipeline[7], is the most effective way to avoid worst regret outcomes. A strategy of balanced deployment avoids maximum regret scenarios which can arise when one technology is favoured and it turns out to be the wrong choice.

Chart 3 shows the amount of avoidable cost ('regret') in the best and worst case scenarios for the balanced pathway. This analysis shows that a balanced pathway leads to regrets of £0 – 1.4 bn across all the scenarios analysed (Chart 3), which is the lowest level across all of the different pathways analysed.

Chart 3 A breakdown of the minimum and maximum additional cost ('regret') caused by a balanced pathway across all the core scenarios, cumulative to 2050



*Discounted back to 2015 using HM Treasury's Green Book social discount rate.
**Includes interconnector and onshore transmission CAPEX.
***Refers to variable OPEX (fuel and carbon costs). Fixed OPEX is included in CAPEX figures.

[7] Ofgem, *Electricity interconnectors*. Available at: https://www.ofgem.gov.uk/electricity/transmission-networks/electricity-interconnectors [last accessed 14 April 2016], and expert input.

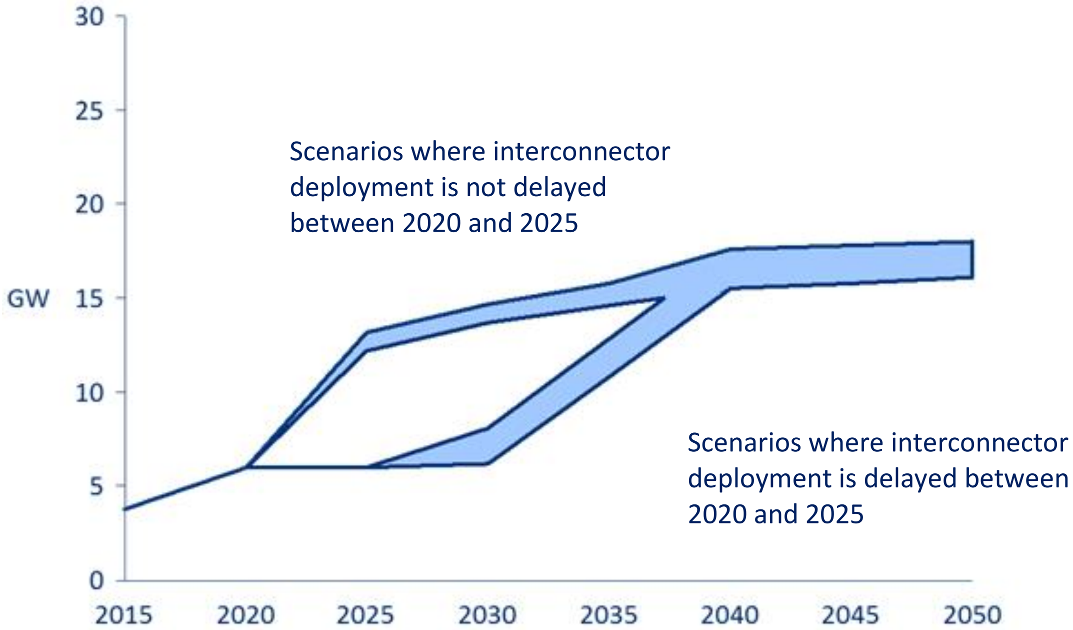
The highest regret for this pathway occurs in a scenario of high DSR cost, low storage costs, full deployment of the current interconnector pipeline and low total system demand. The minimum regret in this Pathway is close to zero and comes from a scenario where DSR cost, storage cost and energy demand are all high. This indicates that a balanced deployment strategy would be close to the optimal in a world where system demand and the costs of flexibility technologies are high.

Interconnectors are a key source of flexibility for the UK, the current capacity pipeline appears to be optimal, and delays to this pipeline would increase costs

Interconnectors are an important source of flexibility in the UK electricity system, particularly in the period from 2020 to 2040. The pipeline[8] out to 2025 of planned interconnector capacity growth appears to be close to optimal[9] across all the scenarios in this analysis, as shown by Chart 4 below. In scenarios where there is a delay to this pipeline between 2020 and 2025, shown by the wedge in the bottom part of the graph, the optimal rate of deployment increases to 'catch-up' from this delay by 2040.

The scenarios where there is a delay to the interconnector pipeline are also more expensive. Other sources of flexibility would be deployed to fill the gap left by the delay. However this analysis shows that this alternative is more expensive, with the overall result of the whole system costing around £1 billion more cumulative to 2050.

Chart 4 Range of optimal deployment of interconnectors to 2050 across the twelve core scenarios*



*Includes 4 GW of legacy interconnector deployment present in 2015. See Appendix for more detail on these scenarios.

[8] Ibid.

[9] This level of deployment is optimal given the modelling assumption of zero annual net energy flows across interconnectors. For more information see 'Complementary analysis – Energy flow across interconnectors'.

DSR has a key role in providing flexibility but also has the greatest uncertainty in terms of cost and uptake

DSR could be a very important provider of flexibility in the UK electricity system, but is also the flexibility technology with the greatest uncertainty in future costs and uptake. There is a significant difference between the maximum technical potential for deployment and realistic levels.

In optimistic scenarios DSR can become one of the cheapest ways to provide flexibility and could grow to very large capacities. Slow deployment in early years could leave the sector forever catching up with what would be an optimal deployment level. As a consequence, the highest regrets around DSR tends to come from pathways where too little is deployed rather than too much.

While other sources of flexibility considered in this study rely mainly on technological breakthroughs or learning effects from deployment to reduce costs, DSR - especially from domestic households - has several non-technical barriers to overcome to be available at scale, and to be so at low cost. Some of the unique cost components of domestic DSR include driving behavioural change in consumers, marketing campaigns for acceptance, contract design, incentive structures to encourage adoption and efficient business processes to manage interactions with large numbers of customers.

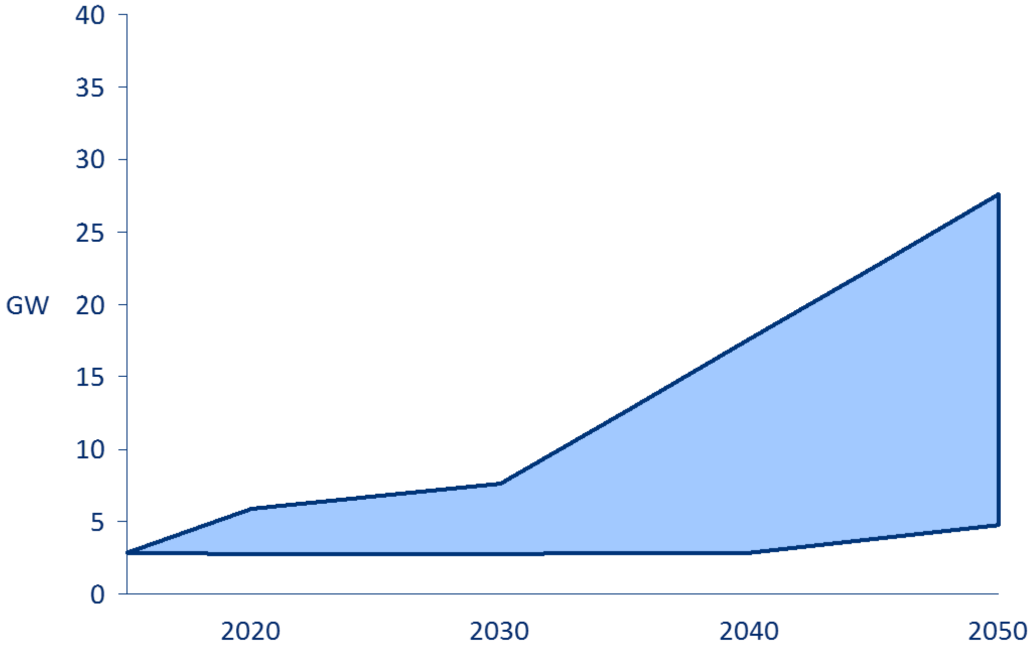
To capture some of the uncertainty in future costs and uptake, assumptions had to be made, which could significantly affect the results. These are detailed in the body of the report and the Appendix.

Energy storage represents a critical ingredient in the future flexibility portfolio, particularly if cost reductions in other flexibility technologies are slow

Although the current costs of energy storage technologies are fairly well known, there is uncertainty in their future cost projections. However, the biggest driver for the deployment of storage is the cost of other flexibility technologies.

The cost-efficient deployment of energy storage greatly depends on the assumed cost of competing flexible options, in particular the cost of DSR. This is illustrated in Chart 5. If DSR does not materialise at a low cost, the optimal mix of flexibility technologies would include 5 to 6 GW of storage capacity by 2020, and between 13 and 28 GW by 2050. With low DSR deployment costs, the efficient deployment of energy storage would be significantly lower, but even those scenarios feature some energy storage.

Chart 5 Range of optimal deployment of energy storage to 2050 across the twelve core scenarios*



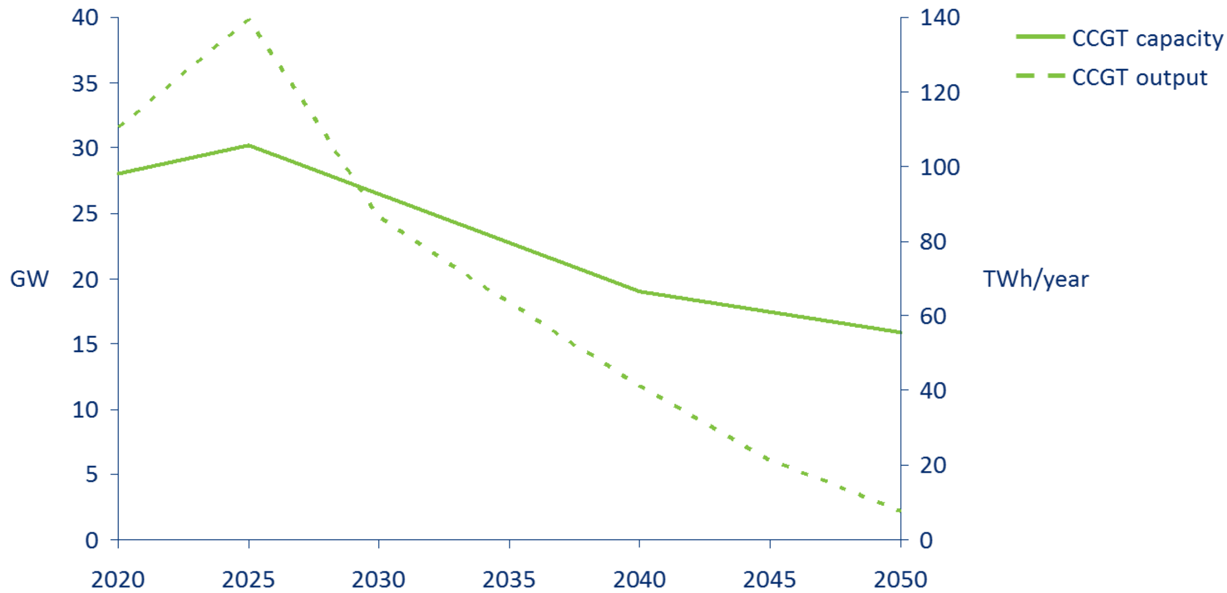
*Includes 2.8 GW of legacy storage capacity present in 2015.

Gas power plants have a long term role in the UK energy system, by providing both flexibility and critical capacity, although with reducing utilisation over time

Across all of the scenarios analysed, conventional combined cycle gas turbines (CCGTs) continue to play an important role in providing flexibility to 2050, irrespective of the cost of DSR and storage, and whether or not there is a delay in the deployment of the interconnector pipeline. This is illustrated for one scenario in Chart 6 below.

Over time the deployment of other sources of flexibility, and steadily tightening targets for carbon intensity of electricity, reduce the output from CCGTs in 2050 to about a tenth of current levels. However the capacity of CCGTs declines much more slowly, reducing by about a third over the same period. This shows that CCGTs will continue to be an important part of the electricity system, albeit with a changing role.

Chart 6 Deployment (GW) and output (TWh/year) of CCGTs to 2050 in a scenario of low demand, low cost of DSR and storage, and no delay to interconnector deployment



Gas peaking plant capacity (a mix of open cycle gas turbines and reciprocating engines) is also increasingly important over time, providing balancing for intermittent renewables and adequacy in case of extreme winters and other rare periods when additional capacity is required.

1 Introduction

Background

The UK electricity system is undergoing significant changes to provide electricity that is secure, affordable and ultimately low carbon. Technology options such as demand response, energy storage, flexible power generation and electricity interconnectors can provide the flexibility required by a future system that may see an increasing share of intermittent renewables and more distributed generation.

This report assesses the benefits of flexibility solutions for a future UK electricity system. It examines potential scenarios the UK could face and the impact they may have in terms of cost to bill payers across these scenarios.

This report is the result of a collaborative project led by the Carbon Trust and Imperial College London, with contributions from interviewees in government, industry and academia. The objective of the project was to strengthen BEIS's understanding of the benefits of flexibility in the GB energy system with the following specific project outcomes:

1. Annual profiles of 'optimal' additional flexibility, by technology, in a core set of scenarios out to 2050;
2. A 'least worst regrets' level of additional flexibility, by technology, across the same set of core scenarios; and
3. Model inputs and understanding to build upon BEIS's own modelling capabilities (e.g. cost trajectories).

This report has benefitted from multiple discussions with all project partners. The results are supported by systems analysis performed by the Carbon Trust, for which the team conducted interviews with UK and international experts from key industries, government stakeholders and academics, as well as dedicated whole electricity system modelling led by Professor Goran Strbac and his team at Imperial College London.

The quantitative analysis is based on data published by the UK's Department of Business, Energy and Industrial Strategy (BEIS) where available, and is complemented by data from widely referenced sources or expert assessments where required. Key assumptions were reviewed by expert steering groups and discussed with senior decision makers in industry and government, as well as with leading research academics, and are provided in the annex of this report. It is nevertheless important to stress that the quantitative results of this report should be interpreted as indicative only – like any other modelling outputs for the UK's future electricity system.

Why do we need to understand flexibility?

Maintaining a resilient, secure and affordable electricity system, as the generation mix and sources of demand change between now and 2050, will pose various challenging investment decisions for the UK. To achieve the UK's decarbonisation targets, the electricity sector will take on its share of mitigation by integrating increasing amounts of intermittent renewable generation, whilst enabling the electrification of the heat and transport sectors through increasing penetration of electric vehicles (EVs) and heat pumps. At the same time traditional sources of flexibility, such as coal-fired generation, will reduce in capacity and new sources of flexibility will be needed to ensure system stability and to adequately meet demand.

Previous analysis by Imperial College for DECC on 'understanding the balancing challenge'[10] highlighted the significant additional investment which will be needed across the electricity system, from generation to network assets, if alternative providers of flexibility are not planned for. Other studies have shown the positive impact of greater flexibility on more cost effectively meeting emission targets and also maintaining security of supply[11].

The modelling for the analysis has shown that the deployment of flexibility technologies could save the UK energy system £17-40 billion cumulative to 2050 against a counterfactual where flexibility technologies are not available (see Chart 1 above). In essence, the successful deployment of flexibility technologies streamlines the electricity system so that there is less need for low carbon generation to meet decarbonisation targets, less need for back-up generation to provide balancing to the grid, and there is better utilisation of the assets that are deployed.

However, understanding flexibility is a complicated task. There are many significant uncertainties including: predictions of the future energy system; the large selection of potential technologies and the many sub-sets within these technologies; cost projections; the different services they provide; technical contingencies surrounding their deployment; and a dynamic between thinking about power versus thinking about energy. For example, taking just one technology area, supercapacitors, lithium ion batteries and flow cells all provide electrical energy storage, but the way they perform, the flexibility services they provide, their capacity to deliver power vs. energy and their cost structures are totally different.

Given that the solutions offering flexibility are vastly different, it is important to better understand the feasibility, scale of provision and also the associated costs and benefits across a range of potential energy futures for these different solutions. As retaining flexibility has a cost as well as an impact on the wider electricity system in terms of the requirement for generation, transmission and distribution of network assets, effective strategic planning to create and retain a portfolio of such solutions offers a significant opportunity to streamline and reduce the costs of the UK's electricity system.

But there is also a significant unpredictability on a strategic level. This amounts to: the timing, extent, pace and geographical distribution of intermittent renewable energy penetration, as well as transport and heat electrification; the uptake of energy efficiency and its impact on demand; fuel prices; and the feasibility, availability and extent of flexibility provided by different solutions.

Yet, even in this context of uncertainty, key decisions need to be made soon that will have a lasting impact on the UK's future energy system. This is primarily because energy generation assets and network configurations have long lifetimes, and so choices made about what is deployed imminently will restrict the options available for decades ahead. What flexibility provides here is option value: small investments in flexibility provide room to postpone decision making until there is better information, hence reducing the need to make potentially high regret decisions. To minimise the possibility of realising high regret decisions, there needs to be the correct infrastructure and policy framework in place for deploying flexibility technologies. The approach of this study centres on a

[10] Imperial College and NERA Consulting, *Understanding the Balancing Challenge*, report for DECC, 2012.

[11] Imperial College and NERA Consulting, *Value of flexibility in a decarbonised grid and system externalities of low-carbon generation technologies*, report for the CCC, 2015.

systems analysis to test the multitude of uncertainties in pursuit of identifying a pathway that avoids the maximum possible regret.

Flexibility technologies – what are they?

As aforementioned, there are a host of potential solutions that can increase flexibility in the system. The analysis in this report focused on the following:

- Demand side response (DSR) of controllable industrial and commercial and consumer loads, through shifting and frequency response, including electric vehicles (EVs) and heat pumps;
- Energy storage technologies, from distributed batteries to large pumped hydro or compressed air systems;
- Interconnectors that can move electricity between countries to reduce demand or supply imbalances; and
- More flexible CCGTs that can operate more dynamically, starting faster, changing output levels faster and turning down further.

System flexibility is also provided by conventional fossil fuelled generation, such as CCGTs, OCGTs, reciprocating engines, coal-fired power plants and others. The modelling for this study includes and values these conventional sources of flexibility, however, the focus of this analysis is on the costs, benefits, risks and uncertainties associated with the new sources of flexibility as outlined above.

It is envisaged that a portfolio of such providers of flexibility will emerge, rather than a single provider, owing to their different stages of development and suitability for different 'types' of flexibility in terms of delivering over a range of time scales and speed of response[12]. As a result, the analysis manipulated the key uncertainties regarding their future costs and deployment, along with different levels of system demand, to generate a wide-ranging sample of scenarios from which the study could investigate how to avoid maximum regret outcomes.

The uncertainties that are particularly relevant for each technology are outlined below, however it is important to be aware that the modelling could only focus on a select sample of these.

There is a large amount of uncertainty and a paucity of data regarding the future costs of DSR. In addition to uncertainty in the cost of distributed smart grid assets this also includes uncertainty in the cost and utilisation of investments in infrastructure, in the transactional costs of managing DSR customers, and in the potential costs of awareness raising and incentivising widespread uptake. The modelling and analysis in this report attempts to incorporate these financial uncertainties, but in addition to the financial uncertainties there are also potentially significant non-financial barriers. These include creating and implementing adequate policy frameworks, as well as the need for a much more mature supply chain than currently exists, both of which could require many years to progress. These non-financial barriers to the uptake of DSR are simply represented in the modelling by upper limits on deployment rates which keep the maximum capacity well below the technical potential (see Appendix).

There is less uncertainty surrounding the current costs of storage technologies, given that numerous types are commercially available today. However, there is ambiguity about future cost projections, which this analysis has tried to capture. Similarly to DSR, additional policies would be required to

[12] Ibid.

accelerate deployment of storage to the levels seen in this analysis, and, once again, it is important to be aware that putting this policy framework in place this could take many years.

The UK already has 4 GW of interconnection to other countries, with much more in the pipeline[13], and therefore the deployment costs of interconnection are better known than for both DSR and storage. As a result, variations in interconnector costs have not been modelled. However interconnectors are large infrastructure projects, with long lead times and significant strategic implications for multiple countries, so delays can be difficult to avoid. Therefore, the risk of delays to the pipeline has been modelled as the key uncertainty for interconnection.

Lastly, the study also gathered information on more flexible CCGTs, which can operate at lower minimum loads, start faster and change output level ('ramp') faster than the existing models used across the UK today. Although many models of more flexible CCGT are in development or coming to market they are not widely commercially available yet so there is a significant uncertainty surrounding their future cost. Although they could be significantly more expensive than existing models, at least initially, the results presented here assumed an optimistic 10% cost increment on existing CCGTs to test whether they would be preferred to other flexibility technologies if this cost can be achieved.

Why use a 'least worst regrets' approach and what does regret mean in this context?

A 'least worst regrets' approach is about modelling a series of worst possible outcomes for different strategic choices, and then identifying which choices have the 'least worst' outcomes. This amounts to minimising the maximum possible regret. Many energy system modelling approaches optimise for the most likely outcome, or calculate an expected value based on the probabilities of various possible outcomes. A 'least worst regrets' approach can complement these approaches, particularly when it is difficult to estimate probabilities, or to predict the most likely outcome, or when the primary concern is avoiding the worst outcome.

The approach used in this report is based on the fact that there are a multitude of uncertainties regarding the UK's future energy system. The optimal mix of flexibility technologies will depend on their relative costs, performance and availability. Projections of these parameters are currently uncertain - highly uncertain in some cases - and yet action needs to be taken now to enable future deployment. Therefore it is important to analyse how to minimise the potential for the worst possible outcome for maintaining a resilient, secure and affordable electricity system.

For example achieving multiple GWs of DSR would require changes to policies, regulations and market structures, which the private sector would need to respond to by changing business models, creating business partnership, making investments and recruiting and developing staff with new skills. These changes would take some time to deliver significant deployment, and the process would need to begin before the optimal deployment level is known.

In addition, some energy infrastructure assets can last for decades before they 'retire' and are removed from the system, and the business case for investing in them is affected by the deployment of flexibility technologies. So investment decisions in energy infrastructure will also need to be taken whilst there is still uncertainty in how much flexibility will be deployed.

[13] Ofgem, *Electricity interconnectors*. Available at: https://www.ofgem.gov.uk/electricity/transmission-networks/electricity-interconnectors [last accessed 14 April 2016], and expert input

This need to make decisions under uncertainty, with time lags between decision and implementation, and long lifetimes between implementation and retirement, leads to the potential for regret. In situations like these a 'least worst regrets' analysis can be used to support decision making, by highlighting pathways that avoid the highest regret outcomes.

Regret in this analysis is defined as the extra cost incurred, as a consequence of a decision, relative to an optimal counterfactual, i.e. when the mix of technologies used to balance the electricity system and meet the electricity needs of Great Britain is more expensive than the cheapest set which could have been used.

2 Method

How do we apply 'least worst regrets' analysis?

For a decision variable to warrant a least-regret analysis, one of following two related conditions needs to hold:

- There is a significant ***temporal lag*** between making the investment decision in an asset and it becoming operational, so that the context and hence the optimal investment could change in the intervening period. For example there may be a need to commit to investments in energy infrastructure with long lead times although the business cases for the investments are affected by factors that will change more quickly

  Or

- The asset being invested in will have long operational life so there is a risk that the investment will become ***stranded*** if the situation changes during its life. For example investing in assets that are only able to operate competitively when energy commodity prices are above or below a certain level, or investing in assets that provide a flexibility service and then seeing the market flooded by cheaper providers of the same service.

For investigating how these two dimensions could affect the UK energy system, the analysis focused on testing the consequences of the most significant uncertainties related to the implementation of flexibility technologies: their cost, time of deployment and system demand. This produced different Pathways that provide insight into what certain decisions could mean for the level of maximum regret under possible future conditions.

The 'least worst regrets' analysis considered the four main flexibility technologies (DSR, storage, more flexible CCGT and interconnection) and created opportunities for regret based on initial deployment levels of each. For DSR, storage and more flexible CCGTs, the analysis assumes that decisions will be taken today, which will commit the UK to certain deployment levels of additional capacity by 2020, with the risk that this will be above or below the optimal level. For interconnectors, because they have longer lead times, it is assumed that decisions will be taken today which will commit the UK to a certain deployment level of additional interconnector capacity by 2025.

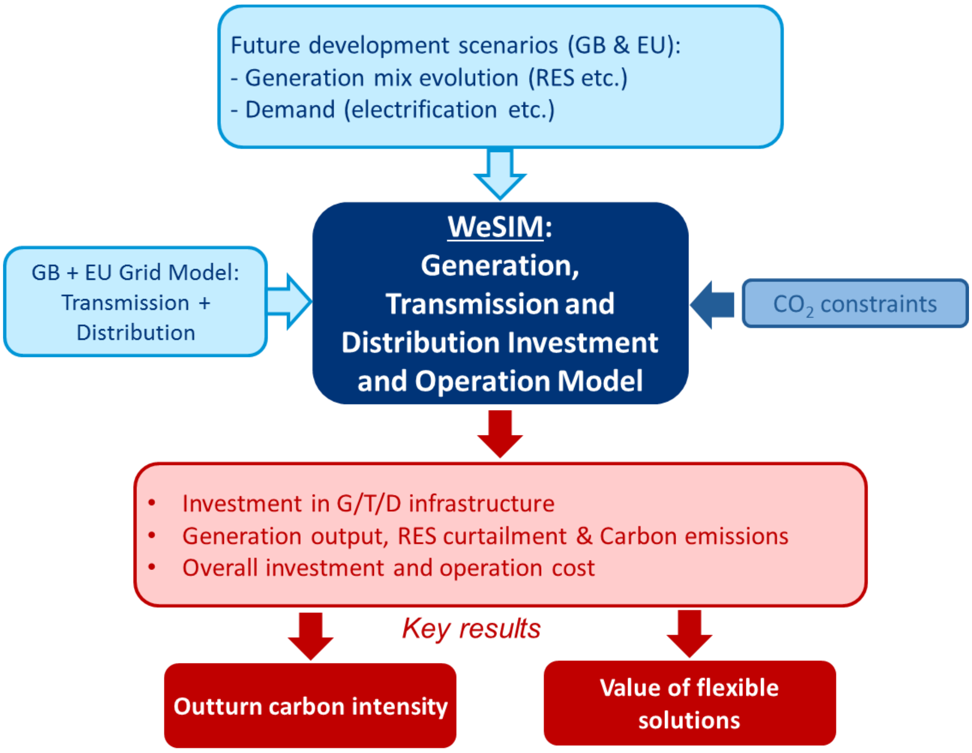
Each opportunity for regret is described as a Pathway. In each Pathway, the initial deployments of flexibility technologies are predetermined, and once installed they remain in the system until they retire, but after the initial period the model is then able to choose its own deployment levels to optimise the system. The cost implications for this divergence from, and later correction to, the optimal deployment are what create the regret value.

To establish optimal deployment scenarios and then subsequently test the Pathways, this study simulated the development of the UK and European energy systems under different scenarios using the Whole-electricity System Investment Model (WeSIM) developed at Imperial College London.

Modelling approach

When considering the benefits of technologies that provide flexibility to the electricity system it is important to be able to simultaneously consider both different time horizons and different scales. WeSIM is able to consider various time horizons from generation transmission and distribution planning years before delivery, to real time system balancing and frequency regulation on a second by second basis. It can also consider various scales of the system from large scale generation and transmission assets to distribution networks at a range of voltages. It then optimises under various constraints to find the least cost design and investment profile for the electricity system over time. See the Appendix for further information on WeSIM and the modelling approach.

Figure 1 Overview of the Imperial College London Whole electricity System Investment Model (WeSIM)



Electricity demand and low carbon generation capacity scenarios

The low and high electricity demand scenarios used in this analysis were derived from BEIS's Energy and Emissions Projections[14] and a series of MARKAL runs called 1A, 1D and 1E[15]. The generation capacities used were taken from BEIS's internal modelling and scaled up/down using the different demand scenarios with some generation optimised using the systems model. For a more detailed discussion of the assumptions and methods of constructing the core scenarios, refer to the Appendix.

[14] DECC, *Updated energy and emissions projections 2015*, 2015.

[15] AEA, *Pathways to 2050 – Detailed Analyses*, report for DECC, 2011.

Core scenarios

BEIS scenarios were used as a baseline for calculating a set of counterfactual scenarios, to explore uncertainty in electricity demand, technology cost and timing of interconnector capacity additions. Within these scenarios the analysis tested permutations of the key uncertainties relating to system demand, technology cost and technology deployment that could lead to regret. This created a set of twelve counterfactual scenarios where flexibility technologies were deployed at an optimal level by WeSIM to help achieve carbon targets[16] at the least cost. Table 1 below shows how the four key uncertainties for flexibility requirements were combined to create 12 core scenarios used throughout the analysis in this report.

Table 1 Summary of the twelve core scenarios and their parameters

Scenario	De	St	Ds	In	System demand	Cost of storage	Cost of DSR	Interconnector deployment
S1	●	●	●	●	Low	Low	Low	Delayed
S2	●	●	●	●	Low	Low	Low	Full
S3	●	●	●	●	Low	Low	High	Full
S4	●	●	●	●	Low	High	Low	Full
S5	●	●	●	●	Low	High	High	Delayed
S6	●	●	●	●	Low	High	High	Full
S7	●	●	●	●	High	Low	Low	Delayed
S8	●	●	●	●	High	Low	Low	Full
S9	●	●	●	●	High	Low	High	Full
S10	●	●	●	●	High	High	Low	Full
S11	●	●	●	●	High	High	High	Delayed
S12	●	●	●	●	High	High	High	Full

The legend on the left of Table 1 above, with the four balls in light or dark blue, and a two-letter abbreviation for each of the parameters, are provided as an *aide memoire* for the design of the scenarios. The same legend is provided under graphs and tables throughout the report to reduce the need to refer back to this table when interpreting the results later. Table 2 below sets out what the light and dark blue ball mean for each parameter.

