Programme Area: Carbon Capture and Storage

Project: Thermal Power with CCS

Title: A framework for assessing the value for money of electricity technologies

Abstract:

The ETI commissioned Frontier Economics to develop a robust framework for comparing the costs and benefits of electricity generation, storage and interconnection investments in Great Britain (GB), and to produce transparent decision support tools that facilitate balanced and evidence-based value for money assessments. This project report develops and applies a framework for assessing value for money that can be applied by policy makers and other interested parties. The framework is designed to assess potential investment decisions in 2025 within the context of GB electricity system transition to meet carbon budgets. The project report sits alongside two transparent Excel-based tools, which can be used to apply the framework. The principles of the framework are capable of being adapted by any user, adopting their own underlying assumptions about technology costs or baseline system.

Context:

Significant investment in new electricity capacity is required over the next decades to meet carbon budgets while maintaining security of supply. Much of this investment could be driven by policy decisions, for example around the allocation of Contracts for Difference (CfDs) to alternative types of low carbon generation. Value for money is a key consideration in these policy decisions. However, there is little consensus around which technologies might provide the best value for money, once their full impacts are taken into account.

Assessing value for money is a complex and difficult task, and many different approaches and assumptions can be used, ranging from simplified metrics (e.g. levelized costs) to complex 'blackbox' modelling.

A FRAMEWORK FOR ASSESSING THE VALUE FOR MONEY OF ELECTRICITY TECHNOLOGIES

A report for the Energy Technologies Institute

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EXECUTIVE SUMMARY

Frontier Economics has been commissioned by the ETI to develop a robust framework for comparing the costs and benefits of electricity generation, storage and interconnection investments in Great Britain (GB), and to produce transparent decision support tools that facilitate their comparison.

Assessing value for money is a complex and difficult task, and many different approaches and assumptions can be used. This report sets out a framework that can be applied by policy makers and other interested parties that can help with such an assessment. We also apply this framework to present illustrative results. These look at potential investment decisions in 2025, against a baseline system where the GB electricity system is on track to meet carbon budgets[1].

Framework

Value for money can be considered from a number of perspectives. This report focusses on developing a framework to assess two aspects.

- **Net costs to society**. Our framework allows consideration of the full costs and benefits to society of alternative technologies, taking account of their impact both on the electricity system and on abatement costs in other sectors[2]. This allows for a comparison of the value for money of different technologies to UK Plc, using an approach consistent with the Government's Green Book[3].
- **Support costs and strike price equivalents**. Our framework also allows assessment of the costs to consumers and taxpayers of supporting incremental investments, both through monetary payments and favourable contract terms. This is useful for understanding the value of monetary and non-monetary support provided to investors through alternative policy arrangements and contractual terms. As part of this analysis, we also produce 'strike price equivalents'. These are estimates of the strike prices technologies would require, if the risk transfers and implicit support granted under current market and policy arrangements were removed.

For this project, we have adopted an approach that enables us to assess the value for money of alternative electricity technology investment decisions in a given year (rather than, for example, focussing on an approach to determine the overall optimal generation mix to meet carbon budgets). The value of these technologies is estimated as an increment to a baseline system. The technologies assessed include generation technologies as well as storage and interconnection.

The six steps of our recommended framework are described in Figure 1.

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1 Specifically, our baseline system is based on the BEIS Reference Scenario.

2 In line with the standard Green Book approach, wider economic benefits, such as the impact on jobs and growth, were out of scope for this study.

3 BEIS (2018), Valuation of energy use and greenhouse gas emissions, Supplementary guidance to the HM Treasury Green Book on Appraisal and Evaluation in Central Government, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/671205/Valuation_of_energy_use_and_greenhouse_gas_emissions_for_appraisal_2017.pdf

Figure 1 Overview of proposed framework

	Step	Recommended approach	Rationale
1	Decide on the scope of costs and benefits	Value for money metrics should include: ▪ whole electricity system costs; ▪ costs and benefits in other sectors; and Other issues, such as the impact on innovation and strategic security of supply should also be considered.	Non-technology costs are material and affect the ranking of technologies in terms of value for money.
2	Define the baseline system	The baseline system should represent the electricity system context for the assessment, including business as usual changes, and likely policy developments. It needs to be defined over the lifetime of the investments being assessed.	The baseline system should represent the most likely future development of the energy sector in the absence of the investment being assessed.
3	Decide on the size of the investment increment	Both small and large increments should be considered, depending on the question that is being asked.	Small increments can inform the assessment of value for money of individual investment decisions. Large increments can help inform decisions on the value for money of a change in strategy.
4	Set up the modelling	Detailed models (covering the electricity system and the wider energy system) are likely to be required.	Simpler methods may be more transparent but they may not capture important elements of value associated with system impacts.
5	Abstract from differences in treatment of technologies under current market and policy arrangements	Technologies should be assessed on a level playing field, which abstracts from current market arrangements.	Investor hurdle rates are used as a proxy for technology risks in the calculation of the net costs to society. These should ideally reflect intrinsic risk associated with the technologies rather than risks associated with the current market arrangements. When calculating the support cost to consumers, implicit support due to risk transfers and unpriced externalities should also be accounted for.
6	Produce metrics	We recommend three types of metrics are produced: ▪ net costs to society; ▪ strike price equivalents; and ▪ net support costs.	These allow both the overall costs to society and the costs to consumers to be assessed.

Source: Frontier Economics

Application of the framework and implications for policy makers

Value for money metrics should include the full set of cost and benefits associated with technologies – both within and outside the electricity sector[4]. This is because their inclusion is likely to affect the value for money ranking. This also implies that the use of partial measures such as levelised costs and strike prices should be avoided where possible.

Value for money metrics should also take account of the value of implicit support and risk transfers under the current policy and market framework. Developing this understanding is necessary to correct for the impact that the policy and market framework has on investor hurdle rates and returns and to allow technologies to be assessed on a level playing field.

The framework presented in this report illustrates the complexity associated with measuring value for money. Detailed modelling is required to capture electricity system interactions, and resulting estimates are extremely sensitive to the assumptions made, particularly regarding the definition of the baseline system (which is the electricity system context into which a specific investment is added) and the discount rates used. This implies the following.

- **It is very difficult to get to the 'right' number.** Given the degree of uncertainty around the key inputs, and the sensitivity of results to these inputs, results from single scenarios should be treated with caution. More robust conclusions are likely to require a structured assessment of a range of scenarios and uncertainties.
- **Results are context specific**. Results of value for money assessments will only apply to a certain investment date and an assumed energy system context. They should not be interpreted as 'generic' estimates that can be applied in multiple situations.
- **Ideally, instead of estimating the value for money of technologies and using this to guide policy decisions, the whole electricity system costs of technologies should be internalised in the market framework.** Many whole electricity system costs are already internalised in the current market. However, differences in Contract for Differences (CfDs) across technologies, as well as the presence of some unpriced externalities, means there is scope for further reform.

Although it is important to keep in mind these considerations, our work has provided many useful insights alongside a framework that allows a greater understanding of the drivers of value for money consideration. This is valuable as there will often be a pragmatic need to assess the value for money of alternative investments or strategies. We have produced a transparent and flexible set of tools, available alongside this report, to assist with such estimation[5]. These allow users to drill into the value for money estimates produced by 'black box' modelling, in order to better understand the main drivers and to help in explaining and using the results to guide decisions.

The results presented in this report illustrate the application of our framework. While we have aimed to base them on credible assumptions, we have not analysed multiple

[4] Wider economic benefits, such as the impact on jobs and growth, were out of scope for this study.

[5] Tool A: Whole Electricity System Cost Tool and Tool B: Investment Support Cost Tool

scenarios and sensitivities. For this reason, conclusions about the absolute or relative value for money of technologies should not be based on the results presented here.

1 INTRODUCTION

Aims of the report

Significant investment in new electricity capacity is required over the next decades to meet carbon budgets while maintaining security of supply. Much of this investment could be driven by policy decisions, for example around the allocation of Contracts for Difference (CfDs) to alternative types of low carbon generation. Value for money is a key consideration in these policy decisions. However, there is little consensus around which technologies might provide the best value for money, once their full impacts are taken into account.

Assessing value for money is a complex and difficult task and many different approaches and assumptions can be used. Metrics which provide a partial, and therefore potentially biased, picture are often quoted in policy debates.

- Levelised costs[6] are frequently used to compare the value for money of technologies. However, while these may be useful for comparing the cost of generation from technologies with similar flexibility characteristics, output patterns and network locations, they do not take account of additional factors such as reliability at times of system stress, differences in the value of electricity generated, knock-on impacts on wider system costs or externalities. All of these factors become more important in a low carbon system.
- CfD strike prices[7] are often used to compare the value for money associated with different electricity technology investments, because they give an indication of how much consumers will directly pay for the output of these technologies. However, differences both in the contractual terms of the CfDs and in the wider policy and regulatory regimes of different technologies, mean that strike price comparisons may not provide a good indication of relative value for money.

Frontier Economics has therefore been commissioned by the ETI to address this gap. The aim of this work is to bring together different perspectives on how to look at the value for money of electricity generation, storage and interconnection investments in Great Britain and to develop a framework for a balanced and evidence-based assessment that can be used by policy makers[8]. This report sits alongside two transparent Excel-based tools[9], which can be used to apply the framework set out in this report.

Scope of our framework

Value for money can be considered from a number of perspectives. This report focusses on developing a framework to assess two aspects of value for money (Figure 2).

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[6] This metric measures the lifetime technology costs of the generation, per unit of output produced.

[7] Low carbon generators are financially supported under a system of contract for differences (CfDs). Under this system, generators are paid the difference between a 'strike price' and the average market price for electricity in GB. Strike prices differ across technologies, varying, in part, according to technology costs.

[8] OCGTs, CCGTs, onshore wind, offshore wind, solar, gas CCS, biomass CCS, nuclear; storage and interconnectors.

[9] Tool A: Whole Electricity System Cost Tool and Tool B: Investment Support Cost Tool.

- **Net costs to society**: Our framework allows consideration of the full costs and benefits to society of alternative technologies (excluding wider economic impacts such as the impacts on jobs and growth). This allows for a comparison of the value for money of different technologies to UK Plc., taking an approach consistent with the Government's Green Book[10].
- **Support costs and strike price equivalents**. Our framework also allows assessment of the costs to consumers and taxpayers of supporting incremental investments under alternative market arrangements. This differs from net costs to society as it is seeking to identify the compensation investors would require over and above market revenues, to make investing in these technologies worthwhile. It therefore looks at costs from an investor, rather than a societal, perspective[11]. We also produce 'strike price equivalents' as part of this analysis. These are estimates of the strike prices that technologies would require, if the risk transfers and implicit support granted under current market and policy arrangements were removed. The analysis of the value of the support implicit in market arrangements could be used to inform the design of multi-technology (and potentially even technology-neutral) CfD auctions.

Figure 2 Aspects of value for money covered in this report

Net costs to society	Adjusted subsidy costs and strike price equivalents
• Understand full costs and benefits of electricity investments (in line with a Green Book assessment)	• Understand the value of policy and regulatory frameworks to investors • Compare required technology strike prices on a level playing field • Understand the full costs to consumers and taxpayers of supporting investment
How does the overall value for money of technologies compare?	What is the full cost to consumers and taxpayers of subsidising technologies under different market arrangements? What would strike prices look like on a level playing field?

Focus is on incremental decisions: For an investment decision in a given year, what is the value for money of alternative technologies?

Source: Frontier Economics

There are different ways of thinking about what constitutes value for money, depending on the policy questions that are being asked (Figure 3). For this project we are interested in assessing the value for money of alternative technologies to meet electricity needs for an investment decision in a given year. For this reason we look at the value for money associated with an incremental investment introduced into a given energy system context.

[10] BEIS (2018), Valuation of energy use and greenhouse gas emissions, Supplementary guidance to the HM Treasury Green Book on Appraisal and Evaluation in Central Government, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/671205/Valuation_of_energy_use_and_greenhouse_gas_emissions_for_appraisal_2017.pdf

[11] This has an impact on the approach taken to discounting. See Section 2.6.

The approach adopted considers both small and large incremental changes to that investment.

- Appraising a small incremental investment change allows us to estimate the value for money of individual investment decisions.
- Appraising a major investment change allows us to consider the value for money of a more significant change of investment strategy.

Our approach is not focussed on assessing the value for money of alternative scenarios for the overall generation mix. This would require a different approach, involving the comparison of optimised whole electricity system scenarios.

Figure 3 Incremental approach compared to a system optimisation approach

	Incremental approach	System optimisation approach
Approach	Appraising a large or small incremental investment change in a given year	Determining the system that meets carbon budgets at least cost
What question can it help with?	For a large or small investment decision in a given year, what is the value for money of alternative technologies?	Which overall generation mix would minimise the costs of meeting carbon budgets and provide maximum value for money?

Source: Frontier Economics

Structure of this report

The remainder of this report is structured as follows.

- Section 2 describes our recommended framework for assessing value for money. We also set out the approach we have applied in our modelling for this work. This is included in a box at the end of each section.
- Section 3 describes the results from a sample application of this framework, focussing on investments made in 2025.
- Section 4 sets out the insights for policy makers from the development of this framework.

FURTHER MATERIAL PUBLISHED ALONGSIDE THIS DOCUMENT

This report is accompanied by two Excel-based decision support tools.

- Tool A: Whole Electricity System Costs
- Tool B: Investment Support Costs

Further detail is also provided in three Appendices:

- Appendix 1: Modelling of whole electricity system costs
- Appendix 2: Reflecting costs and benefits beyond the electricity sector
- Appendix 3: Assessing technology support requirements

2 FRAMEWORK

Our value for money assessment framework involves the six steps described in Figure 4. In this section we describe each of the steps in turn. Further details are provided in Appendices 1-3.

Figure 4 Key steps in the value for money assessment

Step	Recommended approach
Decide on the scope of costs and benefits	Include: • Electricity system costs and benefits • Costs and benefits in other sectors • Innovation and strategic security of supply
Define the baseline energy system	Reflect: • Current trends • Likely policy developments
Decide on the size of the investment increment	Consider: • Small increment (marginal investment) • Large increment (change in investment strategy)
Set up the modelling	• Apply constraints around the loss of load expectation • Monetise carbon emissions
Abstract from different treatment of technologies under current arrangements	• Adjust hurdle rates for implicit subsidies in current market arrangements
Produce metrics	Consider: • Net costs to society • Support costs and strike price equivalents

Source: Frontier Economics

2.1 Decide on the scope of costs and benefits

Value for money assessments are often based purely on direct technology costs (for example, the levelised cost metric is often used). However, the costs over and above the direct technology costs are often material, and need to be taken into account. Therefore, a value for money assessment should include:

- an estimation of whole electricity system costs, based on electricity system modelling;
- an assessment of costs and benefits in other sectors that may result from electricity sector investments, based on bespoke modelling; and

- consideration of other issues, such as the impact on innovation and strategic security of supply, potentially based on qualitative analysis[12].

Figure 5 summarises this approach.

Figure 5 Scope of costs and benefits

Recommended approach	Rationale	Implications
Value for money metrics should include: ▪ Whole electricity system costs. ▪ Costs and benefits in other sectors. Other issues, such as the impact on innovation and strategic security of supply should also be considered.	The impacts of technologies on costs and benefits over and above their direct technology costs are material and affect the ranking of technologies in terms of value for money.	▪ Electricity system modelling is required to assess whole system impacts. ▪ Bespoke modelling may be required to assess wider costs and benefits. ▪ Qualitative analysis may be most appropriate for innovation and strategic security of supply.

Source: Frontier Economics

2.1.1 Whole Electricity System Costs

Approach and rationale

Whole Electricity System Costs (WESC) go beyond the direct technology costs associated with an investment. They measure the change in costs of constructing and operating an electricity system that result from the addition of a given quantity of a particular technology to that system. Research by Frontier Economics for DECC in 2016[13] set out an exhaustive and non-overlapping framework for breaking down the electricity system impacts of technologies, based on a review of the wider literature (Figure 6).

12 Wider economic benefits, such as the impact on jobs and growth, were out of scope for this study.

13 Frontier (2016), Whole power system impacts of electricity generation technologies, https://www.gov.uk/government/publications/whole-power-system-impacts-of-electricity-generation-technologies

Figure 6 The components of Whole Electricity System Costs[14]

Technology direct costs	▪ Capital and operational costs associated with the incremental technology.
Capacity adequacy impacts	▪ To the extent existing capacity can be retired, or new capacity forgone to ensure the same level of security of supply and carbon intensity as the counterfactual, there is a cost saving to the system.
Balancing costs	▪ If the incremental capacity impacts on the uncertainty of supply, it will affect how generators in the rest of the system are called on to help support system stability by altering their output. It will also affect the extent to which they need to be prepared to do so at short notice, potentiallyaffecting their staffing, fuel, and/or maintenance costs.
Network impacts	▪ The incremental technology may require investments to reinforce or extend the existing grid, and changes to power flow may increase or decrease power losses due to transmission and distribution. It is also possible that technologies can free up headroom on the grid, creating network benefits.
Displaced generation impacts	▪ Outputs from the incremental technology can displace higher marginal cost generation, producing variable cost savings, e.g. fuel, carbon. The scale of this is diminished if generators in the rest of the system operate less efficiently, or the incremental technology is curtailed. This category includes the impact on variable costs of ensuring that the same carbon intensity is maintained.

Source: Frontier Economics

While estimates of these impacts in the literature vary significantly, depending on the estimation approaches and assumptions used (Appendix 1), there is broad consensus on the fact that they are material enough to warrant consideration[15]. For example, Figure 5 sets out a range of estimates produced in recent papers in this area.

[14] In this framework, both generation output and capacity can be 'displaced' by the technology that is being added to the system. Capacity that is retired early or new investment that is avoided is counted in the capacity adequacy impacts category. Generation output that is avoided is counted in the displaced generation category.

[15] Our own analysis also finds that these aspects are material – see Section 3.

Figure 7 Existing papers on the value of Whole Electricity System Costs in Great Britain

	Approach	Estimates
UKERC[16] (2017)	A systematic review of around 200 journal papers, reports and other evidence sources	▪ Capacity costs:£1-17/MWh for 20% penetration ▪ Reserve costs/short-run system balancing costs: £0- £5/MWh up to 30% renewables penetration, ▪ Transmission and distribution costs: £5-20/MWh up to 30% renewables penetration
Imperial College, Joint industry project (2016)[17]	Electricity system modelling using the Imperial College Whole-electricity System Investment Model - an electricity system model covering dispatch and investment, across the generation, transmission and distribution systems	WESC, excluding technology direct costs: ▪ Onshore wind: £7/MWh-£40/MWh ▪ Offshore wind: £6/MWh-48/MWh ▪ Solar PV: £8/MWh-£44/MWh ▪ Biomass: -£7-£1/MWh
Nera and Imperial College for Drax (2016)		WESC, excluding technology direct costs: ▪ Onshore wind: £7-9/MWh ▪ Offshore wind: £7/MWh ▪ Solar PV: £12/MWh ▪ Biomass: -£1/MWh
Nera and Imperial College for the CCC (2015)		WESC, excluding technology direct costs: ▪ Wind: £6/MWh-£16/MWh ▪ Solar PV: £6/MWh-28/MWh ▪ CCS: -£8/MWh-£5/MWh
Aurora Energy Research for Solar Trade Association (2016)	Electricity system modelling based on the Aurora Energy Research Electricity System model for Great Britain (a dynamic dispatch model)	▪ Variability costs of solar at £6.8/MWh relative to baseload technology, excluding network costs
Frontier (2015) for Drax	Bespoke modelling based on DECC generation cost assumptions, TNUoS charges, National Grid estimates of balancing requirements and Ofgem estimates of capacity requirements	▪ Replacing a single biomass generating unit with the equivalent investment in offshore wind could cost an additional £650 million to £900 million over the lifetime of the investments(with transmission costs as the most important element)
OECD and the Nuclear Energy Agency (2012)	Review of existing published evidence.	▪ Onshore wind: £18-30/MWh ▪ Offshore wind: £34-45/MWh ▪ Solar PV: £57-89/MWh ▪ Nuclear: £3/MWh

Source: Frontier Economics based on the literature. Note: We have not adjusted for varying price bases.

[16] Values presented covers UK and Ireland. Values cannot be summed.

[17] Costs are for 2030.

Implications

The inclusion of the WESC of investments in an assessment of value for money means that electricity system modelling is required (for example, through the use of dispatch and network models). This is because the level of WESC depend on multiple and complex interactions between the different generation, flexibility and network technologies. For example, the impact of adding a unit of wind generation to a system may depend on a range of factors such as:

- the flexibility of the system, which in turn depends on the baseline quantity of inflexible baseload plant such as nuclear, intermittent renewables and the amount of CCGT, OCGT, storage and interconnection;
- the flexibility of demand; and
- the amount of wind that is already on the system and the correlation of the output of the new unit of wind with the output of the existing wind on the system.

WHOLE ELECTRICITY SYSTEM COSTS: OUR APPROACH IN THIS RESEARCH

To generate the illustrative results presented in Section 3 of this report and in the Whole Electricity System Costs Tool, we use LCP's EnVision model. This model provides a comprehensive simulation of most of the relevant aspects of the power system, with appropriate simplifications to ensure it can be run for multiple scenarios in a reasonable length of time. We note that this model takes a relatively simple approach to network modelling. However network costs will vary significantly by the exact location of the technology under consideration, and the relationship between capacity added, spare capacity in that location and other changes in local conditions foreseen in the future. As we are considering general archetypes and not specific project, more detailed network modelling is unlikely to add much to the questions we are looking at. However, where decision makers are assessing the value for money of specific schemes it is something that they may need to consider further.

2.1.2 Impacts on other sectors

Approach and rationale

A comprehensive value for money assessment should also take account of the positive and negative impacts that electricity sector technologies can have on other sectors[18]. In this project we have considered costs and benefits to other sectors that may be associated with electricity sector investments. Based on a literature review, we identified six main categories (Figure 6). The majority of these potential impacts are likely to relate to the thermal technologies, particularly those involving biomass and carbon capture and storage (CCS).

[18] Further information on this aspect of the framework is in Appendix 2.

Figure 8 Categories of non-electricity sector impacts

Externality	Description
Shared infrastructure	■ New infrastructure required for some electricity generation technologies (e.g. for CCS) may reduce the costs of this infrastructure for other sectors, where there are economies of scale.
Shared skills and supply chain	■ Shared skills or a shared supply chain may impact on costs, efficiency or risks in other sectors.
Shared use of scarce resources	■ Adding new plant may affect fuel demand and prices. For example, the use of biomass in the power sector may push up the costs of biomass in industry.
Innovation and knowledge externalities	■ Deployment of a technology in the power sector may produce learning relevant to the deployment of that technology in other sectors.
Energy externalities	■ Waste energy from power generation (for example waste heat) may have a value elsewhere in the energy system, for example in district heat networks.
Environmental / health externalities	■ Emissions can contribute to environmental damage or impacts on health.

Source: Frontier Economics

Our work has found that some of these wider impacts are sufficiently material to warrant inclusion in a value for money assessment. In particular we have developed illustrative examples that show potentially material impacts in the following areas[19].

- **The impact of power sector CCS deployment on industrial abatement costs, through the potential to share infrastructure.** CCS may be an important abatement option for industry, particularly in energy-intensive industries for which there are limited CO_2 abatement options currently available to meet 2050 targets.[20] CCS deployment in the power sector could affect industrial abatement cost by enabling economies of scale in the transport and storage infrastructure. It is also sometimes argued that CCS in industry would simply not be viable, without the deployment of CCS in the power sector. This is due to low CO_2 volumes from individual industrial sites, and the difficulty in making very long-term infrastructure investments given the risk of relocation or closure in response to global competition.[21] To the extent that this is the case, there may be material benefits to industry associated with deploying CCS in the power sector.
- **The impact of biomass use in the power sector on abatement costs elsewhere**. The use of biomass in the power sector might push up the costs of biomass in the rest of the economy, because there may be limits to the amount of biomass that the UK can access. A higher biomass price could increase the cost of abatement in other sectors. However, any negative impacts may be offset to the extent that the biomass

[19] These estimates rely on specific modelling assumptions and currently available information, and therefore should be regarded as illustrative, context-specific estimates of these externality impacts. Further details on the analysis are presented in Appendix 2.

[20] It may be possible to use hydrogen instead, but this is reliant on a hydrogen supply chain being in place. Source: E4Tech (2015), *Scenarios for deployment of hydrogen in contributing to meeting carbon budgets and the 2050 target.*

[21] DECC (2012), *CCS Roadmap*; Oxburgh (2016), *Lowest cost decarbonisation for the UK: The critical role of CCS.*

in the electricity sector is deployed with CCS, since biomass with CCS produces 'negative emissions' which reduce the amount of abatement required elsewhere.

- **The benefits associated with energy externalities from waste heat**. Waste energy from power generation could have a value elsewhere in the economy, for example in district heat networks. It is most likely that waste heat will come from Biomass CCS and CCGT CCS, since these technologies are more likely to be located close to population centres than nuclear, and more likely to run baseload than unabated CCGT.

Implications

The need to consider costs and benefits outside the electricity sector means that energy models that cover the whole economy such as the ETI's ESME or the TIMES model will be required. These models can be used to estimate the impact on abatement costs elsewhere in the economy of measures taken in the electricity sector. Where impacts are particularly location specific (for example to do with waste heat and shared CCS infrastructure) case studies may be helpful.

INCLUSION OF NON ELECTRICITY SECTOR COSTS AND BENEFITS: OUR APPROACH IN THIS RESEARCH

We have estimated illustrative non-electricity sector costs and benefits associated with technologies (see Appendix 2).

- **Shared infrastructure – CCS.** Using a specific case study of a potential CCS project at the Teesside industrial cluster, we estimate an external benefit to the non-power sector of £0.9/MWh. This is based on the assumption that applying CCS in the electricity sector reduces the cost of applying CCS in industry through economies of scale. Our estimate of the external benefit of CCS rises to £22/MWh (based on ESME modelling) where we assume that the CCS would not be available as a source of abatement in other sectors in the absence of CCS development in the power sector. Specifically, this is based on the assumption that developing the first 3.6GW plant in the power sector[22] would unlock opportunities for CCS elsewhere in the economy. The £22/MWh benefit would only be applicable to the output of this first plant.
- **Shared use of scarce resources.** Using ETI's ESME model, we estimate the external impact of diverting additional biomass resource to the power sector, rather than non-electricity sectors, to be -£35/MWh, where this biomass is used in unabated biomass plant. However, where biomass CCS plant is deployed instead, the 'negative emissions' associated with this plant reduce the abatement required outside the power sector, and therefore offset the external costs associated with reducing the biomass available for non-electricity sector abatement. Taking these two impacts together, biomass CCS results in an estimated external benefit of £10/MWh[23]. We

[22] The 3.6GW size of this plant is based on ETI assumptions on potential early CCS investments.

[23] Care should be taken to ensure the value of the negative emissions is not double-counted, for example this benefit may already be captured if negative emissions are already valued at BEIS appraisal value for carbon in line with the analysis presented in Appendix 1.

note that the costs of diverting biomass from the power sector may be overstated in these estimates. They are based on an assumption that there is a limited biomass resource available across the economy. In reality, biomass supply could increase in response to an increase in price.

- **Energy externalities – waste heat.** Using ETI's ESME model, we estimate the external benefit of waste heat produced from thermal plants to be £1/MWh.

While the estimates we have produced have illustrated the potential materiality and therefore the importance of investigating costs and benefits in these areas, the degree of uncertainty associated with them is significantly higher than the electricity sector WESC. This is because they rely on a wider set of assumptions on likely developments across the whole energy system. In some cases, for example, around shared CCS infrastructure, developing robust assumptions would require further research.

Because of this, we have excluded the wider impacts from the summary results we present in Section 3 and in the Tools published alongside this report.

2.1.3 Wider strategic impacts

In addition to the direct costs and benefits associated with electricity investments, policy-makers may also wish to consider wider, strategic issues such as strategic security of supply and the impact on innovation. However, we do not recommend that quantified estimates of these factors are included in the overall metrics.

- **Strategic security of supply.** A new plant may increase or decrease the reliance of the system on specific fuels or plant designs. While short term security of supply (maintaining a probability of loss of load) is factored into the estimation of WESC, it is also worth considering the impacts of investments on exposure to geopolitical risk over the longer term. Geopolitical risk could include, for example, the risks of a disruption to the supply of a particular commodity due to global political developments. These risks are likely to be associated with rare and unpredictable events. It is therefore difficult to quantify their impact. Given this, strategic security of supply benefits should be considered qualitatively, or through the consideration of multiple modelled scenarios[24].
- **Innovation and learning.** Investment in some technologies may bring down the cost of future investment, particular for less mature technologies. The relationship between UK deployment of a technology and reductions in its cost will depend on the maturity of the technology, and the extent to which UK-specific (rather than global) conditions are important. For example, UK deployment of CCS could potentially reduce costs associated with the transport and storage elements of CCS, given the importance of local geological conditions to these elements. On the other hand, cost reductions in solar PV panels are more likely to be driven by global deployment. Generally, data on

[24] For example, BEIS (2017), *Gas security of supply: A strategic assessment of Great Britain's gas security of supply*, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/651297/gas-security-supply-assessment.pdf

the relationship between UK deployment and costs is relatively limited. We therefore recommend a qualitative assessment is carried out in this area.

There may also be wider economic reasons for investing in technologies, for example to promote regional economic growth. These factors were outside the scope of this research.

WIDER STRATEGIC IMPACTS: OUR APPROACH IN THIS RESEARCH

A full qualitative assessment of these aspects was beyond the scope of this report. We do not present results in this report or in the Tools.

2.2 Define the baseline system

The definition of the baseline energy system to which the incremental investment is added is a key determinant of the results (Figure 9).

Figure 9 Baseline system definition

Recommended approach	Rationale	Implications
▪ The baseline system should include current trends, as well as the most likely policy developments over the lifetime of the interventions being assessed.	▪ The baseline system should represent the most likely future development of the energy sector in the absence of the investment being assessed.	▪ Definition of the baseline system requires detailed assumptions across a large number of areas. ▪ All estimates will be context-specific rather than generic.

Source: Frontier Economics

Approach and rationale

To allow estimation of the value for money of an investment, the baseline system needs to represent both (i) the broad shape of the electricity system context into which an incremental investment is made and (ii) what is most likely to occur in that system context in the absence of that investment, over the lifetime of the investment in question. This means it should include both business as usual changes and likely policy changes over the next decades. It should aim to represent a ‘most likely’ rather than an ‘optimal’ future path, as an optimal path would fail to take into account expected institutional and political constraints (Figure 10).

In practice, this means that a set of detailed assumptions need to made about the baseline system, over the lifetime of the investments being assessed.

- To assess whole electricity system impacts, detailed assumptions are required on the baseline mix of generation, network and flexibility technologies. These assumptions will affect any assessment of the value of a technology intervention. Our review of the literature (Appendix 1) shows that results are particularly sensitive to the following baseline system assumptions:

- the penetration of demand side response (DSR), interconnection and storage[25];
- the baseline generation mix, in particular the penetration of variable or inflexible low carbon plant; and
- assumed spare network capacity.

- To assess costs and benefits outside the electricity sector, assumptions are required around wider developments across the energy sector – for example the extent to which CCS would be able to occur in industrial sectors without power sector CCS investment.

Figure 10 Options for the baseline system

	Optimal path	Most likely path
What does the baseline system represent?	The least cost path to meeting carbon budgets, while maintaining LOLE[26]	A path to meeting carbon budgets that extrapolates trends in relation to the low carbon mix
What can this tell us?	In an ideal world, what is the value for money of alternative technologies in a given year?	Given the projections on a likely path to meeting carbon budgets (based on current policy and trends), which changes to the projected investment mix in a given year would represent the most value for money?
Example scenarios	Scenarios produced using least cost optimising models (e.g. ESME's characterisation of the electricity sector)	The BEIS 'Reference scenario' includes the impact of existing and planned policies[27]

Source: Frontier Economics

Implications

Assumptions made on the baseline system will have large impacts on the resulting WESC estimates. This means that all estimates of value for money will be highly context dependent. It is therefore not possible to produce generic estimates of value for money of

[25] Up to a certain limit, the greater the amount of flexibility (e.g. peaking plant, DSR, interconnection or storage), or spare network capacity that is assumed in the baseline system, the lower will be the WESC of variable or inflexible generation technologies. We note that many of the models used in the estimation of WESC treat flexible technologies other than generation as exogenous – that is, assumptions are made on the quantity of DSR, interconnection or storage that are in place before the WESC of the incremental technology are assessed. This approach is partly due to the fact that there it is difficult to characterise generic DSR and interconnection options, given the heterogeneity of these resources, and the general lack of evidence on cost and performance in the case of DSR (as well as the difficulty in modelling to a sufficient temporal and spatial granularity). To the extent that 'spare' flexible or network capacity has been assumed into the baseline system, this spare capacity can be used to manage the impact of the incremental variable or inflexible technology, reducing the WESC of the incremental inflexible or variable technology. Conversely, assuming too little flexibility or spare network capacity will lead to an overestimate of system impacts.

[26] The Loss of Load Expectation (LOLE) measures the number of hours in the year that demand is expected to exceed supply in the absence of mitigation measures from National Grid.

[27] BEIS (2016), *Updated Energy and Emissions Projections 2016*, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/599539/Updated_energy_and_emissions_projections_2016.pdf

technologies that are valid across a range of contexts. Instead, estimates will only be valid for a specific scenario, and a specific investment date.

BASELINE SYSTEM DEFINITION: OUR APPROACH IN THIS RESEARCH

We have developed a baseline for use in our EnVision and ESME modelling that is broadly consistent with the BEIS Reference Scenario[28]. This represents a path to meeting carbon budgets that takes into account existing and planned policies.

We have chosen 2025 as a year to focus on for new investments. This is in line with the next major round of low carbon investment decisions (since CfDs have already been granted out to 2022/2023).

Developing a baseline from 2025 has involved making assumptions about a range of detailed factors out to 2075, including the following:

- the cost and technical characteristics of electricity technologies and fuels;
- the characteristics of electricity demand;
- the development and application of policies such as the capacity market and CfDs;
- the penetration of low carbon generation and
- the presence of interconnection and DSR[29].

We have drawn on ETI research and 'best estimates' of the future, alongside publicly available evidence for the baseline system. Users of the tools may wish to amend these assumptions with alternative best estimates. Further details are presented in Appendix 1.

2.3 Decide on the size of the investment increment

The impact on system costs of a technology is likely to vary depending on the amount of it that is added to the system. For example, if a large amount of a variable technology such as wind is added to the system, there may be a lower benefit (or higher cost) per MWh than if a smaller amount is added. This is due to effects such as an increased likelihood of curtailment, given a degree of correlation between the output of wind generators.

To ensure these impacts are captured, we recommend that value for money estimates consider increments of different sizes (Figure 11).

[28] BEIS (2016), *Updated Energy and Emissions Projections 2016*, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/599539/Updated_energy_and_emissions_projections_2016.pdf

[29] DSR and interconnection will affect value for money but are not endogenously covered in the model. OCGT and storage, which may play a similar role in the electricity sector are modelled endogenously. For our modelling, we assume interconnection and DSR are held at the level currently available plus any committed investment to 2025. This conservative approach is taken to ensure that we do not underestimate the WESC of variable and inflexible plant by 'baking in' too much flexibility to the system. Further details are set out in Appendix 1.

Figure 11 Increment size

Recommended approach	Rationale	Implications
Both small and large increments should be considered.	The value for money estimation may change, depending on the size of the increment.	Small increments can inform the assessment of value for money of individual investment decisions. Large increments can help inform decisions on the value for money of a change in strategy.

Source: Frontier Economics

- The first approach is to add a very small amount of capacity, to determine the marginal whole electricity system impact. This type of incremental calculation may be appropriate for assessing small changes. As capacity and network investment costs are "lumpy" (it is not possible to build a small fraction of a power station or transmission line), a marginal approach will generally involve smoothing out these costs (e.g. applying an average cost of building new capacity). This allows us to estimate the value for money of individual investment decisions, while avoiding results that could be highly sensitive to "knife-edge" investment decisions.
- A second approach is to add a much larger amount of capacity (Figure 12). To do this we have run the model with a much greater amount of capacity. For example, we increase the capacity of the technology already in the baseline by around 2GW (adjusting the increment of non-baseload technologies by their availability to keep the increment constant in output terms).[30] The 2GW level for baseload was chosen as it represents a change that could realistically be made on the basis of a change in investment strategy.

Figure 12 Small or large increments

	Small change in 2025	Major investment change in 2025
What question can it help with?	For an investment decision in 2025, what is the value for money of alternative technologies?	What is the value for money of a strategic change in technology mix?

Source: Frontier Economics

We recommend both approaches are used when assessing value for money.

In addition, for interconnection, as well as defining the size of the increment, the nature of the increment must be defined – in particular, the geography to which it will be link. This is because there is no single "archetype" interconnector, given that the most significant differences between projects are likely to be driven by their location[31].

[30] For example, an additional 2GW of nuclear or 4GW of offshore wind is assumed to be built over a number of years, subject to a check against build constraints.

[31] See Appendix 1 for discussion of the approach to modelling interconnection.

SIZE OF INCREMENT: OUR APPROACH IN THIS RESEARCH

For generation, we have used both approaches in our EnVision modelling[32].

- We calculate marginal WESC against the baseline, to show the average impacts of adding a small amount of additional capacity to the existing system (1 MW).
- We have then run the model with a much greater amount of capacity of the incremental investment technology.[33] The size of the increments we have used is shown in Figure 13. An increment of 2GW was chosen for OCGT. This was chosen on the basis that it should be large enough to avoid results being driven by the “lumpy” nature of other capacity investments in the model. Increments for other technologies were chosen to ensure the same level of availability[34] (e.g. solar has an average availability of 11%, compared to 95% for the OCGT. The resulting increments were compared to the build rate limits from ESME. The offshore wind increment was reduced from 5.9GW to 5GW to fit within this build limit.

Figure 13 Large increment size

Technology	Amount added under large increment (GW)
CCGT	2.0
OCGT	2.0
Nuclear	2.1
Gas CCS	2.2
Biomass CCS	2.0
Onshore Wind	5.0
Offshore wind	4.0
Solar	17.3
Storage (lithium-ion battery)	4.0
Interconnection (to France)	2.9

Source: Frontier Economics

- As EnVision does not model changes in storage capacity endogenously, it is not possible to assess the marginal WESC in the same way as we do for generation technologies. We therefore only consider a single large increment of storage capacity.
- Similarly, as EnVision does not produce marginal estimates of WESC for interconnection, we have only considered a large increment of capacity for this technology. In terms of deciding on the nature of the increment, we have focussed on an interconnector between GB and France[35]. Data for the French market (forecast power prices, demand, net exports, renewable profiles, and renewable capacity) has been drawn from Frontier’s Central/Western European dispatch and investment model.

[32] As described in Appendix 1, we have also calculated an additional marginal whole system impact where an infinitesimal amount of capacity is added on top of the large increment discussed above. This allows us to investigate the extent to which the marginal whole system impact may vary with penetration of a given technology.

2.4 Set up the modelling

When setting up the modelling for a value for money assessment, there are choices that need to be made about:

- the level of complexity of the modelling; and
- the way in which re-optimisation and constraints are handled.

Our focus in this section is on the electricity system modelling.

Figure 14 Electricity system model set up

Recommended approach	Rationale	Implications
A detailed model is required to estimate most aspects of WESC.	Simpler methods may be more transparent, but they may not capture the key elements.	A large degree of complexity is inevitable.

Source: Frontier Economics

2.4.1 The level of complexity of the modelling

Approach and rationale

In general, there is a trade-off between more complex techniques and simpler approaches.

While simpler and more transparent options are possible, in most cases these have serious limitations. For example, the use of a simple stack model would miss the impact of complex interactions between the generation fleet, interconnection, DSR, storage and networks on a technology's WESC[36].

We therefore recommend that a detailed model is used in the estimation of WESC.

Implications

The degree to which the modelling can be simplified is limited.

[33] For example, this might lead to an additional 2GW of nuclear or 4GW of offshore wind being built over a number of years, subject to a check against build constraints.

[34] Storage "availability" was calculated by dividing its capacity factor by two, to take account of the way it needs to be charged in order to discharge).

[35] See Appendix 1 for further details.

[36] Our review of the options for simplification is presented in Appendix 1.

2.4.2 Determining what capacity is displaced[37] when an investment is added

Approach and rationale

We recommend allowing the model to re-optimise, subject to a security of supply constraint, once the investment increment is added[38]. This re-optimisation will include the retiring of the marginal plant that is no longer needed, as well as adding appropriate network infrastructure and flexible plants. If the model is not allowed to re-optimise, WESC may be overstated. For example, if a large amount of wind is added to the system, large amounts of its output might need to be curtailed due to a lack of appropriate network infrastructure or flexible plants. We recommend allowing the model to re-optimise to build or retire network and generation capacity in response to the new investment. The costs of adapting the system to meet the new technology should then be allocated to the new investment as part of its WESC.

Adding new capacity will also impact on the carbon emissions from the electricity sector[39]. There are two broad options for taking account of this.

- One approach would be to allow the model to re-optimise investment to hold carbon emissions constant, by displacing the marginal plant. This would be consistent with a scenario where the electricity sector had a sector-specific carbon target. This approach is likely to be most useful where the baseline is made up of an optimised low carbon generation mix. Where the baseline low carbon generation mix is exogenously determined (as in our modelling), allowing re-optimisation subject to a carbon constraint risks producing misleading results. For example, the exogenously determined low carbon generation mix may include some expensive technologies. These could be included in the mix because it is expected that they will be deployed for reasons relating to strategic security of supply or because deployment is expected to bring down future costs through innovation. However, their presence would distort the results of an optimisation based on cost. If we allow the model to re-optimise to hold carbon constant and displace these expensive low carbon technologies, we could be overstating the benefits associated with the incremental investment.
- The alternative is to value the change in emissions in line with the BEIS appraisal values for carbon. This approach may be more appropriate for assessing the impact of varying the generation technology mix where there is an economy wide emissions target, such as that imposed by the UK's carbon budgets[40]. Where an exogenously determined baseline has been included, we recommend this approach is taken.

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[37] Over the long-run additional capacity might also be built – e.g. if greater intermittent capacity results in a change in the generation mix from baseload to flexible plant.

[38] Adding capacity may reduce the probability that demand exceeds supply (as quantified by loss of load expectation, LOLE). LOLE measures the number of hours in the year that demand is expected to exceed supply in the absence of mitigation measures from National Grid. We recommend that the re-optimisation is carried out subject to the constraint that LOLE remains at a target level. This is most consistent with the GB market, where capacity auctions are run with the aim of ensuring a LOLE of three hours per year.

[39] This depends on the relative carbon intensity of the technology to the technologies it is displacing.

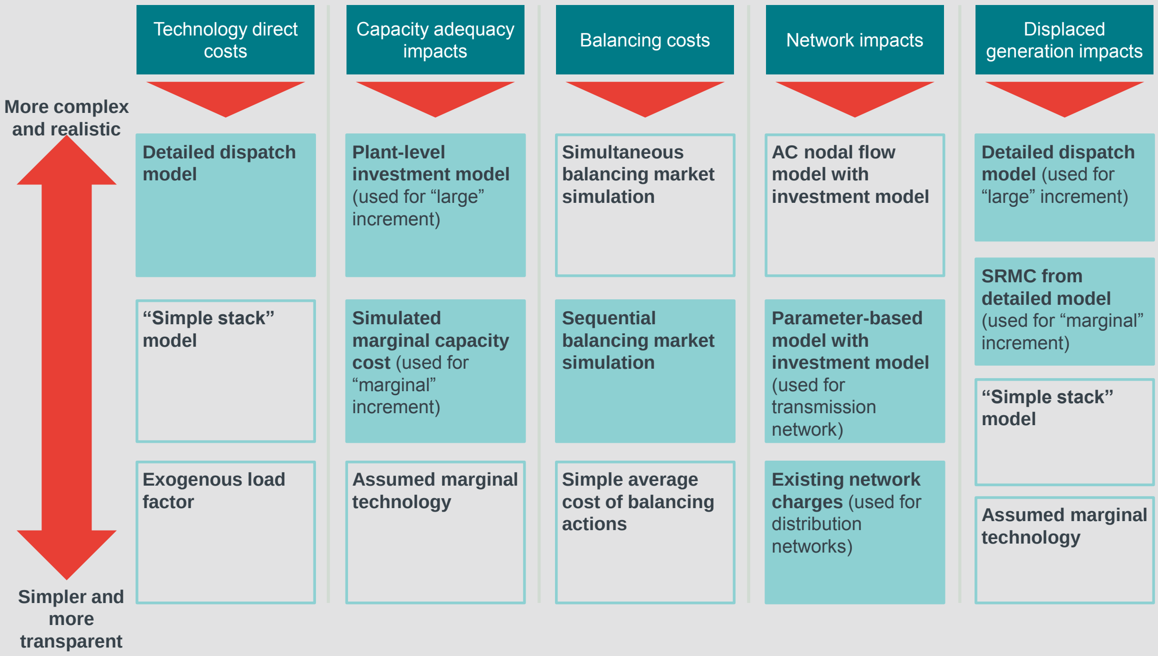
[40] The limitation of this approach is that BEIS appraisal values may under or over -estimate the benefits of carbon saving, where the incremental investment in the electricity sector leads to very large changes in emissions. This is because the

SET UP THE MODELLING: OUR APPROACH IN THIS RESEARCH

The level of complexity

Figure 15 summarises the options and our selected approach to modelling each element of WESC for the increment of technology[41].

Figure 15 Summary of modelling methods



Source: Frontier Economics. Note: Our recommended approach is shaded in blue.

Appendix 1 sets out more detail on each of following elements.

- **Technology direct costs.** We use a detailed dispatch model (EnVision). Alternative, less complex approaches would miss important drivers of value for money, such as the running patterns of flexible plants.
- **Capacity adequacy impacts.** A very simple approach would require an assumption to be made on the marginal technology that is displaced by new investments This would fail to capture how the marginal technology and capacity credit of technologies change under different conditions. We use EnVision which takes these elements into account.
- **Balancing costs.** The simplest approach would use historical balancing costs to project future costs. However, in a rapidly changing market, past balancing costs are unlikely to be a good indicator of those in the future. On the other hand, optimising the market for each balancing service simultaneously would be very computationally intense. We therefore model the market for each balancing service in sequence.
- **Network impacts.** We take a relatively simple approach to network modelling, in line

BEIS values are based on estimates of the abatement costs that will need to be incurred in order to meet specific emissions reduction targets and therefore have been estimated on the basis of a certain emissions trajectory.

41 See Figure 6Figure 6 for a description of the categories of WESC.

with the approach taken in EnVision – as we are considering general archetypes, more detailed, location-specific network modelling is unlikely to add much.

- **Displaced generation impacts.** Once again, we use EnVision. More simple approaches would miss key drivers such as out-of-order dispatch due to policies such as the CfD.

Determining what is displaced

As recommended, we allow the model to re-optimise, subject to a security of supply constraint. To take account of carbon emissions:

- For the small increment approach, we value the change in emissions in line with the BEIS appraisal values for carbon.
- For our large increment results, we have manually adjusted the capacity of renewables in later years to keep relatively constant carbon intensity. This approach has been adopted since the large changes in generation capacity would otherwise lead to very significant changes in carbon intensity, which might then mean that the carbon prices we use are no longer appropriate. By manually selecting a plausible trajectory of renewables, we have avoided the issue described above where an automatic "re-optimisation" of capacity can overstate the benefits of investment.

2.5 Adjust for indirect support provided under current market arrangements

WESC of alternative technologies should be assessed on a level playing field. This level playing field should aim to abstract from risk transfers and implicit support granted under current market and policy arrangements (Figure 16)[42].

[42] These issues are most relevant for the electricity system modelling. Further details on the methodology and its application are provided in Appendix 1.

Figure 16 Adjust for indirect support provided under current market arrangements

Recommended approach	Rationale	Implications
Technologies should be assessed on a level playing field, that corrects for their different treatments under current policy and market arrangements.	▪ Applying Green Book guidance, the cost of capital should be used as a proxy for the risks associated with capital investment in the technologies. To properly assess costs to society, this proxy should reflect fundamental risks associated with these technologies, rather than risks that are associated with current arrangements. ▪ When calculating the subsidy cost to consumers, implicit support should also be included.	An assessment of the value to investors and the impact of hurdle rates of the different treatment of technologies under current market and policy arrangements is required.

Source: Frontier Economics

Approach and rationale

It is important to adjust for indirect support provided under current market arrangements when considering value for money (Figure 16).

- **Net costs to society**. When calculating the net costs to society, investor hurdle rates are used as a proxy for the risk to society associated with investment in these technologies[43]. Investor hurdle rates are usually estimated based on the risks faced by investors under current conditions[44]. However, to ensure they are a good proxy for the risks to society from technology investment, these rates should ideally reflect the intrinsic risk associated with investment (for example due to technical operational risks) rather the risks associated with the current policy framework (for example, the extent to which investors need to bear operational risks under the CfD framework). Identifying the value the current policy framework has on risk to investors, and stripping out this value from investor hurdle rates, is therefore important when calculating costs to society: estimates of the value for money of technologies are highly sensitive to the investor hurdle rates assumed (see Section 3).
- **Net support costs to consumers**. When calculating the net cost to consumers of supporting technologies, we wish to take account of not only the direct monetary support provided to investors, but also any indirect implicit support provided (for example through risk transfers under the CfD framework or through unpriced

[43] As recommended by Green Book guidance. BEIS (2018), *Valuation of energy use and greenhouse gas emissions, Supplementary guidance to the HM Treasury Green Book on Appraisal and Evaluation in Central Government*, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/671205/Valuation_of_energy_use_and_greenhouse_gas_emissions_for_appraisal_2017.pdf

[44] For example, BEIS generation cost estimates draw on NERA (2016) *Hurdle rates for electricity generation technologies.* http://www.nera.com/content/dam/nera/publications/2016/NERA_Hurdle_Rates_for_Electricity_Generation_Technologies.pdf

externalities). This means that as well as identifying the changes to investor risk under the current market framework, we also need to identify and value unpriced externalities.