Table 2 Summary of legend for core scenarios

Parameter	Abbreviation	●	●
System demand	De	Low demand	High demand
Cost of storage	St	Low cost	High cost
Cost of DSR	Ds	Low cost	High cost
Interconnector deployment	In	Delayed deployment	Full deployment

[16] The emission intensity targets used for electricity generation were 100g/kWh in 2030 and 25g/kWh in 2050. See Appendix for further detail.

These twelve core scenarios perform the following functions:

- They provide the basis for the energy system model to calculate an optimal mix of flexibility technologies to deploy;
- These optimal mixes then provide the starting point for the selection of possible pathways for the UK out to 2020/5 that decisions now could lead to; and
- They act as the counterfactual optimal energy system designs to compare against these pathways, therefore enabling a calculation of how much regret each pathway could constitute when compared to the optimal.

The study also completed runs of two additional counterfactual scenarios where no additional flexibility technologies were deployed between 2015 and 2050 to identify the value of flexibility to the UK electricity system under high and low electricity demand conditions (Table 3). As with the twelve core scenarios the 2050 carbon targets still had to be met. The total system costs, cumulative to 2050, of these 2 scenarios were compared against the twelve core scenarios to outline the benefits of deploying flexibility technologies in pursuit of carbon reduction targets, security of supply and the most affordable energy system for the UK.

Table 3 Summary of the scenarios with no deployment of the flexibility technologies in focus and their parameters

Scenario	Carbon constraint	System demand
N1	Yes	Low
N2	Yes	High

Selecting Pathways

The objective for the Pathways used in this analysis is to simulate the potential ramifications of committing to certain deployment profiles of flexibility technologies in the near future. The starting point was to analyse the optimal deployment of the flexibility technologies out to 2020 for DSR, storage and flexible CCGT, and to 2025 for interconnectors, across the twelve core scenarios. This provided a base from which to select Pathways that could reveal the consequences of committing to a deployment profile that is close to optimal for certain scenarios, but far from optimal for others.

The modelling for the least worst regrets analysis can be very time intensive, as the model needs to find the optimal solution in all combinations of the Pathways and the Scenarios. Care is needed in the design and selection of Pathways and only a subset of all the Pathways considered was taken forward for analysis against all twelve of the core scenarios.

First a set of Pathways were designed such that the initial deployment of the technologies was set close to the minimum and maximum range evident across the core scenarios, whilst the other 3 flexibility technologies were not deployed at all. This allowed the Pathways to explore both the effect of different levels of deployment within an optimal range, and the effect of delaying deployment. In addition, a series of 'do nothing' Pathways where designed to explore the consequences of delaying deployment of all four flexibility technologies for different periods of time.

Once the impact of these Pathways was understood more complex Pathways were designed, with deployment constrained to a range rather than a fixed value, and non-zero deployment levels defined for multiple technologies. Finally a subset of all the Pathways modelled, which most clearly demonstrate the results of the analysis, were selected for inclusion in this report. Table 4 below shows the four Pathways chosen for this analysis, with the Appendix containing a fuller set of other Pathways modelled.

Table 4 Summary of the four Pathways and their parameters

Pathway	DSR in 2020	Storage in 2020	Flexible CCGT in 2020	Additional interconnection in 2025[17]
P1a	2-5	-	-	-
P2a	-	1.2-3	-	-
P3a	1-5	0.5-3	1	-
P4a	-	-	-	-

- In **Pathway 1a** the level of DSR deployment in 2020 was set at a minimum of 2 GW and a maximum of 5GW, the deployment of additional storage and more flexible CCGT was set at zero in 2020, and no additional interconnection is installed between 2020 and 2025.
- In **Pathway 2a** the model is forced to deploy storage capacity of between 1.2 GW and 3 GW to 2020, the deployment of additional DSR and more flexible CCGT was set at zero in 2020, and no additional interconnection is installed between 2020 and 2025.
- **Pathway 3a** is a 'balanced pathway' where DSR and storage are allowed to deploy within the set ranges, 1 GW of flexible CCGT is deployed, but no additional interconnection is installed between 2020 and 2025.

[17] Beyond the pipeline of c. 12 GW in the full deployment scenarios, and 6 GW in the delayed deployment scenarios.

- **Pathway 4a** is a 'do nothing' pathway, where the deployment of DSR, storage and more flexible CCGT is set to zero in 2020, growth in the next five years is slow with a more constrained build rate from 2020 to 2025, and no additional interconnection is installed between 2020 and 2025.

Calculating the 'least worst regret' Pathway

As aforesaid, the UK needs to make important decisions about what flexibility technologies to deploy in a climate of uncertainty. These decisions however may not lead to optimal deployment, and therefore could lead to regret. The regret value was calculated by forcing the energy system model to deploy technologies at the committed level until 2020/5, before allowing it to optimise deployment for each scenario, and then assessing the costs of the legacy investments and mitigating actions the energy system model takes in response.

For example, the analysis assumed that DSR deployment to 2020 will be driven by policy decisions made now, that deliver additional DSR deployment of 0 GW, 2-5 GW or 1-5 GW (Table 4 above). After 2020, WeSIM was allowed to 'correct' DSR deployment towards the optimal level. But DSR assets (such as remote sensors, controllers and energy management systems) can last c. ten years once installed, and annual deployment growth is constrained to 1 GW/year to reflect expected constraints in supply chains and shifting consumer attitudes. Consequently, suboptimal DSR deployment will take some years to correct.

The regret for each Pathway-Scenario combination can then be calculated as the difference between the cost of the whole energy system with optimal DSR deployment, and with the DSR deployment to 2020 set by the Pathway. This regret includes the cost of more/less DSR investment, but also the cost of more/less investment in other energy system technologies across generation, transmission, distribution and storage. The scenario with the highest regret determines the 'worst regret' for that Pathway[18].

To judge the 'least worst regret', the analysis identifies the maximum level of regret ('worst regret') across the twelve core Scenarios for each Pathway and then compared these maximum regrets to find the Pathway which has the lowest maximum (or 'least worst') regret. This is graphically demonstrated by the dummy numbers in Table 5 below.

Table 5 Representative summary matrix of a 'least worst regrets' analysis

	S1	S2	S3		Worst regret
P1	0	83	96		96
P2	43	10	100		100
P3	55	78	0		78

Least worst regret	P3	78

[18] There is a worked example in 'Results and discussion' below that outlines this process step-by-step.

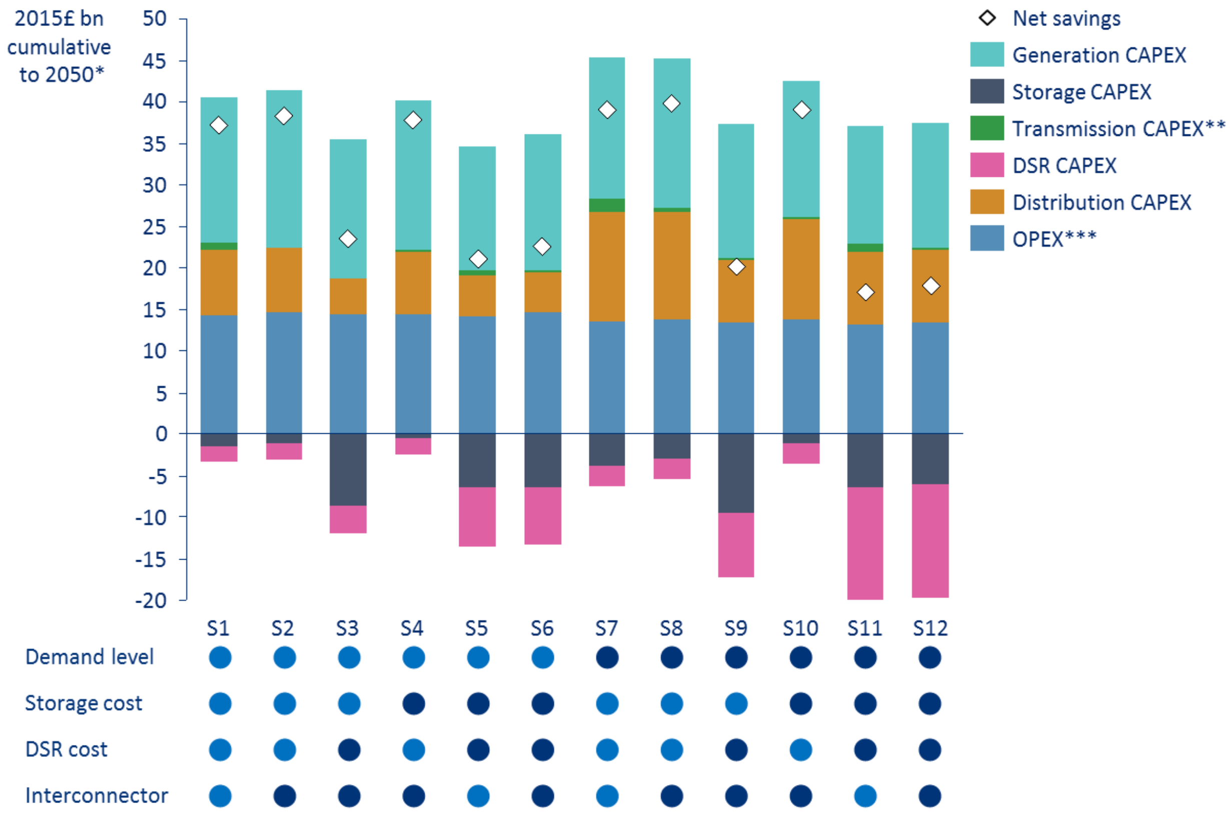
3 Results and discussion

Benefits of flexibility and their impact on other energy system technologies

Deploying flexibility technologies can achieve net savings of £17-40 bn cumulative to 2050 for Great Britain

Across all of the core scenarios, with varying levels of demand, costs of flexibility technologies and interconnector deployment, the total system cost is lower relative to a counterfactual that does not deploy any DSR, storage or additional interconnectors (Chart 7).

Chart 7 Cost differences between the twelve core scenarios and no flexibility scenarios (N1, N2)[19] cumulative to 2050



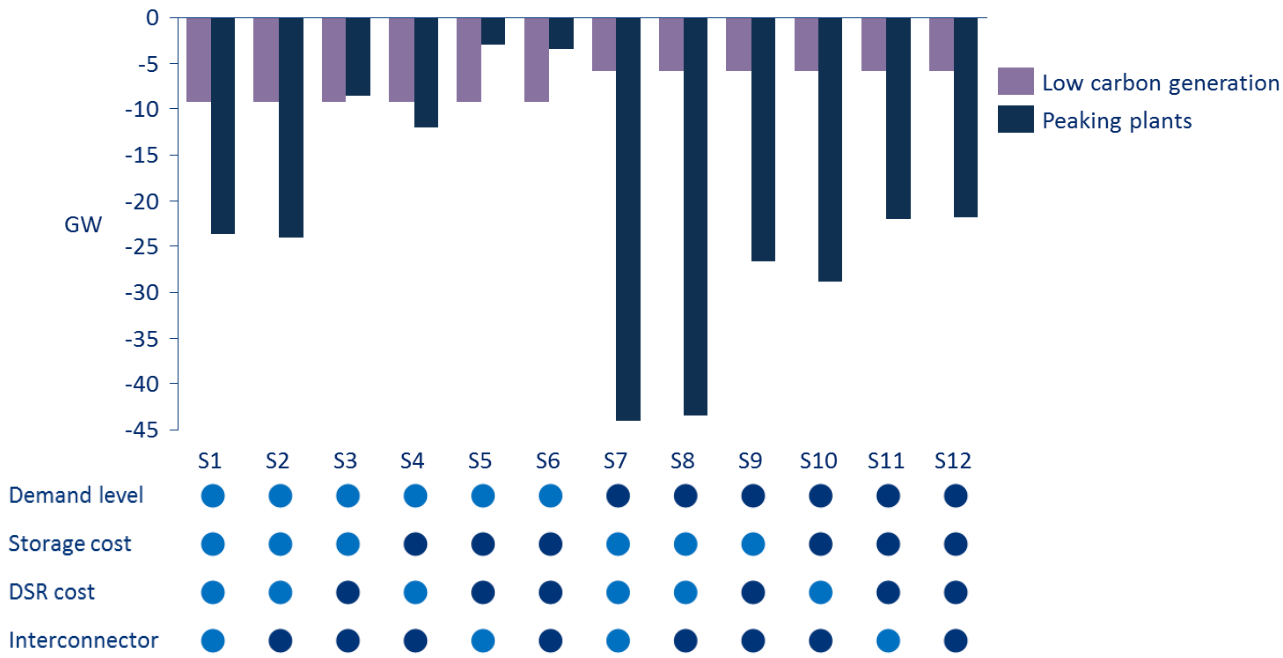
*Discounted back to 2015 using HM Treasury's Green Book social discount rate.
**Includes interconnector and onshore transmission CAPEX.
***Refers to variable OPEX (fuel and carbon costs). Fixed OPEX is included in CAPEX figures.

[19] N1 is used as the counterfactual for the low energy demand scenarios (S1-S6) and N2 for the high energy demand scenarios (S7-S12).

Chart 7 outlines how the costs of deploying storage and DSR (£2-20 bn) are significantly outweighed by the savings from avoided generation CAPEX (£14-19 bn), OPEX (£13-15 bn), distribution CAPEX (£4-13 bn) and transmission CAPEX (£0.04-1.5 bn)[20,21]. These savings represent the avoided investment necessary to meet carbon reduction targets whilst providing security of supply at the most affordable cost, and are explained in detail in the following sections.

A significant driver of these cost savings is that deploying flexibility technologies can result in needing 6-9 GW less low carbon generation to meet carbon targets in 2050, and 3-29 GW less peaking plants to meet peak demand and system stability requirements (Chart 8).

Chart 8 Impact of deploying flexibility technologies on the necessary deployment of low carbon generation* and peaking plants between the twelve core scenarios and no flexibility scenarios (N1, N2) in 2050**



*Gas CCS.
**OCGTs and reciprocating engines.

Flexibility technologies provide multiple services, some of which reduce the need for peaking plants to balance the system, and some of which reduce the need for low carbon generation by increasing the utilisation of intermittent renewable generation. As a result the presence of flexibility technologies has different impacts on the required capacities of peaking plants and low carbon generation.

The benefits of flexibility in reducing investment in peaking plants are most pronounced in S7 and S8 where there is high demand and low cost of flexibility technologies. The converse in S5 and S6 - where there is low demand and high costs of flexibility technologies - is where peaking plant deployment is at its highest.

[20] The ranges for each cost component will not necessarily add up to the range of net savings because they are selected from particular scenarios that may not correspond to the scenarios that represent the range of net savings.

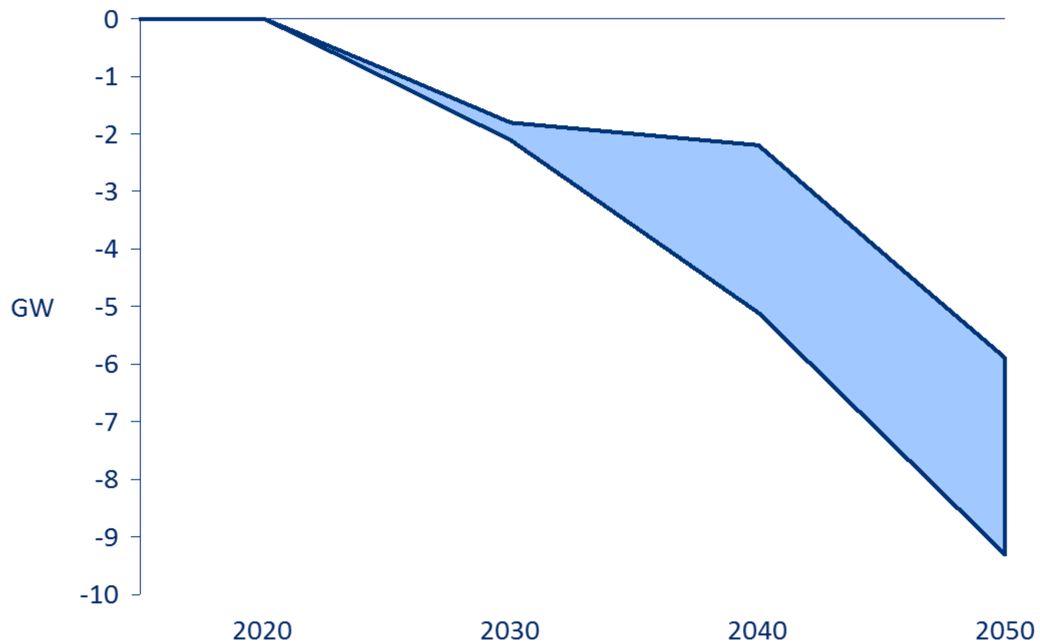
[21] The low demand scenarios (S1-S6) were compared against the low demand no flexibility scenario (N1) and the high demand scenarios (S7-S12) were compared against the high demand no flexibility scenario (N2).

Flexibility enables lower investment to be required in low carbon generation whilst still meeting carbon targets to 2050

A large fraction of the cost savings due to the deployment of flexibility technologies tends to be from reduced CAPEX in generation assets. This is partly driven by requiring less low carbon generation to meet carbon reduction targets. Flexibility is able to improve load factors, reduce curtailment and better match supply and demand across the grid. Greater system flexibility also brings down the total system cost of deploying low carbon generation, such as wind and solar PV, when compared to a system without flexibility technologies. This is because flexibility reduces the total integration cost, wherein there is less need for back-up fossil-fuelled power generation to support intermittent renewables. This enables a lower capacity of low carbon generation to still deliver the required security of supply, adequacy and maintains carbon intensity in line with UK's climate change targets for 2030 and 2050.

In this analysis, the impact of deploying flexibility technologies can result in needing 2 GW less of gas CCS whilst meeting carbon targets in 2030, and 6-9 GW less in 2050 (Chart 9)[22]. The extent of CCS displacement has a small dependence on the costs of DSR and storage, hence there is a small range of reduced low carbon generation amongst the different scenarios. The major divergence between two distinct groupings is driven by the contrast between the low and high demand assumption in the future energy scenario.

Chart 9 Range of impact of deploying flexibility technologies on the necessary deployment of low carbon generation* between the twelve core scenarios and no flexibility scenarios (N1, N2)**



*Gas CCS.
**The differences between the deployments of low carbon generation in the core scenarios compared to the appropriate no flexibility scenarios.

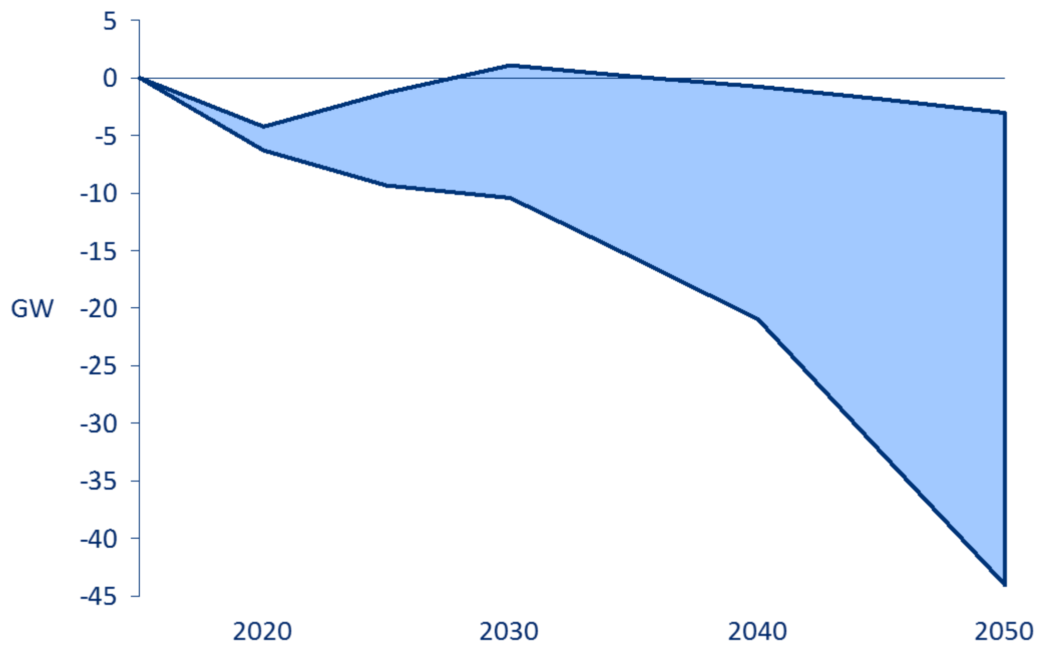
[22] In reality the presence of flexibility technologies could reduce the required capacity of any low carbon generation but to keep the underlying mix of low carbon generation consistent with BEIS scenarios, in the analysis presented here flexibility has only been allowed to affect the deployment of Gas CCS plants.

Flexibility from DSR, storage and interconnectors reduces reliance on conventional peaking assets such as OCGTs and reciprocating engines thereby reducing the cost of the system

One of the key value drivers for new flexibility technologies is aiding the reduction of necessary peaking plants to support the energy system. Peaking plants are required to manage sudden spikes in demand or drops in generation to enable a robust energy system that is able to meet demand effectively. With growing integration of intermittent renewables, there will be an increase in requirement of peaking plant services to ensure there is sufficient supply during periods of low wind or sunshine. They also provide important capacity to manage rare events such as extreme winters or simultaneous failures of multiple generation assets. Because the role of a peaking plant is to provide occasional power rather than baseload energy they often only run for a few hours a year. As a result cheaper, less efficient technologies tend to be favoured as the most cost effective way to meet this need.

DSR, storage and interconnectors are able to reduce the need for conventional peaking assets, such as OCGTs and reciprocating engines. Deploying these flexibility technologies can result in needing up to 10 GW less of peaking plant to meet demand in 2030, and 3-29 GW in 2050 (Chart 10). The range is predominantly driven by the different levels of demand across the scenarios.

Chart 10 Range of impact of deploying flexibility technologies on the necessary deployment of peaking plants* between the twelve core scenarios and no flexibility scenarios (N1, N2)**



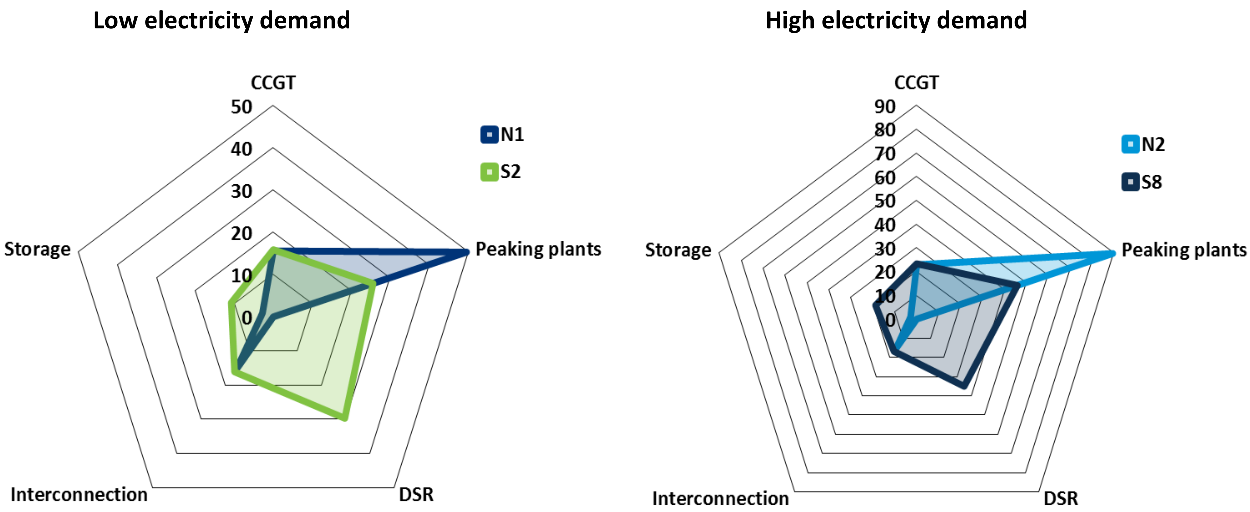
*OCGTs and reciprocating engines.
**The differences between the deployments of peaking plants in the core scenarios compared to the appropriate no flexibility scenarios.

In addition to reducing the CAPEX associated with the required capacity of peaking plant, additional flexibility also reduces the OPEX associated with the fuel consumed to run these plants. The reduction in OPEX is driven both by there being fewer plants in the system, and by the plants that remain being utilised more efficiently and therefore consuming less fuel. A smaller contribution to the reduced OPEX comes from the reduced CCS capacity required to meet carbon targets and the ability to run the CCS plants more efficiently.

New flexibility technologies change the mix of flexibility providers

To illustrate the interaction between different providers of flexibility, the spider charts below show the difference in sources of flexibility across scenarios with (S2, S8[23]) and without (N1, N2) the availability of DSR and storage. Two scenarios are provided in each case to show the impact with both low and high electricity demand (Chart 11).

Chart 11 The share of technologies used to provide flexibility in scenarios with low costs of DSR and storage (S2, S8) and without the deployment of DSR and storage (N1, N2), in 2050 (GW)



Flexibility technologies defer necessary investments in transmission and distribution network reinforcement

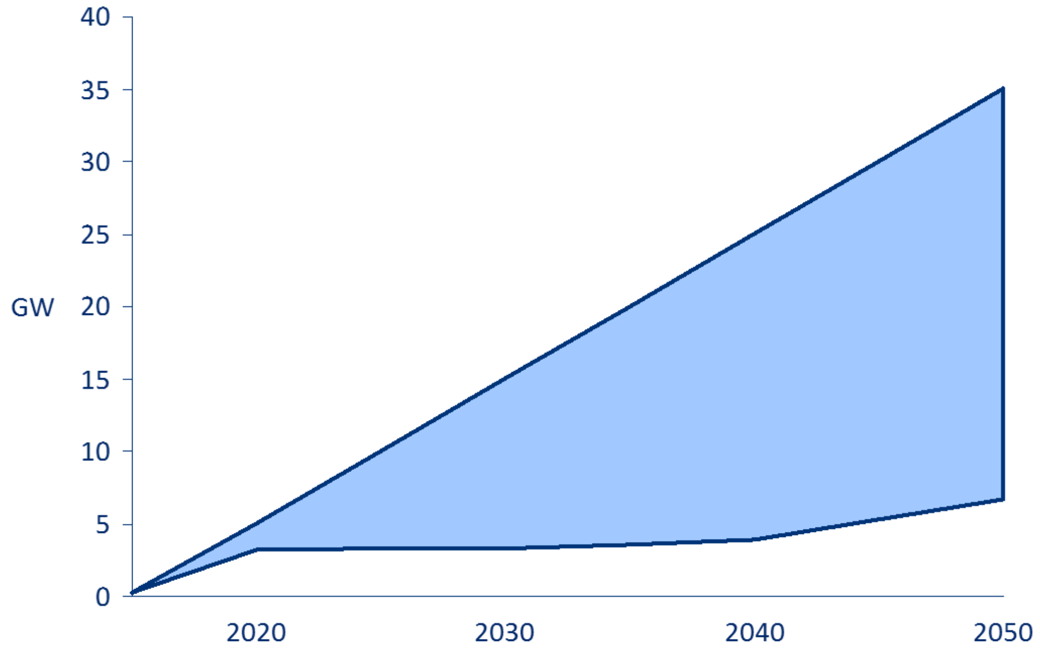
Lastly, flexibility technologies can unlock deferral in conventional reinforcement in transmission and distribution networks. This is particularly significant for the distribution network, where the need for reinforcement is driven by natural load growth, combined with the electrification of heat and transport, in addition to the growth of distributed generation. Given that network capacity is driven primarily by peak loads, technologies like DSR, storage and interconnectors, which can effectively shift the peaks and therefore utilise the existing network infrastructure more effectively and dynamically, can postpone the need to for additional investment to upgrade capacity.

[23] S2 and S8 are scenarios with low costs for DSR and storage and are equivalent scenarios apart from representing low and high electricity demand respectively.

Optimal annual profiles for additional flexibility under core scenarios

DSR - Even with conservative assumptions for DSR costs, optimal deployment in 2020 is still far higher (3.2 GW) than is currently expected

Chart 12 Range of optimal deployment of DSR to 2050 across the twelve core scenarios*



*Includes 0.3 GW of legacy DSR capacity[24] present in 2015.

Table 6 Optimal DSR deployment by scenario, in GW

Scenario	De	St	Ds	In	2020	2030	2050
S1	●	●	●	●	5	11.4	29.7
S2	●	●	●	●	5	11.4	29.7
S3	●	●	●	●	3.2	3.3	6.7
S4	●	●	●	●	5	11.4	29.7
S5	●	●	●	●	3.2	4.2	13
S6	●	●	●	●	3.2	4.1	12.9
S7	●	●	●	●	5	15	35
S8	●	●	●	●	5	15	35
S9	●	●	●	●	3.6	7.8	12.9
S10	●	●	●	●	5	15	35
S11	●	●	●	●	3.6	10.2	20.9
S12	●	●	●	●	3.6	9.9	20.9

[24] This 0.3 GW of legacy DSR capacity is largely industrial and commercial and is 'true DSR', as opposed to on-site backup generation.

The future costs of DSR are more uncertain than those of any of the other technologies considered in this report. This is reflected in the wide cost range in the assumptions (see Appendix), although arguably the full uncertainty is even wider than this range.

This uncertainty in cost changes the optimal level of deployment, but actual deployment levels will be affected by further uncertainties, such as consumer acceptance and the ability of supply chains to scale up capacity. The analysis has captured some parts of the uncertainty in consumer acceptance by including a range of payments to users in the costs of domestic DSR, and have reflected some of the uncertainty in the supply chain constraints by capping maximum deployment at 1 GW per year.

In half of the 12 core scenarios DSR deployment in 2020 is at the maximum level allowed by this cap. This means that the optimal deployment of DSR could be much higher than this, and actual deployment could be much higher if the proxy for supply chain constraints is conservative. By 2030 there is a larger divergence between the low and high DSR cost scenarios, and this continues out to 2050.

Even in high DSR cost scenarios, optimal DSR deployment is 3.2-3.6 GW in 2020; this represents a significant increase from the c. 0.3 GW at the present day, and is far higher than many projections.

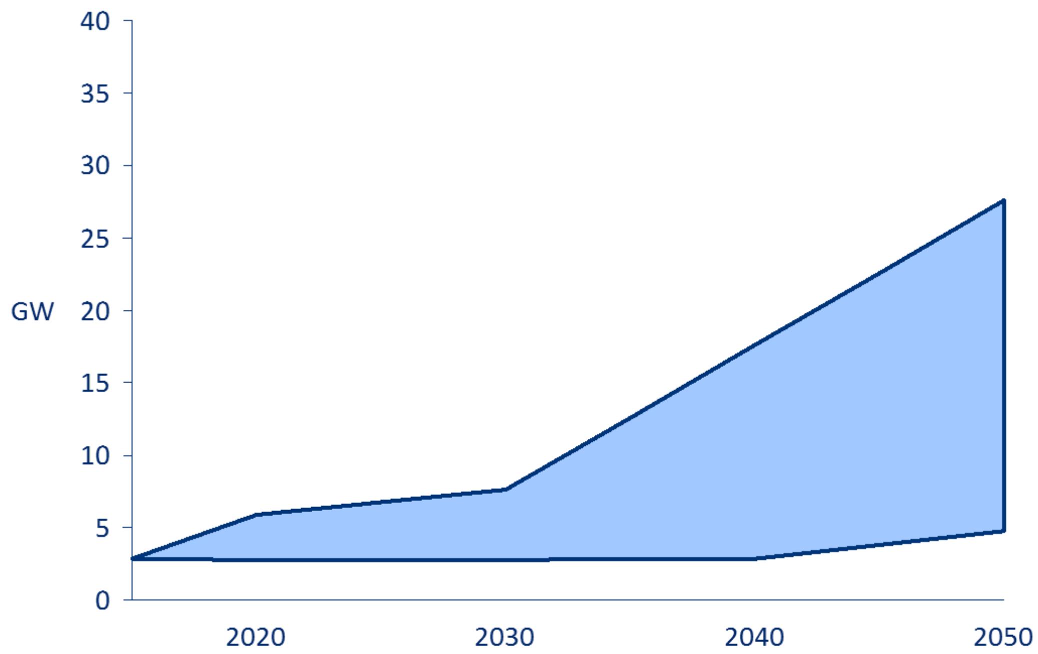
DSR deployment is greatest in scenarios where system demand is high and DSR cost is low – reaching 35 GW in 2050 across S7, S8 and S10. Conversely DSR deployment is lowest in scenarios when DSR cost is high and there is low system demand reaching less than 15 GW in 2050 across S3, S5 and S9.

The lowest DSR deployment occurs when DSR costs are high, demand is low and storage costs are low – only achieving 6.7 GW by 2050 in S3. The fact that DSR deployment is lowest in scenarios when storage costs are low highlights that storage and DSR are providing similar services to the system and are to an extent interchangeable.

Whilst DSR capacities are described here in aggregate, DSR capacities are disaggregated across industrial and commercial, domestic, heat and electric vehicles in the Appendix (Tables 36-39).

Storage – The range of deployments of storage is driven more by the uncertainty in the costs of other technologies, particularly DSR, than in the cost of storage itself

Chart 13 Range of optimal deployment of storage to 2050 across the twelve core scenarios*



*Includes 2.8 GW of legacy storage capacity present in 2015.

Table 7 Optimal storage deployment by scenario, in GW

Scenario	De	St	Ds	In	2020	2030	2050
S1	●	●	●	●	3	3.6	10.8
S2	●	●	●	●	3.1	3.1	10.8
S3	●	●	●	●	5.5	7	23.7
S4	●	●	●	●	3	3	4.8
S5	●	●	●	●	5.9	6.5	12.8
S6	●	●	●	●	5.9	6.4	13.3
S7	●	●	●	●	3.1	4.9	19.1
S8	●	●	●	●	2.8	3.4	18.8
S9	●	●	●	●	4.9	7.6	27.6
S10	●	●	●	●	2.8	2.8	10.5
S11	●	●	●	●	5.4	5.7	16.5
S12	●	●	●	●	5.3	5.3	16.5

Across the core scenarios deployment of storage in 2020 is similar to that of DSR in 2020 - 3-6 GW for storage compared to 3-5 GW of DSR. However, legacy DSR capacity is minimal whereas there is currently 2.8 GW of existing storage capacity. So the deployment of additional storage by 2020 is much smaller - 0-3 GW.

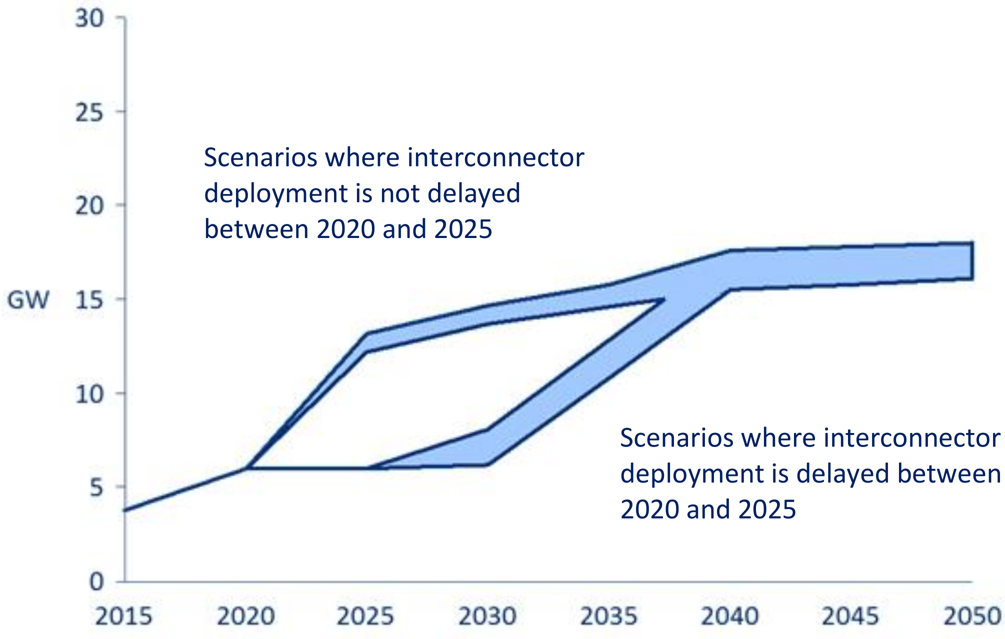
Deployment of storage in 2020 is predominantly determined by the cost of DSR: when DSR cost is low in S1, S2, S4, S7, S8 and S10, deployment of additional storage by 2020 is less than 0.5 GW. This is irrespective of the cost of storage, which is also low in S1, S2, S7 and S8.

By 2030, there is little change across the majority of the scenarios. The two scenarios that represent the largest gains, S7 and S9, are both where there is high system demand and low storage cost.

Out to 2050, there is a rapid increase in deployment rates that is relatively uniform. The exception is S4, where high storage costs are joined by low system demand and low DSR costs. However, where demand is high, along with DSR costs, the deployment of storage is over 16 GW in S11 and S12 despite the cost of storage being similarly high.

Interconnectors – Interconnection with other countries is a key source of flexibility for the UK, the current capacity pipeline appears to be optimal, and delays to this pipeline would increase costs

Chart 14 Range of optimal deployment of interconnectors to 2050 across the twelve core scenarios*



*Includes 4 GW of legacy interconnector deployment present in 2015.

Table 8 Optimal interconnector deployment by scenario, in GW

Scenario	De	St	Ds	In	2020	2030	2050
S1	🔵	🔵	🔵	🔵	6	6.2	16.1
S2	🔵	🔵	🔵	⚫	6	13.7	16.1
S3	🔵	🔵	⚫	⚫	6	13.8	16.2
S4	🔵	⚫	🔵	⚫	6	13.7	16.1
S5	🔵	⚫	⚫	🔵	6	7.2	17.1
S6	🔵	⚫	⚫	⚫	6	13.9	16.3
S7	⚫	🔵	🔵	🔵	6	7.3	17.1
S8	⚫	🔵	🔵	⚫	6	14.4	16.8
S9	⚫	🔵	⚫	⚫	6	13.8	17.2
S10	⚫	⚫	🔵	⚫	6	14.7	17.1
S11	⚫	⚫	⚫	🔵	6	8.1	18
S12	⚫	⚫	⚫	⚫	6	13.7	17.4

In all scenarios it is assumed that the 6 GW of interconnector capacity that is in the pipeline for 2020[25] is successfully deployed. In eight of these scenarios (S2, S3, S4, S6, S8, S9, S10, S12) it is then assume that all of the 12.2 GW in the pipeline for 2025 is also deployed, and the model is free to deploy more than this if cost efficient[26]. This set of scenarios represents the upper blue wedge in Chart 14 above. In the other four scenarios (S1, S5, S7, S11), which represent the lower blue wedge, there is a delay in deploying the pipeline, and so no extra interconnector capacity is deployed between 2020 and 2025. After 2025 the model is free to deploy more if it wants to. The white gap between the two wedges shows that there were no scenarios with interconnector deployment between these two ranges for that period.

The purpose of these two scenarios is to test whether the capacity in the pipeline is optimal, the extent to which optimal interconnector capacity is dependent on the cost of other flexibility technologies, and the extent to which a delay in the interconnector capacity pipeline would influence the deployment of other flexibility technologies.

Interconnector deployment is only significantly differentiated in 2030 across the scenarios when it is constrained between 2020 and 2025. However, once these constraints are lifted from 2025 onwards, the deployment across all scenarios converges to around 16-18 GW by 2040 and grows very little between then and 2050. This is because, in these scenarios, after 2040 DSR and storage are cheaper ways to provide flexibility to the system and so additional interconnector capacity is no longer required[27].

In addition to the core scenarios, further scenarios were also modelled where DSR and storage are not available. In these scenarios interconnector capacity is relied upon much more to provide flexibility with higher deployment from 2020, deployment continuing to grow after 2040, and deployment in 2050 of around 27 GW. See Appendix for further details.

The fact that the optimal level of interconnector deployment in scenarios where the pipeline is delayed recovers to similar levels to those where there is no delay, suggests that the interconnector capacity in the pipeline is close to optimal across these core scenarios. Although a delay to the interconnector pipeline between 2020 and 2025 is largely recovered by 2040, the consequence of this delay is to add a total system cost penalty of c. £1 bn (£0.7-1.6 bn) cumulative to 2050, which can be seen when comparing the scenarios where interconnection deployment is delayed with the equivalent scenarios where it is not.

[25] Ofgem, *Electricity interconnectors*. Available at: https://www.ofgem.gov.uk/electricity/transmission-networks/electricity-interconnectors [last accessed 14 April 2016], and expert input.

[26] See 'Complementary analysis – Energy flow across interconnectors' and Appendix for more detail on assumptions and results relevant to interconnectors.

[27] It should be remembered that in this analysis interconnectors can only provide value to the electricity system by providing flexibility, due to the constraint that annual energy flows must net to zero. So the deployments shown in these scenarios are the optimal levels for interconnector capacity that is only providing flexibility services. In reality interconnectors also provide additional value by allowing net imports of many TWh of electricity each year, so actual optimal levels may be higher than those shown here.

More flexible CCGTs – Deployment is not required in scenarios when significant DSR and storage capacity is deployed, but they become important when other sources of flexibility are not available

Product evolution in combined cycle gas turbines (CCGTs) has tended to focus on increasing efficiency and reducing capital and maintenance costs. Since CCGTs are normally expected to run with high utilisation, flexibility has not been as high a priority. However, as flexibility in electricity systems becomes increasingly valuable, new generations of more flexible CCGT are becoming available. These can start up faster, change output levels ('ramp') faster and generate stably at a lower fraction of their peak output.

More flexible CCGTs were included in the analysis presented here. Although many models of more flexible CCGT are in development or coming to market, they are not widely commercially available yet, so there is a significant uncertainty surrounding their future cost. Whilst they could be significantly more expensive than existing models, at least initially, the results presented here assumed an optimistic 10% cost increment on existing CCGTs to test whether they would be preferred to other flexibility technologies if this cost can be achieved. However, even with this optimistic cost assumption, the model does not choose to deploy more flexible CCGT models across the twelve core scenarios. Conventional CCGT continues to have an important role (see next section) but not more flexible CCGT.

This is largely explained by two factors: Firstly the other flexibility technologies in the scenarios can shift loads to increase the utilisation of intermittent generation as well as providing the same services as a more flexible CCGT, and this provides more value to the model. Secondly, the model is able to get the energy provision it requires from cheaper more efficient CCGT, and get the peaking capacity it requires from cheaper OCGTs and reciprocating engines. Therefore it sees no need to combine both features in one asset, and compromise on the performance and cost of each.

However, if other flexibility technologies, such as DSR and storage, fail to deploy in significant volumes, more flexible CCGT models can become key providers of flexibility services (Chart 15).

Chart 15 Optimal deployment of more flexible CCGTs to 2050 across two scenarios without any DSR and storage deployment

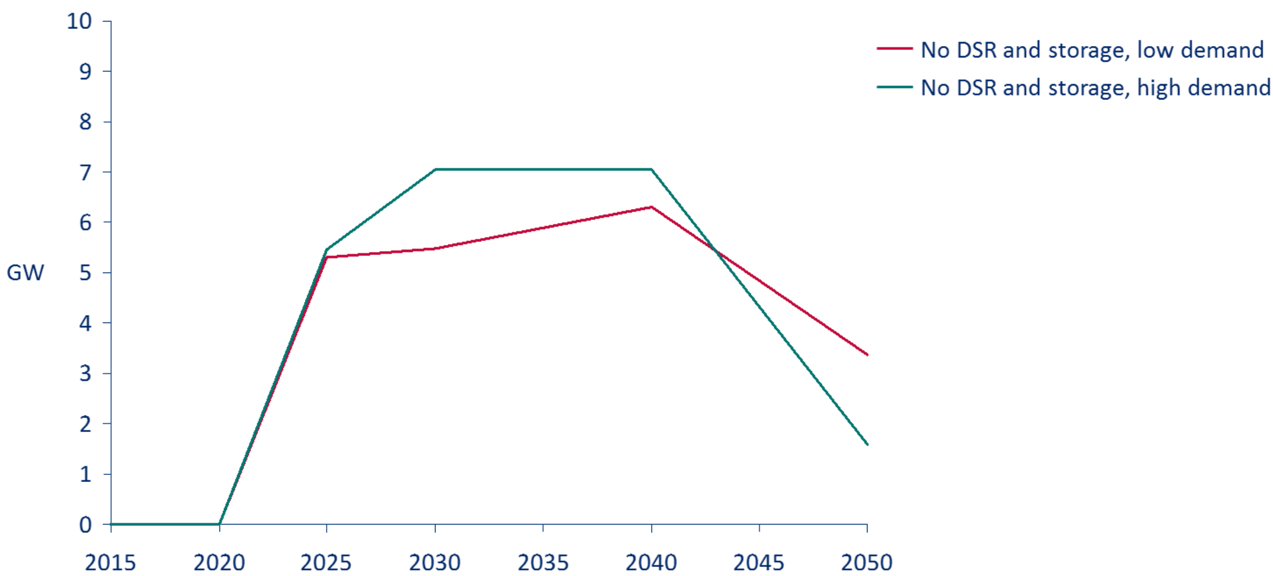


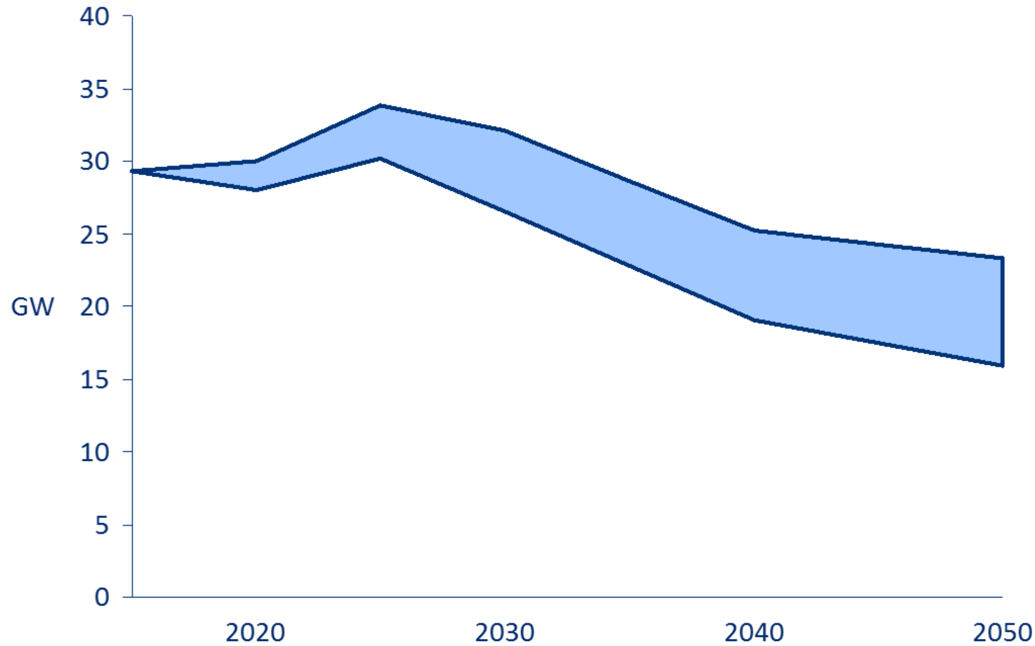
Table 9 Optimal deployment of more flexible CCGTs by scenario, in GW

Scenario	De	St	Ds	In	2020	2030	2050
No DSR and storage, low demand		-	-	-	0	5.5	3.4
No DSR and storage, high demand		-	-	-	0	7.0	1.6

It could be argued that even the lowest deployments of DSR and storage across the twelve scenarios represent optimistic growth rates compared to current levels. Should deployment of these flexibility technologies be lower than in the core scenarios, there could be a role for more flexible CCGT. Accordingly, this analysis ran two scenarios, with low and high demand, that constrain the deployment of DSR and storage to 0 GW from now until 2050. The model responds by deploying more flexible CCGT capacity from 2020. In order to meet the carbon reduction target, this capacity is steadily curtailed with plants retiring without replacement from 2040 to 2050 in both high and low demand scenarios.

Conventional CCGTs – Current models continue to play an important part in the energy system across all of the twelve core scenarios out to 2050, with their role shifting from providing significant output to acting as key back-up generation

Chart 16 Range of deployment of conventional CCGTs to 2050 across the twelve core scenarios*



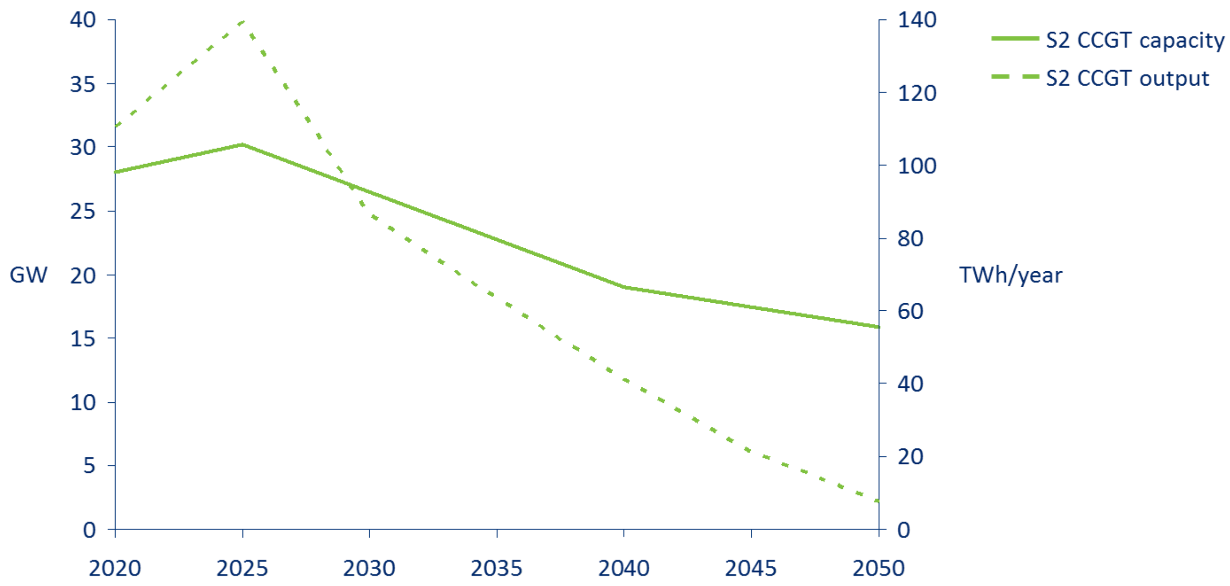
*Includes 29.3 GW of legacy CCGT capacity present in 2015.

Table 10 Conventional CCGT deployment by scenario, in GW

Scenario	De	St	Ds	In	2020	2030	2050
S1	●	●	●	●	28	26.5	15.9
S2	●	●	●	●	28	26.5	15.9
S3	●	●	●	●	28	26.5	15.9
S4	●	●	●	●	28	26.5	15.9
S5	●	●	●	●	28	26.5	15.9
S6	●	●	●	●	28	26.5	15.9
S7	●	●	●	●	30	32.1	23.3
S8	●	●	●	●	30	32.1	23.3
S9	●	●	●	●	30	32.1	23.3
S10	●	●	●	●	30	32.1	23.3
S11	●	●	●	●	30	32.1	23.3
S12	●	●	●	●	30	32.1	23.3

Across all of the twelve scenarios, conventional CCGTs continue to represent significant capacity within the energy system. The primary cause of the range outlined in Chart 16 above is the difference between the low and high energy demand conditions. However, it is important to be aware that the relatively consistent capacity of conventional CCGTs does not illustrate their changing role in the future energy system. Chart 17 below is for one particular scenario and outlines how the capacity of conventional CCGTs drops gradually from 2025 to 2050. It also shows how the output (TWh/year) from this capacity drops much more rapidly after 2025.

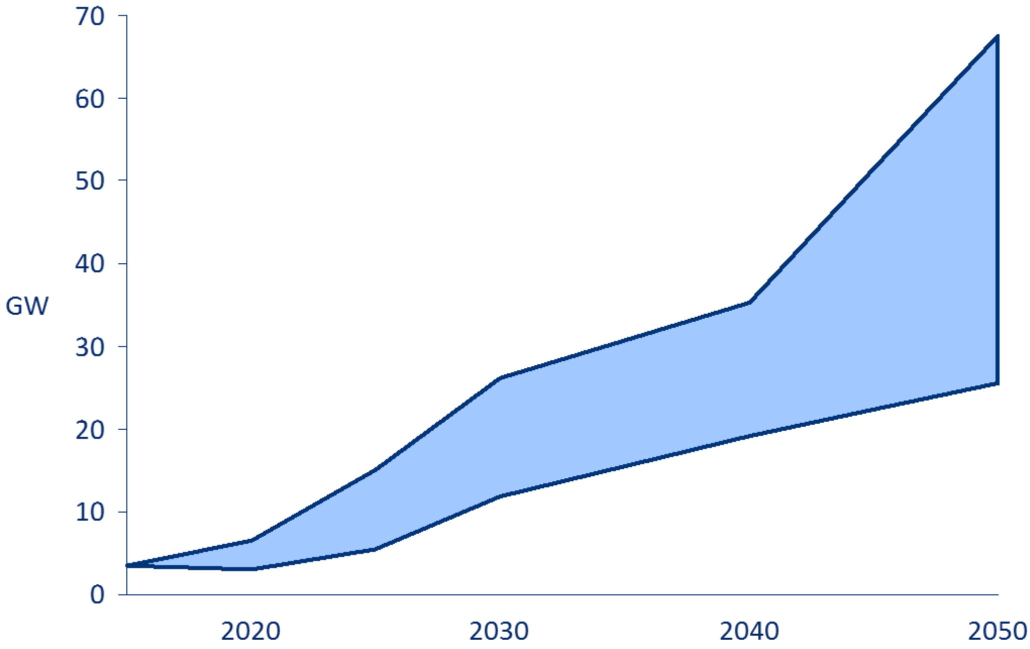
Chart 17 Deployment (GW) and output (TWh/year) of conventional CCGTs to 2050 for S2



This drop in energy output is driven by the changing role of conventional CCGTs, from providing significant levels of energy to the system, to acting as vital back-up generation for increasing amounts of intermittent renewables. In addition, the steep downward trend of output after 2025 is also indicative of the greater deployment of other sources of flexibility, such as DSR and storage. These technologies contribute to peak load management, and cover brief shortfalls of supply, reducing the need for conventional CCGTs to perform that task, but are unable to completely replace CCGTs for rarer more significant shortfalls. This changing, but vital, role for CCGTs in the future is also supported by a large capacity of peaking plants, such as OCGTs and reciprocating engines, as the following section illustrates.

Peaking plants - OCGTs and reciprocating engines have an important role in providing flexibility and ensuring adequate capacity, particularly when DSR and storage are expensive

Chart 18 Range of optimal deployment of peaking plants to 2050 across the twelve core scenarios*



*Includes 3.5 GW of legacy OCGT and reciprocating engine capacity.

Table 11 Optimal peaking plant deployment by scenario, in GW

Scenario	De	St	Ds	In	2020	2030	2050
S1	○	○	○	○	5.1	16.9	25.8
S2	○	○	○	●	4.7	11.9	25.6
S3	○	○	●	●	3.5	14.8	41
S4	○	●	○	●	4.8	12	37.6
S5	○	●	●	○	3.1	19.6	46.6
S6	○	●	●	●	3.1	14.2	46.2
S7	●	○	○	○	6.3	24.3	45.4
S8	●	○	○	●	6.4	20	45.9
S9	●	○	●	●	5.3	21	62.8
S10	●	●	○	●	6.6	20.2	60.6
S11	●	●	●	○	4.6	26.2	67.4
S12	●	●	●	●	4.8	21.3	67.5

In the modelling presented here OCGTs and reciprocating gas engines are treated as very similar assets. They are modelled separately but are presented in aggregate in this report as the distinction between them in the results would probably not be helpful. They provide additional capacity during times of unusually high demand and/or low supply, in particular they provide adequate capacity in relatively rare situations when high demand coincides with outages of other generation capacity. This entails that these technologies often sit on the grid without being utilised, apart from a few hours a year or even less. As a result, a lot of this capacity is for providing essential energy security, rather than acting as flexibility assets that regularly balance the grid.

Optimal deployment of peaking capacity ranges from 12-26 GW in 2030 and 26-68 GW in 2050. The overall electricity demand is the major determinant of their deployment. However their deployment is affected by DSR and storage costs with low costs leading to fewer peaking plants being required.

Although DSR and storage displace peaking plants to an extent, they do not totally replace them. Peaking plants, therefore, remain an important source of peak capacity. The deployment of peaking plants generally remains slightly higher than the combined deployment of DSR and storage, which stands at 8-16 GW in 2030 and 23-51 GW in 2050 across the twelve scenarios. This reveals that although conventional peaking plants are displaced by new technologies for the purpose of providing everyday flexibility (see Chart 18 above), there is still a significant need for peaking capacity to guard against times of extremely high demand and potential outages of generation capacity. As this peaking capacity can see very low utilisation in later years it should be expected that lower CAPEX forms such as reciprocating engines will be an important part of the mix.