Implications

This analysis first requires the definition of a 'level playing field' so technologies can be compared in a way that abstracts from current market arrangements. The level playing field should represent a set of arrangements where no technology receives bespoke favourable contract terms and where the main externalities in the market (associated with carbon, networks and capacity adequacy) have been priced[45]. In practice, creating this level playing field means making adjustments to the investor hurdle rates and other parameters to take account of the indirect support associated with the current market arrangements.

Indirect support can then be calculated by looking at the difference between the direct support (i.e. payments in excess of market revenues) required by investors under current arrangements and the direct support that would be required by investors under the level playing field.

[45] This corrects for the implicit support investors enjoy when they do not have to pay for these externalities (or, alternatively, the costs they incur when positive externalities are not fully recognised).

ADJUSTMENTS TO REFLECT INDIRECT SUPPORT UNDER CURRENT ARRANGEMENTS: OUR APPROACH IN THIS RESEARCH

Definition of a level playing field

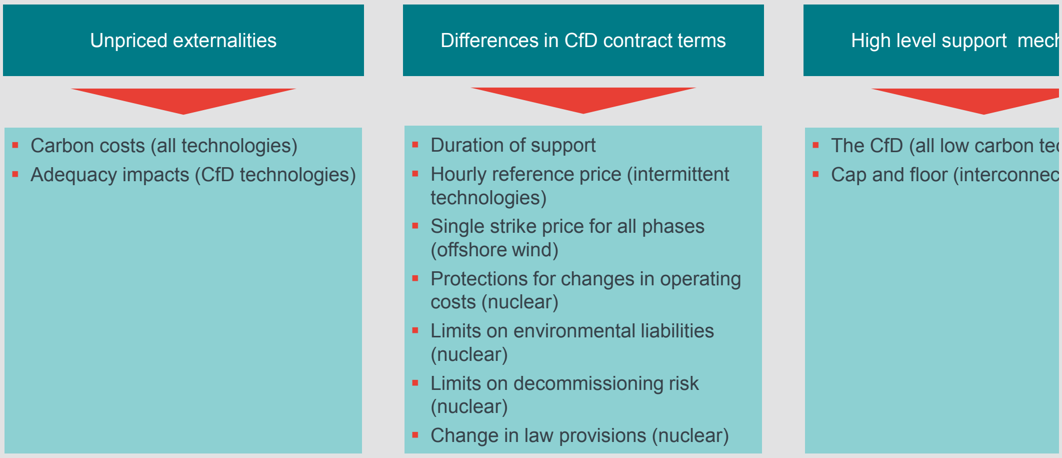
To put all technologies on a level playing field, we consider a set of arrangements where no technology receives bespoke favourable contract terms and where investors receive minimal 'indirect support' in the market.

To represent the level playing field in our analysis, we assume that each technology participates in both the wholesale market and the Capacity Market (CM) on the same basis as new-build generation or storage. Participation in the CM ensures that capacity adequacy impacts are priced. We then make further adjustments to take account of externalities which are currently not fully reflected under existing arrangements [46].

Adjustments to hurdle rates and other parameters reflect a level playing field

We focus on making adjustments for the indirect support by the current CfD and cap and floor system relative to the CM. The main elements we focus on are set out in Figure 17.

Figure 17 Key variations in indirect support across technologies



Source: Frontier Economics

Adjustments are made in two ways.

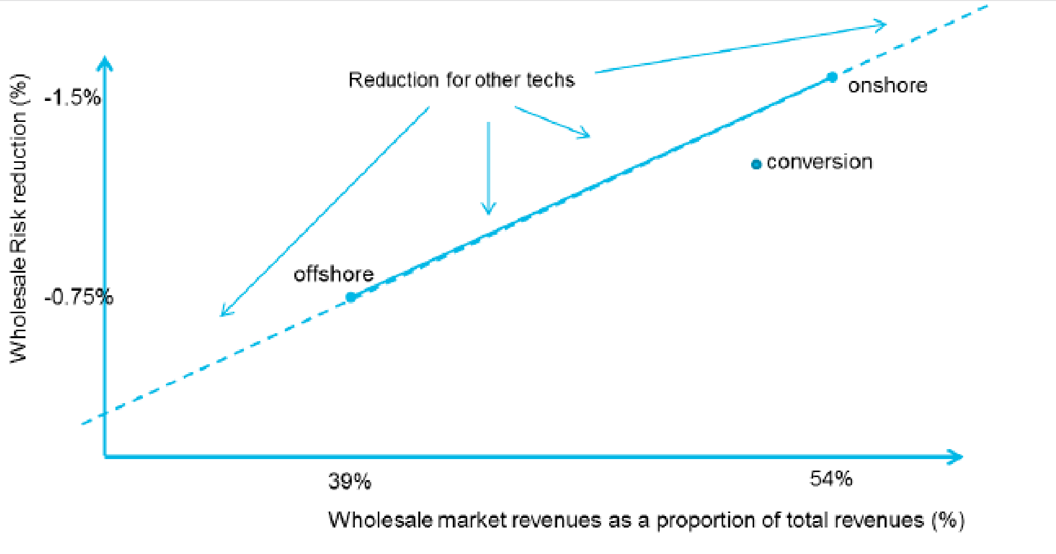
- In some cases, investment costs or returns are adjusted directly, rather than via hurdle rates. For example, to calculate the impact of different reference prices, we substitute the intermittent reference price (which we assume is equal to the average price

[46] For example, we estimate the changes in revenues and costs that would arise if generators faced a carbon price reflecting the marginal cost of abatement, instead of the market price assumed in the EnVision modelling. We use the Government's appraisal values for carbon to estimate the resource cost associated with CO2 emissions. We contrast this to a market carbon price in line with the sum of the assumed EU Emissions Trading Scheme price and the Carbon Price Support tax rate.

received in the market in our modelling) with a proxy for the baseload reference price[47].

- In other cases, we adjust the hurdle rate, based on a change in the risk transfer. For example, moving from a CfD to the CM will increase investors' expectations of wholesale price risk. To value this we apply an approach previously used by DECC in 2013 for setting administrative strike prices under the CfD. In that work, DECC used an estimate provided by NERA (2013) that the impact of introducing the CfD[48] would reduce wholesale market risk for offshore wind (0.75 percentage point reduction in hurdle rate) and onshore wind (0.5 percentage point reduction). DECC then derived hurdle rate reductions from the CfD for other technologies, based on the percentage of their total revenues made up of wholesale market revenues. The method is simplistic, but can be used to derive indicative estimates of exposure to wholesale market risk, given an assumed technology costs and market revenues[49].

Figure 18 Hurdle rate adjustments



Source: DECC (2013) 'EMR Delivery Plan', Annex H, Figure 1.

Estimates of indirect support

We estimate categories of indirect support.

- **Unpriced externalities.** These include the fact that the full external cost of carbon emissions are not captured under the current market arrangements. Unpriced externalities will constitute positive support, for carbon emitting technologies such as CCGT. For technologies with net negative emissions, such as biomass CCS, these will constitute negative support.

[47] We assume the baseload reference price is equal to the annual average baseload price in our modelling. The baseload price and the average price received in the market are modelled using EnVision. See Appendix 1.

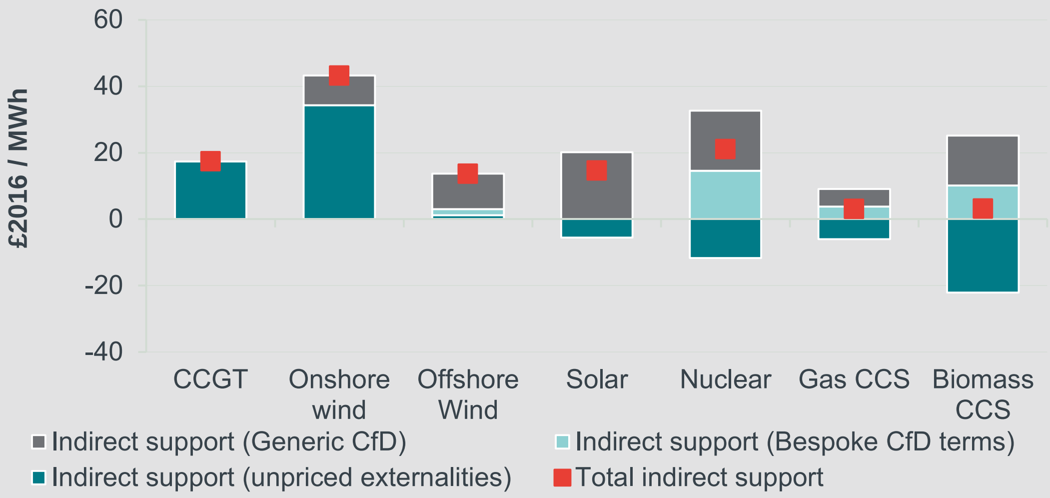
[48] In this work, the CfD was compared to the Renewables Obligation. The Renewables Obligation provided a subsidy, but did not transfer wholesale price risk away from consumers.

[49] We use EnVision modelling to do this. See Appendix 1 for more details.

- **Generic CfD terms**. The generic CfD includes a number of provisions that affect risk, including revenue stability, incentives for timely delivery of capacity and change in law provisions[50]. The presence of these terms constitutes positive support for the relevant technologies.
- **Bespoke CfD terms.** Technologies also receive bespoke support under CfDs - for example, the Hinkley C CfD for nuclear provides increased revenue stability and reduced exposure to construction delay risk and performance risk. Again, the presence of these terms constitutes positive support for the relevant technologies.

Figure 19 presents our estimate of the value of indirect support for investments made in 2025. This analysis shows how differences in indirect support received mean that strike prices do not provide an accurate reflection of the full costs of supporting different technologies. The results also demonstrate the importance of taking a holistic view of the different sources of indirect support being received. Addressing one source while not taking into account others could exacerbate potential distortions.

Figure 19 Indirect support by technology under current arrangements for investments in 2025 (main generation technologies)



Source: Frontier Economics

2.6 Produce metrics

We recommend three metrics are produced to allow the value for money of technologies to be compared.

50 Further details are set out in Appendix 3 and Tool B: Investor Support Costs.

Figure 20 Produce metrics

Recommended approach	Rationale	Implications
We recommend three types of metrics are produced: ▪ net costs to society; ▪ strike price equivalents; and ▪ net support costs.	▪ Estimating net costs to society allows for a comparison of the value for money of different technologies to UK Plc, taking an approach consistent with the Government's Green Book. ▪ Strike price equivalents allow technologies to be compared using adjusted strike prices, that take account of differences in policy support. ▪ Estimating support costs allows assessment of the costs to consumers and taxpayers of subsidising investments under alternative market arrangements.	The metrics are based on the same modelling. However the different perspectives require different approaches to discounting.

Source: Frontier Economics

Approach and rationale

Figure 21 summarises the three metrics that we recommend producing.

Figure 21 Summary of metrics

Question	Metric	Uses
How does the overall value for money of generation technologies compare?	Net costs to society (£/MWh or £/kW)	Policy appraisal in line with Green Book
What would strike prices look like if technologies were put on a level playing field?	Strike price equivalent (£/MWh)	Practical application: development of technology neutral auctions
What is the full cost to consumers of supporting investment in these technologies?	Adjusted support costs (£/MWh)	Distributional impacts, taking account of unpriced externalities and risk transfers

Source: Frontier Economics

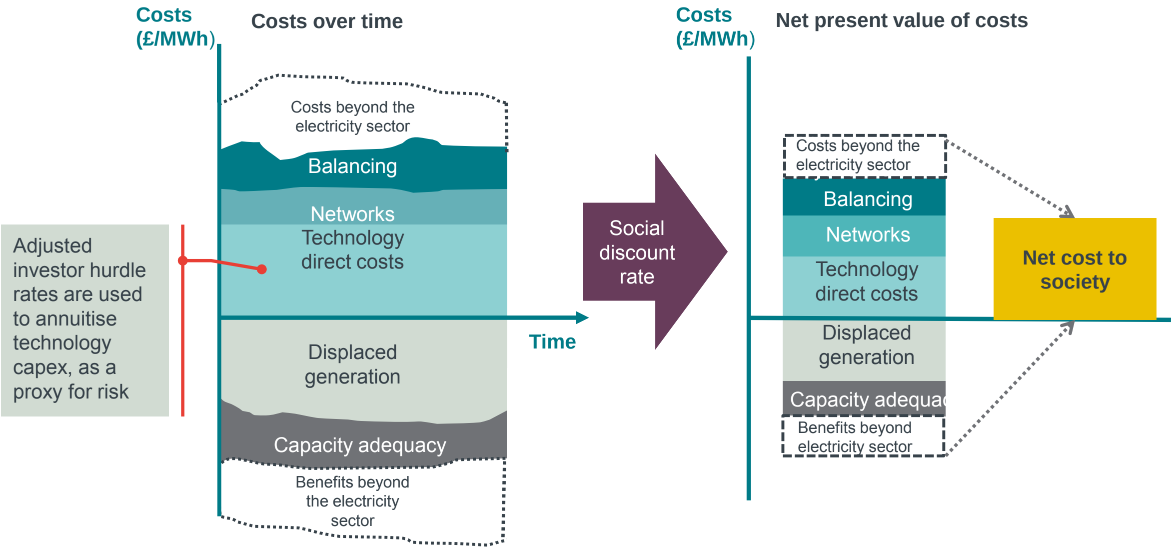
Each of the metrics take account of the full electricity system costs and benefits associated with the technologies, including carbon externalities. However, as discussed below, they differ in terms of the discount or hurdle rates applied in the calculations. This means that the value for money ranking can vary across metrics, as the impact of using different discounting approaches will vary depending on the capital intensity of the technologies.

Net cost to society.

The net cost to society allows policy makers to understand which investments may has the lowest net cost for 'UK Plc', taking an approach consistent with the Government's Green Book. This measure can be expressed on a £/MWh basis for most generation technologies, and on a £/kW basis for technologies that are mainly contributing to flexibility services (such as OCGT). It differs from the commonly used levelised cost measure in two key ways.

- It includes the full set of electricity system costs and benefits (and where possible, wider costs and benefits beyond the electricity sector).
- Because the focus is on the net cost to society, a social discount rate, rather than the is used to discount costs and benefits. Investor hurdle rates tend to be used for discounting in the levelised cost calculation, to give an indication of the revenue investors will require per unit of output.

Figure 22 Illustration of the calculation of net cost to society

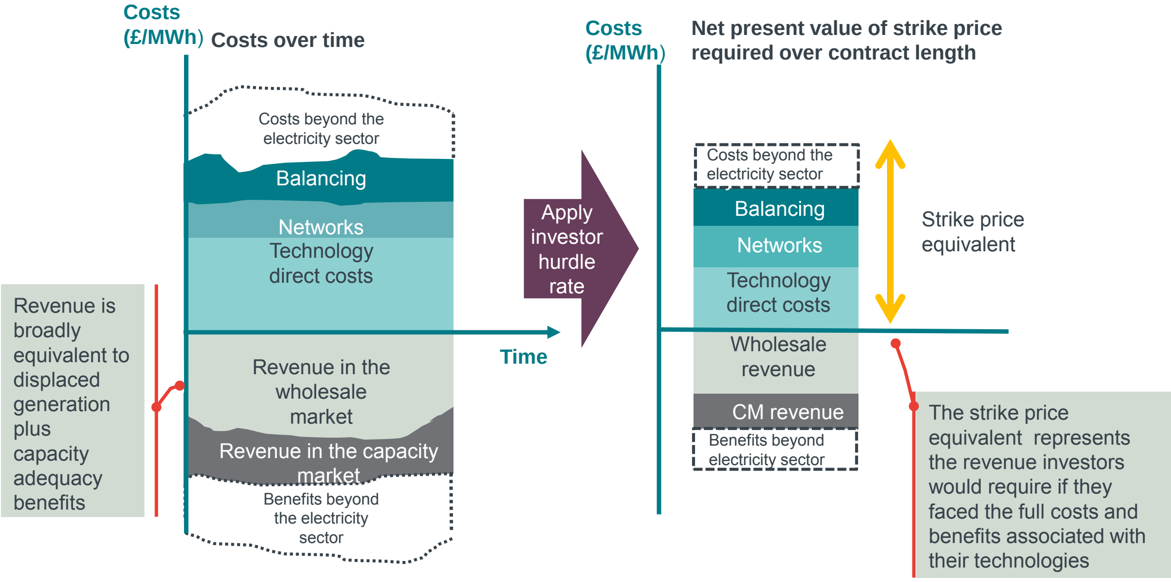


Source: Frontier Economics

Strike price equivalent

The strike price equivalent is a useful proxy for the full cost to consumers (support cost plus wholesale generation cost). It represents the revenue that investors would require if they faced the full costs and benefits associated with their investments. Because it is based on this investor perspective, cost and benefits are discounted at the investor hurdle rate (Figure 23).

Figure 23 Illustration of the calculation of the strike price equivalent



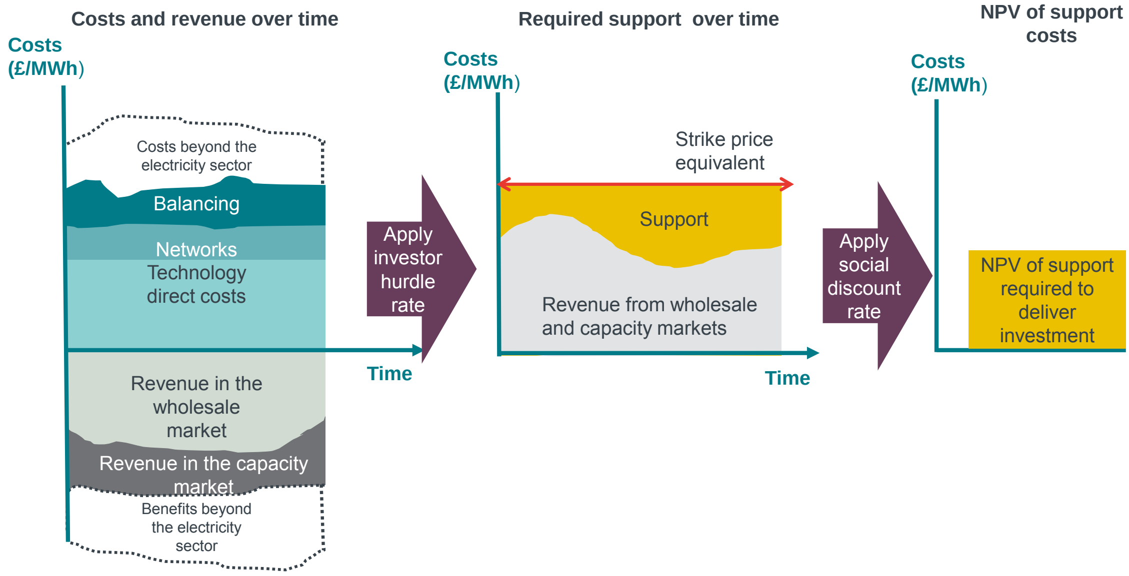
Source: Frontier Economics

Support costs

This metric identifies the costs to consumers of supporting investment in incremental investments under alternative market arrangements. In particular, it allows the overall cost to consumers and taxpayers of supporting alternative technologies to be considered, once unpriced externalities and implicit support associated with different market arrangements have been taken into account.

As described above, the strike price equivalent, (which represents the required return for investors, is calculated using the adjusted investor hurdle rate). The gap between the strike price equivalent and revenue provided by the market constitutes the stream of support over time. This stream is discounted back at the social discount rate to produce the net present value of support costs (Figure 24).

Figure 24 Illustration of the calculation of support costs



Source: Frontier Economics

METRICS: OUR APPROACH IN THIS RESEARCH

Section 3 presents illustrative results for these metrics, based on investments made in 2025 and a baseline system that reflects current trends and existing policies.

The metrics can also be found in the Tools (Figure 25).

Figure 25 Summary of metrics

Metric	Tool	Location
Net costs to society (£/MWh or £/kW)	Tool A: Whole Electricity System Costs	'Summary Results' sheet
Strike price equivalent (£/MWh)	Tool B: Investment Support Costs?	'Control Panel' sheet
Adjusted support costs (£/MWh)	Tool B: Investment Support Costs?	'Control Panel' sheet

As set out above, the illustrative results presented as part of this research exclude non-electricity sector impacts on the basis that our estimates beyond the electricity sector are associated with a much larger degree of uncertainty.

3 APPLICATION OF FRAMEWORK

In this section, we present a set of results that have been obtained by applying the framework described in the Section 2. These results have been produced using LCP's EnVision integrated investment and dispatch model and the toolkit developed by Frontier for this project.

The estimates presented in this section relate to investments made in 2025 in a GB electricity system that is on track to meet carbon budgets. The results are highly sensitive to the detailed assumptions made in the modelling, and non-electricity costs and benefits have not been included[51]. The results should not therefore be interpreted as being definitive estimates of the value for money of different technologies. We present them here to illustrate the results of applying the framework described in Section 2, and to help identify the most important factors that drive the results.

We present each of the three metrics in turn.

- net costs to society;
- strike price equivalent; and
- net support costs.

3.1 Net costs to society

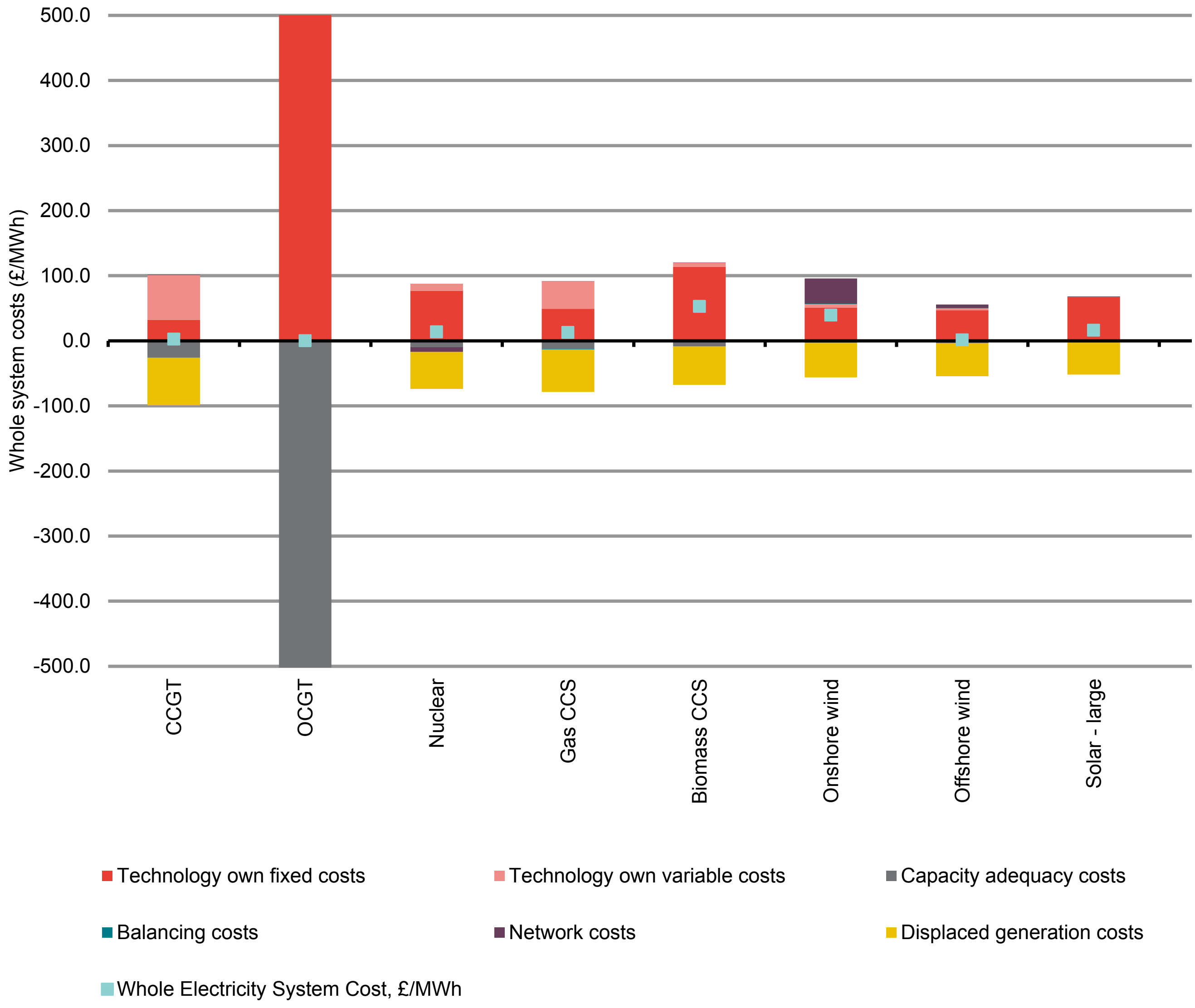
3.1.1 Small increment

Figure 26 shows our estimates of the net costs to society of incremental investments (an additional 1MW of each technology, built in 2025). The figures here, and in the rest of this section, all relate to impacts within the electricity sector only[52].

[51] As noted in Section 2, we do not include the results of the non-electricity sector modelling in this section, due to the higher level of uncertainty associated with these estimates.

[52] The figures in Section 3.1 are taken from Tool A: Whole Electricity System Costs, published alongside this report.

Figure 26 Breakdown of net costs to society by technology for investments in 2025 – 1MW increment run



Source: Frontier Economics

Note: OCGT figures are not fully displayed on this graph – due to the low load factor, the components of WESC when measured on a £/MWh basis are extremely high.

The resulting net costs to society (the sum of the positive and negative bars) are indicated by the blue dots. In Figure 27 we use the following descriptions.

- The technology direct costs (A). This is composed of the net present value of both fixed (capex and fixed opex) and variable (fuel, carbon, and variable O&M) costs[53].

[53] Note that, unlike levelised costs reported by organisations such as BEIS, this excludes all network-related costs beyond any initial connection fee. It includes the capex, fixed opex, fuel costs, carbon costs, and variable opex of running the plant. It also differs from levelised costs in that these tend to be discounted at the investor hurdle rate. Technology own fixed costs include capex annuitised at the level playing field investor hurdle rate, discounted back at the social discount rate.

- The electricity system integration cost (B). This shows the additional change in costs on the wider electricity system as a result of adding the new capacity (including any "long-run" effects from being able to retire other capacity).
- The net costs to society (C) is the sum of these two components.

Figure 27 Net costs to society – marginal increment run

Technology	A Technology direct cost (£/MWh)	Rank	B Electricity system integration cost (MWh)	C = A + B Net costs to society cost (£/MWh)	Rank
CCGT	£101	6	-£98	£3	3
OCGT	£918	8	-£918	£0[54]	1
Nuclear	£88	4	-£74	£14	5
Gas CCS	£91	5	-£78	£13	4
Biomass CCS	£120	7	-£67	£53	8
Onshore Wind	£56	2	-£17	£40	7
Offshore wind	£50	1	-£49	£1	2
Solar	£67	3	-£51	£16	6

Source: *Frontier Economics*

Note: *A and B may not perfectly sum to C due to rounding*

The following general insights can be drawn from these results:

- The sum of electricity system integration costs are all negative (i.e. a reduction in costs). This is because the benefits associated with capacity adequacy and displaced generation outweigh any additional balancing and network costs. This is because the additional capacity being added displaces existing generation and capacity on the system and so will always result in a reduction in these costs[55].
- The addition of the electricity system integration costs are sufficient to make a change to the overall ranking of the technologies. Notably, the effect is enough to improve the ranking of some of the flexible generation technologies (CCGT, OCGT, and CCGT CCS) compared to some of the inflexible or intermittent technologies (nuclear, wind and solar).
- All of the components of the net costs to society have an impact on the final ordering. For example, although balancing costs appear almost insignificant in the chart above, the removal of these from the net cost to society would be sufficient to move nuclear above CCGT CCS. It would therefore be

[54] The technology direct costs and system integration costs are extremely high due to the low load factor of this technology. They perfectly net out, since OCGT is the marginal technology within the capacity market: Whenever any technology is added to the system, the same derated capacity of OCGTs is removed to keep the same loss-of-load-expectation.

[55] Some results in the literature report intermittent technologies as having additional "back-up" costs. This is not the case in our framework, since we are adding additional capacity to a system that already has a sufficient amount: Technologies with a positive but low capacity credit (like wind) will lead to a reduction in capacity adequacy costs.

misleading to carry out analysis that only looked at one of the components of system integration costs.

The specific results for each technology will be highly dependent on the baseline system scenario (i.e. the counterfactual) we have chosen, as well as assumptions around the technology location and year of construction. Two particular results illustrate this.

- As indicated in the table above, onshore wind is modelled as having a higher net cost to society *and* direct technology cost than offshore wind. This result seems counter-intuitive, but can be traced to the following inputs:
  - Offshore wind is modelled as having a much higher average load factor (around 48%) than onshore wind (28%). Its fixed costs are therefore spread over a much smaller amount of energy.[56]
  - Our capex assumptions for offshore wind are around half those published by BEIS in 2016, in order to be consistent with the low strike prices seen in the recent GB CfD auctions.
  - The additional onshore wind we model is assumed to be in the south of Scotland (based on current policy), while the additional offshore wind is off the east coast of England, and therefore closer to the average location of demand in Great Britain. Given the network cost assumptions in EnVision, this produces network costs that are higher for a MW of onshore wind than offshore wind.
- Biomass CCS has a higher technology cost and net cost to society than the other technologies. As shown above, this is driven largely by its high capex and fixed O&M costs. By contrast, the net variable costs of biomass CCS decrease over time as the price of carbon increases, and by 2038 the income it makes from negative emissions outweighs the cost of its fuel. This suggests that Biomass CCS would appear more cost-effective if placed on the system at a later year than 2025.

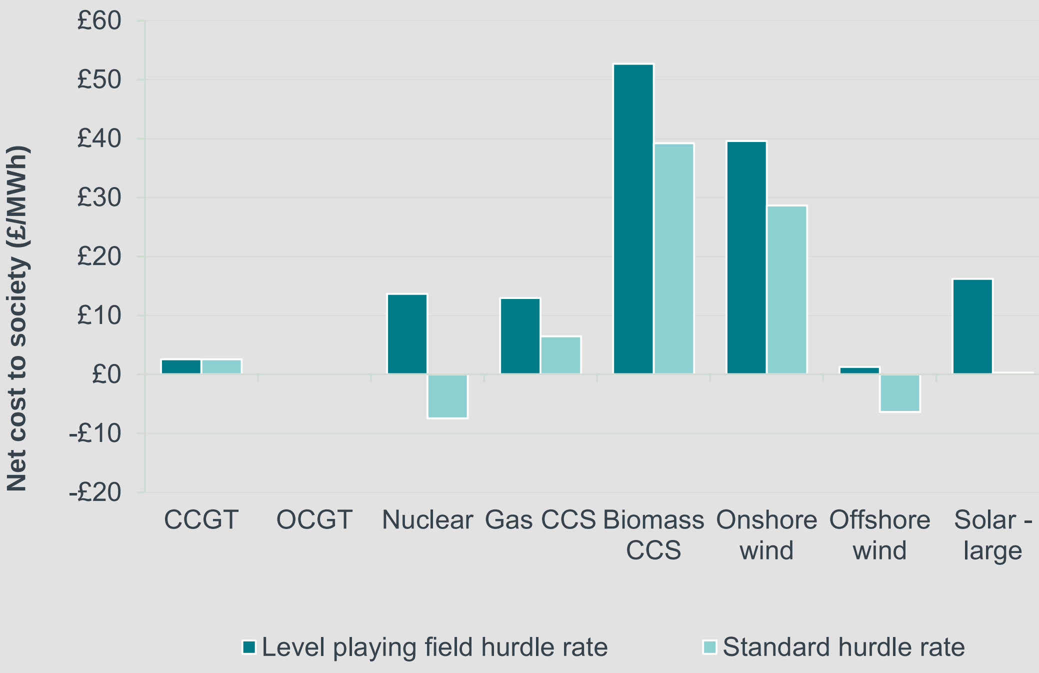
[56] The reduction in capacity adequacy costs is also spread over a smaller amount of energy. However, given the low capacity credit of wind, this effect is outweighed by the effect of the technology own fixed costs appearing higher on a £/MWh basis.

USING HURDLE RATES AS A PROXY FOR TECHNOLOGY RISK

In Section 2.5 we recommend adjusting hurdle rates to abstract from the risks associated with current market and policy arrangements, and to ensure only intrinsic risks associated with the technologies are reflected in the calculation.

Figure 28 compares the net costs to society calculated with an unadjusted investor hurdle rate and one which abstracts from current arrangements and puts technologies on a level playing field. This shows that adjusting hurdle rates has a material impact on the value for money ranking.

Figure 28 The importance of adjusting hurdle rates



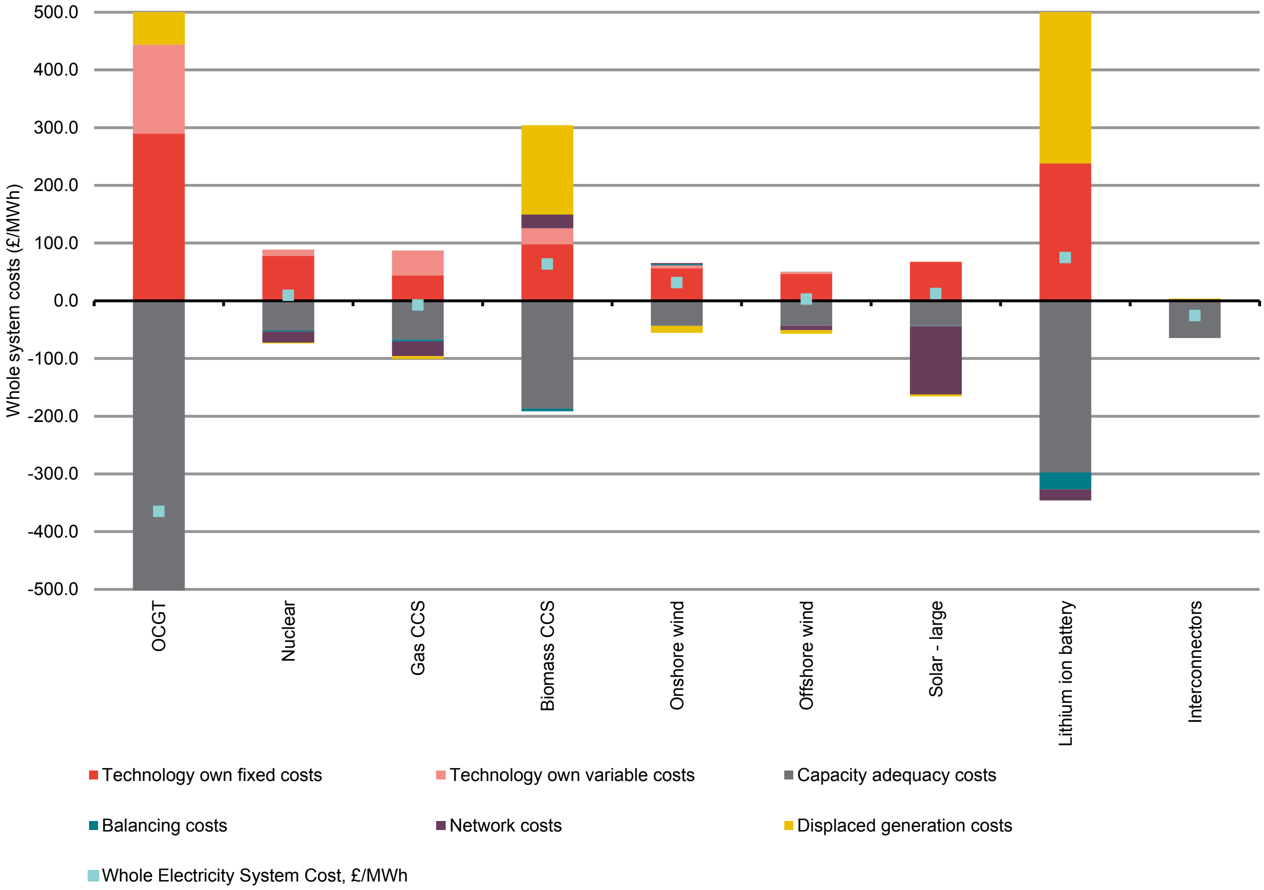
Source: Frontier Economics

3.1.2 Large increment

The tool developed for this project allows us to determine the net cost to society of a larger increment of each technology. This functionality also enables us to calculate a net cost to society for two additional technologies: interconnectors and storage (lithium-ion batteries).

Figure 29 and Figure 30 show the resulting net costs to society figures. For the battery and interconnector, the MWh “generated” relate to energy discharged and imported respectively.

Figure 29 Breakdown of net costs to society by technology for investments in 2025 –large increment run



Source: Frontier Economics

Note: OCGT figures are not fully displayed on this graph – due to the low load factor, the components of WESC when measured on a £/MWh basis are extremely high.

Figure 30 Net costs to society – large increment run

Technology	A Technology own cost (£/MWh)	Rank	B System integration cost (MWh)	C = A + B Net costs to society cost (£/MWh)	Rank
OCGT	£444	9	-£809	-£365	1
Nuclear	£89	6	-£79	£9	5
Gas CCS	£87	5	-£94	-£7	3
Biomass CCS	£126	7	-£62	£64	8
Onshore Wind	£61	3	-£30	£31	7
Offshore wind	£48	1	-£47	£3	4
Solar	£68	4	-£55	£12	6
Lithium-ion battery	£244	8	-£169	£75	9
French interconnector	£54	2	-£80	-£26	2

Source: Frontier Economics

Note: A and B may not perfectly sum to C due to rounding

The general ordering of technologies is very similar to the small increment run. However, the split across the different components of the net cost to society is quite different. For example, while most of the technologies previously had a significant displaced generation benefit and a much smaller capacity adequacy benefit, the capacity adequacy benefit is generally much higher in this run. This reflects the different way in which the two sets of results have been generated:

- Under the small increment run, it is assumed that the new capacity will displace whatever was on the margin in the capacity market (generally OCGT). The OCGT has a relatively low capital cost, hence the low capacity adequacy benefit.
- Under the large increment run, much greater changes to the capacity stack are required. For example, with extra nuclear plant, other low-carbon technologies (such as onshore wind, offshore wind, and solar) may be removed from the stack. These are technologies with no variable running costs (so the displaced generation benefit is far lower), but higher capital costs than the OCGT.

These results also show lithium ion battery with a high net cost to society[57]. This is driven by two main factors.

- The battery is being added to a baseline system that already has a large amount of storage capacity (4GW by 2025) that has endogenously been chosen by the model as a worthwhile investment.
- In addition, as the battery will only tend to discharge during times of high prices, it has a very low load factor (around 4%). As with the OCGT results

[57] Note that our modelling takes into account the benefits of the battery on wholesale and national balancing markets, but not any benefits it can produce through regional balancing activities on the distribution network.

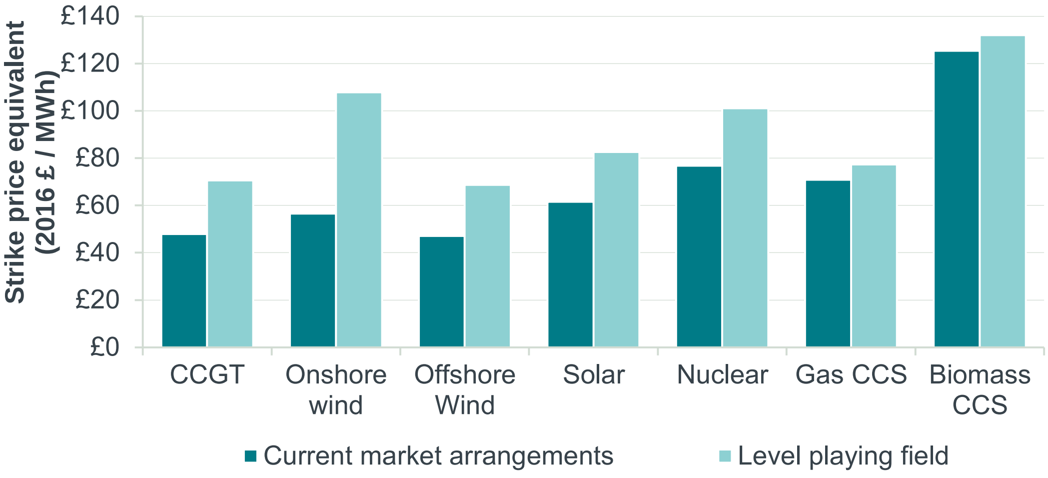
seen elsewhere, this makes the resulting net cost to society on a per-MWh basis seem much higher.[58]

3.2 Strike price equivalents

We next present the estimated strike price under current arrangements and under a level playing field for investments made in 2025 (Figure 31 and Figure 32).

- Strike price equivalents under current arrangements take account of the indirect support provided through unpriced externalities and risk transfers (as discussed in Section 2.5 above).
- The level playing field strike price equivalent estimates the revenue technologies would require in the absence of this indirect support.

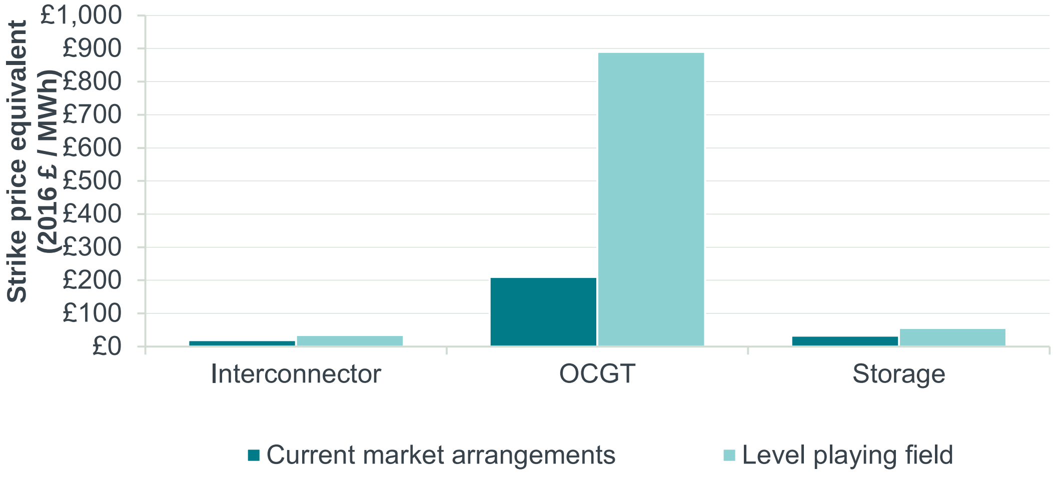
Figure 31 CfD strike price equivalent (main generation technologies)



Source: Frontier Economics

[58] If measured on a per-kW basis, the battery has a net cost to society that is lower than both biomass CCS and onshore wind.

Figure 32 CfD strike price equivalent (interconnector, OCGT and storage)



Source: Frontier Economics

Figure 31 and Figure 32 show that putting technologies on a level playing field has the potential to affect technology rankings. For example, based on our assumptions, gas CCS would become cheaper on a strike price equivalent basis than onshore wind and solar.

Key drivers for the results are as follows.

- For CCGT, moving from current market arrangements to the level playing field requires an increase in the strike price equivalent. This reflects both an increase in the market reference price (due to the increase in carbon prices) and an increase in carbon costs, requiring larger top-up payments.
- Onshore wind, offshore wind, solar and nuclear all require an increase in strike price. This is because of the significant level of indirect support provided to these technologies under current arrangements through the CfD system. As expected, the gap is highest for onshore wind and nuclear, which receive the largest degree of indirect support under the terms of the Hinkley C contract (see Section 2.5 above).
- As explained in Section 3.1 above, the finding that onshore wind is more expensive than offshore wind is in part driven by their assumed respective locations, and that network costs are higher in Scotland (where onshore wind is assumed to be located) than in the east of England (where offshore wind is assumed to be located).
- The strike prices for Gas CCS and Biomass CCS do not change significantly under the level playing field market arrangements. While, indirect support for CCS is net negative, this is in effect cancelled out by the increase in the reference price (due to the increase in carbon price)[59].
- Strike prices for storage and interconnection increase in part due to an increase in the market reference price and in part due to an increase in the amount of support required.

[59] This is described further in Appendix 2.

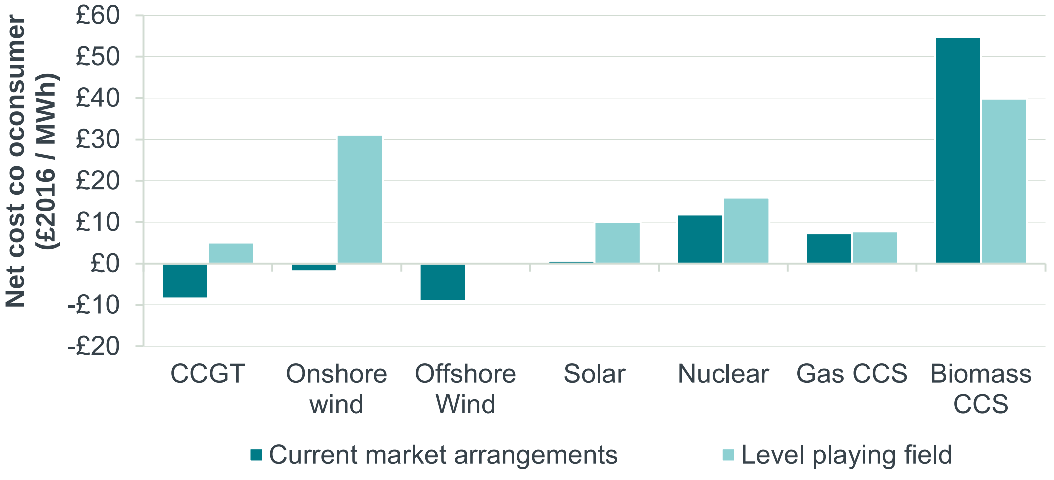
3.3 Support costs

Calculating the required strike price allows us to estimate how the cost to consumers and taxpayers of providing support varies by technology under different arrangements. Once again, we present two figures for each technology:

- an estimate of the support that would be required under current arrangements; and
- an estimate of the support that would be required once all technologies are put on a level playing field.

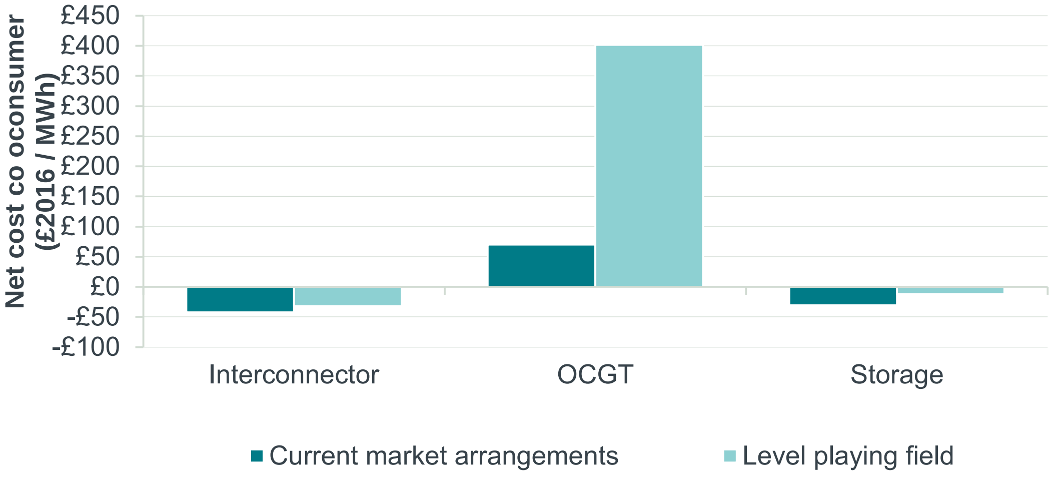
Where a negative estimate of 'support' is shown this means that the wholesale and capacity market revenues estimated based on our baseline assumptions set out above provide more than the required compensation for investors, based on our technology cost and hurdle rate assumptions.

Figure 33 Net support cost to consumers for investments made in 2025 (main generation technologies)



Source: Frontier Economics

Figure 34 Net support cost to consumers for investments made in 2025 (interconnector, OCGT, storage)



Source: Frontier Economics.

Required support is driven by two elements: investor costs associated with the technology and revenues that the technology can gain in the market.

- For CCGT, the net support cost increases as the carbon externality is priced in.
- For all low carbon technologies, fully pricing in the carbon externality leads to a reduction in the support cost. However, the overall effect on the support cost of moving low carbon technologies to a level playing field varies by technology.
  - For solar, onshore wind and offshore wind, support costs increase. This is consistent with the estimated increase in strike prices described above.
  - For nuclear, support costs also increase. This is driven by the higher strike price required, though it is partly mitigated by the shorter assumed contract duration, which tends to lower the net cost to consumers, since the social discount rate is lower than the private discount rate.
  - The combination of a lower strike price (see above), higher wholesale prices (due to fully internalising the carbon externality) and a shorter assumed contract duration contributes to lower estimated support costs for CCS technologies.
- Support costs for storage and interconnectors are negative due to the high projected returns, based on our current assumptions.

The next section explains why some of these results differ, when compared to the net costs to society results presented in Section 3.1 above.