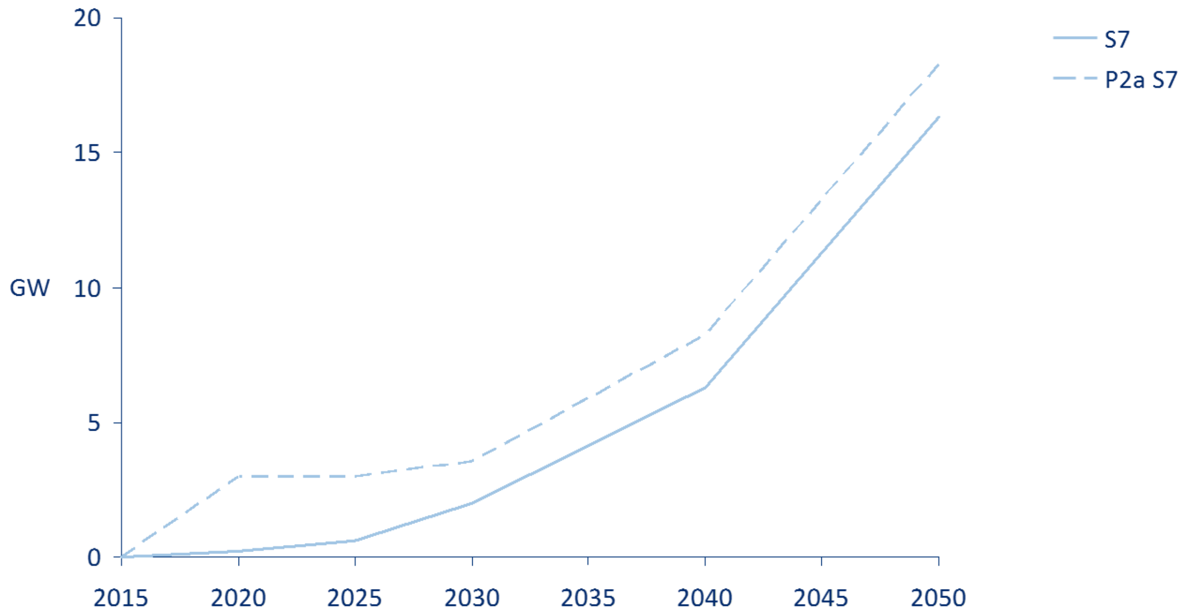
‘Least worst regrets’ analysis

The analysis in this report, and in previous studies, has demonstrated that deploying flexibility technologies will reduce the cost of the transition to a low carbon electricity system and that the steps to achieving that deployment need to start now. However, as stated previously, there is a lack of foresight regarding the best course of action now given the plethora of uncertainties that surround future conditions and the different technologies. Therefore, this study focuses on what choices can be made to avoid the worst possible outcome – in other words, identifying the pathways that lead to the ‘least worst regret’.

This process for calculating the ‘least worst regret’ is illustrated in detail below in steps using a worked example. It starts with just one technology, one Scenario (S7) and one Pathway (P2a), then expands this to all technologies and costs for that combination of one Scenario and one Pathway, and finally expands this to all twelve core Scenarios for that Pathway. In the following section the final regret scores for the combinations of all the pathways with all the scenarios are provided in a matrix (Table 13). For a breakdown of how these regret scores are calculated in each case, see the charts (36-45) in the Appendix.

Pathway 2a forces WeSIM to take additional storage capacity of 1.2-3 GW by 2020, whilst restricting DSR and flexible CCGT deployment to 0 GW in 2020, in addition to no additional interconnection between 2020 and 2025. Chart 19 below shows the different deployment profiles of additional storage (above the 2.8 GW already installed in 2015) when the energy system is optimised for Scenario 7 (solid line) and when it is started on Pathway 2a till 2020, then optimised for Scenario 7 after 2020 (dashed line).

Chart 19 Optimal deployment of additional storage in S7 compared to the additional deployment in P2a S7, to 2050

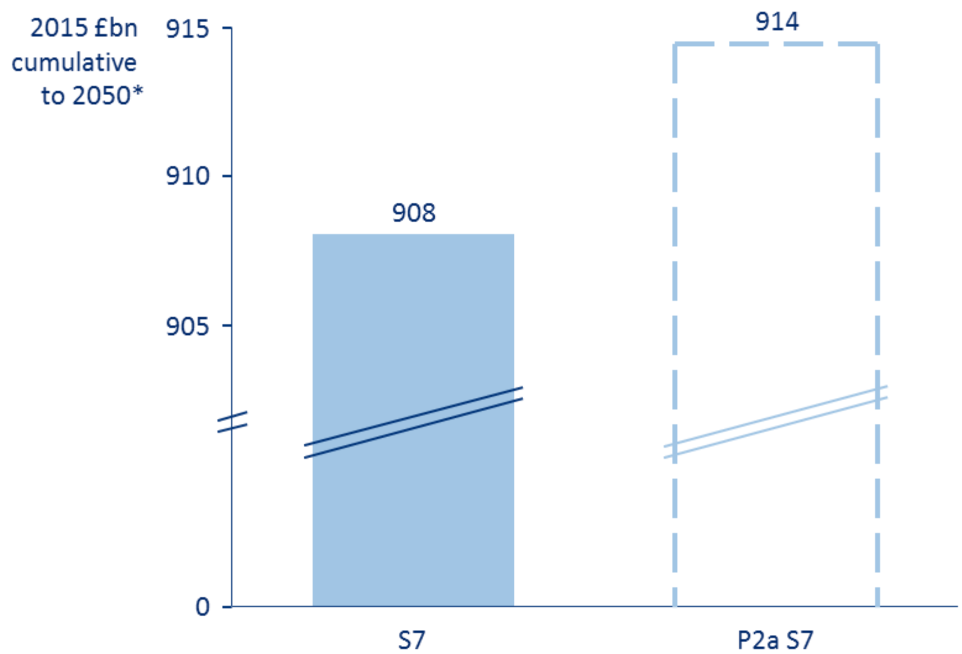


The optimal deployment of additional storage in S7 is close to 0 GW, but Pathway 2a forces in a minimum of 1.2 GW of additional storage. Moreover, because the other flexibility technologies are constrained to 0 GW, the model has a ‘flexibility gap’ to fill and chooses to address this with more storage than the minimum 1.2 GW, reaching 3 GW by 2020. This means that the system now has more storage than it optimally 'wants', so over the next 5 years no more storage is deployed.

Importantly for this combination of Pathway and Scenario, the optimal deployment of DSR in S7 is to deploy at the maximum level of 1 GW/year from 2015 to 2050, but Pathway 2a forces no deployment of DSR in 2020 which leaves the pathway with 5 GW less than the optimal amount. As a result, the deployment of DSR is never able to recover from this 5 GW shortfall and reach the optimal level, so other flexibility technologies deploy in greater volumes to bridge the gap in the system. This is outlined in Chart 19 above, whereby from 2030 onwards storage deployment continues at the same rate as in S7, but from a slightly higher starting point, and that additional deployment is maintained to 2050.

As a result of this divergence from the optimal deployment profile, as evidenced by the difference between the two deployments shown in Chart 19, the energy system incurs extra costs that amount to regret. Chart 20 below outlines the total cost of the energy system in the optimal S7 and in P2a S7, cumulative to 2050 and discounted. It shows that compared to the optimised deployment for Scenario 7 (S7), starting down Pathway 2a and then optimising for Scenario 7 (P2a S7) leads to a total energy system cost that is £6.4 bn more expensive, amounting to £6.4 bn net regret.

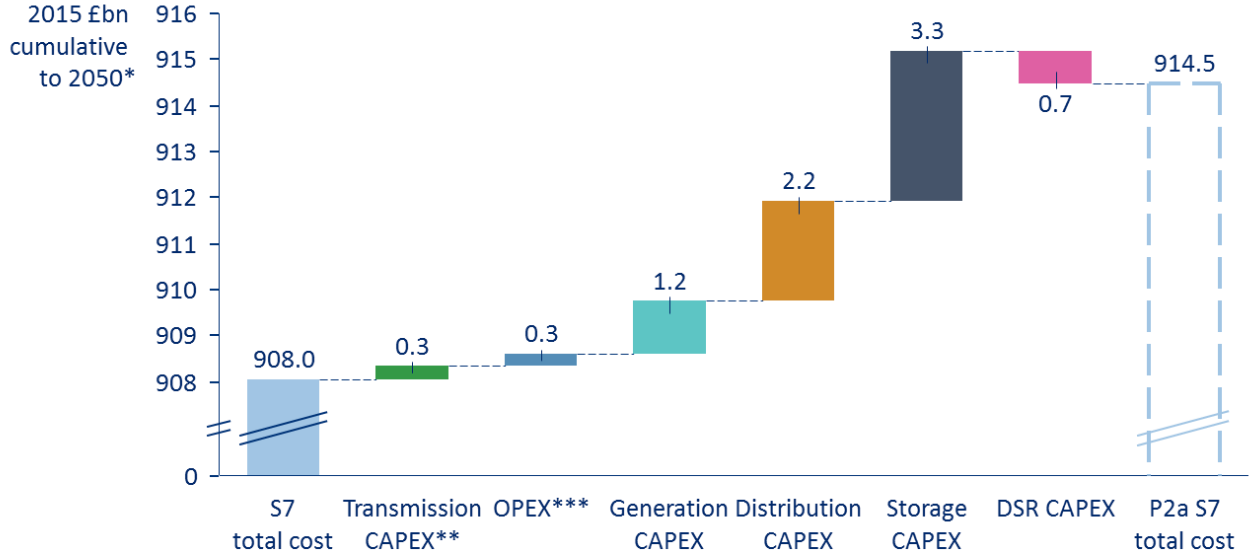
Chart 20 Cost difference between the optimal deployment in S7 compared to deployment in P2a S7, cumulative to 2050



*Discounted back to 2015 using HM Treasury's Green Book social discount rate.

Chart 21 below shows the same difference in total system cost between the optimised S7 and P2a S7, but this time as a waterfall chart, splitting out the parts of the energy system that get cheaper or more expensive as a result of starting off on Pathway 2a. It shows that deploying 5 GW less DSR in 2020 leads to a significant reduction in DSR CAPEX for the energy system, but this saving is far less than the increases in generation, distribution and storage CAPEX. Hence the net regret of £6.4 bn.

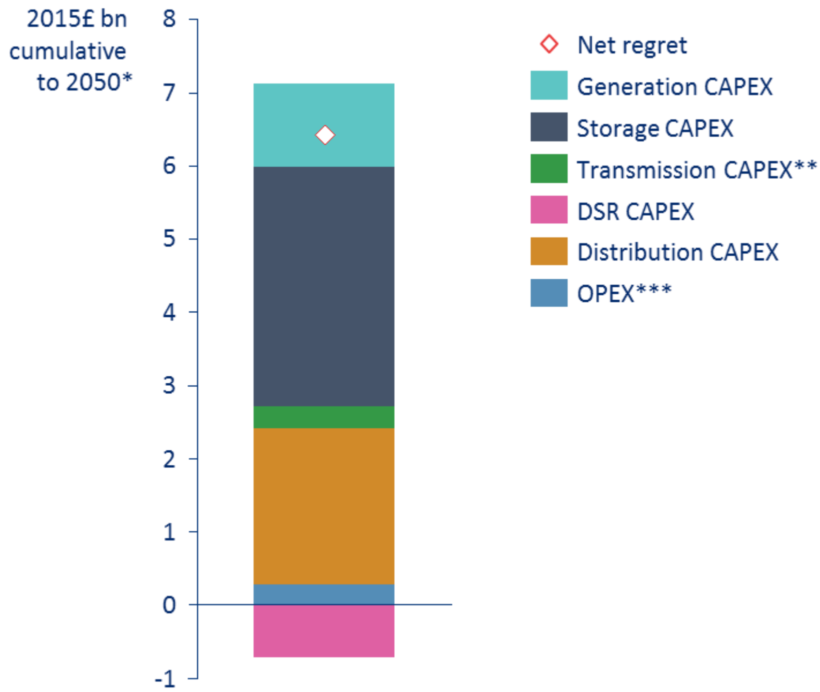
Chart 21 Breakdown of the cost difference between the optimal deployment in S7 compared to deployment in P2a S7, cumulative to 2050



*Discounted back to 2015 using HM Treasury's Green Book social discount rate.
**Includes interconnector and onshore transmission CAPEX.
***Refers to variable OPEX (fuel and carbon costs). Fixed OPEX is included in CAPEX figures.

Chart 22 shows the same information as the waterfall chart above (Chart 21) but as a single stacked bar chart. It also highlights the net regret as a yellow diamond. This more condensed format allows the presentation of regret for the Pathways across all twelve of the core scenarios and is used in all the results of the 'least worst regrets' analysis in the Appendix.

Chart 22 Cost difference between the optimal deployment of S7 and P2a S7, cumulative to 2050

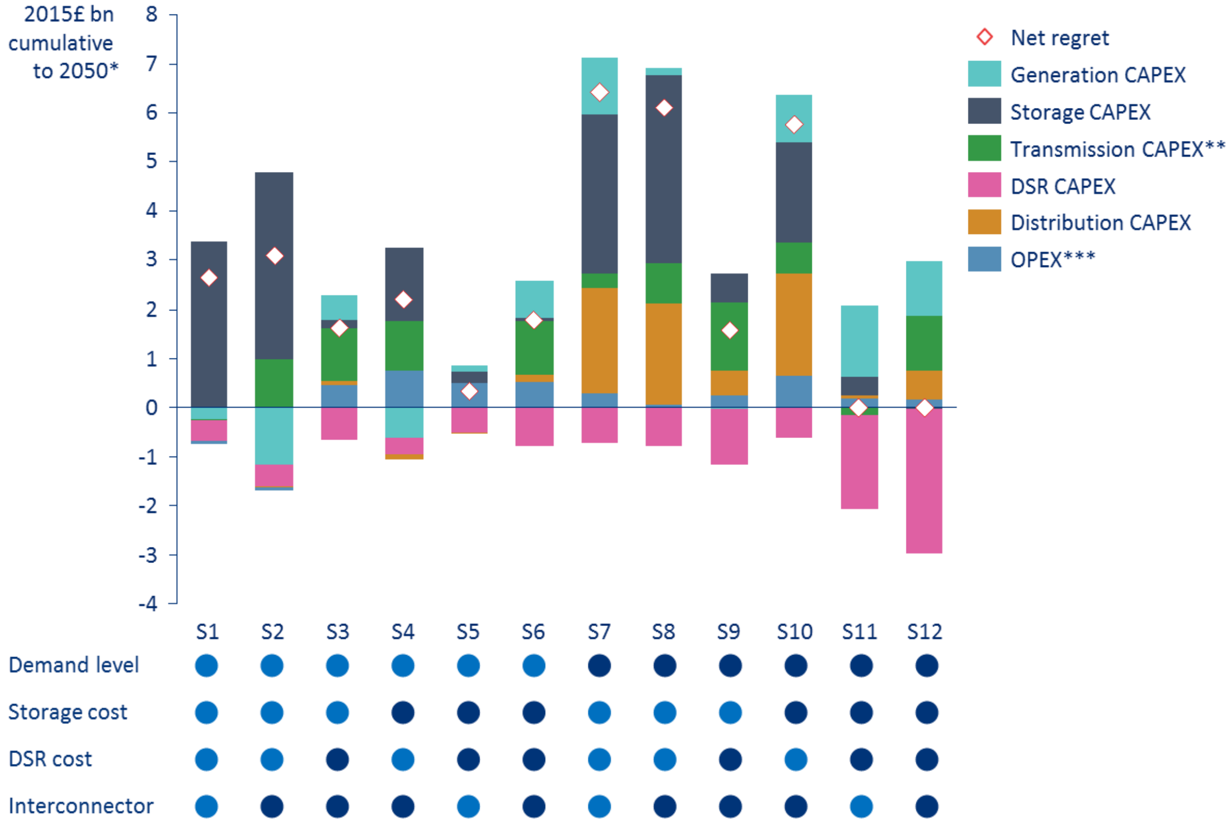


*Discounted back to 2015 using HM Treasury's Green Book social discount rate.
**Includes interconnector and onshore transmission CAPEX.
***Refers to variable OPEX (fuel and carbon costs). Fixed OPEX is included in CAPEX figures.

Pathway 2a – High storage deployment with no deployment of other flexibility technologies to 2020

Chart 23 below outlines the regret for Pathway 2a across the twelve different core scenarios. For the results of the other Pathways, please refer to Charts 37-46 in the Appendix.

Chart 23 Cost difference between the optimal deployment and P2a for the twelve core scenarios, cumulative to 2050



*Discounted back to 2015 using HM Treasury's Green Book social discount rate.
**Includes interconnector and onshore transmission CAPEX.
***Refers to variable OPEX (fuel and carbon costs). Fixed OPEX is included in CAPEX figures.

The worst regret for Pathway 2a is to be found in S7, where it stands at £6.4 billion. In this Scenario and the others with significant net regret (S8, S10), the regret is primarily driven by a combination of extra storage and distribution CAPEX. The regret due to additional storage CAPEX is explained both by the Pathway forcing the model to deploy more storage than was optimal in first 5 years, and, because DSR was restricted to 0 GW in 2020 and it could never recover to its optimal level due to the build rate constraint of 1 GW/year, by the Scenarios then continuing to install extra storage capacity all the way to 2050 to compensate for the reduced DSR capacity. In addition, because of the reduced DSR capacity, DSR is unable to support the distribution network to the same extent and there is a need to invest in extra network reinforcement, as represented by the extra distribution CAPEX.

Interestingly, in S7 and S8 the cost of storage is actually low. However, the cost of DSR is also low, and this undercuts the low value of storage, meaning that the model still prefers DSR, with the regret amplified by the high system demand in these two Scenarios when compared to their low demand equivalents, S1 and S2. This reveals that if the cost of DSR is low, its absence can be a greater factor in increasing regret than the over-deployment of other technologies such as storage.

Whilst in all scenarios the regret is partially mitigated by savings from the reduced deployment of DSR, this is most pronounced when the costs of DSR are high, leading to lower net regret in S3, S5, S6, S9, S11 and S12. In these core Scenarios, the optimal level of storage deployment is within the 1.2-3 GW range proscribed by this Pathway. Therefore, there is less regret associated with storage investment. For some of these scenarios (S11, S12) there is close to zero regret.

In S1, S2 and S4, where the system demand is low, there are significant savings from avoided spend on generation CAPEX because the forced additional storage capacity is sufficient to reduce the need for generation capacity. However, in the corresponding Scenarios where the system demand is high (S7, S8 and S10), there is an increase in generation CAPEX for the system because the additional storage is not sufficient to compensate for the additional generation capacity needed to make up for the reduced DSR capacity.

Extra transmission CAPEX is found in all the scenarios where interconnection deployment is constrained between 2020 and 2025 (S1, S5, S7 and S11). This highlights the value of ensuring the current pipeline of interconnectors are deployed to schedule, and before 2025.

Summary of the 'least worst regrets analysis'

The study conducted the above analysis for ten different pathways (see Appendix for all ten). The four scenarios presented here are summarised in Table 12 below. For more detailed descriptions of each pathway see the Method section and the Appendix.

Table 12 Summary of the four Pathways and their parameters

Pathway	DSR in 2020	Storage in 2020	Flexible CCGT in 2020	Additional interconnection in 2025
P1a	2-5	-	-	-
P2a	-	1.2-3	-	-
P3a	1-5	0.5-3	1	-
P4a	-	-	-	-

The matrix below (Table 13) summarises the regret for each Pathway, in each of the twelve core scenarios, as compared to the optimal deployments for each Scenario, with the column on the far right highlighting the worst regret value for each Pathway.

Table 13 Matrix showing the regret across every Pathway with every Scenario[28], 2015£ bn cumulative to 2050*

	S1	S2	S3	S4	S5	S6	S7	S8	S9	S10	S11	S12	Worst regret
P1a	0.0	0.1	1.7	0.0	0.5	1.6	0.0	0.0	1.0	0.0	0.4	0.2	1.7
P2a	2.6	3.1	1.6	2.2	0.3	1.8	6.4	6.1	1.6	5.8	0.0	0.0	6.4
P3a	0.0	0.2	1.4	0.1	0.2	1.3	0.1	0.0	0.7	0.1	0.0	0.0	1.4
P4a	4.5	4.3	1.8	4.4	0.8	1.6	9.0	8.5	1.7	8.9	1.6	1.4	9.0
De	●	●	●	●	●	●	●	●	●	●	●	●	
St	●	●	●	●	●	●	●	●	●	●	●	●	
Ds	●	●	●	●	●	●	●	●	●	●	●	●	
In	●	●	●	●	●	●	●	●	●	●	●	●	

Least worst regret	P3a	1.4

*Discounted back to 2015 using HM Treasury's Green Book social discount rate

The highest regret occurs in the 'do nothing' Pathway, 4a. This occurs when this Pathway is combined with S7. Importantly, in addition to exposing the UK to the worst of all regrets in S7, it also leads to the highest regret out of the four Pathways in every Scenario except one (S6). Therefore, not deploying any flexibility technologies by 2020 could expose the UK to the highest possible regret and is worse than the other Pathway options in almost every Scenario.

The 'least worst regret' occurs in Pathway 3a, the Pathway that represents a 'balanced' deployment portfolio across DSR, storage and flexible CCGT by 2020. This portfolio of technologies allows the energy system to mitigate against the potential maximum regret situation of over-investing in expensive technologies whilst under-investing in cheap ones by spreading the risk.

Pathway 1a, where DSR deployment is high but the deployment of all the other flexibility technologies are limited, is the next best when it comes to 'least worst regret'. This outlines that deploying too much DSR in does not cause as much regret as not deploying enough DSR in Pathways 2a and 4a.

Pathway 2a has the second highest regret, which is where significant storage deployment is forced but there is no additional deployment of other technologies including DSR. The regret for deploying too much storage is hard to discern because it is dwarfed by the regret of not deploying DSR – particularly when the cost of DSR is low. In the maximum regret Scenarios for this Pathway (S7 and S8), most of the regret is driven by not deploying DSR when its cost is low. Very little comes from over deploying storage because in these Scenarios the cost of storage is also low.

[28] For a breakdown of how these regret scores are calculated in each case see the charts in the Appendix.

Complementary analysis - Energy flow across interconnectors

Whilst designing the 'least worst regrets' analysis, additional analysis was required to support decisions about how to treat interconnectors in the modelling. The results of this additional analysis are interesting in their own right and are reported here.

Introduction

Interconnectors allow the flow of power and energy between different electricity systems, typically in different countries. In the future there is likely to be much more interconnector capacity, and much greater energy flows in response to a greater need for system flexibility. This flow provides many benefits, which can be considered in terms of timescales:

- Over a period of seconds to minutes, interconnectors can stabilise power networks, e.g. through frequency response;
- Over a period of hours interconnectors can provide additional secure capacity, e.g. during peak demand or an outage;
- Over a period of hours to days interconnectors can help to balance intermittent generation, e.g. PV and wind;
- Over a period of months interconnectors can help with seasonal imbalances of supply and demand; and
- Over a period of years interconnectors can provide a net supply of energy to meet the annual electricity demand.

Method

The suite of energy system models used in this analysis cover both the UK and European energy systems and how they interact with each other through interconnectors. The analysis considered different sets of rules and input assumptions, and explored the impact they had on the flow of energy through the interconnectors to help define a set of assumptions that are most appropriate for this analysis.

The parameters and rules considered include:

- Carbon pricing in the UK and Europe, in particular whether they are the same;
- Carbon targets in the UK and Europe, and whether the model optimises for a UK carbon constraint or a European one; and
- Whether net flows of energy across interconnectors are allowed, and if not, over what time period they should net to zero.

Results, discussion and decisions

When net flows of energy across interconnectors are allowed, and the model optimises power generation and interconnector capacities for European carbon constraints rather than UK ones, this leads to a number of outcomes which are optimal (i.e. least cost) for Europe but may not be optimal or realistic for individual member states.

Firstly the optimal solutions tend to see European deployment of generation assets concentrating where local conditions lead to lowest cost and then interconnectors being used to move the energy to meet demand in other countries, for example:

- Solar PV deploys mostly in southern Europe, where higher insolation causes higher capacity factors, but very little deploys in the UK; and
- Wind deployment concentrates in the north and west of Europe, where higher wind speed causes higher capacity factors, leading to far higher deployment in the UK than is needed to meet UK carbon targets.

Secondly, these assumptions can lead to a country building large interconnector capacity not because it needs it, but because it provides a convenient route between generation and demand in two other countries, e.g. the model chooses to build a large interconnector capacity between Ireland and the UK, much larger than the UK needs, as a low cost route for Ireland to export wind to continental Europe (compared to a direct interconnector from Ireland to continental Europe which avoids the UK).

Lastly, these assumptions can lead to a country building much less generation capacity than it needs to meet its own energy needs, instead relying on generation capacity in other countries and interconnectors.

The analysis also explored scenarios where the carbon targets were different between the UK and Europe. These led to more extreme results with very large excess capacities of low carbon generation in some countries.

However, these results ignore the legal and practical need for countries to meet their own carbon targets and to be largely self-sufficient in meeting both their annual electrical energy demand, and their peak power demand. Many of these alternative scenarios resulted in the UK having tens of GW of additional low carbon generation capacity and hundreds of TWh of additional low carbon generation, which is difficult to believe under current policies and market arrangements. Similarly, other scenarios saw the UK importing hundreds of TWh/yr across interconnectors and choosing to deploy far less generation capacity than would be needed to meet peak demand, again it is difficult to believe that the need for self-sufficiency could be relaxed to this extent.

Allowing these outcomes in the 'least worst regret' analysis could have distorted the results and undermined their plausibility. To avoid this, the following constraints and assumptions were applied:

- Energy flows across interconnectors must net to zero on an annual basis;
- The interconnector capacity between the UK and Ireland is limited to 1 GW more than current levels[29];
- There is "shared security" across Europe meaning that interconnection capacity combined with spare generating capacity in neighbouring countries can contribute to the required capacity margin and reduce the generation capacity the UK must build to securely meet peak demand;
- EU carbon prices were set by the EU ETS, and UK carbon prices were set at a level between the EU ETS and the Carbon Price Floor[30];
- Electricity carbon intensity targets are the same in the UK and in Europe; and

[29] Redpoint Energy Limited, *Impacts of further electricity interconnection on Great Britain*, report for DECC, 2013. The figure used is an illustrative example and is not necessarily the optimal level.

[30] The model contains carbon constraints and carbon prices, both of which have the purpose of achieving carbon targets, and hence there is a risk they will conflict in the model. To ensure the model did not over or under achieve the carbon targets, the carbon constraints were made binding, and conservative (low) UK carbon prices were used. (Table 23 in the Appendix)

- The UK and Europe have access to the same flexibility technologies at the same prices.

Even with zero net annual flows of energy, it is possible for the flows across interconnectors to affect carbon intensities. For instance, if the flows of energy in one direction are consistently of higher carbon intensity than the flows in the other direction, the overall energy balance will be zero but there will have been a net flow of carbon. However, using the constraints listed above, the net annual flow of carbon across interconnectors is very close to zero. The flow of carbon across interconnectors has been treated as zero in this analysis.

Another consequence of these constraints is that interconnectors are able to act as a flexibility asset, similar to a very large battery, but not as a source of primary power for the UK. This means that they can provide frequency response, peaking power, balancing for intermittency and even seasonal balancing. But they cannot contribute to the national annual electricity demand, so the UK must build enough generation capacity to be self-sufficient in overall electrical energy, but not necessarily in system balancing. When examining the consequence of this constraint on the possible curtailment of renewable energy generation, there was no impact on the capacity, output or curtailment.

In reality net annual flows across the UK's interconnectors are typically not zero - the UK has imported over 2 TWh (net) every year since 1986, and imported over 20 TWh (net) in 2014[31]. Therefore imposing a constraint of zero annual net flow is not strictly realistic. However, this simplifying assumption avoids the more extreme modelling results encountered with other assumptions. Since this project is about the need for flexibility assets in the UK, this simplification of zero net annual flow is appropriate. But it should be remembered that interconnectors provide the UK with additional value outside the scope of this analysis, so actual optimal deployment levels may be higher than those outlined here.

[31] DECC, *Digest of UK Energy Statistics*, July 2015.

4 Conclusions

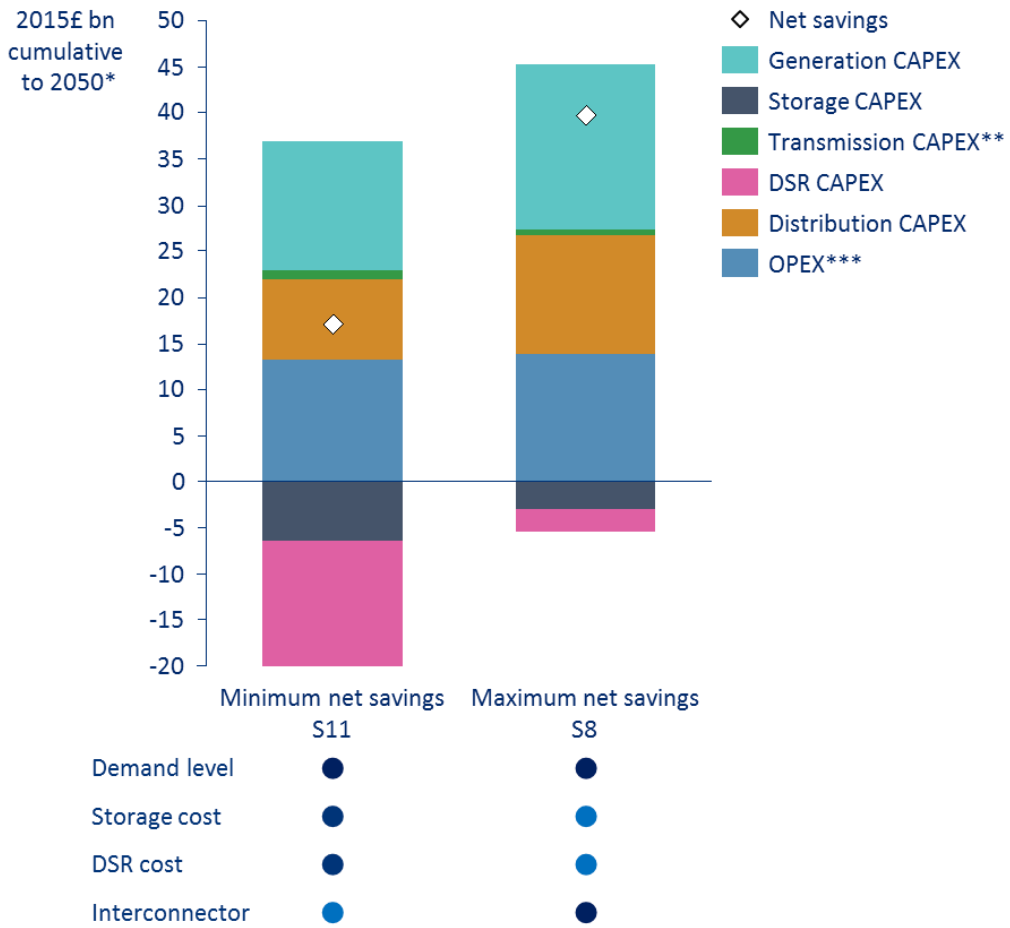
The UK could save £17-40 bn across the electricity system from now to 2050 by deploying flexibility technologies

Flexibility in the energy system, from technologies such as DSR, storage and interconnectors, provide three key sources of value:

1. They reduce the capacity of low carbon generation needed to achieve carbon reduction targets by improving the utilisation of low carbon generation;
2. They enable system balancing at a lower cost by displacing more expensive flexibility options such as peaking plants; and
3. They improve the utilisation of existing conventional generation, and defer investments in transmission and distribution network reinforcement.