3.4 Differences in ranking between the metrics

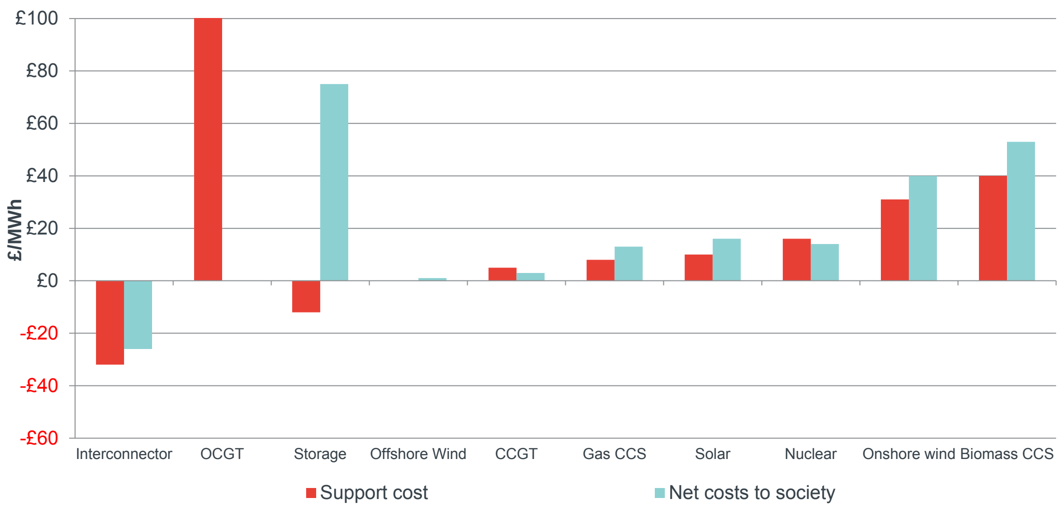
The technology ranking in terms of support costs are broadly similar as those in terms of net costs to society (Figure 35). This makes sense as both metrics assess technologies on a level playing field, accounting for externalities and taking account of the intrinsic risk associated with technologies.

However, there are some differences in the results between the metrics. These are driven by the fact that the profile of costs and benefits (or revenues) over time differs between technologies. These differences are due to a range of factors including:

- the profile of wholesale prices. These rise to 2035 (due to increasing assumed fuel and carbon prices), but start to fall towards the end of the modelling horizon due to the impact of increased deployment of low marginal cost generation;
- the rising appraisal value of carbon;
- the changing load factors of technologies over time as more low carbon plant enters the market; and
- the changing mix of generation and capacity that is displaced by new investments.

Given the different approach to discounting in the two metrics, this results in diverging estimates. Where the net costs of a technology fall over time (for nuclear or CCGT), the technologies will look better under the net costs to society metric, where costs and benefits are discounted back at the social discount rate of 3.5%. Conversely, where net costs rise over time (all other technologies), technologies will look better under the support metric, where costs and revenues are discounted back using the investor hurdle rate. In the case of storage, these impacts are large enough to change the sign of the overall metric. This is partly because the very low load factors of storage (4-6%) mean that small changes in costs and benefits (or revenues) drive very large changes in the £/MWh values.

Figure 35 Comparison of net costs to society and net support costs



Source: Frontier Economics

Note: Values for storage and interconnection relate to the large increments. All other values relate to the small increments. OCGT figures are not fully displayed on this graph – due to the low load factor, the components of WESC when measured on a £/MWh basis are extremely high.

4 IMPLICATIONS FOR POLICY MAKERS

4.1 Estimating value for money

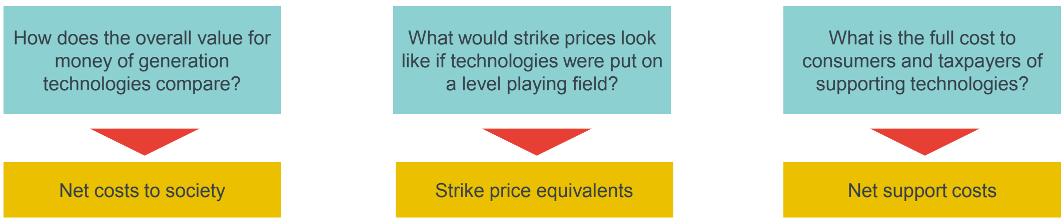
When assessing value for money of electricity generation, storage and interconnection investments, the full set of costs and benefits associated with technologies – both within and outside the electricity sector – should be taken into account. This is because they are likely to be sufficiently material to affect the value for money rankings. This also implies that the use of partial measures such as levelised costs and strike prices should be avoided.

This report has described a framework undertaking value for money assessments and interpreting the results.

We have described three metrics that can be used to inform a discussion of value for money (Figure 36).

- The net cost to society metric is useful for informing a view about the technologies that would provide the best value for money for UK plc.
- In policy debates, strike prices are often used to compare the value for money associated with different electricity technology investments. The strike price equivalents we have produced show how strike prices need to be adjusted to allow technologies to be compared on a level playing field.
- Net support costs provide an estimation of the costs to consumers and taxpayers of supporting technologies. This helps us understand the consequences for consumers and taxpayers of different technology choices.

Figure 36 Recommended metrics



Source: Frontier Economics

We have also produced a transparent and flexible set of tools, available alongside this report, to assist with an estimation of value for money [60]. These allow users to drill into the value for money estimates produced by 'black box' modelling to better understand the main drivers and to help to explain the results.

The framework presented in this report also illustrates the complexity associated with measuring the value for money of technologies. Detailed modelling is required to capture the interactions, and resulting estimates of value for money are extremely sensitive to the range of assumptions made, particularly regarding the definition of the baseline system. This implies the following.

[60] Tool A: Whole Electricity System Costs and Tool B: Investment Support Costs

- **It is very difficult to get to the 'right' number.** Given the degree of uncertainty around the key inputs, and the sensitivity of results to these inputs, multiple scenarios and ranges should be developed.
- **Any results are context specific**. Results of value for money assessments will only apply to a certain investment date and an assumed context. They should not be interpreted as 'generic' estimates that can be applied in multiple situations.
- **Ideally, instead of estimating the value for money of technologies and using this to guide policy decisions, the net costs to society of technologies should be internalised in the market framework**. Many WESCs are already internalised in the current market but differences in Contract for Differences (CfDs) across technologies, as well as the presence of some unpriced externalities, means there is scope for further reform.

4.2 The importance of adjusting for current market and policy frameworks

At present there are differences in the indirect support given to technologies, because of unpriced externalities and contractual terms that transfer risk away from investors to consumers.

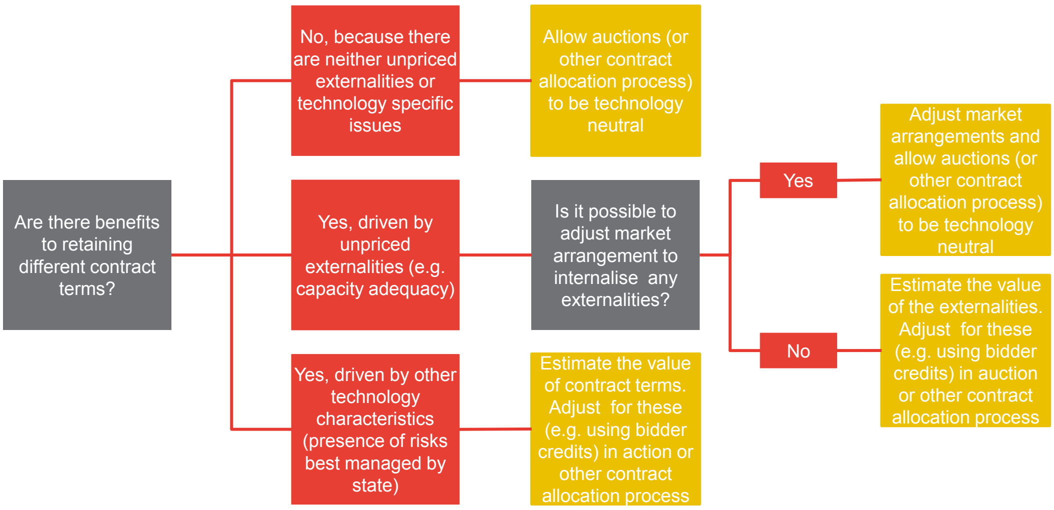
The analysis undertaken to develop this framework has also highlighted the importance of adjusting these differences when assessing value for money. Section 2 describes a methodology for undertaking these adjustments and highlights the importance of making these adjustments when calculating value for money metrics[61].

This methodology could also be used to help improve the technology neutrality of support mechanisms (Figure 37).

- Some of the differences in the treatment of technologies may increase the efficiency of the risk allocation and could therefore reduce overall costs to consumers. However, if there are no (or limited) benefits to different contract terms, a move to technology neutral market arrangements (either for low carbon technologies or for all technologies) would be likely to increase overall efficiency.
- If there are benefits to different contract terms, it may make sense to adjust for these in market arrangements, for example through bidder credits (which compensate bidders for differences in costs and revenues implicit in the contract terms) in an auction mechanism. These could also relate to technology specific contractual issues, for example the longer asset life of nuclear may mean that longer contract terms make sense. Again, an uplift could be added to the strike price to correct for the potential advantage the longer contract could give.

[61] Further details are provided in Appendix 3 and Tool B: Investor Support Costs.

Figure 37 Decision tree for policy makers



Source: Frontier Economics

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ASSESSING THE VALUE FOR MONEY OF ELECTRICITY TECHNOLOGIES

Appendix 1: Modelling of whole electricity system costs

January 2018

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CONTENTS

1 INTRODUCTION

Frontier Economics has been commissioned by the ETI to develop a robust framework for comparing the costs and benefits of electricity generation, storage and interconnection investments in the UK, and to produce transparent supporting tools that facilitate their comparison.

The aim of this work is to bring together different perspectives on how to look at the value for money of electricity generation technologies (Box 1) and to develop a framework for balanced and evidence-based assessment to inform the debate in a way that can be understood by a wide range of stakeholders.

The framework adopted makes use of supporting evidence drawn from the use of electricity system modelling. This report is an appendix to the main report and provides further detail on the modelling framework used.

The report is structured as follows.

- In Section 2, we define Whole Electricity System Costs,[1] describe their measurement in the recent literature and the implications this has for assessing the value for money of technologies.
- Whole Electricity System Costs are generally estimated using electricity system models. In Section 3, we assess the potential to use simpler, more transparent estimation methodologies, and describe the approach we take in the development of the Whole Electricity System Costs Tool [2].

FURTHER MATERIAL PUBLISHED ALONGSIDE THIS DOCUMENT

This research also encompasses the following published documents.

Main report:

Assessing the value for money of electricity technologies

Two Excel-based decision support tools:

- Tool A: Whole Electricity System Costs
- Tool B: Investment Support Costs

Further detail is also provided two further appendices:

- Appendix 2: Reflecting costs and benefits beyond the electricity sector
- Appendix 3: Assessing technology support requirements

[1] This modelling excludes costs and benefits that fall outside the electricity sector (e.g. the costs of competing demands for fuels, or the benefits of using waste heat for district heating). Such costs are considered by whole energy system models such as ESME or Markal.

[2] Published alongside this report

2 EXISTING ASSESSMENTS OF VALUE FOR MONEY OF ELECTRICITY TECHNOLOGIES

In this section, we cover recently published assessments of the value for money of electricity technologies, focusing their electricity system impacts.

We first define and describe the Whole Electricity System Costs of electricity technologies. We then set out how these impacts have been measured in the recent literature. We conclude by describing the implications for assessing the value for money of technologies.

2.1 Whole Electricity System Costs (WESC)

WESC measure the change in costs of constructing and operating an electricity system that result from the addition of a given quantity of a particular technology to that system[3]. In broad terms, this requires:

- simulating the total costs of running a “baseline” electricity system;
- simulating the total costs of running the baseline system after an increment of some technology has been added; and
- calculating the difference between the two costs.

Various modelling decisions need to be made about how to set up the baseline system, and how it should react to the inclusion of the extra capacity. These are discussed further in section 3.1. However, there is broad consensus in the literature on the scope of WESC and which costs should be included in any assessment. Research by Frontier Economics for DECC in 2016[4] sets out an exhaustive and non-overlapping framework for breaking down the electricity system impacts of technologies, based on a review of the wider literature. Throughout this report, we break down electricity system costs and benefits using this framework (Figure 1).

3 Frontier (2016), Whole power system impacts of electricity generation technologies, https://www.gov.uk/government/publications/whole-power-system-impacts-of-electricity-generation-technologies

4 Frontier (2016), Whole power system impacts of electricity generation technologies, https://www.gov.uk/government/publications/whole-power-system-impacts-of-electricity-generation-technologies

Figure 1 The components of WESC[5]

Technology direct costs	▪ Capital and operational costs associated with the incremental technology.
Capacity adequacy impacts	▪ To the extent existing capacity can be retired, or new capacity forgone to ensure the same level of security of supply and carbon intensity as the counterfactual, there is a cost saving to the system.
Balancing costs	▪ If the incremental capacity impacts on the uncertainty of supply, it will affect how generators in the rest of the system are called on to help support system stability by altering their output. It will also affect the extent to which they need to be prepared to do so at short notice, potentiallyaffecting their staffing, fuel, and/or maintenance costs.
Network impacts	▪ The incremental technology may require investments to reinforce or extend the existing grid, and changes to power flow may increase or decrease power losses due to transmission and distribution. It is also possible that technologies can free up headroom on the grid, creating network benefits.
Displaced generation impacts	▪ Outputs from the incremental technology can displace higher marginal cost generation, producing variable cost savings, e.g. fuel, carbon. The scale of this is diminished if generators in the rest of the system operate less efficiently, or the incremental technology is curtailed. This category includes the impact on variable costs of ensuring that the same carbon intensity is maintained.

Source: Frontier Economics

Overall, WESC can be positive or negative, depending both on the characteristics of the technology being added, and the underlying characteristics of the electricity system to which the technology is being added. Examples of how this framework could be applied for two representative technologies are shown in Figure 2.

5 In this framework, both generation output and capacity can be 'displaced' by the technology that is being added to the system. Capacity that is retired early or new investment that is avoided is counted in the Capacity adequacy impacts category. Generation output that is avoided is counted in the Displaced generation category.

Figure 2 Illustrative example using CCGT and solar

	Cost or benefit	CCGT	Solar
Technology direct costs	**Cost -** There will always be capital and operating costs associated with the incremental technology.	**Cost –** This will correspond to the levelised cost (excluding network charges), calculated on the basis of the load factor of the incremental technology.	**Cost** – This will correspond to the levelised cost (excluding network charges).
Capacity adequacy impacts	**Benefit**– This measures the cost reduction associated with the ability to retire or avoid investment in the marginal plant, while still maintaining (i) security of supply and (ii) carbon intensity.	**Benefit** (i) Security of supply impact (benefit) – A new CCGT has a high probability of being available at peak, therefore investing in new CCGT capacity will allow either existing capacity to be retired or investment in new capacity to be avoided. (ii) Carbon intensity impact (benefit or cost) – Depending on the baseline, adding a new new CCGT may mean a small change in carbon intensity (and thus low carbon investment) occurs.	**Benefit** (i) Security of supply impact (neutral) -The probability of solar being available at the system peak (assuming this continues to occur in winter evenings) is close to zero. Therefore the addition of solar capacity is not likely to allow retirement or avoided investment in the marginal plant for security of supply purposes. (ii) Carbon intensity impact (benefit) - The addition of solar will allow the marginal low carbon investment to be avoided.
Balancing costs	**Cost or benefit** – This measures the change in operating costs associated with increased or decreased uncertainty of supply.	**Benefit or neutral** - Additional CCGT capacity is likely to either reduce the uncertainty of supply or have no impact on the uncertainty of supply (depending on marginal plant it has displaced). If the additional CCGT could provide balancing services at a lower cost than the plant already on the system, this may reduce the overall cost of balancing.	**Cost** – Additional solar capacity could increase the uncertainty of supply, leading to an increase in operating costs for other plants on the system.
Network impacts	**Cost or benefit** – Adding new generation can either lead to requirements for network reinforcements (e.g. if the network needs to be reinforced to accommodate generation in a new location), or avoided network costs (e.g. if adding generation close to means the need for transport is diminished).	**Cost or benefit**. Depends on the location of the new plant (and the network conditions at that location), as well as the network costs associated with retirement or avoided investment in the marginal plant. Only transmission costs are likely to be affected.	**Cost or benefit.** Depends on the location of the new plant (and the network conditions at that location), as well as the network costs associated with retirement or avoided investment in the marginal plant. The impact is likely to be mainly on distribution costs.

	Cost or benefit	CCGT	Solar
Displaced generation impacts	**Benefit** – measures the value of the electricity produced, in terms of generation costs from the marginal plant on the system	**Benefit** – A new CCGT will be more efficient and have lower short run marginal costs than the marginal plant.	**Benefit** – Given short run marginal costs that are close to zero, solar will also lead to avoided generation from the marginal plant. However, the per unit benefit of avoided generation is likely to be lower for solar, since it has a lower probability of being available at times of high prices (e.g. winter evenings) than a CCGT.

Source: Frontier Economics

2.2 Measurement of WESC

2.2.1 Overview of the literature

Seven significant recent papers estimate WESC of generation technologies (Figure 3). These focus on a range of low carbon technologies. CCGTs, OCGTs, storage and interconnection are not covered in these studies.

Figure 3 Existing papers on the components of WESC in the UK

	Specific aim	Technologies	Approach	Estimates
UKERC[6] (2017)	To characterise the impacts and assess the costs of integrating variable renewable sources into power systems	Wind and solar	A systematic review of around 200 journal papers, reports and other evidence sources	Capacity costs: £1-17/MWh for 20% penetration Reserve costs/short-run system balancing costs: £0- £5/MWh up to 30% renewables penetration, Transmission and distribution costs £5-20/MWh up to 30% renewables penetration
Imperial College, Joint industry project (2016)[7]	To quantify the system impacts of low-carbon generation technologies in the context of the future UK electricity system	Wind, solar and biomass conversions	Electricity system modelling using the Imperial College Whole-electricity System Investment Model - an electricity system model covering dispatch and investment, across the generation, transmission and distribution systems	WESC, excluding technology direct costs: Onshore wind: £7/MWh-£40/MWh Offshore wind: £6/MWh-48/MWh Solar PV: £8/MWh-£44/MWh Biomass: -£7-£1/MWh
Nera and Imperial College for Drax (2016)[5]	To analyse system integration costs of renewable technologies in the UK and to assess potential policy reforms to better reflect these costs	Wind, solar and biomass conversions		WESC, excluding technology direct costs: Onshore wind: £7-9/MWh Offshore wind: £7/MWh Solar PV: £12/MWh Biomass: -£1/MWh
Nera and Imperial College for the CCC (2015) [5]	To quantify the system impacts of low-carbon generation technologies in the context of the future UK electricity system	Wind, solar and Gas CCS		WESC, excluding technology direct costs: Wind: £6/MWh-£16/MWh Solar PV: £6/MWh-28/MWh CCS: -£8/MWh-£5/MWh
Aurora Energy Research for Solar Trade Association (2016)	To estimate the current and future costs of variability for solar	Solar	Electricity system modelling based on the Aurora Energy Research Electricity System model for Great Britain (a dynamic dispatch model)	Variability costs of solar at £6.8/MWh relative to baseload technology, excluding network costs

[6] Values presented covers UK and Ireland. Values cannot be summed.

[7] Costs are for 2030.

	Specific aim	Technologies	Approach	Estimates
Frontier (2015) for Drax	To assess the total cost of replacing a proportion of biomass conversion with an equivalent level of offshore wind investment	Wind and biomass	Bespoke modelling based on DECC generation cost assumptions, TNUoS charges, National Grid estimates of balancing requirements and Ofgem estimates of capacity requirements	Replacing a single biomass generating unit with the equivalent investment in offshore wind could cost an additional £650 million to £900 million over the lifetime of the investments(with transmission costs as the most important element)
OECD and the Nuclear Energy Agency (2012)	To quantify the system effects of electricity generation technologies	Renewables, nuclear, coal and gas	Review of existing published evidence.	WESC, excluding technology direct costs: Onshore wind: £18-30/MWh Offshore wind: £34-45/MWh Solar PV: £57-89/MWh Nuclear: £3/MWh

Source: Frontier Economics

There is broad agreement in the literature on some points.

- WESC over and above direct technology costs are material enough to warrant assessment and consideration by policymakers, but technology direct costs generally dominate.
- WESC over and above direct technology costs tend to be highest for solar and lowest for dispatchable low carbon plant (CCGT with CCS, or biomass).
- Distribution network costs can be significant for solar[8] and transmission network costs can be significant for offshore wind[9].

However, Figure 3 shows that there is a very large range in estimates both within and across studies. This is because the literature varies in its focus and its purpose, as well as in the detailed assumptions and modelling techniques used.

There are therefore a number of reasons why it is difficult to compare numbers across papers, or to draw a consensus on the overall value of WESC. In particular, studies vary on:

- the scope of the estimation (i.e. on the coverage and exact definitions of the elements set out in Figure 1 above);
- assumptions on the baseline system; and
- other methodological points.

We now discuss each of these further.

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8 For example, Imperial (2016) finds that high distribution reinforcement costs are incurred for solar in 2030 as a results of the increased reversed flows in distribution networks.

9 For example, Frontier (2015) finds that more than half of the additional whole system costs associated with offshore wind relative to biomass could be attributed to offshore wind.

2.2.2 Scope and breakdown of whole system costs

While there is broad consensus the coverage of components and the exact definition varies across studies. Differences include the following.

- Many of the studies exclude technology direct costs.
- Some elements are excluded from some studies. For example Aurora (2015) excludes network costs. In contrast, distribution costs are a major driver of WESC in many scenarios in Imperial (2016).
- Some studies also allocate a portion of network costs to the technology direct cost category. This is in line with the convention to include connection and use of system charges in levelised cost estimates[10]. However, since other studies allocate these costs to the 'network costs' category, it means that it can be difficult to compare estimates of the WESC across studies. For example, in Imperial (2016), the contribution of transmission costs to WESC is found to be close to zero for offshore wind in most scenarios. In contrast, in Frontier (2015), transmission costs make up a significant portion of the difference in whole system costs between biomass and offshore wind.
- The UKERC (2017) systematic review found that in some studies, there is overlap between the capacity adequacy and balancing cost impacts. This could be, for example, because building new plants to ensure capacity adequacy reduces the operating costs associated with balancing.
- Displaced generation impacts also vary across studies. For example, in the Frontier (2016) framework, these take into account the impact that adding variable[11] or inflexible technologies could have on the efficiency of other plants. In other studies, some of these impacts are included in the balancing cost category.

These differences in scope can be associated with significant differences in the resulting estimates. This means that care needs to be taken in directly comparing values from across studies.

2.2.3 Assumptions on the baseline system

There is a broad consensus in the literature that the estimation of the WESC of technologies should be based on system modelling. This is because the level of these impacts depend on multiple and complex interactions between the different generation, flexibility and network technologies. For example, the impact of adding a unit of wind generation to a system may depend on a range of factors such as:

- the flexibility of the system, including the quantity of inflexible baseload plant such as nuclear and the amount of CCGT, OCGT, storage and interconnection;

10 BEIS (2016), *Updated Energy and Emissions Projections 2016*, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/599539/Updated_energy_and_emissions_projections_2016.pdf

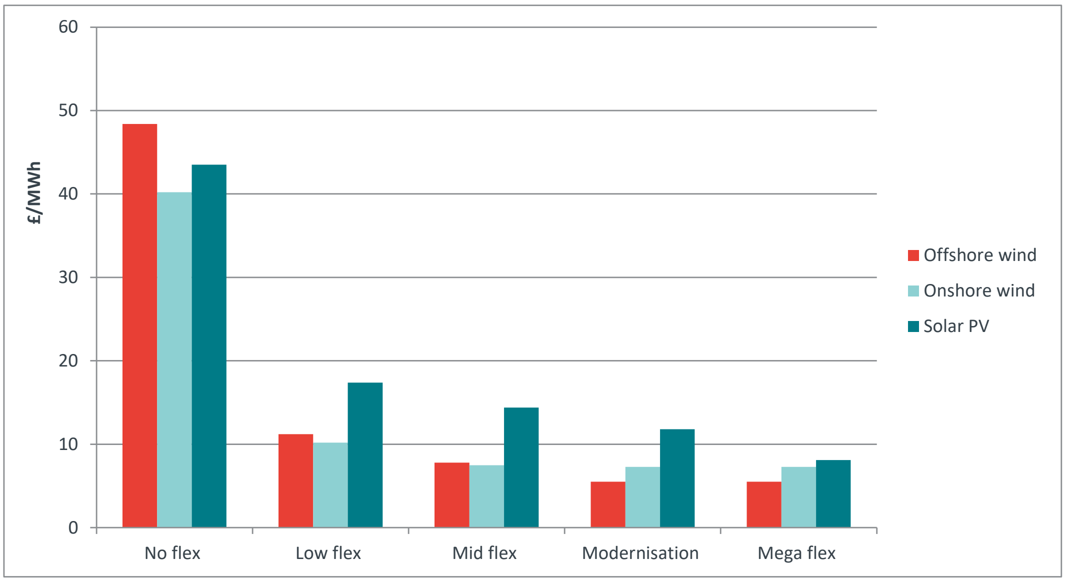
11 'Variable' and 'intermittent' are used interchangeably in the literature to describe the fact that the availability for dispatch of output from renewables such as wind and solar generation is dependent on variable factors such as the weather. In this report we use the term 'variable'.

- the flexibility of demand; and
- the amount of wind that is already on the system and the correlation of the output of the new unit of wind with the output of the existing wind on the system.

To undertake system modelling, a set of detailed assumptions need to be made about the baseline system – that is, the counterfactual mix of generation, network and flexibility technologies.

There is a consensus in the literature that assumptions on the baseline have a major impact on the resulting estimates. For example, Figure 4 shows the wide variation in estimates produced by one study, when assumptions on the flexible technologies (DSR, storage and interconnection) available in the baseline system (out to 2030) were varied.

Figure 4 Illustration of variation in estimates under different baseline assumptions



Source: Based on Imperial (2016)[12]

Note: This study also looked at different scenarios for the generation mix.

The importance of the baseline assumptions has a number of implications.

- **Context dependency.** It is not possible to produce generic estimates of the WESC of technologies that are valid across a range of contexts. Instead, estimates produced by the modelling will only be valid for a specific scenario, and a specific investment date. In particular, when comparing estimates across studies, it is particularly important to take into account the following baseline assumptions, which will apply both at the starting point of the analysis (the investment date), and over the lifetime of the investment being assessed:
  - the penetration of DSR, interconnection and storage;
  - the baseline generation mix, in particular the penetration of variable or inflexible low carbon plant; and

[12] Imperial College London (2016) , *Whole-system cost of variable renewables in future GB electricity system* https://www.e3g.org/docs/Whole-system_cost_of_variable_renewables_in_future_GB_electricity_system.pdf

  - assumed spare network capacity.

- **Risk of under or overestimation of system impacts.** Up to a certain limit, the greater the amount of flexibility (e.g. peaking plant, DSR, interconnection or storage), or spare network capacity that is assumed in the baseline, the lower will be the WESC of variable or inflexible generation technologies[13]. Some of the existing modelling treats flexible technologies other than generation as exogenous – that is, assumptions are made on the quantity of DSR, interconnection or storage that are in place before the WESC of the incremental technology are assessed. This approach is partly due to the fact that it is difficult to characterise generic DSR and interconnection option, given the heterogeneity of these resources, the challenges in representing the spatial and temporal granularity of their benefits within a system model, and the general lack of evidence on cost and performance in the case of DSR. To the extent that 'spare' flexible or network capacity has been assumed into the baseline, this spare capacity can be used to manage the impact of the incremental variable or inflexible technology, reducing the WESC of the incremental inflexible or variable technology. Conversely, assuming too little flexibility or spare network capacity will lead to an overestimate of system impacts.

2.3 Conclusions and implications for the rest of the project

WESC over and above technology costs have generally been found to be sufficiently material to warrant policy makers' consideration

In Section 4 we describe a range of metrics that can be used to assess value for money. Based on the analysis set out above, choosing a metric that includes WESC is likely to be important.

Estimates of WESC are highly context specific.

It is not possible to produce a generic estimate of WESC that can be applied in multiple contexts. There is wide variation in the estimates even within studies, as different assumptions on the baseline system can have large influence on the resulting outputs.

For a balanced comparison between technologies, the full range of WESC should be considered

It is important to ensure that the scope of any estimation covers the full range of impacts. For example, excluding distribution network impacts could underestimate the WESC of solar, relative to other low carbon technologies.

[13] The converse applies for flexible technologies such as CCGT, OCGT, storage and interconnection.

3 MODELLING APPROACHES

As described in Section 2, WESC are generally estimated using complex electricity system models.

In this section, we describe a framework for undertaking this type of assessment and assess the potential to use simpler, more transparent estimation methodologies.

- Calculating WESC requires estimating the total resource costs of the electricity system with and without the technology that is being assessed. We first set out the choices that need to be made when applying this framework.
- We then describe the possible approaches for estimating resource costs of the system, which range from complex models (like the EnVision model used in this project), to simple heuristics. There is a trade-off: the complex techniques can more accurately capture the impacts (including interactions between the different components of system costs), at the expense of potentially becoming a “black box” which obscures the main factors driving the results.
- Within the Whole Electricity System Costs Tool[14], we manage this conflict by expressing the results of a complex modelling in terms of a series of simpler relationships which are more transparent and can be interrogated by users of the tool. The final part of this section explains how we do this.

3.1 Setting out the framework

The WESC of a technology are typically assessed by comparing two scenarios, where one scenario includes the technology in question (a “technology-on” scenario) and the other (the “baseline”) either does not include it or does, but at a lower penetration level. The WESC of the technology is calculated as the difference of the total resource costs between these two scenarios.

To use this framework in practice, we need to define several elements (Figure 5).

[14] Published alongside this document.

Figure 5 Framework for the assessment

Baseline definition	Optimal or current trends
Baseline: exogenous assumptions	Generation, networks and flexibility
Size of the increment	Small or large
Re-optimisation	Short term or long term
Constraints	Carbon and loss of load

Source: Frontier Economics

We discuss each of these decisions (and the approach we have adopted) below.

3.1.1 Baseline definition

As described in Section 2, assumptions about the baseline system are critical.

We wish to assess the WESC of electricity technologies that will be commissioned in 2025 in the context of meeting carbon budgets. Broadly, there are three options for defining a baseline system. These are described in Figure 6.

Figure 6 Options for the baseline system

	Optimal path	Current trends	Projected path to meet carbon budgets
What does the baseline represent?	Represents the least cost path to meeting carbon budgets, while maintaining LOLE	Represents a continuation of current trends and may not meet carbon budgets	Represents a path to meeting carbon budgets that extrapolates current trends in relation to the low carbon mix
What can this tell us?	In an ideal world, what is the value for money of alternative technologies in 2025?	Given current policy and trends, what is the value for money of alternative technologies in 2025?	Given the projections on a likely path to meeting carbon budgets (based on current policy and trends), which changes to the projected investment mix in 2025 would represent the most value for money?
Example scenarios	Scenarios produced using least cost optimising models (e.g. ESME)	The BEIS 'Existing Policies Scenario'. This scenario includes only existing policies [15]	The BEIS 'Reference scenario' includes the impact of existing and planned policies[16]

Source: Frontier Economics

Since we are interested in assessing the value for money in a real world context, but one which meets carbon budgets, we focus on a scenario that best represents the projected path to meet carbon budgets. The BEIS Reference scenario can be used to represent this baseline[17].

3.1.2 Baseline system: exogenous assumptions

Some elements of the baseline (e.g. investment in conventional plants) can be simulated or optimised using an electricity system model. However, a model which allows all forms of investment to be perfectly optimised would fail to take into account institutional and political constraints which may favour a particular technology mix. We focus on a baseline system that represents the projected path to meet carbon budgets, including current and planned policies.

[15] BEIS (2016), *Updated Energy and Emissions Projections 2016*, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/599539/Updated_energy_and_emissions_projections_2016.pdf

[16] BEIS (2016), *Updated Energy and Emissions Projections 2016*, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/599539/Updated_energy_and_emissions_projections_2016.pdf

[17] BEIS (2016), *Updated Energy and Emissions Projections 2016*, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/599539/Updated_energy_and_emissions_projections_2016.pdf

To reflect the existing institutional and policy framework, we make several exogenous assumptions in this modelling.

Low-carbon generation

We 'force on' low carbon technologies in line with the BEIS Reference Scenario. This is a published scenario, which represents a view of the capacity mix under current and planned policies.

The BEIS Reference Scenario does not include a breakdown of renewable plants. We therefore used proportions of renewables based on figures provided by HMT in the Autumn Budget 2017,[18] alongside projections of nuclear and CCS capacity developed for the ETI.

Flexible plants, DSR and interconnection

The rest of the generation mix in the baseline system is made up of:

- plants that are already on the system; and
- other plants that would be economic for investors to build, given currently existing plants, the low carbon plant being 'forced on', and existing policies such as the capacity market. EnVision simulates investment in these plants (which includes CCGT, OCGT and storage) by looking at the revenue they can earn in the wholesale, balancing and capacity markets, and determining whether it is worthwhile for investors to bring them on (taking account of hurdle rates).

Interconnection and DSR will be held at the level currently available plus any committed investment to 2025 (DSR capacity is held static from 2025 onwards, at 1.6GW). This conservative approach is taken to ensure that we do not underestimate the WESC of variable and inflexible plant by 'baking in' too much flexibility to the system.[19]

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[18] HMT (2017) Control for Low Carbon Levies - https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/660986/Control_for_Low_Carbon_Levies_web.pdf

[19] To the extent that interconnectors or DSR may be a cheaper means of providing flexibility, we may therefore overstate the costs of required flexibility.

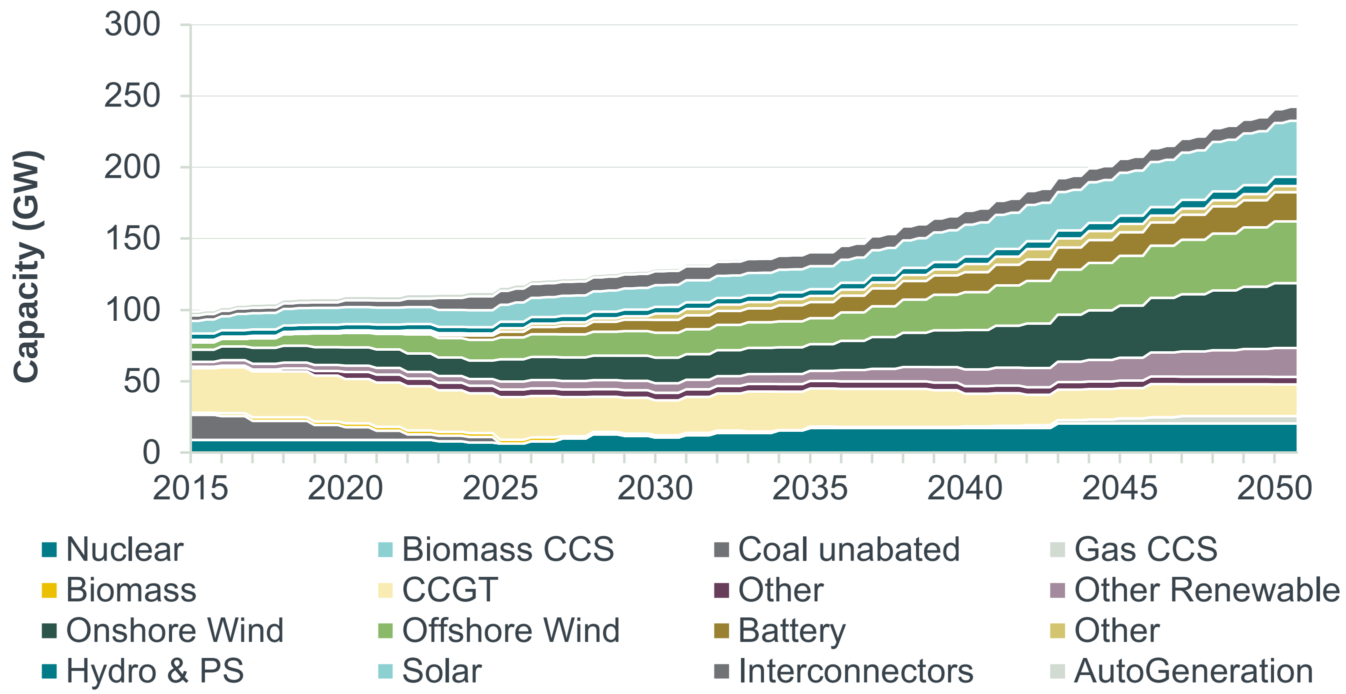
Figure 7 Options for exogenous assumptions of interconnection and DSR

	Only existing or committed investments in interconnection and DSR	'Rational' interconnection and DSR consistent with the baseline system
What question does this help us answer?	Given the flexibility that's already committed to, how does the value for money of technologies vary for investments in 2025?	Some additional flexibility is likely to be required to meet carbon budgets. Assuming this is in place, how does the value for money of technologies vary for investments in 2025?
How does this work in practice?	The model will either add or subtract new CCGT, OCGT or storage to meet the change in flexibility needs associated with the incremental change in investment. The costs associated with this will be allocated to the incremental technology.	The same approach is taken, but if exogenous assumptions on interconnection and DSR have already met the flexibility needs, the cost of doing so will not be associated with the incremental technology.

Source: Frontier Economics

The resulting baseline capacity mix is shown in Figure 8.

Figure 8 Assumed baseline capacity mix



Source: LCP modelling

Summary of assumptions

Figure 9 sets out a summary of baseline assumptions.

Figure 9 Summary of baseline assumptions

Assumption	Source
Low-carbon generation technology capacity	BEIS Reference Scenario[20], with a split by renewable type taken from ETI modelling
Other generation technology capacity	Endogenous build carried out by EnVision
Interconnection capacity	Kept at committed levels to avoid the over-provision of exogenous flexibility
Generation technology capex and opex	ETI modelling for most technologies. Offshore wind capex has been adjusted to be consistent with recent CfD auctions.
Investors' hurdle rates	BEIS Electricity Generation Costs [21]
Fuel and carbon prices	BEIS Valuation Guidance[22]
Generation technology availability	BEIS Electricity Generation Costs[23]
Existing generators	LCP analysis
Demand	BEIS Reference Scenario[24]
Other assumptions (e.g. costs for networks, balancing…)	LCP assumptions

Source: Frontier Economics

3.1.3 Size of the increment

The WESC of a technology may vary depending on the amount of it that is added to the system. For example, if a large amount of a variable technology such as wind is added to the system, there may be a lower benefit or higher cost per MWh than if a smaller amount is added. This is due to effects such as an increased likelihood of curtailment, given a degree of correlation between the output of wind generators.

One approach is to add very small amount of capacity, to determine the marginal whole system impact associated with small changes[25]. As capacity and network investment costs are "lumpy" (it is not possible to build a small fraction of a power

[20] BEIS (2016), *Updated Energy and Emissions Projections 2016*, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/599539/Updated_energy_and_emissions_projections_2016.pdf

[21] BEIS (2016), *Electricity Generation Costs*, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/566567/BEIS_Electricity_Generation_Cost_Report.pdf

[22] BEIS (2017), *Valuation of energy use and greenhouse gas emissions for appraisal*, https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

[23] BEIS (2016), *Electricity Generation Costs*, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/566567/BEIS_Electricity_Generation_Cost_Report.pdf

[24] BEIS (2016), *Updated Energy and Emissions Projections 2016*, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/599539/Updated_energy_and_emissions_projections_2016.pdf

[25] A model such as EnVision can calculate the marginal whole system impact of all technologies within a single model run, greatly increasing the speed with which Whole System Costs can be calculated

station or transmission line), a marginal approach generally involves smoothing out these costs (e.g. applying an average cost of building new capacity).

An alternative approach is to add a much larger amount of capacity. This type of calculation may be more appropriate for assessing the overall direction of investment that should take place (Figure 10) – for example, whether a policy should aim to enable investment in a certain technology type through the allocation of CfDs.

Figure 10 Small or large increments

	Small change in 2025	Major investment change in 2025
What question can it help with?	For an investment decision in 2025, what is the value for money of alternative technologies?	For establishing the direction of investment from 2025, what is the value for money of alternative technologies?

Source: Frontier Economics

We use both approaches:

- We calculate marginal WESC against the counterfactual, to show the average impacts of adding a small amount of additional capacity to the existing system.
- We then run the model with a much greater amount of capacity – for example, increasing the capacity of the technology already in the baseline by around 2GW (adjusting the increment of non-baseload technologies by their availability).[26]
- Finally, we calculate an additional marginal whole system impact where an infinitesimal amount of capacity is added *on top of the large increment discussed above*. This allows us to investigate the extent to which the marginal whole system impact may vary with penetration of a given technology.

3.1.4 Re-optimisation

WESC can be calculated on a "short-term" basis, where the baseline is assumed not to change after the new technology is added. However, this perspective may overstate the whole system costs of the technology. For example, if a large amount of wind is added to the system, a short-run approach may assume that large amounts of its output is curtailed, due to a lack of appropriate network infrastructure or flexible plants.

We instead take a "long-term" approach. This ensures that, as long as the model is able to endogenously build or retire network and generation capacity, any costs of adapting the system to meet the new technology will be allocated to the technology.

[26] For example, this might lead to an additional 2GW of nuclear or 4GW of offshore wind being built over a number of years, subject to a check against build constraints.

3.1.5 Constraints

As described above, we take a "long-term" approach, allowing the simulated investments and retirements to change between the baseline and the scenario that includes the additional technology[27]. To represent existing policy on security of supply and carbon this "re-optimisation"[28] can be carried out holding the loss of load expectation (LOLE) and carbon emissions constant.

LOLE constraint

Adding capacity may reduce the probability that demand exceeds supply (as quantified by LOLE, which measures the number of hours in the year that demand is expected to exceed supply in the absence of mitigation measures from National Grid). This benefit could be captured in one of several ways:

- One potential "long-term" optimisation would seek to re-optimise capacity at least overall cost, where LOLE is valued using the VOLL[29].
- Alternatively, the optimisation could be carried out subject to the constraint that LOLE remains at a target level.

We adopt the latter approach, since this is most consistent with the GB market, where capacity auctions are run with the aim of ensuring a LOLE of three hours per year. EnVision identifies the marginal unit of capacity, and adds or subtracts this technology (with associated "second-round" whole system impacts) to maintain LOLE.

Carbon constraint

Holding all else constant, adding capacity could either increase or reduce carbon emissions (depending on the relative carbon intensity of the technology to the technologies it is displacing). Again, there are two main ways in which this could be optimised over the long-term[30]:

- One method would re-optimise the system in such a way that overall costs (including carbon emissions) are minimised, with any residual change in carbon emissions being valued at the cost of carbon. This approach is appropriate for assessing the impact of varying the generation technology mix where there is an economy wide emissions target, such as that imposed by the UK's carbon budgets[31]. The limitation of this approach is that BEIS appraisal values may under or over-estimate the benefits of carbon saving, where the incremental investment in the electricity sector leads to very large changes in emissions. This is because the BEIS values are based on estimates of the abatement costs that will need to be incurred in order to meet

[27] A "short-term" optimisation would simply value this reduced LOLE, using the Value of Lost Load (VOLL).

[28] EnVision simulates the behaviour of market participants rather than minimising overall resource costs, so this is not strictly a full re-optimisation.

[29] Value of Lost Load.

[30] A "short-term" optimisation would value the change in carbon emissions, at some carbon price.

[31]

specific emissions reduction targets and therefore have been estimated on the basis of a certain emissions trajectory.

- Alternatively, the optimisation could be carried out subject to a constraint on emissions. This would be consistent with a scenario where the electricity sector had a sector-specific carbon target. This approach is likely to be most useful where the baseline is made up of an optimised low carbon generation mix.

We have built into our Whole Electricity System Costs Tool the ability to carry out this second type of re-optimisation. The Tool can identify the technology that is marginal from a carbon abatement point of view (i.e. the technology that is most expensive per tonne of carbon abated) and adds or subtracts this technology (and its whole system impacts) to maintain carbon intensity. However, where the baseline low carbon generation mix is exogenously determined (as in our modelling), allowing any form of re-optimisation risks producing misleading results. For example, the exogenously determined low carbon generation mix may include some expensive technologies. These could be included in the mix because it is expected that they will be deployed for reasons relating to strategic security of supply or because deployment is expected to bring down future costs through innovation. However, their presence would distort the results of an optimisation based on cost. If we allow the model to re-optimise to hold carbon constant and displace these expensive low carbon technologies, we could be overstating the benefits associated with the incremental investment.

Given our exogenously determined baseline, we therefore focus on results that value changes in carbon emissions using ”target consistent” BEIS values.

3.2 Approaches for modelling each component of electricity WESC

Section 3.1 described the important decisions and assumptions required in any estimation of WESC.

Given this framework, we now set out some of the different ways in which each component of WESC can be calculated. In general, there is a trade-off between more complex techniques (which can more accurately capture some of the impacts, including the interactions between different components) and simpler approaches (which will provide a lower level of accuracy, but are potentially more transparent).

Our starting point for each option is the functionality provided by LCP’s EnVision model. As explained below, this model provides a comprehensive simulation of most of the relevant aspects of the power system,[32] with appropriate simplifications to ensure it can be ran for multiple scenarios in a reasonable length of time.

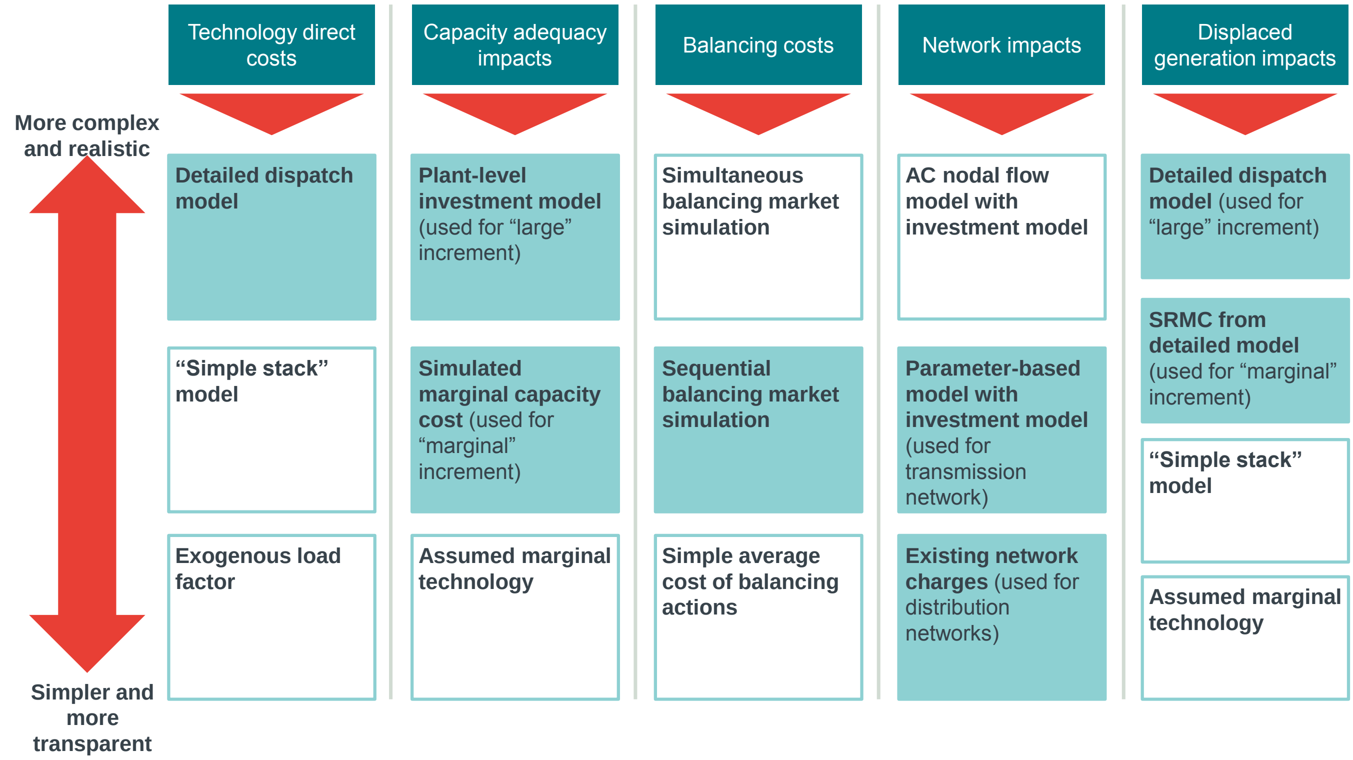
While simpler and more transparent options are possible, in most cases these have serious limitations. We discuss these in the next section.

[32] The network cost modelling within EnVision is relatively simple. However network costs will vary significantly by the exact location of the technology under consideration – as we are considering general archetypes and not specific project, more detailed network modelling is unlikely to add much to this analysis.

3.2.1 Summary of our approach

Figure 11 summarises our approach, with the method we use in our Whole Electricity System Costs Tool highlighted in each row. We provide more detail on each element below.

Figure 11 Summary of modelling methods

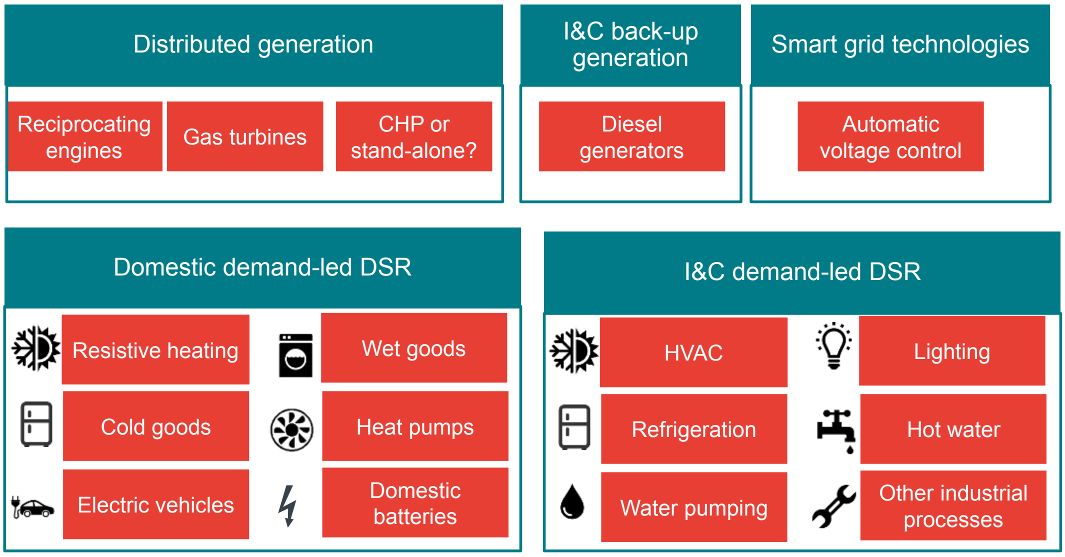


Source: Frontier Economics

These methods are applied to investigate the value for money of CCGT (with and without CCS), OCGT, nuclear, solar PV, offshore wind, onshore wind, storage and biomass CCS. Annex A sets out an approach to assessing value for money for interconnection. We do not seek to estimate the whole system impact of DSR in this report (although some DSR is present in the counterfactual we use), on the basis that it is extremely heterogeneous in terms of its capabilities and costs (Figure 12).[33]

[33] Frontier Economics (2015), *Future potential for demand side response in Great Britain*, https://www.gov.uk/government/publications/future-potential-for-demand-side-response-in-great-britain

Figure 12 Potential sources of DSR



Source: Frontier Economics

3.2.2 Technology direct costs

The technology direct costs are those costs that are included in the simple levelised cost measure (though we note that many estimates of levelised costs also include some network costs). There are two main types of input required for this calculation: estimates of the various components of costs, and load factors.

Cost components include:

- fuel costs (derived from fuel costs, and the efficiency[34] of the technology in converting fuel input to electrical energy);
- carbon costs (derived from efficiency, the emissions intensity of the fuel, and a carbon price);
- other variable operating and maintenance costs, which might vary in proportion to the energy produced, or with the number of starts per year;
- fixed operating and maintenance costs (for example, labour costs); and
- capital expenditure (including financing) costs.

A variety of external sources provide estimates of these costs (for example, BEIS regularly commissions updates of estimates to feed into its electricity generation costs).

To produce a levelised cost, these inputs need to be combined with an estimate of load factor (the number of hours the plant is running, which will depend both on its availability, and on how often it is dispatched). As explained below, this could be carried out using a detailed dispatch model, a simple stack, or by making a simple assumption.

[34] As described below, in more complex models the efficiency itself can be a function of load factor.

A detailed dispatch model

A dispatch model simulates the utilisation of every plant on the system, subject to various constraints, to minimise costs. The load factor of each plant is produced as an output of the model.

Examples of dispatch models include the short-run dispatch components of EnVision (as used by BEIS in the form of the DDM), WeSim (used by Imperial to model whole system costs), or PLEXOS.

Dispatch models can take into account a variety of physical constraints – for example:

- ramping constraints, which stop certain types of generators being able to adjust output immediately;
- the costs of starting up generators (which can be greater for "cold" starts); and
- the way in which the efficiency of a thermal generator can degrade for load factors below its nameplate capacity.

In addition, dispatch models such as EnVision take account of the way markets may not lead to a perfectly cost-minimising dispatch (e.g. policies such as CfDs which may lead to some generation being dispatched "out of merit").

Dispatch models can be run on their own, but can also be integrated with models that cover other aspects of the electricity system, such as investment in new capacity, balancing costs, and network costs.

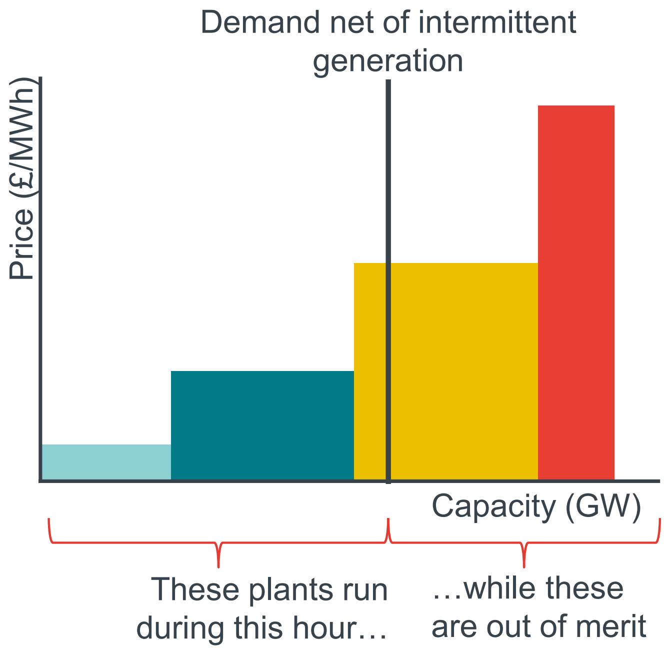
A "simple stack"

A more tractable approach to modelling dispatch is the "simple stack", illustrated below.

In such a model, dispatchable plants are arranged in a merit order of increasing variable costs. Demand (minus of any variable generators) for a time period is overlaid over this, and plants are dispatched in merit order until demand is met.

This approach is equivalent to a simple dispatch model without any of the additional constraints discussed above. As there is no simulation of inflexibility, such a model might dispatch inflexible yet expensive plant less often than would actually be the case. In addition, as these models do not consider other aspects of the electricity system.

Figure 13 Illustration of a "simple stack"



Source: Frontier

Exogenous load factors

An alternative to carrying out any modelling is to simply assume a given load factor. This has the advantage of making the assumption extremely transparent, but may also lead to misleading results if the chosen load factor is inaccurate. For example, using a single historic load factor for wind generation could overestimate the load factor (and thus underestimate costs) for future years, if increased uptake of wind is likely to lead to curtailment and lower load factors.

BEIS's levelised cost analysis uses this approach. For example, peaking plant such as OCGTs are assumed to run for 500 hours per year.

For our Whole Electricity System Costs Tool, we use a detailed dispatch model (EnVision). This is because the inaccuracies associated with simplification may be material (Figure 7).

Figure 14 Technology direct costs: comparison of methodologies

Methodology	Disadvantages compared to a more complex method	Examples
Detailed dispatch model. Simulate least-cost dispatch with an integrated dispatch/investment model to obtain a load factor for the technology under analysis. Combine with generation costs (O&M, capex, fuel etc.) to calculate a levelised cost.		EnVision is such a model, which simulates many technical constraints (although the need to make the model computable means not all complexities are considered).
Simple stack model. As above, but calculate load factors using a "simple stack" of generators (where generators are always dispatched in order of average variable cost).	May not consider out-of-order dispatch due to policies. Increasing simplification will lead to inaccuracies (e.g. flexible but expensive plant may be penalised).	
Exogenous load factor. As above, but use a load factor based on historic figures.	Cannot take into account how load factors may change in the future (e.g. high RES uptake leading to curtailment).	BEIS's levelised cost analysis assumes an arbitrary 500 hours of running for peaking plant.

Source: Frontier Economics

3.2.3 Capacity adequacy impacts

When new capacity is added to the system, it may mean that other capacity can either be retired or not built altogether, while still maintaining the LOLE standard of three hours. If so, the reduced capex and fixed opex will be captured as capacity adequacy impacts.

Plant-level investment model

The most comprehensive way to capture these costs is through a model of investment that takes place at the plant level. Within EnVision, this takes the form of a simulated capacity market. As part of this modelling, the capacity credit (i.e. the extent to which each technology can be relied upon to produce during the winter peak) is calculated for technologies such as wind. This is important, since the capacity credit of variable technologies will diminish as more are placed on the system (since the new generation will be producing at times where there is already plenty of supply).

This form of approach provides a relatively accurate way of simulating capacity adequacy impacts, and we use it for the "large increment" runs. However, the "lumpy" nature of capacity additions means that this would not be a suitable method for use with the "marginal impact" runs. This is since the addition of a very small (e.g. 1MW) increment of capacity would either:

- (most likely) result in no change in the number of other plants required, producing a whole system impact of zero; or
- (unlikely but still possible) result in an entire plant being built or postponed, resulting in an extremely high whole system impact per MWh generated.

Neither of these two outcomes would be meaningful, and the output would be extremely sensitive to small changes in the plant park or demand, which could cause the result to switch between the two extremes. Instead, an approach is needed which can "smooth" the impact – in effect, providing the expected capacity adequacy impact.

Simulated marginal capacity cost

A simplified version of this method still involves simulating the capacity credit of all plants, and determining the marginal unit of capacity. As explained in section 3.1.5, we are ensuring that the carbon intensity of the system remains constant, and so when we are adding a low-carbon plant, this will be the marginal unit of capacity from a carbon savings point of view (i.e. the technology with the greatest whole electricity system cost per tonne of carbon abated). The capacity impact is then calculated as the avoided cost of a quantity of the marginal capacity that is equivalent in derated terms to the added capacity.

For example, consider a situation where the capacity credit of nuclear was 80% and the capacity credit of wind was 10%. If wind was the most expensive form of generation from a "cost per tonne abated" viewpoint, a MW of additional nuclear capacity would mean that roughly 8MW of wind generation could be left unbuilt while maintaining the same LOLE.

This method has the advantage of working with even the smallest capacity increments (since it abstracts away from the "lumpy" nature of capacity), **and so we use it for our "marginal increment" runs**. However, it does not capture "second-order" effects, where the entire shape of the plant park changes over time in response to a new technology. For example, a greatly increased penetration of variable renewables might eventually lead to more flexible and less inflexible generation. The costs and benefits of such a shift would not be captured by this approach.

Assumed marginal technology

The simplest approach to estimating capacity adequacy impacts would be to assume a certain technology is the marginal unit of capacity, and then carry out a similar calculation to the one above using the cost of this technology and historic derating factors. While transparent, such an approach would be entirely driven by the choice of the marginal technology.

These issues are summarises in Figure 15.

Figure 15 Capacity adequacy – options

Methodology	Disadvantages compared to a more complex method	Examples
Plant-level investment model. Simulate investment required to meet a specific LOLE standard. Determine how much lower this investment is, if the additional capacity is added.		EnVision simulates investment – although this cannot be used to find the marginal WESC, due to the very "lumpy" nature of investments.
Simulated marginal capacity cost. Simulate a capacity market for each year to determine the marginal cost of capacity. Use derating factors derived from modelling to determine the cost of the capacity that is displaced.	Doesn't consider second-order effects (such as new variable generation resulting in a gradual move from inflexible to flexible generation).	EnVision uses this method for calculating the marginal whole system cost.
Assumed marginal technology. Assume a single technology (e.g. CCGT) will be displaced. Multiply a historic derating factor for the technology under question by the cost of the marginal plant.	Very sensitive to the assumption on which technology will be on the margin.	.

Source: Frontier Economics

3.2.4 Balancing costs

Balancing impacts reflect changes in the costs of balancing the system in the short-term and keeping the system secure in the face of unexpected outages or changes in output. New plants may increase balancing costs (if its output is unpredictable) or reduce them (if the plants can provide balancing actions at a lower cost than existing plants).

Simultaneous simulation of balancing markets

The demand and supply of the different types of balancing services can all be modelled. For example, EnVision considers the extent to which the following general types of services are required:

- post gate-closure balancing market actions (turn-ups and turn-downs);
- headroom (the ability to turn flexible plant down in response to a sudden drop in system frequency);
- footroom (the ability to turn flexible plant up in response to a sudden increase in system frequency); and
- inertia (the ability of synchronous generators to resist changes in system frequency).

Further information is provided in Annex B.

Some types of plant will be capable of providing multiple different types of balancing services (in addition to supplying in the energy market). In principle, the model could seek to optimise the allocation of plants across all balancing markets simultaneously, although this would be computationally intensive.

Sequential simulation of balancing markets

A slightly simplified version involves modelling each market in series. For example, generation is first dispatched for the energy market, then adjusted to satisfy the headroom requirement, and then this result is adjusted so that the footroom requirement is also satisfied. Removing the need for co-optimisation makes the calculations more manageable, although may mean that the cost of balancing is overstated if the resulting allocation of generators to balancing markets is not perfectly optimal. LCP has previously tested the accuracy of the sequential simulation approach against the outturn balancing costs, and found that the results match closely. In addition, to the extent that there is any residual error in the estimate of balancing costs, this affects both the counterfactual and the “technology on” scenarios, and so tend to net off. **This is the approach which we take for the Whole Electricity System Costs Tool.**

Simple average cost of balancing actions

A simpler way to calculate balancing costs (which avoids the need for any optimisation) might be to calculate, for each technology:

- the relationship between the historic uptake of that type of technology and the net change in the requirement for different balancing services (taking into account both additional balancing actions that may be required, and the ability of the technology to provide balancing services); and
- an average cost for balancing actions.

While relatively transparent, such an approach is likely to provide misleading results for future balancing costs, since the system is likely to look very different (e.g. in terms of the amount of variable generation connected) from the historic data that could be used to obtain the relationships.

Figure 16 Options for estimating balancing impacts

Methodology	Disadvantages compared to a more complex method	Examples
Simultaneous balancing market simulation. Simulate distribution of net system imbalance based on infeed and demand uncertainty, then simulate the costs of ramping up/down to meet this. Simultaneously model demand for other ancillary services , and the costs of running plant to provide them.		
Sequential balancing market simulation. As above, but model each market in series rather than co-optimising.	The lack of co-optimisation may mean that the overall balancing costs are simulated as being slightly higher than they otherwise would be.	EnVision uses this method.
Simple average cost of balancing actions. Derive requirement for and cost of balancing from historic figures.	Results could be inaccurate as past balancing costs are unlikely to be a good indicator of those in the future.	

Source: Frontier Economics

3.2.5 Network costs

These are the costs of building and running the transmission and distribution networks. Depending on the technical characteristics and location of the new plant, as well as any capacity it displaces, these costs may either increase or decrease.

AC nodal flow model with investment model

The most realistic way to model an electricity network is to do so at the level of the components (transformers, overhead and buried lines etc.) that it comprises. For example, DNOs commonly use network design tools (e.g. WinDEBUT) for modelling sections of their network.

Such a model could identify where existing network assets are overloaded. An additional investment module would then be required to determine the optimal reinforcements and their costs.

Although relatively accurate, these models are typically used for small sections of the network. Unless it was known with certainty where on the network the new generation technologies were to be placed, the additional accuracy provided by such a model would be spurious.

Parameter-based model

An alternative is to use a "parameter-based" model. Rather than modelling the physical electrical status of each asset on the network, these models keep track of a set of higher-level parameters which summarise the status of the network. For example, EA Technology's *Transform* model keeps track of the following parameters[35] for each modelled network feeder:

- thermal headroom;
- voltage headroom and legroom; and
- fault level headroom.

When applied to the distribution network, these types of models also tend to model a collection of "representative" networks, rather than any one particular network. For example, the network module of Imperial's WeSim model simulates typical urban, semi-urban, semi-rural and rural networks.[36]

As with the more complex nodal flow models, a parameter-based model would need to include investment functionality to be able to calculate the cost of reinforcing the network to accommodate additional generation.

EnVision includes a simple parameter-based representation of the transmission network, which we use for this modelling. This model uses "dispersion" of the network as its parameter, and has an investment cost for each additional unit of dispersion - see the annex for further details.

EnVision does not model the distribution networks in detail either. Building such a detailed representation of model for our Whole Electricity System Costs Tool is unlikely to add a large amount of value, since:

- of the technologies we are considering, only two (solar PV and storage[37]) will connect directly to the distribution network; and
- the costs of reinforcing networks will significantly vary depending on the state of the specific network in question – an average cost hides this variation.

Existing network charges

The TNUoS and DUoS charges paid by generators should, if cost-reflective, proxy for the average network costs they incur.

There are significant limits to this approach. First, the charges themselves may not be truly cost-reflective. For example, some of the costs that the charges cover may already be sunk, and not reflect true incremental costs (though sunk and cost-reflective elements are generally separately identified). Additionally, the use of current costs may not be a good proxy for future network reinforcement costs (which may, for example, involve the greater use of flexible "smart grid" interventions). Nevertheless, for the reasons given above (this only affects one

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[35] See for example http://www.nienetworks.co.uk/documents/Future_Plans/Development-of-the-Transform-Model-for-NIE-Network.aspx

[36] https://www.theccc.org.uk/wp-content/uploads/2015/10/CCC_Externalities_report_Imperial_Final_21Oct20151.pdf

[37] We do not include an estimate of DUoS charges/credits for storage. This is since the benefits of storage on a particular network (which may include benefits such as local balancing services) will be extremely specific to the local network conditions, and not captured by generic DUoS charges.

technology we are considering (solar PV), and true reinforcement costs will vary significantly by network), **we consider that this approach for distribution is sufficient for our** Whole Electricity System Costs Tool.

We have calculated these figures using the public-available EDCM charging statement for Western Power Distribution's South-West region. This has enabled us to identify the solar farms connected to the EHV network in this region. By cross-referencing to an online database of plant capacities,[38] we have calculated the resulting annual DUoS charge for each plant.[39] Our Tool uses an average DUoS charge for all solar plants above 5MW that we were able to identify.

These are summarised in Figure 17.

Figure 17 Options for network modelling

Methodology	Disadvantages compared to a more complex method	Examples
AC nodal flow model with investment model. Simulate required investment on the T and D networks using a model that takes into account the electrical properties of each network asset.		Detailed network design tools used by DNOs (e.g. WinDebut).
Parameter-based model with investment model. As above, but using a parameter-based model instead (keeping track of factors such as network dispersion) and using representative feeders if modelling the distribution network.	Parametrisation may result in some loss of accuracy. Representative feeders will not reflect unique situations.	WeSim applies a similar approach for T and D modelling. EnVision uses a simple parameter-based model for the transmission network.
Existing network charges Assume that current network charges are cost-reflective and will be maintained in the future.	Results could be inaccurate if charges are not cost reflective or will change systematically in the future.	

Source: Frontier Economics

3.2.6 Displaced generation impacts

Detailed dispatch model

As with the modelling of load factors described in Section 3.2.2, a detailed dispatch model can be used to forecast dispatch of every plant on the system, subject to physical and regulatory constraints. The resulting dispatch schedule can then be used to calculate the variable cost of running all other plants on the system (changes in fixed costs and capex will be picked up by the capacity

[38] https://www.variablepitch.co.uk/

[39] A power factor of unity was assumed when calculating the apparent power for each unit.

adequacy impacts, discussed above). **This is the approach that we use for calculating displaced generation impacts for the "large increment" runs.**

SRMC from detailed dispatch model

A slightly simpler variant of the above is to use the detailed dispatch model to determine which technology is on the margin of the energy market in every period of time, and then calculate the amount of this technology (if any) that is displaced by the new technology.

This is the approach that EnVision uses for the "marginal increment" runs, since it does not require a full simulation of the market under two different scenarios. The limitation is that this method does not take into account the way in which additional variable generation may cause other generators to run in a less efficient way (this is referred to as the "ramping effect" or "flexibility effect"). However, previous analysis by LCP (comparing the results from the "marginal" increment methodology to the difference between two runs with 1MW extra capacity) indicates that this difference is likely to be minor in practice.

Simple stack model

The simple stack model illustrated in Figure 13 could be used for calculating displaced generation impacts. As discussed earlier, the limit of this approach is it does not take into account the more complex constraints that a full dispatch model considers. This may (for example) lead to displaced generation being under-valued, if the simple stack assumes that cheaper generators can run when they would actually be unable to do so due to ramping or other constraints.

Assumed marginal technology

Finally, a simple way of modelling displaced generation costs would be to simply assume a given technology (such as CCGT) is on the margin, and use its costs to calculate displaced generation costs. While transparent, such an approach would be highly sensitive to assumptions on the marginal technology.

These options are set out in Figure 18.

Figure 18 Options for displaced generation

Methodology	Disadvantages compared to a more complex method	Examples
Detailed dispatch model. Simulate least-cost dispatch with an integrated dispatch/investment model to determine generation costs with/without the new plant.		EnVision is such a model, which simulates many technical constraints (although the need to make the model computable means not all complexities are considered).
SRMC from detailed model. Simulate least-cost dispatch with an integrated model. Determine the SRMC of the marginal plant in each hour. When the SRMC of the new plant is below this, calculate the resulting savings.	Doesn't consider the ramping/flexibility effect, where variable generators may cause others to run less efficiently.	EnVision uses this method for calculating the marginal whole system cost.
"Simple stack" model. Use a "simple stack" of generators to determine the marginal cost for every hour	Doesn't consider out-of-order dispatch due to policies. Increasing simplification will lead to inaccuracies.	
Assumed marginal technology. Assume a single technology (e.g. CCGT) is usually at the margin.	Ignores the different value of generation depending on when it occurs.	BEIS levelised cost analysis assumes an arbitrary 500 hours of running for peaking plant.

Source: Frontier Economics

3.3 Expressing the results of complex modelling through simple relationships

As described above, we use relatively complex forms of modelling for most of the components of whole system impact (the main exception being distribution network investment). While complex modelling increases the accuracy of the estimation, there is a risk that such modelling can take the form of a "black box", with little indication of what is driving the output, or why the results of one model differ from the results of another.

To overcome this, we use intermediate outputs from EnVision to "open the black box", and show the key relationships driving each of the components of WESC. This should allow users to better understand and interrogate the drivers of system cost impacts.

3.3.1 Technology direct costs

This is a levelised cost calculation, which can be broken down in the following way:

- present the various cost inputs (e.g. capex, opex, efficiency, fuel prices etc.) used within EnVision;
- extract the modelled load factors from EnVision (for the two “marginal” increments, and the “large” increment); and
- put the two of these together to show levelised costs for each scenario.

3.3.2 Capacity adequacy impacts

The capacity adequacy impacts from EnVision can be broken down in the following way:

- determine the capacity credit of the technology under assessment, for the three different uptake scenarios;
- report the average costs (both capex and opex) of capacity that is being displaced; and
- multiply the two together to generate the avoided cost of capacity.

3.3.3 Balancing costs

We decompose the overall change in balancing cost into the change in the cost of balancing actions, for each balancing service (inertia, headroom, footroom, and the balancing mechanism), separating balancing costs incurred by the technology in question, and the rest of the system.

3.3.4 Network costs

For the transmission network costs, we break down the overall cost difference into the change in transmission network dispersion, and the cost per unit of dispersion.

The distribution network costs are not shown in the illustration below, as the structure of these are taken directly from the charging structure used by DNOs.

3.3.5 Displaced generation impacts

Similarly to capacity adequacy impacts, the displaced generation impact can be decomposed in the load factor of the technology in question, and the average cost of the generation that it is displacing.

ANNEX A ESTIMATING THE WESC OF INTERCONNECTORS

Below, we set out the particular challenges associated with modelling the whole system impact of interconnector. The following section describes our methodology to address these issues, using additional EnVision functionality combined with an extension of the Whole Electricity System Costs Tool.

3.4 Challenges of incorporating interconnection

Investment in interconnection will also be associated with WESC. In principle, the whole system impact of an interconnector can be determined in the same way as for a generator – that is

- simulate all resource costs under a counterfactual;
- add a quantity of additional interconnection to the counterfactual, and let the system re-optimise;
- the difference in resource costs is the whole system impact, and can be allocated across the five categories described in the main body of this report.

However, simulating the whole system impact of an interconnector brings some unique challenges.

Perhaps most significantly, there is no single "archetype" interconnector (unlike the case with, say, a nuclear plant or offshore wind farm, where any project of a given size will tend to have broadly similar whole system costs).[40] An interconnector to continental Europe will connect to a very different system than an interconnector to Scandinavia or Iceland, and the resulting whole system costs could be extremely different.

Another difference is that the variable cost of power from an interconnector (the price of power in the connected market) will vary continually with demand and supply conditions in the connected market. Moreover, these prices will be correlated with those in the GB system, and will be driven by many of the same fundamentals (such as gas and carbon prices). If the prices in the interconnected market are not derived using consistent assumptions, this could produce a systematic "wedge" between the prices which causes the modelled interconnector to always import or export. In addition, legislative differences between countries may have an impact on their relative prices (e.g. the application of the carbon price floor).

Finally, it is necessary to establish where the borders of the system we are measuring the costs of lie. For example, if the interconnector is importing, should the fuel and emissions of foreign plants be counted as a resource cost, or should this instead be encapsulated through the additional cost to GB consumers?

[40] The most significant differences between projects are likely to be driven by their location.

3.5 Methodology

We use EnVision to model the whole system impact of increased interconnection to a specific market. This is likely to be the continental European electricity system, given the potential for particularly great increases in capacity with Northern France, Benelux and Germany.

As EnVision does not model changes in interconnector capacity endogenously, it is not possible to apply the "marginal increment" functionality we use for generation technologies. We therefore only consider a single large increment of interconnector capacity, and compare the whole system costs under this scenario with the counterfactual. We note that data on the cost of the interconnector itself is limited.

EnVision requires a supply curve for the connected market (i.e. a merit order of generation technologies with their capacities and costs) which is consistent with the inputs used for GB. To produce this, Frontier supplied LCP with a set of outputs from its Central/Western European dispatch and investment model:

- Forecast power prices, demand, net exports, renewable profiles, and renewable capacity for the French market
- Similar inputs for the GB market
- Fuel and CO2 prices

LCP transformed the French power prices to take into account the differences in assumptions between the two models.

As with the other technologies, the outputs from EnVision then feed into the Excel-based tool, which required some modifications (e.g. the displaced generation costs module needs to be able to separately consider the benefits of displaced generation when then interconnector is importing, but also the costs of additional generation when it is exporting).

The WESC generated by such a model is produced from a GB perspective. This means that:

- interconnector imports are priced at the wholesale price of electricity paid for the imports, rather than assessing the resource costs (in terms of fuel, carbon etc) on the "foreign" side of the interconnector; and
- interconnector exports lead to a benefit equal to the wholesale price of electricity exported, rather than benefits such as displaced generation on the "foreign" side.

ANNEX B DESCRIPTION OF ENVISION

This section describes LCP's EnVision model

B.1 Introduction

The actual cost of the system "the whole system cost" consists of:

- The costs of constructing, running[41] and maintaining all assets associated with the power system in order to meet demand.
- The cost associated with any failure to meet demand.
- These costs could be divided in many ways but the five categories considered allow this to be analysed in an intuitive way which can be approached within a modelling framework. In particular we can use it to understand the marginal effects of different generation technologies by assessing how their existence affects the cost of all other assets, and any change in likelihood of meeting demand.

As an example we can assess the cost of a new gas plant by:

- The cost of building, running and maintaining the gas plant itself
- The reduction in the costs associated with running other plant whose generation is displaced by the gas plant, e.g. older inefficient gas plant may generate less
- The reduction in the costs associated with building and maintaining[42] other plant whose capacity is displaced by the gas plant, e.g. an older coal station may close earlier
- The change in the cost of balancing the system due to the introduction of the gas plant, e.g. the new flexible gas plant may provide balancing and reserve services at a lower cost than existing plant
- The change in the cost reinforcing the network due to the introduction of the gas plant, e.g. the new plant may be built a long way from demand and increase network costs

In the following sections we outline how these costs can be calculated within our modelling framework, and specifically using LCP's EnVision model.

When using EnVision there are two methods for estimating the impact of the addition of a technology on system costs.

The first, more traditional method is to run a base case, and then run a scenario with an additional amount of capacity added for the technology in question. In the scenario run, the system will "re-balance", with the dispatch and investment decisions of other plant adjusting to accommodate the additional capacity. System costs are reported for each run, broken down by each of the different

[41] Including the cost of imports of electricity over interconnectors

[42] Fixed operating and maintenance costs

cost categories, and these can be compared between the two runs to determine the impact of the capacity added on each category, on an average per MW basis.

The second method is to use EnVision's inbuilt marginal impacts functionality. In any run, the marginal impact costs (on a per MW basis) are reported, based on the addition of an incremental amount of each technology. For most categories, these are calculated based on the resource cost of the marginal unit in a number of markets simulated in the model, e.g. wholesale market, balancing market, capacity market.

- The first method is appropriate for investigating larger changes in capacity, e.g. adding several GWs of a technology, and providing the average cost for this change. However, for smaller incremental amounts of capacity, this method will often produce unstable results, due to the lumpy nature of investment decisions. A small amount of incremental capacity may result in no change to new build, or could trigger a change in a large investment decision and produce very large per MW impacts.
- The second method – the marginal impacts functionality – is the primary focus of this note. In addition to being able to assess the marginal cost impact of adding an incremental amount of capacity, this approach also has the advantage of being able to provide these system cost impacts for all technologies simultaneously, using a single model run.

B.2 Technology direct costs: Modelling approach

Technology direct costs include all the costs associated with building, running and maintaining the incremental plant.

The running costs are calculated based on simulating wholesale market dispatch, i.e. assuming perfect foresight of demand and generation availability, prior to any adjustments in generation due to the provision of reserve services and balancing.

B.2.1 Details of EnVision approach

EnVision's marginal impacts functionality assesses the costs for an archetypal plant of each technology being added to the system (with negligible capacity). To determine the operation of the incremental plant, its SRMC is compared to the SRMC of the marginal plant in the wholesale market within each modelled half hour, across the lifetime of the plant.

Key inputs

- Capital costs, £/kW – including construction and infrastructure costs
- Build time, years – and phasing of capital costs over this period
- Discount rate, % pre-tax real – used to apportion the capital costs as financing costs over lifetime of plant
- Lifetime of plant , years
- Fixed costs, £/kW pa
- SRMC of plant, £/MWh – calculated based on inputs provided for:

  - Efficiency (varies depending on output of the plant) and carbon content of its fuel
  - Fuel price
  - Carbon market price
  - Variable operating & maintenance (VOM) costs
  - Policy support assumptions, e.g. for CFD supported plant contract duration and strike prices. Policy payments do not represent technology direct costs, but can affect the dispatch of the plant and hence have an impact on its technology direct costs.
- Operational constraints on the plant – e.g. minimum stable generation, minimum up/down time, ramping constraints
- Background generation mix – all assumptions related to the operation of other plant on the system, which will feed into where the plant sits in the merit order and hence what its level of generation is.
- Demand
- Variability profiles

Key outputs

Our approach divides technology direct costs outputs into five categories:

- Capital costs
- Fixed operating costs
- Fuel costs
- Carbon costs
- VOM costs
- EnVision provides outputs for each category, by technology on a quarterly basis, in £.
- EnVision also provides outputs for the same categories under the marginal impacts functionality, which outputs results, in £/MW, for the marginal cost associated with adding a small archetypal plant of each technology.

Key uncertainties/simplifications

There is obviously significant uncertainty around many of the key assumptions, e.g. how the capital costs of technologies will change over time, and how commodity prices such as gas and carbon will change over time.

In addition, a less direct uncertainty is how the background generation mix will change over time, and hence the generation profile of the incremental plant. This is of particular importance for the costs associated with a mid-merit technology, such as CCGT.

One significant simplification in EnVision is that a normal model run relies on a deterministic, sample day approach. For assessing peaking plant, or for systems with a high penetration of variable technologies, a stochastic approach could be employed.

B.2.2 Strengths and limits

Technology direct costs are produced using detailed, half hourly dispatch modelling. However, this is essentially a levelised cost of electricity (LCOE) calculation, which can be produced relatively simply if the load factor of the plant is known in advance.

So for technologies – such as CFD supported nuclear and wind – which will tend to be dispatched whenever they are available, the calculation can be replicated relatively easily without a complex dispatch model. However, for mid-merit technologies, which currently includes CCGT and coal, and in the future may also include biomass and CCS, dispatch modelling provides a detailed view on the load factor of the plant, and how this varies through time based on the make-up of the system.

B.3 Displaced generation costs: Modelling approach

Displaced generation costs are the savings realised due to the incremental technology reducing the generation of other plant the system. This consists of savings in fuel, carbon and VOM costs. Like the technology direct generation costs, displaced generation costs are calculated based on simulating wholesale market dispatch, i.e. with perfect foresight of demand and generation availability, prior to any adjustments in generation due to the provision of reserve services and balancing.

B.3.1 Details of EnVision approach

EnVision's marginal impacts functionality assesses the displaced generation cost savings associated with an archetypal plant of each technology being added to the system. To determine the savings in each half hour, the output of the plant is determined by comparing its SRMC to the SRMC of the marginal plant in the wholesale market. If the SRMC of the incremental plant is lower, then the generation from the marginal plant is displaced, and savings are realised based on its running costs.

Key inputs

- Capacity build out of technology, including interconnection
- Demand
- Variability profiles
- For every plant on the system:
  - efficiency (varies depending on output of the plant)
  - operating parameters – start costs, minimum stable generation, minimum up/down times

  - fuel prices
  - carbon price
  - variable operating & maintenance (VOM) costs
  - policy support assumptions, e.g. for CFD supported plant contract duration and strike prices

Key outputs

Our approach divides displaced generation costs into three categories:

- Fuel costs
- Carbon costs
- VOM costs
- EnVision's outputs for the marginal impacts functionality are provided in £/MW for the cost savings associated with adding a small archetypal plant of each technology.

Key uncertainties/simplifications

Unlike the technology own operating costs, which can be estimated with reasonable confidence for a baseload plant such as nuclear, the displaced generation cost estimates are entirely dependent on the background generation mix, and the technologies that appear on the margin in the wholesale market.

As a result, the assumptions for the capacity build out of different technologies are a key uncertainty. The penetration of renewables, and the proportion of time they end up occupying the margin (e.g. in low demand overnight periods) is particularly important. The operating costs of technologies that are likely to be at the margin are also very important, in particular the gas and carbon price assumptions, as gas plant are likely to occupy the margin a significant proportion of the time under most scenarios.

Again, a simplification is that a normal model run relies on a deterministic, sample day approach. For systems with a high penetration of variable technologies, a stochastic approach could be employed.

B.3.2 Strengths and limits

Detailed dispatch modelling is able to capture the complex relationship between the mix of capacity on the system and the time that each type of plant occupies the margin. For example, by running multiple sample days and variable profiles, it can provide an estimate for the number of periods in which renewable technologies will occupy the margin and hence any displaced generation cost savings will be very limited.

Using a simpler approach may also not fully capture the impact of policy support payments, and how these change through time. These policy payments aren't costs from a system cost perspective, as there is no direct resource cost. In many cases these support payments may be in place to support new technologies. The policy payments may also reflect a price being paid for carbon abatement beyond that reflected in the market carbon price.

For example, a biomass or CCS plant receiving CFD support may run “out of merit” due to its CFD top-ups reducing its SRMC below that of technologies with lower running costs, e.g. CCGT. This may result in a positive net generation cost (technology direct costs minus displaced cost savings) rather than a saving in some periods, in the case where the incremental plant is a supported technology running out of merit. The size of this distortion will vary within the year, and across years, depending on the how the season-ahead reference price varies relative to the technology’s strike price.

A limitation to using a detailed modelling approach (in addition to the high degree of uncertainty in many of the input assumptions) is transparency, and the ability to communicate and present results in an easily digestible way.

B.4 Capacity Adequacy: Modelling approach

Capacity Adequacy savings are the costs avoided due to the contribution of the incremental plant to system security. These are the costs avoided from building or maintaining (fixed costs only) plant whose capacity is displaced by the incremental plant. This could be a new plant no longer being built, or an existing plant closing earlier than it would have otherwise.

B.4.1 Details of EnVision approach

EnVision’s marginal impacts functionality assesses the savings in capital costs and fixed operating costs associated with an archetypal plant of each technology being added to the system.

To determine the plant(s) displaced by the capacity of the incremental plant, we must determine the marginal plant, from a capacity perspective, in each year.

EnVision simulates the annual Capacity Market auctions, procuring enough firm capacity to meet the required security standard, i.e. LOLE of 3 hours per year. In each of these auctions there is a marginal plant, which sets the clearing price.

To calculate the saving, the derating of the incremental technology is compared to the derating of the marginal technology in the Capacity Market. This determines the amount of capacity of that technology that would be displaced for every MW added of the incremental plant. For example, solar, with a zero derating, will displace no capacity and result in no saving. If CCGT is the marginal capacity plant, then the addition of 1MW of new CCGT will displace 1MW of this marginal CCGT, as they have the same derating.

Key inputs

- Capital costs of each technology, £/kW
- Fixed operating cost of each technology, £/kW pa
- Hurdle rates of each technology, %, used in calculating each plant’s CM bid, but also in translating the capital costs into financing costs over the displaced plant’s lifetime, which are the actual savings realised.

- Deratings in the Capacity Market
  - Wind is calculated internally on an EFC basis
- Demand
- Capacity Market parameters, including the security standard (LOLE = 3 hours)
- Capacity build out of technology, including interconnection
- All operating costs and assumptions, which feed into the CM bids

Key outputs

Our approach divides up displaced generation costs into two categories:

- Capital cost savings (financing costs)
- Fixed operating cost savings

EnVision's outputs for the marginal impacts functionality, are provided in £/MW for the cost savings associated with adding a small archetypal plant of each technology

Key uncertainties/simplifications

Results are dependent on the plant that is marginal in each CM auction, and the requirement for new capacity in a given year. To avoid results that are overly sensitive to this (e.g. a very large saving for an incremental plant in a year that new build is marginal, but a very small saving for an incremental plant the following year when an existing plant is marginal), we smooth the results by using outputs from all the auctions in the incremental plant's life, though with a greater weighting on earlier auctions.

The modelling assumes that the Capacity Market continues in its current form, with a single annual auction. It also assumes that the marginal plant in the capacity auctions is also the marginal technology in capacity adequacy terms.

A key uncertainty is the capital costs of different technologies, and in particular the technologies that are likely to be marginal in the CM, such as new gas plant.

B.4.2 Strengths and limits

In this category, perhaps more than others, the costs from the marginal functionality are purely theoretical. They are useful for comparative purposes, but do not represent the cost saving that would be incurred by adding a small amount of capacity to the model and rerunning. This is because in the main model functionality (and in reality), the addition of a small amount of capacity will result in very binary outcomes – in most cases it will result in no impact whatsoever, but in some cases it will result in a disproportionately large change, e.g. a 1MW addition resulting in a 500MW plant no longer commissioning. And this large change could happen in year 1 of the plant's life or it could happen in year 20.

The other difference between the costs captured in the marginal functionality and those observed in scenario analysis is that the marginal functionality does not attempt to capture the costs of the system adapting to the change. This includes the second order effects of changes to build or retirements resulting from the incremental plant's effect on the system.

B.5 Balancing costs: Modelling approach

Balancing costs are those caused by the uncertainty of generation and demand. If all plant were reliable, and all generation and demand could be forecast perfectly these costs would be zero.

For assessing marginal impacts this represents the costs saved or incurred due to the incremental plant's impact on the cost of ensuring the system is balanced in real-time. This includes the costs of balancing the system and also providing necessary reserve services, such as frequency response and system inertia.

B.5.1 Details of EnVision approach

EnVision simulates the balancing market based on the uncertainty in the output of demand and variable technologies such as wind and solar. This uncertainty is due to the inaccuracies in the ability to forecast their output ahead of time. In each half hour, the distributions for the possible deviations in demand, wind and solar output are calculated independently and combined to form a single distribution for the net system imbalance for that half hour.

The system costs associated with the balancing market are determined by the changes in cost that result from turning plant up and down to meet the imbalances. In each half hour, the turn up/down decisions are determined for each point on the net imbalance distribution (based on a user defined granularity), and the impact on system costs are recorded.

As a simplified example, in a particular half hour wind output is uncertain, and has equal likelihood of its output deviating by -1GW, 0GW, or +1GW from its original wholesale dispatch. In the -1GW scenario, we turn up the cheapest flexible plant that is available, say, an OCGT. In the +1GW scenario, we would turn down the most expensive flexible plant that is already dispatched, say, a CCGT. The system cost of the balancing market in this half hour is: 33.3% * the system costs from turning the OCGT up + 33.3% * 0 + 33.3% * the system costs saved from turning the CCGT down (the system costs associated with the wind plant generating -1GW and +1GW cancel each other out). In this case, we will have a small net increase in system costs, as the OCGT is less efficient than the CCGT.

EnVision also simulates the provision of headroom, footroom and system inertia[43]. These reserve services cover for a sudden change in frequency, due to a loss in generation or demand, and their requirements are calculated based on the largest infeed loss. In each hour the cost of providing these services is the cost associated with turning eligible plant up/down in order to ensure the requirement of each service is met.

[43] Headroom refers to turn-up frequency response, i.e. that there is sufficient capacity available (often through part-loading) to turn-up in the event sudden change in frequency. Footroom refers to turn-down frequency response, i.e. sufficient plant available to turn down. System inertia refers to the requirement for a minimum level of inertia (usually provided through spinning turbines) on the system, to ensure that the rate of change of frequency (ROCOF) in the event of a sudden change in capacity/demand is kept below a certain limit.

- For headroom this means turning flexible plant up/down so that they are part-loaded and have the ability to quickly ramp-up in response to a sudden drop in system frequency.
- For footroom it means ensuring there are enough flexible plant on the system to ramp-down in the event of a sudden increase in system frequency. Footroom shortages are likely to occur overnight when there is a shortage of flexible plant on the system, and will mean turning down non-flexible plant (such as wind) and turning up flexible plant (such as gas).
- For system inertia, plant which provide inertia (synchronous plant such as gas) are turned up and plant which do not provide inertia are turned down (such as solar). Shortages in system inertia are likely to occur overnight when demand is low (demand provides some inertia) and there are low amounts of synchronous plant generating.

EnVision’s marginal impacts functionality assesses the additional cost or saving within each of the four areas (balancing market, headroom, footroom, system inertia) associated with an archetypal plant of each technology being added to the system. Each of the four services is effectively a separate market, with a marginal plant and cost in each half hour for each service.

Key inputs

- Uncertainty in demand and each technology, e.g. wind, solar
- Requirements for headroom, footroom and inertia
- Operating costs of all flexible plant, i.e. plant that are able to be turned up or down in the procurement of reserve service to provide balancing. This includes assumptions on efficiency, fuel cost, carbon cost, VOM
- Level of inertia provided by each technology
- Operating parameters of each technology, e.g. minimum stable generation, ability to ramp up and down at short notice

Key outputs

Our approach divides up balancing costs into three categories:

- Fuel costs
- Carbon costs
- VOM costs
- EnVision’s marginal impacts functionality provides results in these categories for each of the four areas that are explicitly modelled (headroom, footroom, balancing market, system inertia). These results are provided in £/MW for the costs or savings associated with adding a small archetypal plant of each technology.

Key uncertainties/simplifications

One of key uncertainties is how the forecasting of wind and solar generation will improve over time, as it becomes more and more crucial to the system.

Another key uncertainty is the level of contribution to each service that will be made by new and non-traditional technologies, such as interconnection and storage.

One simplification in the modelling (for computational efficiency) is that each market is modelled in series. So for example generation is adjusted to satisfy the headroom requirement and then this result is adjusted so that the footroom requirement is also satisfied, rather than being co-optimised.

The provision of each service is also modelled independently half hour to half hour, so no minimum up/down time constraints are applied.

B.5.2 Strengths and limits

Our modelling is primarily limited to current assumptions on the costs of providing these services. It is conceivable, particularly looking 20+ years in the future, that technological innovation could significantly reduce the costs of providing these services.

We do not explicitly model any areas outside the four mentioned above (balancing market, headroom, footroom, system inertia), for example reactive power or black starts. In our discussions with National Grid these were identified as the areas where costs are most likely to change significantly over time and vary between different scenarios. In addition, the four areas modelled have been kept relatively generic, rather than trying to capture the precise set of arrangements currently in place.

B.6 Network costs: Modelling approach

Network costs represent the infrastructure costs associated with reinforcing or extending the network.

The marginal network cost represents the additional cost or saving associated with incorporating the incremental plant into the network.

B.7 Details of EnVision approach

EnVision dynamically estimates total network costs associated with the fleet in every quarter. The model calculates the system dispersion, a measure of the size of the network in MW-km, based on total distance of generation from demand.

For this calculation, each plant is assigned a location. Similarly, demand nodes are defined at different locations and given a proportion of peak demand to represent. A measure of the size of the network can then be calculated. Using data from National Grid, the network size metric can be calibrated to represent costs associated with reinforcing the network.

The marginal impacts functionality estimates the effect on total network costs of adding 1MW of each technology. A location must be assumed for the archetypal plant for each technology.

Key inputs

- Capacity build out
- Location of each plant (Lat, Lon)
- Location of demand (aggregated into representative nodes)
- Location of archetypal plant (for marginal impact calculation)
- Relationship between size of network and cost of network reinforcement

Key outputs

Our approach provides total network cost as a single output in each quarter. The total network cost is not broken down and assigned to particular technologies.

The marginal impacts functionality outputs the incremental network costs (in £/MW) associated with adding a small amount of each technology.

Key uncertainties/simplifications

This functionality uses a generic, simplified representation of the network. It does not consider the detail of the current transmission network or take into account specific reinforcement projects.

There is also an assumption that the relationship between the size of the network and network costs is linear, and not specific to the location, e.g. a MW-km in North Scotland is the same cost as a MW-km in the South.

Strengths and limits

The approach is technology neutral, with the network costs calculation based entirely on the location of the plant, rather than the technology itself. Under this approach, two plant of the same capacity in the same location would incur the same network costs. One exception to this is offshore wind, which is assigned additional costs per MW-km, though again this is due to its location rather than anything inherent to the technology.

The simplifications described in the previous section mean that the approach is limited when estimating costs in the short/medium term, which are specific to the projects being carried out. However, when looking 15, 20, 30 years into the future, the generic approach has its advantages, as attempting to model the precise timing and location of major reinforcement projects can become spurious.

To minimise the total network costs on the system, there is a trade-off between the costs of alleviating locational constraints through balancing actions, and the cost of investing in additional network reinforcement. The assumptions used to calibrate the model here assume that a balance is maintained – based on discussions with National Grid, it is assumed that they will carry out reinforcements to maintain constraint costs of approx. £200m pa.

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ASSESSING THE VALUE FOR MONEY OF ELECTRICITY TECHNOLOGIES

Appendix 2: Reflecting costs and benefits beyond the electricity sector

January 2018

CONTENTS

1 INTRODUCTION

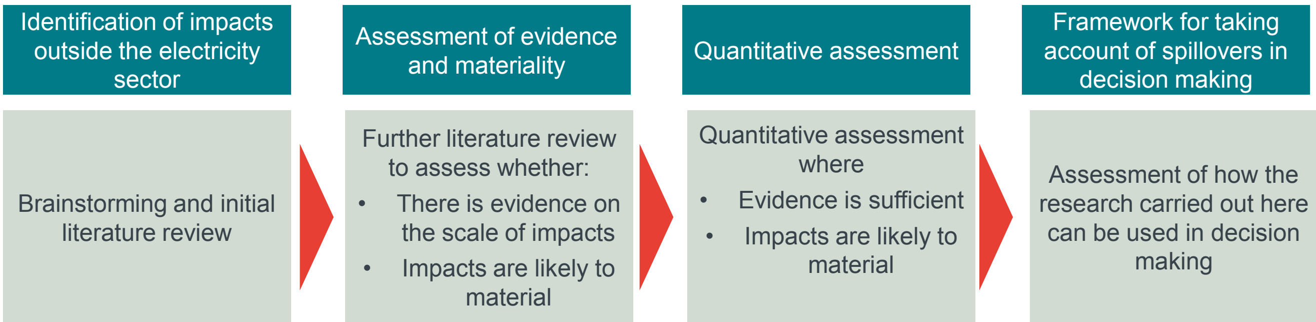
This report aims to assess the various external impacts that electricity technology investments can have. The focus here is only on the external impacts of these investments that impact beyond the electricity sector. Other impacts are covered elsewhere in the project (see Appendix 1).

1.1 Approach

Figure 1 describes our methodology for this work.

- We first identify the non-electricity sector effects associated with the eleven technologies within the scope of this report. These include: CCGT; OCGT; nuclear; CCGT CCS; biomass CCS; onshore wind; offshore wind; solar; storage; interconnectors; and DSR.
- We then review the evidence to understand where these effects are likely to be material, and also to identify where a lack of evidence precludes further assessment.
- Where impacts are likely to be material, and evidence is sufficient, we undertake a quantitative assessment.
- Finally, we outline a framework for taking account of spillovers in decision making.

Figure 1 Overview of methodology



Source: Frontier Economics

1.2 Structure of this report

The report is structured as follows:

- Section 2 provides an overview the key findings and describes how these findings can be taken account of in decision making.
- In Section 3, we summarise the evidence from the literature and modelling on the nature and materiality of non-electricity costs and benefits.

FURTHER MATERIAL PUBLISHED ALONGSIDE THIS DOCUMENT

This research also encompasses the following published documents.

Main report:

Assessing the value for money of electricity technologies

Two Excel-based decision support tools.

- Tool A: Whole Electricity System Costs
- Tool B: Investment Support Costs

Further detail is also provided two further appendices:

- Appendix 1: Modelling of whole electricity system costs
- Appendix 3: Assessing technology support requirements

2 KEY FINDINGS

This section describes the key findings.

- We first outline the non-electricity sector impacts identified through our initial literature review and brainstorming.
- We then summarise our findings on these.
- Finally, we present a framework for how these could be included in decision making.

2.1 Non-electricity sector impacts assessed

Through an initial high-level literature review and brainstorming process, we identified six categories of non-electricity sector impacts for assessment. These are set out in Figure 2 below.