As highlighted in Chart 24 below, flexibility reduces the net cost of the system across all the twelve core scenarios considered in this analysis.

Chart 24 A breakdown of the minimum and maximum cost differences between the twelve core scenarios and the no flexibility scenarios (N1, N2) cumulative to 2050



*Discounted back to 2015 using HM Treasury's Green Book social discount rate.
**Includes interconnector and onshore transmission CAPEX.
***Refers to variable OPEX (fuel and carbon costs). Fixed OPEX is included in CAPEX figures.

This conclusion broadly corroborates with other recent studies that look into the benefits of deploying flexibility technologies. Taking account of the deployment costs of the flexibility technologies, the net system benefits in this analysis amount to £1.4-2.4 bn/year in 2030, assuming an electricity carbon emissions intensity target of 100 g/kWh in 2030. This compares to the gross benefit, where the costs of deployment are not taken into account, of £3-3.8 bn/year in 2030 outlined in a recent Committee on Climate Change study[32]. Additionally, a report by the National Infrastructure Commission[33] posited gross benefits of £2.9-8.1 bn/year in 2030.

Both of these studies do not include the costs of deploying flexibility technologies, which contributes to the increased level of benefit when compared to this analysis. Moreover, the upper region of the range quoted from the National Infrastructure Commission report is due to a more stringent carbon emissions intensity target of 50 g/kWh in 2030, meaning there is higher value in deploying more flexibility technologies by 2030. These methodological differences do not comprehensively explain the discrepancy between all of these studies, but given the significant uncertainty in this form of analysis, all of these studies converge on the conclusion that deploying flexibility technologies could reduce the cost of the UK energy system by billions of pounds cumulatively by 2030.

[32] Committee on Climate Change, *Value of Flexibility in a Decarbonised Grid and System Externalities of Low-Carbon Generation Technologies*, 2015.

[33] National Infrastructure Commission, *Smart Power*, 2016.

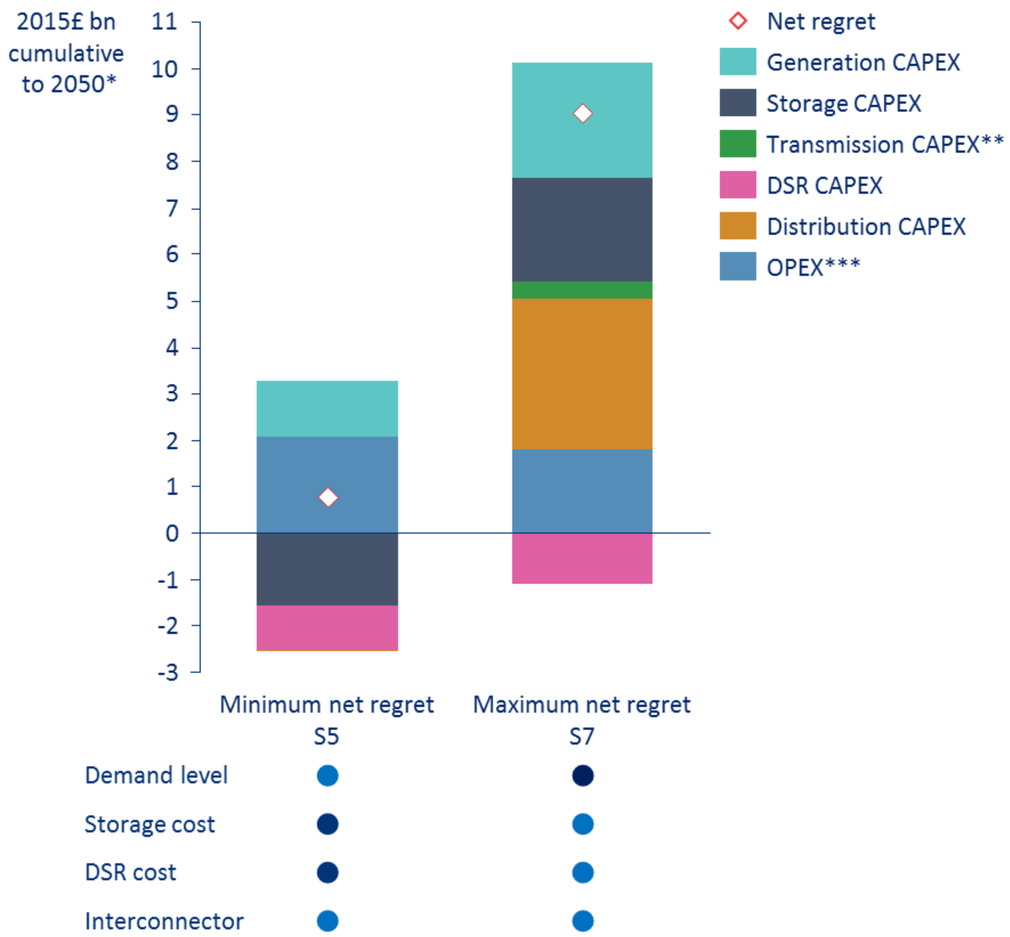
Not deploying any additional sources of flexibility ('do nothing') by 2020 is the Pathway that delivers the overall worst regret for the UK energy system

Not deploying any of the flexibility technologies in 2020 can render the system more expensive by c. £0.8 bn to c. £9 bn across the twelve scenarios, as illustrated in Chart 25 below. This Pathway is also characterised by a slow recovery in deployment from 2020 to 2025, due to no material deployment before this period affecting the ability to bring forward large capacities immediately.

The lower end of the range of the total regret (c. £0.8 bn) is found in a future scenarios where both DSR and storage do not see large cost reductions from their present day levels to 2050. The high cost of both the technologies means that not deploying any storage or DSR in 2020, and having a slow uptake to 2025, is not far from the optimal amount of deployment in that period.

In contrast, the high end of the total regret (c. £9 bn) occurs in a scenario where both DSR and storage do see large cost reductions to 2050. In this scenario, deploying no material levels of these technologies in 2020, and having a slow uptake to 2025, incurs significant regret driven by the potential system cost savings that could have been unlocked by deploying lower cost flexibility technologies.

Chart 25 A breakdown of the minimum and maximum cost differences between the twelve core scenarios and Pathway 4a cumulative to 2050



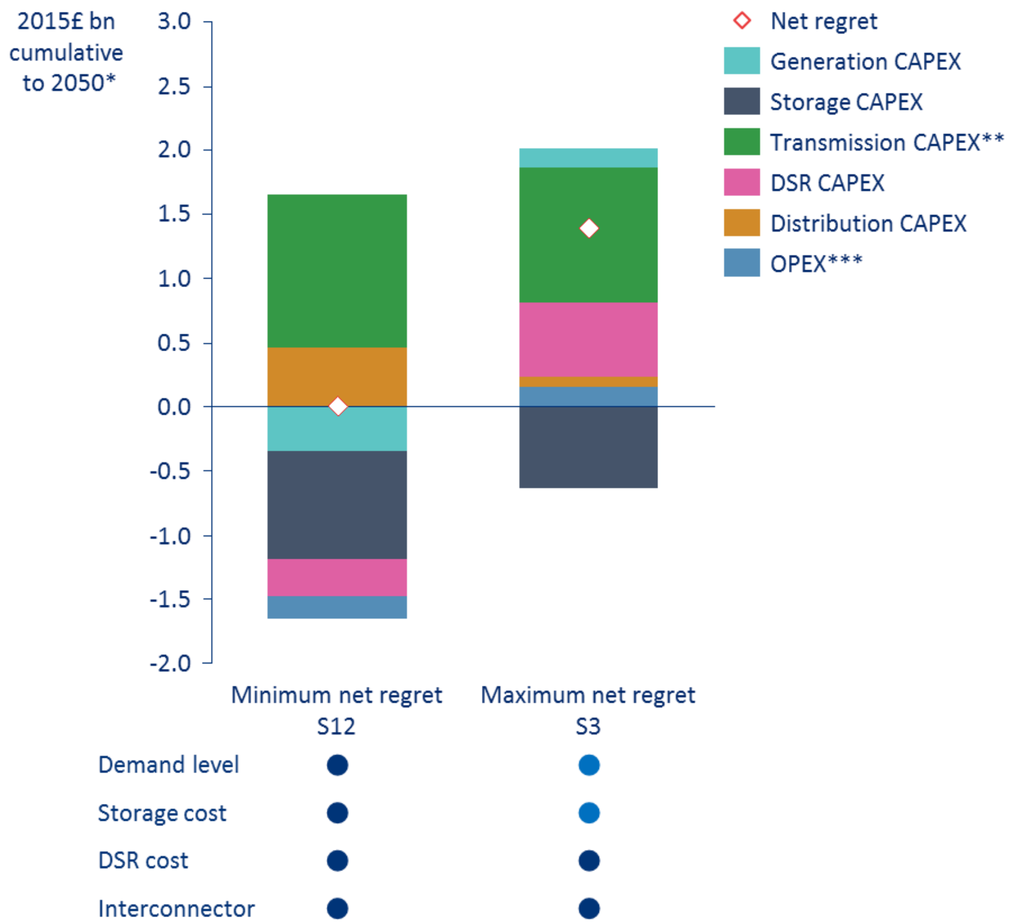
*Discounted back to 2015 using HM Treasury's Green Book social discount rate.
**Includes interconnector and onshore transmission CAPEX.
***Refers to variable OPEX (fuel and carbon costs). Fixed OPEX is included in CAPEX figures.

A 'balanced' strategy of deployment across different sources of flexibility is the 'least worst regret' pathway for the UK energy system

Choosing a 'balanced' deployment pathway across DSR, storage and flexible CCGT produces total regret from c. £0 bn to c. £1.4 bn across the twelve scenarios analysed (Chart 26). Pathway 3a deploys a range of DSR, storage and flexible CCGT in 2020, which delivers the 'least worst regret' across all the pathways examined. This result owes to a strategy of not relying on a single solution, such as DSR or storage, which has significant uncertainties surrounding future cost trajectories. Whilst a single solution could cover flexibility requirements, it could also expose the whole system to the risk of incurring regret when costs are higher than anticipated. The 'balanced' Pathway also assumes that the market design is flexible enough to be able to pull the different sources of flexibility close to their optimal deployment, relative to their respective cost points.

The 'least worst regret' occurs under a scenario of high DSR and low storage costs, with a low total system demand. The regret is driven primarily by the high cost of DSR, which raises the cost of delivering flexibility relative to the counterfactual. The minimum regret in this Pathway comes from a scenario where all the parameters are high. This indicates that a balanced deployment strategy is very close to the optimal in a world where system demand and the cost of flexibility technologies are high.

Chart 26 A breakdown of the minimum and maximum cost differences between the twelve core scenarios and Pathway 3a cumulative to 2050



*Discounted back to 2015 using HM Treasury's Green Book social discount rate.
**Includes interconnector and onshore transmission CAPEX.
***Refers to variable OPEX (fuel and carbon costs). Fixed OPEX is included in CAPEX figures.

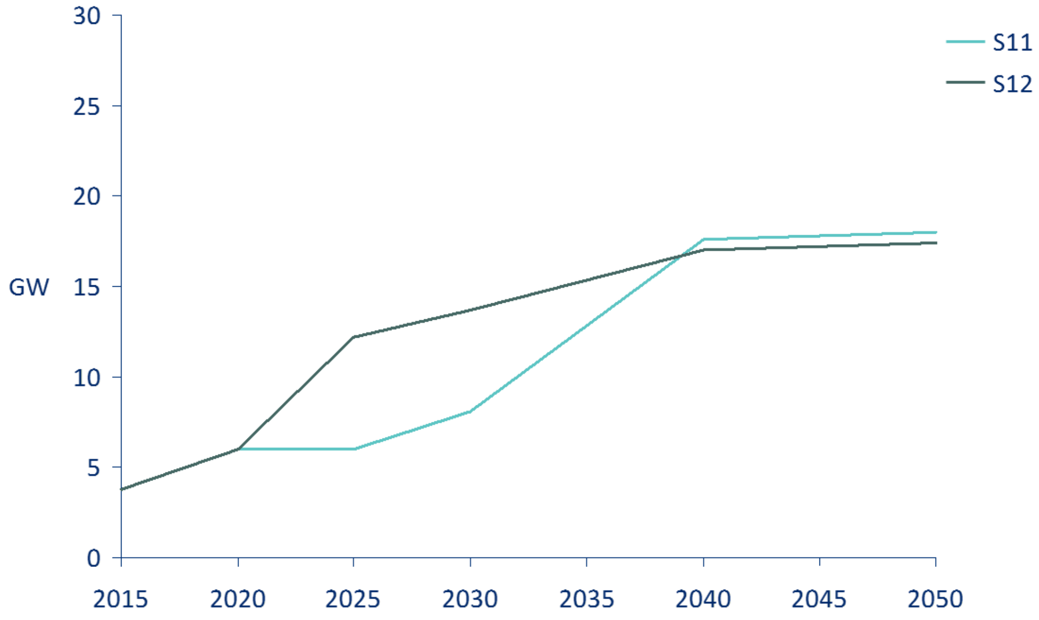
Interconnectors are a key source of flexibility for the UK, the current capacity pipeline appears to be optimal, and delays to this pipeline would increase costs

The analysis shows that the total capacity of interconnection planned and in the pipeline[34] for the UK is chosen by the model to deliver flexibility across every scenario, demonstrating its importance to the system even when other sources of flexibility are available. Chart 27 below outlines this effect for S11 and S12, which are equivalent to each other barring the delay of interconnector deployment in S11. It is evident that when the deployment of interconnectors is constrained for the period between 2020 and 2025, there is an increase in deployment beyond 2025[35] to 'catch up' with pipeline capacity, outlining the system benefit of significant interconnection.

However, delaying the interconnector pipeline from 2020 to 2025 incurs extra costs for the system to the tune of c. £1bn (£0.7-1.6 bn). The primary drivers of this penalty are the additional costs associated with the flexibility provided by extra peaking plant generation, both in terms of increased capital and operational (fuel and maintenance) expenditure. This is compared against scenarios where interconnectors would have provided this service at a lower overall cost to the system.

It should be noted that the 'optimal' level of interconnector capacity in this analysis is calculated using a modelling assumption of zero annual net energy flows. In reality, net flows across interconnectors are not zero, and these flows can provide additional value, so actual 'optimal' interconnector capacity could be higher than outlined here.

Chart 27 Optimal deployment of interconnectors to 2050 for S11 and S12*



*Includes 4 GW of legacy interconnector capacity.

[34] Ofgem, *Electricity interconnectors*. Available at: https://www.ofgem.gov.uk/electricity/transmission-networks/electricity-interconnectors [last accessed 14 April 2016], and expert input.

[35] For a detailed chart of interconnector deployment across different scenarios, please refer to Chart 33 in the Appendix.

Demand side response has a key role in providing flexibility but also has the greatest uncertainty in terms of cost and uptake

While other sources of flexibility considered in this study rely on technological breakthroughs or learning effects from deployment to reduce costs, DSR, especially from domestic households, has several non-technical barriers to overcome to be available at scale, and to be so at low cost levels. Some of the unique cost components of domestic DSR include driving behavioural change in consumers, marketing campaigns for acceptance and contract design.

In addition, there is a need for understanding and evolving pricing structures that seek to compensate consumers for shifting consumption and providing control of loads to third parties. Here, there is also an element of ‘business learning’ - the effect of aggregators or other DSR service providers being able to reduce the cost of sales by streamlining their own processes across consumer engagement, as well as in areas such as contract design and service provision.

These factors combined, drive a large (relative) range of uncertainty in DSR costs, with different components being highly contextual. This then becomes a significant factor in the ‘least worst regret’ analysis, given the nature of the approach itself is sensitive to the extent of cost ranges. The contextual variables of domestic DSR also mean that the trend in overall costs is impacted less by global developments in deployment or technology development, and more by localised action with understanding of efficient roll out strategies for a given context.

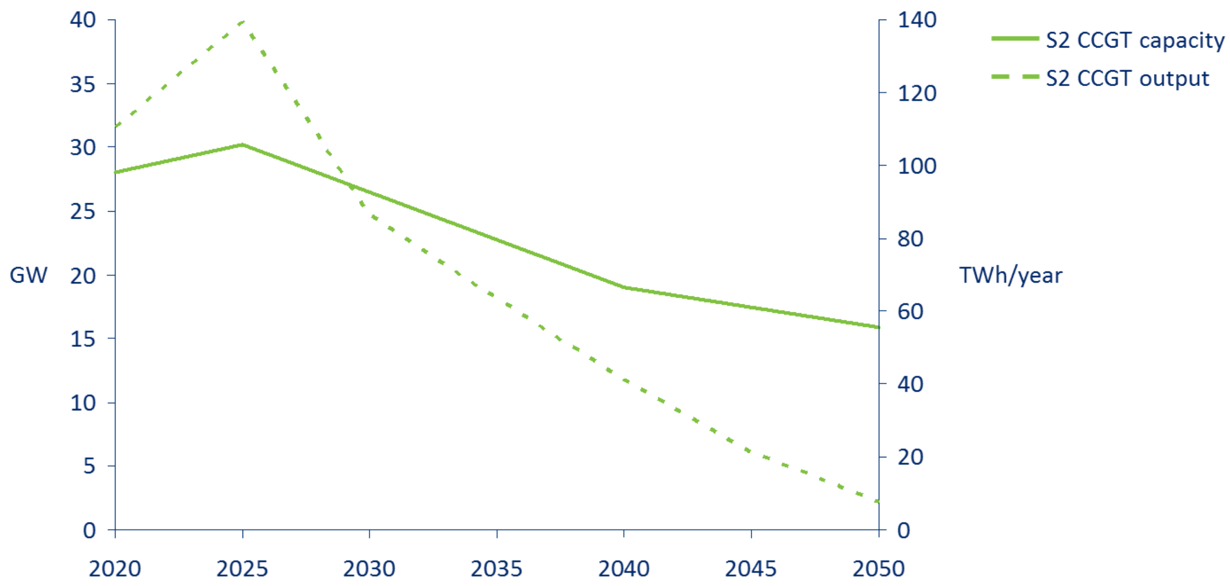
Currently in the UK, DSR from industrial and commercial consumers is growing and serviced by a number of providers. In contrast, while domestic DSR represents a potentially much larger prize, it is non-existent owing to a variety of reasons including those discussed above.

Gas power plants have a long term role in the UK energy system, by providing both flexibility and critical capacity, although with reducing utilisation over time

Across all of the scenarios analysed, conventional CCGTs continue to play an important role in providing flexibility to 2050. As illustrated in Chart 28 below, even though the S2 assumes DSR and storage are available at low cost, conventional CCGTs are required in significant capacities to 2050.

However, increasingly tight constraints on the carbon intensity of electricity means that the output from CCGTs drops significantly after 2025 (Chart 28). This drop in output leads to a slower, steady fall in CCGT capacity (GW) from 2025 as plants retire without replacement (Chart 28). The drop in energy output reveals the changing role of CCGTs - from providing energy, to maintaining critical capacity. This is owing to more renewable energy coming online over time, meaning that conventional CCGTs are providing less energy overall, in addition to the increasing presence of other sources of flexibility, such as DSR and storage, which can help the system manage peaks in demand and troughs in supply with less need for CCGT use.

Chart 28 Deployment (GW) and output (TWh/year) of conventional CCGTs to 2050 for S2



It is important to note that there is also a sustained role for peaking plants, such as OCGTs and gas reciprocating engines, for providing flexibility, albeit at low utilisation factors. Their role in the future energy system is primarily for providing back-up capacity to cover low probability peaks, such as severely harsh winters, and they are vital for security of supply and capacity adequacy even with the deployment of new flexibility technologies. Indeed, across all of the scenarios their deployment increases out to 2050, in part due to the reduction of CCGT capacity online.

5 Appendix

UK Electricity demand scenarios

The electricity demand scenarios utilised for this study, detailed in Tables 14 and 15 below, were based on BEIS's Energy and Emissions Projections[36], which run until 2035, and a series of MARKAL runs called 1A, 1D and 1E, which were conducted for DECC in 2011[37]. To splice these different scenarios together some extrapolation and smoothing was required particularly around electrification of heat and transport to avoid unrealistic peaks in the total electricity demand values. The electricity consumption in the MARKAL scenarios related to hydrogen production was discounted to reduce the complexity of the analysis and keep the scope of the study manageable. The high and low values of demand derived are detailed in Tables 14 and 15 below.

Table 14 UK electricity demand (low) assumptions in TWh from 2020 to 2050 across different loads

Component	Unit	2020	2025	2030	2035	2040	2045	2050
Baseload (including I&C[38] demand)	TWh	267	265	258	256	250	244	240
Heat driven electricity load	TWh	0	6	24	28	32	43	68
EV load	TWh	1	1	3	15	35	50	57
Domestic	TWh	50	50	49	47	47	46	48
Total	TWh	318	322	334	346	364	384	413

Table 15 UK electricity demand (high) assumptions in TWh from 2020 to 2050 across different loads

Component	Unit	2020	2025	2030	2035	2040	2045	2050
Baseload (including I&C demand)	TWh	287	289	292	310	326	349	372
Heat driven electricity load	TWh	0	10	36	42	48	65	103
EV load	TWh	1	9	23	38	53	67	73
Domestic	TWh	52	53	53	55	55	55	55
Total	TWh	342	361	405	445	484	538	607

[36] DECC, *Updated energy and emissions projections 2015*, 2015.

[37] AEA, *Pathways to 2050 – Key Results*, report for DECC, 2011.

[38] Industrial and commercial.

UK Electricity generation capacity scenarios

In line with the method used for estimating the electricity demand values, the ‘medium’ scenario of generation was also taken from BEIS’s Reference scenario. The ‘low’ and ‘‘high’ generation scenarios, detailed in Tables 16 and 17 respectively, were then constructed by scaling the reference generation scenario in proportion to the total electricity demand (TWh) in those respective scenarios. The model runs consisted of two variants: (i) where the emissions targets were not constrained, and here the peaking capacity in the system was allowed to be optimised to ensure there is sufficient reserve and back-up capacity to meet demand securely; (ii) the second run imposed a carbon target described in more detail in Tables 16 and 17, where CCS capacity was allowed to be optimised as required to ensure the imposed emission targets were achieved. Here, CCS was treated as a ‘proxy’ for low carbon technologies to allow the system to make adjustments for achieving the said targets.

Table 16 UK generation (low demand) assumptions in GW from 2020 to 2050 across sources

Component	Unit	2020	2025	2030	2035	2040	2045	2050
Gas CCS	GW	0	1	2	6	12	15	17
Nuclear	GW	8	7	12	13	17	21	26
Wind	GW	21	23	25	27	31	35	37
PV	GW	10	10	10	11	9	11	12
Biomass	GW	3	3	2	2	1	1	1
Geothermal	GW	3	3	4	4	4	4	3
Hydro reservoir	GW	2	2	2	2	2	2	2
Storage	GW	3	3	3	3	3	6	11
Coal	GW	10	2	0	0	0	0	0
Gas	GW	28	30	27	23	19	18	16
Peaking plant	GW	5	6	12	15	19	22	26
Total	GW	93	89	99	105	111	123	140

Table 17 UK generation (high demand) assumptions in GW from 2020 to 2050 across sources

Component	Unit	2020	2025	2030	2035	2040	2045	2050
Gas CCS	GW	0	1	3	7	16	21	26
Nuclear	GW	9	8	15	17	23	29	38
Wind	GW	22	26	31	35	42	48	55
PV	GW	11	11	12	14	11	15	18
Biomass	GW	3	4	3	2	1	1	1
Geothermal	GW	3	4	4	5	5	5	5
Hydro reservoir	GW	2	2	2	2	2	2	2
Storage	GW	3	3	3	4	9	14	19
Coal	GW	11	2	0	0	0	0	0
Gas	GW	30	34	32	28	25	25	23
Peaking plant	GW	7	9	20	27	29	35	46
Total	GW	101	101	125	141	154	180	214

EU demand and generation scenarios

Table 18 EU electricity demand (low) assumptions in TWh from 2020 to 2050 across different loads

Component	Unit	2020	2025	2030	2035	2040	2045	2050
Baseload (including I&C demand)	TWh	2,667	2,651	2,475	2,379	2,289	2,208	2,109
Heat driven electricity load	TWh	0	58	205	223	243	309	462
EV load	TWh	9	58	143	231	315	382	395
Domestic	TWh	491	468	438	405	382	361	341
Total	TWh	3,168	3,235	3,261	3,238	3,229	3,259	3,307

Table 19 EU electricity demand (high) assumptions in TWh from 2020 to 2050 across different loads

Component	Unit	2020	2025	2030	2035	2040	2045	2050
Baseload (including I&C demand)	TWh	2,855	2,898	2,744	2,681	2,618	2,603	2,555
Heat driven electricity load	TWh	0	67	237	261	286	370	564
EV load	TWh	11	71	178	279	368	448	469
Domestic	TWh	525	510	482	454	432	416	397
Total	TWh	3,391	3,545	3,642	3,676	3,703	3,837	3,985

Table 20 EU generation including GB (low demand) assumptions in GW from 2020 to 2050 across sources

Component	Unit	2020	2025	2030	2035	2040	2045	2050
Coal CCS	GW	0	0	0	0	0	0	0
Gas CCS	GW	0	1	2	45	103	116	141
Nuclear	GW	106	83	68	72	76	83	100
Wind	GW	178	237	296	319	345	357	371
PV	GW	118	160	202	238	270	302	335
Biomass	GW	85	97	110	109	109	108	107
Geothermal	GW	16	16	14	14	13	12	12
Hydro river	GW	84	84	84	84	84	84	84
Hydro reservoir	GW	110	110	110	110	110	110	110
Storage	GW	67	67	69	71	72	79	111
Coal	GW	115	87	66	30	0	0	0
Gas	GW	177	149	121	98	72	63	61
Peaking plant	GW	19	19	29	51	88	109	139
Total	GW	1,075	1,109	1,203	1,239	1,292	1,361	1,478

Table 21 EU generation including GB (high demand) assumptions in GW from 2020 to 2050 across sources

Component	Unit	2020	2025	2030	2035	2040	2045	2050
Coal CCS	GW	0	0	0	0	0	0	0
Gas CCS	GW	0	1	3	51	119	137	170
Nuclear	GW	113	91	76	83	89	100	124
Wind	GW	190	260	330	361	394	419	444
PV	GW	127	175	224	267	305	350	395
Biomass	GW	91	107	122	123	123	125	126
Geothermal	GW	18	17	16	15	14	14	14
Hydro river	GW	84	84	84	84	84	84	84
Hydro reservoir	GW	110	110	110	110	110	110	110
Storage	GW	66	66	69	70	76	101	149
Coal	GW	123	96	73	33	0	0	0
Gas	GW	189	163	139	110	84	74	73
Peaking plant	GW	18	17	30	52	65	77	88
Total	GW	4	6	16	29	58	69	93

UK and EU electricity carbon intensity target and price assumptions

The emission targets illustrated in Table 22 were utilised in the energy systems model to impose constraints that serve as one of the key optimisation variables to adjust low carbon generation (CCS). The 5 year targets were based on the Climate Change Committee's review of the Carbon budgets. These carbon targets were uniformly applied to both the EU and the UK to avoid any effects at national boundaries.

Table 22 UK and EU emission intensity targets for electricity generation in g/kWh from 2020 to 2050

Component	Unit	2020	2025	2030	2035	2040	2045	2050
Emissions target	g/kWh	400	200	100	75	50	40	25

In addition to carbon targets, carbon prices were also used to ensure realistic operating behaviour and generator dispatch preferences. The carbon prices shown in Table 23 below were used in the energy system model to allow cost optimisation of different system designs. Higher prices were assumed in the UK than in Europe in recognition of UK policies such as the Carbon Price Floor. However, to avoid any conflict in the model between the carbon prices and the carbon constraints, which could have led to results that over or under achieve the carbon targets, the UK and EU carbon prices were capped at a level below that defined by the Carbon Price Floor (and not sufficient to reach the carbon targets).

Table 23 UK and EU carbon price assumptions in £/tCO_2 from 2020 to 2050

Component	Unit	2020	2025	2030	2035	2040	2045	2050
UK carbon price	£/tCO_2	30	30	30	30	30	30	30
EU carbon price	£/tCO_2	6.6	18.3	30	30	30	30	30

UK and EU topology

The Great Britain electricity system was modelled using 5 regions:

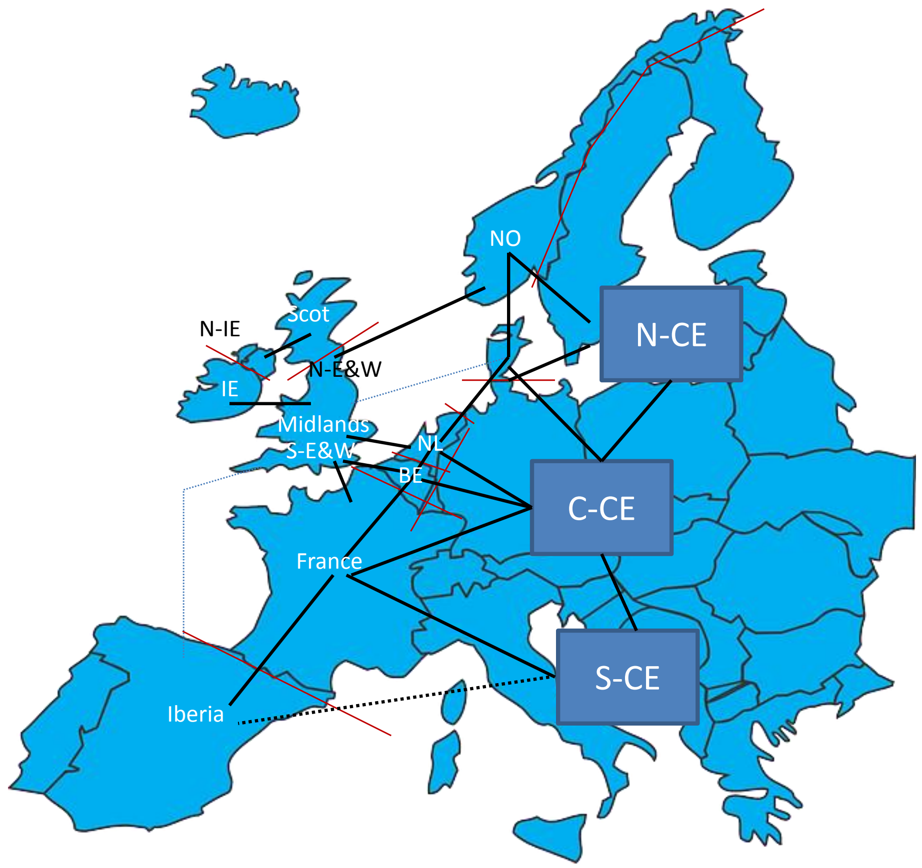
- Scotland;
- Northern England and Wales;
- Midlands;
- South England and Wales; and
- London (embedded within South England in terms of transmission grid).

To study in detail the interconnection between Great Britain and neighbouring systems, the following systems were further assumed as nodes in WeSIM:

- Ireland (2 regions) - Northern Ireland and Republic of Ireland;
- Iberia - aggregated Spain and Portugal;
- France;
- Netherlands;
- Belgium;
- Denmark;
- Norway; and
- Rest of Europe - North, Central and South.

This is also illustrated in Figure 2 below.

Figure 2 Topology of interconnected UK and EU systems considered in the study



For all of the above connections, if allowed by the given scenario, the model was able to add new interconnection capacity if economically justified.

System operation philosophies

In the studies presented in this report the core assumptions on how the GB system interacts with the other European electricity systems, as agreed between BEIS, Imperial and Carbon Trust, included:

- *Energy neutrality*. Although energy exports and imports via each interconnection link are optimised on an hourly basis (subject to interconnection capacity constraints), the energy neutrality constraint has been imposed to ensure that the total annual energy production and consumption in the UK is fully balanced. In other words, the total annual energy exports from the UK to continental Europe are required to exactly balance the total annual energy imports from continental Europe to the UK. Although at present the UK is a net electricity importer, the quantities involved are relatively modest and it is difficult to predict the direction of net energy flows several decades ahead, given that the flows would be driven by the evolution of cost of fuels, carbon and investment cost in the UK and in continental Europe. This constraint also ensured that the quantification of carbon emission intensity within the UK is more robust, given that expressing it per unit of demand or per unit of generation output yields the same value. Finally, this approach ensured that the cost optimisation at the European level also gives sensible results from the perspective of GB cost minimisation (as both GB and European systems were optimised concurrently).

- *Shared security*. In this study it has been assumed that firm capacity required to meet the specified security of supply standard (LOLE equal to 3 hours) in GB and other European systems can be shared between neighbouring systems via interconnectors (rather than each system ensuring sufficient capacity to meet the security target on its own). This is in line with expected developments towards stronger integration of both energy and capacity markets in Europe over the coming decades. The shared security paradigm results in a lower capacity margin maintained in the system.

The above assumptions were adopted for most of the model runs carried out in this study. Nevertheless, a number of sensitivity studies have been conducted with alternative assumptions on energy neutrality (where GB is allowed to be a net importer or exporter) and self-security.

Multi-year Whole Electricity System Investment Model (WeSIM)

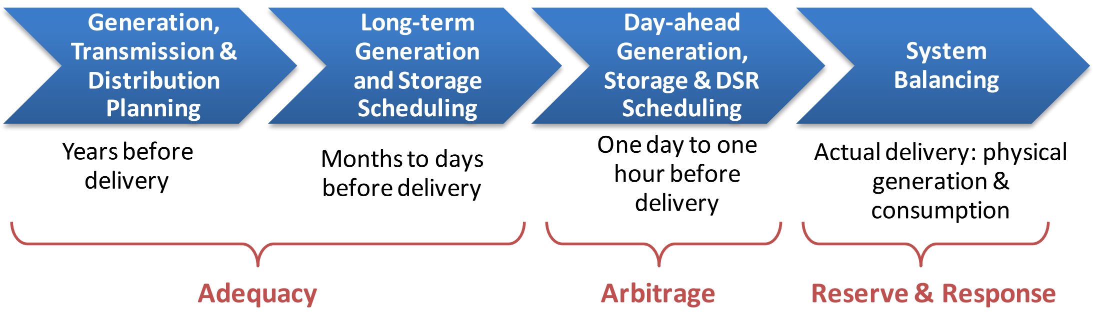
Whole-systems modelling of the electricity sector

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 horizons to real-time balancing on a second-by-second scale (Figure 3); 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 networks (national and interconnections), and local distribution networks 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 3 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 Imperial College 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 in 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.[39] An advantage of WeSIM over most traditional

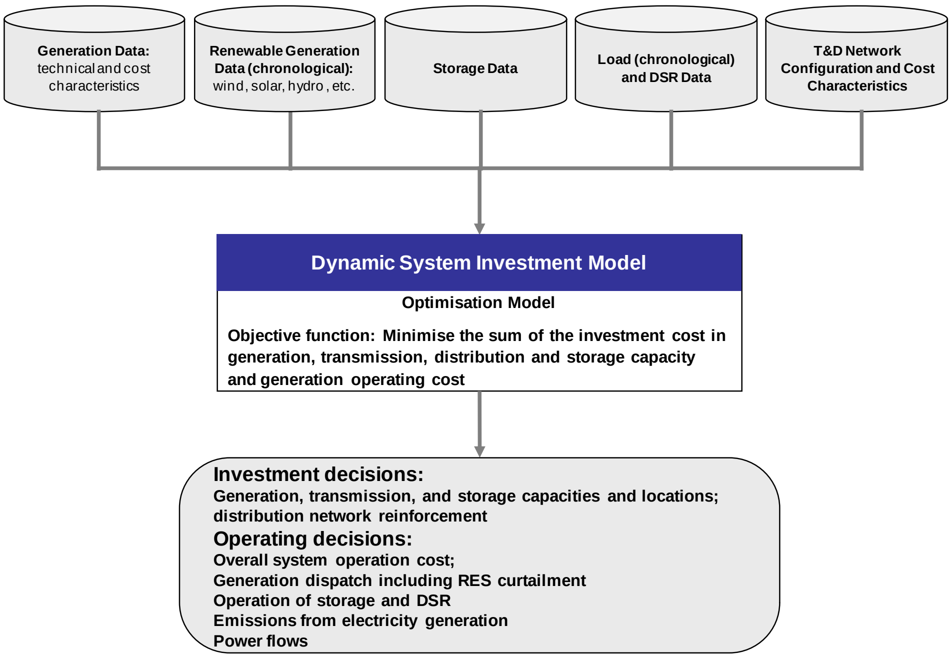
[39] WeSIM model, in various forms, has been used in a number of recent European projects to quantify the system infrastructure requirements and operation cost of integrating large amounts of renewable electricity in Europe. The projects include: (i) "Roadmap 2050: A Practical Guide to a Prosperous, Low Carbon Europe" and (ii)"Power Perspective 2030: On the

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.

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 multiple years (e.g. 2015-2050). All investment decisions and operation decisions are determined simultaneously in order to achieve an overall optimality of the solution. An overview of the WeSIM model structure is given in Figure 4.

Figure 4 Structure of the Whole-electricity System Investment Model (WeSIM)



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

- The investment cost includes the (annualised) capital cost of new generating and storage units, the 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

Road to a Decarbonised Power Sector", both funded by European Climate Foundation (ECF); (continued on following page) (continued from previous page) (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.

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).

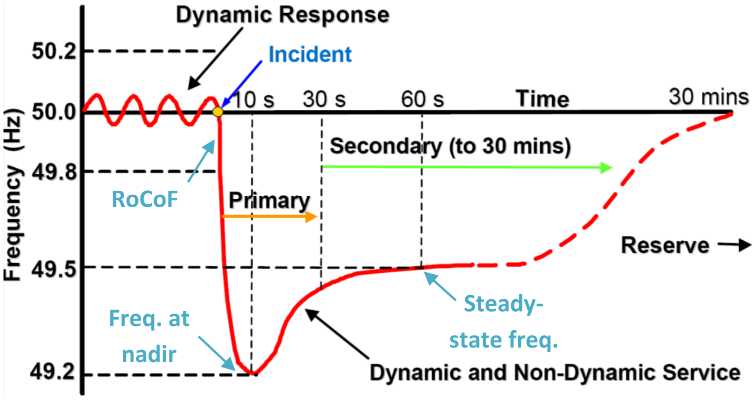
There are a number of equality and inequality constraints that need to be respected by the model while minimising the overall cost. These include:

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

- *Operating reserve constraints,* including 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 the 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 four hour ahead 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%; this may have a material impact of the value of flexibility options. Calculation of reserve and response requirements for a given level of intermittent 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 5.

Figure 5 System frequency evolution after a contingency (source: National Grid)



In WeSIM, frequency response can be provided by:

- Synchronised part-loaded generating units;
- I&C flexible demand;
- Interruptible charging of electric vehicles;
- Smart domestic appliances;
- Interruptible heat storage when charging;
- A proportion of electricity storage when charging; and
- Interconnections.

While reserve services can be provided by:

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

The amount of spinning and standing reserve and response is optimized ex-ante to minimise the expected cost of providing these services, and advanced stochastic generation scheduling models are used to calibrate the amount of reserve and response scheduled in WeSIM[40,41]. 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; (iii) minimum up and down time constraints; and (iv) available frequency response and reserve constraints. In order to keep the size of the problem manageable, generators are grouped according to technologies, and assume

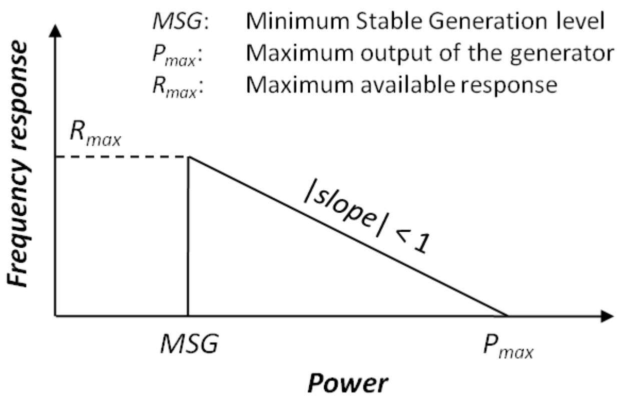
[40] A. Sturt, G. Strbac, "Efficient Stochastic Scheduling for Simulation of Wind-Integrated Power Systems", *IEEE Transactions on Power Systems*, Vol: 27, pp. 323-334, February 2012.

[41] 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, February 2012.

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 6.

- Given that the functional relationship between the available response and the reduced generation output has a slope with an absolute value considerably lower than one, 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 6 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.

- *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.

- *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 intermittent 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.[42] If there is storage in the system, WeSIM may make use of 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.[43] 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 *sharing security* in terms of capacity, i.e. the contribution from other regions to the capacity margin in the UK and vice versa is considered.

- 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.

[42] Historical levels of security supply are achieved by setting VOLL at around 10,000 £/MWh.

[43] 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, August 2011.

Inputs

All costs are in undiscounted 2015£.

The costs and performance assumptions for all other energy technologies were taken from BEIS's Dynamic Dispatch Model.

Demand Side Response

Table 24 Summary of modelling assumptions for domestic DSR*

Component	Unit	2015	2030	2050
Costs (high)**	£/kW	984	984	805
Costs (low)**	£/kW	53	43	23
Lifetime	Years	10	10	10
Maximum build rate	GW/year	1	1	1
Maximum technical potential (low/high demand)	GW	-	13/20	31/42

*Includes consumer loads such as domestic appliances, electric vehicles and heat pumps.
**Costs include CAPEX (£/kW), OPEX (£/kW/year) and payment to customers (£/kW/year).

Table 25 Summary of modelling assumptions for industrial and commercial DSR*

Component	Unit	2015	2030	2050
Costs (high)**	£/kW	400	400	400
Costs (low)**	£/kW	200	200	200
Lifetime	Years	10	10	10
Maximum build rate	GW/year	1	1	1
Maximum technical potential	GW	7	7	7

*Includes commercial loads such as large-scale refrigeration and heavy industry loads.
**Costs include CAPEX (£/kW), OPEX (£/kW/year) and payment to customers (£/kW/year).

Storage

Table 26 Summary of modelling assumptions for bulk storage*

Component	Unit	2015	2030	2050
CAPEX (high)	£/kW	1,727	1,879	2,097
CAPEX (low)	£/kW	673	673	673
Fixed OPEX	£/kW/year	6.1	6.1	6.1
Variable OPEX	£/MWh	0.7	0.7	0.7
Cycle efficiency	%	81	81	81
Duration	Hours	12	12	12
Lifetime**	Years	N/A	N/A	N/A

*Includes a basket of technologies such as pumped hydro and compressed air energy storage.
**The annual fixed OPEX is assumed to maintain the asset in perpetuity.

Table 27 Summary of modelling assumptions for distributed storage*

Component	Unit	2015	2030	2050
CAPEX (high)	£/kW	1,318	1,130	925
CAPEX (low)	£/kW	897	616	374
Fixed OPEX	£/kW/year	4.3	4.3	4.3
Variable OPEX	£/MWh	0.8	0.8	0.8
Cycle efficiency	%	90	90	90
Duration	Hours	2	2	2
Lifetime	Years	5	5	5

*Based on a basket of lithium ion battery technologies.

Table 28 Summary of modelling assumptions for fast storage*

Component	Unit	2015	2030	2050
CAPEX (high)	£/kW	1,688	1,447	1,184
CAPEX (low)	£/kW	338	290	237
Fixed OPEX	£/kW/year	4.3	4.3	4.3
Variable OPEX	£/MWh	0.2	0.2	0.2
Cycle efficiency	%	90	90	90
Duration	Hours	0.3	0.3	0.3
Lifetime	Years	20	20	20

*Includes a basket of technologies such as supercapacitors and flywheels.

More flexible CCGTs

Table 29 Summary of modelling assumptions for more flexible CCGTs*

Component	Unit	2015	2030	2050
CAPEX (high)	£/kW	770	808	808
CAPEX (low)	£/kW	477	444	432
Fixed OPEX	£/kW/year	16	16	16
Variable OPEX	£/MWh	1.4	1.4	1.4
Ramp rate	% of rated/min	90	90	90
Cold start	Hours	2	2	2
Hot start	Hours	0.7	0.7	0.7
Minimum load	% of maximum	20	20	20
Efficiency at minimum load	%	52	52	52
Efficiency at maximum load	%	60	60	60
Response capability	MWresp /MW	10%	10%	10%
Lifetime	Years	25	25	25

*These are based on next generation CCGTs with lower minimum stable generation and faster ramp rates.

Interconnectors

Table 30 Summary of modelling assumptions for interconnectors

Component	Unit	2015	2030	2050
Cost (high)	£m/MW	1.7	1.7	1.7
Cost (low)	£m/MW	0.3	0.3	0.3
Response capability	% of total capacity	7.5	7.5	7.5
Full power reversal	Seconds	0.2	0.2	0.2
Lifetime	Years	N/A	N/A	N/A

Scenarios

Table 31 Summary of the twelve core scenarios and their parameters

Scenario	De	St	Ds	In	System demand	Cost of storage	Cost of DSR	Interconnector deployment
S1	●	●	●	●	Low	Low	Low	Delayed
S2	●	●	●	●	Low	Low	Low	Full
S3	●	●	●	●	Low	Low	High	Full
S4	●	●	●	●	Low	High	Low	Full
S5	●	●	●	●	Low	High	High	Delayed
S6	●	●	●	●	Low	High	High	Full
S7	●	●	●	●	High	Low	Low	Delayed
S8	●	●	●	●	High	Low	Low	Full
S9	●	●	●	●	High	Low	High	Full
S10	●	●	●	●	High	High	Low	Full
S11	●	●	●	●	High	High	High	Delayed
S12	●	●	●	●	High	High	High	Full

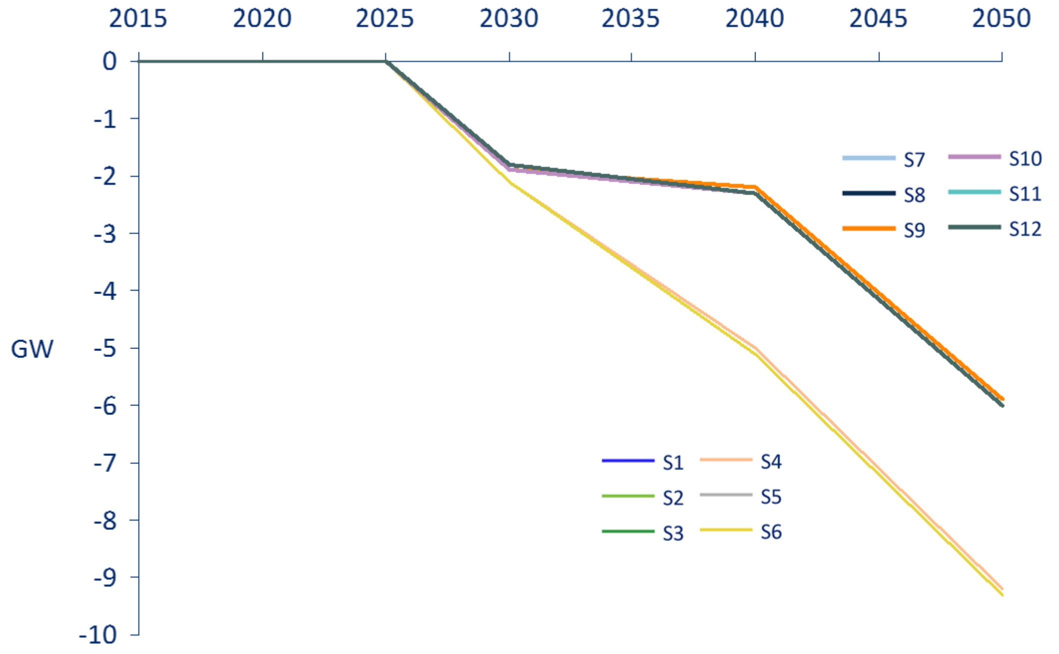
Table 32 Summary of the scenarios with no deployment of the flexibility technologies in focus and their parameters

Scenario	Carbon constraint	System demand
N1	Yes	Low
N2	Yes	High

Results: optimal deployment runs

Impact of flexibility technologies on low carbon generation and peaking plants

Chart 29 Impact of deploying flexibility technologies on the necessary deployment of low carbon generation* between the twelve core scenarios and no flexibility scenarios (N1, N2)

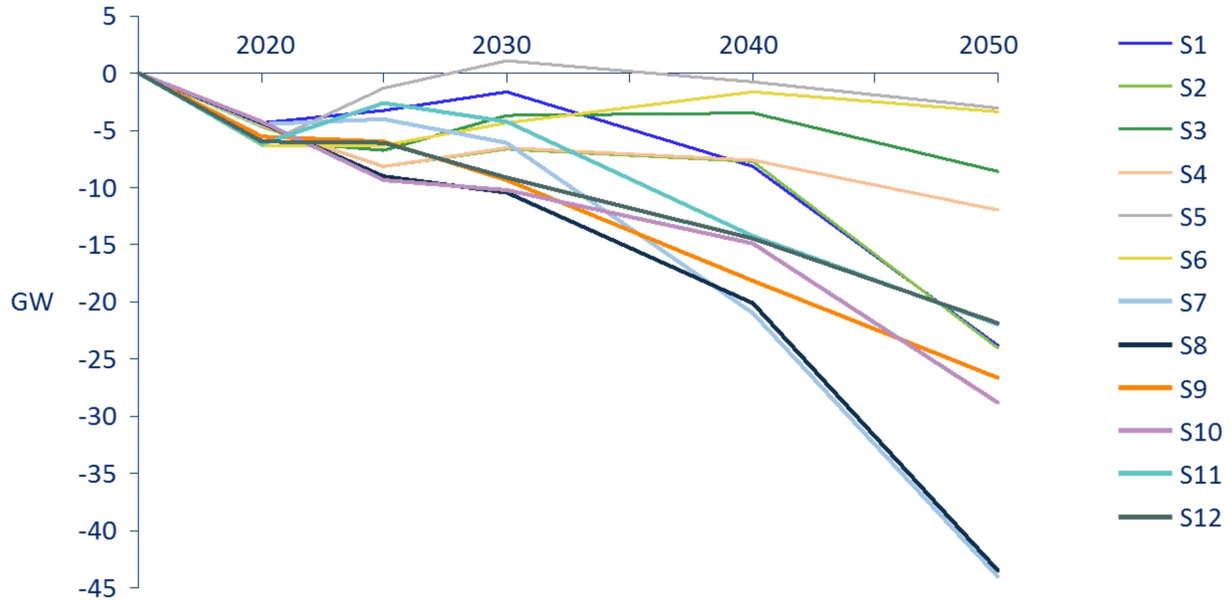


*Gas CCS.
**The differences between the deployments of low carbon generation in the core scenarios compared to the appropriate no flexibility scenarios.

Table 33 Avoided low carbon generation deployment by scenario, in GW

Scenario	De	St	Ds	In	2020	2030	2050
S1	●	●	●	●	0	-2.1	-9.3
S2	●	●	●	●	0	-2.1	-9.2
S3	●	●	●	●	0	-2.1	-9.2
S4	●	●	●	●	0	-2.1	-9.2
S5	●	●	●	●	0	-2.1	-9.3
S6	●	●	●	●	0	-2.1	-9.3
S7	●	●	●	●	0	-1.9	-6
S8	●	●	●	●	0	-1.9	-6
S9	●	●	●	●	0	-1.9	-5.9
S10	●	●	●	●	0	-1.9	-6
S11	●	●	●	●	0	-1.8	-6
S12	●	●	●	●	0	-1.8	-6

Chart 30 Impact of deploying flexibility technologies on the necessary deployment of peaking plants* between the twelve core scenarios and no flexibility scenarios (N1, N2)**



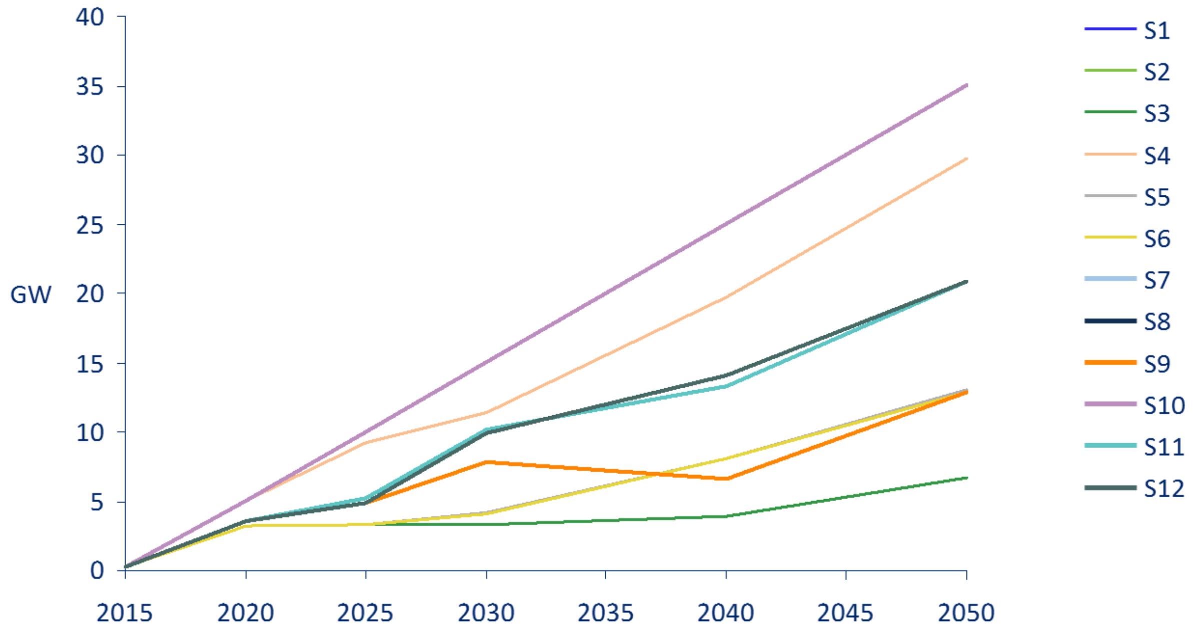
*OCGTs and reciprocating engines.
**The differences between the deployments of peaking plants in the core scenarios compared to the appropriate no flexibility scenarios.

Table 34 Avoided peaking plant deployment by scenario, in GW

Scenario	De	St	Ds	In	2020	2030	2050
S1	○	○	○	○	-4.3	-1.6	-23.8
S2	○	○	○	●	-4.7	-6.6	-24
S3	○	○	●	●	-5.9	-3.7	-8.6
S4	○	●	○	●	-4.6	-6.5	-12
S5	○	●	●	○	-6.3	1.1	-3
S6	○	●	●	●	-6.3	-4.3	-3.4
S7	●	○	○	○	-4.5	-6.1	-44
S8	●	○	○	●	-4.4	-10.4	-43.5
S9	●	○	●	●	-5.5	-9.4	-26.6
S10	●	●	○	●	-4.2	-10.2	-28.8
S11	●	●	●	○	-6.2	-4.2	-22
S12	●	●	●	●	-6	-9.1	-21.9

Optimal deployment of DSR

Chart 31 Optimal deployment of DSR to 2050 across the twelve core scenarios*



*Includes 0.3 GW of legacy DSR capacity.

Table 35 Optimal DSR deployment by scenario, in GW

Scenario	De	St	Ds	In	2020	2030	2050
S1	●	●	●	●	5	11.4	29.7
S2	●	●	●	●	5	11.4	29.7
S3	●	●	●	●	3.2	3.3	6.7
S4	●	●	●	●	5	11.4	29.7
S5	●	●	●	●	3.2	4.2	13
S6	●	●	●	●	3.2	4.1	12.9
S7	●	●	●	●	5	15	35
S8	●	●	●	●	5	15	35
S9	●	●	●	●	3.6	7.8	12.9
S10	●	●	●	●	5	15	35
S11	●	●	●	●	3.6	10.2	20.9
S12	●	●	●	●	3.6	9.9	20.9

Table 35 above represents the total sum of the deployment of the different components of DSR as shown below in Tables 36-39.