Figure 2 Categories of non-electricity sector impacts assessed

Externality	Description
Shared infrastructure	New infrastructure required for some electricity generation technologies (e.g. for CCS) may reduce the costs of this infrastructure for other sectors, where there are economies of scale.
Shared skills and supply chain	Shared skills or a shared supply chain may impact on costs, efficiency or risks in other sectors.
Shared use of scarce resources	Adding new plant may affect fuel demand and prices. For example, the use of biomass in the power sector may push up the costs of biomass in industry.
Innovation and knowledge externalities	Deployment of a technology in the power sector may produce learning relevant to the deployment of that technology in other sectors.
Energy externalities	Waste energy from power generation (for example waste heat) may have a value elsewhere in the energy system, for example in district heat networks.
Environmental / health externalities	Emissions can contribute to environmental damage or impacts on health.

Source: Frontier Economics

Note: The focus of this report is on the impacts outside the electricity sector. Impacts within the electricity sector are covered in Appendix 1.

Figure 3 describes how these impacts are most likely to be relevant to the 11 technologies being covered in this project. This shows that the majority of potential spillovers relate to the thermal technologies, particularly those involving CCS. External impacts from renewables appear likely to be limited to environmental externalities. We did not identify any impacts associated with interconnection.

Figure 3 List of potential non-electricity sector impacts by technology

	Shared infrastructure	Shared skills and supply chain	Shared use of scarce resources	Innovation and knowledge externalities	Energy externalities	Environmental / health externalities
CCGT	⊗	⊗	⊗	⊗	✓	⊖
OCGT	⊗	⊗	⊗	⊗	⊗	⊖
Nuclear	⊗	⊗	⊗	⊗	✓	⊗
CCGT CCS	✓	✓	⊗	✓	✓	⊗
Biomass CCS	✓	✓	⊖	✓	✓	⊖
Onshore wind	⊗	⊗	⊗	⊗	⊗	⊖
Offshore wind	⊗	⊗	⊗	⊗	⊗	⊖
Solar	⊗	⊗	⊗	⊗	⊗	⊖
Storage	⊗	✓	⊗	✓	⊗	⊗
Interconnectors	⊗	⊗	⊗	⊗	⊗	⊗
DSR	✓	⊗	⊗	⊗	⊗	⊗

Source: Frontier Economics
Note: ⊗ = No impact ✓ = Positive impact ⊖ = Negative impact

2.2 Summary of findings

Figure 4 provides an overview of the key outcomes of our review and analysis. These are split into three categories:

- material impacts;
- impacts that are unlikely to be material, based on the evidence; and
- impacts where the evidence is not sufficient.

Figure 4 Overview of findings from review and analysis

	Externality	Relevant technologies
Material impacts	Shared infrastructure - CCS	CCGT CCS; Biomass CCS
	Shared use of scarce resources	Biomass, Biomass CCS
	Innovation and knowledge externalities – CCS	CCGT CCS; Biomass CCS
	Energy externalities – waste heat	CCGT CCS; Biomass CCS;
Non-material impacts	Shared skills and supply chain - storage	Storage
	Innovation and knowledge externalities – storage	Storage
	Environmental externalities - air quality and health	CCGT, CCGT CCS and biomass CCS
	Environmental externalities - wildlife / landscape	CCGT CCS; Biomass CCS; Wind; Solar
Not enough evidence	Shared infrastructure – smart homes	DSR
	Shared skills and supply chain - CCS	CCGT CCS; Biomass CCS
	Environmental externalities - noise	CCGT ; CCGT CCS; Biomass CCS; Wind

Source: Frontier Economics

Using illustrative examples, we have estimated the magnitude of those externalities which are likely to be material and which are quantifiable given available evidence. We have estimated these using either alternative specifications in ETI's ESME model or Frontier calculations based on evidence from the literature.

- **Shared infrastructure – CCS.** Using a specific example of a potential CCS project at the Teesside industrial cluster, we estimate an external benefit to the non-power sector of £0.9/MWh. This is based on the assumption that applying CCS in the electricity sector reduces the cost of applying CCS in industry through economies of scale. Our estimate of the external benefit of CCS rises to £22/MWh where we assume that the CCS would not be available as a source of abatement in other sectors in the absence of CCS development in the power sector. Specifically, this is based on the assumption that developing the first 3.6GW plant[1] would unlock opportunities for CCS elsewhere in the economy. The £22/MWh benefit would only be applicable to the output of this first plant.
- **Shared use of scarce resources.** Using ETI's ESME model, we estimate the external impact of diverting additional biomass resource to the power sector, rather than non-electricity sectors, to be -£35/MWh, assuming unabated biomass plant. However, where biomass CCS plant is deployed instead, the 'negative emissions' associated with this plant reduce the abatement required outside the power sector, and therefore offset the external costs associated with reducing the biomass available for non-electricity sector abatement. Taking these two impacts together, biomass CCS results in an estimated

[1] The 3.6GW size of this plant is based on ETI assumptions on potential early CCS investments.

external benefit of £10/MWh[2]. These estimates should be treated with care. In particular, the external cost element may be overstated as it is based on an assumption that there is a limited biomass resource available across the economy. In reality, biomass supply could increase in response to an increase in price.

- **Energy externalities – waste heat.** Using ETI's ESME model, we estimate the external benefit of waste heat produced from thermal plants to be £1/MWh.

Further details on the basis for these findings are set out in Section 3.

These estimates rely on specific modelling assumptions and currently available information, and therefore are best regarded as illustrative context-specific estimates of these externality impacts. The values do demonstrate that non-electricity sector decarbonisation impacts could be material considerations under credible assumptions. It may make sense to develop estimates across a number of potential scenarios in order to guide decisions on specific investments or policies.

2.3 Insights for policy

The analysis and review undertaken for this work has produced the following insights relevant for policy.

- Policy makers should consider the external costs and benefits of investments in their decision making. In particular:
  - There may be material external costs and benefits associated with investments in CCS technologies. For example, CCS within the power sector could have an impact on enabling or reducing the costs of CCS use elsewhere, through innovation spillovers, or shared infrastructure. There may also be positive waste heat externalities associated with CCS technologies.
  - Biomass use in the power sector may not be the optimal use of this resource from the perspective of economy-wide decarbonisation, to the extent that biomass availability is limited, or that the supply curve for biomass is steep.
- It is not possible or desirable to estimate a generic value for these impacts that can be applied in multiple situations. Given the degree of uncertainty associated with the estimation of these impacts, policy makers should consider a range of scenarios, and carefully challenge input assumptions to the modelling. In particular, our analysis has illustrated the following:
  - Values are highly context specific. For example, the magnitude of the shared infrastructure benefits associated with CCS depends on the assumed scenario for industrial and heat abatement. In particular, it depends on the view taken about the extent to which CCS would be developed in other sectors in the absence of developments in the power

[2] Care should be taken to ensure the value of the negative emissions is not double-counted, for example this benefit may already be captured if negative emissions are already valued at BEIS appraisal value for carbon in line with the analysis presented in Appendix 1.

sector, and on the potential future availability of other abatement options in the industrial and heat sectors.

- As in any modelling exercise, the values produced will depend on the assumptions made in key areas. For example, an assumption that biomass resource availability is limited in the economy could drive a significant negative externality for biomass use in the power sector. While assuming a limit on biomass resource availability may be sensible and pragmatic for general economy-wide modelling of abatement options, alternative views can be taken about the future response of biomass supply to an increase in demand. The impact of such assumptions should be kept in mind, where results are driven by an assumption such as this.
- The definition of the 'marginal investment' is also important. The results are also sensitive to how the benefits from investments are allocated. For example, the shared infrastructure benefits of CCS could in theory all be allocated to the first CCS investment, or spread across a number of early CCS investments.

3 EVIDENCE

This section describes the evidence underlying the key findings set out above. We look at each of the six areas identified in Figure 2 above:

- shared infrastructure;
- shared skills and supply chain;
- shared use of resources;
- innovation and knowledge externalities;
- energy externalities; and
- environmental and health externalities

3.1 Shared infrastructure

New infrastructure required for some electricity generation technologies may reduce the costs of this infrastructure for other sectors, where there are economies of scale.

We have considered the potential cost benefits of shared infrastructure of three technologies as part of our review:

- CCS technologies (CCGT CCS and Biomass CCS);
- smart homes technologies (DSR); and
- methane network infrastructure (CCGT and CCGT CCS).

We discuss each of these in turn in the following sections.

3.1.1 CCS technology

In this section we consider the potential for the application of CCS in the power sector to reduce abatement costs in the industrial sector.

CCS may be an important abatement option in industry, particularly in key energy-intensive industries (such as iron and steel, cement, refining and industrial CHP), for which there are limited CO_2 abatement options currently available to meet 2050 targets.[3] CCS would also be required for hydrogen production value chains, where Steam Methane Reforming technologies are used. Hydrogen may be an important abatement option in the industrial and heat sectors.

There are two potential ways in which CCS could affect industrial abatement costs.

- **Exploiting economies of scale.** CCS requires supporting transport and storage infrastructure, which is capital-intense and subject to economies of scale, and which can be shared across sectors. If CCS is deployed in the power sector, it may reduce the cost of abatement in the industrial sector by reducing the average cost of the shared transport and storage infrastructure used by industry.

[3] It may be possible to use hydrogen instead, but this is reliant on a low carbon hydrogen supply chain being in place. Source: E4Tech (2015), *Scenarios for deployment of hydrogen in contributing to meeting carbon budgets and the 2050 target*

- **Enabling industrial deployment of CCS.** It is also sometimes argued that CCS in industry would simply not be viable, without the deployment of CCS in the power sector. This is due to low CO_2 volumes from individual industrial sites, and the difficulty in making very long-term infrastructure investments in the industrial sector, given the risk that the business on these sites will move or close down in response to global competition.[4] It could also be argued that CCS in the power sector would be required to enable CCS in hydrogen production, though scale is likely to be less of an issue in this case.

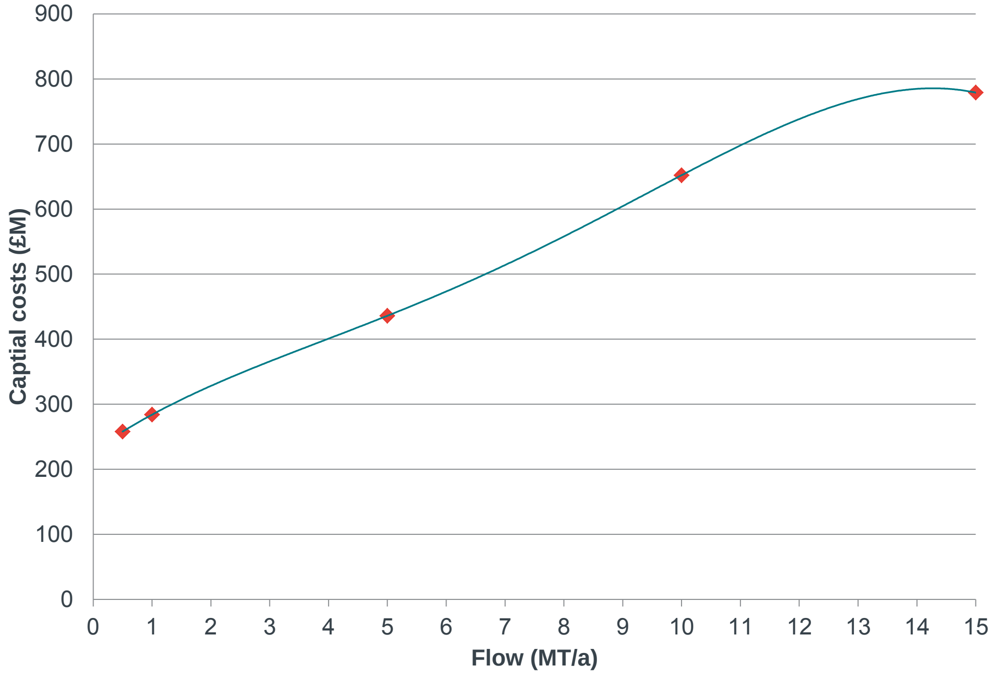
We now consider each of these potential impacts in turn.

Economies of scale

Any initial CCS project must be 'full-chain' by definition, covering the whole process from capture and transport to storage.

The transport and storage elements of CCS have high upfront capital costs and are subject to strong economies of scale (Figure 5).

Figure 5 Incremental cost of adding 0.5MT/a offshore



Source: ETI (2017), CCS offshore scale impact

To provide an illustration of the potential reduction in industrial abatement costs that could result from exploiting these economies of scale through deployment of power sector CCS, we have looked at the potential impact of adding CCS generation to an industrial cluster, such as Teesside.

We have assessed this by estimating the cost to industry of deploying CCS at Teesside, both with and without an anchor load from power CCS, with the

[4] DECC (2012), *CCS Roadmap*; Oxburgh (2016), *Lowest cost decarbonisation for the UK: The critical role of CCS*

difference in costs representing the potential external benefit to industry from the initial development of power sector CCS at the Teesside cluster.

BOX 1: INDUSTRIAL CCS ECONOMIES OF SCALE – KEY ASSUMPTIONS

- We have estimated the amount of carbon captured by an assumed 2.1GW CCGT CCS plant at Teesside. This has been modelled in line with assumptions used throughout the project.
- We assume a fixed level of carbon capture of 2.8mtCO_2/year from industrial sites at Teesside.[5]
- In line with the assumed lifetime of the CCS infrastructure, we assume that carbon is captured over a 40-year period.
- Capex and opex are based on ETI figures for offshore transport and storage costs.[6] Given Teesside's coastal location, offshore costs represent the largest cost component for the CCS infrastructure at the cluster.
- These costs are discounted over the lifetime of the CCS infrastructure to get a net present value, using the social discount rate of 3.5%.[7]

- We then calculate the cost of developing CCS with and without a power sector anchor load:
  - **Industrial cluster only – assume industry pays for the full cost of CCS infrastructure.** Industrial sites at Teesside are estimated to produce 2.8MtCO_2 per year for capture. The capital and operating costs associated with infrastructure to transport and store this level of CO_2 are estimated to be £655m.
  - **Industrial cluster with CCGT CCS – assume industry pays for the proportion of the CCS infrastructure attributable to its emissions.** CO_2 output from an industrial cluster with a CCGT CCS anchor load would be 8.0MtCO_2 per year. The total costs associated with infrastructure to transport and store this level of CO_2 are estimated to be £959m. We attribute 35% of this to industry (in line with the proportion of emissions from industry). Therefore, the cost of CCS infrastructure to industry is estimated to be £336m (i.e. 35% x £959m).

The benefit to industry of a power sector anchor load is therefore estimated to be the costs to industry associated with an industrial cluster, minus the cost to industry when CCS infrastructure costs are shared.

These benefits are expressed in Figure 6 on a total NPV cost basis, and as a £/MWh benefit. The latter is calculated by dividing the £m cost figure by the lifetime MWh produced by the CCGT CCS plant.

5 Pale Blue Dot (2015), *Industrial CCS on Teesside – The Business Case*

6 ETI (2017), *CCS Offshore Scale Impact*

7 BEIS (2016), *Electricity Generation Costs*

Figure 6 Estimated impact of power sector CCS on industrial costs at Teesside cluster

	Cost to industry (NPV)	
	£m	External benefit per unit of output from a CCGT CCS plant (£/MWh)
CCS infrastructure costs incurred under each scenario		
Industry only	655	
Industry plus CCGT CCS	336	
Estimated externality impact		
Benefit to industry of shared infrastructure	**320**	**0.9**

Source: Frontier Economics

Enabling industrial deployment of CCS

It is also sometimes argued that industrial CCS would not happen at all without an anchor load from the power sector. Individual, industrial sites have low CO_2 volumes, clusters may be difficult to organise and very long-term infrastructure investments in the industrial sector may not be possible, given the potential mobility of industry.[8] [9]

It is therefore possible that, at least in the short term, a power sector load will be required to enable industrial CCS.

We have assessed the potential materiality of this using ETI's ESME model[10]. In particular, to measure the benefit of shared infrastructure benefits across the economy, we specified that ESME allows for no CCS outside the power sector, and compare non-power sector costs between this scenario and the baseline scenario.

The total additional benefit (on an NPV basis) to the non-power sector between our baseline and this scenario over the period 2015-2050 is £5.5bn (in 2017 prices).

To estimate this on a £/MWh basis, we have divided this figure by the total discounted generation from a 3.6GW CCGT CCS plant. This results in a £22/MWh externality benefit from shared CCS infrastructure.

8 DECC (2012), *CCS Roadmap*; Oxburgh (2016), *Lowest cost decarbonisation for the UK: The critical role of CCS*

9 CCS for hydrogen production could provide an alternative anchor load. However this is only expected to be deployed at scale in the mid-2030s at the earliest, and therefore is not likely to develop initial shared CCS infrastructure E4Tech (2015), *Scenarios for deployment of hydrogen in contributing to meeting carbon budgets and the 2050 target*

10 Because of the way that ESME allocates the costs of CCS infrastructure costs in its optimisation, it is not possible to directly estimate the incremental impact on industrial abatement costs of adding a CCS plant in the power sector. However, we can use it to measure the impact there is on costs to society, if CCS is not available for industrial abatement. This allows estimation of the external benefits of CCS in the power sector, in a scenario where CCS would not be possible in industry without the power sector anchor load.

3.1.2 Smart homes technology

There may be benefits to consumers from coordinating smart energy technologies used in the home with other functions. For example, smart home technologies that facilitate DSR, such as smart meters could be linked up to home security systems.

Demand for connected homes technology is growing quickly, with global connected home device shipments expected to quadruple between 2015 and 2019. This includes smart home appliances, safety and security systems and smart energy systems.[11]

Connectivity between smart energy meters (currently being rolled-out across the UK) and other smart home devices provides potential benefits for consumers, in particular in improving chore automation. [12]

As well as facilitating DSR, consumers could benefit from managing and operating smart home appliances (such as thermostats, washing machines and dishwashers) remotely. For example, this has been estimated to have the potential to save up to 100 hours of labour per year per household from chore automation, by allowing consumers to automate these devices to be switched on/off remotely in off-peak/peak electricity demand periods or at times of convenience.[13]

More broadly, there may be benefits from smart meters related to cost reductions for other smart home devices, or from enhanced connectivity between devices.

However, robust evidence to assess the materiality of these benefits is not available.

3.1.3 Methane network infrastructure

Demand for methane from the electricity sector could have implications for the cost and availability of the development of gas network infrastructure, such as import terminals and pipelines, given the high capacity costs and economies of scale associated with these.

However, most decarbonisation scenarios do not involve an expansion of the methane network, and any change in how the costs associated with the current network are distributed between the power sector and other sectors, will have a distributional impact, rather than a net impact on costs to society. We therefore do not assess this impact further.

3.2 Shared skills and supply chain

If the electricity sector shares skills or supply chains with other sectors, this may have an impact on efficiency or risks in other sectors.

Our initial review identified that there could be an impact associated with CCS technologies (CCGT CCS and Biomass CCS) and storage.

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11 GSMA (2015), *The impact of the Internet of Things: The connected home*

12 GSMA (2015), *The impact of the Internet of Things: The connected home*; McKinsey Global Institute (2015), *The Internet of Things: Mapping the value beyond the hype*

13 McKinsey Global Institute (2015), *The Internet of Things: Mapping the value beyond the hype*

We discuss each of these in turn in the following sections.

3.2.1 CCS technology

Developing CCS is likely to require specialist skills and supply chains. Developing these could facilitate the deployment of CCS technology in other industrial sectors.

A wide range of skills from a strong skills pool will be needed for full-scale deployment of CCS technologies. This includes skills in chemical and process engineering, pipelines, offshore engineering and geological exploration. Supply chains specific to CCS deployment will also be needed[14].

The development and presence of these skills and supply chains in the power sector may reduce barriers and costs to the long-term development of CCS technologies in other sectors. However, evidence to determine how material these impacts might be is not available[15]. We therefore do not assess these impacts further.

3.2.2 Storage

Deployment of storage in the power sector may have benefits for electric vehicles (EVs) in terms of economies of scale for the supply chain.

However, existing evidence suggests that any supply chain spillovers are not likely to be material, given that:

- the development and application of specific battery technologies is likely to differ between power sector and EV applications; and
- battery technologies deployed for EVs are primarily li-ion and nickel-metal hydride batteries. These supply chains are well-developed in the transport sector relative to the power sector.

We discuss each of these in turn in the sections below.

The development and application of specific battery technologies

The specific performance characteristics of different battery technologies and technologies within the same ‘family’ can vary significantly. For example, a technology that is suitable for the delivery of power in frequency response may not be suitable for, say, use in EVs.[16]

Their development and deployment across the supply chain are therefore likely to be specific to those sectors and applications for which they are most suitable and cost-effective. Therefore, even if a specific type of battery technology can be used in both the power sector and EV deployment, the specific applications may mean that supply chain spillovers between the two sectors are likely to be limited.

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14 DECC (2012), *CCS Roadmap*

15 We note that there is evidence that learning within the electricity sector has had a significant impact on cost, for example, in relation to offshore wind.

16 IRENA (2017), *Electricity storage and renewables: Costs and markets to 2030*

Battery technologies supply chains are well-developed in the transport sector relative to the power sector

Power sector development and use of lithium-ion (li-ion) batteries for storage has thus far been limited relative to the EV sector.

Most EVs use relatively small electro-chemical batteries, such as. li-ion and nickel–metal hydride batteries.[17]

Continued expected cost reductions for li-ion batteries in particular are expected to increase the production capacity for EV batteries. These developments are being driven by both academic research and private sector investment, although the latter is largely led by non-UK companies, such as US-based Tesla. [18]

Therefore our view is that power sector externalities in this are likely to be limited.

3.3 Shared use of scarce resources

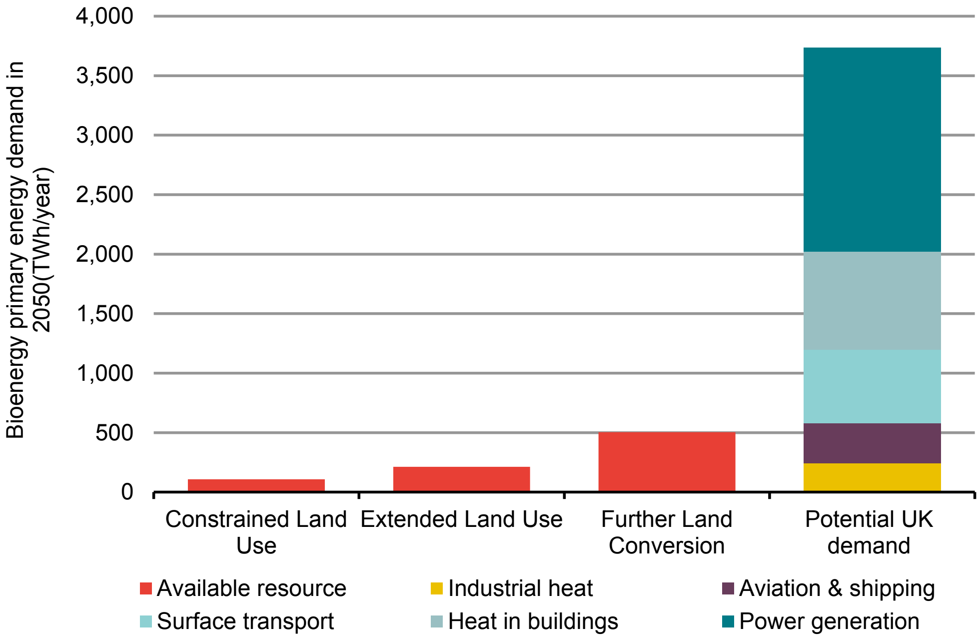
Adding new generation plant to the electricity system may affect fuel demand and prices. In particular, the use of biomass in the power sector in biomass CCS plants might push up the costs of biomass in the rest of the economy if there are supply constraints. Biomass can be used across multiple sectors. For example, agricultural produce can be used for food crops and forestry, but also as fuels in the transport, heat and power sectors, and in industry and construction.

The concern that there may be an external impact on cost applies to biomass rather than other commodities, because there may be limits to the amount of biomass that the UK can access (or that the price of biomass may increase sharply with demand). For example, the Committee on Climate Change considered three scenarios for available biomass resource in the UK, all of which were significantly lower than potential demand for this resource (Figure 7).

[17] IRENA (2017), *Electricity storage and renewables: Costs and markets to 2030*

[18] IRENA (2017), *Electricity storage and renewables: Costs and markets to 2030;* Grantham Institute (2016), *Briefing paper No. 20 - Electrical energy storage for mitigating climate change*

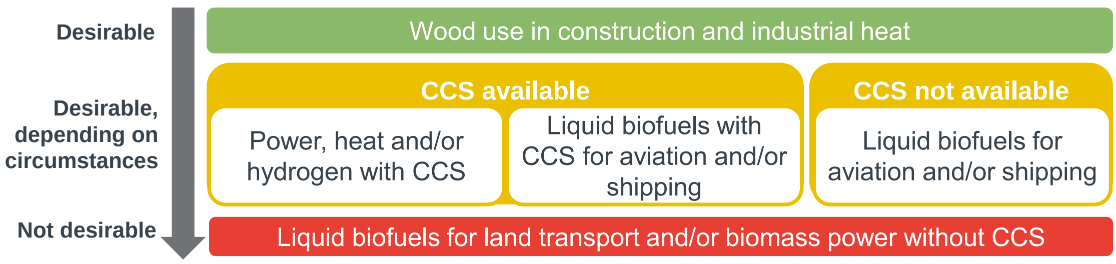
Figure 7 Bioenergy supply constraints versus potential UK demand in 2050



Source: CCC (2011), Bioenergy review, Figure 4.1[19]

CCC Bioenergy Review (Figure 8)[20] also suggests that there may be higher priorities than using biomass in the power sector, though we note that ETI modelling suggests that its use in the power sector (particularly with CCS) may be an important part of abatement strategies. The use of biomass in the power sector may therefore present a negative externality if resources are diverted away from other more cost-effective uses[21].

Figure 8 Overview of the cost-effective use of bioenergy resources in 2050



Source: Adapted from CCC (2011), Bioenergy review, Figure ES.1

[19] In the 'Constrained Land Use' scenario, only around 20% (100Mha) of total global abandoned agricultural land, with an assumed low level of productivity, is used for dedicated energy crops by 2050. The 'Extended Land Use' scenario represents CCC's baseline scenario for land use required for bioenergy in order to meet 2050 targets. This assumes that around 400Mha of land is available for dedicated energy crops by 2050 by allowing for greater use of abandoned agricultural land, but still only allowing for limited used of current agricultural land and previously uncultivated land. The 'Further Land' Conversion' scenario assumes around 50% (700 Mha) of land is used for growing dedicated energy crops by 2050, by using all abandoned agricultural land and allowing for the conversion of current agricultural land or natural habitats.

[20] Committee on Climate Change (2011), Bioenergy review

[21] While generally price signals could ensure that biomass is used where it creates the most value, different levels of policy intervention across sectors could mean allocation is not efficient.

Quantifying the impacts of shared biomass resources

There may be an external cost to the non-electricity sector from reducing the amount of biomass resources available to the non-electricity sector, and using these instead for electricity generation. This will depend on:

- the extent to which biomass resources are limited;
- the importance of biomass as an abatement option outside the power sector; and
- the extent to which negative emissions (where biomass is used with CCS) in the power sector reduce the need for expensive abatement elsewhere.

We have used ESME to assess this non-electricity sector impact of higher power sector biomass demand on the availability of biomass outside the power sector for two scenarios:

1. Force 2GW of non-CCS biomass plant onto the system (subject to the feedstock required for this not exceeding the total amount of biomass that is assumed to be available in the model). This analysis takes into account the reduction in biomass available to non-electricity sectors but because it focusses on biomass without CCS, it does not take account of the reduction in abatement required in the non-electricity sectors that would be delivered by negative emissions from CCS.
2. Force 2GW of biomass CCS plant onto the system (subject to the feedstock required for this not exceeding the total amount of biomass that is assumed to be available in the model). This allows us to account for any benefits that are delivered by negative emissions from CCS.

For both these scenarios, we then compared total non-electricity costs in this scenario to non-electricity costs in the ESME baseline scenario.[22]

Assuming that there are constraints on the total amount of biomass available for the UK, this allows us to estimate the impact of using biomass in the power sector, rather than allowing it to be used for the most cost-effective abatement across the economy.

The estimated benefits are presented in on a total NPV cost basis, and as a £/MWh benefit. To estimate this on a £/MWh basis, we have divided this figure by the total discounted generation from the incremental biomass CCS plant.

[22] Note that in modelling this, ESME does not to use the 2GW of capacity fully, and indeed not at all from 2040-20 50 in its optimisation. This likely reflects that biomass can be more cost-effectively used in other sectors in later years, even if 2GW of capacity is available

Figure 9 Estimated non-electricity sector impact of biomass and biomass CCS

	Biomass (non-CCS)	Biomass CCS
Total estimated externality impact of shared resources (£bn)	-1.7	2.7
Estimated externality impact of shared resources (£/MWh)	**-35**	**10**

Source: Frontier Economics

Note: Figures are presented on an NPV basis in 2017 prices

These estimates may overestimate the external cost element, as they are based on an assumption that there is a limited biomass resource available across the economy. In reality, biomass supply could increase in response to an increase in price

3.4 Innovation and knowledge externalities

Deployment of a technology in the power sector may produce learning relevant to the deployment of that technology in other sectors, particularly at the earlier stages of deployment.

Given that empirical research on the impacts of such innovation and knowledge externalities is limited, we have looked qualitatively at the learning curves associated with relevant generation technologies.

These are set out in the sections below.

3.4.1 CCS technology

Innovation and R&D carried out in the power sector for CCS deployment can be relevant for industry CCS applications. However, innovation will depend on global rather than national deployment, except where there are UK-specific conditions, such as the geological conditions for CCS transport and storage of CCS[23] [24] . This could be material, if it is considered that learning about CCS transport and storage in UK-specific conditions is dependent on power sector CCS deployment as an anchor load.

Some innovation may also be driven by research, rather than the deployment of CCS.

While the evidence suggests that full-chain innovation has the potential to reduce UK costs of CCS deployment by an estimated £10–45bn to 2050[25], it is not clear how much of this is likely to be:

- driven by UK rather than global innovation; and
- attributable to learning by doing rather than learning by research.

[23] LCICG (2012), *Technical innovation needs assessment: Carbon capture & storage in the power sector*

[24] The experience in the UK oil and gas sector provides an analogous example of the existence of a strong geographic component to learning innovation. The UK industry is regarded globally as an innovation leader in subsea operations and deep water experience.

[25] LCICG (2012), *Technical innovation needs assessment: Carbon capture & storage in the power sector*

Therefore it is not possible to estimate the scale of impact on CCS costs elsewhere in the economy arising from CCS deployment specifically in the power sector.

3.4.2 Storage

As discussed in Section 3.2.2, there are unlikely to be spillovers from the electricity storage industry to storage uses in other sectors, given the differences in technologies involved, and the fact that storage development in the EV context is more advanced.

3.5 Energy externalities

Waste energy from power generation could be used elsewhere in the economy, for example in district heat networks.

District heating is generally deployed in areas with both high heat demand density and available local heat resource. Of the power generation technologies within scope, CCGT plant, biomass and CCGT CCS and nuclear have the potential to deliver a local heat supply. However it is most likely that waste heat will come from Biomass CCS and CCGT CCS.

- **Biomass and CCGT CCS.** Biomass CCS and CCGT CCS are likely to run baseload. Therefore waste heat from biomass and CCGT could be used in district heating.
- **CCGT.** CCGT plant can be built close to demand sources to provide waste heat for district heating. However, over time the load factor of CCGT (without CCS) will need to fall, if carbon targets are to be met. Therefore it would not make sense to invest in district heat infrastructure connecting to these plants.
  - **Nuclear.** In theory, nuclear plants could provide a source of waste heat for district heating. Previous ETI research has noted that small modular reactors (SMRs) in particular have the potential to deliver combined heat and power (CHP) by 2030. This, however, is dependent on the availability of district heat infrastructure at locations within a reasonable distance of demand, and the level of public acceptance.[26] Our interpretation of current evidence is that nuclear plant as a source of waste heat is therefore likely to be limited.

A report by Element Energy[27] found that waste heat from power stations can be a highly cost-effective abatement measure with the potential for negative average abatement costs in the range -£79/t CO_2 to -£200/t CO_2,[28]

We have used ESME to estimate the potential value of the waste heat externality, using an illustrative example.

We have specified that the amount of waste heat produced from thermal plants in ESME be reduced across the power sector by an amount equivalent to 0.6GW of

[26] ETI (2015), *The role for nuclear within a low carbon energy system; ETI (2016), Preparing for deployment of a small modular reactor by 2030*

[27] Element Energy (2015), *Research on district heating and local approaches to heat decarbonisation: A study for the Committee on Climate Change*

[28] This includes waste heat from industrial applications also. This does not include waste heat from nuclear plants

baseload capacity in 2025[29] and compared total non-electricity costs in this scenario to total non-electricity costs in the baseline scenario.

This allows us to estimate the value of waste heat from thermal plants (gas CCS, biomass CCS) and nuclear.

The total additional benefit (on an NPV basis) to the non-power sector between our baseline and this scenario for the year 2025 is £5m (in 2017 prices).

To estimate this on a £/MWh basis, we have divided this figure by the total discounted reduction in waste heat production (equivalent to 0.6GW of baseload capacity). This relates to a £1/MWh externality benefit from the use of production and use of additional waste heat from the power sector. Once again, these figures represent an illustrative example only, and are dependent on a range of assumptions around the baseline scenario.

3.6 Environmental and health externalities

3.6.1 Air quality and health

Some electricity generation technologies emit pollutants such as Nitrogen dioxide (NO_X) and Particulate matter (PM) that negatively impact on air quality. In turn, poor air quality incurs heath costs, particularly to people located near such pollutant-emitting plants.

However, emissions of these pollutants from new power stations are likely to be limited, given the need to meet emissions requirements under the Industrial Emissions Directive (IED). For example, the IED is likely to require fitting of selective catalytic reduction (SCR) as a best available technology to reduce NOx emissions[30].

While IED emissions limits from biomass CCS plants are less strict than for CCGT, they are still relatively low[31] (see Figure 10). Therefore we do not quantify these further in this analysis.

29 Given the specifications of the ESME baseline modelling, this is constrained to 0.6GW rather than the full 2GW specified in Figure 11 in ANNEX A.

30 EC (July 2017), *Commission implementation Decision (EU) 2017/1442 of 31 July 2017 establishing best available techniques (BAT) conclusions, under Directive 2010/75/EU of the European Parliament and of the Council, for large combustion plants*

31 Air Quality Expert Group (July 2017), *The potential air quality impacts from biomass combustion*

Figure 10 NOx and PM emissions limits and air quality damage costs by pollutant

Generation technology	Emissions limits* (mg/Nm3)		Air quality damage costs** (£/tonne of emission change, 2015 prices)		
	PM	NOx	PM	NOx	NOx and PM
Biomass (new) – all plants sizes	2-5		2,906	1,263	1,052
Biomass (new) – 100-300MWth	2-5	50-140	2,906	1,263	1,052
Biomass (new) – >300MWth	2-5	40-140	2,906	1,263	1,052
CCGT (new) – >50MWth		10-30	2,906	1,263	1,052
OCGT (new) – >50MWth		15-35	2,906	1,263	1,052

*Source: * EC (July 2017), Commission implementation Decision (EU) 2017/1442 of 31 July 2017 establishing best available techniques (BAT) conclusions, under Directive 2010/75/EU of the European Parliament and of the Council, for large combustion plants*
*** Defra Air Quality Economic Analysis. Available at: https://www.gov.uk/guidance/air-quality-economic-analysis*

3.6.2 Impact on landscape and wildlife

The building of any power plant and the associated transmission technology may have an impact on the landscape, wildlife and biodiversity of the surrounding area. However, these impacts of power generation on biodiversity can be difficult to define, assess and value.

Defra (2013) sets out an assessment of the likely impacts of different low-carbon technologies on biodiversity, as summarised in Figure 11. We have also included estimates of the externality costs of loss of biodiversity estimated by the OECD / NEA across the EU-27 countries over the period 2005-2010.

Figure 11 External cost of power generation on biodiversity (Impact per unit of energy produced)

	CCS technology	Onshore wind	Offshore wind	Biomass
Habitat loss / degradation	**Low and short-term**. In construction of facilities	**Low**. Although impacts of construction of associated infrastructure may be high in certain locations	**Uncertain**. Positive impact from artificial reef development and trawler exclusion	**Variable**. Dependent on habitats affected and management of resources High if native trees replaced with fast-growing alien ones
Disturbance and displacement	**Low and short-term**. In construction of facilities	**Moderate**. Certain birds may be displaced given noise / visual impacts	**Low/Moderate**. 1-5% for the development area incl. construction & transmission Potential 'barrier effect' might impact migratory patterns of some birds	**Moderate**. From increased forestry operations
Mortality of birds and animals	**Low**. From occasional leaks from pipelines/ storage tanks	**Variable**. Collision risk dependent on site location but likely to be too low to impact population	**Low** for migratory sea birds, **Moderate/high** for local birds, dependent on site location	**Low**. Some incidental loss during harvesting of UK-grown crops
OECD/NEA estimate (2005-2010)	N/A	€0.04/MWh	€0.03/MWh	€0.49/MWh (wood biomass)

Source: Defra (2013), Towards integration of low carbon energy and biodiversity policies – literature review of impacts on biodiversity; OECD/NEA (2012), Nuclear energy and renewables: System effects in low-carbon electricity systems

Note: There is limited evidence on solar, although we would expect the impacts to be similar to those for onshore wind

The literature therefore shows that the externality of generation technologies on biodiversity is not likely to be material, except in cases of extreme events or poor management / choice of site location.

3.6.3 Noise impacts

The production of energy from low-carbon generators may lead to noise impacts in the surrounding area. For example, onshore wind turbines may create noise pollution for people nearby.

However, assessing noise impacts can be challenging, given its subjective nature.

Noise impacts are usually quantified based on the number of people / households affected by an increase or decrease of noise levels, measured in average decibels.

Guideline numbers set out in HMT's Green Book from studies across Europe gives a range of €20-30 per household per decibel per year (2001 prices).[32]

However much of the research to date has focussed on the impact of noise from road, rail and aircraft traffic, with limited studies on the impact from the industrial or power sectors

[32] HM Treasury (2011), *The Green Book: Appraisal and Evaluation in Central Government*

Based on the above, there is not enough evidence to reach clear conclusions about the materiality of noise impacts from different choices of generation technologies. However, given the more remote location of larger power plants, these are not likely to be significant.

ANNEX A ESME MODELLING SPECIFICATIONS

Where appropriate, we have worked with ETI's ESME team to specify ESME modelling to be carried out to quantify certain spillover effects under Work Package 3b.

Figure 12 below sets out the specifications for the different ESME runs that have been used to assess the impact of total non-electricity sector costs to society.

Figure 12 ESME specifications used to assess non-electricity sector impacts

Externality	Modelling specification	Rationale
Shared infrastructure – CCS technology	Run ESME with no CCS allowed outside the power sector, and compare total system costs (or non-electricity system costs) between this scenario and the baseline scenario.	This allows us to estimate the impact that CCS can have on abatement costs outside the power sector. If power sector CCS is a necessary enabler for CCS elsewhere in the economy, then any costs reductions can be allocated as an external benefit to power sector.
Shared use of resources - Biomass	Force 2GW of biomass/biomass CCS plant onto the system (subject to the feedstock required for this not exceeding the total amount of biomass that is available) and compare total non-electricity costs in this scenario to non-electricity costs in the baseline scenario.	Assuming that there are constraints on the total amount of biomass available for the UK, this allows us to estimate the impact of using biomass in the power sector rather than allowing it to be used for the most cost-effective abatement across the economy.
Shared use of resources – Biomass CCS	Force 2GW of biomass CCS plant onto the system in 2025 (subject to the feedstock required for this not exceeding the total amount of biomass that is available). Compare total non-electricity costs in this scenario to non-electricity costs in the baseline scenario, holding the constraint on total system wide emissions constant between scenarios.	Assuming that there are constraints on the total amount of biomass available for the UK, this allows us to estimate the external impact of using biomass to produce negative emissions in the power sector.
Energy externalities	Reduce the amount of waste heat produced across the power sector by an amount equivalent to 2GW of baseload capacity in 2025 and compare total non-electricity costs in this scenario to total non-electricity costs in the baseline scenario.	This allows us to estimate the value of waste heat from thermal plants (gas CCS, biomass CCS and nuclear).

Source: Frontier Economics

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frontier economics

ASSESSING THE VALUE FOR MONEY OF ELECTRICITY TECHNOLOGIES

Appendix 3: Assessing technology support requirements

January 2018

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CONTENTS

1 INTRODUCTION

Low carbon generators are financially supported under a system of contract for differences (CfDs). Under this system, generators are paid the difference between a 'strike price' and the average market price for electricity in GB[1]. Strike prices differ across technologies, varying, in part, according to technology costs.

In policy debates, strike prices are often used to compare the value for money associated with different electricity technology investments, because they give an indication of how much consumers will pay for the output of these technologies. However, differences both in the terms of the CfDs and in the wider policy and regulatory regimes of different technologies, mean that strike price comparisons may not provide a good indication of relative value for money. Examples of this type of 'indirect support' are provided in Figure 1. Therefore, for strike prices to be a useful metric for value for money, they need to be adjusted to take account of the variations in 'indirect support' provided.

This report describes how these adjustments can be undertaken. In particular, we produce 'strike price equivalents' that put technologies on a level playing field and facilitate a balanced assessment of the underlying net cost that consumers actually pay for generation from different technologies.

The technologies considered include low carbon technologies that could be eligible for CfDs (onshore wind, offshore wind, large scale solar PV, nuclear, CCGT CCS, Biomass CCS), technologies which only receive revenue from the wholesale and capacity markets (CCGT, OCGT, storage[2]), as well as interconnectors, which are eligible for support under the cap and floor mechanism.

Figure 1 Examples of indirect support[3]

Support element	Example
Support implicit in the design of policies	▪ Contractual terms in CfDs can shift risk from investors to consumers/taxpayers ▪ Capacity adequacy impacts are unpriced under CfDs ▪ Displaced generation impacts are unpriced under intermittent CfDs
Unpriced externalities[4] in the market	▪ Incremental network development costs can exceed network charges paid ▪ The carbon externality may not be fully reflected in carbon price faced by market participants

Source: Frontier Economics

1 As discussed further below, the 'reference price' used to represent the average market price for electricity differs across technologies. https://www.gov.uk/government/publications/contracts-for-difference/contract-for-difference

2 We consider lithium-ion batteries as the representative storage technology in our analysis.

3 By 'support' we mean additional payments or favourable treatment for investors that is provided above and beyond the value of the electricity and capacity adequacy services produced by the technologies. By 'indirect support' we mean the non-monetary elements of this support.

4 In this context, an 'externality' refers to a cost or benefit to society that is not taken into account in the private investor decision.

What can this work tell us?

As well as facilitating a more balanced comparison of the costs to consumers and taxpayers of generation from alternative low carbon technologies, the analysis in this report allows the following questions to be explored.

- **How does the level of indirect support vary by technology under the current market arrangements?** Our analysis puts a monetary value on the different contractual terms received by different technology types under current policy. This can allow us to understand whether particular technologies benefit from more 'hidden advantages' than others, contributing to lower strike prices.
- **How might policy and market frameworks be adjusted to achieve genuine technology neutrality?** Understanding where material levels of indirect support are being provided helps to determine what adjustments would be needed to enable, say, a CfD auction to be truly technologically neutral.

Structure of the remainder of this report

The rest of this report is structured as follows:

- Section 2 describes our overall approach.
- Section 3 presents our key results and conclusions.
- Further details are provided in the Annexes.

FURTHER MATERIAL PUBLISHED ALONGSIDE THIS DOCUMENT

This research also encompasses the following published documents.

Main report:

Assessing the value for money of electricity technologies

Two Excel-based decision support tools.

- Tool A: Whole Electricity System Costs
- Tool B: Investment Support Costs

Further detail is also provided two further appendices:

- Appendix 1: Modelling of whole electricity system costs
- Appendix 2: Reflecting costs and benefits beyond the electricity sector

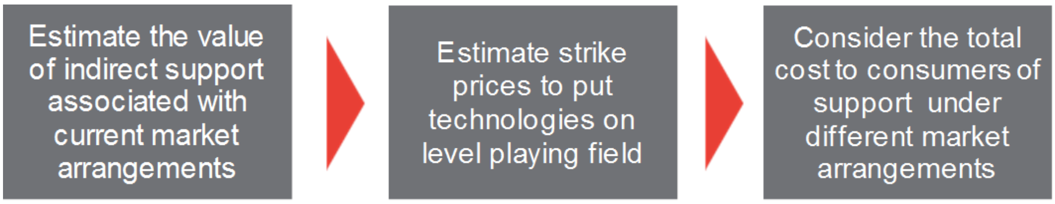
2 APPROACH

Our analysis aims to estimate the following, for investments made in 2025:

- the value of indirect support provided to investors under current market arrangements;
- 'strike price equivalents' so that technologies can be compared in a balanced way to provide insights on value for money; and
- the costs to consumers associated with directly supporting different investments under different assumed market arrangements (where 'direct support' refers to payments investors require over and above market revenues from the wholesale and capacity markets).

This section describes our methodology for undertaking this analysis (Figure 2).

Figure 2 Overview of approach



Source: Frontier Economics

2.1 Valuing the indirect support provided to investors under current market arrangements

In this section:

- we first define a level playing field;
- we then describe what we mean by direct and indirect support, and the relationship to strike price equivalents;
- finally we describe our process for estimating the indirect support under current market arrangements.

2.1.1 How do we define a level playing field?

Our first step is to define a level playing field, so we can compare technologies in a balanced way. To put all technologies on a level playing field, we consider a set of arrangements where no technology receives bespoke favourable contract terms.

We also correct for the main externalities[5] in the market (i.e. where the full costs or benefits that technologies impose on the system are not reflected in the revenues investors earn). Adjusting revenues to correct for these externalities means we can remove the implicit subsidies associated with them.

[5] We identify the main externalities as being associated with carbon, networks and capacity adequacy – see section 2.1.3 for more detail.

We therefore create a level playing field where investors receive minimal 'indirect support' in the market.

To represent this, we assume that each technology participates in both the wholesale market and the Capacity Market (CM) (on the same basis as new-build generation or storage). This means that the value of the generation produced, as well as the capacity adequacy benefits associated with different technology types are reflected in the revenues that investors are assumed to receive. We then make further adjustments to take account of carbon and network externalities which may currently not be fully reflected under existing arrangements.

2.1.2 Direct and indirect support, and the relationship with the strike price equivalent

We calculate the indirect support by looking at the difference between the direct support (i.e. payments in excess of market revenues) required by investors under current arrangements and the direct support that would be required by investors under the level playing field.

The strike price equivalent represents the amount that consumers/taxpayers would need to pay investors for each unit of electricity produced by a given technology, under a set of assumptions about technology costs, the baseline scenario and market arrangements[6]. It is defined as being equal to the sum of the market revenues[7] received by the investor, and the direct payment they would require under those assumptions[8].

Figure 3 illustrates:

- how the strike price equivalent is calculated;
- how the strike price equivalent relates to technology costs; and
- how the level of indirect support under current market arrangements can be determined.

We start from the position that for investment to take place, the costs on the left hand side of the diagram must be matched by the revenue and support shown on the right hand side[9].

- The **costs** associated with the notional electricity technology include:
  - private costs faced by investors under current market arrangements (such as technology, network and balancing costs, and the required rate of return);
  - The additional costs investors would face in the absence of any support mechanism (for example due to a higher required rate of return);and

6 The assumptions we have made on technology costs, the baseline and market arrangements are set out in Annex B.

7 Strictly speaking, market revenues, based on the investor achieving the assumed CfD market reference price. See Section 2.2 for more detail.

8 Since the level playing field strike price equivalent corrects for indirect support received under the current market arrangements, it is equivalent to market revenue plus direct support plus indirect support under current market arrangements (Figure 3).

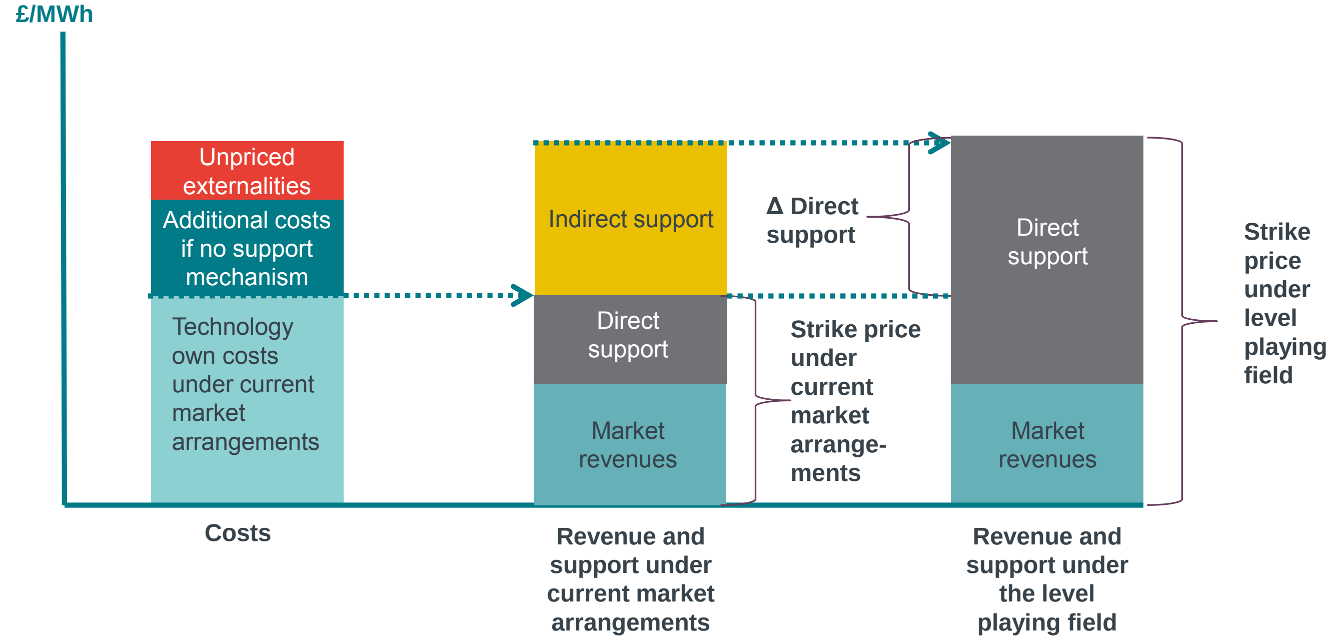
9 While investors could receive more support than they actually require (for example, if a negotiated CfD overcompensated them for the costs of their investment), we assume that in line with a system of allocating CfDs through auctions, payments to investors are just enough to compensate them.

- unpriced externalities such as carbon emissions[10].

- The **total revenues and support** that investors would require to invest in these technologies include[11]:
  - market revenues (from the wholesale, ancillary service and capacity markets);
  - direct support payments (i.e. the monetary payments investors receive under the CfD system for low-carbon generation or the cap and floor regime for interconnectors);
  - indirect support received (non-monetary support in the form of favourable contract terms or unpriced externalities).

Figure 3 represents these elements for both a strike price under current market arrangements and the strike price equivalent on a level playing field (because of our definition of the level playing field, in which all externalities are assumed to be internalised, indirect support under this option is zero). It shows how indirect support can be calculated as the difference between (i) the value of direct support provided to investors under current arrangements and (ii) the value of direct support under conditions associated with the level playing field.

Figure 3 Strike price equivalent, technology costs and indirect support



Source: Frontier Economics

Note: The sizes of the blocks are illustrative only. For example, indirect support may be close to zero under the level playing field arrangements

[10] We note that under current market arrangements, the costs associated with carbon emissions have been partially internalised. However, as described below (Annex A) there remains a gap between the market carbon price and the value used by government for policy appraisal.

[11] Indirect support does not feature in the level playing field strike price equivalent.

2.1.3 How do we estimate the level of indirect support under current market arrangements?

To estimate the level of indirect support under current market arrangements we do the following:

- We first calculate the level of direct support that would be required to deliver investment under current market arrangements.
- We then adjust the hurdle rates and other parameters to take account of the indirect support associated with the current market arrangements (the process and rationale are explained below).
- We recalculate the direct support using the adjusted assumptions, allowing us to estimate the indirect support granted.

We now consider each of these steps in turn.

Calculating direct support required under current market arrangements

To calculate the direct support required under current market arrangements, we model the costs and returns to investors under technology-specific hurdle rates that correspond to current market arrangements[12]. We use BEIS assumptions on technology specific hurdle rates for this purpose.[13]

The process for adjusting hurdle rates and other parameters

We then adjust the hurdle rates and other parameters to take account of indirect support.

Figure 4 describes the key variations in indirect support that we focus on in this research. Annex A presents a detailed description in the variation in contract terms across technologies, and sets out our rationale for focussing on those presented in Figure 4.

Figure 4 Key variations in indirect support across technologies

Unpriced externalities	Differences in CfD contract terms	High level support mechanism
▪ Carbon costs (all technologies) ▪ Adequacy impacts (CfD technologies) ▪ Incremental network costs (all technologies).	▪ Duration of support ▪ Hourly reference price (intermittent technologies) ▪ Single strike price for all phases (offshore wind) ▪ Protections for changes in operating costs (nuclear) ▪ Limits on environmental liabilities (nuclear) ▪ Limits on decommissioning risk (nuclear) ▪ Change in law provisions (nuclear)	▪ The CfD (all low carbon technologies) ▪ Cap and floor (interconnectors).

Source: Frontier Economics

12 This modelling is undertaken using EnVision. Further details are provided in Annex B.

13 BEIS Electricity Generation Costs, 2016, Annex 3, Table 17. Battery storage hurdle rate assumed equal to that of pumped storage.

We first consider implicit support provided where externalities are unpriced (i.e. where investors are not paying the full costs that they impose on the system). These fall into three categories.

- **Carbon (all technologies).** We estimate the changes in revenues and costs that would arise if generators faced a carbon price reflecting the marginal cost of abatement, instead of the market price assumed in the EnVision modelling[14]. We estimate the increase in variable costs as the product of the increase in carbon price and the technology's carbon intensity of generation. We estimate the increase in revenues as the product of the increase in carbon price and the average grid marginal emissions factor.
- **Adequacy impacts.** To ensure any generation adequacy benefits of low-carbon technologies are recognised, we add the capacity payment the technology could hypothetically receive (based on their de-rating factor) to the estimated market revenues. We also take into account the potential decrease in the hurdle rate from receiving the capacity payment.
- **Incremental network costs (all technologies).** Investors may not have to pay the full cost to society of incremental network reinforcement that arises from deployment of their technology. To illustrate how this impact could be estimated, we value this indirect support by calculating the additional support investors would require if they were to bear this cost (over and above the transmission charge they are assumed to pay, implicit in our technology cost assumptions[15]). We use the results of EnVision modelling for our estimate of the incremental network costs to society. That said, the precise results arising from this analysis should be interpreted with care, given the uncertainty around these estimates, and simplifications made in the modelling.

We then look at the differences in CfD terms between technologies. For all technologies except for CCS, we use CfDs currently in place in the market. CCS plants do not currently operate in the market and no CfD is in place for them. Therefore we have made assumptions on the terms that they would be likely to face, based on discussions with the ETI[16].

- **Duration of support (nuclear and CCS).** Nuclear and CCS have longer CfD contracts than other technologies.[17] Spreading support payments over a shorter period (15 years) increases the strike price required (since the required support must be earned over a shorter period[18]). In addition, a reduction in contract length increases investors' exposure to wholesale price risk over the remaining lifetime of the plant (which also impacts on the hurdle rate, as described in Box 1). We take both of these elements into account.
- **Choice of reference price (intermittent).** Intermittent technologies are given an hourly reference price, in contrast to nuclear and CCS technologies, which are given a 'baseload' (i.e. time-weighted average) reference price in their

[14] See Annex A.

[15] See Annex B for more detail.

[16] Our assumptions on CCS contracts are set out in Annex A.

[17] We assume 35 years for nuclear and 25 years for CCS.

[18] In our calculations, these technologies still gain wholesale market revenues over their lifetime so the full capital expenditure does not need to be recovered in 15 years.

CfD. This means that intermittent technologies are paid the difference between their actual market revenues and the strike price. Since hourly prices during which intermittent technologies generate are expected to, on average, be below the baseload price, this means that intermittent technologies earn more direct support for the same strike price. To calculate the impact of this, we substitute the intermittent reference price (which we assume equal to the average price received in the market in our modelling) with a proxy for the baseload reference price[19]. This ensures that our strike price equivalents are a better indication of the direct support being received.

- **Single strike price for all project phases (offshore wind).** Offshore wind farms can apply for CfDs covering up to three distinct project 'phases', to be delivered in consecutive years. All phases receive the same strike price. Given falling technology costs over time and the fact that most large offshore wind projects are likely to be phased, this gives offshore wind projects an advantage relative to other technologies (which do not receive the same treatment).[20] We correct for this advantage by applying an (illustrative) 5% uplift in capex for offshore wind. This is broadly consistent with recent observed cost reductions for offshore wind.[21]
- **Protections for changes in operating costs (nuclear).** Under the current nuclear CfD, the investor bears the risk of changes in opex during the initial 15 year period but is protected for changes following this period. This protection can be expected to lead to a reduction in the hurdle rate. If this protection were removed, this would result in an increase in the strike price. We compare the volatility in historical nuclear opex to historical electricity price volatility and use this comparison to estimate the impact on hurdle rates. Since this protection also relates to the volatility of returns, we base our estimation on the relationships set out in Box 1.
- **Protections for changes in operating costs (CCS):** CCS CfD strike prices are assumed to be indexed with changes in fuel prices. This means that the CfD works to stabilise profit margins, reducing risk. Rather than assess the value of this protection on its own, we include it in our assessment of the benefit of the CfD itself (see below).
- **Limits on environmental liabilities (nuclear).** The impact of capped liability for third party claims on the costs of nuclear power clearly has a value to investors, but is highly uncertain. We base our estimate of the impact on the strike price on an assumed doubling in third party insurance costs for nuclear (although there is the flexibility for users to change this assumption within the accompanying Excel tool).[22]

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19 We assume the baseload reference price is equal to the annual average baseload price in our modelling. The baseload price and the average price received in the market are modelled using EnVision. See Annex B.

20 We understand from BEIS officials that, in practice, the potential for developers to exploit this possibility may be limited by requirements under the CfD for all phases to use the same technology.

21 See Annex B for more detail.

22 CCS is also assumed to benefit from similar protections. However, on the basis of current evidence, we assess the risk associated with CO_2 leakage from storage sites to be small, assuming a robust regulatory regime and well-selected storage sites. See Annex A for more detail.

- **Limits on decommissioning risk (nuclear).** There is an additional benefit that comes from limits to decommissioning risks. Again the value to investors is highly uncertain, but we estimate it by considering the impact on the strike price and consumer support required of a 20% increase in the capped waste management fee of £5.9 billion (2016 prices) offered to Hinkley Point C.
- **Change in law provisions (nuclear).** Finally we illustrate the benefit coming from the change in law provisions, the most significant element of which is cover for politically-motivated shut-downs. One way of illustrating the value of this provision is to assume that, without it, there is a risk that law change would have rendered the investment worthless. We therefore consider the impact on the strike price and consumer support required of investors having to price in a one percent expected probability of complete shutdown following 15 years of operation.

Having adjusted for differences between CfD contracts, we then estimate the indirect support provided by the CfD and cap and floor mechanisms relative to that provided in a world where technologies only receive revenue from the wholesale and capacity markets.

- **CfD.** We calculate the increase in the hurdle rate from low-carbon technologies losing support from the CfD as the increase in hurdle rate resulting from the increase in wholesale market risk (Box 1).
- **Cap and floor.** The cap and floor regime applies to interconnectors[23]. To assess the benefits of the cap and floor regime to investors, we compare the hurdle rate for investing under the cap and floor regime to that of a merchant interconnector participating in the CM. We assume that moving to a merchant system would mean the investors faces increased energy market risk[24].

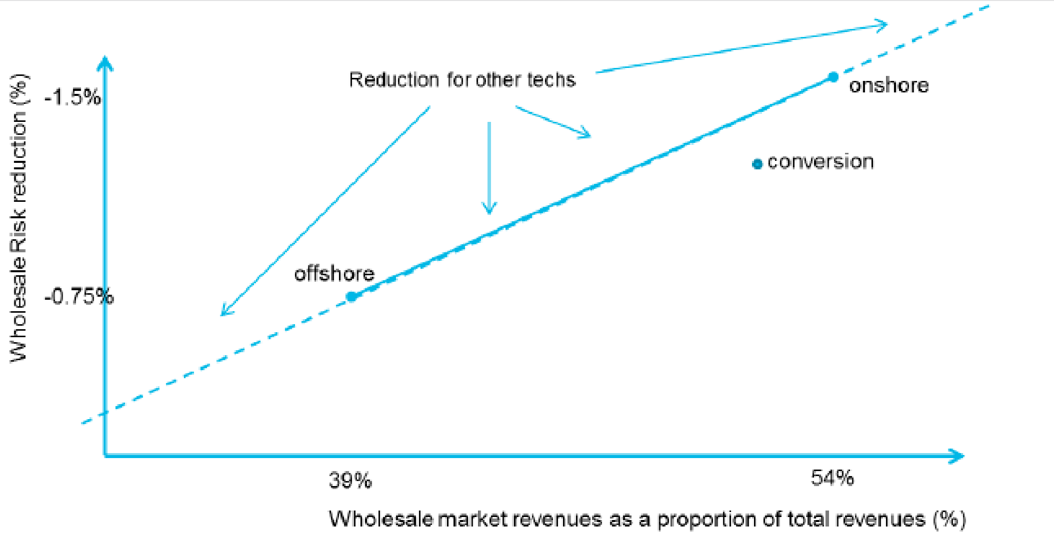
[23] See Annex A for further details.

[24] Using the methodology set out in Box 1.

Box 1: Example of how we consider changes in hurdle rates

The below figure gives an example of how we assess the impact of changes in risk allocation on investor hurdle rates.

Moving from a CfD to the CM will increase investors' expectations of wholesale price risk. To value this we apply an approach previously used by DECC in 2013 for setting administrative strike prices under the CfD. In that work, DECC used an estimate provided by NERA (2013) that the impact of introducing the CfD[25] would reduce wholesale market risk for offshore wind (0.75 percentage point reduction in hurdle rate) and onshore wind (0.5 percentage point reduction). Based on this, DECC derived hurdle rate reductions from the CfD for other technologies, based on the percentage of their total revenues made up of wholesale market revenues.



The method is simplistic, but can be used to derive indicative estimates of exposure to wholesale market risk, given an assumed technology costs and market revenues[26].

Figure 5 WACC increase from loss of CfD[27]

	Onshore wind	Offshore wind	Solar	Nuclear	Gas CCS	Biomass CCS
WACC increase from loss of CfD	3.8%	3.8%	3.8%	2.9%	2.5%	2.2%

[25] In this work, the CfD was compared to the Renewables Obligation. The Renewables Obligation provided a subsidy, but did not transfer wholesale price risk away from consumers.

[26] We use EnVision modelling to do this. See Annex B for more details.

[27] Given the proposal for the CCS CfD to include fuel price indexation, the CCS stabilises not overall wholesale market revenues, but rather just the spread between wholesale market revenues and fuel costs. As a way of recognising this, for CCS we calculate the increase in hurdle rate from the loss in CfD based on the share of this spread in total revenues. To the degree that fuel prices and electricity prices may be correlated going forwards, this may still over-estimate the benefit of the CfD somewhat for CCS. We have not adjusted for this effect in our estimates.

Estimation of indirect support

Having adjusted the hurdle rates (and other parameters) of all technologies to put them on a level playing field, we then calculate the direct support required, based on the level playing field assumptions. The difference between this and the direct support based on current arrangements is the indirect support.

2.2 Estimate strike price equivalents to put technologies on a level playing field

Having calculated the direct support required under current market arrangements and level playing field assumptions, we produce strike price equivalents. As illustrated in Figure 3, strike price equivalents are calculated as the sum of market revenues and direct support and represent the required revenue that investors in alternative technologies in 2025 would require.

Figure 3 shows the average £ per MWh strike price for a technology as being equal to its £ per MWh lifetime technology cost. However, this involves two important simplifications.

- The first is that the levelised cost is calculated over the whole lifetime of the plant, while the CfD duration will, in general, be shorter than this. Therefore, unless market revenues post-CfD (including any possible CM revenues) are higher than the levelised cost, the CfD strike price will need to be higher than the levelised cost to ensure the investment is paid back.
- As noted above, (section 2.1.3, the average price achieved by a technology in the market could be different to its reference price under the CfD. If the reference price is lower than the average price achieved, this would lead to a strike price lower than the levelised cost.

Though these impacts are not shown in Figure 3, we take into account both of these in our modelling.

2.3 Estimate the net support cost

We finally present an estimate of the cost (from a consumer perspective) of the direct support payments (i.e. monetary payments over and above the market revenues) made by consumers (or taxpayers).

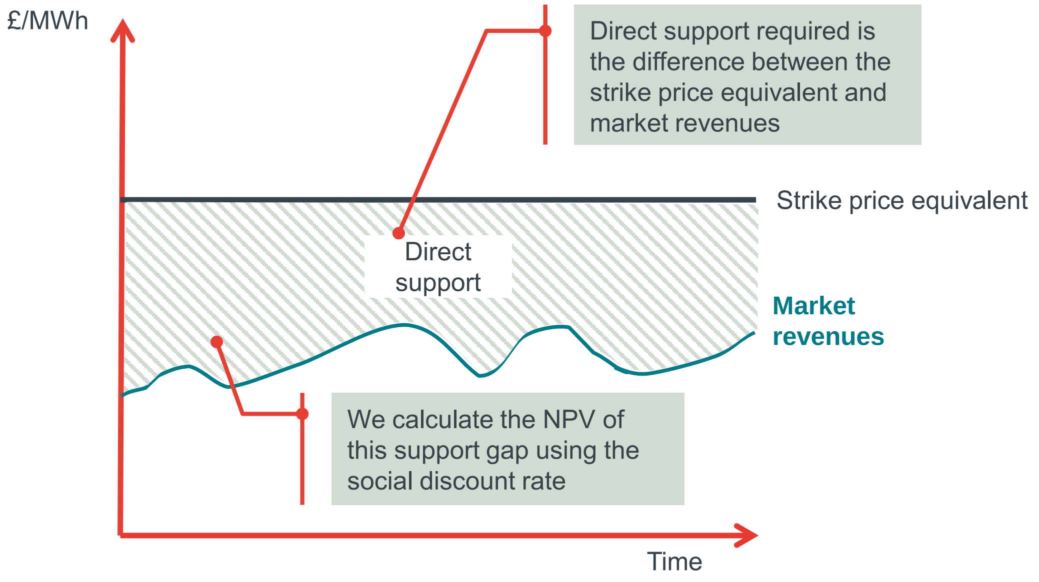
This allows us to compare the relative costs to consumers of supporting alternative technologies.

To calculate the net cost to the consumer (or taxpayer):

- We look at the difference between the strike price (under current arrangements and other the level playing field) and market revenues. Estimates of market revenues also come from the EnVision electricity system modelling. These represent the revenue the investor would receive from the wholesale and capacity markets.

- To calculate the net present value of the direct support paid by consumers for each technology under each market arrangements, we then discount the resulting stream of values back at the social discount rate.
- To present this in £/MWh terms, we divide the present value of support payments by present value of lifetime generation, also calculated using the social discount rate.

Figure 6 Calculating the cost of direct support to consumers



Source: Frontier Economics

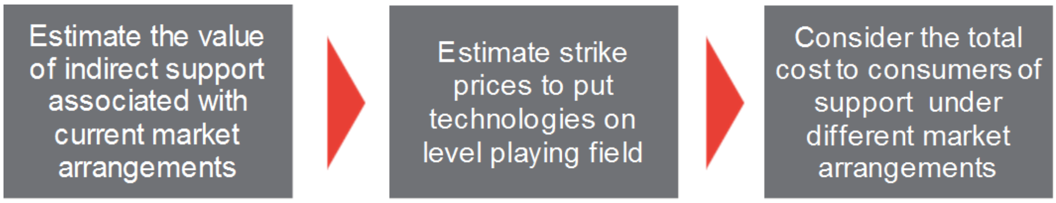
3 RESULTS

This section presents the results of our analysis. The estimates presented in this section are highly sensitive to the detailed assumptions made in the modelling, and should be treated with care. However, they allow us to illustrate how the differences can in practice be quantified.

In particular, these results are based on a range of assumptions (for example, on the costs of technologies deploying in 2025, on the results of EnVision wholesale market modelling and on the impacts of the various contractual and policy differences). Further, for each technology, we have selected only a single point on the supply curve (in practice there will be a range of costs for each technology). These assumptions are set out in more detail in Annex B.

We step through our analysis in three stages, in line with each element of the approach we covered in Section 2 (Figure 7).

Figure 7 Overview of approach



Source: Frontier Economics

3.1 Value of indirect support under current arrangements

The first stage is to estimate the value of indirect support to investors under current arrangements. This is calculated as the difference in direct support required to investors under current arrangements and under a level playing field. As described in Section 2, this indirect support includes favourable contract terms along with unpriced externalities.

Figure 8 and Figure 9 present our estimation of the value of indirect support by technology and illustrates the following.

- Under current market arrangements, onshore wind gets the highest level of indirect support overall of the low-carbon technologies. This is driven largely by the comparatively high associated estimated incremental network costs (onshore wind is assumed to be located in Scotland).[28]
- Nuclear gets the next highest level of indirect support overall of the low-carbon technologies. This is driven by two main factors: a significant portion of assumed indirect support from bespoke CfD terms and the standard wholesale revenue stabilisation benefits associated with CfDs.

[28] This is a particularly example of how the results presented are highly depended on the baseline system scenario (i.e. the counterfactual) we have chosen, as well as assumptions around the technology location and year of construction.

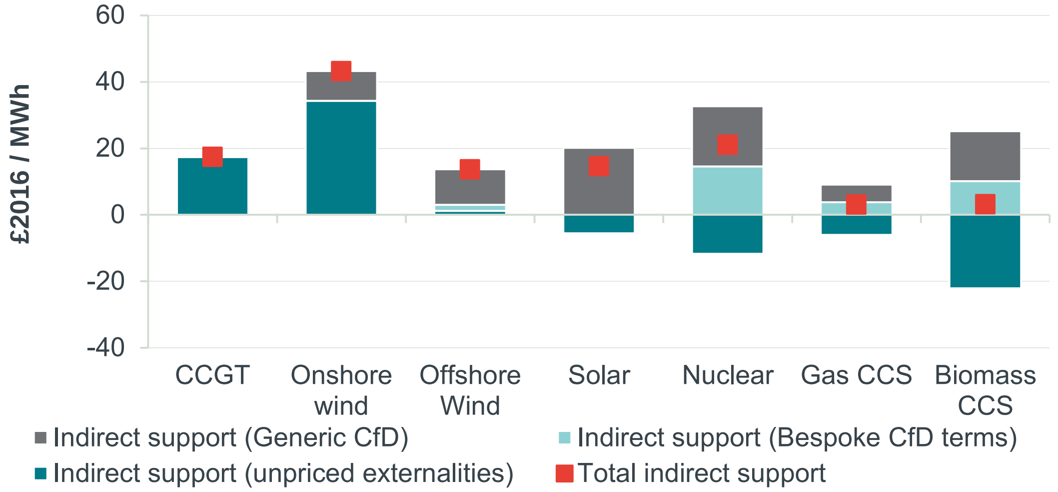
- Solar and offshore wind have the next highest levels of indirect support. This reflects the assumed impact of the CfD on reducing wholesale price risk.
- CCGT receives some indirect support due to the carbon price not being fully priced in.
- Indirect support for CCS technologies is close to zero (and slightly negative for gas CCS). As is the case for all low-carbon technologies, fully pricing in the carbon externality would reduce the support required, in excess of the market price (for biomass CCS, it results in an increase in the value of the negative emissions generated). However, unlike other low carbon technologies, CCS is assumed to not benefit as much from wholesale revenue risk mitigation under the CfD, given that wholesale market revenues net of fuel costs (which are also stabilised by the CfD) are relatively low, compared to overall revenues required.
- Storage is assumed to receive relatively little indirect support from current arrangements. Interconnectors also receive a small amount of indirect support from the cap and floor regime.
- OCGT receives a high estimated level of implicit support due to the carbon price not being fully priced in. However, the precise figure presented should be viewed with caution given the low load factors estimated for OCGT (1-2%) and the relatively simplistic way in which the impact of internalising the carbon price has been calculated.[29]

Overall, the results above show how differences in indirect support received can lead to strike prices not providing an accurate reflection of the full costs of supporting different technologies. The result for onshore wind illustrates the need to consider location when considering costs.

The results for CCS technologies demonstrate the importance of taking a holistic view of the different sources of indirect support being received. Addressing one source while not taking into account others could exacerbate potential distortions instead of reducing them.

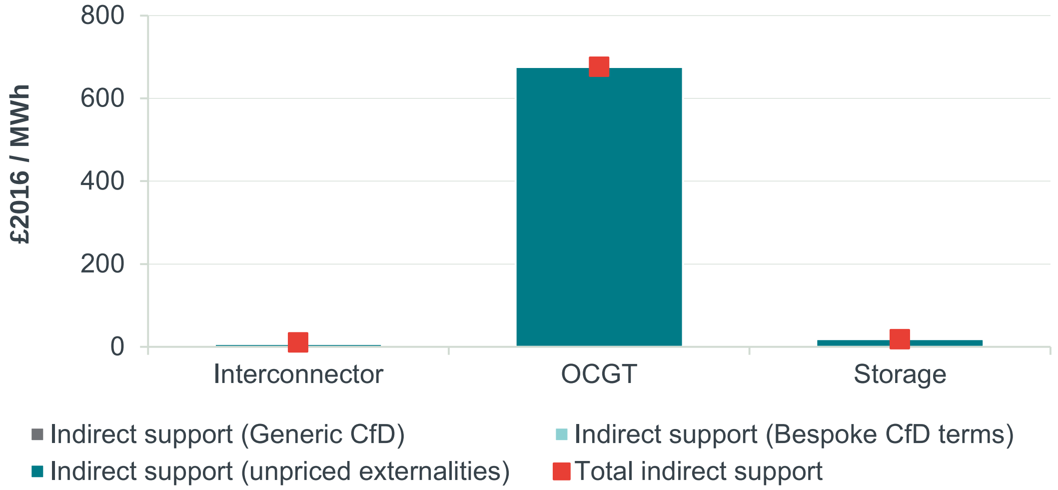
[29] See Annex B for details.

Figure 8 Indirect support by technology under current arrangements



Source: Frontier Economics. 'Key metrics' worksheet of Excel tool.

Figure 9 Indirect support by technology under current arrangements (interconnector, OCGT and storage)



Source: Frontier Economics. 'Key metrics' worksheet of Excel tool.

Note: Storage strike price assumes support is paid on MWh generated while discharging. Interconnector strike price assumes support is paid on MWh imported.

3.2 Level playing field strike price equivalents

We next present the strike price equivalents under current market arrangements and the level playing field strike price equivalent (Figure 10), for investments made in 2025. In general, for most low carbon technologies, the largest impact of a level playing field comes from the loss of the CfD, which increases the level of risk faced, thereby increasing both the strike price and the net cost to consumers.

As described in Section 2, strike price equivalents are calculated as the sum of market revenues and direct support. They represent the revenue that investors would require and the costs consumers may face for the generation from each technology type in 2025.

- Strike price equivalents under current arrangements take account of the indirect support provided through by the presence of unpriced externalities and risk transfers (as estimated in Figure 8 and Figure 9 above).
- The level playing field strike price equivalent estimates the revenue technologies would require in the absence of this indirect support.

What can also be seen from Figure 10 is that putting technologies on a level playing field has the potential to affect technology rankings, based on strike price (equivalent). For example, based on our assumptions, gas CCS would become cheaper on a strike price equivalent basis than onshore wind and solar. Key drivers for the results are as follows:

- For CCGT, , moving from current market arrangements to the level playing field requires an increase in the strike price equivalent. This partly reflects an increase in the market reference price (due to the increase in carbon prices) and an increase in carbon costs, requiring larger top-up payments.
- Onshore wind, offshore wind[30], solar and nuclear all require an increase in strike price. This is because of the significant level of indirect support provided to these technologies under current arrangements. As expected based on Figure 8, the gap is highest for onshore wind and nuclear.
- As explained in section 3.1 above, the finding that onshore wind is more expensive than offshore wind on a strike price equivalent basis is in part driven by their assumed respective locations, and that network costs are higher in Scotland (where onshore wind is assumed to be located) than in the east of England (where offshore wind is assumed to be located).
- The strike prices for Gas CCS and Biomass CCS are not changed significantly under the level playing field market arrangements. While, as described above in section 3.1, indirect support for CCS is net negative, this is in effect cancelled out by the increase in the reference price (due to the increase in carbon price).
- Strike prices for storage and interconnection increase in part due to an increase in the market reference price and in part due to an increase in the amount of support required. [31]
- OCGT requires a large increase in the strike price, due to the effect of pricing in the carbon externality fully. However, as noted above, the summary metric should be interpreted with caution, given the low load factors.

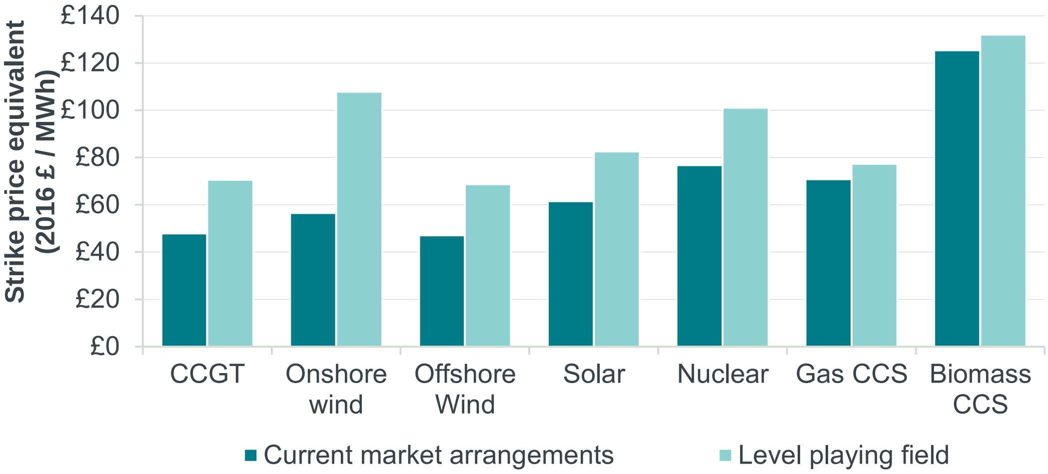
While our analysis focuses on a single point on the technology supply curve, this is also relevant when it comes to considering the full range of cost estimates for

[30] The finding that onshore wind is more expensive than offshore wind is in part driven by their assumed respective locations, and that network costs are higher in Scotland (where onshore wind is assumed to be located) than in the east of England (where offshore wind is assumed to be located).

[31] The low strike price equivalents for storage and interconnection simply reflect the high profitability that results from the assumed technology costs and market modelling. High profits are made possible by the fact that deployment of storage is constrained by build limits in the year of delivery, so the modelled CM auction clearing price is set by more expensive gas-fired generation. For interconnectors, build rates are also , in effect, limited since interconnector deployment is an exogenous assumption.

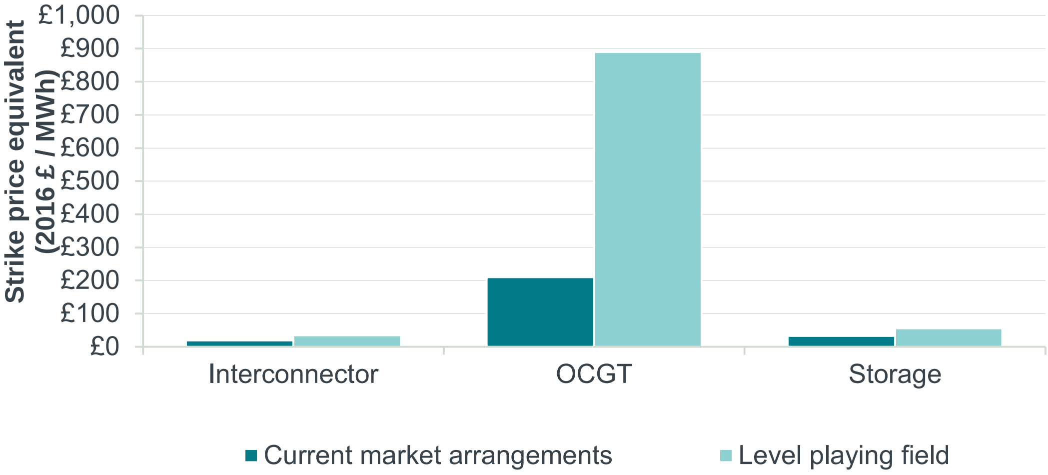
each technology. Putting technologies on a level playing field could increase or reduce the degree to which strike price equivalent ranges for different technologies overlap.

Figure 10 CfD strike price equivalent



Source: Frontier Economics. 'Key metrics' worksheet of Excel tool.

Figure 11 CfD strike price equivalent (interconnector, OCGT and storage)



Source: Frontier Economics. 'Key metrics' worksheet of Excel tool.

Note: Storage strike price assumes support is paid on MWh generated while discharging. Interconnector strike price assumes support is paid on MWh imported.

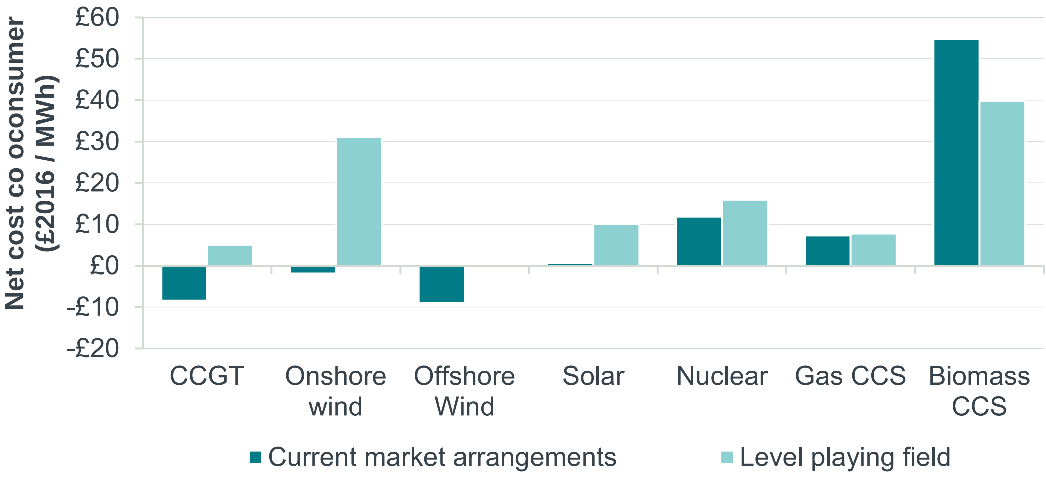
3.3 Support cost

Calculating the required strike price allows us to estimate how the support cost varies by technology under different arrangements. As described in Section 2.3, this support cost represents the net present value of the stream of direct support consumers pay over the lifetime of the technologies. It does not represent the societal cost of these technologies (Box 2).

Required support is driven by two elements: investor costs associated with the technology and revenues that the technology can gain in the market.

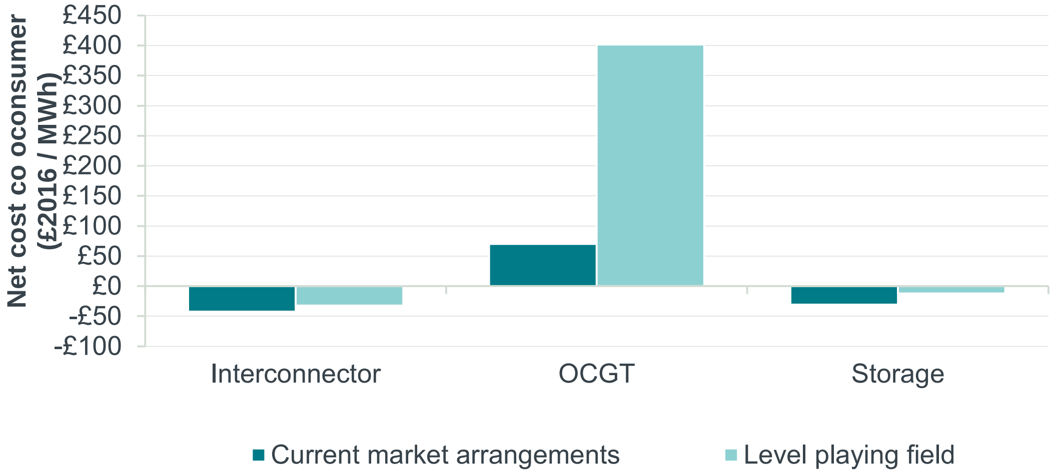
- For CCGT, storage, interconnector and offshore wind, the support cost is negative. In other words, on the basis of current technology cost assumptions and modelling of wholesale market revenues, these technologies could pay back to consumers, on average, and still break even.
- For CCGT, the support cost increases as the carbon externality is priced in.
- For all low carbon technologies, fully pricing in the carbon externality leads to a reduction in the support cost. However, the overall effect on the support cost of moving low carbon technologies to a level playing field varies by technology.
  - For solar, onshore wind and offshore wind, consistent with the estimated increase in strike prices described in Section 3.2 above, support costs increase.
  - For nuclear, support costs also increase. This is driven by the higher strike price required (though is partly mitigated by the shorter assumed contract duration, which tends to lower the support cost, since the social discount rate is lower than the private discount rate).
  - The combination of a lower strike price (see section 3.1 above), higher wholesale prices (due to fully internalising the carbon externality) and a shorter assumed contract duration contributes to lower estimated support costs for CCS technologies.

Figure 12 Support cost



Source: Frontier Economics

Figure 13 Support cost (interconnector, OCGT and storage)



Source: Frontier Economics

Note: Storage strike price assumes support is paid on MWh generated while discharging. Interconnector strike price assumes support is paid on MWh imported.

BOX 2: RELATIONSHIP OF CUSTOMER SUPPORT ESTIMATES TO THE COST TO SOCIETY

The support payment metrics we consider in this report do not relate directly to the resource cost to society of the various technologies. This is because our focus in this report is on understanding how much consumers/taxpayers would need to pay to investors to deliver investment in each technology, under different market arrangements[32]. Given this focus, we discount investor costs and revenues using private hurdle rates, instead of the social discount rate[33]. This means that the results will differ from the results of a purely societal analysis, both in absolute terms and in terms of the relativities between technologies (given differences in profile of costs and revenues across technologies).

3.4 Insights for policy

At present there are differences in the indirect support given to technologies, because of unpriced externalities and contractual terms that transfer risk away from investors and to consumers.

Some of the differences in the treatment of technologies may increase the efficiency of the risk allocation and could therefore reduce overall costs to consumers.

However, these differences complicate comparisons of VfM of public support across different support mechanisms. Where technologies compete for support through the same mechanism, these differences could even result in inefficient

[32] This is therefore looking at a distributional analysis.

[33] Though we use social discount rates to calculate the present value of consumer payments.

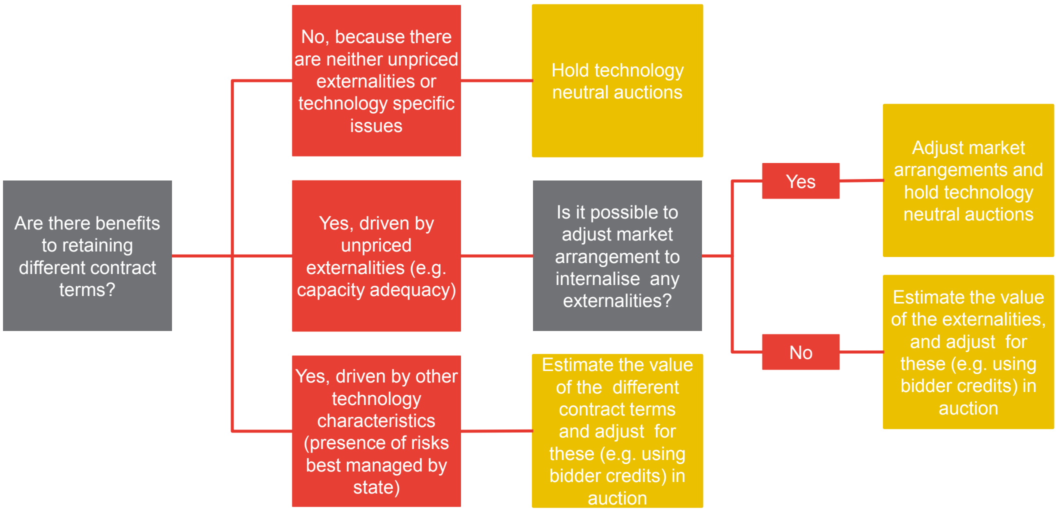
auction outcomes, because certain technologies receive advantages that do not reflect their value to society.

Hence, there is clearly a trade-off between the efficiency gains associated with differential contractual and policy arrangements and those associated with harmonising the terms of support and allowing technologies to compete in auctions on a level playing field, which could also harness further benefits from inter-technology competition.

Figure 14 sets out a decision tree that could help inform policy decisions in this area.

- If there are no (or limited) benefits to different contract terms, a move to technology neutral auctions (either for low carbon technologies or for all technologies) would be likely to increase overall efficiency. However, we note that wider aims, for example around wishing to promote innovation in, or market entry of, a certain technology (e.g. to manage diversity of supply), may still necessitate some differentiation between technologies.
- If there are benefits to different contract terms, it may make sense to adjust for these in an auction, for example through adjusting bidder credits.
  - These could relate to unpriced externalities. For example, to correct for a lower than socially optimal carbon price, an uplift could be applied to bids from those technologies expected to emit more carbon dioxide.
  - These could also relate to technology specific contractual issues, for example the longer asset life of nuclear may mean that longer contract terms make sense. Again, an uplift could be added to the strike price to correct for the potential advantage the longer contract could give in the auction.

Figure 14 Decision tree for policy makers

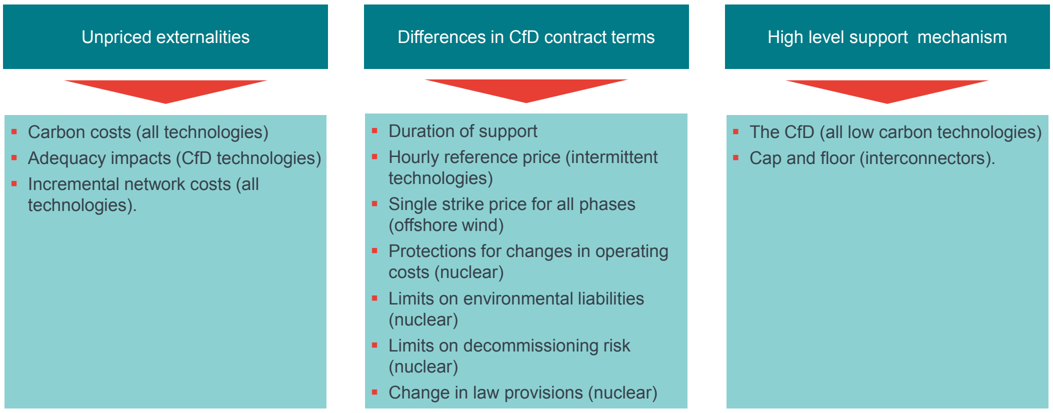


Source: Frontier Economics

ANNEX A KEY DIFFERENCES IN CONTRACTUAL, POLICY OR REGULATORY ARRANGEMENTS

Figure 15 describes the key variations in indirect support that we focus on in our research.

Figure 15 Key variations in indirect support across technologies



Source: Frontier Economics

In this Annex, we provide a description of the differences affecting the direct and indirect support received by investors in electricity technologies and set out our rationale for focussing on the key variations set out above.

- We first set out an overview of the GB electricity market to provide the context for each of the main policies;
- We then identify the key unpriced externalities[34] in the market.
- We itemise the main risks faced by investors in this market and. describe the CM, which represents the 'level playing field' that forms the baseline for our comparative analysis of the risks faced by different technologies under their current support schemes.
- We identify the key differences in support arising from the choice of high-level support mechanism, by comparing the CM with:
  - the cap and floor mechanism for interconnectors; and
  - the 'generic' CfD scheme for low-carbon technologies.
- Finally, we identify the key differences in support received by different low-carbon technologies, arising from different CfD terms.

[34] In this context, an 'externality' refers to a cost or benefit to society that is not taken into account in the private investor decision.

A.1 Overview of the current market arrangements

Investment decisions under current market arrangements are based on one or more of the following expected revenue streams, each of which is associated with a set of risks:

- expected revenues from the sale of power in the wholesale market (Box 3);
- expected revenue from the provision of balancing (or 'ancillary') services to the Transmission System Operator (TSO); and
- expected revenue from the policies in place (such as the CM and CfDs).

Our focus in this section is on the third of these elements – in particular, on valuing the direct and indirect support provided by the policies currently in place. All of the technologies we consider in our analysis are, in principle, eligible to receive some form of support in addition to the revenues from the wholesale market and ancillary services. For example:

- CCGT[35] and OCGT[36] plants, storage, Demand-Side Response (DSR) and interconnectors can participate in the CM;
- interconnectors may also benefit from Ofgem's 'cap and floor' regime; and
- low-carbon technologies are, in general, eligible for support through the CfD scheme.

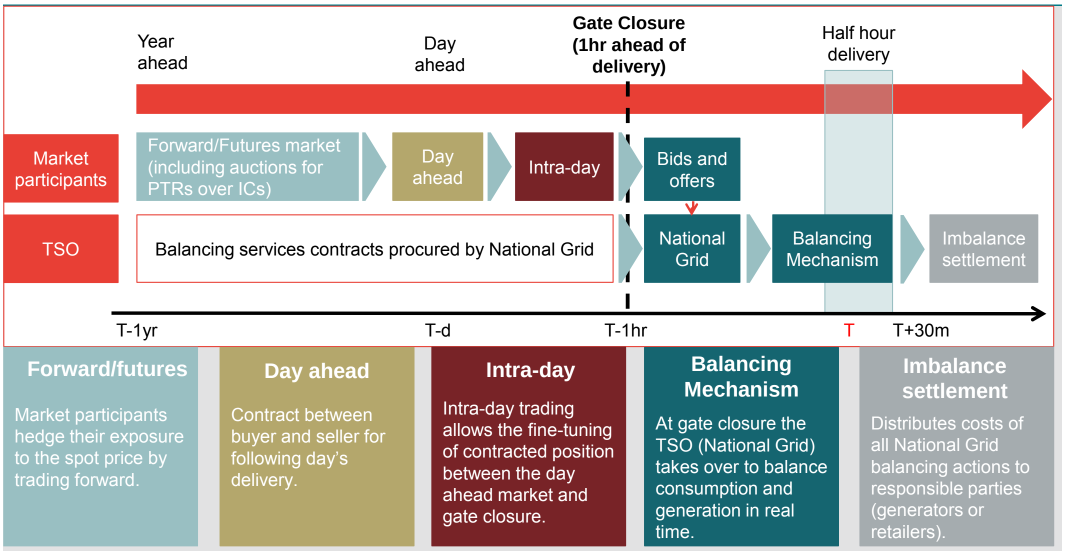
In order to analyse the impacts of these interventions on the risks faced by investors, it is important to first understand the underlying wholesale electricity market arrangements. Box 3 summarises these.

BOX 3: OVERVIEW OF THE GB WHOLESALE ELECTRICITY MARKET

The GB wholesale electricity market is based on bilateral trades between buyers and sellers (usually between generators and suppliers, who sell directly to consumers). Power is traded in different ways (e.g. over-the-counter or on power exchanges) and over different timescales (forward, day-ahead and intraday).

35 Combined Cycle Gas Turbine.

36 Open Cycle Gas Turbine.



Market participants' incentives to trade are driven by imbalance charges (the 'cash-out' price). Parties whose contractual positions do not match their physical position (i.e. metered output) are said to be out of balance. Parties out of balance incur charges (in the event of a negative imbalance) or earn a payment (in the event of a positive imbalance) that reflects the costs incurred by National Grid in addressing the system-wide imbalance.

Many generators (generally smaller market participants) rely on long-term contracts, known as Power Purchase Agreements (PPAs), agreed with a counterparty known as an 'offtaker'. PPAs allow independents to pass on some risks associated with ensuring the power is sold to the offtaker and can be essential to securing investment. Power is sold to the offtaker at a discount to the wholesale price to reflect the risk transfer.

A.2 Unpriced externalities

In the context of this report, an 'externality' refers to a cost or benefit to society that is not taken into account in the private investor decision. We have developed a framework for comparing the net electricity Whole System Costs (WSC) costs to society of different generation investments[37]. These costs are internalised to different degrees for investors, depending on the assumed market arrangements.

Figure 16 describes how WSC are internalised under the level playing field arrangements[38]. The main unpriced externalities relate to:

- carbon costs (part of the displaced generation impacts) not being fully internalised[39];
- adequacy impacts not being internalised for CfD technologies; and
- incremental network costs not being internalised for interconnectors (and possibly not fully for other technologies).

[37] See Appendix 1

[38] See Section 2.1.1 above for a definition of the level playing field.

[39] We provide further explanation of the issue related to carbon costs in Section A.2.1.

Figure 16 Analysis of unpriced externalities

Area of impact	Is there a (significant) unpriced externality?	Comment
Technology direct costs	No.	By definition, these are borne by investors.
Network impacts	Yes, for interconnectors. Unclear, for other technologies.	Under the EU Third Energy Package, interconnectors are treated as part of the transmission network. This prevents certain charges – in particular Transmission Network Use of System (TNUoS) charges – from being levied on them. The lack of TNUoS charges reduces their costs, relative to investments in generation. For other technologies, incremental network impacts may not be correctly priced in, to the extent these differ from the network charges that generators pay themselves. It is unclear whether there should be a systematic difference.
Balancing costs	No.	Imbalance prices have become increasingly cost-reflective, in particular with reforms by Ofgem to make cash-out prices more 'marginal'. Balancing costs can therefore be expected to be already reflected in the assumed PPA discount for a given technology (or the cost of capital, as relevant) or in ancillary service revenues.
Displaced generation impacts	Yes, for all technologies.	The main unpriced externality associated with displaced generation impacts is the carbon price. Broadly speaking, the wholesale electricity price reflects the resource cost of generating electricity (plus a mark-up reflecting scarcity) Technologies that can generate at peak times and displace high-cost generation can earn higher wholesale prices than those technologies unable to generate at peak times. However, based on BEIS assumptions, the wholesale price will not reflect societal costs, since BEIS assumes a wedge between its central appraisal and modelling values for carbon. Based on this, carbon emitting technologies receive implicit support.
Capacity adequacy impacts	Yes, for CfD technologies.	However, there is an unpriced externality associated with the capacity adequacy impacts of low-carbon technologies under the CfD. As discussed above, wholesale prices reflect the value of capacity during periods of scarcity. This is internalised for all technologies. There may however be a residual amount of 'missing money' in the wholesale price mark-up (see Section A.3 below). We assume this 'missing money' recognised in CM revenues, and so will be internalised for those technologies in receipt of CM payments. However CfD holders do not receive CM payments. To the extent that deployment of a given (low-carbon) technology reduces the capacity that needs to be purchased to ensure security of supply, this benefit needs to be taken into account when calculating the 'true' value of support being granted.