Table 36 Optimal industrial and commercial DSR deployment by scenario, in GW

Scenario	De	St	Ds	In	2020	2030	2050
S1	●	●	●	●	0.4	3.2	3.0
S2	●	●	●	●	0.4	3.2	3.0
S3	●	●	●	●	3.2	3.2	3.0
S4	●	●	●	●	0.5	3.2	3.0
S5	●	●	●	●	3.2	3.2	3.0
S6	●	●	●	●	3.2	3.2	3.0
S7	●	●	●	●	0.4	3.6	4.6
S8	●	●	●	●	0.4	3.6	4.6
S9	●	●	●	●	3.6	3.6	4.6
S10	●	●	●	●	0.4	3.6	4.6
S11	●	●	●	●	3.6	3.6	4.6
S12	●	●	●	●	3.6	3.6	4.6

Table 37 Optimal domestic DSR deployment by scenario, in GW

Scenario	De	St	Ds	In	2020	2030	2050
S1	●	●	●	●	4.6	4.8	4.6
S2	●	●	●	●	4.6	4.8	4.6
S3	●	●	●	●	0.0	0.1	3.7
S4	●	●	●	●	4.5	4.8	4.6
S5	●	●	●	●	0.0	0.6	4.6
S6	●	●	●	●	0.0	0.7	4.6
S7	●	●	●	●	4.6	5.1	5.3
S8	●	●	●	●	4.6	5.1	5.3
S9	●	●	●	●	0.0	1.5	4.4
S10	●	●	●	●	4.6	5.1	5.3
S11	●	●	●	●	0.0	3.1	5.3
S12	●	●	●	●	0.0	2.4	5.3

Table 38 Optimal electric vehicles DSR deployment by scenario, in GW

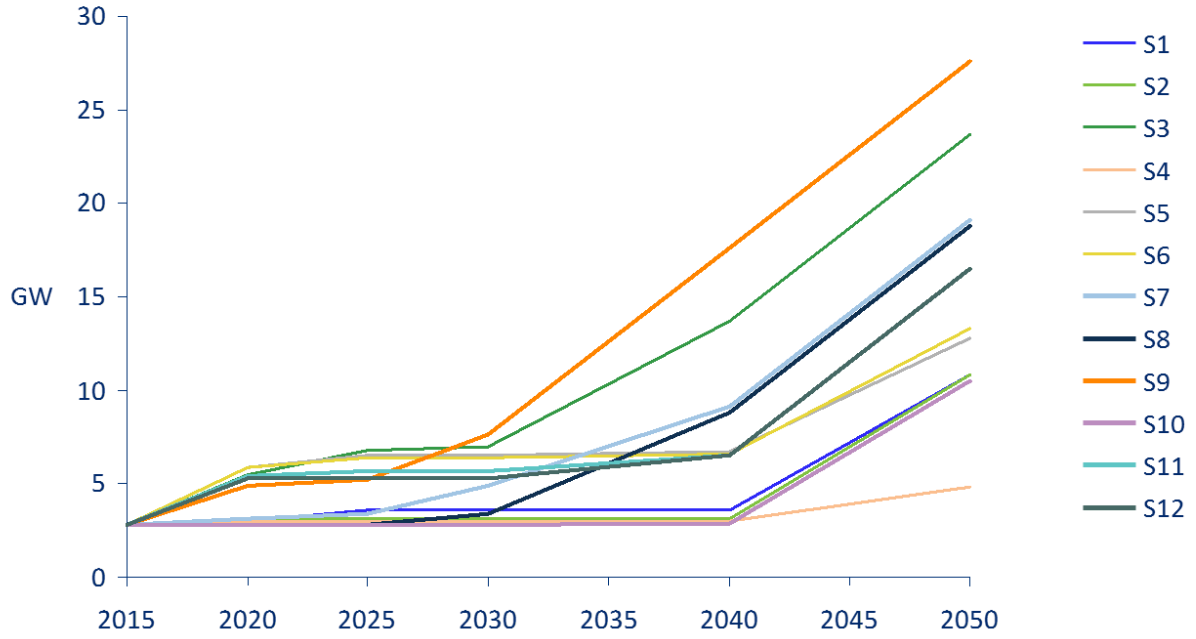
Scenario	De	St	Ds	In	2020	2030	2050
S1	●	●	●	●	0.0	0.9	14.7
S2	●	●	●	●	0.0	0.9	14.7
S3	●	●	●	●	0.0	0.0	0.0
S4	●	●	●	●	0.0	0.9	14.7
S5	●	●	●	●	0.0	0.0	0.0
S6	●	●	●	●	0.0	0.0	0.0
S7	●	●	●	●	0.0	2.4	14.1
S8	●	●	●	●	0.0	2.4	14.1
S9	●	●	●	●	0.0	0.0	0.0
S10	●	●	●	●	0.0	2.4	14.1
S11	●	●	●	●	0.0	0.0	0.0
S12	●	●	●	●	0.0	0.0	0.0

Table 39 Optimal heat DSR deployment by scenario, in GW

Scenario	De	St	Ds	In	2020	2030	2050
S1	●	●	●	●	0.0	2.6	7.3
S2	●	●	●	●	0.0	2.6	7.3
S3	●	●	●	●	0.0	0.0	0.0
S4	●	●	●	●	0.0	2.6	7.3
S5	●	●	●	●	0.0	0.3	5.4
S6	●	●	●	●	0.0	0.2	5.3
S7	●	●	●	●	0.0	3.8	11.0
S8	●	●	●	●	0.0	3.8	11.0
S9	●	●	●	●	0.0	2.6	3.9
S10	●	●	●	●	0.0	3.8	11.0
S11	●	●	●	●	0.0	3.5	11.0
S12	●	●	●	●	0.0	3.8	11.0

Optimal deployment of storage

Chart 32 Optimal deployment of storage to 2050 across the twelve core scenarios*



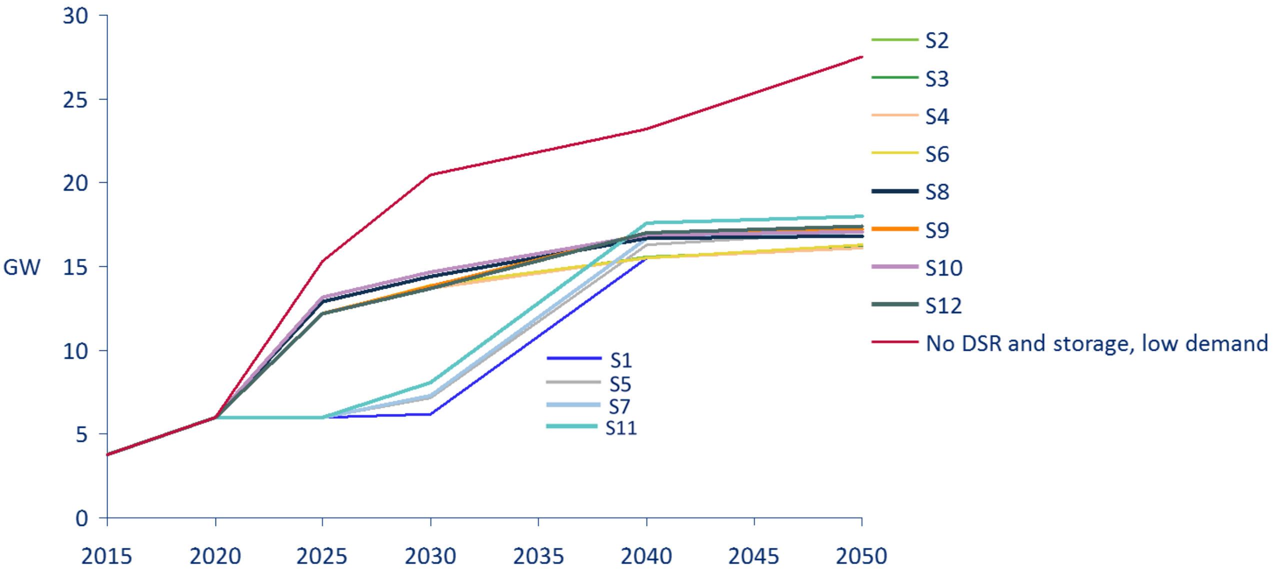
*Includes 2.8 GW of legacy storage capacity.

Table 40 Optimal storage deployment by scenario, in GW

Scenario	De	St	Ds	In	2020	2030	2050
S1	●	●	●	●	3	3.6	10.8
S2	●	●	●	●	3.1	3.1	10.8
S3	●	●	●	●	5.5	7	23.7
S4	●	●	●	●	3	3	4.8
S5	●	●	●	●	5.9	6.5	12.8
S6	●	●	●	●	5.9	6.4	13.3
S7	●	●	●	●	3.1	4.9	19.1
S8	●	●	●	●	2.8	3.4	18.8
S9	●	●	●	●	4.9	7.6	27.6
S10	●	●	●	●	2.8	2.8	10.5
S11	●	●	●	●	5.4	5.7	16.5
S12	●	●	●	●	5.3	5.3	16.5

Optimal deployment of interconnectors

Chart 33 Optimal deployment of interconnectors to 2050 across the twelve core scenarios*



*Includes 4 GW of legacy interconnector capacity.

Table 41 Optimal interconnector deployment by scenario, in GW

Scenario	De	St	Ds	In	2020	2030	2050
S1	○	○	○	○	6	6.2	16.1
S2	○	○	○	●	6	13.7	16.1
S3	○	○	●	●	6	13.8	16.2
S4	○	●	○	●	6	13.7	16.1
S5	○	●	●	○	6	7.2	17.1
S6	○	●	●	●	6	13.9	16.3
S7	●	○	○	○	6	7.3	17.1
S8	●	○	○	●	6	14.4	16.8
S9	●	○	●	●	6	13.8	17.2
S10	●	●	○	●	6	14.7	17.1
S11	●	●	●	○	6	8.1	18
S12	●	●	●	●	6	13.7	17.4
No DSR and storage, low demand	○	-	-	-	6	20.5	27.5

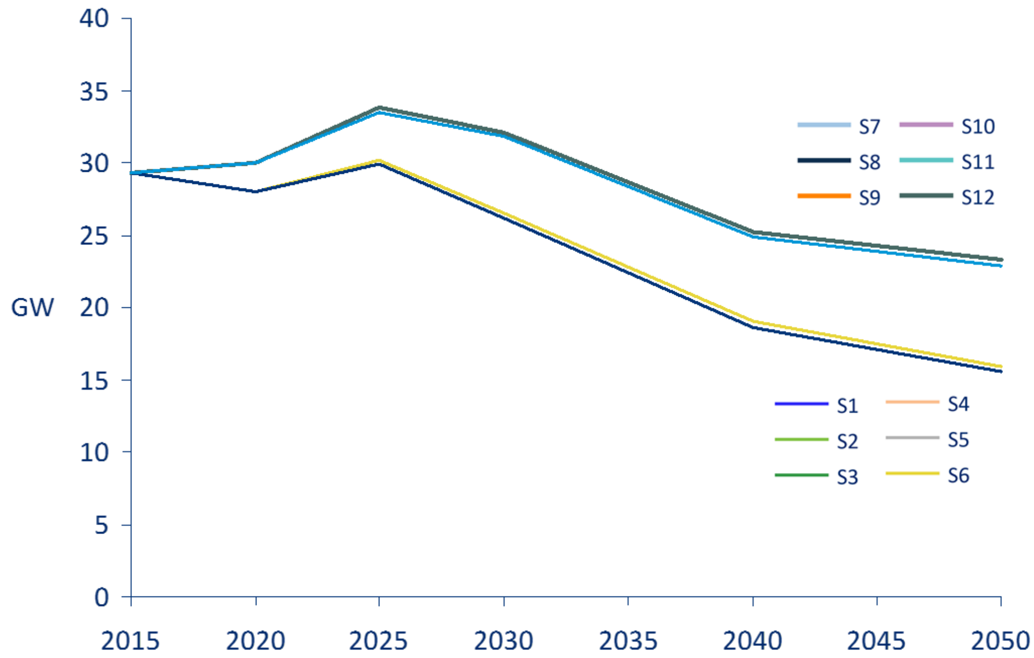
Table 41 above represents the total sum of the deployment of the different interconnections the UK could have with Europe. Table 42 below outlines these different interconnections in GW, for the scenario that has no DSR and storage.

Table 42 Breakdown of optimal interconnector deployment by connection for 'No DSR and storage' scenario, in GW

Interconnection	2020	2030	2050
GB-Ireland	1.0	2.3	2.5
GB-Norway	0	2.3	2.3
GB-Iberia	0	3.2	4.6
GB-France	3.0	6.4	7.8
GB-Belgium	1.0	3.8	3.8
GB-Netherlands	1.0	1.0	3.3
GB-Denmark	0	1.4	3.3
Total	6	20.5	27.5

Deployment of conventional CCGTs

Chart 34 Deployment of conventional CCGTs to 2050 across the twelve core scenarios*



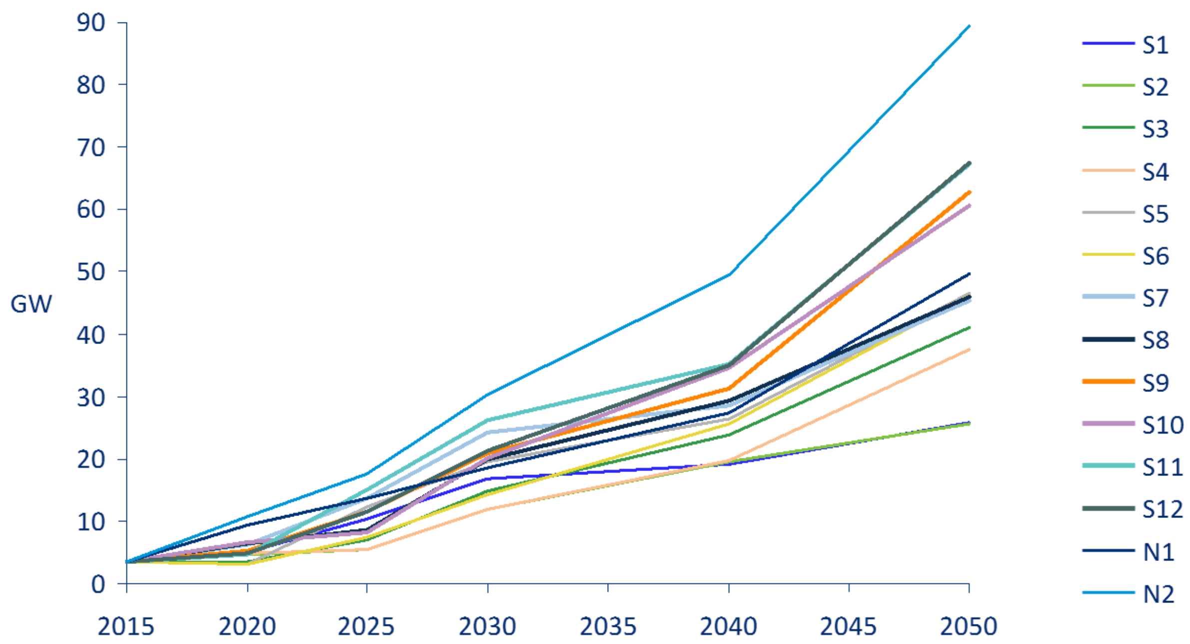
*Includes 29 GW of legacy CCGT capacity.

Table 43 Conventional CCGT deployment by scenario, in GW

Scenario	De	St	Ds	In	2020	2030	2050
S1	●	●	●	●	28	26.5	15.9
S2	●	●	●	●	28	26.5	15.9
S3	●	●	●	●	28	26.5	15.9
S4	●	●	●	●	28	26.5	15.9
S5	●	●	●	●	28	26.5	15.9
S6	●	●	●	●	28	26.5	15.9
S7	●	●	●	●	30	32.1	23.3
S8	●	●	●	●	30	32.1	23.3
S9	●	●	●	●	30	32.1	23.3
S10	●	●	●	●	30	32.1	23.3
S11	●	●	●	●	30	32.1	23.3
S12	●	●	●	●	30	32.1	23.3

Optimal deployment of peaking plants

Chart 35 Optimal deployment of peaking plants to 2050 across the twelve core scenarios and the two no flexibility scenarios*



*Includes 3.5 GW of legacy OCGT and reciprocating engine capacity.

Table 44 Optimal peaking plant deployment by scenario, in GW

Scenario	De	St	Ds	In	2020	2030	2050
S1	●	●	●	●	5.1	16.9	25.8
S2	●	●	●	●	4.7	11.9	25.6
S3	●	●	●	●	3.5	14.8	41
S4	●	●	●	●	4.8	12	37.6
S5	●	●	●	●	3.1	19.6	46.6
S6	●	●	●	●	3.1	14.2	46.2
S7	●	●	●	●	6.3	24.3	45.4
S8	●	●	●	●	6.4	20	45.9
S9	●	●	●	●	5.3	21	62.8
S10	●	●	●	●	6.6	20.2	60.6
S11	●	●	●	●	4.6	26.2	67.4
S12	●	●	●	●	4.8	21.3	67.5
N1	●	-	-	-	9.4	18.5	49.6
N2	●	-	-	-	10.8	30.4	89.4

Results: ‘least worst regrets’

Summary table of the Pathways

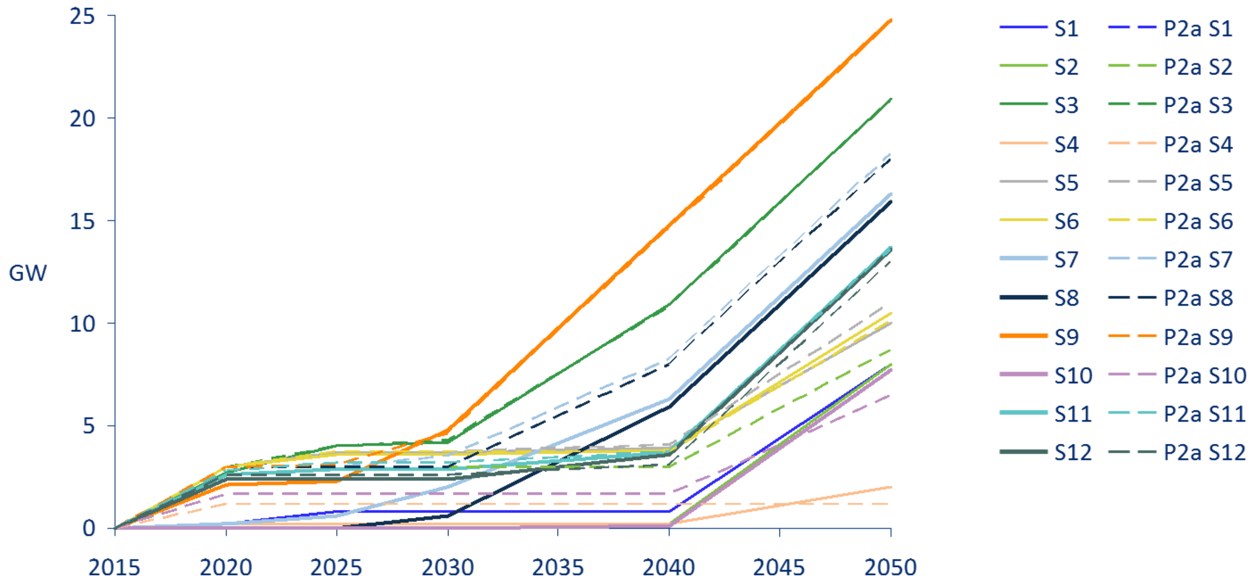
Table 45 Summary of the deployment profiles for the Pathways across the different technologies

Pathway	DSR in 2020	Storage in 2020	Flexible CCGT in 2020	Additional interconnection in 2025
P1a	2-5	-	-	-
P1b	5	-	-	-
P1c	5	-	-	1
P2a	-	1.2-3	-	-
P2b	-	3	-	-
P3a	1-5	0.5-3	1	-
P3b	2.5-5	1.2-3	1	-
P3c	2.5	1.5	0.5	0.5
P4a	-	-	-	-
P4b	-	-	-	-

- In **Pathway 1a** the level of DSR deployment in 2020 was set at a minimum of 2 GW and a maximum of 5GW, the deployment of additional storage and more flexible CCGT was set at zero in 2020, and no additional interconnection is installed between 2020 and 2025.
- **Pathway 1b** the level of DSR deployment in 2020 was fixed at 5 GW in 2020, the deployment of additional storage and more flexible CCGT was set at zero in 2020, and no additional interconnection is installed between 2020 and 2025.
- **Pathway 1c** is similar to 1b apart from the addition of an extra 1 GW of interconnection on top of the existing pipeline by 2025.
- In **Pathway 2a** the model is forced to deploy storage capacity of between 1.2 GW and 3 GW to 2020, the deployment of additional DSR and more flexible CCGT was set at zero in 2020, and no additional interconnection is installed between 2020 and 2025.
- **In Pathway 2b** the level of storage capacity is set at 3 GW in 2020, the deployment of additional DSR and more flexible CCGT was set at zero in 2020, and no additional interconnection is installed between 2020 and 2025.
- **Pathway 3a** is a ‘balanced pathway’ where DSR and storage are allowed to deploy within the set ranges, 1 GW of flexible CCGT is deployed, and no additional interconnection is installed between 2020 and 2025.
- **Pathway 3b** is another ‘balanced pathway’ with the same level of flexible CCGT deployed in 2020 as 3a, but the deployments of DSR and storage are set within a smaller range, whilst there is no additional interconnection by 2025.
- In **Pathway 3c** the initial deployment across all DSR, storage and more flexible CCGTs is fixed at various levels and there is 0.5 GW of additional interconnector capacity in 2025.
- **Pathway 4a** is a ‘do nothing’ pathway, where the deployment of DSR, storage and more flexible CCGT is set to zero in 2020, growth in the next 5 years is slow with a more constrained build rate from 2020 to 2025, and no additional interconnection is installed between 2020 and 2025.
- **Pathway 4b** is another ‘do nothing’ pathway, but there is no additional constraint on the build rates beyond 2020.

‘Least worst regrets’ analysis P2a example

Chart 36 Optimal deployment of additional storage in all the core scenarios compared to additional deployment in the P2a equivalents, to 2050



Summary results of the ‘least worst regrets’ analysis

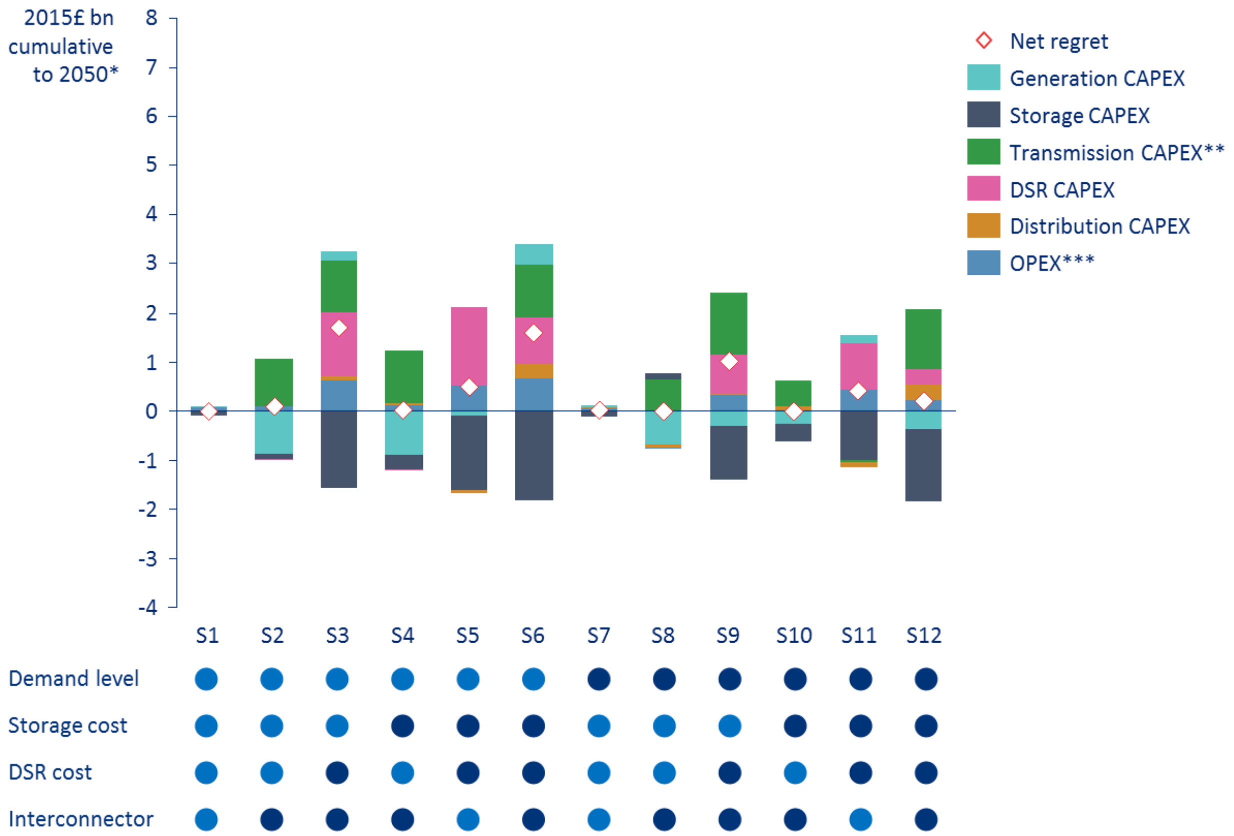
Table 46 Matrix showing the regret across every Pathway with every Scenario, 2015£ million cumulative to 2050*

	S1	S2	S3	S4	S5	S6	S7	S8	S9	S10	S11	S12	Worst regret
P1a	0.0	0.1	1.7	0.0	0.5	1.6	0.0	0.0	1.0	0.0	0.4	0.2	1.7
P1b	0.0	0.1	2.8	0.0	1.7	2.8	0.0	0.0	2.1	0.0	1.7	1.5	2.8
P1c	0.0	0.1	2.8	0.0	1.5	2.8	0.0	0.0	2.1	0.0	1.4	1.5	2.8
P2a	2.6	3.1	1.6	2.2	0.3	1.8	6.4	6.1	1.6	5.8	0.0	0.0	6.4
P2b	2.6	3.1	1.6	3.4	0.3	1.8	6.4	6.1	1.6	6.7	0.9	0.9	6.7
P3a	0.0	0.2	1.4	0.1	0.2	1.3	0.1	0.0	0.7	0.1	0.0	0.0	1.4
P3b	0.1	0.6	1.8	0.7	0.7	1.8	0.2	0.1	1.3	0.4	0.6	0.5	1.8
P3c	0.8	1.3	2.2	1.4	0.8	2.3	2.9	2.8	1.7	3.1	1.0	1.1	3.1
P4a	4.5	4.3	1.8	4.4	0.8	1.6	9.0	8.5	1.7	8.9	1.6	1.4	9.0
P4b	2.3	2.4	1.8	2.4	0.4	1.7	6.4	6.0	1.5	6.3	1.0	0.9	6.4
De	●	●	●	●	●	●	●	●	●	●	●	●	
St	●	●	●	●	●	●	●	●	●	●	●	●	
Ds	●	●	●	●	●	●	●	●	●	●	●	●	
In	●	●	●	●	●	●	●	●	●	●	●	●	

Least worst regret	P3a	1.4

Pathway 1a – High range of DSR deployment; no distributed storage, flexible CCGT or additional interconnector

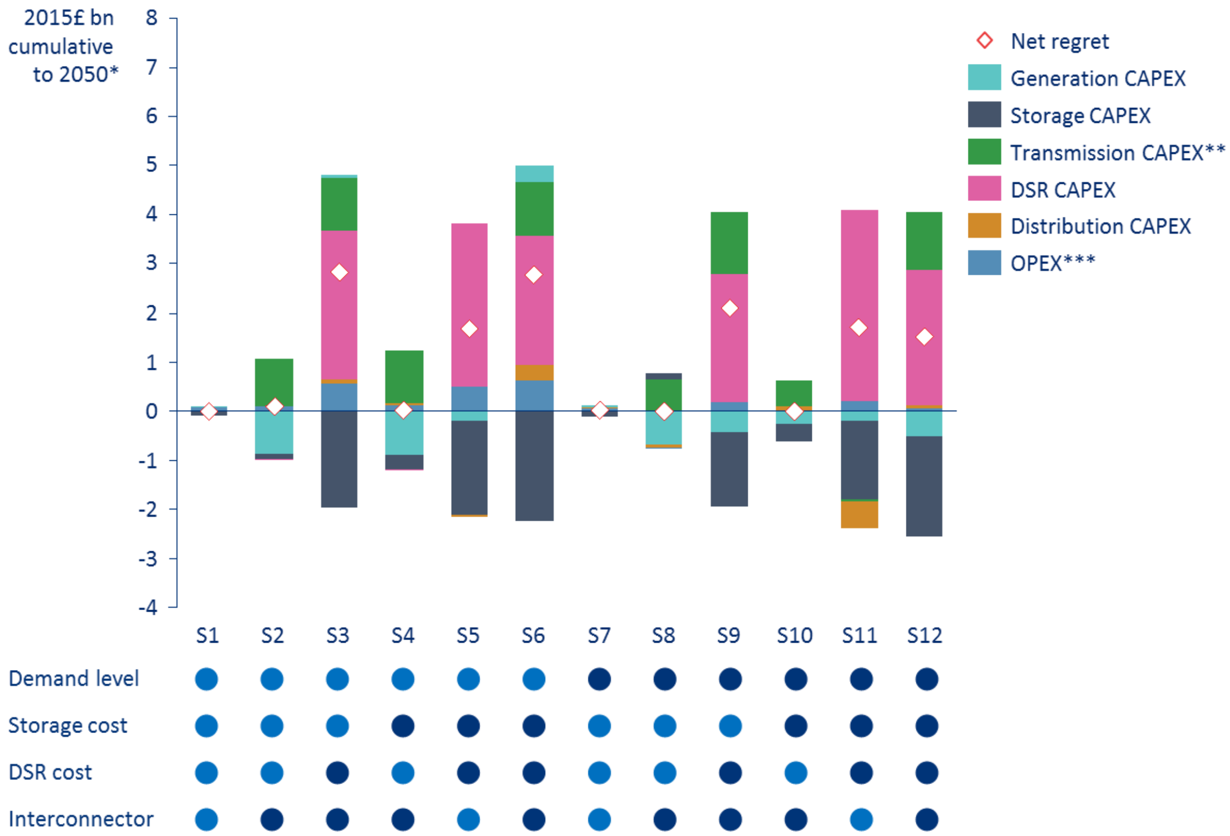
Chart 37 Cost difference between the optimal deployment and P1a for the twelve core scenarios, cumulative to 2050



*Discounted back to 2015 using HM Treasury's Green Book social discount rate.
**Includes interconnector and onshore transmission CAPEX.
***Refers to variable OPEX (fuel and carbon costs). Fixed OPEX is included in CAPEX figures.