Source: Frontier Economics.

A.2.1 Carbon pricing

There are two carbon price series relevant to this work.

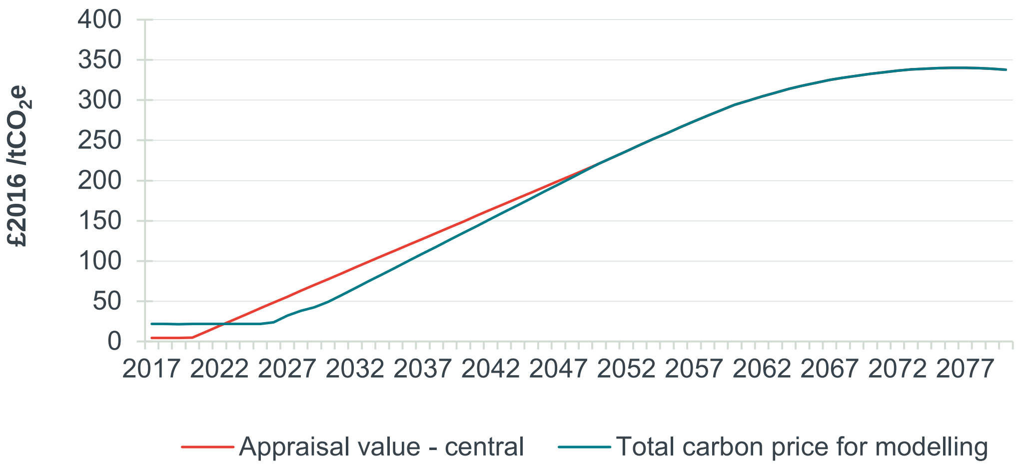
- **Appraisal values.** We use the Government's appraisal values for carbon to estimate the resource cost associated with CO_2 emissions[40]. BEIS central appraisal values rise from £41/tCO_2e (2016 prices) in 2025 to £77/tCO_2e in 2030[41], rising further to £221/tCO_2e in 2050.[42]
- **Market projections**. By contrast, BEIS market participants face a carbon price in line with the sum of the assumed EU Emissions Trading Scheme (ETS) price and the Carbon Price Support (CPS) tax rate.

The future of the CPS post-2025 is in doubt, following the Autumn 2017 Budget.[43] However, even considering policy immediately before the 2017 Budget, there would, based on Government's own assumptions, still be a material wedge between the total price faced by market participants and the Government's appraisal value, at least until 2050.

- The assumed ETS price is £17/tCO_2e (2016 prices) in 2025, rising to £49/tCO_2e in 2030.[44]
- In its most recent levelised cost publication, BEIS appears to have assumed that the market carbon price then increased linearly from 2030 to reach the appraisal value by 2050 (i.e. £221/tCO_2e).

This is illustrated in Figure 17 below.

Figure 17 Comparison of BEIS modelling and appraisal carbon value



Source: Frontier Economics, based on BEIS.

This wedge may represent implicit support to carbon-emitting technologies[45].

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40 See Appendix 1.

41 https://www.gov.uk/government/publications/updated-short-term-traded-carbon-values-used-for-uk-policy-appraisal-2016

42 https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

43 https://www.gov.uk/government/publications/autumn-budget-2017-documents/autumn-budget-2017#policy-decisions

44 https://www.gov.uk/government/publications/updated-short-term-values-used-for-modelling-purposes-2016

We explain further in Annex B how we quantify the difference between costs imposed and those actually paid by different technologies.

A.3 The Capacity Market (CM)

We create a level playing field where investors receive minimal 'indirect support' in the market. In this, we assume that each technology participates in both the wholesale market and the CM (on the same basis as new-build generation or storage). As discussed in section A.2 above, the CM payment can be viewed as internalising the externality associated with capacity adequacy and therefore does not necessarily constitute 'support'.

In the rest of this sub-section, we:

- provide an overview of the CM;
- set out our categorisation of the risks faced by investors (for the assessment of indirect support);
- describe in more detail some of the key features of the CM that affect the risks that participants face;
- summarise the risks faced by CM participants (focussing on investors in new-build CCGT, OCGT and storage); and
- examine how, within the CM, the risks faced by DSR differ to those faced by CCGT, OCGT or storage.

A.3.1 Overview of CM

The CM aims to ensure security of electricity supplies. Broadly speaking, it does so by ensuring sufficient reliable capacity is available to meet peak demand. Beneficiaries receive regular payments (per unit of 'de-rated'[46] capacity). In return, they agree to be available and producing electricity at times of system stress, and to face penalties if they are not available and producing electricity at these times.

The payment is intended principally to correct for two market failures[47]:

- **'Missing Money':** Prices for power in the wholesale market may not rise (or investors may not believe they will rise) to the levels necessary to recover fixed and capital costs, for example because of price caps (or the threat of regulatory intervention).
- **Reliability has characteristics of a 'public good':** Individual consumers cannot (yet) fully signal their willingness to pay for reliable supplies of electricity, since the TSO cannot selectively disconnect customers. This means that consumers all essentially get the same level of reliability (it is 'non-excludable'). As such, a 'free' market would therefore lead to a less than socially optimal level of reliability being provided.

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[45] Given structurally higher prices in GB. interconnectors would probably benefit from a unilateral higher carbon price in GB but not from a lower carbon price

[46] De-rated capacity refers to the amount of capacity determined as being expected (on average) to be available to generate at times of system stress.

[47] DECC (2012), 'Impact Assessment: Electricity Market Reform – Capacity Market', IA No: DECC0103.

Box 4 describes the process for determining the value of CM payments, and allocating these payments among participants. 'New' generators or storage (with the threshold for 'new' being defined in terms of expenditure per kW of de-rated capacity) are offered 15-year agreements.[48] Existing generation and DSR are awarded one-year capacity agreements.

BOX 4: CM: PROCESS

The CM consists of the following stages:[49]

1. Based on advice from National Grid, the CM Delivery Body, Government decides how much capacity to procure.
2. Eligible applicants participate in a pre-qualification process.
3. Pre-qualified applicants participate in a competitive auction for a given delivery year, which determines successful participants (i.e. those that would be willing to accept the lowest CM payment).
4. Between auction and delivery in the delivery year(s), capacity providers may hedge their position in secondary markets. They can do so through physical trading, volume reallocation or by getting insurance to cover penalties.
5. Providers of capacity commit to being available when needed or face penalties (same for all technologies) in the delivery year for stress event warnings provided 4 hours ahead.
6. The costs of capacity agreements are met by energy suppliers and, ultimately, by consumers.

A.3.2 Categorisation of risks

As part of our assessment of the indirect support provided by the CM, cap and floor regime and CfDs, we assess how they affect key risks faced by investors. We summarise our categorisation of these risks in Figure 18 below.[50]

[48] DECC (2014), 'Implementing Electricity Market Reform: Finalised policy positions for implementation of EMR', URN 14D/221, Section 3.2.3.6.

[49] DECC (2014), Section 3.2.

[50] We note that different categorisations and definitions of these risks are possible.

Figure 18 Categorisation of key risks associated with generation investments

Risk	Cause of risk
Construction	Risk that construction costs could be greater than expected. For the purposes of this analysis, we also include 'development risk': the risk that costs incurred prior to construction, during the development process, (e.g. surveys, planning) could be greater than expected.
Construction delay	Risk that construction could be delayed, leading to reduced returns (for example through loss of, or reduction in, support payments).
Operating cost	Risk of unexpected changes in operating costs (including fuel and carbon costs).
Performance	Risk of output being lower than expected for technical reasons (e.g. breakdowns), leading to reduction in revenues and/or increases in costs (for example, costs associated with imbalance charges).
Environmental	Risk of unexpected costs associated with environmental damage (e.g. nuclear accident, CO2 leakage).
Decommissioning	Risk of unexpected costs associated with restoring the site following the end of plant life.
Revenue	Risk that revenues could be lower than expected, in particular due to lower prices or lower output.
Offtake	Risk that there will be no route to market for the power generated.
Policy	Risk of unexpected changes in policy leading to reductions in revenues or increases in costs.

Source: Frontier Economics

Figure 18 omits certain risks that may be relevant for power generation investments which we have specifically excluded from our analysis for the following reasons:

- **Allocation risk:** This describes the risk that investors will not secure support payments (the consequence being that development expenditure may be at risk). The focus of WP2 is on considering the value that investors derive from different contractual arrangements (i.e. taking the award of a support agreement as given). Hence, while there may be differences in allocation risk between technologies or between support mechanisms, these are not the focus of our analysis.
- **Foreign exchange risk:** This describes the risk of adverse currency exchange rate movements, leading to either increases in costs or reductions in revenues, once expressed in terms of the investors' currency. All of the schemes we consider pay out in £,[51] and none of them include any explicit protection against foreign exchange risk, so this does not affect the comparison between schemes.

[51] For interconnectors, we consider only the 50% of the project supported by the GB regime.

A.3.3 Key features of the CM

The CM payment represents the direct support received by beneficiaries. This payment reduces revenue risk for beneficiaries. The CM also includes features that are relevant to construction delay risk, performance risk and policy risk, including[52]:

- incentives for commissioning capacity on time;
- incentives to keep capacity available;
- secondary trading; and
- legislative protections.

Figure 19 below summarises our review of the risks faced by new-build generation and storage participants in the CM, drawing on the summary of the key CM features that we now discuss in detail.

[52] The CM contains no mechanisms that would affect the ordinary risks faced by developers in relation to construction costs, operating costs, environmental costs, decommissioning costs or finding an offtaker

Figure 19 Risks faced by new-build generation and storage CM participants

Risk	Degree to which investors face risk	Treatment
Construction	Fully	The CM provides no protection against the risk associated with construction or development costs.
Construction delay	Mostly	Investors face the risk of a reduction in support or loss in support (plus termination fee) if either insufficient progress towards construction is demonstrated (financial commitment milestone), construction is delayed or capacity is under-delivered. Secondary trading can be used to mitigate this risk.
Operating cost	Fully	The CM provides no protection against the risk associated with operating costs.
Performance	Mostly	The CM introduces penalties (in addition to the possibility of facing imbalance charges) for providers that are unable to meet their capacity obligations by ensuring sufficient generation during stress periods. However, CM penalties are capped and secondary trading can be used to further reduce exposure.
Environmental	Fully	The CM provides no protection against the risk associated with environmental costs.
Decommissioning	Fully	The CM provides no protection against the risk associated with decommissioning costs.
Revenue	Partly	Investors bear wholesale price risk, but in addition benefit from a stable payment (£per kW of de-rated capacity) over the term of the capacity agreement (15 years).
Offtake	Partly	While the CM payment itself is stable, the CM provides no protection against offtake risk in relation to wholesale market revenues associated with their technology investment.
Policy	Partly	Key elements of the CM payment are protected by legislation. However, investors bear the risk (likely to be low) that changes in capacity market or wider electricity market legislation could affect returns.

Source: Frontier Economics

Incentives for commissioning capacity on time (construction delay risk)

New-build plants face penalties for not making sufficient progress on their construction and for not being ready for the delivery year.[53] The penalties were tightened by Government in 2016. [54] The current suite of disincentives includes:

- termination of the agreement in the event that new plants are unable to demonstrate significant financial commitment by the relevant milestone (18 months following award of the capacity agreement), plus a termination fee of £15,000/MW (de-rated);

[53] DECC (2014), Section 3.2.3.

[54] DECC (2016), 'Capacity Market: Government Response to the March 2016 consultation on further reforms to the Capacity Market', URN 16D/027.

- suspension of capacity payments until they become operational, effectively resulting in a shortening of the term of capacity agreements if capacity is delayed;
- termination of the agreement in the event that less than 50% of the amount specified in its capacity agreement ('minimum completion requirement') is operational by 18 months following the start of the plant's first delivery period, plus a termination fee of £35,000/MW (de-rated);
- a pre-auction requirement to lodge credit cover of £10,000/MW (de-rated), intended to deter speculative bids and secure exposure against termination fees; and
- a bar on failed units from participating in two years of future capacity auctions.

Secondary trading (see below) can be used to reduce the risk of exposure to these penalties.

Availability incentives (performance risk)

All providers are also given incentives to ensure that capacity is made available at times of system stress.[55]

System stress events are any settlement periods in which either voltage control or controlled load shedding are experienced (for reasons other than network failures) at any point on the system for 15 minutes or longer. The EMR Delivery Body issues a warning, based on fixed criteria, ahead of an impending stress event. In stress periods, providers' obligations only come into force four hours after the triggering of a CM warning.

The obligations are 'load following': in a stress event where only X% (less than 100%) of the total capacity with capacity agreements is required to meet demand, each provider is only required to be generating electricity or reducing demand up to X% of their full capacity obligation. In addition, there are limited delivery exceptions provided for force majeure events outside of a provider's control.

Providers that do not deliver sufficient energy at times of system stress to meet their scaled obligation are required to pay a penalty.

- The penalty rate (£/MWh) for each obligation is 1/24th of the relevant auction's clearing price, adjusted for inflation.
- Penalties are capped at 200% of a provider's monthly capacity revenues. This means that, given the weighting of monthly payments according to system demand, providers may be exposed to a penalty liability of up to 20% of their annual revenue in any one month.
- Penalties are subject to an overarching annual cap of 100% of annual revenues, and are applied and capped at CMU level, not portfolio level.

Secondary trading (see below) can be used to reduce the risk of exposure to these penalties.

[55] DECC (2014), Section 3.2.5.

Providers that deliver more than their capacity obligations at times of system stress, preceded by a Capacity Market warning, are paid for their over-delivery. The rate of over-delivery payment is calculated by dividing the total penalty payments received by the Settlement Body in a stress event by the total amount of over-delivered energy in the same stress event. This rate is capped at the prevailing CM penalty rate.

Secondary trading (construction delay and performance risk)

Providers can trade their capacity obligations in secondary markets to manage risk. They may wish to do so for a number of reasons, for example:

- to manage the risk of a stress event coinciding with planned maintenance;
- because it is no longer economic to meet capacity obligations;
- due to delays in build time; or
- to manage risk within the portfolio of capacity market units (CMUs).

Providers can trade:

- physically, with pre-qualified parties that did not opt out of the auction, and that have no existing obligations, i.e.
    - were unsuccessful in the auction;
    - are new plant commissioning early; or,
    - are other new capacity such as new DSR.
- through 'volume re-allocation', i.e. allocation of excess output to another CMU; or
- financially, through private markets.

Reduction in revenue risk

The capacity payment provides a source of stable cash flow over the duration of the contract. This is likely to contribute to an overall reduction in revenue risk, reducing the direct support required.

We have previously found this effect to be material. Based on analysis carried out in 2014[56], we found the CM payment to have a broadly similar risk profile to arrangements such as PFI contracts, contracts for offshore transmission owners (OFTOs) and RAB-based utilities. We find that the risk premium for the most relevant comparators (in addition to the risk-free rate) to lie generally in the order of magnitude of 2% (post-tax, nominal). By contrast, we estimated the risk premium for energy market revenue to be in the range of 3-4% (post-tax, nominal). Hence projects receiving 100% of revenues from the CM payment could have a cost of capital around 1-2 percentage points lower than projects earning only energy market revenues.

Legislative protections (policy risk)

Certain features of the capacity agreement and CM regulations are described by Government as 'not subject to amendment' and 'protected through the regulations'. These include: the capacity agreement, the capacity cleared price, the based period for indexation, the relevant milestone date, the annual penalty

[56] Confidential client

cap and monthly penalty cap, the rates for termination fees and the capacity obligation for which the capacity agreement is issued.[57] That said, investors do bear the (admittedly low) risk that the CM legislation itself could be changed or that wider market legislation could change in a way that could adversely affect returns.

A.3.4 CM: Key differences in risks faced by DSR

DSR is treated differently to new-build generation or storage capacity within the CM in two main respects[58].

First, DSR providers can only be awarded one-year capacity agreements[59] (as opposed to 15 year for new build). The impact of this is ambiguous, and may differ depending on the type of DSR provider:

- On the one hand, it could reduce risk. For example, with a 15-year CM agreement, a DSR provider meeting its CM obligations by contracting with, say, an industrial consumer, faces the risk that the industrial consumer could go out of business before the end of the CM agreement.
- On the other hand, it could instead be argued that, compared to new build generation or storage, DSR providers cannot achieve comparable revenue stability, increasing the cost of capital and support required, other things equal. However, any loss DSR suffers from having a shorter agreement may be less substantial than it would be for new-build generation, given that some types of DSR may require lower capital expenditure, and could be less likely to rely on external financing for investment. This indeed, is the Government's stated rationale for offering 15 year agreements only to new capacity.[60]

Second, while other providers need to lodge credit cover of £10,000/MW (de-rated requirements for DSR are lower than for other providers:

- 'Proven' DSR (i.e. DSR that can submit evidence of previous performance) does not need to lodge any credit cover; [61]
- 'Unproven' DSR only needs to lodge pre-auction credit cover of £5,000/MW (de-rated). [62]

To the extent that reduced credit cover requirements lead to an increase in unsecured termination fee liabilities relative to other CM participants, they imply a transfer of risk from DSR providers to consumers. However, imposing the burden of credit cover was, presumably, viewed as unnecessary in the case of 'proven' DSR, given that the risk of non-delivery is (by definition) likely to be small. The rationale for reduced credit cover for unproven DSR is not clear to us, but the

57 DECC (2014), Section 3.6.2.5.

58 There are some differences in the way existing and refurbished capacity is treated under the CM, compared to new capacity. However, since the focus of our analysis is on comparing differences in the cost of supporting new-build technologies in 2025, we do not consider these differences further in our analysis.

59 DECC (2014), Section 3.2.3.6.

60 EC (2014) 'State aid SA.35980 (2014/N-2) – United Kingdom: Electricity market reform – Capacity market' , C (2014) 5083 final, paragraphs 59, 106 and 107.

61 DECC (2014), Section 3.3.1.2.

62 DECC (2016).

treatment would be consistent with an implicit policy objective to stimulate the growth of DSR.

In Figure 20 we summarise how risks faced by DSR participants in the CM differ, compared to new-build generation and storage.

Figure 20 Risks faced by DSR, compared to new-build generation and storage in the CM

Risk	Change in indirect support, compared to baseline	Significance	Explanation / Rationale
Construction delay	↑	Low	Lower credit cover requirement for DSR. For 'proven' DSR, likely because of lower risk of non-delivery. For 'unproven' DSR, potentially an implicit policy objective to support the growth of DSR.
Revenue	↕	Low	DSR receives only a 1-year agreement, (as opposed to 15-year agreement). Unclear whether this increases or reduces risk. Rationale may be because the benefit of a longer agreement is limited for DSR, given (in general) lower capital expenditure requirements.

Source: Frontier Economics

Note that, given the diversity of DSR providers, DSR is not included in the quantitative analysis in Annex B.

A.4 Cap and floor regime for interconnectors

Interconnectors can gain from participation in the CM, but can also apply to be subject to Ofgem's 'cap and floor' regime.[63]

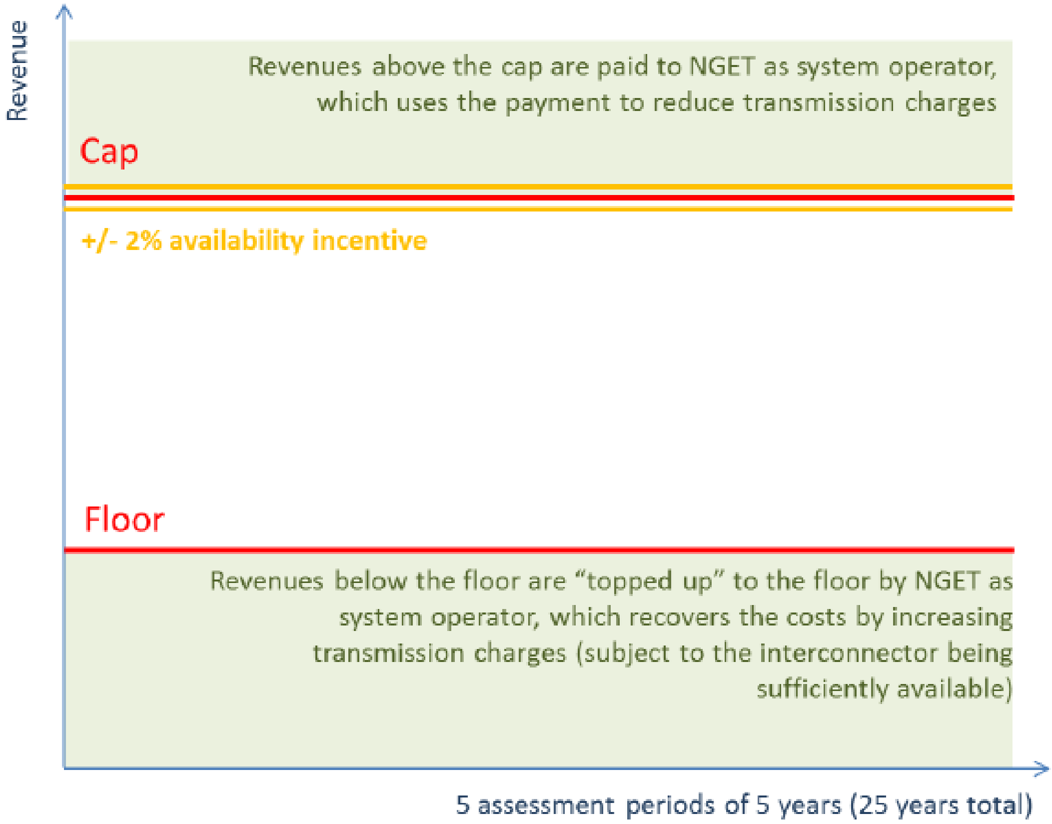
The cap and floor regime sets a maximum (cap) and minimum (floor) level to the revenues accrued by interconnector developers. Within this band, they are free to earn revenues from (and face the risk of changes in):

- congestion revenues (i.e. the difference in price spreads between bidding zones);
- CM participation (subject to their de-rating factor); and
- providing ancillary services.

The regime is illustrated in Figure 21 below.

[63] Ofgem (2016), 'Cap and floor regime summary for the second window', letter dated 11 May 2016.

Figure 21 Cap and floor regime illustration



Source: Ofgem (2016)

Note: 'NGET' stands for 'National Grid Electricity Transmission', the GB TSO.

In the rest of this sub-section:

- we discuss other issues that may affect the direct support that interconnector developers receive; and
- we describe in more detail some of the key features of the cap and floor regime that affect the risks that interconnector developers face, and therefore the indirect support they receive, compared to new-build generation and storage in the CM.

A.4.1 Interconnectors: direct support

The direct support received by interconnectors is the value of 'top up' payments received from NGET, in the event that revenues fall below the 'floor' level. These payments are uncertain, and depend on the level of revenues interconnectors can expect to earn from congestion revenues, CM participation and ancillary services.

A.4.2 Interconnectors: indirect support

The cap and floor regime include a number of provisions that affect construction risk, construction delay risk, operating cost risk, performance risk and decommissioning risk, including:

- the approach to ensuring revenue stability

- reviews of capital expenditure requirements;
- incentives for timely delivery of interconnector capacity;
- reviews of operating cost allowances;
- availability incentives; and
- reviews of decommissioning cost allowances.

We describe each of these below in more detail. Figure 22 summarises how risks faced by interconnectors differ, compared to new-build generation and storage in the CM. In addition, as discussed in Section A.2 above, interconnectors do not face TNUoS charges which, compared to generation, reduces their expected costs.

Figure 22 Risks faced by interconnectors, compared to new-build generation and storage in the CM

Risk	Change in indirect support, compared to baseline	Significance	Explanation / Rationale
Construction	↑	High	Re-openers (for pre-defined construction cost elements) just prior to beginning of operations. Compensation for actual development expenditure, subject to this being judged efficient. This reduces the risk to investors for cost areas that may be difficult to control, while still preserving some efficiency incentives.
Construction delay	↓	Low	Delay in coming into effect of floor if construction is delayed, which represents an additional layer of risk, compared to the CM. This incentivises timely commissioning. Effect on cost of capital unlikely to be significant, however, given floor only mitigates against worst-case outcomes and is merely delayed
Operating cost	↑	Low	Re-openers for certain cost elements. Lack of exposure to changes in TNUoS charges. Re-openers reduce risk to investors for cost areas that may be difficult to control, while preserving efficiency incentives. Effect unlikely to be significant given relatively low opex for interconnectors.
Performance	↓	High	Reduction in cap if availability is reduced. Temporary loss of floor if availability below 80%. Incentivises high availability. Effect on risk could be substantial due to increased difficulty of repairing interconnectors in the event of an outage.
Decommissioning	↑	Low	Re-openers for additional costs caused by new legislation. Reduces risk to investors for cost areas that may be difficult to control, while preserving efficiency incentives

Risk	Change in indirect support, compared to baseline	Significance	Explanation / Rationale
Revenue	↑	High	DSR receives only a 1-year agreement, (as opposed to 15-year agreement). Unclear whether this increases or reduces risk. Rationale may be because the benefit of a longer agreement is limited for DSR, given (in general) lower capital expenditure requirements.

Source: Frontier Economics

Revenue stability

The cap on revenues is intended to prevent excessive returns, while the floor on revenues is intended to reduce revenue uncertainty, thereby reducing risk (in particular by limiting the downside risk). While there is a wide band of 'merchant' exposure between the cap and the floor, the reduction in the cost of capital from the cap and floor regime is still likely to be significant.

Support is granted for 25 years, a further factor that would lead to a lower cost of capital, compared to the CM.

Capital expenditure review (construction risk)

During the post-construction review (PCR), which takes place shortly before operation, the final cap and floor levels for the project are set. The cap and floor levels may be updated taking into account certain deviations in the actual value of capital expenditures (from initial expectations). According to Ofgem, only deviations that were highlighted at the initial stage as potential areas to revisit can result in adjustments to cap and floor levels. [64]

This mitigates the risk associated with uncertain capex (by allowing contingencies for specific, pre-defined elements) while preserving incentives for developers to manage other aspects of capex.

The presence of such a re-opener (of the floor level of support in particular) is likely to reduce risk significantly, compared to the CM, which offers no protection against unexpected variations in capex.

All expenditures during the project development phase are compensated for, subject to spending being judged to be efficient.

Incentives for timely delivery (construction delay risk)

Under the default regime, the regime start date is the earlier of: [65]

- the actual 'full commissioning date'; or
- 12 months after the target (i.e. expected) completion date.

[64] Ofgem (2016), Annex 2.

[65] Ofgem (2016), Annex 1.

The cap comes into effect on the regime start date, while the floor comes into effect on the full commissioning date. Hence, delays in commissioning will lead to a reduction in the duration of support through the floor.

This incentivises timely delivery of interconnector capacity and is similar to the incentives in place in the CM. Assuming that the interconnector also participates in the CM, this is likely to introduce an additional layer of risk. However, given the floor (which mitigates against the worst-case outcomes) is merely delayed, we do not judge this to be a significant risk.

Operating cost reviews

There are multiple sources of mitigation of operating cost risk within the cap and floor regime:

- Projected opex is reviewed at the PCR stage and is reflected in the final cap and floor regimes. After ten years of the regime, there is the possibility of one review and re-set of the operating cost allowance.
- Certain opex items are deemed ‘non-controllable’ (e.g. Crown Estate lease fees, property rates and taxes, licence fees and network rates). Changes in these costs lead to a direct revenue adjustment (upwards or downwards), overriding the limits set by the cap and floor.
- Developers may claim (efficiently incurred) costs related to force majeure events.

Compared to the CM, each of these is likely to reduce risk, helping to reduce the support required. The logic appears to be to allow pass-through of costs that are less likely to be in control of the developer, while incentivising developers to keep controllable opex to a minimum (at least over the medium-term). The benefit may be limited, though, considering interconnectors’ low levels of opex.

A further point to note is that, given that interconnectors do not face TNUoS charges (see Section A.2 above), they do not face the risk of changes in these charges either.

Availability incentives (performance risk)

If availability exceeds or falls short of a target level, then the cap level is (respectively) increased or reduced annually by +/- 2%. Interconnectors lose eligibility for floor payments for a year if availability is below 80% in that year.

This provides additional incentives, on top of CM penalties, to ensure high availability. However, the potential for a loss of floor payments in particular reduces the risk mitigation from the floor, increasing the support required. The increase in risk could be substantial: an outage on a subsea cable could, given its relative inaccessibility, take months to repair.

Decommissioning cost reviews

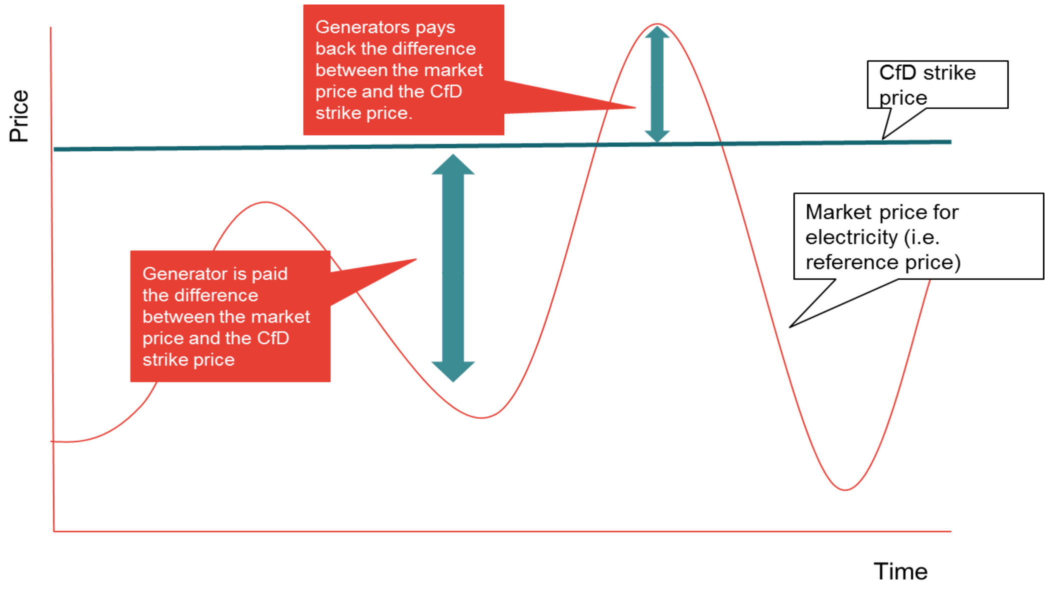
Should the developer become exposed to additional (or reduced) decommissioning costs as a consequence of changes in legislative requirements, the difference in (efficiently-incurred) costs will be passed through as an adjustment (whether upwards or downwards) of the cap and floor levels.

Compared to the CM, this is likely to reduce risk, helping to reduce the support required. The logic appears to be to allow pass-through of costs that are unlikely to be in control of the developer.

A.5 Contracts for Difference (CfDs)

The CfD mechanism is currently the main tool used in the UK to support low-carbon generation. A CfD is a private law contract between a generator and a state-owned counterparty. CfD holders are paid the difference between a fixed ‘strike price’ and a ‘reference price’. The reference price represents an index of market prices. Overall, the CfD mechanism aims to stabilise the price received per MWh of low-carbon electricity generated.[66] Figure 23 below illustrates the CfD mechanism.

Figure 23 Illustration of the CfD mechanism



Source: Frontier Economics

We look at CfDs for three groups of technologies.

- **Renewables.** Most renewable technologies are offered a ‘generic’ CfD. The terms of the generic CfD are broadly similar across technologies, with some differences for offshore wind, which we consider below[67]. Renewable technologies in receipt of a CfD also benefit from the presence of the ‘offtaker of last resort’ (OLR). The OLR offers a ‘backstop PPA’ (at a discount that is intended to be higher than the ‘market’ discount) to renewable projects in receipt of a CfD who might otherwise not be able to find an offtaker willing to offer a PPA at a reasonable price.
- **Nuclear.** The only nuclear plant to have so far signed a CfD, Hinkley Point C (HPC), received a bespoke CfD. HPC also benefitted from other forms of support, including a partial state guarantee of debt.

[66] DECC (2014), Section 2.1.

[67] There are also some differences for private wire generation. This is outside the scope of the current work.

- **CCS.** No CCS projects have yet signed a CfD. We elaborate below on the features of the CfD we assume for new-build CCS, which draw from experience with the CCS competitions.

3.4.1 Generic CfD

Together with the OLR, the generic CfD includes a number of provisions, which affect revenue risk, construction delay risk, performance risk, offtake risk and policy risk, including:

- revenue stability (both the overall mechanism and, for intermittent technologies, the choice of CfD reference price);
- incentives for timely delivery of capacity;
- compared to the CM, reduced incentives to ensure the availability of capacity during system stress periods;
- a backstop PPA under the OLR scheme; and
- change in law provisions.

These are summarised in Figure 24, which sets out risks faced by generic CfD holders differ, compared to new-build generation and storage in the CM.

Figure 24 Risks faced by generic CfD holders, compared to new-build generation and storage in the CM

Risk	Change in indirect support, compared to baseline	Significance	Explanation / Rationale
Construction delay	↑	Low	Compared to CM, face only loss in support (with no financial penalty) in case of non-delivery of minimum capacity requirement. Rationale may be due to lack of specific time-bound decarbonisation targets for the power sector. Overall, effect on cost of capital lower since expected termination fees would be low in relation to overall costs.
Performance	↑	Low	Unlike CM, no specific additional incentives to make capacity available during times of system stress. Likely due to CfD and CM schemes being viewed as meeting separate objectives (although there may still be an element of implicit support in this treatment). Overall, effect on cost of capital is limited since stress events should be rare and penalties are, in any event, capped at 100% of annual revenues.
Revenue	↑	High	The CfD brings the benefit of price stability (though no capacity payment).
Offtake	↑	Low	Benefit from backstop PPA under OLR scheme (potential reduction in PPA discount). Intended to lower risks and costs around securing route to market. Analysis commissioned by DECC found this effect to be minimal.
Policy	↑	Low	Protections against qualifying shut-down and curtailment events. Government better-placed than investors to manage such risks. Though risks likely to be low for renewable technologies.

Source: Frontier Economics

In the rest of this sub-section, we describe in more detail some of the key features of the generic CfD regime and OLR that affect the risks that renewable technologies face, and therefore the indirect support they receive, compared to new build and storage in the CM.

A.5.1 Incentives for timely delivery of capacity (construction delay risk)

Following CfD signature, CfD holders must meet a number of obligations. These are aimed at encouraging timely progress of projects towards commissioning. [68]

- Within a year of signature ('Milestone Delivery Date', or MDD), developers must demonstrate that a 'substantial financial commitment' has been entered into, or face having their CfD terminated.
- Developers have a time window ('Target Commissioning Window', or TCW) within which they can commission without penalty. The TCW is set differently for each technology, taking into account the technical challenges faced. Failure to deliver sufficient capacity within the TCW results in the term of the CfD commencing (effectively resulting in a shortening of the period over which support payments are made, since payments can only start once the conditions precedent have been met).
- Failure to deliver sufficient capacity before the Longstop Date (which lies beyond the end of the TCW) could result in termination of the CfD.
- Developers are able to adjust the contracted capacity at the MDD and at the Longstop Date. Projects above 30MW can make a 25 percent (downward) adjustment to capacity at the MDD, without reduction in the Strike Price.
- Developers must deliver at least 95% of the revised capacity by the Longstop Date for payments to commence.
- Generators may be relieved from liability under the CfD for any breach that has been caused by a Force Majeure event.

Unlike the CM, applicants for support under the CfD need not submit any collateral during the application process. However, if a successful applicant either fails to sign a CfD or fails to demonstrate substantial financial commitment by the MDD, the site can be excluded in participating in future allocation rounds for 24 months.[69]

The ability to exit a contract (albeit not without cost) means that the CfD provides a degree of real option value to developers (as does the CM agreement). The lack of a financial penalty for not proceeding to the MDD means that, compared to the CM, this option may be cheaper to exploit for CfD holders. This additional option value may be reflected in lower hurdle rates.

The rationale for the greater flexibility is likely to be due to the different purposes of the mechanisms.

- The objective of the CM is to ensure security of supply, which can be viewed as more time-critical: it needs to be ensured in each year.

[68] DECC (2014), Section 2.2.4.

[69] BEIS (2016), 'Contracts for Difference: Government Response to the Consultation on Changes to the Non-Delivery Disincentive for CFD Allocation'.

- On the other hand, the CfD is intended to help drive decarbonisation of electricity. There are no specific time-bound decarbonisation targets for the power sector (though there are overall economy-wide decarbonisation targets), meaning that government may be able to give CfD developers greater latitude in the amount and timing of capacity delivered, compared to CM participants.

That said, the timing and extent of future deployment of CfD technologies is, in some cases (i.e. to the extent that de-rating factors for CfD technologies are above zero), a crucial determinant of the volume of capacity that needs to be procured through the CM. To the extent this capacity is being relied upon to turn up, therefore, there is a case for exposing it to the same conditions for delivery as CM capacity. The current rules can therefore, in our view, be viewed as indirect support to CfD capacity with a non-zero derating factor (essentially, any CfD technology apart from solar PV).

Overall, though we do not think this indirect support is likely to be material for the technologies under consideration.

- Given the relatively high capex requirements for nuclear and CCS, even the maximum termination fee would be relatively small in relation to overall costs.[70]
- While capex requirements are lower for onshore and offshore wind, de-rating factors are also lower[71], meaning that any penalty is still likely to be small in relation to overall costs.[72] De-rating factors for solar are zero.

A.5.2 Availability incentives (performance risk)

Unlike the CM, the CfD contains no specific incentives for ensuring capacity is made available at peak times. This seems to be due the CfD being viewed as support for low-carbon generation, while the CM is viewed as support for ensuring security of electricity supplies. The penalties for non-availability in the CM are therefore aimed at ensuring this security is indeed provided.

CfD holders are instead exposed to the risk that performance issues lead to a reduction in the CfD payments received.[73] It is unclear which risk is more material. The penalties for non-availability under the CM are more severe, but the risk exposure is concentrated in stress periods.

That said, it is not clear why CfD holders should face reduced obligations to ensure availability of capacity at times of system stress. Placing the same

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[70] For example, we assume capex of approximately £1,600/kW for gas CCS commissioning in 2025. Assuming the maximum CM termination fee (£35,000/MW de-rated) is held constant in real terms, a 90% de-rating factor and a 10% probability of hitting the penalty, then the expected penalty amounts to around 0.2% of capex. The figures would be lower still for nuclear and biomass CCS, given their higher capex requirements.

[71] Equivalent firm capacities for onshore and offshore wind commissioning in 2025 are 7.5% and 14.5% respectively.

[72] For example, BEIS' 'low' assumption for capex of onshore wind commissioning in 2025 is £955/kW (2014 prices). Assuming the maximum CM termination fee (£35,000/MW de-rated) is held constant in real terms, a 7.5% de-rating factor and a 10% probability of hitting the penalty, then the expected penalty amounts to less than 0.1% of capex.

[73] Note, all technologies, regardless of the support mechanism, face the risk of a potential loss in wholesale market revenues, as well as exposure to imbalance prices.

incentives on CfD holders (at least, subject to their de-rating factor) might ensure that auctions select a mix of CfD capacity better suited to meeting Government's security of supply objectives.

If it were to be concluded that the lack of specific additional availability incentives entailed a risk transfer from CfD holders to consumers (relative to the CM), we do not think this transfer is likely to be material at present.

- Stress events are, by design, rare. It may seem that there is a certain circularity in this argument (stress events should only be rare if the CM availability incentives are effective). However, we believe that, especially following recent reforms, imbalance prices should ensure strong incentives for capacity to be available at times of stress.
- Exposure to penalties is in any case capped annually to 100 percent of revenues under the CM.
- For renewables in particular, the exposure is low. Indeed, for onshore and offshore wind, given their relatively low de-rating factors (around 10%), their obligations under the CM would effectively only account for a relatively small proportion of their overall capacity. For solar PV, the risk is non-existent: given solar PV's zero de-rating factor, investors in PV could face no obligations under the CM (though neither would they be able to earn CM payments).

A.5.3 Revenue stability: CfD mechanism

As explained above, the CfD aims to reduce wholesale price uncertainty. The operating costs of low-carbon generation are, in general, not well correlated with electricity prices. These, in turn, depend largely on the movements in fossil fuel prices and carbon prices, which are likely to be correlated with general market movements. Hence, reducing wholesale price uncertainty is likely to reduce the cost of capital faced by generators.[74]

In 2013, DECC commissioned analysis by NERA[75] looking at how the risks (including wholesale price risk) under the CfD would differ, compared to the predecessor scheme, the Renewables Obligation (under which generators were exposed to wholesale price risk). Based on that analysis, DECC calculated that, depending on the technology, the wholesale price risk reduction from the CfD could lead to a reduction in the hurdle rate of between zero and three percentage points (pre-tax real). In other words, this analysis found that the revenue stability provided by the CfD has a material impact in terms of reducing the cost of capital.

A.5.4 Backstop PPA (offtake risk)

The OLR aims to promote the availability of PPAs for renewable generators with CfDs. It provides a 'backstop' or 'last resort' PPA of a duration no longer than 12 months to generators who might not otherwise be able to find a PPA. The backstop PPA discount is set at a level intended to be larger than discounts

[74] A further crucial assumption is that the market cannot provide equivalent long-term hedging products.

[75] NERA (2013), 'Changes in Hurdle Rates for Low Carbon Generation Technologies due to the Shift from the UK Renewables Obligation to a Contracts for Difference Regime'.

expected to be offered by the market. It is currently set at £25/MWh (in 2012 prices, and indexed to inflation).

In their 2014 analysis[76] for DECC on the OLR proposals, Baringa examined two potential benefits for consumers for the OLR:

- **Benefits from greater competition in the PPA market:** In a possible state of the world in which the market for PPAs was uncompetitive, the OLR could reduce market power, reducing rents on PPA discounts and therefore costs to consumers (if CfD strike prices were determined through a competitive auction).
- **Benefits from a reduced PPA discount:** Baringa assume that the presence of the backstop PPA would reduce risks to offtakers. This is because it puts a cap on the cost to offtakers of buying themselves out of their long-term PPAs. This reduces the need for offtakers to insure themselves against very high costs of selling the power, and could therefore allow them to set lower discounts up-front.

To the extent that the OLR does indeed address a market failure (market power abuse) that is specific to renewable technologies, then this aspect of it should not be seen as an additional subsidy. The benefit arising from a reduced risk premium, however, could be viewed as indirect support for renewable technologies. That said, Baringa found this effect would be minimal given the backstop PPA discount of £25/MWh. [77]

A.5.5 Protection against changes in policy (policy risk)

The CfD contains four provisions not present in the CM agreement that aim to mitigate the risk of certain policy and regulatory changes. These include protection against:

- certain changes in law;
- changes in 'generation taxes';
- changes in certain balancing and transmission loss-related charges; and
- qualifying curtailment and shutdown events.

We consider each of these in turn, below.

Under the change in law provisions of the generic CfD, generators will be protected against '…*material and unforeseeable changes in law that uniquely target specific technologies, individual projects or CfD holders in the group*'. [78] Protection can take the form of a strike price adjustment or direct compensation. According to DECC at the time: [79]

> *'These provisions are primarily designed to address the risk that the price stability afforded by the CfD is unduly impacted by*

[76] Baringa (2014), *Cost Benefit Analysis in support of DECC's Impact Assessment of the Offtake r of Last Resort,* https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/278574/Baringa_Impact_Assessment_-_Final.pdf

[77] Baringa (2014), Section 3.3.

[78] DECC (2014a), Annex A, p. 26.

[79] DECC (2014a), Annex A, p. 26.

> *unforeseeable changes in law, regulation or industry documentation. The CfD will therefore protect generators against specific and discriminatory changes in law and for changes in law that have an unjustifiable discriminatory effect. It will not protect against other general changes in law which are considered to be usual business risks that developers already take in the existing market without compensation.'*

Our view as economists is that, the rationale of the change in law provisions is to reduce risk to investors. However, we would argue that they can be viewed simply as something that enable and reinforce the price stability benefits of the CfD to investors, and are therefore not an additional source of benefit to investors.

Similar arguments apply to the protections against changes in generation taxes and certain balancing charges and charges for transmission losses. The protections are limited to those taxes or charges that market participants would normally be able to pass through into the wholesale market price.

Since the CfD effectively fixes an overall price for the power, CfD holders, would, in the absence of these protections, be exposed to an increase in costs and consequent reduction in profits. Allowing adjustments to the CfD strike prices for changes in such charges or taxes reduces risk to investors, but can also be simply necessary for the benefits of price stability in the CfD to be preserved. [80]

The CfD also provides cover against qualifying shutdown events and curtailment.[81] These protections constitute an additional benefit for CfD holders, compared to holders of a CM agreement.

Curtailment compensation can be claimed if, as a result of a change in law, generators are curtailed by the system operator and are also prevented from being appropriately compensated for this curtailment (for example by not being allowed to place bids in the Balancing Mechanism). Presumably, the aim is to reduce generators' concern around any possible temptation for policymakers to take steps to reduce compensation for curtailment, as deployment of low marginal cost low-carbon generation increases in the future and periods of curtailment increase.

Qualifying shut-down events are those other than for the following reasons:

- Health, safety, security, environmental considerations (or any other Relevant Matters);
- the generator's own negligence or fault; or
- a State Aid decision.

In other words, this protection is intended to protect against a politically-motivated shutdown. The generator can claim compensation that would leave it as well off had the CfD been allowed to continue.

[80] DECC (2014a), Annex A, p. 28 and p.30.

[81] DECC (2014a), Annex A, p. 28 and p.29.

Both provisions are clearly aimed to avoid that generators need to price the associated risks into the strike price. They are also risks that Government is clearly better-placed to manage than investors.

However, we regard the value of these protections as being relatively insignificant for renewable generators:

- **Curtailment:** The provisions for stopping CfD payments during periods of negative pricing[82] give CfD holders unilateral incentives to reduce output at times of system-wide excess.
- **Qualifying shut-down:** We are not aware of any examples, in the UK or elsewhere within Europe, of renewable installations being shut down for political reasons.

A.6 Differences in CfD terms granted to different technologies

In this sub-section, we describe how differences in contractual arrangements affect the direct and indirect support received by offshore wind, nuclear; and CCS.

A.6.1 Offshore wind

Offshore wind farms can apply for CfDs covering up to three distinct project ‘phases’, to be delivered in consecutive years. All phases receive the same strike price. [83] This results in an increase in indirect support, compared to onshore wind and solar, as we explain further below.

As is the case for other low-carbon technologies, the cost of deploying offshore wind is expected to continue to fall over time. This means that the strike price bid in an auction of a phased offshore wind project, with its first phase commissioning in 2025, will reflect not just the costs of the phase commissioning in 2025, but an average of costs over the three phases commissioning over 2025 to 2027. We understand that in practice, there may be requirements for all phases to use the same technology. This may limit the cost reduction between phases somewhat, but may not eliminate it completely.

Most large offshore wind projects are likely to be phased. Indeed, all three projects that won support in the most recent CfD auction consisted of three phases.[84] However, other technologies (including other ‘less established’ technologies against which offshore wind currently directly competes in auctions) do not receive the same treatment, and so are not able to take into account future reductions in costs when placing an auction bid. So, other things equal, the phasing treatment gives offshore wind a competitive advantage in auctions.

[82] As a condition for EU State aid approval of the CfD scheme, DECC agreed to revise future CfD s awarded to prevent support payments in respect of any period of six or more consecutive hours during which the intermittent reference price is negative.

[83] DECC (2014), Section 2.2.7.

[84] https://www.gov.uk/government/publications/contracts-for-difference-cfd-second-allocation-round-results

The fixing of the strike price given to all phases seems mainly motivated by a desire to provide certainty[85] to investors over the level of support that will be available for the project as a whole. For example, if developers had to re-apply for support for future phases, they would price in the risk that such support may not be granted.

That said, the rationale for giving (phased) offshore wind a particular financial advantage relative to other technologies is not clear to us. It might, in theory, be possible to make adjustments that could address the issue.

A.6.2 Nuclear

In this sub-section:

- We give an overview of how the arrangements in place for new nuclear differ, compared to renewables under the generic CfD, taking the arrangements in place for HPC[86] as a starting point.
- We discuss issues that affect the direct support received by nuclear.
- We describe in more detail some of the key features of HPC arrangements affect the risks that nuclear faces, and therefore the indirect support it receives.

Overview of HPC arrangements

The National Audit Office (NAO)[87] describes the HPC deal as having four parts:

- a bespoke CfD, with a ‘baseload’ reference price, lasting for 35 years;
- a ‘funded decommissioning plan’ (FDP) under which HPC must set aside up to £7.3 billion (2016 prices) of revenue to cover the costs of decommissioning and waste management;
- a state guarantee of up to £2 billion of corporate bonds issued by HPC to finance construction; and
- a Secretary of State Investor Agreement (SoSIA), under which the Government agrees to compensate HPC if policy changes result in the shutdown of HPC.

Nuclear: Direct support

The duration of the HPC contract (35 years) is longer than that of the standard CfD duration and of the CM agreement (both 15 years). Since the social discount rate is less than the investor’s discount rate, a longer contract is likely, other things equal, to result in a higher present value of support payments by consumers.

This also means that comparisons of strike prices alone will not provide a reliable indication of the relative magnitudes of support payments by consumers over the duration of the CfD.

85 DECC (2014a), Annex A, p. 19.

86 Note: throughout this section, we use ‘HPC’ to refer to both the plant and its owners.

87 NAO (2017) ‘Report by the Comptroller and Auditor General - Department for Business, Energy & Industrial Strategy: Hinkley Point C’.