Pathway 1b – High fixed DSR deployment; no distributed storage, flexible CCGT or additional interconnector

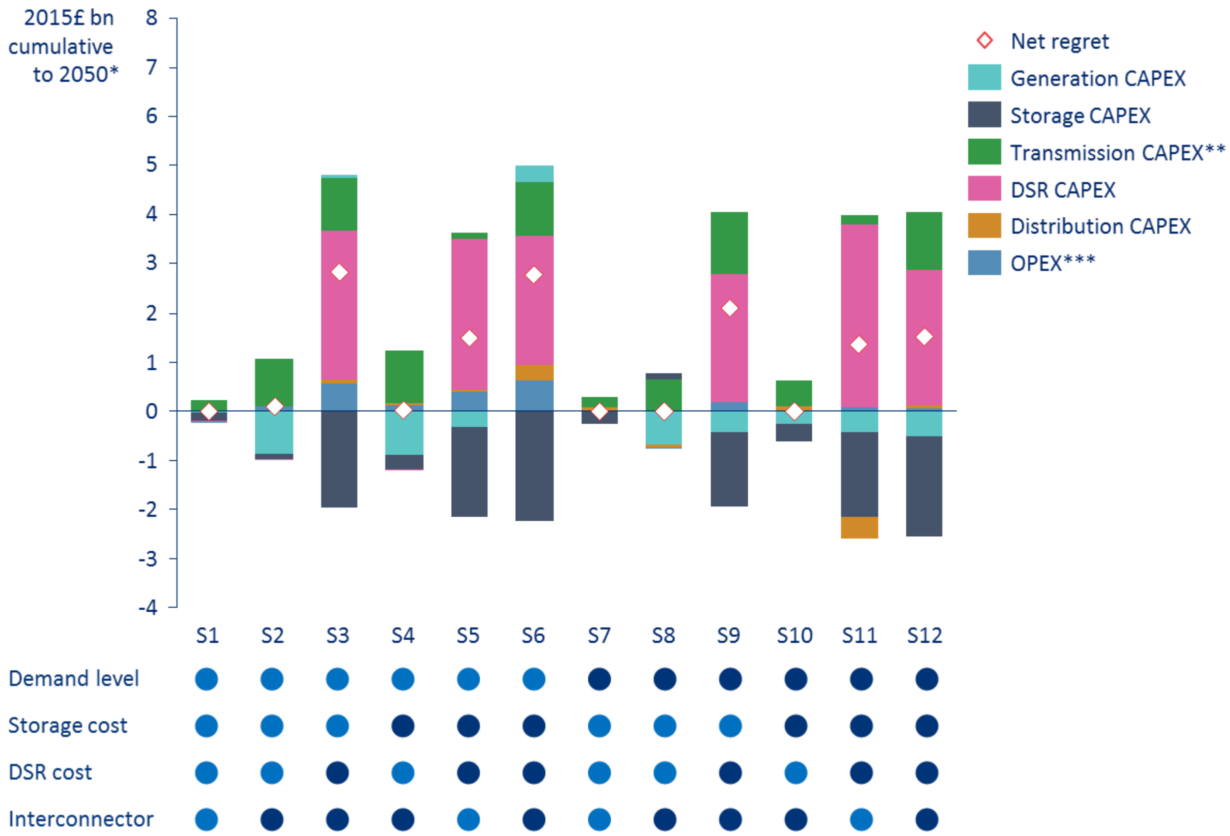
Chart 38 Cost difference between the optimal deployment and P1b for the twelve core scenarios, cumulative to 2050



*Discounted back to 2015 using HM Treasury's Green Book social discount rate.
**Includes interconnector and onshore transmission CAPEX.
***Refers to variable OPEX (fuel and carbon costs). Fixed OPEX is included in CAPEX figures.

Pathway 1c – High fixed DSR deployment with additional interconnector; no distributed storage or flexible CCGT

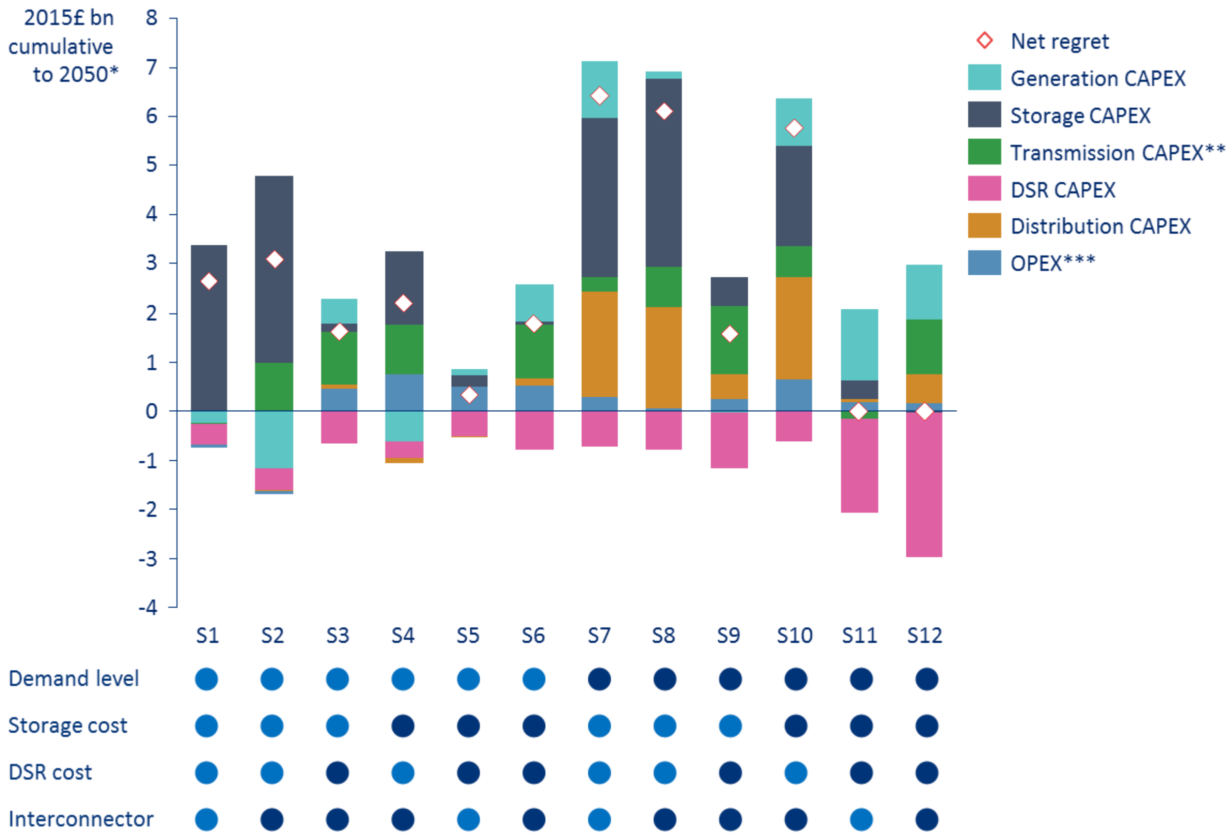
Chart 39 Cost difference between the optimal deployment and P1c for the twelve core scenarios, cumulative to 2050



*Discounted back to 2015 using HM Treasury's Green Book social discount rate.
**Includes interconnector and onshore transmission CAPEX.
***Refers to variable OPEX (fuel and carbon costs). Fixed OPEX is included in CAPEX figures.

Pathway 2a – High range of storage deployment; no DSR, flexible CCGT or additional interconnector

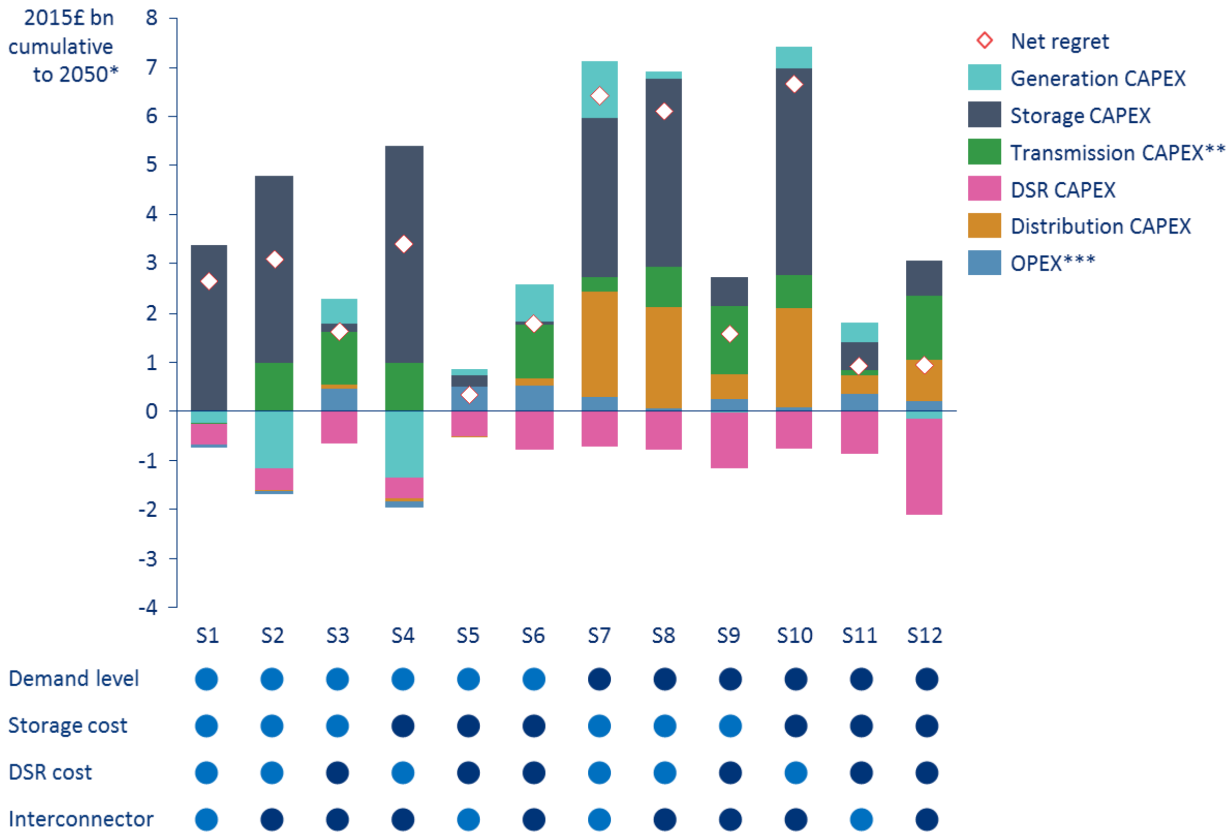
Chart 40 Cost difference between the optimal deployment and P2a for the twelve core scenarios, cumulative to 2050



*Discounted back to 2015 using HM Treasury's Green Book social discount rate.
**Includes interconnector and onshore transmission CAPEX.
***Refers to variable OPEX (fuel and carbon costs). Fixed OPEX is included in CAPEX figures.

Pathway 2b – High fixed storage deployment; no DSR, flexible CCGT or additional interconnector

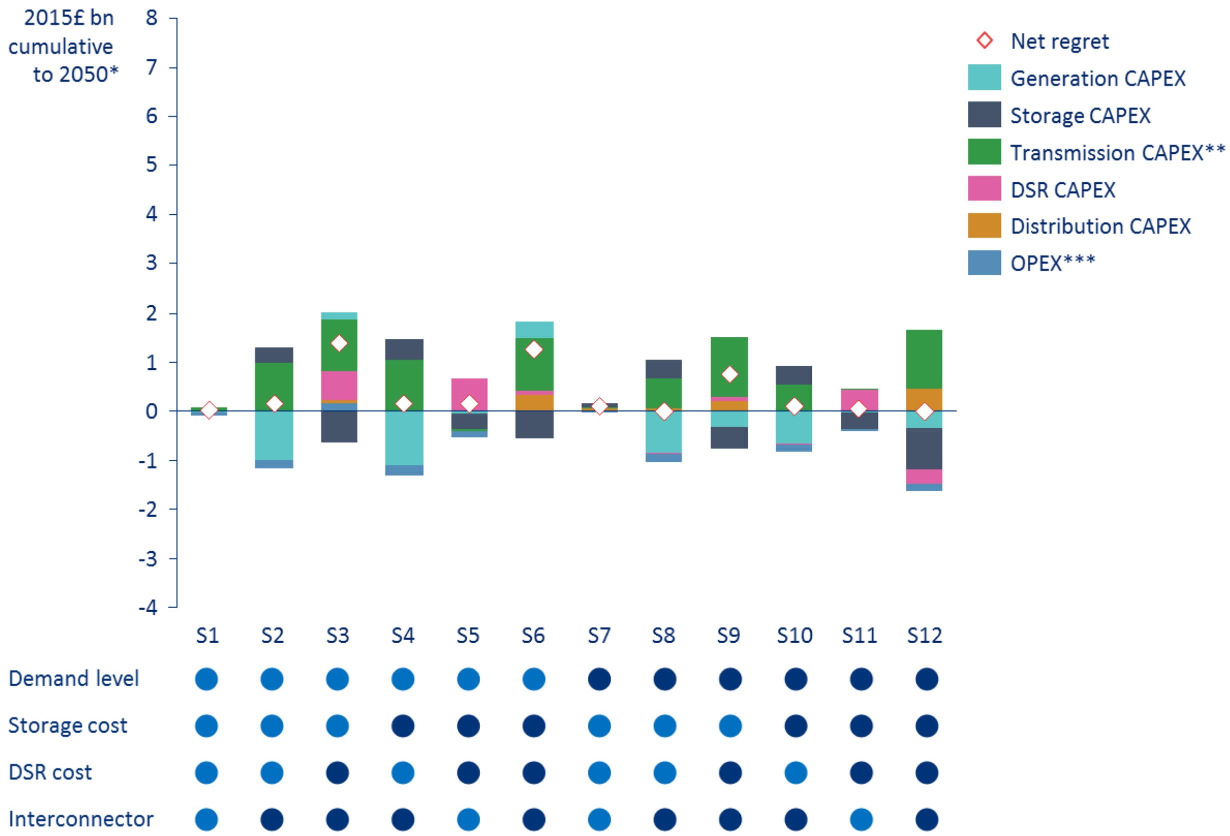
Chart 41 Cost difference between the optimal deployment and P2b for the twelve core scenarios, cumulative to 2050



*Discounted back to 2015 using HM Treasury's Green Book social discount rate.
**Includes interconnector and onshore transmission CAPEX.
***Refers to variable OPEX (fuel and carbon costs). Fixed OPEX is included in CAPEX figures.

Pathway 3a – Balanced range of deployment across DSR, storage and flexible CCGT; no additional interconnector

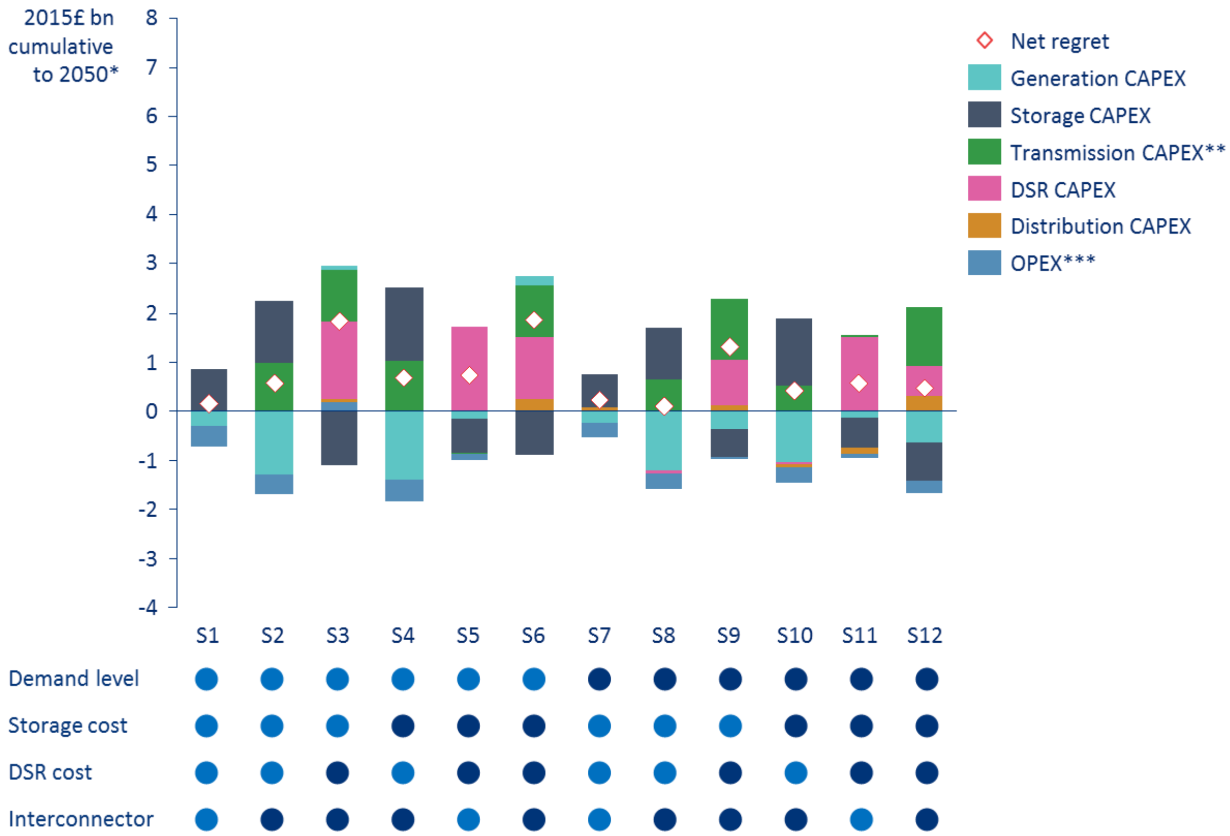
Chart 42 Cost difference between the optimal deployment and P3a for the twelve core scenarios, cumulative to 2050



*Discounted back to 2015 using HM Treasury's Green Book social discount rate.
**Includes interconnector and onshore transmission CAPEX.
***Refers to variable OPEX (fuel and carbon costs). Fixed OPEX is included in CAPEX figures.

Pathway 3b – Balanced small range of deployment across DSR, storage and flexible CCGT; no additional interconnector

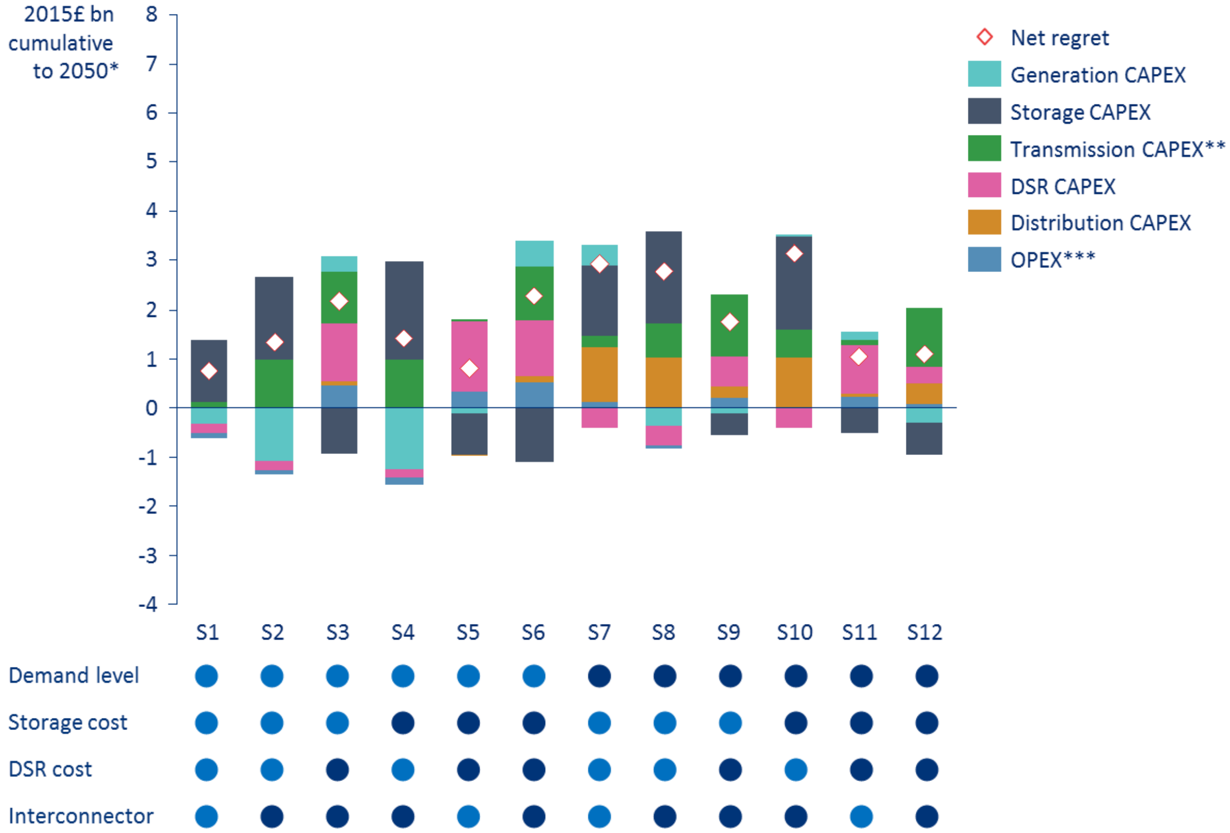
Chart 43 Cost difference between the optimal deployment and P3b for the twelve core scenarios, cumulative to 2050



*Discounted back to 2015 using HM Treasury's Green Book social discount rate.
**Includes interconnector and onshore transmission CAPEX.
***Refers to variable OPEX (fuel and carbon costs). Fixed OPEX is included in CAPEX figures.

Pathway 3c – Balanced fixed deployment across the four flexibility technologies

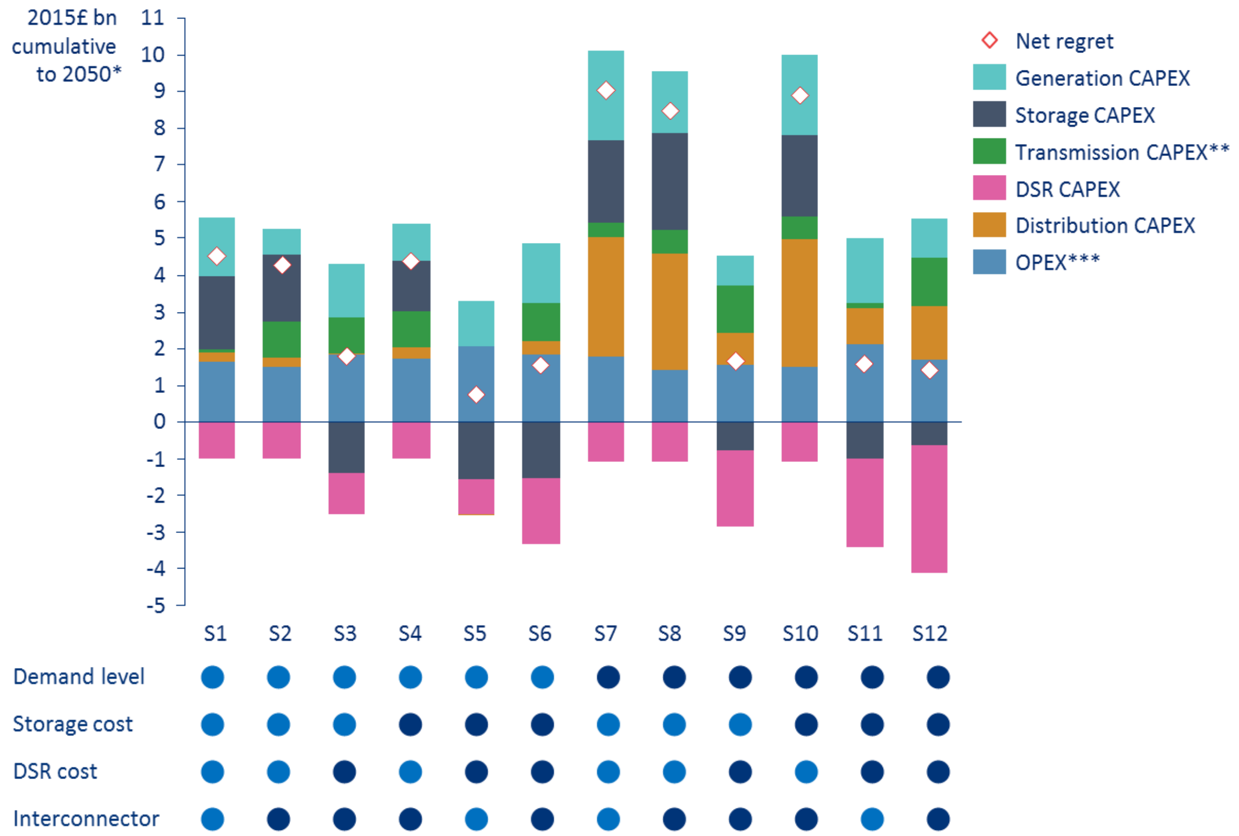
Chart 44 Cost difference between the optimal deployment and P3c for the twelve core scenarios, cumulative to 2050



*Discounted back to 2015 using HM Treasury's Green Book social discount rate.
**Includes interconnector and onshore transmission CAPEX.
***Refers to variable OPEX (fuel and carbon costs). Fixed OPEX is included in CAPEX figures.

Pathway 4a – Deploy no flexibility technologies until after 2020, with a build constraint of 50% from 2020-2025

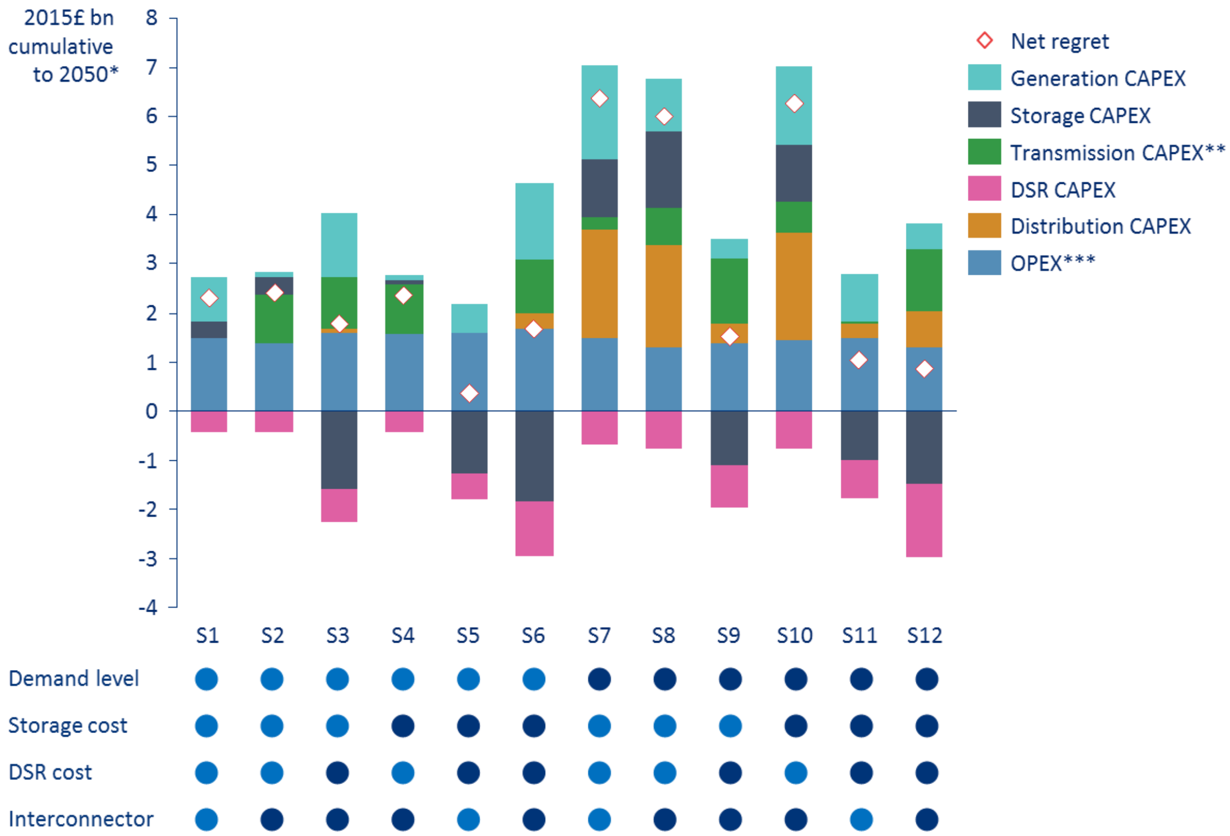
Chart 45 Cost difference between the optimal deployment and P4a for the twelve core scenarios, cumulative to 2050



*Discounted back to 2015 using HM Treasury's Green Book social discount rate.
**Includes interconnector and onshore transmission CAPEX.
***Refers to variable OPEX (fuel and carbon costs). Fixed OPEX is included in CAPEX figures.

Pathway 4b – Deploy no flexibility technologies until after 2020, with no build constraint after 2020

Chart 46 Cost difference between the optimal deployment and P4b for the twelve core scenarios, cumulative to 2050



*Discounted back to 2015 using HM Treasury's Green Book social discount rate.
**Includes interconnector and onshore transmission CAPEX.
***Refers to variable OPEX (fuel and carbon costs). Fixed OPEX is included in CAPEX figures.

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