Nuclear: Indirect support

Unlike the renewable technologies considered in our analysis, nuclear receives a ‘baseload’ reference price.

As is the case for the renewables under the generic CfD, compared to the CM, the HPC CfD provides increased revenue stability and reduced exposure to construction delay risk and performance risk. Unlike renewables, however, nuclear cannot benefit from the OLR.

The arrangements in place for HPC differ further in the following respects, compared to the CM, in ways that affect revenue risk, construction risk, operating cost risk, environmental risk, decommissioning risk and policy risk:

- the duration of the CfD (35 years as opposed to 15 years);
- the presence of gain-share arrangements;
- greater flexibility on the size of the plant to be delivered;
- the presence of a state debt guarantee;
- CfD strike price reviews in the event of changes in operating expenditures (‘opex’);
- capped liability towards third parties in the event of a nuclear incident (as do new nuclear projects, in general);
- a cap on the price set by Government for radioactive waste disposal; and
- the extent and importance of the change in law provisions.

We discuss each of these issues below, after discussing the issues relating to the reference price for nuclear. Figure 25 summarises our analysis of the risks faced by nuclear under the HPC arrangements, compared to new-build generation and storage in the CM.

Figure 25 Risks faced by nuclear, compared to new-build generation and storage in the CM

Risk	Change in indirect support, compared to baseline	Significance	Explanation / Rationale
Construction	↕	Low	Partial guarantee of debt during construction – intended to make it easier to secure finance. However, offset by guarantee fee.
Construction delay	↑	Low	Developers have greater flexibility over size of project to be delivered[88] and face only loss in support (with no financial penalty) in case of non-delivery of minimum capacity requirement. Rationale likely due to lack of specific time-bound decarbonisation targets for the power sector.
Operating cost	↑	High	Adjustments in the strike price (at years 15 and 25) for certain changes in opex. Protection for longer-term opex risk only, which investors may be less well-placed to manage.
Performance	↑	Low	No specific additional incentives to make capacity available during times of system stress. Likely due to CfD and CM schemes being viewed as meeting separate objectives (although the efficiency of this choice is questionable).
Environmental	↑	High	Cap on third party liability in event of nuclear incident. Rationale is impossibility of securing insurance for uncapped liabilities.
Decommissioning	↑	High	Limits on exposure to decommission cost risk. Avoids HPC having to take on risk of unquantifiable liability.

[88] For example, HPC can still receive support if only one of the two reactors is delivered.

Risk	Change in indirect support, compared to baseline	Significance	Explanation / Rationale
Revenue	↑	High	The CfD brings the benefit of price stability (though no capacity payment). Nuclear also has a longer contract duration (35 years) and gain share arrangements. The longer duration of support for nuclear intended to reduce risk to developer further. Longer duration and gain share arrangements also may also be intended to protect consumers from 'high regret' scenarios.
Policy	↑	High	Protections against qualifying shut-down and curtailment events and certain other events largely specific to nuclear. Justification likely due to Government being better-placed than investors to manage such risks.

Source: Frontier Economics

Reference price

'Baseload' technologies (such as nuclear and biomass) are given a season-ahead or year-ahead 'baseload' reference price (i.e. a forward price representing an expectation of the time-weighted average of wholesale prices over a 6- or 12-month period). Intermittent technologies (such as wind and solar) use day-ahead hourly prices as their CfD reference price. We explain the rationale for this difference in the corresponding section under 'Generic CfD: indirect support'.

Going forward, it is expected that prices in the hours in which intermittent technologies tend to generate will be lower than the time-weighted average 'baseload' price. So, on average, the reference price for intermittent technologies will be below the time-weighted 'baseload' price.

This means that, for a given strike price level, the CfD payments expected to be made to an intermittent technology are greater than would be expected for a technology receiving a baseload reference price (such as biomass or nuclear).

Duration of CfD (revenue risk)

In addition to the effect on direct support (described above), a longer CfD duration has an impact on indirect support. A longer contract reduces uncertainty over future revenues, reducing risk. [89] This, in turn reduces the payments that consumers need to make, somewhat offsetting the impact of a longer contract on the direct support paid.

[89] According to EDF, the 35 year duration of the HPC CfD was necessary to enable the project to be financed. See EC (2014a), paragraph 255.

The longer contract may also be intended to protect consumers against 'high regret' scenarios in which electricity prices (following the initial 15 years of the CfD term) end up being far higher than initially expected.

Gain share

The HPC arrangements include the following provisions for the sharing of gains between Government and HPC.

- **Construction gain-share:** Consumers will receive half of any savings in actual construction costs against forecast up to £1 billion, and 75% of any savings above £1 billion.[90]
- **Equity gain-share:** If, at any time during the plant's lifetime, the equity Internal Rate of Return (IRR) exceeds 11.4% (nominal), the additional returns are shared in the ratio 30:70 between consumers and HPC respectively. If the return is above both 13.5% (nominal) and 11.5% (real), the gain is shared 60:40 between consumers and HPC. [91]
- **Tax re-opener:** If the amount of tax payable by HPC falls (due to changes in shareholder funding and tax structure), the strike price will be reduced or payments will be made by HPC. No increases in the strike price will be allowed. [92]

None of these provisions affect the downside risk that investors face. However, they do limit the ability of investors to capture any upside. From an investor perspective, therefore, these provisions are likely to either significantly reduce the expected return, or lead to an increase in the hurdle rate (asymmetric risk).

The net (expected) impact from the consumer perspective is, however, uncertain. On the one hand, an increase in the investor hurdle rate would lead to an increase in the strike price. On the other hand, the possibility of sharing in the gains could offset this. The magnitude of any impact would also depend on the likelihood of the gain share mechanisms being triggered.

The possibility that consumers could make a net (expected) gain may, in fact, not be the main reason for having the gains share provisions in place. Rather, they may be viewed as protecting consumers from 'high regret' scenarios in which HPC's actual returns end up being far higher than initially expected.

State credit guarantee (construction risk)

If HPC had decided to issue bonds to help finance construction[93], Government has agreed to provide an initial guarantee of this debt (up to a value of £2 billion). Under the guarantee, as a last resort, Government agrees to the timely repayment of principal and payment of interest of the debt covered.[94] In return, HPC pays an upfront fee of £10 million and an annual commitment fee of 0.25%.

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[90] NAO (2017), paragraph 1.26.

[91] NAO (2017), Figures 15 and 16.

[92] EC (2014a), 'Commission Decision of 08.10.2014 on the aid measure SA.34947 (2013/C) (ex 2013/N) which the United Kingdom is planning to implement for support to the Hinkley Point C Nuclear Power Station', C(2014) 7142 final cor, paragraph 34.

[93] HPC is now to be financed 100% by equity contributions.

[94] EC (2014a), paragraph 49.

Any draw-downs under the guarantee would result in an annual fee of 2.95%.[95] A further guarantee of up to £13.1 billion could subsequently have been made available, subject to approval.[96]

The guarantee makes it easier for the project to secure finance, since it exposes investors to fewer risks. It implies a transfer of risk from investors to taxpayers.

For HPC, at least, the credit guarantee was clearly important to securing agreement from investors on the overall package on offer. However, the precise value to the investor is difficult to quantify, once the guarantee fees are taken into account. In principle, these fees are intended to approximate a 'hypothetical market rate'.[97]

Opex re-openers (operating cost risk)

At years 15 and 25 of the CfD, the strike price may be adjusted (upwards or downwards) in line with changes in certain operational cost items (including fuel, insurance, business rates and transmission charges).[98]

The rationale for re opex re-openers is likely that, while operators are better-placed to manage opex risk in the medium-term, they are less-well placed to manage uncertainty in opex over the longer term. The re-openers for opex are therefore likely to significantly reduce risks for developers.

Third party liability

Nuclear operators in the UK are required to meet the first EUR 1200 million of third party claims arising from a nuclear incident.[99] While the UK has gone beyond the minimum cap of EUR 700 million required under international law, taxpayers are still liable for any costs above this.[100]

The liability cap therefore implies a transfer of risk[101] from investors to taxpayers. The magnitude of the risk transfer is, however, not easily quantified, since:

- Insurance is not available for uncapped liability; and
- Uncapped liability does not necessarily guarantee unlimited pay-out, since the company may become insolvent before all claims are paid.[102]

Indeed, we are not aware of any attempts by Government or the Office of Budget Responsibility to quantify its contingent liability. That said, the impact could be

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[95] NAO (2017), Footnote 28.

[96] NAO (2017), p.16.

[97] EC (2014a), paragraph 475.

[98] EC (2014a), paragraph 31. In addition, there is a one-off adjustment to the strike price for business rates once the plant commissions. See EC (2014a), paragraph 35.

[99] NAO (2017), paragraph 3.16.

[100] Part of this liability would be met by a pool financed by contributions from all signatories to the Brussels Convention in the event of an incident. The value of the pool is EUR 300 million, and UK taxpayers would also need to contribute. This funding would be used first once the EUR 1200 million limit had been reached.

[101] It should however also be noted that the nuclear liability scheme is extensive and complex. Nuclear operators must have insurance, whereas conventional operators are not legally required to do so. And, in case of a nuclear incident, nuclear operators are strictly liable: that is, there is no need to prove fault. Under normal tort law, a conventional generator could only be successfully sued for any issues if they can be shown to be at fault.

[102] DECC (2012a), 'Impact Assessment: Proposed legislation to implement the amended Paris and Brussels Conventions on 3rd party nuclear liability', IA No: DECC0037, Annex 3.

significant. For example, DECC[103] assumed that increasing the liability cap from £140 million to EUR 1200 million could lead to a 2-10x increase in the third party liability component of nuclear insurance.[104]

Decommissioning

Under the FDP, HPC must set aside revenues into a fund, to cover the expected costs of decommissioning of £7.3 billion (2016 prices). However, the NAO has noted that taxpayers are nevertheless exposed to certain risks that the arrangements may not be sufficient to cover the actual decommissioning costs that may arise, in particular the following. [105]

- Government has agreed to dispose of radioactive waste from HPC, for a fee. The fee is capped at £5.9 billion (2016 prices), to avoid HPC having to take on the risk of an unquantifiable liability. This is a conservative estimate, above the central estimate of costs of £2.9 billion. However, the figure is highly uncertain, not least because Government has not yet established an enduring solution for disposing of radioactive waste.
- If HPC's investors are unable to contribute to the FDP, the liability for any costs unmet by the fund would transfer to taxpayers.

Past experience suggests that forecasts of decommissioning costs are, however, subject to much uncertainty. The Nuclear Decommissioning Authority (NDA) makes periodic estimates of the provisions required for decommissioning retired nuclear plants in the UK. Uncertainty arises in particular from the fact that the forecasts take into account lifetime costs of decommissioning over a timeframe of more than 100 years.

In 2007, the NAO found[106] that total undiscounted NDA provision costs had increased by 30% between 2003 and 2007 from £56 billion to £73 billion. After taking into account inflation and expenditure undertaken at the sites since 2005, the NAO found that the provision had increased by 18% on a like-for-like basis.[107] Current estimates of the undiscounted provision stand at £118 billion, with a range between £97bn and £222bn.[108]

Given the magnitude of decommissioning costs, and the potential for forecasts to change significantly over time, the arrangements for decommissioning therefore imply a material transfer of risk from investors to taxpayers.

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103 DECC (2012a).

104 Another study (commissioned by the German Renewable Energy Federation) estimated that internalising the full damages associated with the probability of nuclear incidents could lead to an increase in the costs of generating nuclear power of between EUR 13.9/MWh to EUR 2360/MWh. See Versicherungsforen Leipzig (2011) 'Study: Calculating a risk-appropriate insurance premium to cover third-party liability risks that result from operation of nuclear power plants'. We have not attempted to review the robustness of these estimates, and we understand some stakeholders have called into question the study's independence.

105 NAO (2017), paragraph 3.21.

106 NAO (2008), 'The Nuclear Decommissioning Authority: Taking forward decommissioning'.

107 The main reason for these large increases was due to inclusion of items previously unaccounted for in earlier estimates such as work on Sellafield's legacy ponds and silos.

108 NDA (2017) 'Annual Report & Accounts 2016/17'. While the undiscounted figures can facilitate comparisons between years, the more meaningful metric is probably the discounted total nuclear provisioning costs. The discount rate changes periodically. Currently, the rate used is negative, meaning the central discounted value (£164 billion) is higher than the undiscounted value.

Change in law (policy risk)

The HPC CfD contains similar change in law protections to the generic CfD. However, these are a number of additional elements:[109]

- The SoSIA essentially extends the potential for compensation in the event of qualifying curtailment and shutdown events until the end of HPC's life, expected to be around 60 years following commissioning.
- The CfD and SoSIA include compensation in the event that government actions lead to HPC being unable to secure third party liability insurance cover.
- The CfD includes cover for 'specific tax changes in law', which include taxes on uranium or adverse changes in specific ways in which HPC's tax is treated by HMRC.
- The CfD includes cover for a change in regulatory approach that results in nuclear safety and environmental regulators no longer assessing risk reduction options by reference to whether the costs of implementation would be disproportionate.

In general, the protections seem intended to cover risks that are either specific to nuclear or more serious for nuclear, in view of its relatively high up-front investment costs and long lifetime, compared to other technologies. Taxpayers or consumers bear the risk that compensation may need to be paid out, but government is better placed than nuclear developers to manage these risks.

The protections are likely to be of significant value to investors. The government has estimated that compensation in the event of a political shutdown of HPC could cost up to £22 billion (2012 prices).[110] And, in contrast to renewable technologies, there are clear examples internationally of politically-motivated shut-down of nuclear plants.

For example, following the Fukushima Daiichi incident in 2011, there was an immediate review of the safety of nuclear plants in most countries with nuclear programmes.[111]

- In Japan, only 2 out of the 50 reactors were remained open one year later, while the rest were subjected to inspections, stress testing or even decommissioning.
- Germany, in 2010, had 17 reactors operating. Within days of the incident, Germany suspended operations at seven older nuclear plants (operational before 1980) and decided that another plant (temporarily offline for technical reasons) should not be restarted. In May 2011 announced its decision to completely withdraw from the use of nuclear power by 2022.
- In Switzerland, the government decided to close its five nuclear plants gradually between 2019 and 2034.

[109] EC (2014a), paragraphs 37 to 56, 74 and 75 and NAO (2017), Figure 15.

[110] NAO (2017), paragraph 3.

[111] World Energy Council (2012) 'World Energy Perspective: Nuclear Energy One Year After Fukushima'

A.6.3 Differences in assumed support for CCS

In this sub-section:

- We give an overview of how the assumed arrangements in place for CCS (gas and biomass) differ, compared to renewables under the generic CfD;
- We discuss issues that affect the direct support received by CCS.
- We describe in more detail some of the key features of the assumed arrangements affect the risks that CCS faces, and therefore the indirect support it receives.

Overview of assumed arrangements for CCS

No CCS projects have yet signed a CfD. ETI has summarised the key aspects of the arrangements we should assume are in place for new CCS, for the purposes of our analysis:

- a bespoke CfD, with a 'baseload' reference price, lasting for 15 years (ETI has also asked us to consider a possible CfD duration of 25 years);
- a 'funded decommissioning plan' (or similar);
- a state guarantee for project debt; and
- a 'future liability fund' (or similar) under which CCS must set aside revenues to cover the costs of a potential.

CCS: direct support

As with nuclear, if a contract longer than 15 years is considered for CCS, this will result in a higher present value of support payments made by consumers.

CCS: indirect support

As is the case for the generic CfD, compared to the CM, the CCS CfD provides increased revenue stability on the one hand and reduced exposure to construction delay risk and performance risk. Unlike renewables, CCS cannot benefit from the OLR.

The assumed arrangements in place for CCS differ further in the following respects, compared to the CM, in ways that affect revenue risk, construction risk, operating cost risk, environmental risk, decommissioning risk and policy risk:

- the duration of the CfD (in addition to the generic duration of 15 years, we consider a variant with a 25 year CfD);
- the presence of gain-share arrangements;
- the presence of a state debt guarantee;
- periodic CfD Strike price re-basing in line with movements in fuel prices;
- the risk of a reduction in support if CO_2 capture levels fall below a given percentage;
- capped liability in the event of a CO_2 leakage; and
- the extensiveness and importance of the change in law provisions.

We discuss each of these issues below. Figure 26 summarises our analysis of the risks faced by CCS under the assumed arrangements, compared to new-build generation and storage in the CM.

Figure 26 Risks faced by CCS, compared to new-build generation and storage in the CM

Risk	Change in indirect support, compared to baseline	Significance	Explanation / Rationale
Construction	↕	Low	Partial guarantee of debt during construction – intended to make it easier to secure finance. However, offset by guarantee fee.
Construction delay	↑	Low	Assuming similar arrangements to generic CfD, developers have greater flexibility over size of project to be delivered and face only loss in support (with no financial penalty) in case of non-delivery of minimum capacity requirement. Rationale likely due to lack of specific time-bound decarbonisation targets for the power sector.
Operating cost	↑	High	Adjustments in the strike price for changes in fuel prices. Risk for investors may in some situations increase, compared to not having a CfD, if this indexation were not provided.
Performance	↑	Low	No specific additional incentives to make capacity available during times of system stress. Likely due to CfD and CM schemes being viewed as meeting separate objectives (although the efficiency of this choice is questionable). Loss in support if reduction in percentage of CO_2 emissions captured to below 90%. Increases risk, but does not involve any obvious support (direct or indirect).
Environmental	↑	Low	Cap on third party liability in event of CO_2 leakage. Rationale is impossibility of securing insurance for uncapped liabilities. Risk assessed as low in view of low probability of leakage, assuming robust regulatory regime and well-selected storage site.

Risk	Change in indirect support, compared to baseline	Significance	Explanation / Rationale
Decommissioning	↑	Unclear	Potential limits on exposure to decommission cost risk. Avoids CCS having to take on risk of unquantifiable liability.
Revenue	↑	High	The CfD brings the benefit of price stability (though no capacity payment). CCS also has a longer contract duration (25 years) and gain share arrangements. The longer duration of support for nuclear intended to reduce risk to developer further. Longer duration and gain share arrangements also may also be intended to protect consumers from 'high regret' scenarios.
Policy	↑	Unclear	Protections against qualifying shut-down and curtailment events and certain other events. Government better-placed than investors to manage such risks.

Source: Frontier Economics

Duration of CfD (revenue risk)

As discussed above for nuclear, a longer CfD duration reduces uncertainty over future revenues, somewhat offsetting the impact of a longer contract on the direct support paid.

Gain share

The assumed arrangements in place include the following provisions for the sharing of gains between Government and CCS:

- **Equity gain-share:** Gain share arrangements based on equity returns, where exceed agreed ROE.
- **Tax re-opener:** Provision to adjust in respect tax payable and in respect of way venture is structured and financed (we assume that, as is the case for HPC, that this can only lead to a reduction in the strike price).

As above, for HPC, such provisions are likely to either significantly reduce the expected return, or lead to an increase in the hurdle rate (asymmetric risk) for in investors. The net (expected) impact from the consumer perspective is, however, uncertain. On the one hand, an increase in the investor hurdle rate would lead to an increase in the strike price. On the other hand, the possibility of sharing in the gains could offset this.

State credit guarantee (construction risk)

As above for HPC, the precise impact on the CCS investor is difficult to ascertain, once the guarantee fees are taken into account.

Fuel price indexation (operating cost risk)

Particularly in the case of gas CCS, fuel and wholesale electricity prices may be positively correlated. A CfD stabilising the electricity price could therefore lead to increased volatility in profits, rather than reduced volatility.

Indexing the strike price with movements in fuel prices simply corrects this, preserving the original intent of the CfD. A further rationale for this provision is that, as is the case with electricity prices, investors may find it difficult to hedge fuel prices over the longer term.

Target CO_2 capture rate (Performance risk)

CfD payments are assumed to be made on all metered output. However, when the CO_2 capture rate falls below 90%, each 1% drop is assumed to be reflected in the CfD applying to 1% less output.

This is similar to provisions in the generic CfD that ensure that payments are only made on qualifying renewable output, and is presumably intended to incentivise the effectiveness of CCS technology in the first place.

Potentially, though we assume a 95% capture rate for CCS, this provision may still entail a particular risk to CCS, given the relative novelty of the technology. Different designs of the CO_2 capture threshold (e.g. different thresholds or different rates at which support is withdrawn) are possible. However, it is difficult to judge whether the proposed design would involve indirect support to CCS or whether it would penalise CCS, relative to other technologies.

Capped CO_2 liability (Environmental risk)

A leak of CO_2 from storage would pose a clear risk to the environment. To the extent the CO_2 price faced by investors in the event of a leak reflects the value of CO_2 abatement to society, this should translate into a financial risk to the investor. In addition, there could be negative impacts on human or animal health.[112]

Capping the liability therefore implies a transfer of risk from investors to taxpayers. Investors may be unable to secure full commercial insurance for uncapped liabilities (given the limited experience with CCS in GB). The rationale for this risk transfer is presumably to avoid that investors need to quantify this risk into the support they require.

In a review of studies on the topic, Pop (2015) observed the following:

> *'Numerous commentators emphasise that both the likelihood and magnitude of potential leakage can be considered minor and should not be overstated. A frequently quoted Intergovernmental Panel on Climate Change ('IPCC') estimate states that the quantity of CO2 escaping from rigorously selected storage sites will remain below 1%. This is 'very likely' for the first hundred years and 'likely' over the first thousand years. A properly selected and competently managed storage*

[112] Pop, Anda (2015), 'The EU Legal Liability Framework for Carbon Capture and Storage: Managing the Risk of Leakage While Encouraging Investment', p.38.

> *site could experience a level of leakage that is 'much less than 0.1 per cent in even 1 million years'.* [113]

A paper by Imperial College researchers also considered that '…*a robust permitting process … would minimize the likelihood of leakage to virtually zero*'.[114]

In view of this, we consider the size of the risk transfer is likely to be small.

Decommissioning

To the extent that CCS's liability for decommissioning costs is capped, this implies a transfer of risk from investors to taxpayers (or consumers). Given that there have been no CCS projects in GB, it is not possible to assess the scale of the risk.

Change in law (policy risk)

The assumed CCS CfD contains similar change in law protections to the generic CfD. Compensation is also available in the event that government actions lead to CCS being unable to secure commercial insurance cover. Again, however, it is difficult to assess the materiality of these provisions for CCS.

A.7 Summary

Figure 27 highlights the significant differences in indirect and direct support we have identified in the preceding analysis. The arrows indicate the impact on support granted by consumers. An upward arrow (↑) indicates that the provision in question implies additional direct or indirect support provided by consumers, compared to the baseline (and vice versa for a downward arrow).

[113] Pop (2015), p.37.

[114] Makuch, Z., S. Georgieva and B. Oraee-Mirzamani, 'On the Need for Synergistic Regulatory and Financial Parameters for Carbon Capture and Storage'.

Figure 27 Summary of key differences in direct and indirect support received, compared to baseline

	DSR	Onshore wind / Solar PV	Offshore wind	Nuclear	CCS (gas and biomass)	Interconnector
Direct						
Duration of support	↓			↑	↑	↑
Indirect (unpriced externalities)						
Carbon costs	↕	↓	↓	↓	↓	↕
Adequacy impacts		↑	↑	↑	↑	
Incremental network costs	↕	↕	↕	↕	↕	↑
Indirect (high-level support mechanism)						
CfD (revenue risk)		↑	↑	↑	↑	
Cap and floor (construction risk)						↑
Cap and floor (performance risk)						↓
Cap and floor (revenue risk)						↑
Indirect (differences in contractual terms)						
Intermittent CfD reference price		↑	↑			
Single strike price for all phases (offshore wind)			↑			
Protections for changes in opex				↑	↑	
Limits on environmental liabilities	-	-	-	↑		-
Limited decommissioning risk	-	-	-	↑		
Duration of support (impact on revenue risk)				↑	↑	
Change in law provisions (policy risk)				↑		

Source: Frontier Economics.

In Annex B, we go on to quantify the impacts of all differences summarised in Figure 27 above.

ANNEX B DETAILED MODELLING APPROACH

In this section, we set out our approach to quantifying the direct and indirect support granted to technologies. As described in Section 2 we undertake this quantification by comparing the direct support a given technology receives under current arrangements with the direct support the technology would require if it only received CM support.

- We first summarise our overall approach.
- We then explain the assumptions underlying our estimates of the direct support received by technologies commissioning in 2025, based on current contractual and regulatory arrangements.
- Finally, we explain our approach to quantifying the impact of the key differences (as summarised in Section A.7) on the support received.

B.1 Summary of overall approach

Overall, we proceed as follows:

- As a starting point, we estimate the present value of direct support payments required ('support gap')[115] to bring new-build capacity forward in 2025, based on current market and policy arrangements. We do so based on existing estimates of technology costs and costs of capital, and EnVision modelling of revenues (given our projected capacity mix and demand).
- We then assume that carbon, network and generation adequacy impacts are fully priced in.
- For each technology, we amend assumptions on costs of capital, costs or revenues as appropriate, to reflect the terms they would get under a generic CfD and (subsequently) the CM.
- Based on these revised assumptions, we re-calculate the 'support gap' for each technology.

At each stage, we convert the support required using two key metrics.

- The first metric is the **CfD strike price equivalent (£/MWh)**. This metric measures the total revenue required by investors per MWh of power produced over the duration of the contract.
- The second metric is the **(net) support (£/MWh)**. Although not frequently used by stakeholders, we feel that this metric gives a better indication of the social value of support given, (as it uses the social discount rate to value differences in the timing of support payments made).

We explain below in more detail:

- How we estimate the 'support gap'; and

[115] The support gap could end up being negative, if market revenues are more than sufficient to cover costs.

- How we convert this to the two key metrics set out above.

B.1.1 Estimating the support gap

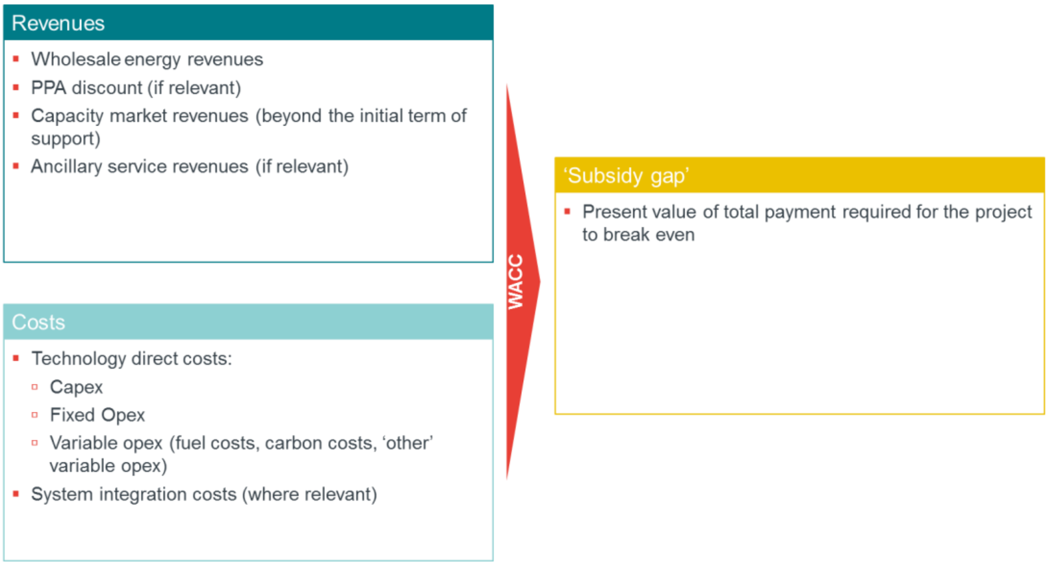
When calculating the support gap, we take an approach similar to that that used by BEIS to calculate administrative strike prices for the CfD.[116]

We first calculate the present value of technology direct costs for technologies commissioning in 2025. We do so from the perspective of the investor (i.e. based on the technology-specific hurdle rate), over the lifetime of the investment.

We then calculate the present value of market revenues (i.e. before revenues from support schemes), also at investor hurdle rates. We subtract the present value of market revenues[117] from the present value of costs to calculate the support gap.

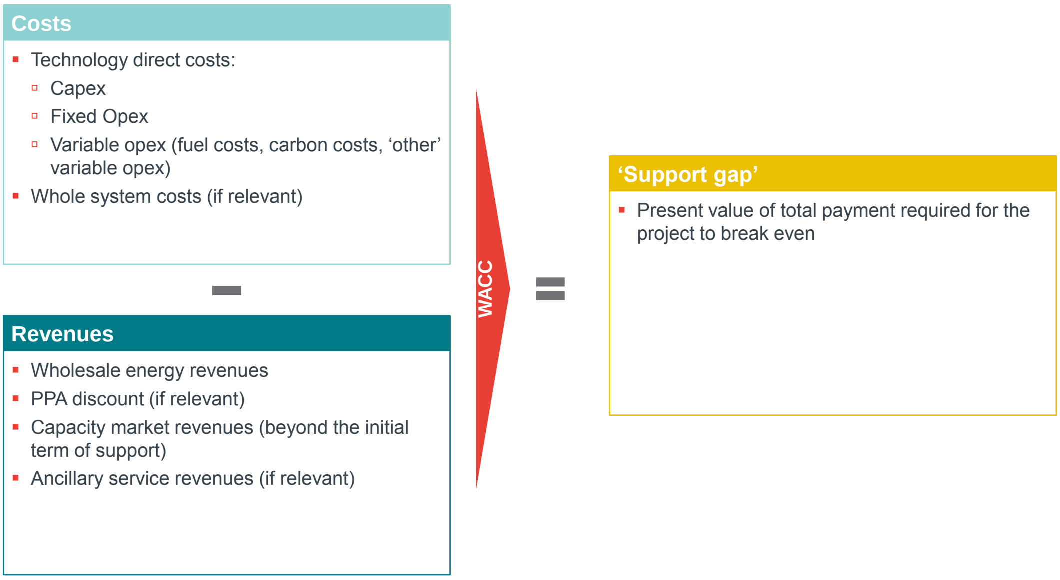
Figure 28 summarises this process.

Figure 28 Calculating the support gap



[116] BEIS (2016a), 'Contracts for Difference: An explanation of the methodology used to set administrative CFD strike prices for the next CFD allocation round'

[117] Note that, in our calculations of costs and revenues, we assume perfect foresight on the part of investors, i.e. we assume they can 'see' the projected profile of fuel, carbon and electricity prices in their entirety.



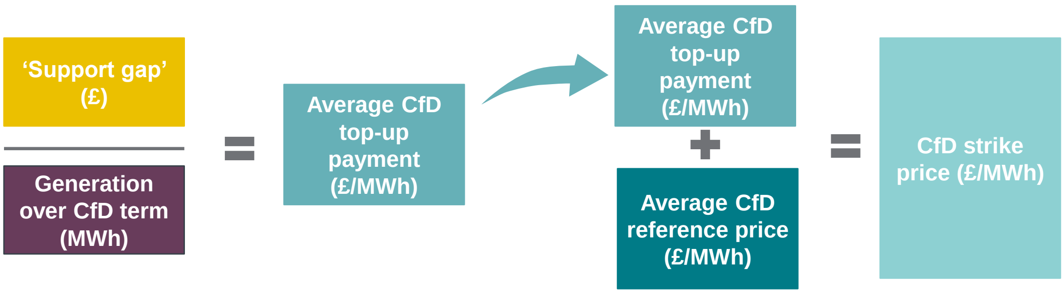
Source: Frontier Economics.

B.1.2 Conversion to key metrics

CfD strike price equivalent

We convert the support gap into an average amount of support per MWh of generation over the assumed CfD term, by dividing by the present value of generation during the CfD. We add this figure to the average CfD reference price (note: this may be different to the average price captured by the technology from the market) to estimate the strike price equivalent in £/MWh (Figure 29).

Figure 29 Calculation of CfD strike price equivalent



Source: Frontier Economics

Net cost to consumer (societal perspective)

- Finally, based on the calculated strike price, we calculate our measure of the net present value of (CfD) consumer support payments from a societal perspective, in £/MWh in the following steps.
- We calculate the profile of support payments over time (i.e. annual CfD payments, calculated as the difference between strike price and reference price);
- We calculate the present value of the profile of the resulting flow of (net) support payments at the social discount rate; and

- We divide the present value of support payments by present value of lifetime generation, also calculated using the social discount rate.
- This analysis can give us a sense of the relative importance of the differences in treatment given to different technologies. It also provides a framework for considering how these differences can be controlled for, if technologies are made to compete for support against each other.

The estimates of the impacts of various differences on the support required are sensitive to assumptions. However, the benchmarks for carrying out this kind of analysis are scarce. In preparing our analysis, we have had to make certain (in some cases subjective) judgements regarding our choice of assumptions. The estimates presented in this paper should therefore be seen as illustrative.

B.2 Assumptions used in estimating cost of direct support based on current arrangements

Our assumptions for costs are based on the following:

- **Technology capital and operating expenditures ('Assumptions' tab of Excel tool):**
  - onshore wind and solar PV: BEIS 2016 'low' technology cost assumptions;[118]
  - offshore wind: capex has been adjusted from BEIS assumptions to be consistent with the clearing strike price of £57.50/MWh (2012 prices) set for projects delivering in 2022/23 in the auction for 'less established technologies' (including offshore wind) that concluded in September 2017;[119]
  - CCGT, OCGT, nuclear: Baringa assumptions for ETI ;
  - storage (Li-ion battery): ETI
  - gas CCS: ETI assumptions on costs for a full-chain CCS project;
  - biomass CCS: The difference between Baringa and ETI cost assumptions for gas CCS has been added to the assumed Baringa costs for biomass CCS;
  - interconnectors: Capex assumed to be equal to that of Britned (£500m per 1GW of cable);
- **Load factors ('Main envision outputs' tab of Excel tool):** from the outputs of EnVision modelling;
- **Fuel prices ('Assumptions' tab of Excel tool):**
  - Natural Gas: BEIS 'central' values;[120]
  - Biomass and uranium: BEIS 'central' values; [121]
- **Carbon prices ('Assumptions' tab of Excel tool):** BEIS 'central' values for modelling purposes, plus carbon price support (CPS) rates; [122]

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118 BEIS (2016b), 'Electricity generation costs'.

119 https://www.gov.uk/government/publications/contracts-for-difference-cfd-second-allocation-round-results

120 BEIS (2016c) 'BEIS 2016 Fossil fuel price assumptions'

121 BEIS (2016b), Table 20.

- **Incremental network costs to society ('Incremental network costs' tab of Excel tool):** from the outputs of EnVision modelling;
- **Network charges paid ('Assumptions' and 'TNUoS' tabs of Excel tool):**
  - National Grid Forecast Of TNUoS Tariffs for 2022/23 (dated November 2017);
  - (for solar only) estimated DUoS charges for EHV-connected solar PV in the WPD South-Western region; and
- **Hurdle rates ('Assumptions' tab of Excel tool):** BEIS technology-specific hurdle rates. [123]

We include the following components in our estimate of 'market' revenues, based on EnVision modelling outputs **('Main envision outputs' tab of Excel tool)**:

- Wholesale energy revenues;[124]
- Capacity market revenues (if relevant); and
- Ancillary service revenues (if relevant).

B.3 Approach to quantifying impact of contractual, regulatory and policy differences on support received

We quantify, in turn, the following groups of differences in the way that technologies are supported:

- Unpriced externalities:
  - carbon costs (all technologies);
  - adequacy impacts (CfD technologies); and
  - incremental network costs (all technologies).
- Differences between CfD technologies:
  - duration of support;
  - single strike price for all phases (offshore wind);
  - protections for changes in operating costs (nuclear);
  - limits on environmental liabilities (nuclear);
  - limits on decommissioning risk (nuclear);
  - change in law provisions (nuclear);
- The high level support mechanism:
  - the generic CfD itself (for low carbon technologies); and

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122 BEIS (2017), 'Updated short-term traded carbon values used for modelling purposes'. CPS is set at £18/tCO2 until 2019/20 and at £18/tCO2 uprated with inflation in 2020/21 in line with recent government announcements. For the purposes of modelling we have assumed that the total carbon price after 2020/21 remains constant in real terms. However, the projected EU ETS price exceeds the total carbon price from the mid-2020s. As a result we assume that from the point where the EU ETS price exceeds the total carbon price and till 2030, the carbon price faced by the gas and coal sectors coincides with the EU ETS price.

123 BEIS (2016b), Annex 3.

124 We consider wholesale revenues net of assumed PPA discount for offshore wind (5%) and onshore wind and solar (10%). The figures for offshore and offshore wind are based on National Grid (2013) 'EMR analytical report', p.57. The PPA discount for solar has been assumed to be equal to that for onshore wind.

- cap and floor (interconnectors).

We explain our approach to quantification below.

B.3.1 Unpriced externalities

Carbon (all technologies)

We estimate the changes in revenues and costs that would arise, if generators faced the appraisal value of carbon instead of the price assumed in EnVision modelling. We estimate the increase in variable costs as the product of the increase in carbon price and the technology's carbon intensity of generation.

We estimate the increase in revenues as the product of the increase in carbon price and the average grid marginal emissions factor, estimated in the EnVision modelling. This in effect assumes that a change in the assumed carbon price has no impact on the merit order and the resulting dispatch pattern (with knock-on impacts on wholesale prices). While our approach in therefore involves somewhat of a simplification, it provides a reasonable estimate of the first-order impact of a change in carbon price.

Adequacy impacts

To ensure any generation adequacy benefits of low-carbon technologies are recognised, we add the capacity payment the technology could hypothetically receive (based on their assumed de-rating factor[125]) to the estimated market revenues, before estimating the support gap. This ensures that the support gap reflects only the additional support needed, in excess of revenues that reflect the generation adequacy benefits the technology may bring to the system.

We also account for the potential reduction in hurdle rate from receipt of the CM payment.

Based on the same 2014 Frontier analysis cited above in section A.3.2, we estimate a mid-point risk premium of 1.6% (post-tax, nominal) for wholesale market revenues, compared to a capacity payment. We convert this to a pre-tax real figure for each technology, based on effective tax rates assumed by DECC/BEIS[126] and assuming inflation of 2% (consistent with the Bank of England inflation target for the Consumer Price Index (CPI)).

We then calculate the share of total revenues derived from the CM payment. The reduction in the hurdle rate from receiving the required support in the form of a capacity payment is calculated as this percentage, multiplied by the risk premium.

The resulting reduction in hurdle rate is shown in Figure 30 below.

[125] See 'Assumptions' tab of the Excel tool.

[126] DECC (2013a), 'Electricity generation costs, Table 15. Source for nuclear: BEIS (2016b), Annex 3. Coal CCS ETR used for biomass CCS.

Figure 30 WACC decrease from gain of CM payment

	Onshore wind	Offshore wind	Solar	Nuclear	CCGT CCS	Biomass CCS
WACC decrease from gain of capacity payment	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%

Source: Frontier Economics. See 'WACC adjustments' tab of the Excel tool for calculations.

Incremental network costs (all technologies)

As discussed above, investors may pay or less than the full cost to society of incremental network reinforcement that arises from deployment of their technology.

As a proxy for this impact, we value this indirect support by calculating the additional support investors would require, if they were to bear the full cost. We use the results of EnVision modelling for our estimate of the full incremental network costs to society. That said, the precise results arising from this analysis should be interpreted with care, given the uncertainty around these estimates, and simplifications made in the modelling.

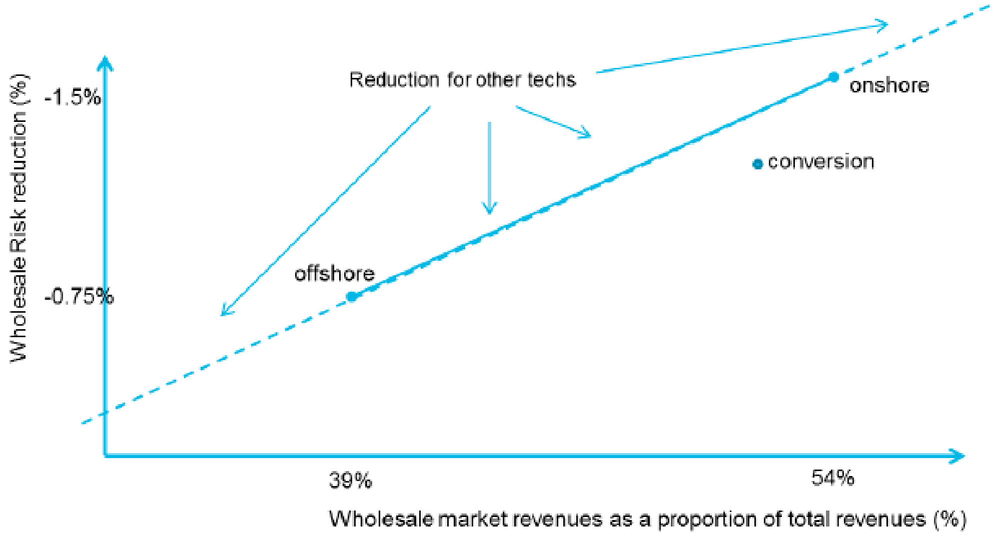
B.3.2 The high level support mechanism

The generic CfD

We calculate the increase in the hurdle rate from low-carbon technologies losing the CfD's protection against wholesale market risk.

We use an approach used previously by DECC in 2013 for setting administrative strike prices under the CfD. NERA (2013) had estimated the impact of the CfD (compared to the RO) on reducing wholesale market risk for offshore wind (0.75 percentage point reduction in hurdle rate) and onshore wind (0.5 percentage point reduction). Based on this, DECC derived hurdle rate reductions from the CfD for other technologies, based on the percentage of total revenues made up of wholesale market revenues (Figure 31).

Figure 31 Illustration of method for determining the 'wholesale market risk' element of total hurdle rate adjustments for renewable technologies under CfDs



Source: DECC (2013) 'EMR Delivery Plan', Annex H, Figure 1.

The method is simplistic, but can be used to derive indicative estimates of exposure to wholesale market risk for the technologies considered, as shown in Figure 32 below. This takes into account EnVision modelling of wholesale market revenues and the technology direct cost assumptions summarised above.

Figure 32 WACC increase from loss of CfD

	Onshore wind	Offshore wind	Solar	Nuclear	CCGT CCS	Biomass CCS
WACC increase from loss of CfD	3.8%	3.8%	3.8%	2.9%	2.5%	2.2%

Source: Frontier Economics. See 'WACC adjustments' tab of the Excel tool for calculations.

Given the proposal for the CCS CfD to include fuel price indexation, the CCS stabilises not overall wholesale market revenues, but rather wholesale market revenues, net of fuel costs. We take account of this in our estimation by netting off fuel costs from wholesale revenues and total revenues. This allows us to estimate the increase in hurdle rate from the loss in CfD based on the share of wholesale revenues net of fuel costs.

The estimates in Figure 32 are higher for those technologies with lower capex requirements (onshore wind, offshore wind and solar), since wholesale revenues make up a greater proportion of total revenues. They are lowest for CCS, given their higher capex and lower proportion of net revenues being stabilised by the CfD.

Cap and floor (interconnectors)

We assume, for illustrative purposes, that the hurdle rate under the cap and floor regime is equal to 6.5% (pre-tax real), similar to the baseline hurdle rate (under the CfD) that we assume for onshore wind (6.7%). On the one hand, interconnectors face a higher degree of merchant revenue risk exposure under the cap and floor regime (compared to onshore wind under the CfD and slightly higher performance risk. On the other hand, interconnectors face lower construction risk.

We assume that the level of the floor is set at an (assumed) cost of debt of 4.0%, and that the cap is set at an assumed cost of equity of 10.0%.[127]

Rather than look at the value of individual differences within the cap and floor regime to investors, we consider their impact as a package. That is, we compare the hurdle rate for investing under the cap and floor regime to that of a merchant interconnector participating in the CM only. We assume, for illustrative purposes, that the resulting increase in construction and revenue risk amounts to an additional 1 percentage point (pre-tax real) for the hurdle rate.[128]

This is lower than the impact of the loss of the CfD on the hurdle rate for low-carbon technologies, and reflects the fact that the cap and floor does not mitigate risk in the same way as a CfD, since interconnectors are exposed to a relatively high degree of merchant risk within the cap and floor. Differences between CfD technologies

Duration of support (nuclear and CCS)

A longer contract will affect required support in two ways that offset each other to some degree:

- Spreading support payments over a longer period will reduce the strike price required (since the required support can be earned over a longer period). A further reduction arises due to the extension of wholesale market risk reduction beyond the 15 year period of a generic CfD.
- Support payments are calculated taking the investor's discount rate into account. Since the social discount rate is less than the investor's discount rate, a longer contract will, other things equal, result in a higher present value of support payments by consumers.

To calculate the risk reduction element, we apportion the estimates of wholesale market risk reduction arising from the CfD set out in Section B.3.2 above between the initial 15 year period and the subsequent period of the CfD, based on the two periods' respective shares in the present value of total revenues earned under the CfD.

Because of the discounting effect, the initial 15 year period accounts for the bulk of the wholesale market risk reduction. The estimated WACC reductions arising from a longer contract are 1.1 percentage points for nuclear, and 0.5 percentage points for both gas CCS and biomass CCS. [129]

[127] Assuming a 20% corporation tax rate, and a debt:equity ratio of 70:30, this results in the pre-tax WACC estimate of 6.5%.

[128] This assumption can be adjusted in the 'WACC adjustments' tab of the Excel tool.

[129] See 'WACC adjustments' tab of the Excel tool for calculations.

Choice of reference price (intermittent)

Nuclear and CCS technologies are assumed to be given an average baseload reference price in their CfD, while intermittent technologies are given an hourly reference price.

This means the average reference price for intermittent CfDs will be close to the average wholesale price they achieve on the market. If the average price 'captured' is lower than the baseload price then, assuming the support gap is unchanged, the CfD strike price would be lower.

We calculate the impact on the CfD strike price of substituting the intermittent reference price (which we assume equal to the average price captured) with the baseload reference price, effectively bringing intermittent low-carbon generation in line with nuclear and CCS.

Single strike price for all phases (offshore wind)

We aim to estimate the impact of treating the first phase of an offshore wind farm as a standalone project on support required.

Recent auction results in GB (and elsewhere in Europe) indicate that the costs of offshore wind have fallen rapidly in recent years. However, it is difficult to draw clear inferences from these on the relationship between costs of different phases of an offshore wind farm.

As such, we proxy for the impact by assuming an illustrative 5% uplift[130] in capex for the first phase of the wind farm, compared to the average of all three phases. This is broadly in line with observed cost reductions for offshore wind:

- The Offshore Renewable Energy Catapult and the Offshore Wind Programme Board estimated a 32% reduction in levelised costs for offshore wind over 2010/11 to 2015/16.[131]
- This translates into roughly a 7% reduction in costs annually over the period, and was driven in large part by reductions in capex (through increases in turbine ratings) as well as reductions in the hurdle rate.

Protections for changes in operating costs (nuclear)

Under the HPC CfD, the investor bears the risk of changes in opex during the initial 15 year period but is protected for changes following this period. This protection therefore can be expected to lead to a reduction in the hurdle rate. Removing this protection should result in an increase in both the strike price and direct support required for nuclear.

Historical volatility in GB opex for the existing nuclear fleet may give a sense as to the magnitude of the risks going forward for new nuclear. We have compared the volatility in historical nuclear opex (from the financial statements of British Energy and its successor companies) to historical electricity price volatility. We calculate that opex volatility is roughly 40% of wholesale price volatility.

We scale the cost of capital benefit (arising from increased revenue certainty) from a longer contract (see section B.3.2) by this percentage to arrive at an

130 This assumption can be adjusted in the 'Control Panel' tab of the Excel tool.

131 ORE Catapult and OWPB (2017), 'Cost Reduction Monitoring Framework 2016'.

estimate of 0.4 percentage points for the cost of capital reduction from the opex re-openers for nuclear. [132]

Fuel price indexation for CCS is considered as part of the impact of the CfD on reducing wholesale market risk (section B.3.2).

Limits on environmental liabilities (nuclear)

As discussed in section A.6, the impact of uncapped liability for third party claims on the costs of nuclear power is highly uncertain. We consider the impact on the strike price and consumer support required of an illustrative doubling[133] in third party insurance costs for nuclear (although there is the flexibility for users to change this within the accompanying Excel tool).

Based on DECC estimates, we assume that the baseline level of third party-related insurance costs (assumed to be already included in our assumption on fixed operating costs) for nuclear is £16,800/MW/year (2016 prices). [134]

Limits on decommissioning risk (nuclear)

We consider the impact on the strike price and consumer support required of an illustrative 20% increase in the capped waste management fee of £5.9 billion (2016 prices) offered to HPC. This translates into an increase in costs at the decommissioning date of £370,000/MW. [135]

Change in law provisions (nuclear)

We consider the impact on the strike price and consumer support required of political shut-down cover in the HPC arrangements. Specifically, we consider investors having to price in an illustrative one percent expected probability of complete shut down following 15 years[136] of operation (though there is flexibility for the user to change these assumptions in the accompanying Excel tool).

[132] See 'WACC adjustments' tab of the Excel tool for calculations.

[133] This assumption can be adjusted in the 'Control Panel' tab of the Excel tool.

[134] See 'Assumptions' sheet of Excel tool. Based on DECC (2012a). DECC assumed total insurance costs of £10,000/MW/year (2011 prices), before implementation of the Paris and Brussels conventions, which resulted in an increase in the liability cap. Of this figure, DECC assumed 20% related to third party insurance costs. Consistent with DECC, we have assumed that a 7.5 times increase of third party insurance costs following Paris and Brussels implementation (the average increase calculated by DECC based on stakeholder responses).

[135] This assumption can be adjusted in the 'Control Panel' tab of the Excel tool.

[136] Both of these assumptions can be adjusted in the 'Control Panel' tab of the Excel tool.

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